MANITOBA HYDRO

2019/20 ELECTRIC RATE APPLICATION

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MANITOBA HYDRO

2019/20 ELECTRIC RATE APPLICATION

1.0 OVERVIEW AND REASONS FOR THE REQUESTED RATE INCREASE

On May 5, 2017, Manitoba Hydro filed a comprehensive 2017/18 & 2018/19 General Rate Application ("GRA") with the Public Utilities Board of Manitoba ("PUB") and a lengthy and extensive review of Manitoba Hydro's operations, forecasts, financial plans, capital expenditures, and operating expenses was conducted over the course of nine months. Following its review, the PUB issued Order 59/18, dated May 1, 2018, which approved a 3.6% average electric rate increase effective June 1, 2018. Order 59/18 also contained a number of directives and recommendations requiring work to be undertaken and completed by Manitoba Hydro prior to filing its next GRA.

With the appointment of a new Manitoba Hydro-Electric Board ("MHEB"), a comprehensive review of Manitoba Hydro's operations, forecasts and financial plans is currently being undertaken to allow the MHEB to establish a long-term financial plan for the Corporation. As a result of the foregoing, and further to Manitoba Hydro's correspondence of November 12, 2018 and the PUB's correspondence of November 21, 2018, Manitoba Hydro is submitting to the PUB a one-year rate increase application for the 2019/20 fiscal year which is based on financial information currently approved by the MHEB for the 2018/19 and 2019/20 fiscal years as set forth in its letter of November 12, 2018. Upon the MHEB's development and approval of a long-term financial plan, Manitoba Hydro will submit a full GRA to the PUB, anticipated to be filed in late 2019. A fulsome review of Manitoba Hydro's responses to those directives contained in Order 59/18 which the PUB indicated in its November 21, 2018 correspondence would be deferred, will also be addressed as part of the next GRA.

In this Application, Manitoba Hydro is requesting an Order pursuant to section 25(1) of *The Crown Corporations Governance and Accountability Act* for final approval of a 3.5% rate increase for all customer classes to be effective April 1, 2019. As shown in Appendix 1, page 1, this increase is projected to generate additional revenues of $59

million and would result in a modest contribution to financial reserves (net income) of $31 million in 2019/20. Absent the proposed rate increase for 2019/20, Manitoba Hydro is projecting a net loss of $28 million from Electric operations based on current assumptions.

As noted by the PUB in Order 59/18 (page 173):

> *The Integrated Financial Forecast filed in the proceeding as Manitoba Hydro Exhibit 93 supports the Board's decision on the level of the overall rate increase. This financial scenario included: continued deferral of $20 million in ineligible overheads, amortized at a 30-year rate; Average Service Life depreciation methodology, without amortization of the difference with the Equal Life Group methodology; achievement of a 25% equity level over a longer period of time, specifically by 2035/36; and debt management based on a weighted average term to maturity of 12 years. In many respects, and as a departure from Manitoba Hydro's plan and Integrated Financial Forecast assumptions, Manitoba Hydro Exhibit 93 is therefore reflective of many of the Board's decisions in this Order.*

Considering the MHEB is undertaking a comprehensive review of Manitoba Hydro's operations, forecasts and financial plans to allow for the establishment of a long-term financial plan for the Corporation, for purposes of its rate request for the 2019/20 fiscal year, Manitoba Hydro has noted the PUB's comment regarding Manitoba Hydro Exhibit 93 from the 2017/18 & 2018/19 GRA ("Exhibit 93") and prepared the current Application utilizing a comparison to Exhibit 93.

Since Order 59/18 was issued, Manitoba Hydro's cumulative earnings (actual and projected) over the three year period 2017/18 to 2019/20 have deteriorated by nearly $200 million compared to Exhibit 93 as shown in the following Figure 1.1.

Figure 1.1: Comparison of Actual and Projected Net Income to Exhibit 93

(In Millions of Dollars)

	2017/18	2018/19	2019/20	Total
Actual & Projected Net Income	18 [1]	51 [2]	31 [3]	100
Exhibit 93 Net Income [4]	94	143	61	298
Increase/(Decrease)	(75)	(93)	(30)	(198)

[1] 2017/18 Actual net income (Section 2.1)

[2] 2018/19 Financial Outlook (Section 2.3)

[3] 2019/20 Interim Budget including 3.5% proposed rate increase (Section 2.4)

[4] Includes a projected 3.57% rate increase

Actual net income results for 2017/18 were lower than anticipated in Exhibit 93 mainly due to lower export prices, the impact of U.S. transmission outages which led to lower volumes and a higher proportion of off peak sales at lower prices, as well as higher net finance costs.

The outlook for 2018/19 net income is also much lower compared to Exhibit 93 which is primarily attributable to lower net export revenues as a result of below average water conditions impacting generation, as well as increases in depreciation and financing costs arising from the earlier than planned in-service of Bipole III, which went into service July 4, 2018 compared to a budgeted in-service date of July 31, 2018.

Exhibit 93 projected net income of $61 million for electric operations for the 2019/20 fiscal year. In comparison, the 2019/20 Interim Budget, which includes the proposed 3.5% rate increase requested in this application, projects net income of $31 million. The deterioration in projected net income for electric operations is mainly attributable to higher net financing costs. Exhibit 93 had assumed that Manitoba Hydro could take advantage of lower interest costs on debt issues with shorter terms to maturity. Since the 2017/18 & 2018/19 GRA, the interest rate yield curve has continued to flatten and the savings expected from shorter term borrowings are no longer available.

In the absence of the proposed 3.5% rate increase, a net loss of $28 million would be projected in 2019/20 under the same forecast assumptions, increasing the cumulative deterioration in earnings to approximately $260 million over the three year period from 2017/18 to 2019/20.

Exhibit 93, which assumed more favourable financial results and annual 3.57% rate increases, projected over $400 million in cumulative net financial losses over the six year period from 2022/23 to 2027/28 following the planned Keeyask in-service. Although Manitoba Hydro has not yet updated its longer term forecast, the lower than expected financial results in 2017/18 to 2019/20 compared to Exhibit 93 will exacerbate the losses projected in Exhibit 93. It follows that without the proposed 3.5% rate increase, the cumulative losses projected in Exhibit 93 following the Keeyask in-service will be even more significant.

Manitoba Hydro's net income has historically been extremely variable. Key drivers of net income such as water flow conditions, weather, interest rates and export prices are unpredictable and outside of Manitoba Hydro's control. Section 2.4.4 of this Application presents an analysis of the sensitivity of projected net income or losses for 2019/20 to key assumptions in the Interim Budget. Water flow conditions can vary projected net income for 2019/20 by as much as $360 million between the 10th and 90th percentile of net revenues under the 102 years of historic flow conditions. Colder or warmer winter weather can vary projected net income for 2019/20 by more than $60 million. With interest rates 1% above or below that forecasted, net income for the 2019/20 Interim Budget could vary by approximately $30 million. Export prices higher or lower than the reference forecast used in the 2019/20 Interim Budget can produce a variation of up to $50 million.

Without the proposed 3.5% rate increase, the likelihood of financial losses is greater given the variability of factors such as water, weather, interest rates and export prices. This potential annual variation in financial results and the deterioration in the Corporation's financial position relative to Exhibit 93 in the period leading up to the Keeyask in-service date also underscores the need for a reasonable rate increase in the 2019/20 fiscal year.

The requested 3.5% rate increase effective April 1, 2019 generates a modest level of net income under average water flow conditions that will assist in gradually building the revenue base and reduce the risk of the Corporation incurring a loss in 2019/20. The 3.5% requested rate increase is aligned with PUB-approved rate increases since 2015 and keeps Manitoba's customer rates and estimated bill impacts among the lowest in North America.

Section 2.0 of Manitoba Hydro's 2019/20 Electric Rate Application provides a summary of Manitoba Hydro's actual financial results for the 2017/18 fiscal year, its current financial position and financial outlook for 2018/19, as well as its Interim Budget and Planning Assumptions for the 2019/20 Test Year. Included in this discussion is an overview of Manitoba Hydro's current capital expenditure forecast and an update on the status of its Major New Generation and Transmission projects.

Section 3.0 provides updated rate schedules and customer bill impacts for the proposed rate increase, as well as a comparison of Manitoba Hydro's electricity rates to neighbouring jurisdictions. If approved, the April 1, 2019 rate increase would result in a $3.30 increase in the monthly bill of a residential customer without electric space heat using 1,000 kilowatt-hours ("kWh") per month, and a $6.30 increase in the monthly bill for a residential customer with electric space heat using 2,000 kWh per month.

Throughout this Application, Manitoba Hydro has also provided a brief update on certain directives and recommendations of the PUB as outlined in its Order 59/18. As noted above, further review of PUB directives will be addressed at the next full GRA filed by Manitoba Hydro.

2.0 MANITOBA HYDRO'S FINANCIAL POSITION AND OUTLOOK

Section 2.0 provides analyses of the actual and forecast revenues and expenses related to Manitoba Hydro's electric operations for 2017/18 to 2019/20.

Manitoba Hydro's Financial Outlook for 2018/19 and the 2019/20 Interim Budget form the basis of the current one-year rate application for a 3.5% average revenue

increase effective April 1, 2019. Manitoba Hydro's financial results are prepared in accordance with International Financial Reporting Standards (IFRS).

2.1 2017/18 Actual Financial Results from Electric Operations

Section 2.1 compares 2017/18 actual financial results with Manitoba Hydro's 2017/18 Approved Budget. The 2017/18 Approved Budget, filed with the 2017/18 & 2018/19 GRA, was approved by the MHEB in March 2017 with MH16 for the purposes of financial reporting comparisons throughout the fiscal year and reflected a budgeted net income of $111 million.

Figure 2.1 below compares Manitoba Hydro's actual net income from Electric operations for the 2017/18 fiscal year of $18 million to the approved MH16 budget.

Figure 2.1: 2017/18 Actual Financial Results from Electric Operations Compared to the Approved Budget (MH16)

MANITOBA HYDRO
STATEMENT OF INCOME
For the Year Ended March 31, 2018
(In Millions of Dollars)

	ACTUAL	BUDGET	INCREASE (DECREASE)
Revenues			
Domestic revenue	$1 616	$1 657	($41)
BPIII Reserve Account	(152)	(119)	(33)
Extraprovincial	437	454	(17)
Other	30	30	-
	1 931	2 022	(91)
Expenses			
Operating and administrative	517	518	1
Net finance expense	578	558	(20)
Depreciation and amortization	402	396	(6)
Water rentals and assessments	126	124	(2)
Fuel and power purchased	130	135	5
Capital and other taxes	130	132	2
Other expenses	501	115	(386)
Corporate allocations	8	8	-
	2 393	1 987	(405)
Net income (loss) before net movement in regulatory balances	(462)	35	(496)
Net movement in regulatory balances	472	68	404
Net Income	**$10**	**$102**	**($92)**
Net income (loss) attributable to:			
Manitoba Hydro	**$18**	**$111**	**($93)**
Non-controlling interests	(8)	(9)	1
	$10	**$102**	**($92)**

Actual net income in 2017/18 was $93 million lower than budget primarily due to a 3.36% interim electric rate increase effective August 1, 2017 being granted as opposed to the 7.9% requested by Manitoba Hydro in its 2017/18 & 2018/19 GRA. The PUB directed that all revenues flowing from the 3.36% rate increase be added to the previously established Bipole III deferral account, to be recognized when Bipole III comes into service. Additionally, a continuation of weaker than forecast opportunity prices in the export market and higher financing costs also contributed to the lower than budgeted net income for 2017/18.

In addition to the impact of the lower than requested rate increase, actual domestic revenue was lower than budget as a result of the cooler summer weather which reduced air conditioning load, partially offset by higher customer usage (excluding weather impacts).

Actual extraprovincial revenues were lower than budget as export prices in the opportunity market did not reach forecasted levels. In addition, export volumes were lower than budget as a result of U.S. transmission outages leading to a higher proportion of off peak sales at lower prices.

The higher net finance expense reflects earlier than planned borrowings to take advantage of favourable market conditions, lower capitalized interest due to delayed capital spending as well as higher foreign exchange losses on U.S. cash balances resulting from the strengthening Canadian dollar. This was partially offset by higher interest income on pre-funded cash balances.

Actual other expenses were higher than budget primarily due to the transfer of the $379 million construction in progress balance related to the discontinuance of the Conawapa Generating Station project to a regulatory asset. The increase in other expenses, to a large degree, is offset in the net movement in regulatory balances (removed from the statement of income, deferred and subsequently amortized through net movement in regulatory balances). The regulatory asset will be amortized over 30 years as directed by the PUB in Order 59/18.

Exhibit 93 was filed as an update to MH16 for information purposes. Compared to the $111 million approved budget, the projected income for 2017/18 under Exhibit 93 was $94 million or $17 million lower due to the PUB's interim approval of the 3.36% rate increase compared to the 7.9% requested which was largely offset by a forecasted improvement in water flow conditions and weakening of the Canadian dollar resulting in higher forecast export revenues.

On an actual basis, 2017/18 net income was $75 million lower than forecast in Exhibit 93 as shown in Figure 2.2 below. The reduction in net income compared to Exhibit 93 was due to lower than forecast water flow conditions, as well as lower

export prices and U.S. transmission outages described above, resulting in lower net export revenues.

Figure 2.2: 2017/18 Actual Financial Results from Electric Operations Compared to Exhibit 93

MANITOBA HYDRO
STATEMENT OF INCOME
For the Year Ended March 31, 2018
(In Millions of Dollars)

	ACTUAL	EXHIBIT 93	INCREASE (DECREASE)
Revenues			
Domestic revenue	$1,616	$1,615	$1
BPIII Reserve Account	(152)	(151)	(1)
Extraprovincial	437	514	(77)
Other	30	30	(0)
	1,931	2,008	(77)
Expenses			
Operating and administrative	517	518	1
Net finance expense	578	570	(8)
Depreciation and amortization	402	396	(6)
Water rentals and assessments	126	130	4
Fuel and power purchased	130	124	(6)
Capital and other taxes	130	132	2
Other expenses	501	116	(385)
Corporate allocations	8	8	0
	2,393	1,995	(397)
Net income (loss) before net movement in regulatory balances	(462)	13	(474)
Net movement in regulatory balances	472	72	400
Net Income	**$10**	**85**	**($74)**
Net income (loss) attributable to:			
Manitoba Hydro	**$18**	**$94**	**($75)**
Non-controlling interests	(8)	(8)	0
	$10	**$85**	**($74)**

The 67th Annual Report of the MHEB for the year ending March 31, 2018 can be found in Appendix 3.

Page 56 of the Annual Report provides Manitoba Hydro's Consolidated Statement of Cash Flows. As explained in Note 3(s) to the Financial Statements for the year ended March 31, 2018, the Corporation elected to present cash flows from operating activities using the indirect method as compared to the direct method used for the

year ended March 31, 2017, which is consistent with other utilities in the electric industry and Manitoba Public Insurance. In addition, cash flows related to capitalized interest were reclassified from investing activities to operating activities. Both the indirect and direct cash flow methods and the reclassification of capitalized interest are acceptable under IFRS. In their Audit Findings report for the year ended March 31, 2018, Manitoba Hydro's independent external auditors (KPMG) concurred with the changes in presentation as noted above.

To assist with the comparison of the Consolidated Statement of Cash Flows for the year ended March 31, 2017, included in the 66th Annual Report of the MHEB filed as part of the 2017/18 & 2018/19 GRA, Manitoba Hydro has restated its Consolidated Statement of Cash Flows for the year ended March 31, 2018 under the Direct Method, and included it as Appendix 2 to this Application. As can be seen, regardless of whether the Indirect Method or Direct Method is used, the cash and cash equivalents at year end will remain the same.

2.2 2018/19 Actual Results to September 30, 2018 - Electric Operations

Manitoba Hydro's net loss from Electric operations for the first six months of the 2018/19 fiscal year was $32 million compared to a budgeted net loss of $37 million (which incorporated the 3.6% rate increase and accounting changes approved by the PUB effective June 1, 2018), as shown in the following Figure 2.3.

Figure 2.3: 2018/19 Actual Results to September 30, 2018 from Electric Operations

MANITOBA HYDRO
STATEMENT OF INCOME
For the Six Month Period Ended September 30, 2018
(In Millions of Dollars)

	ACTUAL	BUDGET	INCREASE (DECREASE)
Revenues			
Domestic revenue	$736	$707	$ 29
BPIII Reserve Account	(25)	(37)	12
Extraprovincial	249	250	(1)
Other	12	15	(3)
	972	935	37
Expenses			
Operating and administrative	249	249	-
Net finance expense	340	314	(26)
Depreciation and amortization	221	217	(4)
Water rentals and assessments	54	59	5
Fuel and power purchased	59	56	(3)
Capital and other taxes	71	71	-
Other expenses	46	36	(10)
Corporate allocations	4	4	-
	1 044	1 006	(38)
Net loss before net movement in regulatory balances	(72)	(71)	(1)
Net movement in regulatory balances	38	30	8
Net Loss	**($34)**	**($41)**	**$7**
Net loss attributable to:			
Manitoba Hydro	**($32)**	**($37)**	**$5**
Non-controlling interests	(2)	(4)	2
	($34)	**($41)**	**$7**

The net loss in the first six months of the 2018/19 fiscal year was lower than projected primarily due to favourable weather impacts partially offset by increased financing costs and depreciation expense associated with the earlier in-service date for Bipole III.

Actual domestic revenue was higher than budget primarily due to the impacts of weather, specifically warmer summer weather which increased air conditioning load and a cooler April and September which increased heating load. In addition, the earlier in-service date of Bipole III resulted in an increase in domestic revenue

associated with the correspondingly earlier draw-down of the Bipole III deferral account into revenues.

Actual finance expense was higher than budget due to higher net interest on debt primarily as a result of Bipole III going into service earlier than projected as well as lower overall capital spending on the Bipole III project. In addition, there were unfavourable foreign exchange impacts resulting from the weakening Canadian dollar.

Actual depreciation and amortization expense reflect the impact of the earlier in-service date for Bipole III and therefore are higher than budget.

Actual fuel and power purchased was higher than budget due to a write off of coal inventory as a result of the Brandon Thermal Generating Station no longer being operational as a coal powered generator. This is partially offset by lower transmission charges due to redirecting transmission to lower cost nodes as well as lower purchased volumes.

Appendices 4 and 5 provide the MHEB Quarterly Reports for the three months ended June 30, 2018 and the six months ended September 30, 2018 respectively.

2.3 2018/19 Financial Outlook

As shown in Figure 2.4 below, Manitoba Hydro is projecting annual net income for Electric Operations of $51 million in the 2018/19 Financial Outlook compared to net income of $143 million projected in Exhibit 93. The 2018/19 Outlook incorporates actual financial results and water flow conditions to September 30, 2018 and assumes average water flow conditions and normal winter weather for the remainder of the year. The 2018/19 Outlook was reviewed and approved by the MHEB in late October for inclusion in this Application.

Figure 2.4: 2018/19 Financial Outlook Compared to Exhibit 93 for Electric Operations

MANITOBA HYDRO
STATEMENT OF INCOME
For the Year Ended March 31, 2019
(In Millions of Dollars)

	2018/19 OUTLOOK	EXHIBIT 93	INCREASE (DECREASE)
Revenues			
Domestic revenue	$1 701	$1 675	$ 26
BPIII Reserve Account	14	3	11
Extraprovincial	392	469	(77)
Other	30	31	(1)
	2 137	2 178	(41)
Expenses			
Operating and administrative	501	501	-
Net finance expense	708	656	(52)
Depreciation and amortization	473	471	(2)
Water rentals and assessments	113	120	7
Fuel and power purchased	138	140	2
Capital and other taxes	142	145	3
Other expenses	78	109	31
Corporate allocations	8	8	-
	2 161	2 150	(11)
Net income (loss) before net movement in regulatory balances	(24)	27	(52)
Net movement in regulatory balances	69	115	(46)
Net Income	**$45**	**$142**	**($98)**
Net income (loss) attributable to:			
Manitoba Hydro	**$51**	**$143**	**($93)**
Non-controlling interests	(6)	(1)	(5)
	$45	**$142**	**($98)**

The net income in the 2018/19 Outlook is $93 million lower compared to the net income from Exhibit 93 primarily due to lower net export revenues as well as an increase in financing costs partially offset by higher domestic revenue.

Domestic Revenue is $26 million higher than Exhibit 93 due to weather impacts (warmer summer weather which increased air conditioning load and a cooler April and September which increased heating load) as well as increased revenues associated with the earlier in-service date of Bipole III.

The decrease in Extraprovincial Revenue is primarily a result of below average water conditions impacting generation.

The increase of $52 million in Net Finance Expense is primarily attributable to higher forecasted interest rates. Subsequent to the filing of Exhibit 93 and during the course of the 2017/18 & 2018/19 GRA, the Bank of Canada interest rates rose such that the cost advantage to borrowing more shorter term maturities did not materialize. The yield curve continued to flatten such that there is now only a minimal difference between the all-in borrowing cost for a 5 year Province of Manitoba bond and a 30 year Province of Manitoba bond. As such, Manitoba Hydro reverted to a longer term borrowing strategy of targeting a 20 year weighted average term to maturity ("WATM") for new borrowings as opposed to the 12 year assumption in Exhibit 93. In addition, financing costs are higher due to the impacts of Bipole III going into service earlier than planned.

The Outlook for Other Expenses is $31 million lower compared to Exhibit 93, which is offset in net movement (the majority of other expenses are removed from the statement of income, deferred and subsequently amortized through net movement in regulatory balances). The remaining variance in net movement is primarily due to the annual amortization of the Conawapa deferral account which was not reflected in Exhibit 93 but was endorsed by the PUB in Order 59/18.

2.3.1 Water Conditions as of September 30, 2018

The total volume of water in reservoir storage was approximately 10% below average at the end of September. The water level on Lake Winnipeg, Manitoba Hydro's largest reservoir, was about one foot below historic average for the end of September period; this is approximately a 1 in 10 year low. This is in contrast to September 2017 when the water level on Lake Winnipeg was close to the historic average.

Following nine consecutive months of below average precipitation, water conditions began to improve in September particularly over the Winnipeg River and Lake Winnipeg local basins which were especially dry.

Manitoba Hydro expects water flows to be below average through the winter and overall hydraulic generation to be below average. In addition to inflow uncertainty, factors such as weather, export market prices and ice restrictions are drivers of revenue uncertainty for the remainder of the year.

Additional information on hydraulic generation, water conditions and extra-provincial energy exchange data is provided in Appendix 9.

2.3.2 Business Operations Capital – Recommendations of the PUB

At pages 110 and 111 of Order 59/18, the PUB concluded:

> *The Board finds that Business Operations Capital spending can be safely decreased by $160 million, based on Manitoba Hydro's evidence that it can defer $160 million of spending in the Test Year.*
>
> *…*
>
> *The Board recognizes that Order in Council 92/2017 does not give the Board authority to direct Manitoba Hydro to amend its planned Business Operations Capital spending. Rather the Board has factored into its rate decision the reduction in Business Operations Capital of $160 million. Manitoba Hydro can decide whether to accept the Board's findings and reduce its Test Year Business Operations Capital spending, or to incur additional debt in order to maintain spending at the proposed levels in CEF16.*
>
> *The reduction in spending on Business Operations Capital in no way diminishes Manitoba Hydro's responsibility and obligation to provide for an ongoing safe and reliable supply of energy to its customers in the most efficient and environmentally sensitive manner. The Board expects that Manitoba Hydro will appropriately assess, plan and prioritize Business Operations Capital spending in order to meet its obligations in this regard.*

The 2018/19 Financial Outlook includes the investment of $515 million for Business Operations Capital and represents the Corporation's best estimate of the expenses

necessary to support the safe, sustainable and reliable operations in this period. To ensure sustainable, safe and reliable operation of the Manitoba Hydro system to the benefit of its customers, the projects identified in the 2018/19 Financial Outlook are projects which are active and cannot be cancelled without a cost to the safe and reliable services being provided. Manitoba Hydro will continue to assess active projects on an on-going basis which may impact timing, investments may be reduced accordingly.

2.3.3 Demand Side Management Deferral ("DSM") Account

In accordance with the PUB's direction in Orders 43/13 and 73/15, Manitoba Hydro established DSM deferral accounts for the years 2012/13 through to 2016/17 to capture the differences between planned and actual electric DSM spending. In Directive 23 of Order 59/18, the PUB directed Manitoba Hydro to discontinue the accounting practice of recognizing a DSM Deferral Account. As Order 59/18 was issued in advance of Manitoba Hydro finalizing its financial statements for the year ended March 31, 2018, for consistency with the PUB's direction in Order 59/18, Manitoba Hydro did not record the difference between its planned and actual DSM spending for the 2017/18 fiscal year to the deferral account.

As of March 31, 2018, $48.8 million had accrued to the DSM deferral account. Manitoba Hydro's 2018/19 Outlook assumes that the DSM deferred regulatory asset and corresponding credit will be written-off as of March 31, 2019. There will be no impact to net income as a result of the write-off as the deferred debit and credit accounts will completely offset each other. Manitoba Hydro has made a similar assumption with respect to its natural gas DSM Deferral Account, which will be reviewed by the PUB at Centra Gas Manitoba Inc.'s 2019/20 General Rate Application.

2.3.4 Regulatory Deferrals and Amortizations

Order 59/18 set out a number of directives for the following regulatory deferral accounts and related amortization periods: :

- Directive 17 - Manitoba Hydro continue to use its existing Average Service Life methodology for calculating depreciation rates for rate-setting purposes, without reversion to Equal Life Group in the financial forecast and not

amortize the difference between Average Service Life and Equal Life Group for rate setting.

- Directive 19 - Manitoba Hydro to recognize the costs pertaining to the construction of the Conawapa Generating Station as a regulatory asset and amortize over a 30 year period.
- Directive 21 - Manitoba Hydro continue the annual deferral of $20 million in ineligible overhead. The regulatory account balance is to be amortized over 34 years.
- Directive 22 - Manitoba Hydro to begin recognizing the Bipole III Deferral Account in domestic revenues following the in-service date of Bipole III, amortized over a five-year period.

Manitoba Hydro has reflected the above-noted directives in the 2018/19 Financial Outlook and in the planning assumptions underlying the 2019/20 Interim Budget.

2.3.5 Demand Side Management Spending

Order 59/18 recommended that Manitoba Hydro reduce its demand side management programming and review it for cost effectiveness and cease or modify spending on programs that are no longer cost effective, except for programming targeted at lower-income and First Nations on-reserve customers.

In 2017, the Province of Manitoba tabled legislation, *The Efficiency Manitoba Act* ("The Efficiency Act") to create a new Crown Corporation to be known as Efficiency Manitoba which has a mandate to provide Demand Side Management programming. On January 24, 2018, excepting a few sections, The Efficiency Act was proclaimed and is now in effect. While Efficiency Manitoba is still in its formative stage, Manitoba Hydro continues to deliver Demand Side Management programs to meet the needs of Manitoba customers until the full transition occurs to Efficiency Manitoba. Until such time as the transition occurs and *The Energy Savings Act* has been repealed, the obligations of Manitoba Hydro to consult with the Minister to prepare a yearly energy efficiency plan remain in effect.

Manitoba Hydro's 2017/18 DSM plan filed with the PUB in response to PUB MFR 61 during the 2017/18 & 2018/19 GRA was the plan that Manitoba Hydro prepared in

consultation with the Minister appointed to administer *The Energy Savings Act*. As the targets, programming and spending on energy efficiency and demand side management detailed in the reports filed with the PUB are set in consultation with the Government, these targets and spending cannot be unilaterally adjusted by Manitoba Hydro. As the 2018/19 Financial Outlook incorporates targets and spending assumptions set in consultation with Government, the PUB's recommendation to reduce DSM spending from its revenue requirement as a result of the new, lower marginal value has not been incorporated into the 2018/19 Financial Outlook.

2.4 2019/20 Interim Budget and Planning Assumptions

Manitoba Hydro's projected financial results and key financial and economic inputs underlying the 2019/20 Interim Budget are discussed in the following Sections.

2.4.1 2019/20 Interim Budget

Manitoba Hydro is projecting an annual net income for Electric Operations of $31 million for the 2019/20 fiscal year, inclusive of the 3.5% proposed rate increase, compared to net income of $61 million in Exhibit 93, as shown in the following Figure. The 2019/20 Interim Budget shown below in Figure 2.5 assumes average revenues and costs based on Manitoba Hydro's long term record of water and normal weather for the year.

Figure 2.5: Comparison of 2019/20 Interim Budget to Exhibit 93

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

	Interim Budget	Exhibit 93	Increase/ (Decrease)
For the year ended March 31		**2020**	
REVENUES			
Domestic Revenue	1 737	1 720	17
BPIII Reserve Account	78	79	(1)
Extraprovincial	411	420	(9)
Other	29	31	(3)
	2 255	2 251	4
EXPENSES			
Operating and Administrative	511	511	(0)
Net Finance Expense	765	721	44
Depreciation and Amortization	508	515	(7)
Water Rentals and Assessments	111	110	1
Fuel and Power Purchased	160	158	2
Capital and Other Taxes	150	154	(4)
Other Expenses	111	481	(371)
Corporate Allocation	8	8	(0)
	2 325	2 660	(335)
Net Income before Net Movement in Reg. Deferral	(70)	(409)	339
Net Movement in Regulatory Deferral	103	473	(370)
Net Income	33	64	(30)
Net Income Attributable to:			
Manitoba Hydro	**31**	**61**	**(30)**
Non-controlling Interest	2	2	(1)
	33	64	(30)
Percent Increase	3.50%	3.57%	

The decrease in net income of $30 million is primarily attributable to higher finance expense partially offset by an increase in domestic revenue.

The increase in domestic revenue of $17 million reflects higher than anticipated load requirements in response to the PUB-approved 3.36% electricity rate increase in 2017/18 and lower forecast savings arising from program based DSM initiatives.

The increase of $44 million in net finance expense is primarily attributable to higher than forecasted interest rates. Exhibit 93 filed in the 2017/18 & 2018/19 GRA included savings of approximately $500 million due to lowering the WATM of new debt issuance from 20 years to 12 years in order to take advantage of borrowing rates in the short end of the yield curve. As discussed in Section 2.3, since Exhibit 93 was filed, the Bank of Canada has continued to raise interest rates. While yields have risen across all terms since the last forecasts were filed, the yield curve continued to flatten throughout 2018 and remains exceptionally flat. While the shape of the yield curve and interest rates themselves are subject to further change, the savings opportunity associated with shorter term borrowings continues to be substantially compromised.

The significant reduction in other expenses is offset in net movement and reflects the March 31, 2018 transfer of the $379 million construction in progress balance for the Conawapa Generating Station project compared to the planning assumption of April 1, 2019 in Exhibit 93.

2.4.2 2019/20 Planning Assumptions

The following provides a summary of the key financial and economic inputs underlying the 2019/20 Interim Budget including the Electric load forecast, forecast interest and foreign exchange rates, export prices and water flow conditions as well as assumptions with respect to Regulatory Deferrals.

<u>2019/20 General Consumer Sales (GW.h)</u>

General Consumer Sales includes the energy supplied to all of Manitoba Hydro's domestic customers. General Consumer Sales in the 2019/20 Interim Budget reflects the 2017 Electric Load Forecast adjusted for actual consumption experienced in 2017/18 and is compared to the 2017 Electric Load Forecast assumed in Exhibit 93. Manitoba Hydro is presently preparing the 2018 Electric Load Forecast which will be used in the preparation of MH19 and will be filed at the next General Rate

Application in late 2019. Planned additional savings are incorporated in the forecast of domestic revenue separately from the Load Forecast.

The future program based DSM savings incorporated in the 2019/20 Interim Budget are based on the 15-Year DSM Plan Supplement Report filed in Appendix 7.2 of the 2017/18 & 2018/19 GRA adjusted for actual DSM savings achieved in 2017/18 and the carry-forward effects of the changes made to the 2018/19 one-year DSM plan prepared in consultation with the Manitoba government. Manitoba Hydro is presently working in consultation with the Manitoba government to prepare the 2019/20 one-year DSM plan which will be incorporated into MH19 and filed as part of the next General Rate Application in late 2019. The 2019/20 DSM plan will incorporate the direction provided by Government.

Figure 2.6 below compares the forecast of General Consumer Sales between the Interim Budget and Exhibit 93.

Figure 2.6: Comparison of General Consumer Sales Volumes (GW.h)

GW.h	2019/20 Interim Budget	Exhibit 93	Increase/ (Decrease)
Residential	7,875	7,835	40
General Service	15,074	14,984	90
Area & Roadway Lighting	92	92	0
Sub-Total	**23,041**	**22,911**	**130**
Planned DSM Savings	(834)	(933)	99
Total	**22,207**	**21,977**	**230**

The actual domestic electric rate increase of 3.36% effective August 1, 2017 as opposed to the planned rate increase of 7.9%, which underpins the load forecast assumed in Exhibit 93, impacts the elasticity effect of prices such that load is expected to increase in 2019/20 for electricity in the residential sector by 40 GW.h and in the general service sector by 90 GW.h. The 99 GW.h decrease to the planned DSM savings are due to delays to the implementation of customer sited self-

generation systems and the removal of the Fuel Choice initiative and Conservation Rates from the DSM plan.

2019/20 Interest Rates & Exchange Rates

Figure 2.7 below compares the interest rate and exchange rate assumptions underpinning the 2019/20 Interim Budget and Exhibit 93. The forecasted 20-year average interest rate listed under Exhibit 93 has been included for comparison purposes only as the 12-year average rate was used to derive the finance expense related to the issuances of new Canadian debt and is no longer being used in the 2019/20 Interim Budget.

Figure 2.7: Comparison of Interest Rates & Exchange Rates

	2019/20 Interim Budget Winter 2017	**Exhibit 93 Spring 2017**
MH Short Term Interest Rate*	2.20%	1.55%
MH Long Term Interest Rate*		
12 Year WATM	N/A	3.45%
20 Year WATM	4.00%	3.90%
U.S. – Cdn Exchange Rate	1.26	1.29

* Not including the 1% Provincial Guarantee Fee

Forecast interest rates are trending at about the same level as shown in Figure 2.7 . Section 2.4.4 provides a sensitivity analysis of the 2019/20 Interim Budget assuming interest rates at 1% higher or lower than the rates reflected in Figure 2.7 .

Although Figure 2.7 shows a slight strengthening of the Canadian dollar since Manitoba Hydro's 2017/18 & 2018/19 GRA, net income is generally not sensitive to changes in the U.S. exchange rate due to Manitoba Hydro's hedging policies and practices.

2019/20 Net Interchange Revenues and Generation Costs

The 2019/20 Interim Budget reflects Manitoba Hydro's reference electricity export price forecast and a simulation of the full historic flow record to derive the average net interchange revenues and generation costs. The reference electricity export prices from the 2017 Energy Price Forecast (Fall Update) for 2019/20 were approximately 6% to 7% lower than the prices from the 2017 Energy Price Forecast (Spring) assumed in Exhibit 93 and filed in the 2017/18 & 2018/19 GRA.

Hydraulic generation in 2019/20 is primarily driven by future precipitation which is impossible to forecast accurately beyond a one week period. As such, Manitoba Hydro uses its full historic flow record to project future net interchange revenues and generation costs beyond the 2018/19 fiscal year. Section 2.4.4 provides an analysis of the sensitivity of the 2019/20 Interim Budget to both electricity export prices and water flow conditions.

Manitoba Hydro has relatively small levels of unsold dependable energy and capacity in 2019/20. In forecasting the net interchange revenues and generation for both the 2019/20 Interim Budget and Exhibit 93, the Corporation has not projected incremental revenues associated with surplus dependable capacity. This is consistent with the PUB's finding on page 128 of Order 59/18:

> *Manitoba Hydro's change of methodology - to remove capacity values and dependability premiums from the substantial surplus dependable energy -* ***is reasonable in the near term****, but is not reasonable in the long term as it biases the export forecast to be low and is not consistent with third party forecasters nor with the needs in the Midcontinent Independent System Operator and Minnesota markets. (****emphasis added****)*

Regulatory Deferral Accounts and Accounting Assumptions

Manitoba Hydro's 2019/20 Interim Budget incorporates the PUB's direction in Order 59/18 for the regulatory deferral accounts listed in Figure 2.8, compared to Exhibit 93.

Figure 2.8: Accounting Treatment for Regulatory Deferral Accounts

	2019/20 Interim Budget	**Exhibit 93**
Ineligible Overhead		
Annual Provision	$20 million	$20 million
Amortization Period	34 years	30 years
Deferral	Indefinite	Indefinite
Equal Life Group (ELG)/Average Service Life (ASL)		
Amortization Period	None	None
Deferral	Indefinite	Indefinite
Costs Related to Conawapa		
Deferral Amount	$379 million	$379 million
Recorded in the Regulatory Deferral Account	Mar 31/18	Apr 1/19
Amortization Period	30 year	30 year

2.4.3 2019/20 Interim Budget with and without 3.5% Revenue Increase

Manitoba Hydro is requesting approval of a 3.5% rate increase to be effective April 1, 2019. This increase is projected to generate additional revenues of approximately $59 million and would result in a modest net income of $31 million in 2019/20. Absent the proposed rate increase for 2019/20, Manitoba Hydro is projecting a net loss of $28 million from Electric operations. Figure 2.9 compares the 2019/20 Interim Budget with and without the 3.5% revenue increase.

Figure 2.9: 2019/20 Interim Budget with and without the 3.5% Revenue Increase

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

	Interim Budget (3.50%)	Interim Budget (0.00%)	Increase/ (Decrease)
For the year ended March 31		**2020**	
REVENUES			
Domestic Revenue	1 737	1 678	59
BPIII Reserve Account	78	78	-
Extraprovincial	411	411	-
Other	29	29	-
	2 255	2 196	59
EXPENSES			
Operating and Administrative	511	511	-
Net Finance Expense	765	765	(1)
Depreciation and Amortization	508	508	-
Water Rentals and Assessments	111	111	-
Fuel and Power Purchased	160	160	-
Capital and Other Taxes	150	150	0
Other Expenses	111	111	-
Corporate Allocation	8	8	-
	2 325	2 325	(1)
Net Income before Net Movement in Reg. Deferral	(70)	(129)	59
Net Movement in Regulatory Deferral	103	103	-
Net Income	33	(26)	59
Net Income Attributable to:			
Manitoba Hydro	**31**	**(28)**	**59**
Non-controlling Interest	2	2	0
	33	(26)	59
Percent Increase	3.50%	0.00%	

2.4.4 2019/20 Sensitivity Analysis

This section provides an indication of the impact of changes in water flow conditions, weather, interest rates and export prices on the 2019/20 Interim Budget net income of $31 million.

The net income or loss resulting under each of the key changes in assumptions is shown below in Figure 2.10. Figure 2.10 also shows that the likelihood of a financial loss is greater without the proposed 3.5% rate increase under the range of sensitivities considered.

Figure 2.10: Key Variable Sensitivity Impacts on 2019/20 Interim Budget Net Income/ (Loss) With and Without the 3.5% Proposed Rate Increase

	Projected Net Income/(Loss)	
	3.5% Proposed Rate Increase	**No Rate Increase**
Interim 2019/20 Budget	$31 M	($28) M
Low Water Flow (10th percentile net interchange revenues and generation costs)	($169) M	($229) M
High Water Flow (90th percentile net interchange revenues and generation costs)	$194 M	$134 M
Colder than normal winter weather	$63 M	$4 M
Warmer than normal winter weather	($0) M	($60) M
+ 1% Interest Rates	$16 M	($43) M
- 1% Interest Rates	$45 M	($14) M
Low Export Price Case	($2) M	($61) M
High Export Price Case	$49 M	($10) M

The 2019/20 Interim Budget assumes average net interchange revenues and generation costs for the historic water flow record. The historic water flow record has a great deal of variability from the highest to the lowest flow which creates a dramatic range of the possible net interchange revenues and generation costs that could occur in a given year. 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. Due to this asymmetry, the average revenues and costs of the historic water flow record is the equivalent to approximately the 40th percentile or P40 and not the median or P50. To demonstrate the range of possible net interchange revenues and generation costs, the P10 and P90 sensitivities have been provided. Figure 2.10 shows that the

projected income or loss for 2019/20 can vary by more than $360 million due to water flow conditions.

The 2019/20 Interim Budget assumes a weather adjusted forecast for General Consumer Sales. A record cold or warm winter will increase or decrease Manitoba's 2019/20 energy consumption by approximately 4%. An increase or decrease to domestic revenue due to a colder or warmer than normal winter will be partially offset by an associated decrease or increase to net interchange revenues and generation costs. Figure 2.10 shows that projected net income for 2019/20 can vary by more than $60 million due to colder or warmer winter weather.

Manitoba Hydro is planning to raise approximately $2.4 billion in new debt issuances in 2019/20. The interest rates affixed to new debt issuances have a lasting effect due to the perpetual nature of long-term debt (20-year WATM) which makes this a different risk than drought. The interest rate sensitivity demonstrates 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. Figure 2.10 shows that the 2019/20 Interim Budget net income could vary by approximately $30 million with interest rates 1% above or below that forecasted.

The 2019/20 Interim Budget reflects Manitoba Hydro's reference electricity export price forecast derived from several independent price forecasts for the MISO region. There is uncertainty in each of these pricing factors, and particular uncertainty as to how future legislative and regulatory requirements may evolve. As such, Manitoba Hydro has developed high and low electricity export price forecasts as sensitivities around the reference case using information prepared by the U.S. Energy Information Administration (EIA). Figure 2.10 shows that projected net income from 2019/20 can vary by $50 million if export prices vary from the forecast reference export prices assumed in 2019/20 Interim Budget.

2.4.5 Information on Other Cash Payments

Directive 10 of Order 59/18 requested Manitoba Hydro to provide information about the Other Cash Payments included in its Cash Flow Statement. Manitoba Hydro has provided additional details on the Cash Flow Statement included in

Appendix 1. In addition to the further line item breakdown provided on the Cash Flow Statement, the "Other" category balance of $11 million in 2017/18 under Financing Activities represents the advance to Centra which is eliminated upon consolidation. The "Other" category of $3 million under Investing Activities is primarily investments in assets held for sale as well as payments associated with various obligations.

2.4.6 Operating & Administrative Costs

Consistent with Exhibit 93, Manitoba Hydro's preliminary O&A target included in the 2019/20 Interim Budget is $511 million reflecting an inflationary increase of 2% over the $501 million of O&A expenses included in the 2018/19 Financial Outlook. The 2% increase is aligned with Manitoba CPI. Manitoba Hydro is committed to achieving this level of O&A expenditure and is in the process of developing detailed budgets for 2019/20 to support this commitment.

As discussed in the 2017/18 & 2018/19 GRA, the implementation of a significant work force reduction strategy resulted in cost reductions in both 2017/18 and 2018/19. As shown in Figure 2.11, O&A costs were $19 million lower in 2017/18 than the prior year and are projected to be further reduced by $16 million in 2018/19.

Figure 2.11: Year over Year Comparison of O&A Costs

(in millions of dollars)	2016/17 Actual	2017/18 Actual	2018/19 Budget	2019/20 Forecast
O&A Expenditures	$536	$517	$501	$511
Year over Year Inc / (Dec)		-3.5%	-3.1%	2.0%

The year over year decreases in 2017/18 and 2018/19 are primarily due to the impact of the Voluntary Departure Program ("VDP") which was launched in April 2017 as a means to accomplish the Corporation's workforce reduction target of 900 employees over a 3 year period ending March 31, 2020. A total of 821 employees were approved under the VDP with the majority of staff departing by March 2018. Manitoba Hydro's headcount as of April 2017, excluding summer students and

seasonal workers, was approximately 6150. The Corporation's projected headcount to March 2020 is approximately 5250.

Appendix 8 provides Manitoba Hydro's O&A Expenses Quarterly Report for the year ending March 31, 2018 as well as the quarters ending June 30th and September 30th 2018, filed in response to Directive 14 of Order 73/15. O&A performance to the end of September 2018 is closely aligned with budget. The September 30, 2018 report provides information for the 2018/19 annual budget by cost element.

2.4.7 Impacts of VDP on Pension

At March 31, 2018 Manitoba Hydro recognized a $30 million actuarial loss in Other Comprehensive Income (OCI) related to the VDP departures based on a December 2017 valuation of the pension liability. The loss is primarily a result of deviations in pension valuation assumptions. The pension valuation assumes age 59 as the average age of retirement and that pensioners will take a monthly pension payment. Individuals retiring as part of the VDP who were 55-58 years of age at retirement had a negative impact on the pension valuation as did individuals who withdrew the commuted value of their pension. Manitoba Hydro's actuary (Ellement Consulting) estimates that annual pension payments will increase by approximately $1 million per year once all the VDP individuals have retired and the current service rate is expected to decrease by 5% by 2019. Additional actuarial losses on the pension obligation of approximately $30 million and $7 million are projected for March 2019 and March 2020 respectively using fiscal 2017/18 VDP valuation impacts as a proxy.

2.5 Capital Expenditure Forecast (CEF18)

Appendix 6 contains a copy of Manitoba Hydro's Capital Expenditure Forecast (CEF18) from 2018/19 to 2027/28. CEF18 identifies all projects greater than $1 million in response to Directive 15 of Order 73/15. Projects greater than $15 million appear in the body of the report and projects less than $15 million are summarized in Appendix II of the report.

Figure 2.12 provides a comparison of CEF18 to CEF16 for Electric operations, which shows a decrease of $303.6 million over the 10 year period to 2027/28.

Figure 2.12: Comparison of CEF18 to CEF16

	2019	2020	2021	2022	2023	2019-2013 5 Year Total	2019-2028 10 Year Total
CEF16	$ 2,742.1	$ 1,884.2	$ 1,666.5	$ 1,332.5	$ 945.2	$ 8,570.5	$ 12,122.4
Inc (Dec)	(72.1)	(65.1)	(97.3)	64.2	(4.4)	(174.8)	(303.6)
CEF18	$ 2,670.0	$ 1,819.1	$ 1,569.2	$ 1,396.7	$ 940.8	$ 8,395.7	$ 11,818.8

Figure 2.13 provides a summary of the changes of $303.6 million over the 10 year period ending 2027/28.

Figure 2.13: Summary of CEF18 Forecast Changes

($ Millions)	10 Year Increase (Decrease)
MAJOR NEW GENERATION & TRANSMISSION	**(266.9)**
Keeyask - Generation	(133.8)
Bipole III Reliability	21.9
Manitoba-Minnesota Transmission Project	53.6
Birtle Transmission	4.4
Other Major New Generation & Transmission	(212.9)
Electric Business Operations Capital	**0.2**
Generation System	(65.3)
Transmission System	(123.7)
Distribution System	175.5
Corporate Infrastructure	6.4
Unallocated Target Adjustment	7.2
Electric DSM Program	**(36.9)**
ELECTRIC CAPITAL EXPENDITURE & DSM FORECAST TOTAL	**(303.6)**

Major New Generation and Transmission ("MNGT") capital expenditures over the 10-year period are forecast to be $5,391.2 million. Compared to CEF16, this is a reduction of $266.9 million primarily associated with Other MNGT projects included in CEF16. Several of these projects were completed in 2017/18 including: Wuskwatim–Generation, Pointe du Bois Spillway Replacement, Kelsey Improvements & Upgrades, Riel 230/500kV Station, Kettle Improvements & Upgrades and Pointe du Bois Transmission. The Grand Rapids Fish Hatchery Upgrade & Expansion project has been reclassified to Business Operations Capital

and all future investment requirements related to the Gillam Redevelopment and Expansion Project will also be included as Business Operations Capital items. In addition, the Keeyask – Generation project cash flow reduced by $134 million over the 10 year period, however, the total project forecast remains unchanged at $8.7 billion. The Business Operations Capital (BOC) forecast did not materially change compared to CEF16.

2.5.1 Summary of MNGT Projects

A summary of capital expenditure requirements for each project within MNGT can be found in CEF18 on pages 10 through 12. Figure 2.14 summarizes by investment category the total project cost and forecast cash flow for each of the 4 projects.

Figure 2.14: Total Project Costs for Major New Generation & Transmission

MAJOR NEW GENERATION & TRANSMISSION ($ Millions)	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
Capacity & Growth								
New Energy								
Keeyask - Generation	8,726.0	1,265.4	1,016.6	846.9	763.9	311.2	4,204.0	4,241.3
System Load Capacity								
Bipole III - Converter Stations	2,780.7	345.7	23.1	0.2	-	-	369.0	369.0
Bipole III - Transmission Line	1,957.6	290.2	10.2	2.4	-	-	302.8	302.8
Bipole III - Collector Lines	246.6	25.6	-	-	-	-	25.6	25.6
Bipole III - Community Development Initiative	56.6	1.1	-	-	-	-	1.1	1.1
System Load Capacity Total	**5,041.5**	**662.6**	**33.4**	**2.6**	**-**	**-**	**698.5**	**698.5**
Grid Interconnections - Import/ Export								
Manitoba-Minnesota Transmission Project	451.7	162.0	144.4	91.2	-	-	397.6	397.6
Birtle Transmission	56.5	2.5	20.0	18.2	13.0	-	53.8	53.8
Grid Interconnections - Import/ Export Total	**508.2**	**164.5**	**164.5**	**109.3**	**13.1**	**-**	**451.4**	**451.4**
Capacity & Growth Total	**14,275.7**	**2,092.5**	**1,214.4**	**958.9**	**777.0**	**311.2**	**5,353.9**	**5,391.2**

Directives 15 and 16 of Order 59/18 directed Manitoba Hydro to consider implementing recommendations made by the IEC's with respect to Keeyask, MMTP and GNTL, as well as filing detailed quarterly reports for all Major New Generation and Transmission projects currently under development. An update with respect to each of these directives is provided below.

Directive 15 of Order 59/18

Manitoba Hydro has implemented certain recommendations, and is in the process of considering implementation of other recommendations made by the IECs in the 2017/18 & 2018/19 GRA for those projects that are within its control in order to properly assess any projected cost savings and schedule impacts.

With respect to the Manitoba Minnesota Transmission Project, recommendations were mainly focused on schedule modifications such as breaking apart long duration activities and removing constraints. These recommendations have been addressed and a basis of estimate will be prepared when details of contractor pricing are received. Currently however, it does not appear that these changes have had a measurable impact to the project budget.

With respect to the Keeyask project, the recommendations proposed by MGF Project Services were primarily focused on improving outcomes of the General Civil Works Contractor ("GCC") with the goal of achieving the control budget of $8.7 billion and the control schedule first unit In-Service Date of August 2021.

In January 2018, during the 2017/18 & 2018/19 GRA, Manitoba Hydro laid out its approach on the closer collaboration between Manitoba Hydro and the GCC to improve performance and achieve the plan for the 2018 construction season and ultimately deliver the project within the revised control budget of $8.7B and related schedule. The intended approach aligned with the closer collaboration on execution planning and oversight of the GCC recommended by MGF as well as working with the GCC to develop an achievable plan in 2018 based on production experienced to date. Manitoba Hydro has increased the pressure on the GCC to perform, and has collaborated wherever possible to stimulate greater productivity.

By the end of November 2018, the GCC exceeded the concrete production goal of 105,000 m3 for the year representing a year-over-year improvement of more than 20% over last year's production. In total, more than 83% of the required volume of concrete to build the Keeyask Generating Station has now been placed. The GCC also met the planned quantities for earthworks for the year, achieving roughly double the volumes of production from last year. In addition to improving production rates, the work completed in 2018 was also completed more efficiently. Though significant project risks remain, the progress to date has been positive and the necessary improvements to achieve the control budget of $8.7B are being realized and the first unit In-Service Date (ISD) is currently trending ahead of the control schedule.

Directive 16 of Order 59/18

Manitoba Hydro has provided detailed quarterly reports on the following MNGT capital projects:

- Keeyask Generating Station – a 7 unit, 695-megawatt hydroelectric generating station under construction at Gull Rapids on the low Nelson River in northern Manitoba.
- Bipole III Transmission Reliability Project – a high voltage direct current transmission line that delivers renewable energy to southern Manitoba. Bipole III was brought into service on July 4, 2018.
- Manitoba–Minnesota Transmission Project – a new 500kV AC Transmission Line between Winnipeg and Duluth, Minnesota which will connect to the Minnesota Power's proposed Great Northern Transmission Line.
- Birtle Transmission Project – a new 230kV Transmission Line between Birtle, Manitoba and Tantallon, Saskatchewan.

Please see Appendix 7 for copies of Manitoba Hydro's Public MNGT Capital Reports for the quarter ended March 31, 2018, and the quarters ended June 30, 2018 and September 30, 2018.

3.0 PROPOSED RATE CHANGES & CUSTOMER IMPACTS BY CLASS

Manitoba Hydro's electric rates were last adjusted effective June 1, 2018 to reflect the 3.6% rate increase approved by the PUB in Order 59/18. Pursuant to Order 59/18, the rates that came into effect on June 1, 2018 reflected the following rate design considerations:

- the creation of a First Nation On Reserve Residential customer class, with no increase from August 1, 2017 rates;
- the application of no rate increase from August 1, 2017 rates to Residential Diesel class customers, and,
- the adjustment of class revenues to commence migration of customer classes toward the Zone of Reasonableness ("ZOR") of 95% to 105% over a ten year period.

Manitoba Hydro filed an Application to Review and Vary some of the directives in Order 59/18 including the directives related to the creation of a First Nation on Reserve Residential Customer Class. In its Order 90/18, dated July 13, 2018, the PUB denied Manitoba Hydro's application to Review and Vary these directives. On August 10, 2018, Manitoba Hydro filed a Motion with the Court of Appeal seeking Leave to Appeal portions of PUB Orders 59/18 and 90/18 with respect to the creation of a new customer class for First Nation on Reserve Customers. As of the filing of this Application, these issues remain before the Court of Appeal.

As part of its 2019/20 one-year electric rate application, Manitoba Hydro is requesting approval of a 3.5% rate increase, effective April 1, 2019, to be applied equally, across all customer classes.

In Order 59/18 the PUB directed for the 2018/19 test year rate, that Manitoba Hydro is to assume a 10-year timeframe to move all classes within the zone of reasonableness. The PUB further stated at page 199 of Order 59/18 that it would *"…examine the Revenue to Cost Coverage ratios arising from the Prospective Cost of Service Study filed with the next GRA and will consider adjustment to the differentiation of rates as necessary, including to consider the impact of Bipole III entering service".*

Manitoba Hydro intends to continue the migration of customer classes into the ZOR in its next full General Rate Application, anticipated to be filed in late 2019, based on the results of its next Prospective Cost of Service Study ("PCOSS") to be developed following approval by the MHEB of a new Integrated Financial Forecast. The next PCOSS will reflect Bipole III coming into service. As this is anticipated to have a significant impact on customer class costs, pausing further differentiation until Manitoba Hydro can assess which classes may remain outside the ZOR once the impacts of Bipole III have been reflected will limit potential over-corrections that may be unnecessary following Bipole III coming into service. The across-the-board increase proposed as part of this Application will not negatively impact the migration of class revenues that has been achieved to date following the implementation of differentiated rates approved by the PUB in Order 59/18.

In consideration of this one-year electric rate application and in absence of an updated PCOSS, Manitoba Hydro is proposing to apply the increase to all components of the rates (monthly basic charges, energy charges and demand charges) on an across-the-board basis for all customer classes, with the exception of Diesel General Service. For Diesel General Service customers Manitoba Hydro is proposing to increase the grid portion of the rate (Basic Charge and first 2,000 kWh per month for non-government customers) by 3.5% with the non-grid portion of the rate remaining unchanged.

Until the Court of Appeal rules on the issue of the creation of a First Nations On-Reserve Residential customer class, Manitoba Hydro proposes to apply the same rate increase to all residential customers (including the First Nations On-Reserve Residential and Diesel Residential customers) for the 2019/20 fiscal year.

The proposed 3.5% rate increase applied on an across-the-board basis generates additional revenue of $59 million for fiscal 2019/20.

On a class by class basis, the proposed increase in revenues is shown in Figure 3.1 below.

Figure 3.1: Additional Revenues by Customer Class

Customer Class	2019/20 Additional $(000s)
Residential	24,800
General Service (GS) Small*	11,900
GS Medium	7,400
GS Large	13,600
Area & Roadway Lighting	800
Miscellaneous	200
Total General Consumers Revenue	58,800

*includes revenues from General Service customers in Diesel Communities

A Proof of Revenue for the 2019/20 test year depicting the total revenue increase by customer class is provided in Appendix 10. Rate Schedules for proposed rates effective April 1, 2019 are provided in Appendix 11 and Bill Comparisons between current June 1, 2018 rates and proposed April 1, 2019 rates are provided in Appendix 12.

3.1 Rate Design and Cost of Service Directives

Order 59/18 set out a number of directives related to Manitoba Hydro's cost of service study and rate structures.

Directives 24 to 27

Manitoba Hydro has completed the modifications to the cost allocation model that will be used for future Cost of Service Studies to reflect these directives which direct non-tariffable transmission costs be excluded from the allocation of export revenues, the addition of a new subfuction to allocate the specified customer services costs to all classes other than GSL 30-100kV and GSL >100kV and export revenues be treated as a reduction to cost in the calculation of Revenue to Cost Coverage ratios. Manitoba Hydro is continuing to study the Service Drop allocator and Common Costs and intends to have the review completed in time for the next Prospective Cost of Service Study to be filed with the next full GRA.

Directive 28

Directive 28 requested information regarding the rationale for the declining block rate structure for the General Service customer classes and an evaluation of the block thresholds and charges. The declining block rate structure for the General Service Small, General Service Small Demand and General Service Medium customers is on account of class consolidation that began with rates implemented on July 1, 2008 and was necessary to recover the demand costs related to General Service Small customers that are not demand metered and to reflect the higher load factors of the General Service Small Demand and General Service Medium customers. There are no changes currently proposed to these customer classes as Manitoba Hydro intends to study whether consolidation of these classes continues to be appropriate.

Directive 29

Directive 29 directed filing of a time-of-use rate design proposal for general service large customers. Manitoba Hydro has invited customers in the General Service Large >100 class and representatives of the Manitoba Industrial Power Users Group to a kick off meeting on December 4, 2018 which will mark the beginning of the customer consultation phase. The consultation phase, originally anticipated to begin by the end of October 2018, was delayed to allow for additional internal review to analyze and study the key inputs and considerations underlying a time-of-use rates proposal in order to provide customers with updates that will allow for meaningful participation at the outset of the consultation process. Over the next several months, through group and individual consultations, Manitoba Hydro intends to solicit feedback and gather information from customers for the purposes of developing the new rate structure.

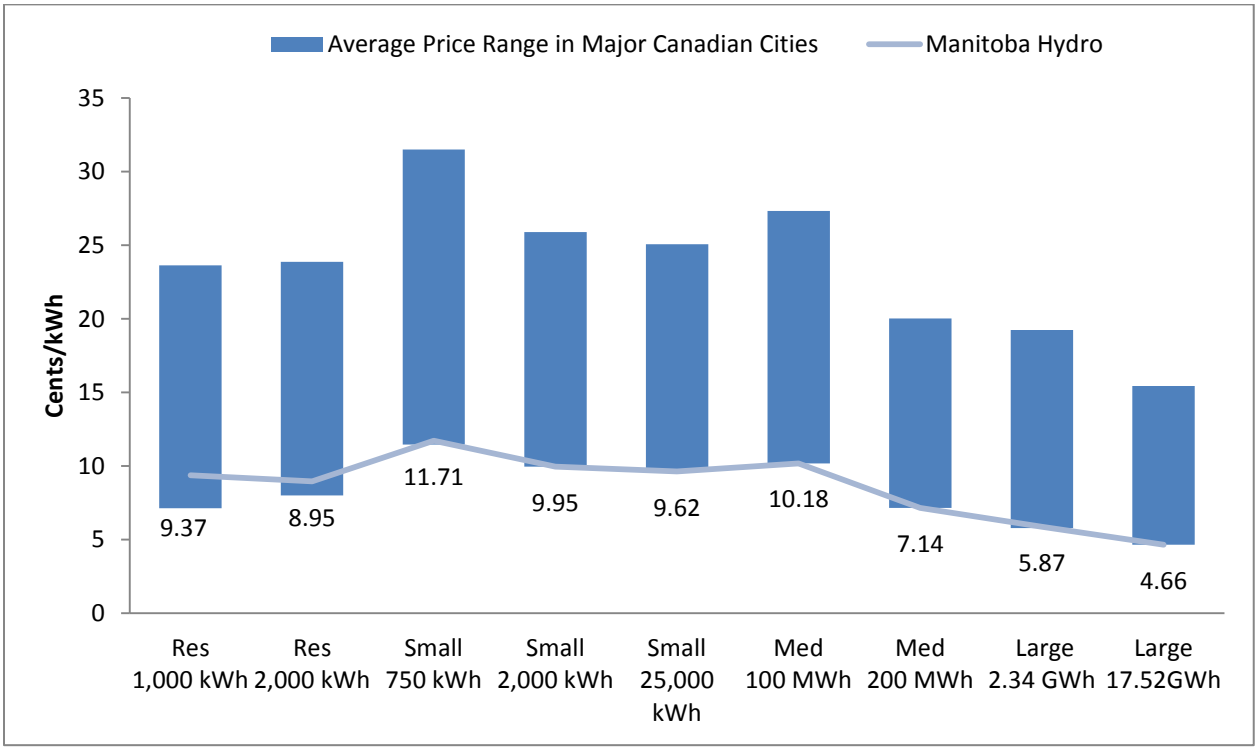
3.2 Comparison of Manitoba Hydro's Electricity rates to Neighbouring Jurisdictions

Manitoba Hydro has used Hydro Quebec's annual *"Comparison of Electricity Prices in Major North American Cities"*[1], to compare average rates for all major rate classes paid by Manitoba customers with those of other major Canadian utilities, as shown in Figure 3.2.

[1] http://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf

Figure 3.2: Comparison of Average Electricity Prices in Major Canadian Cities

Rates in effect April 1, 2018 (Price per kWh)



The 2018 Hydro Quebec survey demonstrates that the average price per kWh paid by Manitobans is amongst the lowest in large Canadian cities.

A summary of rate changes from utilities across Canada from 2007 to 2019 is provided in Figure 3.3 below.

Figure 3.3: Utility Rate Changes 2007 to 2019

Utility Rate Changes (%)															
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	Cumulative	Current Rate Index***
Manitoba Hydro	2.2	5.00	2.90	2.80	2.00	4.40	3.50	2.75	3.95	3.36	3.36	3.60	3.50	53.1	100
Hydro Quebec	1.90	2.90	1.20	0.35	-0.40	-0.50	2.41	4.30	2.90	0.70	0.70	0.30	0.80**	18.9	109
BC Hydro	2.10	0.83	9.28	7.29	7.77	7.07	1.44	9.00	6.00	4.00	3.50	3.00	3.00	86.4	142
SaskPower	4.20	0.00	8.50	4.50	0.00	0.00	4.90	5.50	5.00	5.00	3.50	3.50	0.00	54.4	159
NB Power	5.90	3.00	3.00	3.00	0.00	0.00	2.00	2.00	1.60	1.66	1.77	0.88	2.00	30.2	171
NS Power	3.80	0.00	9.30	0.00	6.05	8.70	3.00	3.00	0.00	-1.00	1.50	1.70	1.50	43.9	n/a
Toronto Hydro	-4.11	-0.99	4.95	10.84	-8.18	18.80	-7.52	18.93	-3.07	20.47	-2.52	-25.38	2.00	14.8	n/a

* Where published information on proposed increases is not available, Manitoba Hydro has assumed a 2% inflationary increase

** Hydro Quebec is proposing an overall 0.8% increase in 2019, but only 0.2% for industrial customers.

*** This index is based on the Edison Electric Institute Survey and compares the average price per kWh for the various utilities. Manitoba Hydro's average price is $0.0649/kWh in Canadian dollars based on 12 months data ending December 2017.

In addition to average prices, a comparison of monthly bills aids in providing context for what customers in each jurisdiction are paying on a monthly basis. The charts provided in Figures 3.4 to 3.8 compare projected monthly bills for major Canadian cities in 2019/20. Consistent with calculations in Figure 3.4, where published information on projected increases is not available, a simplifying and conservative assumption has been made that annual rate increases will be in line with inflation at 2% each year. Where information is available, projected rate increases have been reflected in the bill calculations.

Figure 3.4: Residential Monthly Bill Comparisons in 2019/20

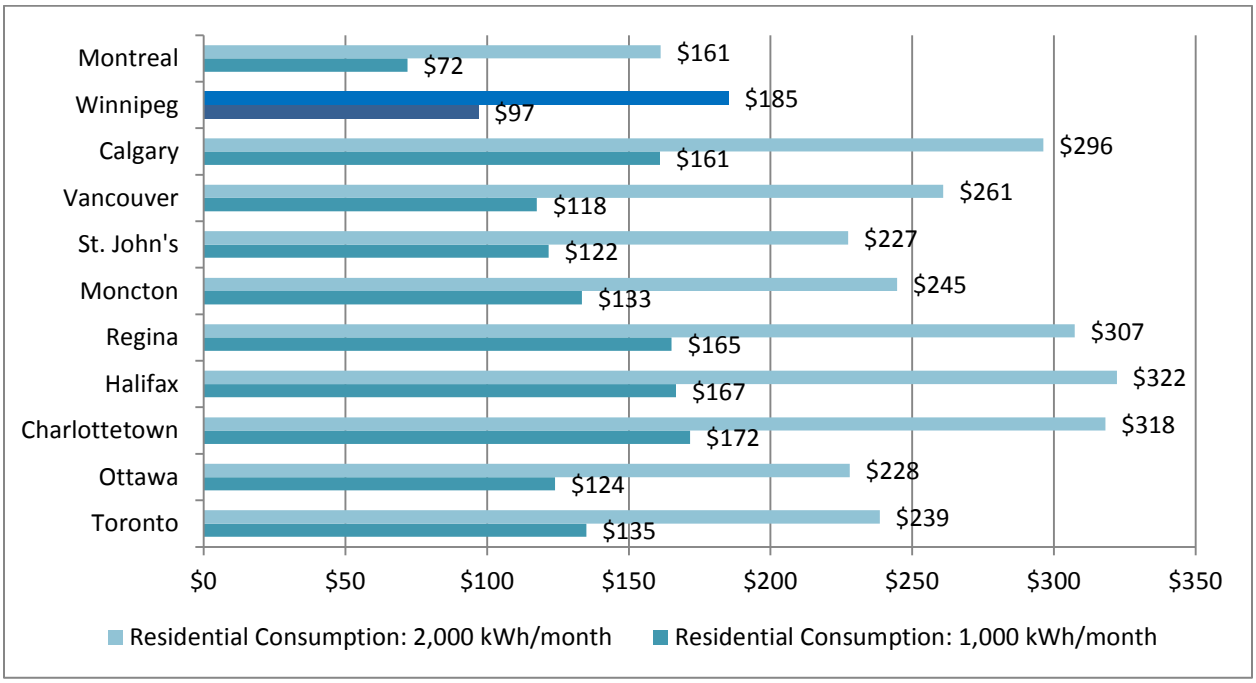


Figure 3.5: Small Power (10,000 kWh) Monthly Bill Comparisons in 2019/20

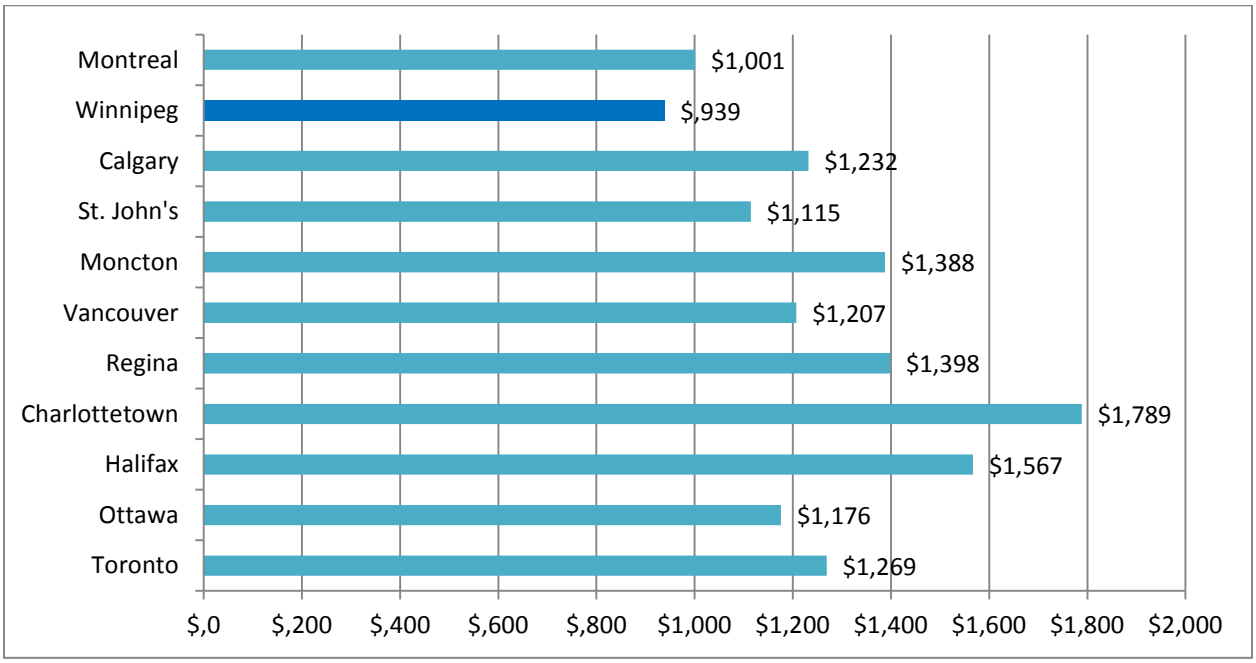


Figure 3.6: Medium Power (1,000 kW) Monthly Bill Comparisons in 2019/20

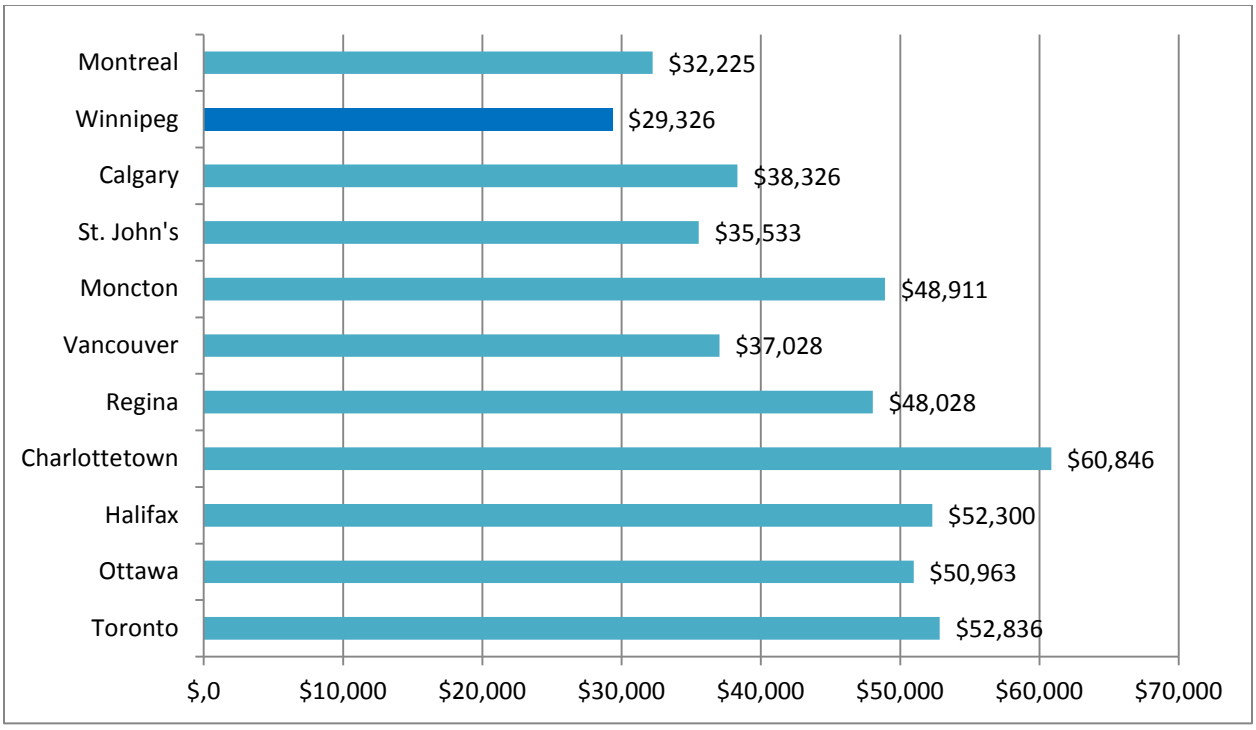


Figure 3.7: Large Power (5,000kW) Monthly Bill Comparisons in 2019/20

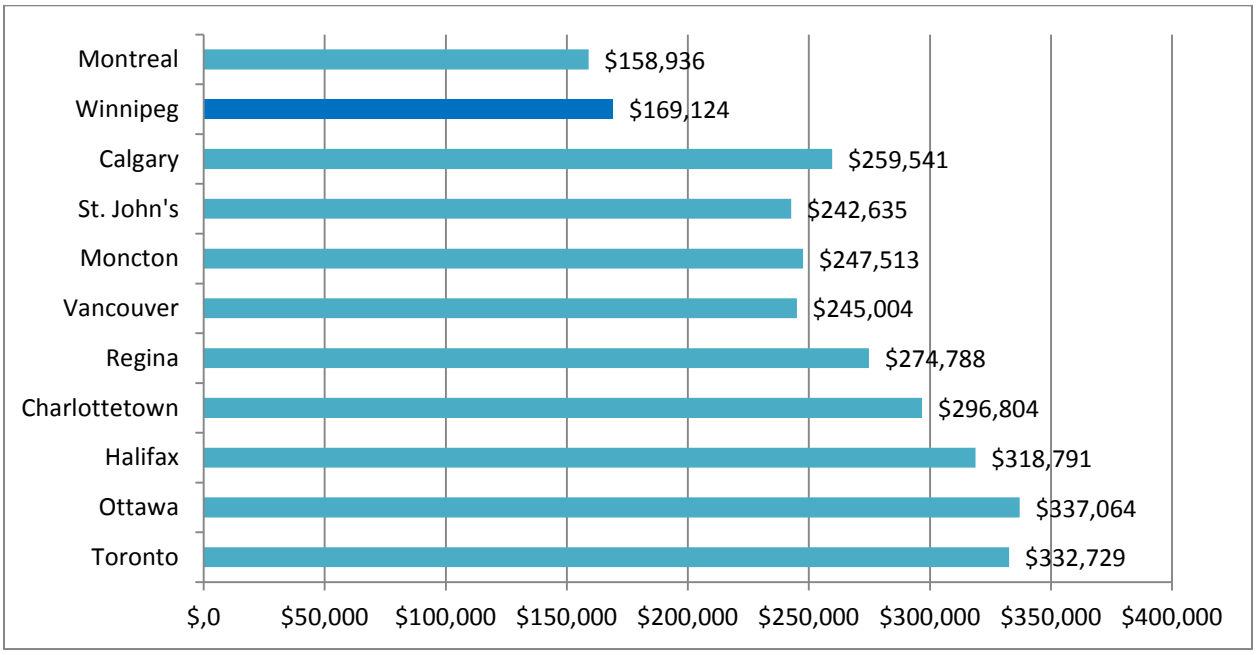
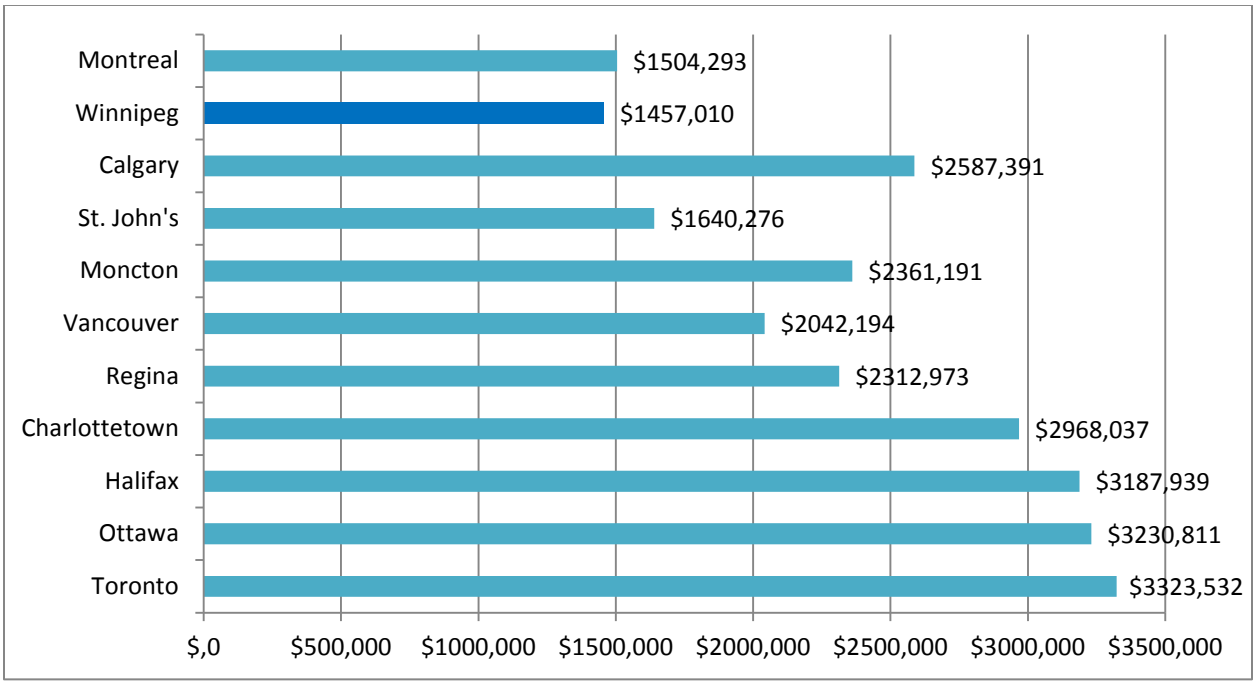


Figure 3.8: Large Power (50,000kW) Monthly Bill Comparisons in 2019/20



To measure its 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 each state. Figure 3.9 below provides the Total Retail Average Rate compared to other low-cost jurisdictions and neighboring utilities, including primary Mid-continent Independent System Operator states, based on the July 2018 DOE data and July 1, 2018 EEI data, using an exchange rate of 1 US $ =1.32154 Canadian as of July 3, 2018. The Average Retail Rate was determined by dividing the combined total revenue billed by the combined total kilowatt hours billed for the 12-month period ending June 30, 2018 for all customer classes (residential, commercial and industrial).

Figure 3.9: Average Retail Price

State / Province	Average Retail Price Cents per kWh
Manitoba Hydro	6.49*
Hydro Quebec	6.97
BC Hydro	9.22
SaskPower	10.67
North Dakota	11.00
South Dakota	13.09
Minnesota	12.36
Wisconsin	14.06

*Total revenue used in the calculation includes PUB-approved rate increases of 3.36% effective August 1, 2017 and the portion of 3.6% effective June 1 to June 30, 2018.

As demonstrated in the Figures above, Manitoba continues to maintain an advantage over most North American jurisdictions with respect to the average monthly customer bills and average prices for all customer classes.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2018	OUTLOOK 2019	INTERIM BUDGET 2020
REVENUES			
Domestic Revenue			
at approved rates	1 616	1 701	1 678
additional	-	-	59
BPIII Reserve Account	(152)	14	78
Extraprovincial	437	392	411
Other	30	30	29
	1 931	2 137	2 255
EXPENSES			
Operating and Administrative	517	501	511
Net Finance Expense	578	708	765
Depreciation and Amortization	402	473	508
Water Rentals and Assessments	126	113	111
Fuel and Power Purchased	130	138	160
Capital and Other Taxes	130	142	150
Other Expenses	501	78	111
Corporate Allocation	8	8	8
	2 393	2 161	2 325
Net Income before Net Movement in Reg. Deferral	(462)	(24)	(70)
Net Movement in Regulatory Deferral	472	69	103
Net Income	10	45	33
Net Income Attributable to:			
Manitoba Hydro	**18**	**51**	**31**
Non-controlling Interest	(8)	(6)	2
	10	45	33
PUB Approved Percent Increase	3.36%	3.60%	-
Proposed Percent Increase	-	-	3.50%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2018	OUTLOOK 2019	INTERIM BUDGET 2020
ASSETS			
Plant in Service	13 681	19 106	19 645
Accumulated Depreciation	(1 302)	(1 774)	(2 233)
Net Plant in Service	12 380	17 332	17 412
Construction in Progress	8 995	6 322	7 511
Current and Other Assets	1 792	1 890	2 388
Goodwill and Intangible Assets	440	693	895
Total Assets before Regulatory Deferral	23 607	26 237	28 206
Regulatory Deferral Balance	933	948	1 050
	24 540	27 184	29 256
LIABILITIES AND EQUITY			
Long-Term Debt	17 813	21 396	22 430
Current and Other Liabilities	3 777	2 729	3 784
Provisions	60	49	47
Deferred Revenue	414	472	478
BPIII Reserve Account	348	333	255
Retained Earnings	2 767	2 818	2 850
Accumulated Other Comprehensive Income	(688)	(613)	(586)
Total Liabilities and Equity before Regulatory Deferral	24 491	27 184	29 256
Regulatory Deferral Balance	49	-	-
	24 540	27 184	29 256

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

For the year ended March 31	ACTUAL 2018	OUTLOOK 2019	INTERIM BUDGET 2020
OPERATING ACTIVITIES			
Net Income	10	45	33
Add Back:			
Depreciation and Amortization	402	473	508
Net Finance Expense	578	708	765
Net Movement Impacts on Depreciation and Finance Expense	3	23	26
Adjustments for Non-Cash Items	(12)	15	(8)
Adjustments for Non-Cash Working Capital Accounts	(256)	(40)	(38)
Interest Paid	(880)	(974)	(1 065)
Interest Received	23	10	21
Cash Provided by Operating Activities	(132)	260	242
FINANCING ACTIVITIES			
Proceeds from Long-Term Debt	3 441	3 780	2 350
Retirement of Long-Term Debt	(583)	(1 000)	(346)
Repayments from/(Advances to) External Entities	(57)	(51)	(45)
Proceeds from Partnership Issuances	44	50	44
Sinking Fund Withdrawals	165	0	0
Sinking Fund Payment	(165)	(213)	(254)
Other	(11)	(0)	0
Cash Provided by Financing Activities	2 833	2 567	1 749
INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2 610)	(2 465)	(1 523)
Additions to Intangible Assets	(133)	(225)	(198)
Additions to Regulatory Deferral Balances	(93)	(90)	(127)
Contributions Received	194	57	13
Cash Paid to the City of Winnipeg	(16)	(16)	(16)
Cash Paid for Mitigation and Major Development Liabilities	(46)	(130)	(68)
Other	(3)	(0)	(0)
Cash Used for Investing Activities	(2 706)	(2 869)	(1 918)
Net Increase (Decrease) in Cash	(4)	(43)	73
Cash at Beginning of Year	634	574	530
Cash at End of Year	629	530	604

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

For the year ended March 31	ACTUAL 2018	OUTLOOK 2019	INTERIM BUDGET 2020
OPERATING ACTIVITIES			
Cash Receipts from Customers	1 883	2 067	2 165
Cash Paid to Suppliers and Employees	(1 158)	(844)	(879)
Interest Paid	(880)	(974)	(1 065)
Interest Received	23	10	21
Cash Provided by Operating Activities	(132)	260	242
FINANCING ACTIVITIES			
Proceeds from Long-Term Debt	3 441	3 780	2 350
Retirement of Long-Term Debt	(583)	(1 000)	(346)
Repayments from/(Advances to) External Entities	(57)	(51)	(45)
Proceeds from Partnership Issuances	44	50	44
Sinking Fund Withdrawals	165	0	0
Sinking Fund Payment	(165)	(213)	(254)
Other	(11)	(0)	0
Cash Provided by Financing Activities	2 833	2 567	1 749
INVESTING ACTIVITIES			
Additions to Capital Assets	(2 610)	(2 465)	(1 523)
Additions to Intangible Assets	(133)	(225)	(198)
Additions to Regulatory Deferral Balances	(93)	(90)	(127)
Contributions Received	194	57	13
Cash Paid to the City	(16)	(16)	(16)
Cash Paid for Mitigation and Major Development Liabilities	(46)	(130)	(68)
Other	(3)	(0)	(0)
Cash Used for Investing Activities	(2 706)	(2 869)	(1 918)
Net Increase (Decrease) in Cash	(4)	(43)	73
Cash at Beginning of Year	634	574	530
Cash at End of Year	629	530	604

CONSOLIDATED CASH FLOW STATEMENT - DIRECT
FOR THE YEAR ENDED MARCH 31

(In Millions of Dollars)

	2018	2017
Operating Activities		
Cash receipts from customers	$2 287	$2 330
Cash paid to suppliers and employees	(1 491)	(889)
Interest received	23	17
Interest paid	(913)	(834)
Cash provided by (used for) operating activities	(94)	623
Investing Activities		
Additions to property, plant and equipment	(2 652)	(2 678)
Additions to intangible assets	(137)	(121)
Additions to regulatory deferral balances	(105)	(87)
Contributions received	195	134
Cash paid to the City of Winnipeg	(16)	(16)
Cash paid for mitigation obligations	(30)	(21)
Cash paid for major development obligations	(15)	(11)
Other	(4)	13
Cash used for investing activities	(2 764)	(2 785)
Financing Activities		
Proceeds from long-term debt	3 400	2 186
Retirement of long-term debt	(583)	(320)
Repayments from (advances to) external parties	(57)	(53)
Proceeds from partnership issuances	44	42
Proceeds from short-term borrowings	50	-
Sinking fund investment withdrawals	165	146
Sinking fund investment payments	(165)	(146)
Cash provided by financing activities	2 854	1 855
Net decrease in cash and cash equivalents	(4)	(309)
Cash and cash equivalents, beginning of year	646	955
Cash and cash equivalents, end of year	**$642**	**$646**

Transforming our service.

Manitoba Hydro-Electric Board 67th Annual Report
For the year ended March 31, 2018



Manitoba Hydro

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Cover photo: Construction of the Bipole III Transmission Reliability Project.

Letter of Transmittal

July 27, 2018

Honourable Cliff Cullen

Minister of Crown Services
Legislative Building
Winnipeg, Manitoba
R3C 0V8

Dear Minister,

I present the 67th Annual Report of the Manitoba Hydro-Electric Board, together with the financial statements for the fiscal year ended March 31, 2018.



Respectfully submitted,

Marina R. James, MBA
Chair, Manitoba Hydro-Electric Board

Our service area in km^2

650 000

Total debt

$19.2 billion

Total assets

$25.2 billion

Number of natural gas customers

281 990







Kilometres of distribution lines

75 500

Kilometres of transmission lines

12 400

*this total previously included 66-kilovolt lines that are now included in total distribution kilometres.

Kilometres of natural gas lines

10 329

Number of Indigenous employees

1 026







Number of communities with natural gas service

132



Number of electricity customers

580 262





Total electricity capability

5 648
megawatts

Total number of full-time employees

5 998*

*See page 107 for definition of full-time employees



Sunset in Grand Rapids, Manitoba

Corporate Profile

Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. We are a leader in providing renewable energy and clean-burning natural gas. Our award-winning demand side management programs help Manitoba residents and businesses conserve energy and lower their energy costs.

We also trade electricity within four wholesale markets in the Midwestern United States and Canada. Nearly all of the electricity Manitoba Hydro produces each year is renewable hydro power generated using the province's abundant water resources. Our export of electricity helps to keep our rates in Manitoba lower than they would otherwise be and displaces greenhouse emissions in markets where fossil fuels are used for electricity production.

Mission

We create value for Manitobans by meeting our customers' expectations for the delivery of safe, reliable energy services at a fair price.

Strategic Priorities

- Restore financial sustainability
- Deliver an excellent customer experience
- Engage employees in our transformation
- Respect and support Indigenous peoples in all aspects of our business

Foundational Principles

- Safety
- Respectful engagement with communities and stakeholders
- Environmental leadership
- Respect for each other

President & CEO's Letter to Customers

Transforming our service

Every day our customers use our products and services. Even when they are at rest, energy powers their homes, and the businesses and services they rely on. Over 580,000 Manitoba customers rely on us for electricity, and over 280,000 for natural gas service. We recognize and appreciate that Manitobans depend on us to meet their critical energy requirements.

Providing safe, reliable and economic service to our customers is at the core of everything we do. Over the past year, we continued to make the needed investments in our system to ensure a reliable supply of energy and also took steps to address the financial impacts of this sizable investment.

We maintain our strong focus on completing our major capital projects, including the Bipole III Transmission Reliability Project, the Keeyask Generating Station and the Manitoba-Minnesota Transmission Project. As we execute on approved projects, we focus on safety, efficiency, quality, schedule and cost.

We are now projecting our overall debt to grow to about $25 billion in the next five years as we complete major projects such as the Bipole III Transmission Reliability Project and the Keeyask Generating Station and work to rebuild aging parts of our system that are failing, such as wood poles and substations. This level of debt increases the potential financial exposure from risks facing the corporation and is a concern for both the corporation and our customers who may be exposed to higher rate increases in the event of rising interest rates, a prolonged drought or a major system failure.

We've taken a balanced approach to addressing this financial risk that includes management restructuring and a 15 per cent workforce reduction, pursuit of additional sales of surplus electricity outside of Manitoba and regulatory filings with the Manitoba Public Utilities Board (PUB) seeking annual electricity rate increases.

A voluntary departure program offered last spring saw over 800 employees opt to leave the corporation by the end of January 2018, which will result in substantial and sustainable savings. While achieving cost savings, we remain committed to keeping safety at the fore of all we do; efficiencies will not come at the cost of safety to our staff or the public.

Further opportunities are being developed to reduce our operating and maintenance costs – most recently through our Strategic Sourcing Initiative. Annually, we spend approximately $750 million procuring goods and services for our operations – through strategic procurement initiatives we estimate annual recurring savings of $36 million will be realized over the next three years. This approach is an acceleration of the work already begun in our Supply Chain Management Performance Enhancement Program initiated in 2015, which has resulted in accumulated realized savings totaling approximately $22 million to the end of this fiscal year.

Reducing costs is only one part of our work to restore financial stability. We continue to seek export sales and are in active discussions to lengthen contract arrangements and negotiate new export sales of benefit to our organization and our Manitoba customers. Manitoba Hydro's renewable, virtually emission-free hydro power continues to be viewed favourably by our export customers.

We will also continue to be disciplined stewards of capital in determining how and where we make necessary re-investments in an aging electricity system. We are improving our tools and strategies to continuously improve our decision making in asset management.

Rate increases are also part of our balanced approach. In 2017, we submitted a General Rate Application (GRA) to the Manitoba Public Utilities Board (PUB) which has the authority to review and set electricity rates in Manitoba. We requested they confirm a previous 3.36 per cent rate increase approved on an interim basis in 2016; as well as a 7.9 per cent increase effective August 1, 2017, and an additional 7.9 per cent increase effective April 1, 2018. On May 1, 2018 the PUB confirmed the 3.36 per cent increase effective August 1, 2016. They also confirmed a 3.36 per cent increase effective August 1, 2017 and approved a 3.6 per cent average rate increase effective June 1, 2018 — substantially less than requested.

We will work closely with the newly appointed Manitoba Hydro-Electric Board (MHEB) to understand the fuller implications of the PUB decision and determine the right approach going forward to establish a long term, sustainable financial plan.

We maintain our strong focus on completing our major capital projects, including the Bipole III Transmission Reliability Project, the Keeyask Generating Station and the Manitoba-Minnesota Transmission Project (MMTP). As we execute on approved projects, we focus on safety, efficiency, quality, schedule and cost.

To that end, I am pleased to report that Bipole III is nearing completion and is expected to come into service as planned in July 2018. The transmission line is fully constructed, connected to both the Riel and Keewatinohk Converter Stations and is undergoing final testing and integration with the rest of the Manitoba Hydro system. Once in operation, Bipole III will strengthen our reliability, reducing our reliance on Bipole I and II. It will also serve as our link to transport the energy generated from the Keeyask Project to Southern Manitoba and export markets.

To remain an industry leader, Manitoba Hydro must continue to modernize and enhance our customer experience.

Construction of the Keeyask Generating Station is now more than halfway complete. It is impressive to see what has been achieved so far both on the ground and with respect to its outstanding performance on employment targets, safety record and environmental performance.

Keeyask currently remains on track to meet its control budget of $8.7 billion and scheduled in-service date of August 2021 for Unit 1. However, with four years of construction still ahead, there are many risks that could impact the project. To effectively manage these risks to cost and schedule, our entire project team is actively working to find efficiencies while pushing ahead to meet our production goals with the same dedication to safety, the environment and quality.

Through our Keeyask and Wuskwatim partnerships with First Nations communities, our organization took important steps in strengthening relationships with Indigenous peoples. These efforts enable us to address historical issues and work with our partners to create employment and business opportunities. The Keeyask Project has seen success on both these fronts. The value of Direct Negotiated Contracts (DNC's) with partner First Nation businesses for infrastructure and generating station construction meets and exceeds the value committed in the Joint Keeyask Development Agreement (JKDA).

Keeyask has also far exceeded the Keeyask Cree Nation (KCN) employment target set in the JKDA for the entire construction phase. Employment of Manitobans, Indigenous persons and members from the partner First Nations communities on the project also remains strong. From project commencement to the end of March 2018, of the 16,317 total hires, 71 per cent are from Manitoba; 44 per cent have self-declared as being Indigenous; and 22 per cent are from our KCN partner communities. Beyond the legacy of clean, renewable energy the Keeyask Project will create, it has already created a legacy of skills and opportunities for individuals in our province.

Manitoba Hydro is well advanced in the regulatory process for licensing of our MMTP. In October, 2017 following the provincial regulatory process and hearing, the Clean Environment Commission (CEC) issued their report recommending that a Provincial Environment Act Licence be issued. A Federal regulatory review process is underway with the National Energy Board holding public hearings in June 2018. Manitoba Hydro's current schedule, assuming the required licences are issued this fall, calls for construction to start on MMTP in late 2018.

We continue to invest in renewal of our aging infrastructure to further secure our service and ensure public safety. This includes initiatives such as our ongoing attention to the 1.1 million wood poles that carry our distribution lines and power to customers throughout the province. More than half the poles in our province are over 30 years old. Annually, we inspect and treat more than 60,000 power distribution poles in order to extend their life and save on replacement costs.

We're also making great progress addressing our electrical system capacity in Winnipeg. We are on track to meet our targets of fewer than 20 per cent of our stations being overloaded by the year 2020 and fewer than five per cent by 2030. The new Adelaide station, which opened in September 2017, is indicative of our efforts and provides much needed capacity in our downtown core. The 66-kilovolt (kV), gas-insulated facility features state-of-the-art technology to make our electrical grid more reliable. The station can be expanded as load increases and the construction of Adelaide permits the decommissioning of obsolete equipment in our King Street station.

In our last fiscal year, we successfully completed the Slave Falls Creek spillway conversion. At nearly 90 years old, the spillway showed signs of deterioration and leakage that posed a safety risk. Construction of the project began in January and was completed in October, on schedule and under budget.

Early 2018 brought the Manitoba provincial government's proclamation of The Efficiency Manitoba Act, which launched a new stand-alone Crown Corporation tasked to deliver electric and natural gas demand side management (DSM) programs and services. For more than a quarter century, Manitoba Hydro's Power Smart* programs have been a very visible, valued part of our service offering to customers. As we prepare to retire that brand and transfer that function to Efficiency Manitoba, it creates a new opportunity to take a close look at our organization from our customers' perspectives to understand their needs and how best to meet their expectations and drive efficiencies.

There's no question, service preferences are changing. More and more customers are seeking simpler, more convenient interactions often through online channels.

To remain an industry leader, Manitoba Hydro must continue to modernize and enhance our customer experience. In 2017-2018, we completed the consolidation of 36 district offices and closure of cash counters. Since 2007, we have seen a steady decline in customer transactions at rural district offices and a corresponding shift to using larger customer service centres or completing bill payments online or by phone.

We have always been focused on serving our customers and providing for their energy needs now and into the future. Our focus is now intensified on taking that service to a higher level.

For customers, the consolidation enables us to apply our resources towards innovative technologies. This includes the recent enhancement of our web-based service tools. In 2017, we launched a new service outage page that includes a map updated every 15 minutes with outage details, a tabulated list of current outages, and a link to our real-time Twitter feed for more information. Customers can also report outages directly from this page. This is only a start, as we review the many ways customers interact with our organization and think about how to make these points of contact better. We have always been focused on serving our customers and providing for their energy needs now and into the future. Our focus is now intensified on taking that service to a higher level.

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

Five new members, including a new chair, were appointed to the MHEB by the Government of Manitoba in March 2018. I want to extend my thanks to our previous chair and board members who worked hard during their time with the MHEB to provide valuable guidance and support to the corporation. Manitoba Hydro's executive management team looks forward to working closely with chair, Marina R. James and the other newly appointed members of the MHEB who assume the very important role of providing strategic governance and oversight for Manitoba Hydro.

I'd like to close by acknowledging and sincerely thanking all Manitoba Hydro employees, who have proven their resilience and ongoing dedication to the corporation and our customers through a year of significant challenges and changes. In the end, our people build our energy systems and serve our customers. They are diverse, skilled, experienced, committed and the key strength that ensures Manitoba Hydro will continue to deliver safe, reliable and cost effective energy to Manitobans. It's a privilege to work with them.



Kelvin Shepherd, P.Eng
President and Chief Executive Officer
Manitoba Hydro

Report on Performance — 2017-18 Highlights

- Erected the final of 3,076 towers on the 1,384 kilometre Bipole III transmission line; valve halls at both the Riel Station and Keewatinohk Converter Station energized to 500,000 volts.
- First of seven draft tube liners installed at the Keeyask Project; achieved critical milestones of enclosure of the powerhouse service bay and units 1, 2&3; and completion of concrete work on the spillway.
- The Manitoba Clean Environment Commission recommended an Environment Act Licence be granted for our Manitoba-Minnesota Transmission Project (MMTP) – a 500,000 volt transmission line in southeastern Manitoba.
- Completed the conversion of the Slave Falls Creek spillway structure to a non-overflow dam on schedule and under budget at a final cost of $12.8 million versus the projected $17.5 million.
- Opened Adelaide Station, a 66,000-volt substation that strengthens the reliability of our electrical grid in Winnipeg and strengthens our ability to meet growing energy demands in our downtown core.
- Opened our new compressed natural gas station near Winnipeg, which allows our corporation to respond rapidly to natural gas outages.
- Switched almost 69,000 street lights to new energy-efficient Light Emitting Diode (LED) lights under the six-year Power Smart* LED Roadway Lighting Conversion Program launched in 2014 – making us more than halfway through the program target to convert over 130,000 street lights in the province by 2021.
- The Affordable Energy Program (AEP) commemorated the completion of upgrades to 20,000 homes that have helped our customers reduce their consumption by approximately 28 gigawatt hours of electricity and 9.3 million cubic metres of gas.
- Received two ENERGY STAR Canada Awards – Provincial Utility of the Year and Promotional Campaign of the Year.
- Named as one of our country's top employers for the eighth consecutive year by Canada's Top Employers Project.



The finished Slave Falls Creek spillway structure

Major projects update

Bipole III Transmission Reliability Project

The Bipole III Transmission Reliability Project is nearing completion and will come into service in July 2018. When complete, Bipole III will strengthen the reliability and security of the province's energy supply by creating an alternate connection to deliver electricity from northern generating stations to customers in southern Manitoba.

This year saw the Bipole III transmission line fully constructed, and connected to both the Riel and Keewatinohk Converter Stations. Construction at the converter stations is nearly complete.

The first two of Riel Station's four synchronous condensers – 360,000-kilogram machines that rotate at 1,200 revolutions per minute and help stabilize Hydro's system – went into service this April 2018. Focus is now on completing the remaining work for the synchronous condensers at the Riel Converter Station, commissioning and a trial operation period as Bipole III is integrated into the Manitoba Hydro system.

When completed, the Bipole III Project will add 2,000 megawatts (MW) to Manitoba Hydro's high-voltage direct current transmission capacity.

July 2018 – projected in-service date
$5.04 billion – total estimated cost
$4.2 billion – total spent to March 31, 2018
3,235 – active hires as of March 31, 2018

- **77 per cent** – Manitoba residents
- **28 per cent** – Indigenous persons



Construction at the Keewatinohk Converter Station

Keeyask Generating Station

The Keeyask Project is a 695-MW hydroelectric generating station being developed in partnership between Manitoba Hydro and four Manitoba First Nations – Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation and Fox Lake Cree Nation.

When completed in 2021/22, the Keeyask Generating Station will provide a new source of electricity needed to maintain a reliable supply for Manitoba.

Keeyask is a massive, complex project and aggressive targets were set for the 2017 construction season. This resulted in a significant improvement in production across the project compared to the previous year. Work achieved included completion of the concrete work for the spillway structure; sizeable progress on the earth structures (dam and dykes); and enclosure of the service bay and powerhouse units 1, 2 and 3. Installation of the gates and guides, as well as the tower, bridge and hoists, was started which will enable the diversion of water through the spillway in 2018.

The project remains strong on safety, environmental protection and partner community participation. Since 2014, there has been a steady, continuous improvement of the project safety record.

Keeyask Cree Nation (KCN) and Indigenous employment targets outlined in the Joint Keeyask Development Agreement have also been exceeded. A milestone of two million KCN labour hours and four million Indigenous hours worked on the Keeyask Project was reached in July 2017.

The project continues to push to achieve its production goals, and be diligent at minimizing costs and capitalizing on cost-saving opportunities to meet the in-service date and budget.

August 2021 – project in-service date
$8.7 billion – total estimated cost
$4.51 billion – spent to March 31, 2018
16,137 total hires to the project

- **71 per cent** Manitoba residents
- **45 per cent** Indigenous persons



Construction of the powerhouse at the Keeyask site

SAFETY

Promoting safety is one of Manitoba Hydro's foundational principles. We are committed to continuously improving safety performance and focusing on strategies to instill a safety and health culture in all corporate activities.

MEASURE	TARGET	PERFORMANCE
Accident severity rate (days per 200 000 hrs worked)	<12	13.83
Accident frequency rate (accidents per 200 000 hrs worked)	<0.60	1.35
Serious incidents	0	6

DELIVER AN EXCELLENT CUSTOMER EXPERIENCE

While continuing to deliver safe, reliable energy at a fair price, we are working to enhance our customer experience.

MEASURE	TARGET	PERFORMANCE
System average interruption duration (minutes per year)	<116	131.9
System average interruption frequency (outages per year)	<1.4	1.45
Customer satisfaction	>8.2/10	8.0

RESTORE FINANCIAL SUSTAINABILITY

In order for us to maintain and grow our business as well as manage our operating risks, a strong financial position is a necessity. We are committed to carefully managing costs and utilizing resources efficiently and effectively to fulfill our mandate and provide maximum value to our stakeholders and customers.

MEASURE	TARGET	PERFORMANCE
Debt:equity ratio	75:25	85:15
Interest coverage	1.80	1.50
Capital coverage	1.20	0.50

WORKFORCE MANAGEMENT & INDIGENOUS RELATIONS

A highly skilled and motivated workforce that reflects the demographics of Manitoba is critical to our success. Engaging impacted Indigenous communities in a positive way is vital to enhancing working relationships. We continue to place emphasis on addressing the adverse effects of our operations and fostering respect and support of Indigenous peoples in all aspects of our business.

MEASURE	TARGET	PERFORMANCE
Indigenous – province-wide workforce	18%	19.4%
Indigenous – northern workforce	47%	48.8%
Persons with disabilities	6%	8.2%
Visible minorities	9%	9.2%

ENVIRONMENTAL LEADERSHIP

Protecting the environment is an integral part of everything we do. Manitoba Hydro integrates environmentally responsible practices into all aspects of our business. Environmental protection is carried out with dedication to monitoring programs, climate change initiatives and environmental research and development.

MEASURE	TARGET	PERFORMANCE
Renewable electricity generated in Manitoba	≥99%	99.73%
Total annual GHG emissions	≤520 kt	104 kt
Repeat environmental audit findings	0 repeat findings	0

DEMAND SIDE MANAGEMENT

Demand side management plays a key role in meeting Manitoba's future energy needs in a sustainable manner as the province's population and economy continues to grow. Our efforts assist customers in using energy more efficiently and result in overall lower energy bills.

MEASURE	TARGET	PERFORMANCE
Annual incremental electric energy saved	310 GWh	417 GWh
Electric capacity saved annually	238 MW	257 MW
Natural gas energy saved annually	9.4 million cubic metres	6.6 million cubic metres

Corporate 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 2017-18 which allege wrongdoing as defined in The Public Interest Disclosure (Whistleblower Protection) Act:

Total number of disclosures received:	0
Number of disclosures ongoing from 2017-18	2
Number of disclosures acted upon:	2
Number of disclosures not acted upon:	0
Number of investigations commenced/continued:	2
Number of disclosures verified:	0
Number of disclosures not verified:	0
Number of disclosures carried forward to 2018-19:	2

Manitoba Hydro-Electric Board



Appearing from left to right: Michael Moore, Vice-Chair; Lisa Meeches, Marina R. James, Chair; Wade Linden, Melanie McKague, Cliff Graydon.

Manitoba Hydro Senior Officers



Appearing from left to right:

Shane Mailey, P. Eng
Vice-President,
Transmission

Bryan Luce
Vice-President,
Human Resources
& Corporate Services

Jeffrey Betker, B.A., B.Comm (Hons), MBA
Vice President, Indigenous Relations

Kelvin Shepherd, P. Eng
President and Chief Executive
Officer

Lorne Midford, P. Eng
Vice-President,
Generation & Wholesale

Siobhan Vinish
Vice-President,
Marketing & Customer Service

Ken Tennenhouse, LL. B
General Counsel &
Corporate Secretary

Jamie McCallum
Chief Finance & Strategy Officer

Financial Review

Management's Discussion and Analysis

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The following Management's Discussion and Analysis (MD&A) provides comments on the financial results of Manitoba Hydro (the corporation) for the year ended March 31, 2018 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. The fiscal 2018 financial information discussed below has been prepared in accordance with International Financial Reporting Standards (IFRS).

Summary of Consolidated Results

Consolidated Statement of Income

Manitoba Hydro's consolidated net income from electricity and natural gas operations for the fiscal year ended March 31, 2018 was $37 million compared to $71 million in the previous fiscal year. Net income decreased by $34 million primarily as a result of restructuring charges driven by the implementation of a significant cost reduction program. The cost reduction program includes a multi-year plan to achieve a 900 person staff reduction already substantially achieved primarily through the implementation of a Voluntary Departure Program (VDP) launched in April 2017. The number of executives was reduced by 30%, and overall the corporation reduced its management staff by 26%. In addition to position reductions, Manitoba Hydro has committed to achieve procurement savings through supply chain management initiatives.

Excluding restructuring expenses, Manitoba Hydro would have reported net income of $87 million in 2017-18, an improvement of $33 million over the prior year excluding a $20 million gain on sale of property and a $3 million restructuring charge. The improvement was mostly attributable to higher domestic electricity revenue resulting from colder weather and customer growth along with a reduction in operating and administrative expenses as a result of the cost reduction program. These improvements were partially offset by lower extraprovincial revenues (net of power purchased and water rental expenses) due to lower hydraulic generation.

The following table provides results on the two primary operating segments of Manitoba Hydro as well as the consolidated results.

	Electric		Natural Gas		Consolidated*		
	2018	2017	**2018**	2017	**2018**	2017	Change
	millions of dollars						
Revenues							
Manitoba	**1 494**	1 467	**346**	345	**1 893**	1 867	26
Extraprovincial	**437**	460	**-**	-	**437**	460	(23)
	1 931	1 927	**346**	345	**2 330**	2 327	3
Expenses	**2 393**	1 952	**346**	330	**2 780**	2 323	457
Net income (loss) before net movement in regulatory balances	**(462)**	(25)	**-**	15	**(450)**	4	(454)
Net movement in regulatory balances	**472**	66	**7**	(11)	**479**	55	424
Net income (loss)	**10**	41	**7**	4	**29**	59	(30)
Net income (loss) attributable to:							
Manitoba Hydro	**18**	53	**7**	4	**37**	71	(34)
Non-controlling interests	(8)	(12)	**-**	-	(8)	(12)	4
	10	41	**7**	4	**29**	59	(30)
Total assets and regulatory debits	**24 540**	21 733	**752**	721	**25 169**	22 338	2 831
Retained earnings	**2 767**	2 749	**76**	69	**2 936**	2 899	37
Financial Ratios							
Debt: equity					**85:15**	84:16	
Interest coverage					**1.50**	1.54	
Capital coverage					**0.50**	1.48	

*Includes other segments and eliminations

Consolidated net income attributable to Manitoba Hydro of $37 million for the 2018 fiscal year was comprised of net income of $18 million in the electric segment, net income of $7 million in the natural gas segment, net income of $10 million from subsidiaries and a $2 million net income related to adjustments required on consolidation to harmonize accounting policies between electric and natural gas operations related to the gas meter exchange program.

Consolidated net income for 2017-18 was $84 million lower than the budgeted net income of $121 million which was primarily due to the Public Utilities Board's (PUB) decision to deny the corporation's request for a 7.9% interim rate increase as at August 1, 2017. The PUB did approve a 3.36% interim electricity rate increase August 1, 2017 but directed that the entire increase be added to the previously established Bipole III deferral account. Also contributing to the lower than forecasted net income was a continuation of weaker than planned opportunity prices in the export market and higher financing costs.

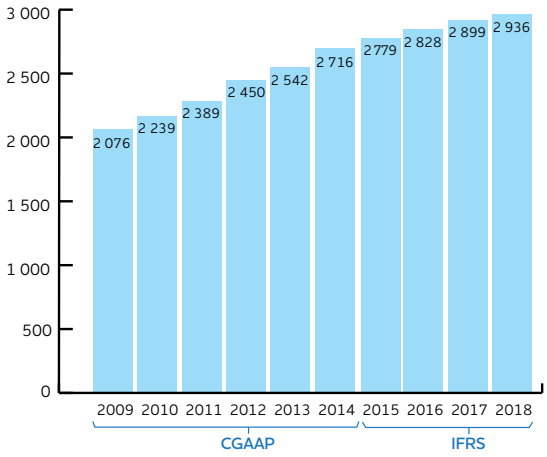
Financial Targets

Manitoba Hydro has three primary financial targets which are used to assess the financial strength of the corporation. The first is to maintain a minimum equity ratio of 25%, a measure of the portion of assets that are financed by internally generated funds rather than debt. The second is an interest coverage ratio which considers earnings before interest, depreciation and amortization adjusted for net movement impacts with a minimum target of greater than 1.80 that measures the ability to meet interest payment obligations with cash flow. The third is to maintain a capital coverage ratio of greater than 1.20 which is a measure of the ability of cash flow from operations to fund sustaining capital expenditures.

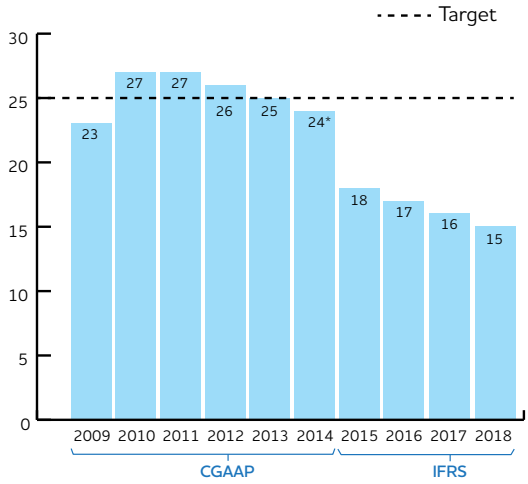
Consolidated net income of $37 million contributed to the corporation's retained earnings of $2 936 million at March 31, 2018. The equity ratio of 15% is lower than the 25% target. The decline in the equity ratio since 2011 is primarily due to higher debt levels to fund significant investment in major new generation and transmission facilities, transitional adjustments upon adoption of IFRS and significantly lower levels of net income as compared to earlier years. The interest coverage ratio of 1.50 was below the target level of 1.80 primarily due to lower levels of net income. The capital coverage ratio of 0.50 was below the target level of 1.20 primarily due to a decline in cash flow as a result of higher payments to vendors.

The capital coverage ratio has certain limitations particularly during periods of significant capital investment which Manitoba Hydro is currently undertaking. The 2017 level of 1.48 was positively impacted by a $364 million increase in accounts payable and accrued liabilities which was driven mostly by a significant payment accrual on the Bipole III Reliability project. In turn, in 2018, payment was made with respect to the accrual thereby contributing to a $339 million reduction in accounts payable and accrued liabilities thereby reducing cash flow and the capital coverage ratio.

Retained Earnings
For the year ended March 31
millions of dollars

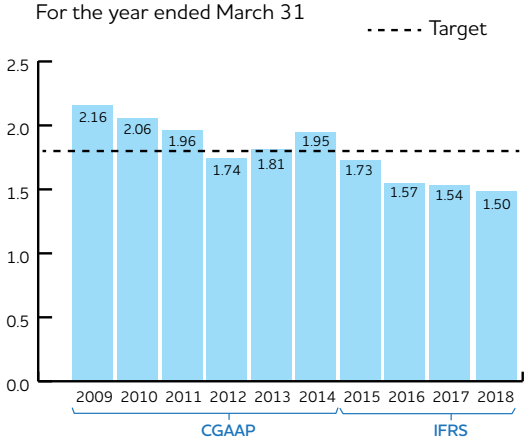


Equity Ratio
For the year ended March 31

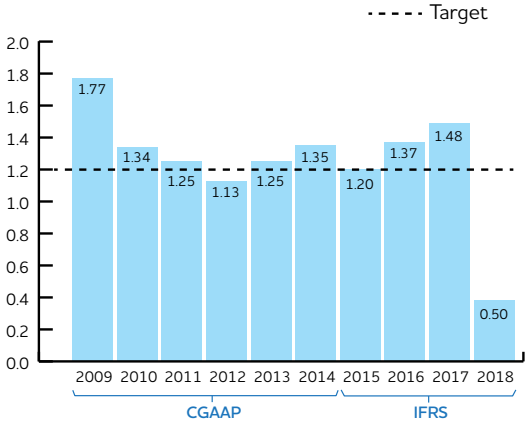


* On transition to IFRS on April 1, 2014, retained earnings was adjusted to $2 643 which reduced the equity ratio to 21%.

Interest Coverage Ratio
For the year ended March 31



Capital Coverage Ratio
For the year ended March 31



Subsequent to year-end, on May 1, 2018 the PUB issued Order 59/18 in respect of Manitoba Hydro's 2017-18 and 2018-19 electric rate application. The PUB denied Manitoba Hydro's request for a 7.9% rate increase as of April 1, 2018 and awarded a 3.6% average rate increase to be effective June 1, 2018. In its Order, the PUB signalled it no longer acknowledges the validity of the 25% equity ratio for the purposes of rate-setting and will not consider pacing to achieve such a ratio until at least after the 2023-24 fiscal year when the Keeyask Generating Station project is fully in service.

The PUB has ordered a technical conference on the establishment of a minimum retained earnings or similar test to provide guidance in setting consumer rates. Manitoba Hydro expects to obtain further clarity on PUB expectations with respect to financial targets and will need to incorporate these into future financial plans and rate applications.

Consolidated Statement of Financial Position

The following table provides a summary of Manitoba Hydro's consolidated statement of financial position.

	2018	2017	increase/ (decrease)
	millions of dollars		
Current assets	**1 221**	1 262	(41)
Property, plant and equipment	**21 979**	19 757	2 222
Non-current assets	**925**	753	172
Total assets	**24 125**	21 772	2 353
Regulatory deferral balances	**1 044**	566	478
Total assets and regulatory deferral balances	**25 169**	22 338	2 831
Current liabilities	**2 080**	1 631	449
Long-term debt	**18 200**	16 102	2 098
Non-current liabilities	**2 360**	2 168	192
Total liabilities	**22 640**	19 901	2 739
Equity	**2 453**	2 360	93
Total liabilities and equity	**25 093**	22 261	2 832
Regulatory deferral balances	**76**	77	(1)
Total liabilities, equity and regulatory deferral balances	**25 169**	22 338	2 831

Significant changes are explained below:

Current assets decreased $41 million primarily as a result of lower advances to the general civil contractor for the construction of the Keeyask Generating Station partially offset by increased receivables from customers as a result of colder winter weather and the impact of the electric rate increase August 1, 2017.

Property, plant and equipment increased by $2 222 million for capital expenditures for the development of major new generation and transmission facilities as well as additions, improvements and replacement of existing infrastructure.

Non-current assets increased by $172 million primarily due to the investment in the Great Northern Transmission Line (GNTL), advances made to Keeyask partners and easements associated with the Bipole III Reliability project.

Current liabilities increased by $449 million due to an increase in the current portion of long-term debt partially offset by a decrease in payables related to major capital projects. Long-term debt increased by $2 098 million to fund the investment in these major projects. Non-current liabilities increased by $192 million due to an increase in revenue set aside in the Bipole III deferral account and higher future employee benefit obligations due to actuarial losses on the pension liability associated with the reduction in the discount rate and the VDP.

Regulatory deferral balances increased primarily due to the transfer of the construction in progress balance of $379 million related to the Conawapa Generating Station as a result of the corporation's decision to discontinue further development of the station at this time. In addition, there was an increase in the annual investment in demand side management (DSM) programs as well as higher losses on the disposition of assets.

Consolidated Statement of Cash Flow

Manitoba Hydro's primary sources of liquidity and capital are funds generated from operations and debt financing through the Province of Manitoba. These sources are used for multiple purposes including investment in generation, transmission and distribution facilities, to fund operating and maintenance activities and to service long-term debt.

The following table provides a summary of Manitoba Hydro's consolidated statement of cash flows.

	2018	2017	change
	millions of dollars		
Cash and cash equivalents, beginning of year	**646**	955	(309)
Cash (used for) provided by operating activities	**(94)**	623	(717)
Cash used for investing activities	**(2 764)**	(2 787)	23
Cash provided by financing activities	**2 854**	1 855	999
Cash and cash equivalents, end of year	**642**	646	(4)

Cash from operating activities includes cash receipts from customers, cash paid to suppliers and employees as well as interest payments.

Cash used for operations in 2017-18 was $94 million, a decrease of $717 million from the cash provided in the previous year. The change reflects the significant reduction in the unusually high payable balances at March 31, 2017 related to the Bipole III Reliability project.

The corporation's electric and natural gas segments are capital intensive in nature and require continued investment in infrastructure to construct new generation, transmission and distribution facilities, increase capacity of existing facilities and maintain and improve service, reliability, safety and environmental performance.

Cash flow used in investing activities in 2017-18 was $2 764 million, compared to $2 787 million in 2016-17. The decrease was primarily due to additional contributions set aside in the Bipole III deferral partially offset by increased investment in GNTL and a change in the purchased gas variance account (PGVA) associated with the lower collection of prior period gas commodity costs from customers and increased commodity purchases.

Manitoba Hydro's authority to issue debt is provided through *The Loan Act*, which is approved each year and grants borrowing authority to meet the corporation's new debt financing requirements. *The Manitoba Hydro Act* grants the corporation the power to issue short-term promissory notes in the name of the Manitoba Hydro-Electric Board (MHEB) up to an aggregate sum of $500 million of principal outstanding at any one time. As at March 31, 2018 the corporation had $50 million outstanding on its short-term programs. Authority to refinance any maturing long-term debt is provided through *The Financial Administration Act*. The majority of Manitoba Hydro's long-term debt is obtained through advances from the Province of Manitoba.

The primary use of the long-term borrowing program is to provide debt financing for investment in new generation and transmission and, if needed, to fund continuing operations. The primary use of the short-term borrowing program is to safeguard the corporation from liquidity risk by providing a credit facility to support the corporation's temporary cash requirements. Both long and short-term borrowings are unconditionally guaranteed as to principal and interest by the Province of Manitoba (except for mitigation bonds issued by the MHEB).

Cash provided by financing activities in 2017-18 was $2 854 million, compared to $1 855 million in 2016-17 and is comprised primarily of proceeds from long-term debt through advances from the Province. Proceeds from financing arranged by the corporation amount to $3 400 million compared to $2 186 million in the previous year. Current year proceeds were used to fund new capital requirements and to refinance long-term debt maturing during the year. The corporation issued debt at a weighted average rate of 2.67% during 2017-18 (excluding the provincial debt guarantee fee) reflecting in part a decision to issue relatively shorter term maturity debt to take advantage of attractive market conditions.

Electric Segment

The electric segment is responsible for the generation, transmission and distribution of electrical energy adequate for the needs of the Province of Manitoba and engages in wholesale power related transactions in order to assist in providing a reliable and dependable supply of power to Manitoba and to minimize the net costs to Manitoba customers. The electric segment includes Manitoba Hydro's ownership interests in the Wuskwatim Power Limited Partnership (WPLP), the Keeyask Hydropower Limited Partnership (KHLP) and a subsidiary formed to participate in the development of a new transmission line to the United States. Manitoba Hydro provides electric service to 509 465 residential and 70 797 commercial and industrial customers in Manitoba.

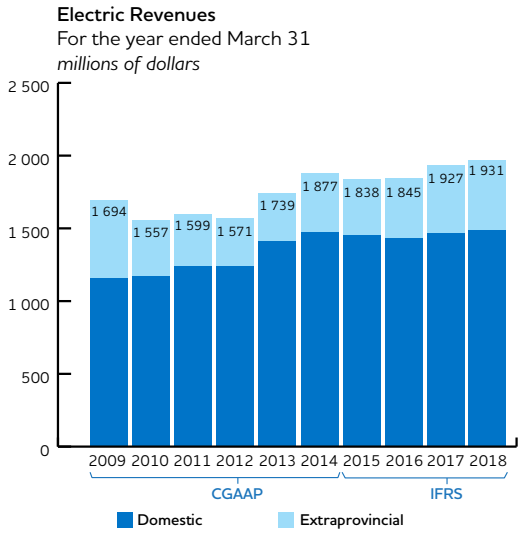
Net income attributable to Manitoba Hydro in the electric segment was $18 million in 2017-18 compared to net income of $53 million in the previous fiscal year. Without restructuring charges, net income in the electric segment would have been $65 million compared to $36 million in 2016-17 (excluding restructuring charges and the gain on sale of land).

Electric Revenues

Domestic revenue includes the sale of electricity to residential, commercial and industrial customers in Manitoba and other miscellaneous revenues. Residential customers are comprised of all housing types including apartment blocks, seasonal cottages and farm houses. Commercial customers are comprised of small and medium establishments including retail outlets, schools, universities and hospitals. Industrial customers are comprised of large establishments who own their own transformation and are primarily engaged in mining and/or manufacturing activities. Revenues are impacted by weather, electricity rates, customer growth and energy usage. Other revenue in the electric segment includes amortization of customer contributions, provision of services on customer owned plant, gains on the sale of property and net rental revenue between Manitoba Hydro and other telecom and cable providers.

Extraprovincial revenue includes revenues from Canadian and U.S. export sales as well as revenues from other related export market activities such as arbitrage opportunities between wholesale energy markets, transmission credits and the sale of renewable energy certificates. Canadian and U.S. sales include both dependable and opportunity sales. Dependable sales are export contracts sourced from Manitoba Hydro's hydraulic energy available during lowest water conditions, are typically negotiated at least one year in advance and have duration of greater than six months. Opportunity sales are based on excess energy, are generally over shorter periods and are transacted primarily in markets operated by an independent system operator such as the Midcontinent Independent System Operator (MISO). Opportunity sales are also negotiated directly with a purchasing party. Extraprovincial sales are impacted by changes in water flow conditions, export prices, foreign exchange rates and domestic usage. Extraprovincial sales volumes are dependent on the availability of surplus generation that requires favourable water flow conditions and the availability of transmission to export markets.

Total electric revenues were $1 931 million, an increase of $4 million or 0.2% from the previous year. This was the result of an increase of $27 million in domestic revenues partly offset by a $23 million decrease in extraprovincial revenues. Increases in domestic revenues are the result of colder winter weather and growth in the number of customers. Lower extraprovincial revenues were primarily due to lower U.S. opportunity sales volumes resulting from lower generation as well as U.S. transmission line outages partially offset by slightly higher export prices.



The breakdown of electric revenues is as follows:

Electric Revenues and kWh Sales

For the year ended March 31

	2018	2017	% change	2018	2017	% change
	millions of dollars			*millions of kWh*		
Domestic						
Electricity sales						
Residential	**616**	582	5.8	**7 636**	7 250	5.3
Commercial	**508**	496	2.4	**7 041**	6 873	2.4
Industrial	**340**	341	(0.3)	**7 828**	7 843	(0.2)
	1 464	1 419	3.2	**22 505**	21 966	2.5
Other revenue	**30**	48	(37.5)			
Domestic revenue	**1 494**	1 467	1.8	**22 505**	21 966	2.5
Extraprovincial						
Dependable	**260**	248	4.8	**3 361**	3 310	1.5
Opportunity	**168**	202	(16.8)	**6 087**	7 962	(23.5)
Other	**9**	10	(10.0)			
Extraprovincial revenue	**437**	460	(5.0)	**9 448**	11 272	(16.2)
	1 931	1 927	0.2	**31 953**	33 238	(3.9)

Revenues from electricity sales in Manitoba totaled $1 464 million in 2017-18, an increase of $45 million from the previous year. Electricity consumption in Manitoba was 22 505 million kilowatt-hours, 539 million kilowatt-hours higher than the previous year. The increase in consumption was mainly due to colder winter weather and an increase in the number of customers in all customer classes.

Revenues from sales to residential customers for 2017-18 amounted to $616 million, an increase of $34 million or 5.8% from the previous year. The increase was primarily attributable to colder winter weather and customer growth of 6 298 customers to 509 465, an increase of 1.3% compared to the previous year.

Revenues from commercial customers amounted to $508 million in 2017-18, an increase of $12 million or 2.4% from the previous year. The increase was mainly attributable to colder winter weather and customer growth of 515 customers to 70 409.

Revenues from industrial customers amounted to $340 million, a decrease of $1 million or 0.3% from the previous year. The decrease was mainly attributable to lower customer usage partially offset by customer growth of 11 customers to 388.

Other revenues amounted to $30 million, a decrease of $18 million or 37.5% from the previous year. The decrease was mainly the result of gains on the sale of property which occurred in the prior year.

Electric Revenues
For the year ended March 31, 2018



Residential	31%
General service	26%
Extraprovincial	23%
Industrial	18%
Other	2%

Extraprovincial revenues totaled $437 million in 2017-18, a decrease of $23 million from the previous year. The decrease reflects lower U.S. opportunity sales volumes due to U.S. transmission line outages and lower generation as well as unfavourable foreign exchange impacts from the strengthening Canadian dollar partially offset by higher export prices primarily on dependable and contract sales. Opportunity volumes were down 1 875 GWh or 24% compared to the prior year. Of the total extraprovincial revenues, $396 million or 91% was derived from the U.S. market, $38 million or 8% was from sales to Canadian markets and $3 million or 1% was related to arbitrage opportunities between wholesale energy markets.

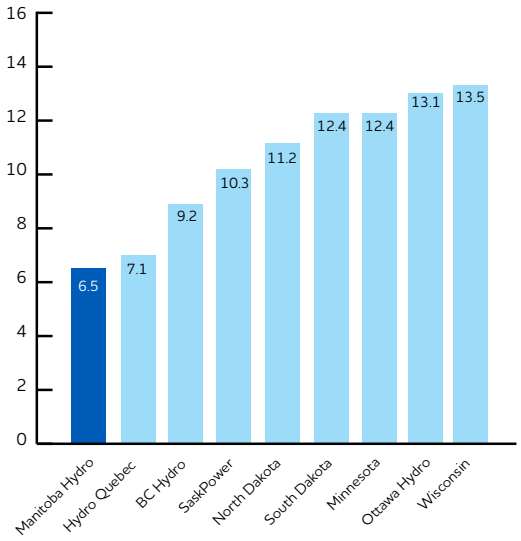
Electric Rates

The PUB issued Order 59/18 on May 1, 2018, which directed that the 3.36% electricity rate increases previously approved on an interim basis effective August 1, 2016 and August 1, 2017 both be approved as final. The PUB had directed that these increases be added to the previously established deferred revenue account to mitigate rate increases when the Bipole III Reliability project comes into service. During the 2017-18 fiscal year $152 million was set aside for this purpose. At the end of fiscal 2018, the balance in this deferral account totaled $348 million, which reflects the total of the set aside increases of 1.5% approved by the PUB effective May 1, 2013, 0.75% effective May 1, 2014, 2.15% effective August 1, 2015 and the above noted 3.36% effective August 1, 2016 and a further 3.36% effective August 1, 2017.

In Order 59/18, the PUB denied the corporation's request for a 7.9% across-the-board rate increase effective April 1, 2018 but approved a 3.6% average rate increase to be recovered in consumers' rates effective June 1, 2018.

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.

Average Retail Price of Electricity
cents/kWh (Cdn)



Electric Expenses

Electric expenses totaled $2 393 million for 2017-18, an increase of $441 million or 22.6% over the previous year. Excluding the transfer of the construction in progress balance related to the Conawapa Generating Station of $379 million (which is offset in net movement in regulatory balances), electric expenses increased $62 million. The increase in expenses was mainly the result of an increase in other expenses primarily attributable to restructuring charges driven by the implementation of a significant cost reduction program.

The breakdown of electric expenses is as follows:

Electric Expenses

For the year ended March 31

	2018	2017	% change
	millions of dollars		
Finance expense	**601**	608	(1.2)
Operating and administrative	**517**	536	(3.5)
Depreciation and amortization	**402**	375	7.2
Water rentals and assessments	**126**	131	(3.8)
Fuel and power purchased	**130**	132	(1.5)
Capital and other taxes	**130**	119	9.2
Other expenses	**502**	60	736.7
Corporate allocation	**8**	8	-
Finance income	**(23)**	(17)	35.3
	2 393	1 952	22.6

Finance expense includes interest on short and long-term borrowings and the provincial debt guarantee fee paid to the Province of Manitoba, foreign exchange gains and losses, accretion expense on provisions and other long-term liabilities, partially offset by interest capitalized for those qualifying assets under construction. Finance expense is impacted by borrowing requirements for capital investment, interest rates on borrowings and the capitalization of interest.

Finance expense totaled $601 million in 2017-18, a decrease of $7 million or 1.0% from the previous year. The decrease was primarily due to higher capitalization of financing costs driven by interest being capitalized at the weighted average rate whereas the actual rate on new borrowings during the year was lower. This was partially offset by higher foreign exchange losses on U.S. cash balances resulting from the strengthening Canadian dollar.

Operating and administrative expenses are comprised primarily of labour and benefits, materials, contracted services and overhead costs associated with operating, maintaining and administering the facilities and programs of the corporation and providing services to customers.

In 2017-18, operating and administrative expenses for electric operations amounted to $517 million, a decrease of $19 million, or 3.5% compared to 2016-17. The decrease in operating and administrative expenses is primarily attributable to a reduction in employee related expenditures resulting from the corporate restructuring initiative partially offset by an increase in uncollectible accounts.

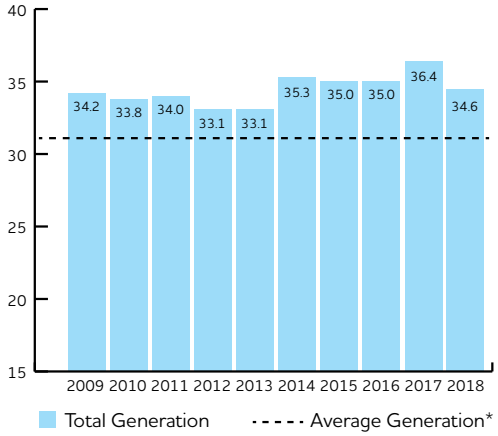
Depreciation and amortization includes depreciation of property, plant and equipment and amortization of intangible assets as well as any gains or losses on disposal of assets.

Depreciation and amortization expense amounted to $402 million in 2017-18, an increase of $27 million or 7.2% from the previous year. The increase was mainly attributable to new additions to plant and equipment coming into service including the Adelaide and St. Vital stations. The Adelaide station was built to address safety, operating and maintenance concerns with the King Street station which was built in the early 1900's and supplies approximately one third of the distribution load in the downtown area. With the construction of the Adelaide station, the King Street station will be decommissioned. The St. Vital station addresses load requirements in southeast Winnipeg that could no longer be managed by the existing station.

Water rentals and assessments includes water rentals paid to the Province of Manitoba for the use of water resources in the operation of the corporation's hydraulic generating stations and assessments paid to various regulatory and market organizations.

Water rentals and assessments amounted to $126 million in 2017-18 as compared to $131 million in the prior year. The decrease reflects lower hydraulic generation in 2017-18 compared to the previous year which had above average water flows. Hydraulic generation amounted to 34.6 billion kilowatt-hours in 2017-18 compared to 36.4 billion kilowatt-hours in the previous year which is a decrease of 5%. Fiscal 2017-18 reflected the 14th consecutive year of water flows above long-term average. Over the past 110 years the next longest period of above average water flow conditions was five years.

Hydraulic Generation
For the year ended March 31
billions of kWh



* Average hydraulic generation is based on historic river flows since 1912 and the current hydroelectric generation fleet

Fuel and power purchased includes fuel for the thermal generating stations and remote diesel sites, purchased electrical energy from external Canadian and U.S. suppliers, wind power purchased from the independently-owned St. Leon and St. Joseph wind farms and transmission charges. Fuel and power purchases are impacted by weather, market prices for electricity and water flow conditions. If water conditions are low, electricity purchases are necessary to meet the energy requirements of Manitobans. Manitoba Hydro has experienced higher than average hydraulic generation over the past several years largely as a result of favourable water supply conditions reducing the requirement to purchase power.

Fuel and power purchased was $130 million in 2017-18, a decrease of $2 million or 1.5% from 2016-17. The decrease was primarily due to lower transmission charges as a result of redirecting transmission to lower cost nodes as well as lower prices partially offset by higher purchased volumes due to lower generation.

Capital and other taxes includes payments to the Province of Manitoba for capital and payroll tax and to municipalities within the Province of Manitoba for property taxes.

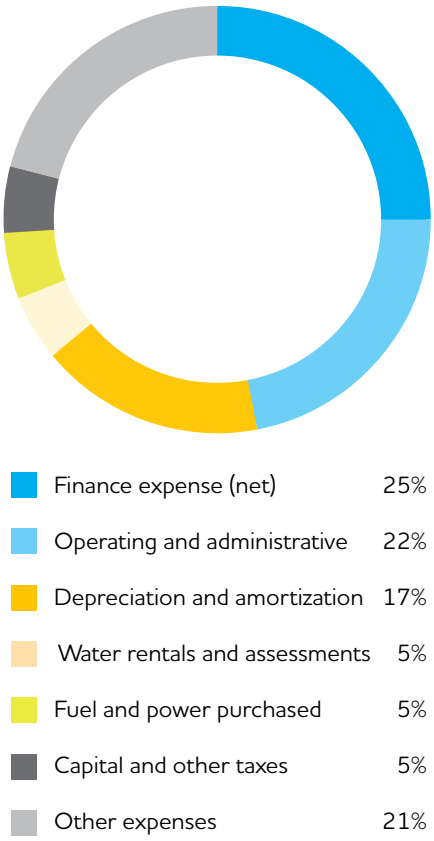
Capital and other taxes amounted to $130 million in 2017-18, an increase of $11 million or 9.2% compared to the previous year. The change was primarily due to increased capital taxes as a result of higher debt levels related to additional capital investment in projects such as Keeyask and Bipole III.

Other expenses include expenditures associated with DSM programs designed to reduce overall energy consumption and assist customers in managing their energy costs as well as other miscellaneous expenditures. The majority of other expenses are removed from the statement of income, deferred and subsequently amortized through net movement in regulatory balances.

In 2017-18, other expenses also includes the transfer of the construction in progress balance related to the Conawapa Generating Station of $379 million as a result of the corporation's decision to discontinue further development of the station. As part of the corporation's 2017-18 electric General Rate Application, Manitoba Hydro requested and received approval by the PUB for the recognition of the costs of Conawapa in a regulatory deferral balance and subsequent amortization over a 30 year period. No amortization was recognized in 2017-18.

Excluding the Conawapa transfer, other expenses amounted to $123 million in 2017-18, an increase of $63 million or 105% compared to the previous year. The increase was primarily due to $47 million in restructuring charges driven by the implementation of a significant cost reduction program as well as higher spending on DSM programs such as LED Roadway Lighting Conversion, Commercial Lighting and Solar Technologies. Electric DSM expenditures for the year totaled $64 million, an increase of $13 million over 2016-17.

Electric Expenses
For the year ended March 31, 2018



Electric Net Movement in Regulatory Balances

The corporation's financial results were prepared using the interim standard IFRS 14 *Regulatory Deferral Accounts* which allows Manitoba Hydro to continue to recognize regulated balances for financial reporting purposes. This results in the deferral of costs and recoveries that under IFRS would otherwise be recorded as expenses or income in the current accounting period. The deferred amounts are expected to be either recovered or refunded through future rate adjustments.

The net movement in regulatory balances captures the timing differences between financial reporting under IFRS and those amounts approved by the PUB for rate-setting purposes. The change in the net movement in regulatory balances of $406 million was primarily due to the Conawapa transfer, higher DSM expenditures and increased losses on disposal of property, plant and equipment.

Electric Capital Expenditures

The electric capital expenditure program relates to investments in major new generation and transmission facilities, as well as additions, improvements and replacement of existing infrastructure.

Expenditures for capital construction totaled $2 924 million in 2017-18 compared to $2 892 million during the previous fiscal year. This includes $2 463 million for the development of new major generation and transmission facilities, an increase of $101 million when compared to 2016-17. Current year expenditures include $1 244 million (2017 - $904 million) for the Keeyask Generating Station and $1 137 million (2017 - $1 373 million) for the Bipole III Reliability project. Amounts include the capitalized interest associated with construction in progress.

The Bipole III Reliability project is nearing completion and will come into service in July 2018. When complete, Bipole III will strengthen reliability of Manitoba Hydro's electricity supply by reducing dependency on existing high voltage direct current transmission lines and the Dorsey Converter Station which are relied upon to deliver over 70% of the electricity produced in Manitoba. The Bipole III Reliability project includes a 1 384 kilometre, 500 kilovolt (kV) transmission line with two converter stations. The two new converter stations, the Keewatinohk Converter Station and the Riel Converter Station, will provide additional capacity to existing Bipole I and II HVDC transmission systems. The project also provides additional capacity for delivery of hydroelectric generation to southern Manitoba.

The construction of the Bipole III 500 kV transmission line was completed and turned over for commissioning on March 31, 2018 whereas construction of the Bipole III converter stations is near completion. At March 31, 2018, life to date expenditures for the Bipole III Reliability project totaled $4 289 million including capitalized interest.

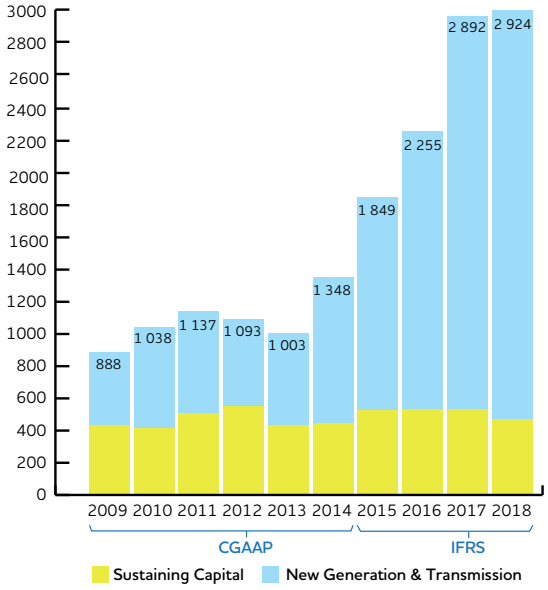
The Keeyask Generating Station will be a source of renewable energy, providing approximately 695 megawatts of capacity and producing an average of 4 400 gigawatt hours of electricity each year. The renewable hydroelectric energy produced will be integrated into the corporation's electric system to maintain a reliable supply for Manitoba with surplus energy available for export until necessary to meet domestic requirements.

During the 2018 fiscal year, almost 90 000 m^3 of concrete was placed on the powerhouse, intake, tailrace, service bay and spillway. At the end of March 2018, approximately half of the total volume of concrete required for the Keeyask Project has been placed. Key milestones were achieved on schedule during the year and the project is on track to divert the Nelson River through the spillway in the summer of 2018. The Keeyask Project is forecasting to meet the control budget of $8.7 billion and have a first unit in-service in advance of the control schedule of August 2021. This will require improvement in the performance of the general civil contractor and no materialization of major risks. At March 31, 2018, total expenditures for Keeyask generation and related transmission amounted to $4 508 million including capitalized interest.

Capital expenditures required for additions, improvements and replacement of existing infrastructure amounted to $461 million, a decrease of $69 million compared to the previous fiscal year. The reduction was primarily attributable to the distribution system, related to large station projects such as Adelaide and St. Vital stations coming to completion. In addition, expenditures declined in 2017-18 due to a decrease in resource availability as a result of a reassignment of resources to focus on the Bipole III Reliability project and the impacts of the VDP.

Current year expenditures include investments in urban and rural distribution development such as the new McPhillips station and the refurbished St. Vital station required to address increasing customer load. In addition, transmission capacity enhancements such as the Lake Winnipeg east system improvements were necessary to accommodate regional load growth and system expansion. Manitoba Hydro is also investing in the replacement and refurbishment of existing assets to address degradation and obsolescence given that many of the corporation's assets were installed several decades ago.

Electric Capital Expenditures
For the year ended March 31
millions of dollars



Wuskwatim Power Limited Partnership

The WPLP owns and operates the Wuskwatim Generating Station and related works, excluding the transmission facilities. The WPLP has two limited partners, Manitoba Hydro and Taskinigahp Power Corporation (TPC), which is owned beneficially by Nisichawayasihk Cree Nation, and a General Partner which is a wholly-owned subsidiary of Manitoba Hydro.

The WPLP reported a net loss for 2017-18 of $25 million which is consistent with expectations. This is compared to a net loss of $36 million in 2016-17. Manitoba Hydro's 67% share of the loss was $17 million (2017 - $24 million) and TPC's 33% share of the loss was $8 million (2017 - $12 million).

Keeyask Hydropower Limited Partnership

The KHLP was formed to carry on the business of developing, owning and operating the Keeyask Generating Station and related works excluding the transmission facilities but including all dams, dikes, channels, excavations and roads. Manitoba Hydro, Cree Nation Partners (owned beneficially by Tataskweyak Cree Nation and War Lake), FCLN Keeyask Investments Inc. (owned beneficially by Fox Lake) and York Factory First Nation Limited Partnership (owned beneficially by York Factory) are limited partners of KHLP. The General Partner is a wholly-owned subsidiary of Manitoba Hydro. The KHLP will have no impact on the statement of income until the generating station goes into service.

Natural Gas Segment

Centra Gas Manitoba Inc. (Centra) is a wholly-owned subsidiary of Manitoba Hydro. Centra distributes natural gas to 255 868 residential and 26 122 commercial and industrial customers in Manitoba.

The net income in the natural gas segment was $7 million in 2017-18 compared to net income of $4 million in the previous fiscal year. The increase in net income over the previous year was primarily attributable to colder winter weather partially offset by lower rates and restructuring costs. The decrease in rates is a result of the PUB directing Centra to revert the non-gas components of rates to levels approved in Order 46/10.

Natural Gas Revenues and Cost of Gas

For the natural gas segment, customer classes are distinguished based on the level of annual consumption and include residential, large and small general service, large commercial and industrial as well as interruptible and transportation service. Interruptible customers may have service interrupted periodically upon notice in exchange for a reduced rate. Transportation service customers purchase their own gas commodity and pay only for the delivery of natural gas.

Revenues from the sale and distribution of natural gas during 2017-18 were $344 million, an increase of $1 million from the previous year. The slight increase in revenue is primarily due to colder weather and customer growth partially offset by lower weighted average cost of gas (WACOG) charged to customers. Natural gas deliveries were 2 048 million cubic metres in 2017-18 compared to 1 986 million cubic metres in 2016-17.

As directed by the PUB, $3.8 million of revenue from 2017-18 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, 2018, there is a remaining balance of $25 million in the Furnace Replacement Program.

The breakdown of natural gas revenue is as follows:

Natural Gas Revenues and Deliveries
For the year ended March 31

	2018	2017	% change	**2018**	2017	% change
	millions of dollars			*millions of cubic metres*		
Residential	**174**	172	1.2	**579**	524	10.5
Large general service	**104**	106	(1.9)	**545**	501	8.8
Large commercial & industrial	**28**	27	3.7	**189**	161	17.4
Small general service	**27**	26	3.8	**107**	95	12.6
Interruptible	**6**	6	-	**46**	44	4.5
Transportation service and other	**5**	6	(16.7)	**582**	661	(12.0)
Revenue	**344**	343	0.3	**2 048**	1 986	3.1

The actual cost of gas purchased is comprised of all expenses incurred in the procurement and delivery of natural gas to the Manitoba marketplace, including commodity supply, transportation and storage costs either from Western Canada or U.S. sources.

Centra purchased 817 million cubic metres of natural gas based on monthly Alberta indexed pricing, 274 million cubic metres under daily Alberta indexed pricing and 291 million cubic metres from a number of other supply sources. Centra also delivered natural gas on behalf of brokers to 8 063 (2017 – 10 701) customers receiving natural gas under Direct Purchase arrangements.

Cost of Gas Sold
For the year ended March 31

	2018	2017	change
	millions of dollars		
Cost of gas sold			
Purchased costs	**196**	183	13
PGVA	(3)	16	(19)
WACOG	**193**	199	(6)

The cost of gas purchased during 2017-18 was $196 million, an increase of $13 million from the previous year. This increase was the result of higher purchased volumes due to colder weather partially offset by slightly lower prices. The differences between the cost of gas embedded in customer rates (WACOG) and the actual cost of gas purchased are accumulated in the PGVAs, which ensures that only the actual cost of gas, no more or less, is ultimately passed on to customers. Any differences in these accounts are either refunded to, or collected from customers in future rates.

For income statement purposes the actual cost of gas purchased is adjusted in the net movement in regulatory balances for the impact of the PGVA accounts. For 2017-18, the total of actual cost of gas purchased combined with the PGVA adjustment is $193 million compared to $199 million for 2016-17.

The resulting gross margin after considering the net movement in PGVAs is $150 million for 2017-18 compared to $144 million for 2016-17, which is an increase of $6 million due to colder winter weather and customer growth partially offset by lower rates.

Natural Gas Rates

In accordance with Centra's quarterly rate-setting methodology, annualized rates for natural gas supplied to residential customers changed during 2017-18 as follows:

- May 1, 2017 3.1% decrease
- August 1, 2017 2.8% decrease
- November 1, 2017 2.7% decrease
- February 1, 2018 2.1% decrease

The change in natural gas rates reflects the fluctuations in pricing for natural gas purchased by Centra.

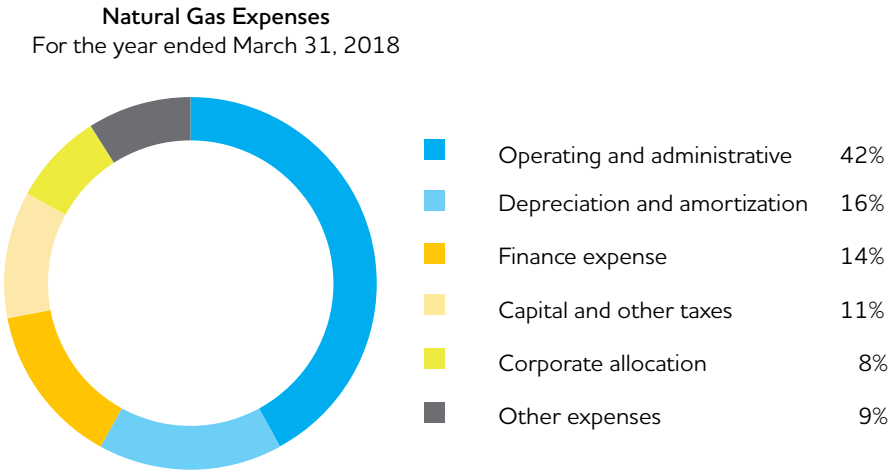
Natural gas prices have been declining since 2009 and the average bill is low relative to 10 years ago. Manitoba Hydro's natural gas customers have benefited as a result. The total annual natural gas bill for a typical residential customer in Manitoba in 2017-18 was 33% lower than in 2007-08.

In addition, the PUB directed a general rate decrease of approximately 1.2% effective August 1, 2017 which reflects the reversion of the non-gas costs of operating Centra to levels approved by the PUB in 2010.

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, 2018 there were 73 customers (2017 – 99 customers) on Centra's fixed rate service. Total natural gas deliveries under this service were 1.2 million cubic metres (2017 – 0.7 million cubic metres).

Natural Gas Expenses

Expenses attributable to the natural gas operations, excluding cost of gas sold amounted to $150 million in 2017-18, which was $3 million higher than the previous year primarily attributable to restructuring charges of $3 million. In addition, there were increases of $2 million in finance expenses and $1 million in depreciation and amortization partially offset by a decrease of $2 million in operating and administrative expenses.



Natural Gas Expenses

For the year ended March 31

	2018	2017	% change
	millions of dollars		
Operating and administrative	**63**	65	(3.1)
Finance expense	**21**	19	10.5
Depreciation and amortization	**24**	23	4.3
Capital and other taxes	**16**	16	-
Other expenses	**14**	12	16.7
Corporate allocation	**12**	12	-
	150	147	2.0

Natural Gas Net Movement in Regulatory Balances

The natural gas net movement in regulatory balances captures the timing differences between financial reporting under IFRS and those amounts approved by the PUB for rate-setting purposes. The change in the net movement in regulatory balances of $18 million was primarily the result of the change in the PGVA balance due to lower collection of prior gas costs from customers and increased commodity purchases, partially offset by transportation costs.

Natural Gas Capital Expenditures

The capital expenditure program relates to new business, system improvement and other expenditures to meet the needs of natural gas customers. Capital expenditures in the natural gas sector were $37 million in 2017-18 compared to $59 million in the previous fiscal year. The decrease is primarily due to the Winnipeg Northwest project which was completed in 2016-17. The Winnipeg Northwest project provides additional capacity as well as a second gas supply to communities north of Winnipeg and offers operational flexibility to the Winnipeg natural gas network to permit pipeline inspection activities. This project was the single largest natural gas project (approximately $30 million) since a major expansion in the mid-1990's.

Other Segment

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.

Manitoba Hydro also owns Minell Pipelines Ltd. (Minell) and Teshmont LP Holdings Ltd. (Teshmont).

The following table provides a summary of the financial results of the subsidiary companies excluding Centra for the fiscal year ended March 31, 2018 compared to the previous fiscal year. The results of Minell and Teshmont are included in Other in the table below:

Other Segment

For the year ended March 31

	MHI		MHUS		Other		Total	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017
				millions of dollars				
Revenues	**58.9**	59.7	**4.8**	4.7	**1.0**	1.1	**64.7**	65.5
Expenses	**48.8**	48.5	**5.4**	5.1	**0.4**	0.6	**54.6**	54.2
Net income (loss)	**10.1**	11.2	**(0.6)**	(0.4)	**0.6**	0.5	**10.1**	11.3

Risk Management

Manitoba Hydro faces a number of risks in the fulfillment of its mission and mandate. The corporation has a relatively low tolerance for risk due to its monopoly responsibility to ensure the provision of reliable energy services to Manitobans. However, Manitoba Hydro must balance the costs of risk management and mitigation with impacts on rates. As such, some risks can and should be accepted and to a prescribed degree in order 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 mandate and objectives;
- implementing measures that mitigate risk to reasonable levels at a reasonable cost;
- taking action to minimize the consequences of negative occurrences; and
- prudentially capturing opportunities to provide benefits to all stakeholders.

Most of Manitoba Hydro's risk management efforts are focused on reducing the likelihood of occurrence of negative events. However, the corporation also has plans in place to reduce the consequences 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 Management 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 utility are significant. These risks include:

- the impacts of weather on supply and demand;
- changing customer expectations and behavior;
- impact of water flow conditions on generation of hydraulic energy;
- regulatory approval of increases to electricity and natural gas rates;
- export price and market uncertainties including access, transmission and contractual relationships;
- availability and cost of debt necessary to fund the business;
- skilled labour availability and costs;
- cost of completion of in-flight capital programs;
- aging infrastructure maintenance and replacement;
- accelerated technological change.

Manitoba Hydro manages these risks through an integrated control framework. Manitoba Hydro's strategy is to further augment its risk management and mitigation of negative occurrences through achieving and maintaining of an adequate level of financial reserves through prudent liquidity management and a less indebted balance sheet.

Manitoba Hydro has identified the following risks as being of most critical attention and focus over the next 12 months or longer. Each reflect elevated levels of likelihood, high consequences even after any mitigation initiatives and a current status that is outside of the corporation's assessed risk tolerance for each.

RISK FACTOR	LIKELIHOOD	CONSEQUENCE	TOLERANCE	RISK RATING
Completion of major capital projects– further slippage on construction costs and schedule have significant financial impacts as well as impacts to Indigenous and customer relationships, reputation and standing with certain stakeholders.	High	High	Low	Yellow
Interest rates – in a period of unprecedented capital borrowing requirements, Manitoba Hydro has an elevated sensitivity to rising interest rates.	Medium	High	Medium	Green
Implementing electricity rate increases – PUB acceptance of rate increases sufficient to generate adequate levels of income and cash flow to manage Manitoba Hydro indebtedness.	Medium	High	Medium	Yellow
Meeting financial targets & maintaining credit standing – maintain self-supporting status and the ability to access low cost debt.	High	High	Medium	Yellow
Aging infrastructure – Manitoba Hydro is in the process of implementing enhanced asset management tools to determine the optimal level of investment and prioritize projects to sustain existing infrastructure and address capacity constraints; may need to reassess investment levels.	Medium	Medium	Medium	Yellow

Yellow = some emerging issues to be monitored and additional action required to bring the risk back to within established tolerance.
Green = risk is under control and no additional action required.

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. Manitoba Hydro has significant processes and safeguards in place to minimize the probability of these risks presenting. These risks are quantified in the following table:

RISK	POTENTIAL FINANCIAL IMPACT	TOLERANCE/RATING
Infrastructure Prolonged loss of supply	> $2 billion	Low
Drought Water Supply Variation/Drought	> $1.4 billion for a 5 year drought commencing in 2018-19	Low
Loss of export market access	> 25% of electricity revenue	Low

Outlook

Manitoba Hydro expects its net income for 2018-19 to be marginally higher than what was experienced in 2017-18 factoring in the 3.6% rate increase approved by the PUB effective June 1, 2018 and assuming current water conditions and normal weather.

The corporation's earnings can fluctuate significantly due to various non-controllable factors such as the amount of water inflows, weather, domestic load requirements particularly related to the usage of a handful of very large industrial users, market prices for electricity and interest rates. The impact on earnings with respect to water inflows is particularly sensitive to spring and summer precipitation amounts. The net income outlook for 2018-19 assumes the continuation of current export market conditions, normal precipitation for the remainder of the year and normal winter weather.

On May 1, 2018 the PUB issued Order 59/18 which directed a 3.6% average increase to consumer rates effective June 1, 2018. In addition, the PUB has directed that Manitoba Hydro participate in a technical conference the PUB will convene to consider the establishment of a minimum retained earnings or other similar test to provide guidance on consumer rate setting. In Order 59/18 the PUB has signaled that, at least for the time being, the regulator does not support rate setting aimed at progressing toward Manitoba Hydro's long held financial targets particularly the 75:25 debt: equity ratio. When coupled with the potential implementation of rules-based regulation focusing on maintenance of minimum retained earnings, Manitoba Hydro is concerned with respect to its ability to abate debt growth and potential uncertainty in the profile of future rate increases. The technical conference is an important next step for Manitoba Hydro to work with the PUB to achieve clarity on longer term financial targets that will be supported by regular rate increases. The timing of Manitoba Hydro's next General Rate Application is also uncertain as, in addition to the technical conference, the PUB has directed Manitoba Hydro to complete a number of other matters before it can proceed with its next rate request.

Management Report

For the year ended March 31, 2018

The accompanying consolidated financial statements have been prepared by management of the Manitoba Hydro-Electric Board (the corporation), who are responsible for the integrity, consistency and reliability of the information presented. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards.

The preparation of the consolidated financial statements necessarily involves the use of estimates and assumptions based on management's judgments, particularly when transactions affecting the current period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances. The preparation of the consolidated financial statements includes information regarding the estimated impact of future events and transactions. Actual results in the future may differ from the present assessment of this information because future events and circumstances may not occur as expected. The consolidated financial statements have been prepared within reasonable limits of materiality in light of information available up to June 27, 2018.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal controls, which is designed to provide reasonable assurance that the corporation's assets are safeguarded and appropriately accounted for, that financial information is relevant, reliable and accurate, and that transactions are properly authorized and executed. The system includes formal policies and procedures as well as the appropriate delegation of authority and segregation of responsibilities within the organization. An internal audit function evaluates the effectiveness of these controls and reports its findings to management and the Audit Committee of the Board of Directors.

The Board of Directors, through the Audit Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit Committee, which is comprised of outside and unrelated directors, meets periodically with management, the internal auditors and the external auditors to satisfy itself that each group has properly discharged its responsibility with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and management's discussion and analysis and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The consolidated financial statements were reviewed by the Audit Committee, and on their recommendation, were approved by the Board of Directors. The consolidated financial statements have been examined by KPMG LLP, independent external auditors appointed by the Lieutenant Governor in Council. The external auditors' responsibility is to express their opinion on whether the consolidated financial statements are fairly presented in accordance with International Financial Reporting Standards. The Independent Auditors' Report outlines the scope of their examination and their opinion.

On behalf of management:





Kelvin Shepherd, P. Eng
President & Chief Executive Officer

Jamie McCallum
Chief Finance & Strategy Officer

Winnipeg, Canada
June 27, 2018

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 statement of financial position as at March 31, 2018, the consolidated statements of income, cash flows, comprehensive income and changes in equity for the year then ended, and notes, comprising 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 International Financial Reporting Standards, 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 our judgement, 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, we 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 consolidated financial position of Manitoba Hydro-Electric Board as at March 31, 2018 and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with International Financial Reporting Standards.

Comparative Information

Without modifying our opinion, we draw attention to Note 3(s) to the consolidated financial statements which indicates that certain comparative information in the statement of cash flows presented for the year ended March 31, 2017 has been restated for changes in accounting policies.

The consolidated financial statements of Manitoba Hydro-Electric Board as at and for the year ended March 31, 2017, excluding the restatements described in Note 3(s) to the consolidated financial statements, were audited by another auditor who expressed an unmodified opinion on those financial statements on July 5, 2017.

As part of our audit of the consolidated financial statements as at and for the year ended March 31, 2018 we audited the restatements described in Note 3(s) to the consolidated financial statements that were applied to restate the comparative information in the statement of cash flows presented for the year ended March 31, 2017. In our opinion, the restatements are appropriate and have been properly applied.

We were not engaged to audit, review, or apply any procedures to the March 31, 2017 consolidated financial statements other than with respect to the restatements described in Note 3(s) to the consolidated financial statements. Accordingly, we do not express an opinion or any other form of assurance on those financial statements taken as a whole.

KPMG LLP

Chartered Professional Accountants

June 27, 2018
Winnipeg, Canada

Consolidated Statement of Income

For the year ended March 31

millions of Canadian dollars

	Notes	2018	2017
Revenues			
Domestic			
Electric		**1 464**	1 419
Gas		**343**	342
Extraprovincial	5	**437**	460
Other	6	**86**	106
		2 330	2 327
Expenses			
Finance expense	7	**641**	645
Operating and administrative	8	**586**	608
Depreciation and amortization	9	**430**	402
Cost of gas sold		**196**	183
Water rentals and assessments		**126**	131
Fuel and power purchased	10	**130**	132
Capital and other taxes	11	**146**	135
Other expenses	12	**548**	104
Finance income		**(23)**	(17)
		2 780	2 323
Net income (loss) before net movement in regulatory balances		**(450)**	4
Net movement in regulatory balances	20	**479**	55
Net Income		**29**	59
Net income (loss) attributable to:			
Manitoba Hydro		**37**	71
Non-controlling interests	29	(8)	(12)
		29	59

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statement of Financial Position

As at March 31

millions of Canadian dollars

	Notes	2018	2017
Assets			
Current Assets			
Cash and cash equivalents	13	**642**	646
Accounts receivable and accrued revenue	14	**428**	385
Prepaid expenses		**39**	123
Inventory	15	**112**	108
		1 221	1 262
Property, Plant and Equipment	16	**21 979**	19 757
Non-Current Assets			
Goodwill		**107**	107
Intangible assets	18	**408**	293
Loans and other receivables	19	**410**	353
		925	753
Total assets before regulatory deferral balance		**24 125**	21 772
Regulatory deferral balance	20	**1 044**	566
Total assets and regulatory deferral balance		**25 169**	22 338

On behalf of the Board of Directors:

Marina R. James
Chair of the Board

Melanie McKague
Chair of the Audit Committee

	Notes	2018	2017
Liabilities and Equity			
Current Liabilities			
Current portion of long-term debt	21	**1 000**	336
Accounts payable and accrued liabilities	22	**742**	1 083
Notes payable	23	**50**	-
Other liabilities	24	**162**	98
Accrued interest		**126**	114
		2 080	1 631
Long-Term Debt	21	**18 200**	16 102
Non-Current Liabilities			
Other long-term liabilities	25	**623**	638
Employee future benefits	26	**908**	818
Deferred revenue	27	**769**	642
Provisions	28	**60**	70
		2 360	2 168
Total liabilities		**22 640**	19 901
Equity			
Retained earnings		**2 936**	2 899
Accumulated other comprehensive loss		**(688)**	(709)
Equity attributable to Manitoba Hydro		**2 248**	2 190
Non-controlling interests	29	**205**	170
Total equity		**2 453**	2 360
Total liabilities and equity before regulatory deferral balance		**25 093**	22 261
Regulatory deferral balance	20	**76**	77
Total liabilities, equity and regulatory deferral balance		**25 169**	22 338

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statement of Cash Flows

For the year ended March 31

millions of Canadian dollars

	Notes	2018	2017
Operating Activities			
Net income		**29**	59
Add back:			
Depreciation and amortization	8	**430**	402
Finance expense	7	**641**	645
Net movement impacts on depreciation, amortization and finance expense		**11**	17
Finance income		**(23)**	(17)
Adjustments for non-cash items		**(23)**	(13)
Adjustments for changes in non-cash working capital accounts			
Accounts receivable and accrued revenue		**(43)**	3
Prepaid expenses		**85**	(83)
Accounts payable and accrued liabilities		**(339)**	364
Other		**28**	63
Interest received		**23**	17
Interest paid		**(913)**	(834)
Cash (used for) provided by operating activities		**(94)**	623
Investing Activities			
Additions to property, plant and equipment		**(2 652)**	(2 678)
Additions to intangible assets		**(137)**	(121)
Additions to regulatory deferral balances		**(105)**	(87)
Contributions received		**199**	133
Cash paid to the City of Winnipeg		**(16)**	(16)
Cash paid for mitigation obligations		**(30)**	(21)
Cash paid for major development obligations		**(15)**	(11)
Other		**(8)**	14
Cash used for investing activities		**(2 764)**	(2 787)

	Notes	2018	2017
Financing Activities			
Proceeds from long-term debt	21	**3 400**	2 186
Retirement of long-term debt	21	**(582)**	(320)
Repayment from (advances to) external entities		**(58)**	(53)
Proceeds from partnership issuances		**44**	42
Proceeds from short-term borrowings	23	**50**	–
Sinking fund investment withdrawals	17	**165**	146
Sinking fund investment purchases	17	**(165)**	(146)
Cash provided by financing activities		**2 854**	1 855
Net decrease in cash and cash equivalents		**(4)**	(309)
Cash and cash equivalents, beginning of year		**646**	955
Cash and cash equivalents, end of year		**642**	646

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statement of Comprehensive Income

For the year ended March 31

millions of Canadian dollars

	2018	2017
Net Income	**29**	59
Other comprehensive income (loss)		
Items that will not be reclassified to income		
Net experience (losses) gains on pensions	**(58)**	94
Items that will be reclassified to income		
Cash flow hedges - unrealized foreign exchange gains (losses) on debt	**57**	(47)
Items that have been reclassified to income		
Cash flow hedges - realized foreign exchange losses on debt	**22**	20
	21	67
Comprehensive Income	**50**	126
Comprehensive income (loss) attributable to:		
Manitoba Hydro	**58**	138
Non-controlling interests	(8)	(12)
	50	126

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statement of Changes in Equity

millions of Canadian dollars

	Notes	Retained earnings	Accumulated other comprehensive income (loss)	**Manitoba Hydro**	Non-controlling interests	Total equity
Balance as at April 1, 2016		2 828	(776)	**2 052**	140	2 192
Net income (loss)		71	-	**71**	(12)	59
Other comprehensive income		-	67	**67**	-	67
Comprehensive income (loss)		71	67	**138**	(12)	126
Change in ownership interest	29	-	-	**-**	42	42
Balance as at March 31, 2017		2 899	(709)	**2 190**	170	2 360
Net income (loss)		37	-	**37**	(8)	29
Other comprehensive income		-	21	**21**	-	21
Comprehensive income (loss)		37	21	**58**	(8)	50
Change in ownership interest	29	-	-	**-**	43	43
Balance as at March 31, 2018		**2 936**	**(688)**	**2 248**	**205**	**2 453**

The accompanying notes are an integral part of the consolidated financial statements.

Note 1 Reporting entity

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.

These consolidated financial statements include the accounts of Manitoba Hydro and its wholly-owned subsidiaries including Centra Gas Manitoba Inc. (Centra), Minell Pipelines Ltd. (Minell), 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 that was formed to participate in the development of a new transmission line in 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 interest in the Keeyask Hydropower Limited Partnership (KHLP). For purposes of consolidation, all significant intercompany accounts and transactions have been eliminated.

Note 2 Basis of presentation

(a) Statement of compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS).

These consolidated financial statements were approved for issue by the Manitoba Hydro-Electric Board on June 27, 2018.

(b) Basis of measurement

These consolidated financial statements have been prepared on a historical cost basis except for the following material items in the consolidated statement of financial position:

- Financial instruments accounted for in accordance with the financial instrument categories defined in Note 3(n)
- Employee future benefits defined in Note 3(k)
- Provisions defined in Note 3(l).

(c) Functional and presentation currency

The consolidated financial statements are presented in millions of Canadian dollars, the functional currency of the corporation.

(d) Use of estimates and judgment

The preparation of consolidated financial statements in accordance with IFRS requires management to make estimates and assumptions that affect amounts reported as assets, liabilities, income and expenses.

Areas of significant management estimates and judgments are outlined in the following summary and significant accounting policies included in Note 3:

- Accrued revenue for domestic electricity and natural gas deliveries not yet billed at year-end and allowance for doubtful accounts (Note 3(b))
- Useful life estimates for depreciable and amortizable assets (Notes 3(g), 16 and 18)
- Determination of cash generating unit as it pertains to impairment testing (Note 3(h) and (j))
- Measurement of accrued liabilities (Note 22)
- Measurement of other long-term liabilities and underlying estimates of future cash flows (Note 25)
- Measurement of employee future benefits and underlying actuarial assumptions (Notes 3(k) and 26)
- Measurement of provisions and underlying estimates of future cash flows (Notes 3(l) and 28)
- Fair value measurement of financial instruments (Notes 3(n) and 30)
- Identification and reporting of operating segments (Note 34).

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively.

Note 3 Significant accounting policies

(a) Regulatory deferral accounts

In January 2014, the International Accounting Standards Board (IASB) issued an interim standard, IFRS 14 *Regulatory Deferral Accounts*, which provides guidance on accounting for the effects of rate regulation under IFRS. This guidance allows entities that conduct rate-regulated activities to continue to recognize regulatory deferral accounts. This interim standard is effective for financial reporting periods beginning on or after January 1, 2016. The corporation has elected to adopt IFRS 14 in its consolidated financial statements. The interim standard is only intended to provide temporary guidance until the IASB completes its comprehensive project on rate-regulated activities. IFRS 14 remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

Regulatory deferral account balances usually represent timing differences between the recognition of items of income or expenses for regulatory purposes and the recognition of those items for financial reporting purposes. Regulatory deferral account balances arising from rate-regulated activities are recognized and measured separately if they do not meet the criteria to be recognized as an asset or liability in accordance with other standards. The balances recorded as regulatory deferral balances will be recovered or refunded in future rates, based on approvals by the Public Utilities Board of Manitoba (PUB). These amounts would otherwise have been included in the determination of net income in the year they are incurred.

Under rate regulation, the prices charged for the sale of electricity and natural gas within Manitoba are subject to review and approval by the 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 natural gas service plus a sufficient contribution to retained earnings.

The following regulatory deferral account balances are initially recorded at cost and amortized on a straight-line basis using the specified periods:

Demand side management (DSM) programs	10	years
Site restoration costs	15	years
Deferred taxes	30	years
Acquisition costs	30	years
Regulatory costs	up to 5	years
Ineligible overhead	34	years

The Affordable Energy Fund is amortized to the consolidated statement of income at the same rate as the obligation is drawn down. The purchased gas variance account (PGVA) is recovered or refunded over a period determined by the PUB.

The amortization of the loss on disposal of assets, change in depreciation methodologies from average service life (ASL) to equal life group (ELG), difference in depreciation rate used for gas meters and the impact of the 2014 depreciation study will be determined by the PUB at a future regulatory proceeding.

(b) Revenue recognition

Domestic electricity and natural gas revenues are recognized upon delivery to the customer and charged in accordance with rates approved by the PUB. Unbilled revenues are recorded based on an estimated amount of electricity and natural gas delivered and not yet billed at year-end.

Extraprovincial electricity revenue is recorded upon the delivery of energy or settlement of the financial transaction.

Consulting, technology and maintenance services and other miscellaneous revenue is recognized when services are provided or goods are shipped to the customer. Revenue from fixed price contracts is recognized under the percentage-of-completion method. The percentage of completion is determined by comparing the costs incurred at the consolidated statement of financial position date to the total estimated costs, which include costs incurred plus anticipated costs for completing a contract.

Deferred revenue related to customer contributions is recognized over the life of the related asset for which the contribution was received.

(c) Cost of gas

Natural gas is recorded at purchased cost upon delivery to gas customers.

(d) Finance expense and finance income

Finance expense includes interest on short and long-term borrowings and the provincial debt guarantee fee paid to the Province of Manitoba, foreign exchange gains and losses, the mark to market of foreign exchange forward contracts, accretion expense on provisions and other long-term liabilities, offset by interest capitalized for those qualifying assets under construction. Foreign exchange gains and losses include amounts that had been recognized in other comprehensive income and reclassified from equity to net income in the same periods during which the hedged forecast cash flows (being U.S. export revenues) affect net income. All borrowing costs are recognized using the effective interest rate method. Finance income includes interest earned on loans and advances to external parties and temporary investments.

(e) 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 are subject to an insignificant risk of changes in value.

(f) Inventory

Materials and supplies, fuel and natural gas inventories are valued at the lower of average cost and net realizable value. Replacement cost is used as management's best estimate of the net realizable value for materials and supplies and fuel inventory.

Materials, supplies, fuel and natural gas are charged to inventory when purchased and not immediately required for use. These inventories are expensed or capitalized when used. Those materials, supplies and fuel purchased for immediate use are expensed directly.

(g) Property, plant and equipment

Property, plant and equipment (PP&E) is recorded at cost less accumulated depreciation. Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, contracted services, direct labour and interest applied at the weighted average cost of debt outstanding during the period. 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.

Depreciation is calculated on a straight-line remaining life basis using the ELG procedure. The major components of generating stations are depreciated over the lesser of the remaining life of the major components or the remaining life of the associated generating station.

Generation	4 – 125 years
Transmission lines	10 – 85 years
Substations	15 – 65 years
Distribution systems	10 – 75 years
Other	5 – 100 years

The estimated service lives of the assets are based upon depreciation studies conducted periodically by the corporation. A depreciation study was last completed in 2015.

The net gain or loss on retirement of these assets is charged to depreciation in the period incurred and then removed through net movement in regulatory balances. When the costs of removing an asset from service are incurred to facilitate the installation of a new asset, the costs to remove the asset from service are added to the costs of the new asset. When an asset is retired from service and not replaced with a similar asset, the costs of removing the asset from service are treated similarly to the net gain or loss on retirement of assets.

A reasonable estimate of the present value of the future cash flows required to retire an asset from service is recorded when the recognition criteria for a provision (Note 3(l)(i)) are met. An equivalent amount is added to the carrying cost of the related asset and is amortized over the asset's remaining service life. The discount rate used to measure the cash flows reflects current market assessments of the time value of money and the risks specific to the obligation.

(h) Goodwill

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.

(i) Intangible assets

Intangible assets include computer application development costs, land easements and transmission rights. Intangible assets are recorded at cost less accumulated amortization. The cost of computer application development includes software, direct charges for labour, materials, contracted services and interest during development applied at the weighted average cost of debt outstanding during the period. The corporation's intangible assets have finite useful lives and are amortized over their useful lives on a straight-line basis with the amortization included in depreciation and amortization expense. The expected useful lives are as follows:

Computer application development	5 – 11 years
Land easements	75 years
Transmission rights	1 – 12 years

Transmission rights are amortized over the contractual period of the right plus a one-term renewal. The estimated service lives of computer application development and land easements are based upon depreciation studies conducted periodically by the corporation. A depreciation study was last completed in 2015.

(j) Impairment of non-financial assets

Non-financial assets subject to impairment testing include goodwill, intangible assets and property, plant and equipment. The corporation tests goodwill and material intangible assets under construction at least annually for impairment. Assets subject to depreciation and amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

An impairment test is performed by comparing the carrying amount of the asset or cash generating unit (CGU) to its recoverable amount. The recoverable amount is calculated as the higher of the fair value less costs to sell and the present value of the future cash flows from an asset or CGU. The corporation has determined its CGUs to be at the segment level. This is the lowest level for which there are separately identifiable cash flows as rates for electricity and natural gas revenue are set by the PUB at the segment level. An impairment would be recognized as a charge against operations in the year of impairment if the carrying amount exceeds the recoverable amount.

(k) Employee future benefits

Manitoba Hydro provides future benefits, including pension and other benefits, to both existing and retired employees.

The costs and obligations of defined benefit pension plans and other benefits are determined by an independent actuary using the accrued benefit actuarial cost method and reflect management's best estimate of future compensation increases, service lives and inflation. Pension expense consists of the cost of pension benefits earned during the year and net interest income or expense. Interest income on plan assets is determined by multiplying the fair value of the plan assets by the discount rate used to determine the accrued benefit obligation at the start of the annual reporting period. This considers any changes in the plan assets held during the period as a result of contributions and benefit payments. Interest expense on the accrued benefit obligation is determined by multiplying the accrued benefit obligation by the discount rate used at the start of the annual reporting period.

Experience gains or losses on the asset and actuarial gains or losses on the obligation are recognized in other comprehensive income (OCI) in the period in which they occur. Past service costs, which arise when a change is made to plan benefits, are recognized immediately in profit or loss.

Other future benefits earned by employees include vacation, vested sick leave, severance and retirement health plans. Where applicable, the future costs of these benefits are determined by an independent actuary and reflect management's best estimates.

(l) Provisions

In accordance with International Accounting Standards (IAS) 37 *Provisions, Contingent Liabilities and Contingent Assets*, a provision is required to be recognized where there is a present legal or constructive obligation as a result of a past event that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation, the timing or amount of which are uncertain.

(i) Asset retirement obligations

Asset retirement obligations are estimated by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to the passage of time is recognized as a finance expense.

(ii) Affordable Energy Fund

The Affordable Energy Fund was determined based on Provincial Legislation. The timing of disbursements is uncertain due to the unpredictability of future customer participation.

(iii) Mitigation

Provisions arising from Manitoba Hydro's mitigation program are recognized when there is an expectation that expenditures will be incurred to address the adverse effects of past hydroelectric development on Indigenous and other communities. These provisions are based on management's best estimate of the consideration required to settle the obligation. The corporation reviews its estimates of future mitigation expenditures on an ongoing basis.

(iv) Major development

Provisions arising from Manitoba Hydro's major development projects are recognized when there is an expectation that expenditures will be incurred to address project-related adverse effects on Indigenous and other communities. These provisions are based on management's best estimate of the consideration required to settle the obligation. The corporation reviews its estimates of future major development expenditures on an ongoing basis.

(v) Other provisions

Other provisions have been established for obligations discovered, which require recognition in the financial statements due to the likelihood of settlement and the presence of an obligation, either from past events or constructive in nature.

(m) Government grants

Government grants are recognized when there is reasonable assurance they will be received and the corporation will comply with the conditions associated with the grant. Government grants that compensate the corporation for expenses incurred are recognized in profit or loss in the same period in which the expenses are recognized. Grants that compensate the corporation for the cost of an asset are recorded as deferred revenue and recognized in other revenue over the service life of the related asset.

(n) 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 except for those financial instruments measured at fair value through profit or loss. Transaction costs directly attributable to the acquisition of financial instruments classified as fair value through profit or loss are expensed as incurred. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of the following categories: loans and receivables, fair value through profit or loss, available-for-sale or other financial liabilities.

Financial instruments classified as loans and receivables and other financial liabilities are carried at amortized cost using the effective interest method of amortization. Available-for-sale financial assets are subsequently measured at fair value with unrealized gains and losses recorded in OCI until the instrument is derecognized or impaired. Financial instruments classified as fair value through profit or loss are subsequently measured at fair value with changes in fair value recognized in the consolidated statement of income in the period in which they arise.

Financial assets classified as loans and receivables are subject to impairment testing at the end of each reporting period. Impairment losses are recorded when there is objective evidence that impairment has occurred due to one or more events such as default or delinquency in interest or principal payments, or significant financial difficulty experienced by the counterparty. Trade receivables that are not assessed for impairment individually are assessed for impairment on a collective basis. Objective evidence of impairment includes the corporation's past historical loss rates applied to groups for which the historical loss rates were observed.

A financial liability is derecognized when the obligation under the liability is discharged, cancelled or expires. When an existing financial liability is replaced with substantially different terms or the terms of an existing liability are substantially modified, such an exchange or modification is treated as derecognition of the original liability and the recognition of a new liability is recorded at fair value. The differences in the respective carrying amounts are recognized as gains or losses in net income.

(o) Foreign currency translation

Revenues and expenses resulting from transactions in foreign currencies are translated to Canadian dollar equivalents at exchange rates approximating those in effect at the transaction date.

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the reporting 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.

(p) Derivatives

The corporation does not engage in derivative trading or speculative activities. All derivative instruments are carried at fair value on the consolidated statement of financial position 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 the consolidated statement of income.

(q) Hedges

The corporation has designated cash flow 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. 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.

(r) Non-controlling interests

Non-controlling interests represent 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 interests within the equity section of the consolidated statement of financial position. The portion of the net income or net loss attributable to the parent and non-controlling interests is reported on the consolidated statement of income.

(s) Change in accounting policy

For the year ended March 31, 2018, the corporation elected to present cash flows from operating activities using the indirect method, as compared to the direct method used for the year ended March 31, 2017, as it provides more relevant information. The comparative information has been reclassified for this change in presentation. Additionally, cash flows related to capitalized interest of $248 million in the year ended March 31, 2017 have been reclassified from investing activities to operating activities in order to present cash flows related to capitalized interest consistently with interest cash flows that are not capitalized.

Note 4 Future accounting pronouncements

The following new standards and amendments are not yet effective for the year ended March 31, 2018, and have not been applied in preparing these consolidated financial statements. The corporation does not have any plans to early adopt the new standards and the full extent of the impact on adoption of the following standards is not known at this time:

IFRS 9 – *Financial Instruments*

IFRS 9 *Financial Instruments* was finalized in July 2014 and replaces IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 includes revised guidance for the classification and measurement of financial assets and liabilities, a new expected credit loss model to measure impairment of financial assets and significant improvements in hedge accounting. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. This new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted.

IFRS 15 – *Revenue from Contracts with Customers*

IFRS 15 *Revenue from Contracts with Customers* was issued in May 2014 and replaces IAS 18 *Revenue* and IFRS Interpretations Committee (IFRIC) 18 *Transfers of Assets from Customers*. The standard provides a single five-step model to be applied to all contracts with customers to determine when to recognize revenue and at what amount. The underlying principle of IFRS 15 is that an entity recognizes revenue that shows the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. This new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted.

IFRS 16 – *Leases*

IFRS 16 *Leases* was issued in January 2016 and replaces current lease accounting requirements under IFRS. The standard provides a single lessee accounting model, requiring the recognition of assets and liabilities for all leases unless the lease term is 12 months or less or the underlying asset has a low value. This new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted if IFRS 15 *Revenue from Contracts with Customers* has also been applied.

Note 5 Extraprovincial revenue

	2018	2017
Dependable sales	**260**	249
Opportunity sales	**168**	202
Other	**9**	9
	437	460

Dependable sales are sourced from Manitoba Hydro's hydraulic energy available during lowest water conditions and typically with a duration of greater than six months. Opportunity sales are based on excess energy, are generally over shorter periods and are transacted primarily in markets operated by an independent system operator such as the Midcontinent Independent System Operator.

The majority of extraprovincial revenue is from sales to the U.S. The average effective exchange rate for the year was $1.00 U.S. = $1.29 Canadian (2017 – $1.00 U.S. = $1.31 Canadian).

Note 6 Other revenue

	2018	2017
Consulting, technology and maintenance services	**55**	56
Customer contributions	**17**	18
Miscellaneous revenue	**14**	32
	86	106

Consulting, technology and maintenance services consist of professional consulting, operations, maintenance and project management services provided to energy sectors world-wide.

Customer contributions are the recognition of deferred revenue related to contributions in aid of construction (Note 27) and the recovery of period costs from customers.

Note 7 Finance expense

	2018	2017
Interest on debt	**768**	711
Provincial debt guarantee fee	**158**	136
Accretion	**32**	29
Interest capitalized	**(343)**	(248)
Foreign exchange loss	**26**	17
	641	645

The Provincial debt guarantee fee during the year was 1.00% of the corporation's total outstanding debt guaranteed by the Province of Manitoba (2017 – 1.00%). Interest was capitalized during the year at 4.80% (2017 – 4.89%).

Note 8 Operating and administrative

	2018	2017
Salaries and benefits	**436**	457
External services	**96**	99
Materials, motor vehicles and supplies	**35**	35
Other	**19**	17
	586	608

Additional salaries and benefits, including termination benefits, are included in other expenses (Note 12) in the amount of $67 million (2017 – $19 million).

Note 9 Depreciation and amortization

	2018	2017
Depreciation of property, plant and equipment (Note 16)	**395**	383
Amortization of intangible assets (Note 18)	**24**	22
Loss (gain) on disposal of property, plant and equipment	**11**	(3)
	430	402

Note 10 Fuel and power purchased

	2018	2017
Wind purchases	**73**	73
Transmission charges	**35**	46
Power purchases	**16**	5
Thermal fuel purchases	**6**	8
	130	132

Included in power purchases above is amortization of transmission rights of $1 million (2017 - $2 million).

Note 11 Capital and other taxes

	2018	2017
Corporate capital tax	**95**	84
Property tax and grants in lieu of tax	**37**	38
Payroll tax	**14**	13
	146	135

Note 12 Other expenses

	2018	2017
Discontinuance of Conawapa Generating Station development (Note 20)	**379**	-
Demand side management expenses	**75**	61
Restructuring costs	**50**	4
Consulting, technology and maintenance expenses	**32**	33
Miscellaneous	**12**	6
	548	104

Of the total other expenses, $466 million (2017 – $67 million) are subsequently deferred in regulatory deferral balances through net movement in regulatory balances (Note 20).

Note 13 Cash and cash equivalents

	2018	2017
Temporary investments	**454**	525
Cash	**186**	116
Restricted cash	**2**	5
	642	646

Temporary investments consist of cash invested with the Province of Manitoba and have a maturity of less than 30 days. Restricted cash consists of deposits held for letters of guarantees for customer contracts, callable at any time.

Note 14 Accounts receivable and accrued revenue

	2018	2017
Trade accounts receivable	**289**	249
Accrued revenue	**89**	85
Other receivables	**28**	21
Taxes receivable	**21**	20
Current portion of loans and other receivables (Note 19)	**20**	21
Allowance for doubtful accounts	**(19)**	(11)
	428	385

Note 15 Inventory

	2018	2017
Materials and supplies	**67**	66
Natural gas	**26**	25
Fuel	**19**	17
	112	108

Inventory recognized as an expense during the year was $40 million (2017 – $41 million). The write-down of inventory during 2018 was nil (2017 – $1 million). No reversals of write-downs occurred during the year (2017 – nil).

Note 16 Property, plant and equipment

	Generation	Transmission lines	Substations	Distribution systems	Other	Construction in progress	Total
Cost or deemed cost							
Balance, April 1, 2016	6 106	763	2 372	2 824	979	4 837	17 881
Additions	119	22	36	218	53	2 519	2 967
Disposals and/or retirements	(7)	(3)	(5)	(15)	(18)	-	(48)
Assets placed in service*	47	15	87	64	32	(245)	-
Transfers to (from) PP&E	(1)	1	1	(4)	1	(25)	(27)
Balance, March 31, 2017	6 264	798	2 491	3 087	1 047	7 086	20 773
Additions	127	15	65	198	41	2 564	3 010
Disposals and/or retirements	(8)	(1)	(12)	(19)	(22)	-	(62)
Assets placed in service*	70	17	119	50	16	(272)	-
Transfers to (from) PP&E	(2)	-	69	(68)	(1)	(379)	(381)
Balance, March 31, 2018	**6 451**	**829**	**2 732**	**3 248**	**1 081**	**8 999**	**23 340**
Accumulated depreciation							
Balance, April 1, 2016	239	26	155	148	105	-	673
Depreciation expense	130	14	89	89	61	-	383
Disposals and/or retirements	(6)	(1)	(6)	(10)	(17)	-	(40)
Balance, March 31, 2017	363	39	238	227	149	-	1 016
Depreciation expense	133	14	94	93	61	-	395
Disposals and/or retirements	(7)	(1)	(9)	(13)	(20)	-	(50)
Transfers to (from) PP&E	-	-	3	(3)	-	-	-
Balance, March 31, 2018	**489**	**52**	**326**	**304**	**190**	**-**	**1 361**
Net book value							
Balance, March 31, 2017	5 901	759	2 253	2 860	898	7 086	19 757
Balance, March 31, 2018	**5 962**	**777**	**2 406**	**2 944**	**891**	**8 999**	**21 979**

*Represents projects that were in construction in progress at the beginning of the year.

Included in additions is interest capitalized during construction of $337 million (2017 – $243 million).

Note 17 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 $165 million (2017 – $146 million). Interest earned on sinking fund investments is recognized in finance expense. As at March 31, 2018 sinking fund investments totaled nil (2017 – nil).

Note 18 Intangible assets

	Computer application development	Land easements	Transmission rights	Under development	Total
Cost or deemed cost					
Balance, April 1, 2016	120	87	10	21	238
Additions	12	38	29	20	99
Retirements	(3)	-	-	-	(3)
Assets placed into service*	15	2	-	(17)	-
Transfers	-	-	25	-	25
Balance, March 31, 2017	144	127	64	24	359
Additions	9	17	101	14	141
Retirements	(2)	-	-	-	(2)
Assets placed into service*	8	1	-	(9)	-
Balance, March 31, 2018	**159**	**145**	**165**	**29**	**498**
Accumulated amortization					
Balance, April 1, 2016	37	2	5	-	44
Amortization	21	2	2	-	25
Retirements	(3)	-	-	-	(3)
Balance, March 31, 2017	55	4	7	-	66
Amortization	22	2	1	-	25
Retirements	(1)	-	-	-	(1)
Balance, March 31, 2018	**76**	**6**	**8**	**-**	**90**
Net book value					
Balance, March 31, 2017	89	123	57	24	293
Balance, March 31, 2018	**83**	**139**	**157**	**29**	**408**

*Represents projects that were in "under development" at the beginning of the year.

Computer application development is a combination of internally developed and externally acquired intangible assets. Included in additions is interest capitalized during development of $4 million (2017 – $2 million).

Note 19 Loans and other receivables

	2018	2017
Loans to Keeyask investment entities (Note 29)	**185**	135
Loan to Wuskwatim investment entity (Note 29)	**142**	135
Contract receivables and other	**103**	104
	430	374
Less: current portion (Note 14)	**(20)**	(21)
	410	353

Accrued interest related to loans receivable is included in the loan balances above and is recognized in finance income.

Note 20 Regulatory deferral balances

	March 31, 2017	Balances arising in the year	Recovery / reversal	**March 31, 2018**	Remaining recovery / reversal period
					(years)
Regulatory deferral debit balances					
Electric					
DSM programs[1]	253	64	(36)	**281**	1 - 10
Site restoration	28	1	(3)	**26**	1 - 15
Change in depreciation method	91	32	-	**123**	*
Deferred ineligible overhead	61	20	(2)	**79**	1 - 34
Acquisition costs	9	-	-	**9**	13 - 16
Affordable Energy Fund	4	-	-	**4**	***
Loss on disposal of assets	10	9	-	**19**	**
Regulatory costs	6	10	(2)	**14**	1 - 5
Conawapa	-	379	-	**379**	1 - 30
Gas					
DSM programs[1]	61	11	(9)	**63**	1 - 10
Deferred taxes	21	2	(3)	**20**	11
Site restoration	3	-	-	**3**	1 - 15
Loss on disposal of assets	9	2	-	**11**	**
Change in depreciation method	6	2	-	**8**	*
Regulatory costs	1	1	(1)	**1**	1 - 5
Deferred ineligible overhead	2	1	-	**3**	34
Change in depreciation rate - meters	1	-	-	**1**	**
	566	534	(56)	**1 044**	
Regulatory deferral credit balances					
Electric					
DSM deferral	49	-	-	**49**	**
Gas					
DSM deferral	8	-	-	**8**	**
PGVA	17	(195)	193	**15**	****
Impact of 2014 depreciation study	3	1	-	**4**	**
	77	(194)	193	**76**	
Net movement in regulatory balances		728	(249)	**479**	

[1] Included in DSM programs is the difference between actual and planned expenditures for electric and gas DSM programs for the fiscal years 2013 to 2017.

* In Order 59/18, the PUB directed Manitoba Hydro to not amortize the cumulative depreciation difference between the ASL and ELG methods of depreciation for rate-setting.

** The amortization periods for these accounts will be determined by the PUB as part of a future regulatory proceeding.

*** The Affordable Energy Fund is amortized to the consolidated statement of income at the same rate as the provision (Note 28) is drawn down.

**** The PGVA is recovered or refunded in future rates.

Notes to the Consolidated Financial Statements

For the year ended March 31, 2018
(in millions of Canadian dollars)

	March 31, 2016	Balances arising in the year	Recovery / reversal	March 31, 2017	Remaining recovery / reversal period
					(years)
Regulatory deferral debit balances					
Electric					
DSM programs[1]	232	56	(35)	253	1 - 10
Site restoration	31	1	(4)	28	1 - 15
Change in depreciation method	60	31	-	91	*
Deferred ineligible overhead	40	21	-	61	1 - 34
Acquisition costs	10	-	(1)	9	14 - 17
Affordable Energy Fund	4	-	-	4	***
Loss on disposal of assets	9	1	-	10	**
Regulatory costs	4	4	(2)	6	1 - 5
Gas					
DSM programs[1]	57	13	(9)	61	1 - 10
Deferred taxes	23	2	(4)	21	12
Site restoration	3	-	-	3	1 - 15
Loss on disposal of assets	6	3	-	9	**
Change in depreciation method	4	2	-	6	*
Regulatory costs	1	1	(1)	1	1 - 5
Deferred ineligible overhead	2	-	-	2	**
Change in depreciation rate - meters	-	1	-	1	**
	486	136	(56)	566	
Regulatory deferral credit balances					
Electric					
DSM deferral	43	6	-	49	**
Gas					
DSM deferral	6	2	-	8	**
PGVA	1	(182)	198	17	****
Impact of 2014 depreciation study	2	1	-	3	**
	52	(173)	198	77	
Net movement in regulatory balances		309	(254)	55	

[1] Included in DSM programs is the difference between actual and planned expenditures for electric and gas DSM programs for the fiscal years 2013 to 2017.

* In Order 59/18, the PUB directed Manitoba Hydro to not amortize the cumulative depreciation difference between the ASL and ELG methods of depreciation for rate-setting.

** The amortization periods for these accounts will be determined by the PUB as part of a future regulatory proceeding.

*** The Affordable Energy Fund is amortized to the consolidated statement of income at the same rate as the provision (Note 28) is drawn down.

**** The PGVA is recovered or refunded in future rates.

The balances arising in the year consist of additions to regulatory deferral balances. The recovery/reversal consists of amounts recovered from customers through the amortization of existing regulatory balances or rate riders. The net impact of these transactions results in the net movement in regulatory deferral balances on the consolidated statement of income.

Balances arising in the year include $2 million (2017 – $2 million) for carrying costs on deferred taxes, the Affordable Energy Fund and the PGVA.

The regulatory deferral debit balances of the corporation consist of the following:

DSM program expenditures are incurred for energy conservation programs to encourage residential, commercial and industrial customers to use energy more efficiently.

Site restoration expenditures are incurred for the remediation of contaminated corporate facilities and diesel generating sites.

Change in depreciation method represents the cumulative annual difference in depreciation expense between the ASL method of depreciation as applied by Manitoba Hydro prior to its transition to IFRS and the ELG method as applied by Manitoba Hydro under IFRS.

Deferred ineligible overhead is the cumulative annual difference in overhead capitalized for financial reporting purposes under IFRS and overhead capitalized for rate setting purposes.

Acquisition costs relate to costs associated with the acquisition of Centra and Minell (July 1999) and Winnipeg Hydro (September 2002).

The Affordable Energy Fund relates to future DSM expenditures in connection with *The Winter Heating Cost Control Act*. The intent of the Affordable Energy Fund is to provide funding for projects that would not otherwise be funded by DSM programs.

Loss on disposal of assets is the net asset retirement losses for those assets retired prior to or subsequent to reaching their expected service life as determined under the ELG method of depreciation.

Regulatory costs are those incurred as a result of electric and gas regulatory hearings.

Deferred taxes are the taxes paid by Centra (July 1999) as a result of its change to non-taxable status upon acquisition by Manitoba Hydro.

Conawapa relates to the one-time transfer of costs incurred to date in relation to the Conawapa Generating Station project which has been discontinued.

Change in depreciation rate on meters represents the difference between depreciation on gas meters between the 20-year rate used for financial reporting purposes and the 25-year rate used for rate-setting purposes.

The regulatory deferral credit balances of the corporation consist of the following:

Purchased gas variance 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. Purchased gas variance accounts are reflected as a regulatory debit or credit depending if the amounts represent a recovery from or a refund to the customers, respectively.

Impact of 2014 depreciation study represents the cumulative unamortized difference in depreciation between the ASL method based on the 2010 depreciation study and the ASL method based on the 2014 depreciation study. The PUB requires the use of 2010 ASL depreciation rates for Centra for rate setting purposes pending review at the next gas regulatory proceeding.

DSM deferral - In Orders 43/13 and 85/13, the PUB directed that the differences between actual and planned spending on electric and gas DSM programs for the 2013 and 2014 fiscal years be recognized as a liability. In Order 73/15, the PUB further directed that the difference in fiscal 2015 and 2016 spending be added to this deferral. Consistent with Order 73/15, the difference in spending for 2017 was also added to the deferral. The cumulative differences have been recorded as a regulatory deferral credit balance with an offsetting balance recorded as a regulatory deferral debit balance. In Order 59/18, the PUB directed Manitoba Hydro to discontinue the deferral of differences between actual and planned DSM spending; as such, the difference in spending beginning in fiscal 2018 has not been added to the deferral. The disposition of the cumulative balances will be determined by the PUB at a future regulatory proceeding.

Note 21 Long-term debt

	Advances from the Province	Manitoba HydroBonds	Manitoba Hydro-Electric Board Bonds	Other*	Total
Balance, April 1, 2016	14 437	26	145	(81)	14 527
Issues	2 163	-	-	23	2 186
Maturities	(301)	(19)	-	-	(320)
Foreign exchange adjustments	42	-	-	1	43
Amortization of net premiums and transaction costs	-	-	-	2	2
Balance, March 31, 2017	16 341	7	145	(55)	16 438
Issues	3 380	-	-	20	3 400
Maturities	(560)	(2)	(20)	-	(582)
Foreign exchange adjustments	(52)	-	-	(6)	(58)
Amortization of net premiums and transaction costs	-	-	-	2	2
	19 109	5	125	(39)	19 200
Less: current portion	(990)	(5)	(5)	-	(1 000)
Balance, March 31, 2018	**18 119**	**-**	**120**	**(39)**	**18 200**

*Other includes adjustments to carrying value of dual currency bonds, transaction costs and debt discounts and premiums.

During the year, the corporation arranged long-term financing of $3 400 million (2017 – $2 186 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 $995 million (2017 – $330 million) of debt maturities and $5 million (2017 – $6 million) of Manitoba HydroBonds with a maturity date in 2018.

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 (2017 – $65 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:

Years of maturity	Canadian	Canadian yields	U.S.	U.S. yields	**2018 Total**	2017 Total
2019	1 000	7.2%	-	-	**1 000**	996
2020	297	4.7%	71	6.5%	**368**	374
2021	975	3.0%	322	8.3%	**1 297**	1 308
2022	303	1.7%	838	9.4%	**1 141**	1 119
2023	980	1.8%	193	3.7%	**1 173**	496
	3 555	2.6%	1 424	8.1%	**4 979**	4 294
2024-2028	3 737	3.0%	-	-	**3 737**	2 789
2029-2033	1 056	8.1%	-	-	**1 056**	1 006
2034-2038	1 035	4.7%	-	-	**1 035**	1 035
2039-2043	2 194	4.3%	-	-	**2 194**	2 194
2044-2048	2 852	3.4%	-	-	**2 852**	2 852
2049-2065	3 386	3.6%	-	-	**3 386**	1 986
	17 815	3.8%	1 424	8.1%	**19 239**	16 156

Included in the above Canadian maturity amounts are ten (2017 – seven) dual currency bonds with the principal amount repayable in Canadian currency and interest payments denominated in U.S. currency. Six dual currency bonds mature in the 2018-19 fiscal year in the amount of $490 million Canadian (2017 - $490 million), three mature in the 2019-20 fiscal year in the amount of $122 million Canadian (2017 - nil), while one matures in the 2025-26 fiscal year in the amount of $130 million Canadian (2017 - $130 million). U.S. debt is translated into Canadian dollars at the exchange rate prevailing at the consolidated statement of financial position date, $1.00 U.S. = $1.29 Canadian (2017 – $1.00 U.S. = $1.33 Canadian).

Note 22 Accounts payable and accrued liabilities

	2018	2017
Trade and other payables	**611**	964
Employee payroll and benefit accruals	**77**	68
Taxes payable	**44**	40
Water rentals and assessments	**10**	11
	742	1 083

Included in accounts payable and accrued liabilities are accruals based on an estimated amount of services completed or goods and materials received but not invoiced.

Note 23 Notes Payable

	2018	2017
Balance, April 1	-	-
Issues	150	-
Maturities	(100)	-
Balance, March 31	50	-

Notes payable at March 31, 2018 had a weighted average term to maturity of nine days and a weighted average rate of 1.25%. *The Manitoba Hydro Act* grants the corporation the power to issue short-term promissory notes up to an aggregate amount of $500 million denominated in Canadian and/or U.S. currency which includes access to bank credit facilities that provide for overdrafts and notes payable under certain conditions.

Note 24 Other liabilities

	2018	2017
Current portion of other long-term liabilities (Note 25)	90	78
Current portion of deferred revenue (Note 27)	71	19
Current portion of provisions (Note 28)	1	1
	162	98

The current portion of other long-term liabilities consists of the current portions of mitigation liability of $37 million (2017 – $26 million), major development liability of $32 million (2017 – $31 million), perpetual obligation to the City of Winnipeg for the acquisition of Winnipeg Hydro of $16 million (2017 – $16 million) and refundable advances from customers of $5 million (2017 – $5 million).

The current portion of deferred revenue represents Bipole III contributions in the amount of $54 million (2017 – nil) as well as customer contributions in aid of construction and advance payments from customers for extraprovincial sales, software maintenance and international consulting work.

The current portion of provisions represents the asset retirement obligation for the removal and disposal of polychlorinated biphenyl (PCB) contaminated fluid in equipment bushings at transmission and distribution stations and for the decommissioning of the coal pile associated with the Brandon Thermal Generating Station.

Note 25 Other long-term liabilities

	2018	2017
Mitigation liability	**204**	209
Major development liability	**213**	210
Perpetual obligation	**215**	215
Refundable advances from customers	**79**	79
Other	**2**	3
	713	716
Less: current portion (Note 24)	**(90)**	(78)
	623	638

Mitigation

Manitoba Hydro's mitigation program addresses past, present and ongoing adverse effects of historical hydroelectric development. The mitigation program, established in the late 1970s to address project impacts through alleviation of adverse effects, remedial works and residual 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 hydroelectric development in five signatory Indigenous communities. The mitigation program was expanded to address impacts arising from all past hydroelectric developments (prior to the Wuskwatim generating station), particularly for Indigenous 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 historical hydroelectric development amounted to $46 million during the year (2017 – $63 million). Payments made during the year totaled $69 million (2017 – $43 million). In recognition of future mitigation payments, the corporation has recorded a liability of $204 million (2017 – $209 million). There are other mitigation issues, the outcomes of which are not determinable at this time.

Included in mitigation 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 obligation outstanding as at March 31, 2018 totaled $8 million (2017 – $8 million).

The discount rates used to determine the present value of mitigation obligations range from 2.95% to 8.50%.

Major development

Beginning with the development of the Wuskwatim generating station, project-related adverse effects are identified and addressed during project planning (including the environmental assessment process), which is done in advance of project construction. As such, mitigation measures are built into project design where possible. The costs for these mitigation measures, as well as any residual compensation requirements, are therefore accounted for in the capital cost estimates for each individual project.

Programs and adverse effects agreements have been negotiated to mitigate and compensate for all anticipated project-related impacts for major new generation and transmission development projects including Wuskwatim, Keeyask, Bipole III and the Manitoba-Minnesota transmission line. The corporation has recorded a liability of $213 million (2017 – $210 million) to reflect these agreements. These expenditures are included in the costs of the associated projects and amortized over the life of the assets. Payments made during the year totaled $20 million (2017 – $19 million).

The discount rates used to determine the present value of the major development obligation range from 2.95% to 5.05%.

Perpetual obligation

Effective September 3, 2002, the corporation acquired the net assets of Winnipeg Hydro from the City of Winnipeg. The obligation represents the net present value of payments to the City of Winnipeg of $16 million per annum in perpetuity.

The discount rate used to determine the present value of the perpetual obligation was 7.45%.

Note 26 Employee future benefits

	2018	2017
Net pension liability	**634**	540
Other employee future benefits liability	**274**	278
	908	818

Pension plans

Manitoba Hydro and its employees are participating members of the Civil Service Superannuation Plan (the Plan) established under *The Civil Service Superannuation Act* (CSSA). Manitoba Hydro employees are eligible for pension benefits based on years of service and on the average earnings of the five best years. As a non-matching employer, the provisions of the CSSA require the corporation to contribute approximately 50% of the pension disbursements made to retired employees. Manitoba Hydro provides its portion of pension benefits through a separately administered fund, the Manitoba Hydro Pension Fund (MHPF). Manitoba Hydro and employees make contributions based on a percentage of pensionable earnings in accordance with the CSSA. The corporation expects to pay $35 million in contributions to this defined benefit plan in fiscal 2019.

Manitoba Hydro employees with pensionable service after June 1, 2006 are eligible for an additional pension benefit under the Enhanced Hydro Benefit Plan (EHBP). The EHBP improves the pension formula used to calculate pension benefits. Manitoba Hydro funds the enhanced pension benefit through contributions based on 0.50% of pensionable earnings to a separate trust account that is managed by the Civil Service Superannuation Board (CSSB). The EHBP funds are co-mingled with the Civil Service Superannuation Fund (CSSF) assets for investment purposes. The corporation expects to pay $2 million in contributions to this defined benefit plan in fiscal 2019.

The former employees of Centra are entitled to pension benefits earned under the Centra curtailed pension plans. The Centra curtailed pension plans are Registered Pension Trusts as defined in the *Income Tax Act (Canada)*. The Master Trust is made up of three individual plans including the Centra Gas Manitoba Inc. Pension Plan for Salaried Employees, the Centra Gas Manitoba Inc. Union Employees' Pension Plan and the Centra Gas Manitoba Inc. (Rural) Local 681 Pension Plan. Centra is required to make special payments to the plans at amounts considered necessary to ensure that the benefits will be fully provided for at retirement as determined in the actuarial valuation dated December 31, 2016. The corporation expects to pay $1 million in special payments to these defined benefit plans in fiscal 2019. The plans are registered with the Pension Commission of Manitoba and subject to the rules and regulations of *The Pension Benefits Act of Manitoba*. The Master Trust assets are held in trust with State Street Trust Company of Canada. The CSSB acts as the investment manager.

MHUS employees are eligible for pension benefits under the Plan. As a matching employer under the CSSA, MHUS is required to match employee contributions at a prescribed rate. MHUS' pension expense is recognized at the time contributions are made. Manitoba Hydro does not carry a pension asset or obligation on its consolidated financial statements related to MHUS.

The former employees of Winnipeg Hydro continue to earn benefits under the Winnipeg Civic Employee Benefits Program (WCEBP), which upon the acquisition of Winnipeg Hydro, Manitoba Hydro became a participating employer. The WCEBP is a defined benefit plan that provides pension benefits based on years of service and on the average earnings of the five best years. Manitoba Hydro does not carry a pension asset or obligation on its consolidated financial statements related to the former employees of Winnipeg Hydro. The WCEBP is governed by an independent board of trustees and a trust agreement that limits Manitoba

Hydro's contribution rates. The structure of the trust agreement also limits Manitoba Hydro's exposure to future unfunded liabilities. Contributions to the plan are accounted for similar to a defined contribution 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.

An independent actuary calculates the liability for pension expense purposes as at December 31 each year with the most recent actuarial valuations being completed as at December 31, 2017. The next actuarial valuations for all plans will occur as at December 2018.

These valuations incorporate management's assumptions and take into consideration the long-term nature of the pension plans. The actuary selects the demographic assumptions. The corporation's management in consultation with the actuary determines the economic assumptions such as discount rate. The accrued benefit actuarial cost method with salary projection is used to determine the pension benefit obligation and current service cost.

The following table presents information pertaining to the Manitoba Hydro Plan, the EHBP and the Centra curtailed plans that are recognized in the consolidated financial statements:

	Manitoba Hydro Plan		EHBP		Centra curtailed pension plans		Total	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017
Plan assets at fair value								
Balance at beginning of year	**1 015**	938	**27**	24	**130**	121	**1 172**	1 083
Return on assets	**69**	104	**3**	2	**8**	13	**80**	119
Employer contributions	**37**	37	**2**	2	**2**	1	**41**	40
Benefit payments and refunds	**(77)**	(64)	**(1)**	(1)	**(6)**	(5)	**(84)**	(70)
	1 044	1 015	**31**	27	**134**	130	**1 209**	1 172
Pension obligation								
Balance at beginning of year	**1 553**	1 515	**38**	35	**121**	121	**1 712**	1 671
Interest cost	**59**	59	**1**	1	**5**	5	**65**	65
Current service cost	**52**	60	**3**	4	**-**	-	**55**	64
Benefit payments and refunds	**(77)**	(64)	**(1)**	(1)	**(6)**	(5)	**(84)**	(70)
Actuarial losses (gains) arising from changes in financial assumptions	**87**	(17)	**3**	(1)	**5**	-	**95**	(18)
	1 674	1 553	**44**	38	**125**	121	**1 843**	1 712
Net pension (liability) asset	**(630)**	(538)	**(13)**	(11)	**9**	9	**(634)**	(540)

The gain on pension fund assets for the MHPF for the fiscal year ended March 31, 2018 was 7.4% (2017 – 11.7% return). The gain for the Centra curtailed plan fund assets for the year ended March 31, 2018 was 7.0% (2017 – 11.9% return). The weighted average term to maturity on fixed income investments is 10.7 years (2017 – 9.9 years).

The investment income earned on the EHBP funds is based on the market rate of return that is earned by the CSSF. For the year ended December 31, 2017, the CSSF earned a rate of return of 10.8% (2017 – 5.66%) on fund assets.

The most recent actuarial valuations for the pension plans for going concern funding purposes were prepared as at December 31, 2017, at which date the Manitoba Hydro Plan was 89% and the EHBP was 104% funded. The Manitoba Hydro Plan is exempt from the funding and solvency test funding requirements of *The Pension Benefits Act*. The Centra curtailed pension plans are subject to a solvency valuation for funding purposes with the latest valuation taking place as at December 31, 2017. The Centra Salaried, Union and Rural plans were 98%, 105% and 95% funded, respectively, at that date.

The corporation's pension expense related to each of the pension benefit plans is as follows:

	Manitoba Hydro Plan		EHBP		Centra curtailed pension plans	
	2018	2017	**2018**	2017	**2018**	2017
Current service cost	**52**	60	**3**	4	**-**	-
Interest on assets	**(41)**	(39)	**(1)**	(1)	**(5)**	(5)
Interest on obligation	**59**	59	**1**	1	**5**	5
Administrative fees	**4**	4	**-**	-	**1**	1
	74	84	**3**	4	**1**	1

Pension expense for the former Winnipeg Hydro employees is equal to employer contributions to the WCEBP. Total contributions to the WCEBP during the year amounted to $1 million (2017 – $1 million) and reflect an employer contribution rate approximating 7.6% of pensionable earnings as of January 2, 2018. Pension expense for MHUS and MHI is equal to the employer contributions and is expensed during the year. The amounts are not material.

Assumptions

The significant actuarial assumptions adopted in measuring the corporation's pension and other employee benefit obligations are as follows:

	2018	2017
Discount rate - pensions	**3.60%**	3.80%
Discount rate - other benefits	**3.60%**	3.80%
Rate of compensation increase, including merit and promotions	**0.00 - 2.00%**	0.00 - 2.00%
Long-term inflation rate	**2.10%**	2.00%

Sensitivity of assumptions

The sensitivities of the principle assumptions used to measure the defined benefit obligations are set out below:

Assumption	Change in assumption	Impact on Manitoba Hydro Plan	Impact on EHBP	Impact on Centra curtailed pension plans
Discount rate	+ 0.50%	(116)	(4)	(7)
	- 0.50%	151	5	8
Inflation rate	+ 0.10%	(20)	-	(1)
	- 0.10%	20	-	1
Wage rate	+ 0.10%	6	-	-

The sensitivity analyses are based on a change in a significant assumption, keeping all other assumptions constant. The sensitivity analyses may not be representative of an actual change in the defined benefit obligation as it is unlikely that the changes in assumptions would occur in isolation of one another.

Benefit plan asset allocation

The following is a summary of the asset mix of the plans' investments at fair value:

	MHPF		Centra curtailed pension plans	
	2018	2017	**2018**	2017
Equities	**60%**	63%	**59%**	62%
Bonds and debentures	**20%**	20%	**20%**	20%
Real estate	**13%**	11%	**13%**	11%
Infrastructure	**6%**	5%	**5%**	5%
Private credit	**1%**	-	**1%**	-
Short-term investments	**-**	1%	**2%**	2%
	100%	100%	**100%**	100%

Other employee future benefits

Manitoba Hydro also provides some unfunded non-pension employee future benefits including banked incidental days, vacation days, long-term disability, workers compensation, retiree health spending, sick leave vesting and severance. The following table presents information concerning other employee future benefits:

	2018	2017
Balance at beginning of year	**278**	271
Interest cost	**7**	7
Current service cost	**19**	20
Benefit payments	**(37)**	(22)
Actuarial loss from changes in financial assumptions	**7**	2
Benefits liability	**274**	278

Key management personnel

The key management personnel of the corporation have been defined as members of the Manitoba Hydro-Electric Board and Manitoba Hydro's executives. The directors' fees are authorized by the Lieutenant Governor in Council. Manitoba Hydro's executives receive a base salary, in addition to non-cash benefits, employer contributions to the corporation's post-employment defined pension plan and other post-employment benefits.

Key management personnel compensation is as follows:

	2018	2017
Salaries and other short-term employee benefits	**3**	4
Post-employment benefits*	**-**	-
	3	4

*Amounts round to less than $1 million.

Note 27 Deferred revenue

	2018	2017
Contributions in aid of construction	**483**	455
Bipole III contribution	**348**	196
Deferred revenue	**9**	10
	840	661
Less: current portion (Note 24)	**(71)**	(19)
	769	642

Contributions in aid of construction are required from customers whenever the costs of extending service exceed specified construction allowances. These contributions include government grants. Contributions are initially recorded as deferred revenue and are subsequently recognized as revenue over the lives of the related assets.

The PUB has directed that the following percentages of approved rate increases be set aside as a Bipole III contribution to be utilized to mitigate the required rate increases when Bipole III is placed in-service:

- Order 43/13 1.50% of the approved 3.50%
- Order 49/14 0.75% of the approved 2.75%
- Order 73/15 2.15% of the approved 3.95%
- Order 59/16 3.36% of the approved 3.36%
- Order 80/17 3.36% of the approved 3.36%.

During the year, $152 million (2017 – $96 million) was set aside for this purpose. The PUB directed in Order 59/18, that the balance in this account should begin to be recognized in other revenue following the in-service date of Bipole III in fiscal 2018-19, amortized over a five year period.

Note 28 Provisions

	Mitigation provisions	Major development provisions	Asset retirement obligations	Affordable Energy Fund	Other provisions	Total
Balance, April 1, 2016	23	-	27	4	-	54
Provisions made	32	-	(20)	-	4	16
Provisions used	-	-	(1)	-	-	(1)
Accretion	1	-	1	-	-	2
Balance, March 31, 2017	56	-	7	4	4	71
Provisions made	(1)	3	-	-	1	3
Provisions used	(12)	-	(1)	-	(2)	(15)
Accretion	2	-	-	-	-	2
Balance, March 31, 2018	**45**	**3**	**6**	**4**	**3**	**61**

	2018	2017
Analyzed as:		
Current (Note 24)	**1**	1
Non-current	**60**	70
	61	71

Mitigation

A provision has been recognized for certain mitigation related obligations arising from ongoing adverse effects of past hydroelectric development. The amount recognized as a provision is the best estimate of the consideration required to settle the obligation at the reporting date. Once a final settlement is reached, these obligations will be transferred to other long-term liabilities (Note 25).

Discount rates used to determine the present value of mitigation related provisions were 4.00% (2017 - 3.75% to 4.15%).

Major development

A provision has been recognized for certain major development related obligations arising from impacts of current hydroelectric development. The amount recognized as a provision is the best estimate of the consideration required to settle the obligation at the reporting date. Once a final settlement is reached, these obligations will be transferred to other long-term liabilities (Note 25).

Discount rates used to determine the present value of major development related provisions were 3.80%.

Asset retirement obligations

An asset retirement obligation continues to be recognized for the future decommissioning of the Brandon Thermal Generating Station coal pile. The estimate was adjusted as a result of plans to repurpose parts of the station and only remove the coal pile. The corporation estimates the undiscounted cash flows required to settle the asset retirement obligations are approximately $3 million (2017 – $3 million), which is expected to be incurred in 2020.

The corporation recognizes an asset retirement obligation for the removal and disposal of PCB contaminated fluid in equipment bushings at transmission and distribution stations. The estimated undiscounted cash flows required to settle the asset retirement obligation are approximately $3 million (2017 – $4 million), which is expected to be incurred by 2024.

No funds are being set aside to settle the asset retirement obligations. The discount rates used to determine the fair market value of asset retirement obligations range from 1.80% to 2.02% (2017 - 0.75% to 1.30%).

Affordable Energy Fund

In accordance with the requirements of *The Winter Heating Cost Control Act*, Manitoba Hydro established an Affordable Energy Fund in the initial amount of $35 million for the purpose of providing funding for projects that would not otherwise be funded by DSM programs. Expenditures of nil (2017 – nil) during the year were charged to operations with the regulatory deferral balance and the provision reduced accordingly.

Other provisions

Other provisions have been established for obligations discovered, which require recognition in the financial statements due to the likelihood of settlement and the presence of an obligation, either from past events or constructive in nature.

Note 29 Non-controlling interests

	2018	2017
Wuskwatim Power Limited Partnership		
Taskinigahp Power Corporation	**32**	40
Keeyask Hydropower Limited Partnership		
Cree Nation Partners Limited Partnership	**103**	78
Fox Lake Cree Nation Keeyask Investments Inc.	**35**	26
York Factory First Nation Limited Partnership	**35**	26
	173	130
	205	170

Manitoba Hydro has entered into the WPLP 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 assets were placed into service during the 2012-13 year.

The 33% ownership interest of TPC in the WPLP of $32 million (2017 – $40 million) is represented as a non-controlling interest within the equity section of the consolidated statement of financial position. TPC's portion of the net loss of the WPLP during 2017-18 is $8 million (2017 – $12 million).

In accordance with the partnership agreements, Manitoba Hydro provides debt financing to TPC for investment in WPLP. As at March 31, 2018, Manitoba Hydro has provided advances to TPC of $88 million (2017 – $88 million). In addition, Manitoba Hydro provides advances on future WPLP distributions to NCN. As at March 31, 2018, Manitoba Hydro has provided advances to NCN of $7 million (2017 – $6 million). The advances plus interest are repayable by TPC through distributions from the WPLP. In exchange for forgiveness of the advances and interest, TPC has the option to put all their units back to Manitoba Hydro at any time between June 29, 2037 and June 29, 2062.

Manitoba Hydro has also entered into the KHLP with 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) to carry on the business of developing, owning and operating the Keeyask Generating Station. Cree Nation Partners Limited Partnership (CNPLP) is owned beneficially by TCN and War Lake through CNP, FLCN Keeyask Investments Inc. (FLCNKII) is owned beneficially by Fox Lake and York

Factory First Nation Limited Partnership (YFFNLP) is owned beneficially by York Factory. The generating station is currently under construction and projected to be placed into service in 2021.

The 15% ownership interest of CNPLP, the 5% ownership interest of FLCNKII and the 5% ownership interest of YFFNLP in the KHLP totaling $173 million (2017 – $130 million) is represented as a non-controlling interest within the equity section of the consolidated statement of financial position.

In accordance with the partnership agreements, Manitoba Hydro provides debt financing to CNPLP, FLCNKII and YFFNLP. As at March 31, 2018, Manitoba Hydro has provided advances to CNPLP of $103 million (2017 – $76 million), FLCNKII of $34 million (2017 – $25 million) and YFFNLP of $34 million (2017 – $25 million). The advances plus interest are repayable by CNPLP, FLCNKII and YFFNLP through distributions from the KHLP. In exchange for forgiveness of the advances and interest, CNPLP, FLCNKII and YFFNLP have the option at the final closing date (six months after the last unit in-service date of the Keeyask Generating Station) to convert their common units to preferred units based on their invested capital and return their common units to Manitoba Hydro or to put all their units back to Manitoba Hydro.

Summarized financial information before intercompany eliminations for WPLP and KHLP are as follows:

	2018	2017
WPLP		
Current assets	**21**	13
Non-current assets	**1 504**	1 526
Current liabilities	**23**	24
Non-current liabilities	**1 405**	1 393
Revenue	**91**	80
Net loss	**(25)**	(36)
KHLP		
Current assets	**8**	89
Non-current assets	**4 401**	3 202
Current liabilities	**235**	152
Non-current liabilities	**3 183**	2 398

Note 30 Financial instruments

The carrying amounts and fair values of the corporation's non-derivative financial instruments were as follows:

		2018		2017	
	Level	Carrying value	Fair value	Carrying value	Fair value
Fair value through profit and loss					
Cash and cash equivalents	1	**642**	**642**	646	646
Loans and receivables					
Accounts receivable and accrued revenue	*	**408**	**408**	364	364
Loans and other receivables (including current portion)	2	**430**	**460**	374	397
Other financial liabilities					
Accounts payable and accrued liabilities	*	**742**	**742**	1 083	1 083
Note payable	2	**50**	**50**	-	-
Long-term debt (including current portion)	2	**19 200**	**21 194**	16 438	18 456
Mitigation liability (including current portion)	2	**204**	**253**	209	259
Major development liability (including current portion)	2	**213**	**244**	210	244
Perpetual obligation (including current portion)	2	**215**	**385**	215	370

*carried at values that approximate fair value

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.

Fair value Level 2 measurements are derived from quoted market yields at the close of business on the consolidated statement of financial position date for similar instruments available in the capital market. There are nominal amounts measured at Level 3 that are based on internally developed valuation models, and 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 have 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, temporary 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 natural gas customer base. Customers participating in residential financing programs are subject to credit reviews and must meet specific criteria before they are approved for a residential loan or financing. Equity loans advanced to Indigenous partners are secured by their ownership investment units in the Wuskwatim and Keeyask generating stations. 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 values of the corporation's aged accounts receivable and related allowance for doubtful accounts are presented in the following table:

	Manitoba	Extraprovincial	**2018**	2017
Under 30 days	205	24	**229**	198
31 to 60 days	21	-	**21**	16
61 to 90 days	10	-	**10**	7
Over 90 days	29	-	**29**	28
	265	24	**289**	249
Allowance for doubtful accounts	(19)	-	**(19)**	(11)
Total accounts receivable	246	24	**270**	238

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 as at the consolidated statement of financial position date:

	Carrying value	2019	2020	2021	2022	2023	2024 and thereafter
Non-derivative financial liabilities							
Accounts payable and accrued liabilities	742	742	-	-	-	-	-
Note payable	50	50	-	-	-	-	-
Long-term debt*	19 326	1 950	1 268	2 168	1 941	1 899	26 240
Mitigation liability	204	37	18	22	23	21	395
Major development liability	213	30	15	15	15	16	593
Perpetual obligation	215	16	16	16	16	16	16**
	20 750	2 825	1 317	2 221	1 995	1 952	27 244

*includes current portion and interest payments but excludes the Provincial debt guarantee fee
**per year in perpetuity

(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 OCI until future hedged U.S. export revenues are realized, at which time the associated gains or losses in AOCI are recognized in net income. For the year ended March 31, 2018, unrealized foreign exchange translation gains of $57 million (2017 – $47 million losses) were recognized in OCI and net losses of $22 million (2017 – $20 million) were reclassified from OCI into net income. In addition, the corporation utilizes foreign exchange forward contracts to hedge U.S. long-term debt balances, for which hedge accounting is not applied. The monthly foreign exchange revaluation of these U.S. long-term debt balances and the mark to market of the foreign exchange forward contracts offsets in net income. The fair value of these forward contracts of $2.6 million (2017 – nil) is included in accounts receivable and accrued revenue and classified as Level 2 fair value measurements.

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, 2018, a change in the Canadian dollar of plus (minus) $0.10 relative to the U.S. dollar would decrease (increase) net income by $2 million (2017 – $8 million), while OCI would increase (decrease) by $101 million (2017 – $120 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 short-term and long-term debt, fixed rate long-term debt maturing within 12 months, less sinking fund withdrawals, offset by the change in interest capitalization. As at March 31, 2018, an increase or decrease of 1% in the interest rate would reduce or increase net income, respectively, by $6 million (2017 - $3 million), with no impact to OCI.

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 natural gas for delivery to customers throughout Manitoba. The corporation mitigates commodity price risk through its limited use of derivative financial instruments. Manitoba Hydro does not use derivative contracts for trading or speculative purposes.

The corporation has entered into commodity derivative contracts as at March 31, 2018. The fair value of these contracts of $0.4 million (2017 – $1 million) is included in accounts receivable and accrued revenue and classified as Level 2 fair value measurements.

Note 31 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%.

The corporation's equity ratio was as follows:

	2018	2017
Long-term debt (Note 21)	**18 200**	16 102
Current portion of long-term debt (Note 21)	**1 000**	336
Notes payable (Note 23)	**50**	–
Less: Cash and cash equivalents (Note 13)	**(642)**	(646)
Net debt	**18 608**	15 792
Retained earnings	**2 936**	2 899
Accumulated other comprehensive loss	**(688)**	(709)
Contributions in aid of construction (Note 27)	**483**	455
Bipole III contribution (Note 27)	**348**	196
Non-controlling interest (Note 29)	**205**	170
Total equity	**3 284**	3 011
Equity ratio	**15%**	16%

Manitoba Hydro issues debt for its capital requirements under the authority of *The Manitoba Hydro Act*, *The Loan Act* and *The Financial Administration 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. Authority to refinance any maturing long-term debt is provided through *The Financial Administration Act*. The majority of Manitoba Hydro's long-term debt is obtained through advances from the Province of Manitoba.

Note 32 Related parties

Manitoba Hydro is a Crown corporation controlled by the Province of Manitoba. As a result, the corporation has a related party relationship with all entities that are controlled, jointly controlled or significantly influenced by the Province of Manitoba. However, as permitted by IAS 24 *Related Party Disclosures*, the corporation is exempt from disclosure requirements relating to transactions with the Province of Manitoba and any other entity that is a related party because the Province of Manitoba has control, joint control or significant influence over both the corporation and the other entity.

Significant transactions with the Province of Manitoba and other related provincial entities consist of:

- Long-term debt – the corporation obtains the majority of its long-term debt through advances from the Province of Manitoba (Note 21),
- Provincial Debt Guarantee Fee – the corporation pays the Province of Manitoba an annual fee on the outstanding debt. The Provincial Debt Guarantee Fee of $158 million (2017 – $136 million) for the year was 1.00% (2017 – 1.00%) of the corporation's total outstanding debt guaranteed by the Province of Manitoba,
- Sale of electricity and natural gas – energy sales to related parties,
- Water rentals – amounts 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 (2017 – $3.34 per MWh) totalling $116 million (2017 – $122 million), and
- Taxes – amounts are paid to the Province of Manitoba for corporate capital tax, payroll tax (Note 11) and provincial sales tax, all of which are incurred in the normal course of business.

Routine operating transactions with related parties are settled at prevailing market prices under normal trade terms.

Note 33 Commitments and contingencies

Manitoba Hydro has energy purchase commitments of $1 591 million (2017 – $1 419 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 2037. In addition, other outstanding commitments principally for construction are approximately $2 132 million (2017 – $3 330 million).

As at March 31, 2018, total future minimum lease payments committed under operating leases amounted to $10 million (2017 - $12 million).

During the year, Manitoba Hydro entered into an agreement with an independent third party pipeline company to increase pipeline capacity. As part of the agreement, the corporation has committed to pay its share of the pre-license development costs associated with the contract, limited to $19 million, in the event that the federal license is not granted for the project. While the potential costs are quantified, no obligating event has occurred and so a provision has not been booked.

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 PCB 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. Management believes that any settlements related to these matters will not have a material adverse effect on Manitoba Hydro's consolidated financial position or results of operations.

Manitoba Hydro provides guarantees to counterparties for natural gas purchases. At March 31, 2018, there is an outstanding guarantee totaling $30 million (2017 – $40 million) which matures October 31, 2018. Letters of credit in the amount of $75 million (2017 – $74 million) have been issued for construction and energy related transactions with maturities until 2049.

Note 34 Segmented information

Operating segments are reported consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for allocating resources and assessing performance of operations, has been identified as the President and Chief Executive Officer. The corporation is managed as three segments, electricity operations, natural gas operations and other, based on how financial information is produced internally for the purposes of making operating decisions.

Segment descriptions

Electric Operations

Electric operations derives its revenue from the sale of electricity in both Manitoba and to the export markets. Manitoba Hydro's electric operations also includes subsidiaries WPLP, KHLP and 6690271 Manitoba Ltd. Electricity is sold in Manitoba to residential, commercial and industrial customers while extraprovincial sales of electricity are to the U.S. and Canadian markets. Domestic electricity sales are regulated by the PUB.

Natural Gas Operations

The operations of Centra make up the entire natural gas operations segment. Centra is regulated by the PUB and generates revenue through the sale and distribution of natural gas to residential, commercial and industrial customers throughout Manitoba.

Other Segment

The other segment includes the operations of all other subsidiaries of the corporation, including MHI, MHUS, Minell and Teshmont.

MHI derives its revenue by providing 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.

MHUS generates revenue by providing meter reading, interactive voice response systems and contracted services primarily to Manitoba Hydro and Centra.

Minell operates a pipeline transmission system extending from Moosomin, Saskatchewan to Russell, Manitoba and is regulated by the National Energy Board. Revenues are derived through the rentals of Minell's gas transmission facilities to Centra as they are used solely for the transportation of natural gas on behalf of Centra.

Teshmont is a holding company established to acquire a 40% ownership of Teshmont Consultants Limited Partnership, which carries on a high voltage engineering and consulting practice.

Segmented results

Results by operating segment for the years ended March 31, 2018 and 2017 are shown below. Intersegment eliminations are presented to reconcile segment results to the corporation's consolidated totals. Eliminations have been made for intersegment transactions and balances.

Notes to the Consolidated Financial Statements

For the year ended March 31, 2018
(in millions of Canadian dollars)

	Electric operations		Natural gas operations		Other segment		Eliminations		Total	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Revenues										
External revenue	**1 931**	1 927	**345**	344	**54**	56	**-**	-	**2 330**	2 327
Intersegment revenue	**-**	-	**1**	1	**10**	9	**(11)**	(10)	**-**	-
	1 931	1 927	**346**	345	**64**	65	**(11)**	(10)	**2 330**	2 327
Expenses										
Finance expense	**601**	608	**21**	19	**1**	-	**18**	18	**641**	645
Operating and administrative	**517**	536	**63**	65	**17**	17	**(11)**	**(10)**	**586**	608
Depreciation and amortization	**402**	375	**24**	23	**1**	2	**3**	2	**430**	402
Cost of gas sold	**-**	-	**196**	183	**-**	-	**-**	-	**196**	183
Water rentals and assessments	**126**	131	**-**	-	**-**	-	**-**	-	**126**	131
Fuel and power purchased	**130**	132	**-**	-	**-**	-	**-**	-	**130**	132
Capital and other taxes	**130**	119	**16**	16	**-**	-	**-**	-	**146**	135
Other expenses	**502**	60	**14**	12	**35**	35	**(3)**	(3)	**548**	104
Finance income	**(23)**	(17)	**-**	-	**-**	-	**-**	-	**(23)**	(17)
Corporate allocation	**8**	8	**12**	12	**-**	-	**(20)**	(20)	**-**	-
	2 393	1 952	**346**	330	**54**	54	**(13)**	(13)	**2 780**	2 323
Net income (loss) before net movement in regulatory deferral balances	**(462)**	(25)	**-**	15	**10**	11	**2**	3	**(450)**	4
Net movement in regulatory deferral balances	**472**	66	**7**	(11)	**-**	-	**-**	-	**479**	55
Net Income	**10**	41	**7**	4	**10**	11	**2**	3	**29**	59
Net income (loss) attributable to:										
Manitoba Hydro	**18**	53	**7**	4	**10**	11	**2**	3	**37**	71
Non-controlling interests	(8)	(12)	-	-	-	-	-	-	(8)	(12)
	10	41	**7**	4	**10**	11	**2**	3	**29**	59

	Electric operations		Natural gas operations		Other segment		Eliminations		Total	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Total assets	**23 606**	21 271	**642**	617	**96**	85	**(219)**	(201)	**24 125**	21 772
Total regulatory deferral debit balances	**934**	462	**110**	104	**-**	-	**-**	-	**1 044**	566
Total liabilities	**22 207**	19 474	**528**	503	**16**	15	**(111)**	(91)	**22 640**	19 901
Total regulatory deferral credit balances	**49**	49	**27**	28	**-**	-	**-**	-	**76**	77
Retained earnings	**2 767**	2 749	**76**	69	**79**	69	**14**	12	**2 936**	2 899

Note 35 Comparative figures

Where appropriate, comparative figures for 2017 have been reclassified in order to conform to the presentation adopted in 2018.

Financial statistics

For the year ended March 31	IFRS				CGAAP					
	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
					dollars are in millions					
Revenues										
Domestic Electric	**1 464**	1 419	1 399	1 424	1 405	1 341	1 193	1 200	1 145	1 127
Gas	**343**	342	353	427	413	328	328	403	452	578
Extraprovincial	**437**	460	415	384	402	329	333	358	385	533
Other	**86**	106	91	81	72	70	46	42	29	36
	2 330	2 327	2 258	2 316	2 292	2 068	1 900	2 003	2 011	2 274
Expenses										
Finance expense	**641**	645	620	551	470	489	423	425	410	471
Operating and administrative	**586**	608	614	614	558	533	481	463	440	429
Depreciation and amortization	**430**	402	394	378	442	423	381	393	384	368
Cost of gas sold	**196**	183	181	266	252	182	197	261	316	431
Water rentals and assessments	**126**	131	126	125	125	118	119	120	121	123
Fuel and power purchased	**130**	132	117	129	140	109	116	66	62	86
Capital and other taxes	**146**	135	123	115	117	105	103	102	99	87
Other expenses	**548**	104	114	77	36	30	19	23	16	13
Finance income	**(23)**	(17)	(23)	(26)	-	-	-	-	-	-
	2 780	2 323	2 266	2 229	2 140	1 989	1 839	1 853	1 848	2 008
Net income (loss) before net movement in regulatory accounts	**(450)**	4	(8)	87	152	79	61	150	163	266
Net movement in regulatory accounts	**479**	55	47	38	-	-	-	-	-	-
Net Income	**29**	59	39	125	152	79	61	150	163	266
Net income (loss) attributable to:										
Manitoba Hydro	**37**	71	49	136	174	92	61	150	163	266
Non-controlling interests	**(8)**	(12)	(10)	(11)	(22)	(13)	-	-	-	-
	29	59	39	125	152	79	61	150	163	266
Assets										
Property, plant and equipment	**21 979**	19 757	17 208	15 222	13 627	12 508	11 797	10 954	10 128	9 382
Sinking fund investments	**-**	-	-	114	111	352	372	282	822	666
Current and other assets	**2 146**	2 015	2 085	1 821	1 901	1 682	1 622	1 646	1 487	1 499
Regulatory deferral debits	**1 044**	566	486	410	-	-	-	-	-	-
	25 169	22 338	19 779	17 567	15 639	14 542	13 791	12 882	12 437	11 547
Liabilities and Equity										
Long-term debt	**18 200**	16 102	14 201	12 303	10 460	9 329	9 101	8 617	8 228	7 668
Current and other liabilities	**3 671**	3 157	2 799	2 603	1 913	1 937	1 495	1 127	1 328	1 637
Deferred revenue	**769**	642	535	459	381	340	318	295	295	296
Regulatory deferral credits	**76**	77	52	23	-	-	-	-	-	-
Non-controlling interests	**205**	170	140	120	73	95	100	87	62	39
Retained earnings	**2 936**	2 899	2 828	2 779	2 716	2 542	2 450	2 389	2 239	2 076
Accumulated other comprehensive income (loss)	**(688)**	(709)	(776)	(720)	96	299	327	367	285	(169)
	25 169	22 338	19 779	17 567	15 639	14 542	13 791	12 882	12 437	11 547
Cash Flows										
Operating activities	**(94)**	623	607	519	691	589	567	595	589	688
Financing activities	**2 854**	1 855	2 111	1 560	1 125	635	725	674	1 124	424
Investing activities	**(2 764)**	(2 787)	(2 257)	(1 727)	(1 706)	(1 242)	(1 312)	(1 373)	(1 698)	(1 086)
Financial Indicators										
Equity ratio [1]	**15%**	16%	17%	18%	24%	25%	26%	27%	27%	23%
Interest coverage [2]	**1.50**	1.54	1.57	1.73	1.95	1.81	1.74	1.96	2.06	2.16
Capital coverage [3]	**0.50**	1.48	1.37	1.20	1.35	1.25	1.13	1.25	1.34	1.77

[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 earnings before finance expense and depreciation and amortization adjusted for net movement impacts divided by finance expense.

[3] Capital coverage represents internally generated funds divided by capital construction expenditures.

Operating statistics

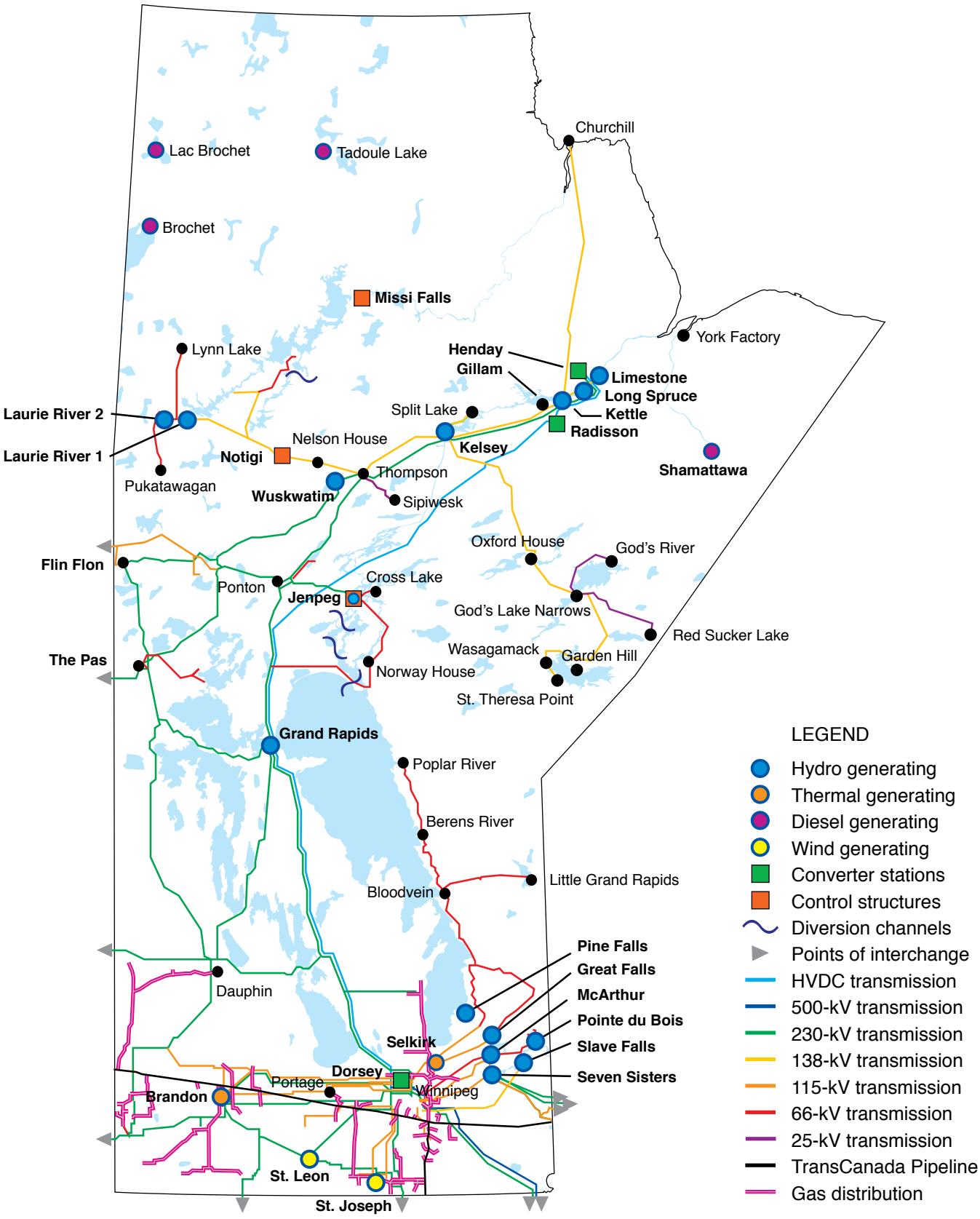
For the year ended March 31

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Electric System Capability										
Capability (000 kW)	**5 648**	5 679	5 680	5 691	5 715	5 675	5 475	5 489	5 501	5 480
Manitoba firm peak demand (000 kW)	**4 735**	4 801	4 460	4 688	4 720	4 535	4 343	4 261	4 359	4 477
Per cent change	**(1.4)**	7.6	(4.9)	(0.7)	4.1	4.4	1.9	(2.2)	(2.6)	4.8
Electric System Supply										
Total energy supplied (millions of kWh)										
Generation	**34 613**	36 433	34 990	35 044	35 392	33 230	33 235	34 102	33 961	34 528
Isolated systems	**14**	15	14	15	14	14	14	13	13	13
	34 627	36 448	35 004	35 059	35 406	33 244	33 249	34 115	33 974	34 541
Electric Load at Generation (millions of kWh)										
Integrated system	**23 288**	25 144	24 566	25 399	25 510	24 650	23 499	23 783	23 295	24 285
Isolated system	**14**	15	14	15	14	14	14	13	13	13
	23 302	25 159	24 580	25 414	25 524	24 664	23 513	23 796	23 308	24 298
Per cent change	**(7.4)**	2.4	(3.3)	(0.4)	3.5	4.9	(1.2)	2.1	(4.1)	1.3
Electric System Deliveries (millions of kWh)										
Energy delivered in Manitoba										
Residential	**7 636**	7 250	7 181	7 788	7 888	7 334	6 930	7 060	6 899	6 954
Commercial / Industrial	**14 869**	14 716	14 473	14 670	14 450	14 143	13 840	13 727	13 587	14 256
	22 505	21 966	21 654	22 458	22 338	21 477	20 770	20 787	20 486	21 210
Extraprovincial	**9 448**	11 272	10 281	9 811	10 537	9 087	10 244	10 344	10 860	10 122
	31 953	33 238	31 935	32 269	32 875	30 564	31 014	31 131	31 346	31 332
Gas Deliveries (millions of cubic metres)										
Residential	**579**	524	498	597	664	602	509	591	581	696
Commercial / Industrial	**887**	801	748	870	964	849	728	821	803	866
Transportation	**582**	661	600	604	652	598	629	584	619	603
	2 048	1 986	1 846	2 071	2 280	2 049	1 866	1 996	2 003	2 165
Number of Customers										
Electric:										
Residential	**509 465**	503 167	497 699	492 275	486 654	480 254	474 661	469 635	465 055	460 804
Commercial / Industrial	**70 797**	70 271	69 935	69 594	69 106	68 520	68 020	67 664	67 304	66 668
	580 262	573 438	567 634	561 869	555 760	548 774	542 681	537 299	532 359	527 472
Gas:										
Residential	**255 868**	253 357	251 142	249 313	247 010	244 768	242 813	241 123	239 535	239 597
Commercial / Industrial	**26 122**	25 911	25 716	25 504	25 218	25 018	24 886	24 838	24 766	23 411
	281 990	279 268	276 858	274 817	272 228	269 786	267 699	265 961	264 301	263 008
Full Time Equivalent (FTE) [1]	**5 998[2]**	6 411	6 410	6 483	6 556	6 463	6 413	6 394	6 236	6 080

[1] Regular FTEs includes employees of subsidiaries as well as seasonal, hourly and part-time staff. It is derived by calculating total straight time hours in the year divided by 1 916 hours per FTE. The 2017-18 FTE figure includes employees that departed the corporation through the Voluntary Departure Program/management reorganization and contains the portion of the year those employees worked prior to their departure date.

[2] Includes participants in Voluntary Departure Program on pre-retirement leave and/or salary continuance as at March 31, 2018

Major electric & natural gas facilities



Sources of electrical energy generated & purchased

For the year ended March 31, 2018

Nelson River	**74.64 %**	**Saskatchewan River**	**6.61 %**	**Thermal**	**0.12 %**
Billion kWh generated	**26.9**	**Billion kWh generated**	**2.4**	**Billion kWh generated**	**0.0**
Limestone	24.05 %	Grand Rapids	6.61 %	Brandon	0.09 %
Kettle	23.49 %			Selkirk	0.03 %
Long Spruce	19.20 %	**Laurie River**	**0.17 %**		
Kelsey	6.09 %	**Billion kWh generated**	**0.1**	**Purchases (excl. wind)**	**1.16 %**
Jenpeg	1.81 %	Laurie River 1	0.08 %	**Billion kWh purchased**	**0.4**
		Laurie River 2	0.09 %		
Winnipeg River	**10.53 %**			**Wind**	**2.72 %**
Billion kWh generated	**3.8**	**Burntwood River**	**4.06 %**	**Billion kWh purchased**	**1.0**
Seven Sisters	3.07 %	**Billion kWh generated**	**1.5**		
Great Falls	2.65 %	Wuskwatim	4.06 %		
Pine Falls	1.67 %				
Pointe du Bois	0.61 %				
Slave Falls	1.35 %				
McArthur	1.18 %				

Manitoba Hydro generating stations & capabilities

Interconnected Capabilities			
Station	Location	Number of units	Net Capability (MW)
Hydraulic			
Great Falls	Winnipeg River	6	**136**
Seven Sisters	Winnipeg River	6	**164**
Pine Falls	Winnipeg River	6	**83**
McArthur	Winnipeg River	8	**54**
Pointe du Bois	Winnipeg River	16	**56**
Slave Falls	Winnipeg River	8	**68**
Grand Rapids	Saskatchewan River	4	**479**
Kelsey	Nelson River	7	**286**
Kettle	Nelson River	12	**1 220**
Jenpeg	Nelson River	6	**90**
Long Spruce	Nelson River	10	**980**
Limestone	Nelson River	10	**1 350**
Laurie River (2)	Laurie River	3	**10**
Wuskwatim	Burntwood River	3	**212**
Thermal			
Brandon		3	**324**
Selkirk		2	**125**
Isolated Capabilities			
Diesel			
Brochet			**3**
Lac Brochet			**2**
Shamattawa			**4**
Tadoule Lake			**2**
Total Generating Capability			**5 648**



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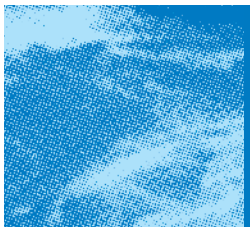
8-2-2018

The Manitoba Hydro-Electric Board

Quarterly Report

for the three months ended
June 30, 2018





Report from **The Chair of the Board** and by **The President and Chief Executive Officer**

Financial Overview

Manitoba Hydro's consolidated net loss was $12 million for the first three months of the 2018-19 fiscal year compared to a net loss of $70 million for the same period last year. The decrease in the net loss is primarily attributable to higher restructuring costs in the prior year driven by the implementation of a significant cost reduction program. Excluding restructuring expenses, Manitoba Hydro would have reported a net loss of $9 million, an improvement of $19 million over the prior year. The improvement is mostly attributable to weather impacts resulting in an increase of $11 million in domestic electric revenue and a decrease of $17 million in operating and administrative expenses associated with savings from the Voluntary Departure Program (VDP). These improvements were partially offset by a decrease in net extraprovincial revenues (net of power purchased and water rental expenses) of $8 million as a result of less favourable water conditions in the current year, higher depreciation and amortization expense as new assets were placed in-service and higher capital taxes resulting from increased debt associated with major capital projects. The cost of natural gas is a flow through cost passed onto customers through rates approved by the Public Utilities Board (PUB) and therefore is not a driver for the decrease in net loss compared to the prior year.

The consolidated net loss was comprised of a $6 million loss in the electricity segment, an $8 million loss in the natural gas segment, a $1 million net profit in the other segment and a $1 million profit impact in adjustments and eliminations.

Manitoba Hydro's budgeted net income for 2018-19 is approximately $130 million, however after factoring in the impact of the PUB's decision to grant a 3.6% rate increase rather than the requested 7.9% increase Manitoba Hydro is expecting net income to be approximately $70 million. The projection for the remainder of the year assumes average water flow conditions and normal winter weather.

Electric Segment

Revenues from electricity sales within Manitoba totaled $332 million for the three-month period, which was $11 million or 3% higher than the same period last year. The increase in domestic revenue was primarily attributable to the impacts of weather compared to prior year. Extraprovincial revenues of $116 million were $18 million or 13% lower than the same period last year reflecting lower U.S. opportunity and dependable sales volumes predominantly as a result of lower generation due to less favourable water conditions compared to 2017-18, partially offset by modestly higher export prices. Overall, energy sold in the export market was 1.8 billion kilowatt-hours compared to 3.3 billion kilowatt-hours sold in the same period last year. Other revenues of $8 million were $1 million or 14% higher than the same period last year due to an increase in projects for third parties.

Expenses attributable to electricity operations, including the net movement in regulatory deferral balances, totaled $463 million for the three-month period. This represented a decrease of $63 million or 12% as compared to the same period last year. The decrease was primarily due to a $35 million decrease in other expenses and a $15 million decrease in operating and administrative expenses. The decrease in other expenses was primarily due to $40 million in restructuring charges in the prior year associated with the VDP partially offset by higher demand side management costs which are removed and deferred in net movement in regulatory balances. The decrease in operating and administrative expenses is primarily due to lower staffing costs as a result of the VDP.

The net loss before net movement in regulatory balances is $24 million. The net movement in regulatory balances captures the timing differences of revenues and expenses for financial reporting purposes and those amounts approved by the PUB for rate-setting purposes. After considering the net movement of $17 million in the regulatory deferral balances, there is a net loss of $7 million of which $6 million is attributable to Manitoba Hydro and $1 million is attributable to non-controlling interest. The 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 2018-19 fiscal year.

Expenditures for capital construction for the three-month period amounted to $574 million compared to $662 million for the same period last year. Expenditures for the current period included $354 million related to construction of the Keeyask Project and $111 million for the Bipole III Reliability Project. The remaining capital expenditures were predominantly incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province. The corporation also incurred $17 million for electric demand side management programs.

Natural Gas Segment

The net loss in the natural gas segment was $8 million for the three-month period compared to an $11 million net loss for the same period last year. The decrease in the net loss is primarily due to higher restructuring costs incurred in the prior year and lower operating and administrative expenses as a result of the VDP. Delivered gas volumes were 377 million cubic metres compared to 317 million cubic metres for the same period last year.

Expenses attributable to natural gas operations excluding cost of gas sold amounted to $37 million compared to $39 million for the same period last year. The decrease in expenses is primarily attributable to higher restructuring charges in the prior year and savings in operating and administrative expenses as a result of the VDP.

The net loss before net movement in regulatory balances is $8 million. Impacts of net movement in regulatory balances are not material.

Capital expenditures in the natural gas segment were $7 million for the current three-month period compared to $8 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 $3 million for gas demand side management programs.

Other Segment

The other segment includes Manitoba Hydro International Ltd., Manitoba Hydro Utility Services, Minell Pipelines Ltd. and Teshmont Holdings Ltd. The net income was $1 million in the other segment for the three-month period which is consistent with the same period last year. Revenue was $14 million compared to $15 million for the same period last year. Expenses attributable to the other segment amounted to $13 million which was $1 million lower than the prior year principally due to foreign exchange impacts.

There is also a $1 million profit impact in adjustments and eliminations as a result of the requirement to harmonize accounting policies between electric and natural gas operations related to the gas meter exchange program.

PUB orders 3.6% average rate increase

On May 1, 2018 the PUB approved the new electricity rate schedule for Manitoba Hydro. Effective June 1, 2018 Manitoba Hydro's electricity rates changed to reflect an overall average rate increase of 3.6%. The PUB also finalized the previously approved interim rate increases of 3.36% effective August 1, 2016 and 3.36% effective August 1, 2017.

As part of the PUB's order, individual customer classes also had their rates adjusted to more accurately reflect the true cost to serve those customers. This, coupled with the PUB's creation of the new First Nation on-reserve residential customer class, resulted in different customer classes seeing different levels of rate increases to meet the 3.6% average rate increase approved by the PUB. Larger commercial and industrial customers received a rate increase less than 3.6% while other classes, such as residential, received a rate increase greater than 3.6%. The residential customer class rate is now 8.527¢/kWh (excluding monthly basic fee). The First Nation on-reserve residential customer class rate is 8.196¢/kWh, which was the previous residential customer class rate.

Bipole III commissioning begins for summer 2018 in-service

On Monday, April 2, 2018 the Bipole III transmission system was successfully energized for the first time. After five years of construction, the nearly 1 400 kilometre, 500-kilovolt (kV)

high-voltage, direct current (HVDC) transmission line linked the Keewatinohk Converter Station near Gillam to the Riel Converter Station near Winnipeg. First power was one of a long series of commissioning tests, designed to test equipment and confirm reliability, to be carried out on the line and the converter stations prior to the project's in-service date scheduled for the summer of 2018. All commission and testing activity was completed before the end of June and on July 4, 2018 the line was put into service.

Work on the Keewatinohk Converter Station began in 2012. Challenges included difficult geotechnical conditions and the site's remote northern location. Construction of the Riel Converter Station started in the summer of 2015. It had the additional complexity of building a converter station at an already energized, large terminal station as there already was a 500-kV-to-230-kV switchyard operating at the Riel site.

Bipole III will strengthen the reliability and security of Manitoba's electricity supply by reducing dependency on the two existing HVDC lines (Bipoles I and II) and Dorsey Converter Station near Rosser. These facilities, built in the 1960s and 70s, currently deliver electricity produced by hydroelectric generating stations on the Nelson River to southern Manitoba—more than 70% of all electricity produced in the province.

Keeyask spillway completed; generator unit installation begins

Work on the spillway at the Keeyask Generating Station, including the installation of the six spillway gates, hoist towers and hoist housing, was completed on schedule in the early part of the 2018 construction season. Other critical milestones reached this spring included the enclosure of the powerhouse generator units four and five and placement of 105 000 cubic metres of concrete. Progress to date has improved the schedule outlook for the first of seven units to go into service in the fall of 2020, about 10 months ahead of the August 2021 control schedule.

Located approximately 725 kilometres north of Winnipeg on the lower Nelson River, the Keeyask Project is a 695-megawatt hydroelectric generating station being developed in a partnership between Manitoba Hydro and four Keeyask Cree Nation (KCN) Partner communities: Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation and Fox Lake Cree Nation.

Employment of Manitobans, Indigenous persons and members from the four KCN Partner communities remains strong. From project commencement to the end of March 2018, of the 16 317 total hires, 71% are from Manitoba; 44% have self-declared as being Indigenous; and 22% are from the KCN Partner communities.

New planned outage customer notification system up and running

As of May 1, 2018 Manitoba Hydro began notifying customers by telephone several days before a planned power outage affects their community. These outages are typically required for maintenance purposes or to upgrade local electrical services. The new automated system informs customers about scheduled outages affecting 20 customers or more.

The process uses a new auto-dialer service and is one of the first major projects under Manitoba's Hydro's recently-formed Strategic Transformation Office charged with helping the corporation meet its strategic priority of delivering an excellent customer experience. The new initiative also decreases the administrative resources required to make manual phone calls or hand deliver notifications to affected customers.

To date, the automated calls have reached over 80% of customers affected by a scheduled outage either directly or through voicemail.



Marina R. James
Chair of the Board



Kelvin Shepherd, P. Eng.
President and
Chief Executive Officer
August 14, 2018

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Three Months Ended June 30	
	2018	**2017**
Revenues		
Domestic – Electric	332	321
– Gas	54	54
Extraprovincial	116	134
Other	21	20
	523	529
Expenses		
Cost of gas sold	26	34
Operating and administrative	140	157
Finance expense (net)	154	164
Depreciation and amortization	108	105
Water rentals and assessments	27	32
Fuel and power purchased	26	31
Capital and other taxes	40	37
Other expenses	32	68
	553	628
Net loss before net movement in regulatory balances	(30)	(99)
Net movement in regulatory balances	17	26
Net Loss	(13)	(73)
Net loss attributable to:		
Manitoba Hydro	(12)	(70)
Non-controlling interest	(1)	(3)
	(13)	(73)

Consolidated Statement of Financial Position

In Millions of Dollars (Unaudited)

	As at June 30	*As at March 31*	*As at June 30*
	2018	**2018**	**2017**
Assets			
Current assets	1 442	1 221	1 452
Property, plant and equipment	22 474	21 979	20 331
Non-current assets	996	925	765
Total assets before regulatory deferral balance	24 912	24 125	22 548
Regulatory deferral balance	1 061	1 044	586
	25 973	25 169	23 134
Liabilities and Equity			
Current liabilities	1 676	2 080	1 613
Long-term debt	19 298	18 200	16 891
Other long-term liabilities	1 605	1 591	1 534
Deferred revenue	886	769	680
Non-controlling interest	217	205	174
Retained earnings	2 924	2 936	2 829
Accumulated other comprehensive loss	(710)	(688)	(658)
Total liabilities and equity before regulatory deferral balance	25 896	25 093	23 063
Regulatory deferral balance	77	76	71
	25 973	21 169	23 134

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Three Months Ended June 30	
	2018	**2017**
Operating Activities	(124)	(216)
Investing Activities	(529)	(609)
Financing Activities	829	1 028
Net increase in cash	176	203
Cash at beginning of period	642	646
Cash at end of period	818	849

Consolidated Statement of Comprehensive Loss

In Millions of Dollars (Unaudited)

	Three Months Ended June 30	
	2018	**2017**
Net Loss attributable to Manitoba Hydro	(12)	(70)
Other Comprehensive Income (Loss)		
Items that will be reclassified to income		
Unrealized foreign exchange gains (losses) on debt in cash flow hedges	(29)	43
Items that have been reclassified to income		
Realized foreign exchange losses on debt in cash flow hedges	7	8
	(22)	51
Comprehensive Loss attributable to Manitoba Hydro	(34)	(19)

Segmented Information

In Millions of Dollars (Unaudited)

	Electric Segment		Natural gas segment		Other segment		Eliminations		Total	
Three Months Ended June 30	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**
Revenue	456	462	55	55	14	15	(2)	(3)	523	529
Expenses	480	545	63	73	13	14	(3)	(4)	553	628
Net income (loss) before net movement in regulatory balances	(24)	(83)	(8)	(18)	1	1	1	1	(30)	(99)
Net movement in regulatory balances	17	19	-	7	-	-	-	-	17	26
Net Income (Loss)	(7)	(64)	(8)	(11)	1	1	1	1	(13)	(73)
Net income (loss) attribute to:										
Manitoba Hydro	(6)	(61)	(8)	(11)	1	1	1	1	(12)	(70)
Non-controlling interest	(1)	(3)	-	-	-	-	-	-	(1)	(3)
	(7)	(64)	(8)	(11)	1	1	1	1	(13)	(73)
Total Assets	25 368	22 549	729	705	97	90	(221)	(210)	25 973	23 134

Generation and Delivery Statistics

	Three Months Ended June 30	
	2018	**2017**
Electricity in gigawatt-hours		
Hydraulic generation	7 445	8 776
Thermal generation	5	2
Scheduled energy imports	39	23
Wind purchases (Manitoba)	202	243
Total system supply	7 691	9 044
Gas in millions of cubic metres		
Gas sales	195	174
Gas transportation	182	143
	377	317

The Manitoba Hydro-Electric Board

Quarterly Report

for the three months ended
June 30, 2018

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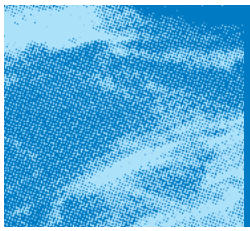
Manitoba Hydro

The Manitoba Hydro-Electric Board

Quarterly Report

for the six months ended
September 30, 2018





Report from **The Chair of the Board** and by **The President and Chief Executive Officer**

Financial Overview

Manitoba Hydro's consolidated net loss was $52 million for the first six months of the 2018-19 fiscal year compared to a net loss of $93 million for the same period last year. The decrease in the net loss is primarily attributable to higher restructuring costs in the prior year driven by the implementation of a significant cost reduction program. Excluding restructuring expenses, Manitoba Hydro would have reported a net loss of $48 million compared to a net loss of $49 million in the prior year. The $1 million improvement is mostly attributable to weather and rate impacts including the recognition of revenue that had been set aside for when Bipole III came into service, resulting in an increase of $63 million in domestic electric revenue. There was also a decrease of $19 million in operating and administrative expenses associated with savings from the Voluntary Departure Program (VDP). These improvements were partially offset by a $35 million increase in financing costs and an increase of $25 million in depreciation and amortization expense primarily as a result of the in-service of Bipole III. In addition, there was a decrease in net export revenues (net of fuel and power purchased and water rental expenses) of $18 million as a result of less favourable water conditions in the current year. The cost of natural gas is a flow through cost passed onto customers through rates approved by the Public Utilities Board (PUB) and therefore is not a driver for the decrease in net loss compared to the prior year.

The consolidated net loss was comprised of a $32 million loss in the electricity segment, a $23 million loss in the natural gas segment, a $2 million net profit in the other segment and a $1 million profit impact in adjustments and eliminations.

Manitoba Hydro's budgeted net income for 2018-19 is approximately $130 million; however Manitoba Hydro is expecting net income to be approximately $60 million. The lower expected net income factors in the impact of the PUB's decision to grant a 3.6% rate increase rather than the requested 7.9% increase and unfavourable water conditions, partially offset by favourable weather impacts throughout the first six months. The projection for the remainder of the year assumes average water flow conditions and normal winter weather.

Electric Segment

Revenues from electricity sales within Manitoba totaled $692 million for the six-month period, which was $63 million or 10% higher than the same period last year. The increase in domestic revenue was primarily attributable to the impacts of weather and rate increases compared to the prior year. Extraprovincial revenues of $249 million were $26 million or 9% lower than the same period last year reflecting lower U.S. opportunity and dependable sales volumes predominantly as a result of lower generation due to less favourable water conditions compared to 2017-18, partially offset by modestly higher export prices. Overall, energy sold in the export market was 4.0 billion kilowatt-hours compared to 6.9 billion kilowatt-hours sold in the same period last year. Other revenues of $54 million were $15 million or 38% higher than the same period last year due to the amortization of the Bipole III reserve into income.

Expenses attributable to electricity operations, including the net movement in regulatory deferral balances, totaled $1 006 million for the six-month period. This represented an increase of $13 million or 1% as compared to the same period last year. Excluding restructuring charges, expenses increased $51 million over the prior year. The increase was primarily due to a $36 million increase in net finance expense due to interest associated with Bipole III and higher debt volumes and a $24 million increase in depreciation largely due to Bipole III going into service at the beginning of July. There was also an increase in fuel costs as a result of a $9 million write off of coal inventory as the Brandon Thermal Generating Station is no longer operational as a coal powered generator. Amortization of regulatory deferrals increased $9 million due to amortization of the Conawapa deferral and ineligible overhead as per direction from the PUB. This was partially offset by a decrease of $16 million in operating and administrative expenses due to a reduction in employee related expenditures as a result of the VDP and an $11 million decrease in water rentals and assessments due to lower generation.

The net loss before net movement in regulatory balances was $72 million. The net movement in regulatory balances captures the timing differences of revenues and expenses for financial reporting purposes and those amounts approved by the PUB for rate-setting purposes. After considering the net movement of $38 million in the regulatory deferral balances, there is a net loss of $34 million of which $32 million is attributable to Manitoba Hydro and $2 million is attributable to non-controlling interest. The 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 2018-19 fiscal year.

Expenditures for capital construction for the six-month period amounted to $1 076 million compared to $1 437 million for the same period last year. Expenditures for the current period included $700 million related to construction of the Keeyask Project and $144 million for the Bipole III Reliability Project. The remaining capital expenditures were predominantly incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province. The corporation also incurred $39 million for electric demand side management programs.

Natural Gas Segment

The net loss in the natural gas segment was $23 million for the six-month period compared to a $26 million net loss for the same period last year. The decrease in the net loss is primarily due to increased revenue due to weather impacts, higher restructuring costs incurred in the prior year and lower operating and administrative expenses as a result of the VDP. Delivered gas volumes were 639 million cubic metres compared to 530 million cubic metres for the same period last year.

Expenses attributable to natural gas operations excluding cost of gas sold amounted to $73 million compared to $75 million for the same period last year. The decrease in expenses is primarily attributable to lower current year employee related expenditures as a result of the VDP and higher restructuring charges in the prior year.

The net loss before net movement in regulatory balances is $26 million. After considering the net movement of $3 million in the regulatory balances, there is a net loss of $23 million.

Capital expenditures in the natural gas segment were $19 million for the current six-month period compared to $18 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 $5 million for gas demand side management programs.

Other Segment

The other segment includes Manitoba Hydro International Ltd., Manitoba Hydro Utility Services, Minell Pipelines Ltd. and Teshmont Holdings Ltd. The net income was $2 million in the other segment for the six-month period which is consistent with the same period last year. Revenue was $27 million compared to $30 million for the same period last year. Expenses attributable to the other segment amounted to $25 million which was $3 million lower than the prior year. The decrease in both revenue and expenses is primarily due to fewer projects undertaken at Manitoba Hydro International Ltd. compared to the prior year.

There is also a $1 million profit impact in adjustments and eliminations as a result of the requirement to harmonize accounting policies between electric and natural gas operations related to the gas meter exchange program.

Bipole III Delivering Enhanced Reliability to Manitobans

Wednesday, July 4, 2018 marked the commercial in-service date of the Bipole III transmission system, adding 2 000 megawatts to Manitoba Hydro's high-voltage, direct current (HVDC) transmission capacity. Bipole III, consisting of a 500 000-volt HVDC transmission line and two converter stations, helps ensure a safe and reliable supply of electricity from northern Manitoba to southern Manitoba and beyond. The nearly 1 400-kilometre transmission line links Keewatinohk Converter Station near Gillam to the Riel Converter Station near Winnipeg.

Over 70% of the province's electricity is generated by hydroelectric generating stations on the Nelson River and prior to the completion of Bipole III was delivered to customers in southern Manitoba over Bipoles I and II, which were built in the 1960s and 70s. These two transmissions lines run alongside each other for much of their route and end at the same point: Dorsey Converter Station. Bipole III helps significantly mitigate the risk of large extended outages which could occur if there was a major failure of Bipole I, Bipole II or the Dorsey station.

At its height, Bipole III was one of the 20 largest projects under construction in North America, involving more than two million hours of labour by Indigenous employees and over 8 million labour hours total. Construction lasted five years.

Bipole III was completed on time and is forecasted to be approximately $300 million under the current control budget of $5.04 billion.

Keeyask Update — Increased Teamwork, Effort and Production

Located approximately 725 kilometres north of Winnipeg on the lower Nelson River, the Keeyask Project is a 695-megawatt hydroelectric generating station being developed in a partnership between Manitoba Hydro and four Keeyask Cree Nation (KCN) communities: Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation and Fox Lake Cree Nation.

As of the end of September 2018, 83% of the 2018 construction plan for Keeyask Generating Station structures has been completed exceeding the amount of concrete placed in all of 2017. On earthworks, 85% of the 2018 plan is completed, placing approximately one million more cubic metres of material than last year.

The goal of the Structures Division this year at Keeyask was to place 105 000 cubic metres (m3) of concrete. As of the end of September 2018, 91 000 m3 has been placed with between 19 000 and 24 000 m3 remaining to be placed before the end of the calendar year. This improvement in production quantity is in addition to reducing the cost per cubic metre by 22%.

By the end of September 2018, the Earthworks Division moved and placed 2.25 million m3 of materials. They achieved this production while also reducing unit costs by 14%. Last year, the team moved 1.3 million m3. This year's goal is to move 2.4 million m3.

Tailrace (the area immediately downstream of the powerhouse) excavation was scheduled to begin at the end of October 2018, but started early and as of the end of September 2018, the Earthworks Division has completed 40% of the work and started on the winter work plan.

Based on the improvements in construction progress during 2018, the first of seven generating units is now forecasted to go into service in October 2020, in advance of the current control schedule August 2021 in-service target previously announced in 2017. The project is currently tracking towards meeting the established $8.7 billion project control budget.

Manitoba Hydro Addresses Growth in the Province's Southeast

Work began in September 2018 on site preparation for the new De Salaberry East Station, located on Highway 52 northwest of Kleefeld. Manitoba Hydro is building the new station to meet demand for electricity in southeastern Manitoba, including the Steinbach, Richer and south St. Vital areas. Customer demand for electricity in the southeast has grown at over twice the Manitoba average over the past 10 years.

To support this growth, the De Salaberry East Station will convert 230-kilovolt (kV) electrical transmission to 66-kV distribution for use in nearby communities, including Hanover, De Salaberry, Richot and the City of Steinbach. De Salaberry East Station will also lessen the loads carried by three other electrical substations in the area and improve reliability of electricity delivery to nearby communities. The forecasted in-service date for the De Salaberry East Station is the fall of 2020.

Manitoba Hydro Employees Support Their Communities

From the 2018 Point Douglas Run, 2018 United Way Plane Pull and the 2018 Dragon Boat Race, Manitoba Hydro employees volunteered to support their communities and to raise funds for worthy programs that benefit our province.

On September 15, 2018, a Manitoba Hydro team of volunteers raised $4 424 in the Point Douglas Run to support Norquay Community Centre, the North Point Douglas Women's Centre and Graffiti Art Programming Inc.

On September 14, 2018, a Manitoba Hydro team raised $4 153 for United Way at the United Way Plane Pull.

During the weekend of September 7-9, 2018, the Manitoba Hydro "Power Paddlers" participated in the 2018 Dragon Boat Races, raising $13 700 for CancerCare Manitoba and the Children's Hospital Foundation.



Marina R. James
Chair of the Board



Kelvin Shepherd, P. Eng.
President and
Chief Executive Officer
November 14, 2018

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		*Three Months Ended September 30*	
	2018	**2017**	**2018**	**2017**
Revenues				
Domestic – Electric	692	629	360	308
– Gas	92	88	38	34
Extraprovincial	249	275	133	141
Other	54	39	33	19
	1 087	1 031	564	502
Expenses				
Cost of gas sold	46	53	20	19
Operating and administrative	284	303	144	146
Finance expense (net)	359	324	205	160
Depreciation and amortization	235	210	127	105
Water rentals and assessments	54	64	27	32
Fuel and power purchased	59	57	33	26
Capital and other taxes	80	74	40	37
Other expenses	65	99	33	31
	1 182	1 184	629	556
Net loss before net movement in regulatory balances	(95)	(153)	(65)	(54)
Net movement in regulatory balances	41	53	24	27
Net Loss	(54)	(100)	(41)	(27)
Net loss attributable to:				
Manitoba Hydro	(52)	(93)	(40)	(23)
Non-controlling interest	(2)	(7)	(1)	(4)
	(54)	(100)	(41)	(27)

Consolidated Statement of Financial Position

In Millions of Dollars (Unaudited)

	As at September 30	*As at March 31*	*As at September 30*
	2018	**2018**	**2017**
Assets			
Current assets	1 265	1 221	1 203
Property, plant and equipment	22 882	21 979	21 050
Non-current assets	1 029	925	794
Total assets before regulatory deferral balance	25 176	24 125	23 047
Regulatory deferral balance	1 083	1 044	608
	26 259	25 169	23 655
Liabilities and Equity			
Current liabilities	1 041	2 080	2 023
Long-term debt	20 212	18 200	16 887
Other long-term liabilities	1 620	1 591	1 555
Deferred revenue	877	769	727
Non-controlling interest	231	205	184
Retained earnings	2 884	2 936	2 806
Accumulated other comprehensive loss	(680)	(688)	(592)
Total liabilities and equity before regulatory deferral balance	26 185	25 093	23 590
Regulatory deferral balance	74	76	65
	26 259	25 169	23 655

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		*Three Months Ended September 30*	
	2018	**2017**	**2018**	**2017**
Operating Activities	(126)	(237)	(2)	(21)
Investing Activities	(1 056)	(1 351)	(527)	(742)
Financing Activities	1 288	1 556	459	528
Net increase (decrease) in cash	106	(32)	(70)	(235)
Cash at beginning of period	642	646	818	849
Cash at end of period	748	614	748	614

Consolidated Statement of Comprehensive Loss

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		*Three Months Ended September 30*	
	2018	**2017**	**2018**	**2017**
Net Loss attributable to Manitoba Hydro	(52)	(93)	(40)	(23)
Other Comprehensive Income (Loss)				
Items that will be reclassified to income				
Unrealized foreign exchange gains (losses) on debt in cash flow hedges	(6)	104	23	61
Items that have been reclassified to income				
Realized foreign exchange losses on debt in cash flow hedges	14	13	7	5
	8	117	30	66
Comprehensive Income (Loss) attributable to Manitoba Hydro	(44)	24	(10)	43

Segmented Information

In Millions of Dollars (Unaudited)

	Electric segment		Natural gas segment		Other segment		Eliminations		Total	
Six Months Ended September 30	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**
Revenue	972	916	93	89	27	30	(5)	(4)	1 087	1 031
Expenses	1 044	1 033	119	128	25	28	(6)	(5)	1 182	1 184
Net income (loss) before net movement in regulatory balances	(72)	(117)	(26)	(39)	2	2	1	1	(95)	(153)
Net movement in regulatory balances	38	40	3	13	-	-	-	-	41	53
Net Income (Loss)	(34)	(77)	(23)	(26)	2	2	1	1	(54)	(100)
Net income (loss) attribute to:										
Manitoba Hydro	(32)	(70)	(23)	(26)	2	2	1	1	(52)	(93)
Non-controlling interest	(2)	(7)	-	-	-	-	-	-	(2)	(7)
	(34)	(77)	(23)	(26)	2	2	1	1	(54)	(100)
Three Months Ended September 30										
Revenue	516	454	38	34	13	15	(3)	(1)	564	502
Expenses	564	488	56	55	12	14	(3)	(1)	629	556
Net income (loss) before net movement in regulatory balances	(48)	(34)	(18)	(21)	1	1	-	-	(65)	(54)
Net movement in regulatory balances	21	21	3	6	-	-	-	-	24	27
Net Income (Loss)	(27)	(13)	(15)	(15)	1	1	-	-	(41)	(27)
Net income (loss) attribute to:										
Manitoba Hydro	(26)	(9)	(15)	(15)	1	1	-	-	(40)	(23)
Non-controlling interest	(1)	(4)	-	-	-	-	-	-	(1)	(4)
	(27)	(13)	(15)	(15)	1	1	-	-	(41)	(27)
Total assets	25 667	23 094	735	718	98	90	(241)	(247)	26 259	23 655

Generation and Delivery Statistics

	Six Months Ended September 30		*Three Months Ended September 30*	
	2018	**2017**	**2018**	**2017**
Electricity in gigawatt-hours				
Hydraulic generation	14 927	17 926	7 482	9 150
Thermal generation	5	11	-	9
Scheduled energy imports	85	35	46	12
Wind purchases (Manitoba)	393	428	191	185
Total system supply	15 410	18 400	7 719	9 356
Gas in millions of cubic metres				
Gas sales	300	263	105	89
Gas transportation	339	267	157	124
	639	530	262	213

The Manitoba Hydro-Electric Board

Quarterly Report

for the six months ended
September 30, 2018

For further information contact:

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Manitoba Hydro



April 2018

Capital Expenditure Forecast
(CEF18) 2018/19 – 2027/28

Manitoba Hydro

Capital Expenditure & Demand Side Management Forecast (CEF18)
2018/19 – 2027/28

FINANCE & STRATEGY
APRIL 2018

Manitoba Hydro

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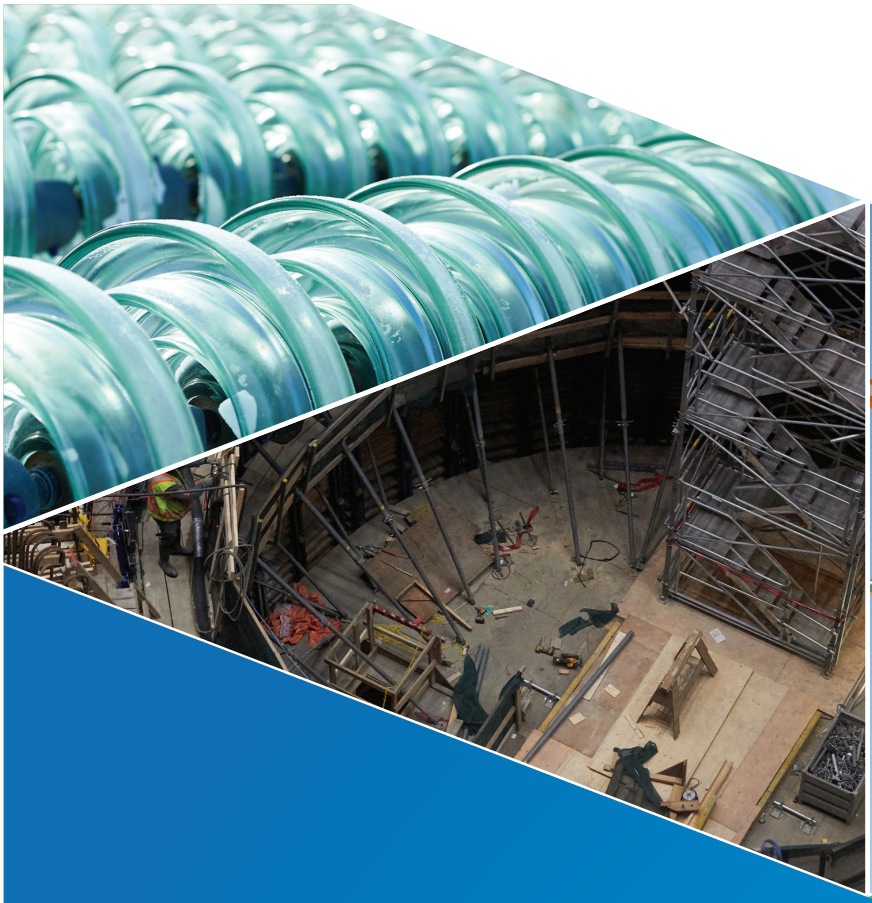
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Section A

CEF18 Summary

A – CEF18 Summary

The Capital Expenditure & Demand Side Management Forecast (CEF18) is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities required to deliver safe reliable energy services to customers at a fair price. CEF18 also includes a projection of Manitoba Hydro's expenditures related to the corporation's Electric and Natural Gas Demand Side Management (DSM) programs.

CEF18 forecasts capital expenditures during the ten year period from 2018/19 to 2027/28. The forecast of capital expenditures in the short term is comprised of executing projects and programs. The longer term forecast is comprised of anticipated expenditure trends. Projects are investments planned on an individual basis with a scope, schedule and budget whereas programs are a collection of small investments that are administered in common.

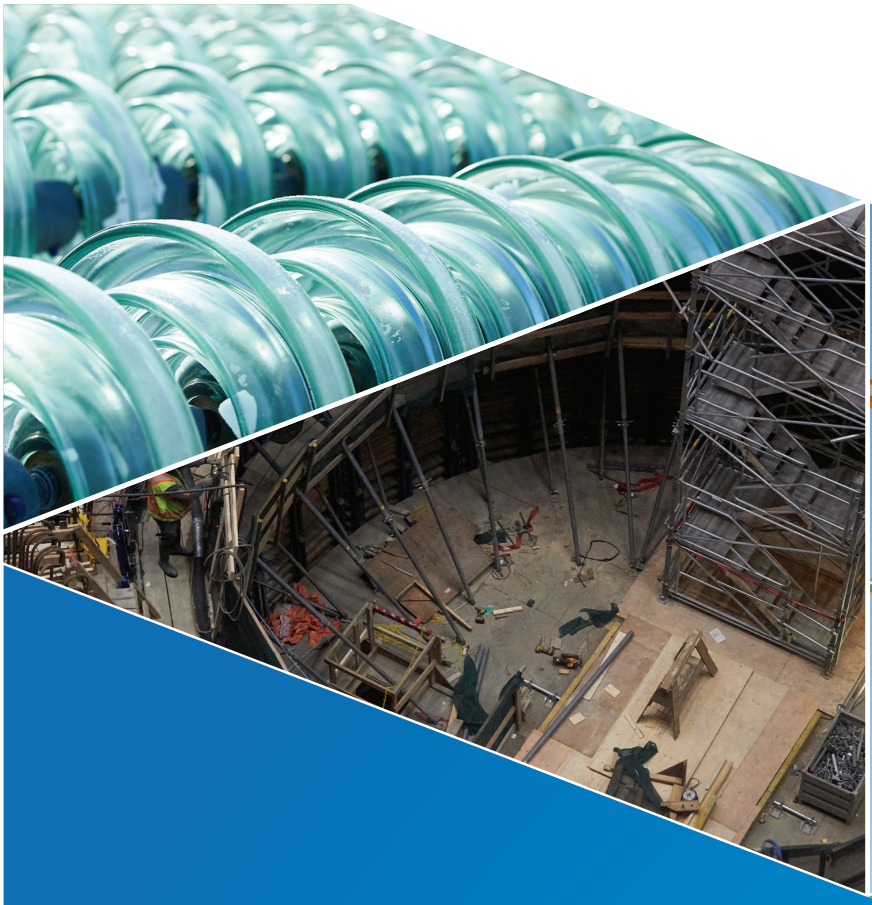
Capital expenditures are categorized between Major New Generation & Transmission (MNG&T) projects and Business Operations Capital. MNG&T projects provide significant new generation or transmission capacity which are typically substantial in cost. Business Operations Capital addresses requirements to sustain electricity and natural gas service through replacement of aging or obsolete assets, capacity enhancements as well as system expansion due to load growth. Also included are expenditures which support business operations such as fleet, administrative buildings and information technology hardware and software. Business Operations Capital is further categorized by operating system: Generation, Transmission and Distribution, as well as Corporate Infrastructure. A breakdown of the Capital Expenditure & Demand Side Management Forecast (CEF18) is shown below.

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18) SUMMARY
(in millions of dollars)

	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
1.0 MAJOR NEW GENERATION & TRANSMISSION	**2 092.5**	**1 214.4**	**958.9**	**777.0**	**311.2**	**5 353.9**	**5 391.2**
2.0 BUSINESS OPERATIONS CAPITAL	**547.1**	**546.3**	**557.9**	**569.9**	**601.0**	**2 822.2**	**6 074.7**
2.1 Electric Business Operations Capital	**515.0**	**510.5**	**521.4**	**532.7**	**563.0**	**2 642.7**	**5 693.9**
2.1.1 Generation System	95.0	105.0	107.1	109.2	130.0	546.3	1 228.2
2.1.2 Transmission System	130.0	130.0	130.0	130.0	130.0	650.0	1 331.9
2.1.3 Distribution System	210.0	220.5	229.3	238.5	248.0	1 146.4	2 545.3
2.1.4 Corporate Infrastructure	80.0	55.0	55.0	55.0	55.0	300.0	588.5
2.2 Natural Gas Business Operations Capital	**32.1**	**35.8**	**36.5**	**37.2**	**38.0**	**179.5**	**380.8**
2.2.1 Distribution System & Corporate Infrastructure	32.1	35.8	36.5	37.2	38.0	179.5	380.8
3.0 DEMAND SIDE MANAGEMENT	**71.9**	**105.1**	**99.6**	**97.8**	**77.0**	**451.4**	**837.4**
CONSOLIDATED CAPITAL EXPENDITURE & DSM FORECAST TOTAL	**2 711.5**	**1 865.7**	**1 616.4**	**1 444.7**	**989.2**	**8 627.5**	**12 303.3**
ELECTRIC CAPITAL & DSM FORECAST TOTAL	2 670.0	1 819.1	1 569.2	1 396.7	940.8	8 395.7	11 818.8
NATURAL GAS CAPITAL & DSM FORECAST TOTAL	41.5	46.6	47.2	48.0	48.4	231.7	484.5

Both MNG&T and Business Operations Capital are classified further by investment category. For a full description of level 1 and 2 investment categories, please refer to Appendix I – Investment Category Definitions.

Appendix II – Projects Greater than $1 Million and Less than $15 Million provides a listing of executing and new projects greater than $1 million and less than $15 million. Projects greater than $15 million are listed separately within Section B – Capital Expenditure & Demand Side Management Forecast by Investment Category.





Section B

Capital Expenditure & Demand Side Management Forecast by Investment Category

1.0 Major New Generation & Transmission 10

2.0 Business Operations Capital 13

3.0 Demand Side Management 25

B – Capital Expenditure & Demand Side Management Forecast by Investment Category

Manitoba Hydro has incorporated the use of investment categories, which are commonly used within the industry to provide stakeholders with a better understanding of the primary driver for the investments. The primary investment categories (level 1) are Capacity & Growth, Sustainment and Business Operations Support. Capacity & Growth investments provide for future load growth or address existing capacity constraints in various geographic areas on the transmission and distribution system. Sustainment investments are required to ensure the continued and future performance capability of the system and address the issue of aging or obsolete assets. Business Operations Support investments support corporate operations including corporate facilities, information technology, and fleet investments. Detailed investment category definitions are included in Appendix I -Investment Category Definitions.

The following schedule provides a summary of capital expenditure requirements for Major New Generation & Transmission and Business Operations Capital, as well as Demand Side Management.

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)

(in millions of dollars)

	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
1.0 MAJOR NEW GENERATION & TRANSMISSION								
Capacity & Growth Projects								
Keeyask - Generation	8 726.0	1 265.4	1 016.6	846.9	763.9	311.2	4 204.0	4 241.3
Bipole III Reliability	5 041.5	662.6	33.4	2.6	-	-	698.5	698.5
Manitoba-Minnesota Transmission Project	451.7	162.0	144.4	91.2	-	-	397.6	397.6
Birtle Transmission	56.5	2.5	20.0	18.2	13.0	-	53.8	53.8
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**2 092.5**	**1 214.4**	**958.9**	**777.0**	**311.2**	**5 353.9**	**5 391.2**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)

(in millions of dollars)

	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
2.0 BUSINESS OPERATIONS CAPITAL								
2.1 Electric Business Operations Capital								
2.1.1 Generation System								
Sustainment Projects								
Water Licenses & Renewals	99.0	10.7	9.9	4.4	0.3	-	25.2	25.2
Pine Falls Units 1-4 Major Overhauls	77.1	7.4	5.7	0.2	-	-	13.2	13.2
Generation North Sewer & Domestic Water System	31.2	6.0	4.4	0.8	2.1	0.5	13.8	16.6
Grand Rapids Unit Transformer Replacement	23.2	1.8	-	-	-	-	1.8	1.8
Public Water Safety/Security	22.4	3.5	5.2	2.8	-	-	11.5	11.5
Slave Falls Seven Bay Sluiceway	17.7	2.2	0.7	-	-	-	2.9	2.9
Other Projects	252.0	34.5	32.9	19.2	5.5	1.4	93.4	95.2
Subtotal		66.1	58.8	27.3	7.8	1.9	161.9	166.4
Business Operations Support Projects								
Town of Gillam Paving and Land Drainage	32.2	5.3	5.5	6.3	5.7	6.6	29.5	30.7
Grand Rapids Fish Hatchery Upgrade & Expansion	23.2	1.4	8.1	5.6	3.7	-	18.9	18.9
Town of Gillam Water Treatment Plant	23.1	0.2	16.9	5.8	-	-	22.9	22.9
Sewer & Water Linear Infrastructure	15.3	-	4.6	5.0	5.8	-	15.3	15.3
Other Projects	101.0	28.6	13.7	1.0	1.0	0.1	44.4	44.4
Subtotal		35.6	48.8	23.6	16.3	6.7	131.0	132.2
Programs	NA	8.6	9.2	9.3	9.5	9.7	46.3	97.9
Generation System Subtotal		**110.3**	**116.7**	**60.3**	**33.6**	**18.3**	**339.2**	**396.6**
Target Variance	NA	(15.3)	(11.7)	46.8	75.6	111.7	207.2	831.6
Generation System Total		**95.0**	**105.0**	**107.1**	**109.2**	**130.0**	**546.3**	**1 228.2**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)

(in millions of dollars)

	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
2.0 BUSINESS OPERATIONS CAPITAL								
2.1 Electric Business Operations Capital								
2.1.2 Transmission System								
Sustainment Projects								
Bipole 2 Thyristor Valve Replacement	236.0	0.1	0.1	2.5	5.6	9.9	18.3	235.7
HVDC Transformer Sustainment	177.5	19.7	8.9	4.5	2.5	6.5	42.1	43.9
Dorsey Synchronous Condenser Refurbishment	78.0	2.7	3.1	3.9	4.4	5.8	19.9	19.9
Transmission Line Upgrades for Improved Clearance	74.0	5.0	5.1	18.1	18.4	18.8	65.4	65.4
Transmission Transformer Sustainment	64.1	-	0.2	0.3	2.2	1.3	4.0	33.5
Station Battery Bank Capacity & System Reliability Increase	45.6	0.1	1.7	1.1	0.5	-	3.4	3.4
Transmission Line Protection & Teleprotection Replacement	26.0	2.1	0.3	-	-	-	2.3	2.3
Bipole I&II Spacer Damper Replacement (Phase 2)	24.0	2.2	-	-	-	-	2.2	2.2
HVDC BP2 Valve Hall Wall Bushing Replacement	18.8	0.6	-	-	-	0.1	0.6	18.2
13.2kV Shunt Reactor Replacements	16.2	4.0	3.1	-	-	-	7.1	7.1
HVDC - Gapped Arrester Replacement	15.8	2.4	2.9	0.4	0.6	0.3	6.7	10.8
PCB Bushing Elimination	15.3	1.6	1.7	1.7	1.9	1.9	8.9	11.6
Other Projects	182.3	23.2	12.3	10.4	8.6	2.8	57.4	72.4
Subtotal		63.7	39.4	43.0	44.7	47.5	238.2	526.3
Capacity & Growth Projects								
St. Vital-DeSalaberry T/L & DeSalaberry Station	118.9	14.2	42.8	52.7	2.6	2.0	114.2	114.2
Lake Winnipeg East System Improvements	79.3	1.6	-	-	-	-	1.6	1.6
DeSalaberry-Letellier 230kV Transmission Line	67.9	4.6	13.7	16.8	28.4	-	63.5	63.5
Winnipeg-Brandon Transmission System Improvements	43.9	0.2	0.2	0.2	0.2	0.2	0.9	29.8
Southwest Winnipeg 115kV Transmission Improvement	39.2	0.3	24.1	10.3	1.6	0.1	36.4	36.4
Laverendrye-St. Vital 230kV Line & Breakers	33.7	1.2	0.5	3.6	10.8	5.3	21.5	21.5
Stanley Area 115kV to 230kV Migration	24.9	5.2	-	-	0.6	5.9	11.7	19.0
Stanley Station 2nd Bank & S60L Sectionalization	15.3	2.8	-	-	-	-	2.8	2.8
Other Projects	58.8	14.7	1.3	0.3	9.5	6.9	32.7	37.8
Subtotal		44.8	82.6	83.9	53.7	20.4	285.4	326.6
Programs	NA	26.3	26.3	26.8	27.4	27.9	134.8	283.0
Transmission System Subtotal		**134.8**	**148.3**	**153.7**	**125.7**	**95.8**	**658.3**	**1 135.9**
Target Variance	NA	(4.8)	(18.3)	(23.7)	4.3	34.2	(8.3)	195.9
Transmission System Total		**130.0**	**130.0**	**130.0**	**130.0**	**130.0**	**650.0**	**1 331.9**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)

(in millions of dollars)

	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
2.0 BUSINESS OPERATIONS CAPITAL								
2.1 Electric Business Operations Capital								
2.1.3 Distribution System								
Programs								
Asset Renewal	NA	73.3	76.4	77.9	79.5	81.1	388.1	818.5
Customer Connections	NA	31.1	31.8	32.4	33.1	33.7	162.1	341.1
Capacity Additions	NA	19.0	19.8	20.2	20.6	21.0	100.6	212.2
Mandated Requirements	NA	9.1	10.4	10.6	10.8	11.0	51.8	110.2
Other Programs	NA	2.1	2.2	2.2	2.3	2.3	11.1	23.6
Subtotal		134.5	140.5	143.4	146.2	149.1	713.8	1 505.5
Capacity & Growth Projects								
Panet Station - 66/24kV	51.8	18.1	31.9	-	-	-	50.0	50.0
Reenders Station - 66/12kV	46.8	3.1	22.3	20.9	-	-	46.3	46.3
St. Vital Station - 115/24kV	39.5	0.6	-	-	-	-	0.6	0.6
McPhillips Station - 115kV/24kV	35.2	5.0	0.6	-	-	-	5.6	5.7
Martin Station 66-4/12kV Station	32.8	0.1	-	-	-	-	0.1	0.1
Mohawk Station Bank Addition	17.0	4.5	0.9	-	-	-	5.4	5.4
Harrow Station Bank Addition	15.4	8.6	5.4	-	-	-	14.0	14.0
Other Projects	200.0	30.5	25.6	1.5	-	-	57.6	57.6
Subtotal		70.5	86.7	22.4	-	-	179.6	179.7
Sustainment Projects								
Adelaide Station - 66/12kV	69.6	12.8	2.7	-	-	-	15.5	15.5
Other Projects	52.3	15.4	1.1	1.1	-	-	17.6	17.6
Subtotal		28.2	3.7	1.1	-	-	33.0	33.0
Distribution System Subtotal		**233.2**	**231.0**	**166.9**	**146.2**	**149.2**	**926.5**	**1 718.2**
Target Variance	NA	(23.2)	(10.5)	62.5	92.3	98.9	219.9	827.1
Distribution System Total		**210.0**	**220.5**	**229.3**	**238.5**	**248.0**	**1 146.4**	**2 545.3**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)

(in millions of dollars)

	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
2.0 BUSINESS OPERATIONS CAPITAL								
2.1 Electric Business Operations Capital								
2.1.4 Corporate Infrastructure								
Programs								
Fleet	NA	14.5	14.5	14.8	15.1	15.4	74.3	155.9
Information Technology	NA	10.4	13.8	14.1	14.4	9.3	62.0	111.5
Facilities	NA	3.8	10.2	10.5	10.7	10.9	46.0	103.7
Other Programs	NA	2.2	2.2	2.2	2.3	2.3	11.3	23.7
Subtotal		30.8	40.8	41.6	42.4	37.9	193.5	394.9
Business Operations Support Projects								
Gillam Recreation Center Refurbishment	38.3	25.2	0.6	-	-	-	25.7	25.7
Enterprise Asset Management - Phase 2	35.2	2.9	-	-	-	-	2.9	2.9
Rural Consolidation	18.8	4.3	-	-	-	-	4.3	4.3
Other Projects	41.3	17.3	0.1	-	-	-	17.4	17.4
Subtotal		49.8	0.6	-	-	-	50.4	50.4
Corporate Infrastructure Subtotal		**80.6**	**41.4**	**41.6**	**42.4**	**37.9**	**243.9**	**445.3**
Target Variance	NA	(0.6)	13.6	13.4	12.6	17.1	56.1	143.2
Corporate Infrastructure Total		**80.0**	**55.0**	**55.0**	**55.0**	**55.0**	**300.0**	**588.5**
Electric Business Operations Capital Total		**515.0**	**510.5**	**521.4**	**532.7**	**563.0**	**2 642.7**	**5 693.9**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)

(in millions of dollars)

	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
2.0 BUSINESS OPERATIONS CAPITAL								
2.2 Natural Gas Business Operations Capital								
2.2.1 Distribution System & Corporate Infrastructure								
Programs								
Capacity & Additions	NA	24.1	24.8	25.3	25.8	26.3	126.2	265.8
Meters & Mandated Requirements	NA	5.7	9.3	9.5	9.7	9.9	44.3	96.9
Subtotal		29.8	34.1	34.8	35.5	36.2	170.5	362.7
Sustainment Projects	24.8	7.4	4.0	1.8	1.5	-	14.7	14.7
Capacity & Growth Projects	12.3	1.7	3.4	2.5	0.3	-	7.9	7.9
Distribution System & Corporate Infrastructure Subtotal		**38.9**	**41.5**	**39.1**	**37.3**	**36.2**	**193.0**	**385.2**
Target Variance	NA	(6.8)	(5.7)	(2.6)	(0.1)	1.8	(13.5)	(4.4)
Natural Gas Business Operations Capital Total		**32.1**	**35.8**	**36.5**	**37.2**	**38.0**	**179.5**	**380.8**
BUSINESS OPERATIONS CAPITAL TOTAL		**547.1**	**546.3**	**557.9**	**569.9**	**601.0**	**2 822.2**	**6 074.7**

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)

(in millions of dollars)

	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
3.0 DEMAND SIDE MANAGEMENT								
Electric Programs	NA	62.5	94.3	88.9	86.9	66.5	399.1	733.7
Natural Gas Programs	NA	9.4	10.8	10.8	10.9	10.4	52.2	103.7
DEMAND SIDE MANAGEMENT TOTAL		**71.9**	**105.1**	**99.6**	**97.8**	**77.0**	**451.4**	**837.4**

1.0 – Major New Generation & Transmission

Manitoba Hydro's Major New Generation & Transmission investments are entirely driven by the Capacity & Growth investment category as shown below.

MAJOR NEW GENERATION & TRANSMISSION ($ Millions)	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
Capacity & Growth								
New Energy								
Keeyask - Generation	8 726.0	1 265.4	1 016.6	846.9	763.9	311.2	4 204.0	4 241.3
System Load Capacity								
Bipole III - Converter Stations	2 780.7	345.7	23.1	0.2	-	-	369.0	369.0
Bipole III - Transmission Line	1 957.6	290.2	10.2	2.4	-	-	302.8	302.8
Bipole III - Collector Lines	246.6	25.6	-	-	-	-	25.6	25.6
Bipole III - Community Development Initiative	56.6	1.1	-	-	-	-	1.1	1.1
System Load Capacity Total	**5 041.5**	**662.6**	**33.4**	**2.6**	**-**	**-**	**698.5**	**698.5**
Grid Interconnections - Import/ Export								
Manitoba-Minnesota Transmission Project	451.7	162.0	144.4	91.2	-	-	397.6	397.6
Birtle Transmission	56.5	2.5	20.0	18.2	13.0	-	53.8	53.8
Grid Interconnections - Import/ Export Total	**508.2**	**164.5**	**164.5**	**109.3**	**13.1**	**-**	**451.4**	**451.4**
Capacity & Growth Total	**14 275.7**	**2 092.5**	**1 214.4**	**958.9**	**777.0**	**311.2**	**5 353.9**	**5 391.2**

Each of the projects is described below along with changes from the last approved Capital Expenditure and Demand Side Management Forecast (CEF16).

1.1 Keeyask

The Keeyask project is a 695-megawatt (MW) hydroelectric generating station that is being developed in a partnership between Manitoba Hydro and four Manitoba First Nations: Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation, and Fox Lake Cree Nation. Working together, the Partners are known collectively as the Keeyask Hydropower Limited Partnership.

Located approximately 725 km north of Winnipeg on the lower Nelson River, construction of the Keeyask project includes:

- 7 unit powerhouse/service bay complex on the north side of Gull Rapids;
- 7 bay spillway on the south side of Gull Rapids;
- More than 2 km of dams across Gull Rapids; and
- 23 km of dykes built on the north and south side of the reservoir.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 8 726.0	$ 1 290.5	$ 1 116.7	$ 867.9	$ 707.1	$ 329.9	$ 63.0
Increase (Decrease)	-	(25.1)	(100.2)	(21.0)	56.9	(18.7)	(25.7)
Revised Forecast	$ 8 726.0	$ 1 265.4	$ 1 016.6	$ 846.9	$ 763.9	$ 311.2	$ 37.3

Status:

No change in total project forecast from CEF16, the project is in the construction phase with first power expected in 2021/22.

1.2 Bipole III Reliability

This high voltage direct current (HVDC) transmission project is required to improve overall system reliability and dependability and involves the construction of:

- A 500kV HVDC transmission line linking the northern power generating complex on the Lower Nelson River with the conversion and delivery system in southern Manitoba;
- 2 new converter stations – Keewatinohk Station in northern Manitoba, located northeast of Gillam and Riel Station, located east of Winnipeg. In addition, there are 2 ground electrodes - 1 at each converter station; and
- Additional 230-kV transmission collector lines in the north to tie the new Keewatinohk Converter Station into the existing northern alternating current (AC) system.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 5 041.5	$ 657.1	$ 17.1	$ 2.5	$ -	$ -	$ -
Increase (Decrease)	-	5.4	16.3	0.1	-	-	-
Revised Forecast	$ 5 041.5	$ 662.6	$ 33.4	$ 2.6	$ -	$ -	$ -

Status:
No change in total project forecast from CEF16, the project is in the construction phase with in-service expected in 2018/19.

1.3 Manitoba-Minnesota Transmission Project

The Manitoba–Minnesota Transmission Project will strengthen the overall reliability of Manitoba's electricity supply, will allow Manitoba Hydro to fulfill current export sales agreements and increase access to markets in the United States, supporting export sales. The project includes:

- Construction of a 500kV AC transmission line from the Winnipeg area to the U.S. border in southeastern Manitoba where it will connect to the Great Northern Transmission Line to be constructed by Minnesota Power; and
- Upgrades to associated electrical stations at Dorsey, Riel and Glenboro.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 453.2	$ 114.3	$ 82.9	$ 146.8	$ -	$ -	$ -
Increase (Decrease)	(1.5)	47.7	61.5	(55.7)	-	-	-
Revised Forecast	$ 451.7	$ 162.0	$ 144.4	$ 91.2	$ -	$ -	$ -

Status:
The total project forecast in CEF18 has been decreased by $1.5 million from CEF16. The project is in the planning and design phase with an application before the National Energy Board for review and approval with expected in-service in 2020/21.

1.4 Birtle Transmission

The Birtle Transmission project, previously named the Manitoba-Saskatchewan Transmission Project, is a new 230-kV transmission line to be built from Birtle Station to the Manitoba–Saskatchewan border, which is required to supply the SaskPower 100MW System Power Sale.

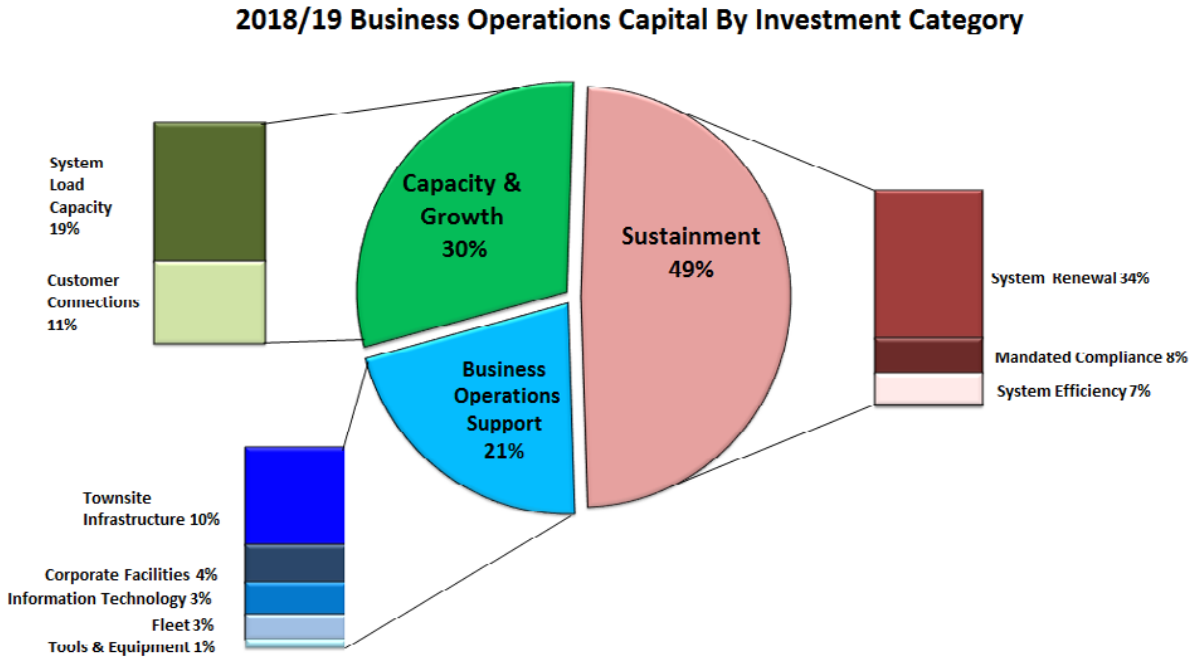
	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 56.5	$ 2.3	$ 18.6	$ 17.7	$ 10.8	$ -	$ -
Increase (Decrease)	-	0.2	1.4	0.5	2.2	-	-
Revised Forecast	$ 56.5	$ 2.5	$ 20.0	$ 18.2	$ 13.0	$ -	$ -

Status:

The total project forecast in CEF18 is unchanged from CEF16. The project is awaiting approval of an environmental license, upon receipt of which construction will begin. This project is expected to be in-service in 2021/22.

2.0 – Business Operations Capital – Consolidated

The 2018/19 forecast for Electric and Natural Gas Business Operations Capital by investment category is shown below.



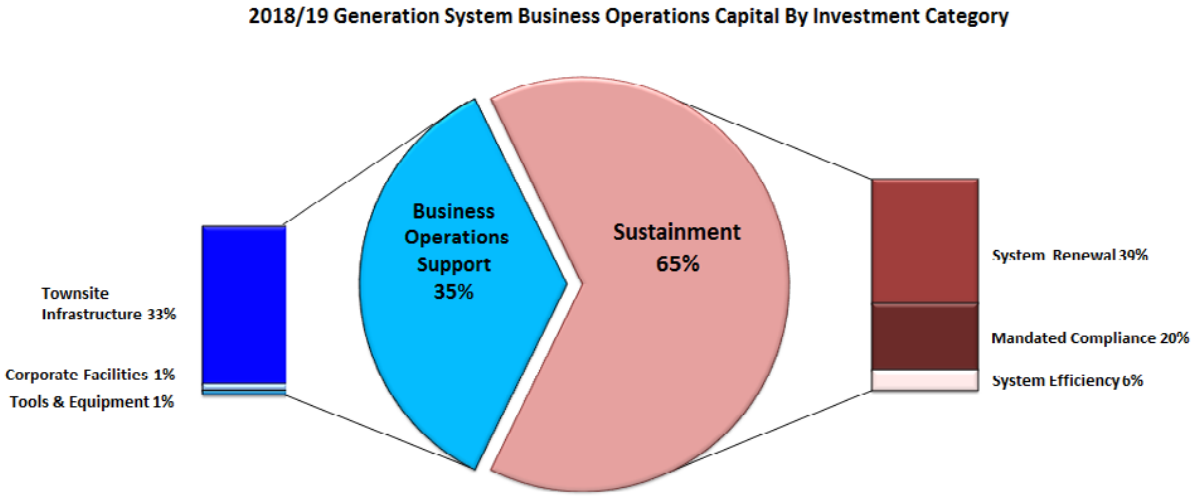
Appendix II – Projects Greater than $1 Million and Less than $15 Million contains a list of all executing and new Business Operations Capital projects by investment category with a total project forecast between $1 million and $15 million, including projected cashflows. Projects with a total forecast of greater than $15 million are listed in Section B – Capital Expenditure & Demand Side Management Forecast by Investment Category.

2.1 – Business Operations Capital – Electric

2.1.1 – Generation System

Manitoba Hydro's generation system is made up of 15 hydraulic and 2 thermal generating stations with sufficient capacity to meet domestic and export customer commitments for the foreseeable future once Keeyask Generating Station is placed into service. Generation system assets include water retaining structures, water control equipment, generation drive train assets and associated station infrastructure as well as support infrastructure such as airports and town sites at remote locations.

The generation system capital expenditure forecast for 2018/19 is comprised of projects and programs resulting from sustainment and business operations support investment categories with the majority of the forecast requirements to address system renewal of the generation system and townsite infrastructure requirements primarily for the Town of Gillam, as shown below.



Investment category and cashflow details for generation projects with a total project forecast of greater than $15 million can be found in Section B – Capital Expenditure & Demand Side Management Forecast by Investment Category and projects with a total project forecast between $1 million and $15 million can be found in Appendix II – Projects Greater than $1 Million and Less than $15 Million.

Additional details for generation system projects with a total project forecast of greater than $50 million are summarized below.

2.1.1.1 - Water Licenses & Renewals

The Water Licenses & Renewals project is to secure license finalization and/or renewals for Manitoba Hydro's hydraulic plants to reduce risk exposure, maintain operating flexibility, maximize export revenues and contribute to financial strength.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 99.0	$ 8.8	$ 9.0	$ 7.8	$ -	$ -	$ -
Increase (Decrease)	-	1.9	0.9	(3.4)	0.3	-	-
Revised Forecast	$ 99.0	$ 10.7	$ 9.9	$ 4.4	$ 0.3	$ -	$ -

Investment Category:
Sustainment – Mandated Compliance

Status:
No change in total project forecast from CEF16, cash flow changes reflect a revised work schedule.

2.1.1.2 - Pine Falls Units 1-4 Major Overhauls

The Pine Falls Units 1-4 Major Overhauls project is to address upgrades and modernization of various components required to ensure reliable, safe and economical operations. Upgrades include generator rewinds, transformer and turbine installations and machine associated water passage components.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 88.8	$ 9.9	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	(11.7)	(2.5)	5.7	0.2	-	-	-
Revised Forecast	$ 77.1	$ 7.4	$ 5.7	$ 0.2	$ -	$ -	$ -

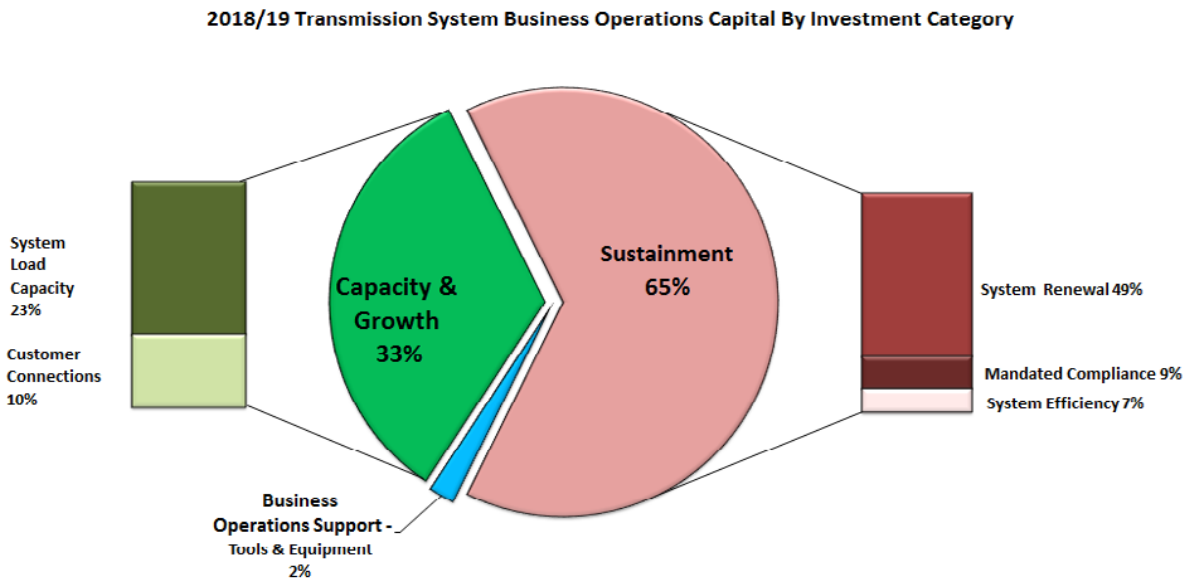
Investment Category:
Sustainment – System Renewal

Status:
Total project forecast was reduced from CEF16 to reflect a reduction in risks realized. In-service is expected in 2019/20.

2.1.2 – Transmission System

Manitoba Hydro's transmission system consists of over 10 500 km of AC transmission lines and 110 terminal stations, plus almost 1 900 km of HVDC transmission lines and 3 converter stations. Collectively, these systems enable the delivery of power from multiple points of generation to customers across the province and beyond provincial borders. Manitoba Hydro's major transmission system assets include overhead conductor and hardware, wood pole structures and steel structures, and transmission station equipment such as breakers, protection relays and transformers, as well as highly sophisticated apparatus at the HVDC converter stations.

The transmission system capital expenditure forecast for 2018/19 is comprised mainly of sustainment and capacity and growth projects and programs with the majority of the forecast requirements to address system renewal of the transmission system as well as system load capacity as outlined below.



Investment category and cashflow details for transmission projects with a total project forecast of greater than $15 million can be found in Section B – Capital Expenditure & Demand Side Management Forecast by Investment Category above and projects with a total project forecast between $1 million and $15 million can be found in Appendix II – Projects Greater than $1 Million and Less than $15 Million.

Additional details for transmission system projects with a total project forecast of greater than $50 million are summarized below.

2.1.2.1 - Bipole 2 Thyristor Valve Replacement

The Bipole 2 Thyristor Valve Replacement project will replace thyristor valve groups and controls nearing the end of useful life which will result in a significant decrease in failures, reduce maintenance requirements and improve the overall reliability of Bipole II.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 236.0	$ 0.5	$ 0.5	$ 1.3	$ 13.6	$ 22.9	$ 197.1
Increase (Decrease)	-	(0.4)	(0.4)	1.2	(8.0)	(13.0)	20.3
Revised Forecast	$ 236.0	$ 0.1	$ 0.1	$ 2.5	$ 5.6	$ 9.9	$ 217.4

Investment Category:
Sustainment – System Renewal

Status:
No change to the total project forecast from CEF16. In-service is expected in 2026/27.

2.1.2.2 - HVDC Transformer Sustainment

The HVDC Transformer Sustainment project is to maintain an inventory of spare converter transformers and plan for the proactive replacement of critical transformers to limit outage durations and outage costs in the event of transformer failures.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 178.4	$ 9.9	$ 0.4	$ 0.1	$ 1.0	$ -	$ 16.6
Increase (Decrease)	(0.9)	9.8	8.5	4.4	1.5	6.5	(14.8)
Revised Forecast	$ 177.5	$ 19.7	$ 8.9	$ 4.5	$ 2.5	$ 6.5	$ 1.8

Investment Category:
Sustainment – System Renewal

Status:
Total project forecast decreased from CEF16 as cashflows were revised to reflected transformer delivery dates. Last in-service is expected in 2036/37.

2.1.2.3 - Dorsey Synchronous Condenser Refurbishment

The Dorsey Synchronous Condenser Refurbishment project is for the mechanical refurbishment of the synchronous condensers (SC) to prevent catastrophic failure and to ensure 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.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 73.6	$ 0.5	$ -	$ -	$ -	$ -	$ 8.5
Increase (Decrease)	4.4	2.2	3.1	3.9	4.4	5.8	(8.5)
Revised Forecast	$ 78.0	$ 2.7	$ 3.1	$ 3.9	$ 4.4	$ 5.8	$ -

Investment Category:
Sustainment – System Renewal

Status:
Total project forecast increased from CEF16 to reflect the deferral of work to accommodate other projects as well as advancing overhauls of SC11 and SC12 to mitigate failure risk of SC13Y. Final in-service is expected in 2022/23.

2.1.2.4 - Transmission Line Upgrades for Improved Clearance

The Transmission Line Upgrades for Improved Clearance project is to upgrade over 1 000 transmission spans to meet Canadian Standards Association (CSA) Standards for line clearance to ensure continued reliability and operations of the electrical system as well as to mitigate risks to public safety due to insufficient line clearance.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 74.7	$ 5.1	$ 5.2	$ 16.7	$ 17.0	$ 17.3	$ -
Increase (Decrease)	(0.7)	(0.1)	(0.1)	1.4	1.4	1.5	-
Revised Forecast	$ 74.0	$ 5.0	$ 5.1	$ 18.1	$ 18.4	$ 18.8	$ -

Investment Category:
Sustainment – Mandated Compliance

Status:
No significant change to the total project forecast from CEF16. Final in-service is expected in 2022/23.

2.1.2.5 - Transmission Transformer Sustainment

The Transmission Transformer Sustainment project is for the proactive replacement or refurbishment of transformers to reduce system failure risks, maintain system reliability and reduce repair and refurbishment costs associated with the transmission transformer asset base.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 64.4	$ -	$ 0.2	$ 0.3	$ 2.2	$ 1.3	$ 29.7
Increase (Decrease)	(0.3)	-	-	-	-	-	(0.2)
Revised Forecast	$ 64.1	$ -	$ 0.2	$ 0.3	$ 2.2	$ 1.3	$ 29.5

Investment Category:
Sustainment – System Renewal

Status:
Total project forecast decreased from CEF16 to reflect revised cashflows. Final in-service expected in 2032/33.

2.1.2.6 - St Vital-DeSalaberry Transmission Line & DeSalaberry Station

The St. Vital-DeSalaberry Transmission Line & DeSalaberry Station project is to construct a new 230-66kV station in the DeSalaberry area and a new 230kV line from the St. Vital Station to the new 230-66kV station. The project includes terminations and communications to address reliability, voltage and loading issues from above ground load growth in south Winnipeg and southeastern Manitoba.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	118.9	14.2	42.8	52.7	2.6	2.0	-
Revised Forecast	$ 118.9	$ 14.2	$ 42.8	$ 52.7	$ 2.6	$ 2.0	$ -

Investment Category:
Capacity & Growth – System Load Capacity

Status:
Construction is scheduled to start in the summer of 2018 with an in-service date of 2020/21.

2.1.2.7 - Lake Winnipeg East System Improvements

The Lake Winnipeg East System Improvements project is to build a new 115/66kV Manigotagan station and a new 65 km 115kV transmission line from the Pine Falls station to the Manigotagan Corner station to provide firm capacity for Pine Falls area load and enable the Bloodvein static var compensator (SVC) to effectively control voltage.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 75.5	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	3.8	1.6	-	-	-	-	-
Revised Forecast	$ 79.3	$ 1.6	$ -	$ -	$ -	$ -	$ -

Investment Category:
Capacity & Growth – System Load Capacity

Status:
Total project forecast increased from CEF16 as a result of contractor delays and higher construction costs than expected. The contractor delays have resulted in deferral of the in-service date to 2018/19 from 2017/18.

2.1.2.8 - DeSalaberry-Letellier 230kV Transmission Line

The DeSalaberry-Letellier 230kV Transmission Line project is to design and build a new 230kV transmission line from the proposed new DeSalaberry Station to the Letellier Station, including associated terminations and communications to improve the power network in Southern Manitoba. This project is required to ensure reliability of supply and ensure loads can be served.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	67.9	4.6	13.7	16.8	28.4	-	-
Revised Forecast	$ 67.9	$ 4.6	$ 13.7	$ 16.8	$ 28.4	$ -	$ -

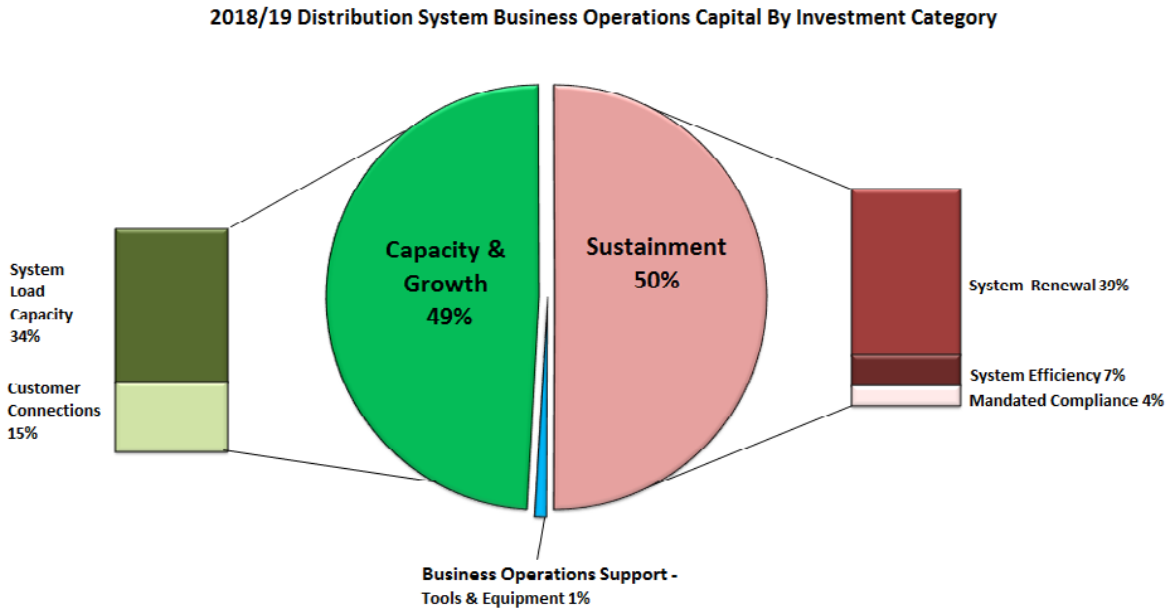
Investment Category:
Capacity & Growth – System Load Capacity

Status:
Detailed design will begin in 2018, construction will begin in the summer of 2020 and in-service is anticipated in 2021/22.

2.1.3 – Distribution System

Manitoba Hydro's distribution system is made up of 381 substations that transform electricity from high transmission voltages to voltages suitable for safe distribution throughout the province. The distribution system has 68 100 km of distribution lines, 280 substations across rural Manitoba and 101 substations within the City of Winnipeg. Major distribution system asset classes include underground cables, manholes, duct lines, transformers, substation breakers, conductors, wood poles and street light standards. These assets have relatively low per unit costs but there are millions of separate components spread across the province.

The distribution system capital expenditure forecast for fiscal 2018/19 is comprised mainly of capacity & growth and sustainment projects and programs with the majority of the forecast requirements to address system renewal and system load capacity requirements for the distribution system, as outlined below.



Programs comprise a significant portion of the distribution capital expenditures specifically in the areas of (1) asset renewal, driven by aging infrastructure; (2) customer connections, driven by customer needs; and (3) capacity additions, primarily driven by customer behavior.

Investment category and cashflow details for distribution projects with a total project forecast of greater than $15 million can be found in Section B – Capital Expenditure & Demand Side Management Forecast by Investment Category and projects with a total project forecast between $1 million and $15 million can be found in Appendix II – Projects Greater than $1 Million and Less than $15 Million.

Additional details for distribution system projects with a total project forecast of greater than $50 million are summarized below.

2.1.3.1 - Panet Station – 66/24kV

The Panet Station – 66/24kV project is to install a 2-bank 115k/V-24kV station to replace the existing 24kV distribution equipment at Dawson Road to fulfill customer-driven demand for electricity in the area as well as providing a reliable supply to customers in contingency situations.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 51.8	$ 19.2	$ 13.9	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(1.1)	18.0	-	-	-	-
Revised Forecast	$ 51.8	$ 18.1	$ 31.9	$ -	$ -	$ -	$ -

Investment Category:
Capacity & Growth – System Load Capacity

Status:
Construction will begin in 2018/19 with in-service in 2019/2020.

2.1.3.2 - Adelaide Station – 66/12kV

The Adelaide Station – 66/12kV project is for the construction of a new Adelaide Station to allow for the decommissioning of King Station, thus addressing all concerns with safety and aging infrastructure at King Station. The Adelaide Station will also provide sufficient area capacity to allow the deferral of the William Station project.

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	$ 62.1	$ 3.2	$ 0.9	$ -	$ -	$ -	$ -
Increase (Decrease)	7.5	9.6	1.8	-	-	-	-
Revised Forecast	$ 69.6	$ 12.8	$ 2.7	$ -	$ -	$ -	$ -

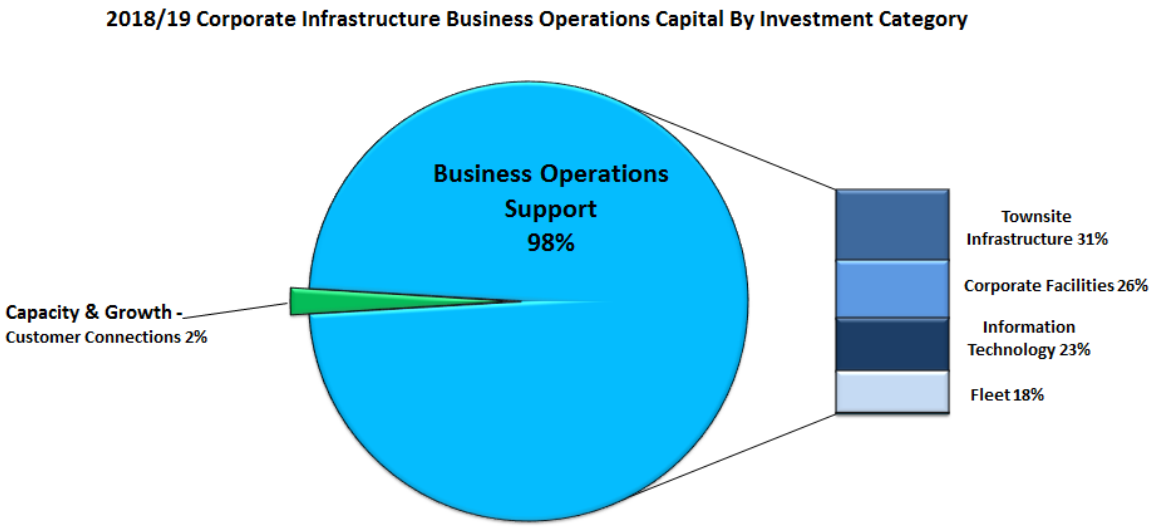
Investment Category:
Sustainment – System Renewal

Status:
Increase in forecast from CEF16 due to change in project scope during the planning phase. Final in-service date of 2019/20 remains unchanged.

2.1.4 – Corporate Infrastructure

Manitoba Hydro's corporate infrastructure system includes assets that are shared across the corporation organized into four main categories: townsite infrastructure, corporate facilities, information technology and fleet.

The corporate infrastructure system capital expenditure forecast for 2018/19 is comprised mainly of business operations support projects and programs, as outlined below.



Investment category and cashflow details for corporate infrastructure projects with a total project forecast of greater than $15 million can be found in Section B – Capital Expenditure & Demand Side Management Forecast by Investment Category and projects with a total project forecast between $1 million and $15 million can be found in Appendix II – Projects Greater than $1 Million and Less than $15 Million.

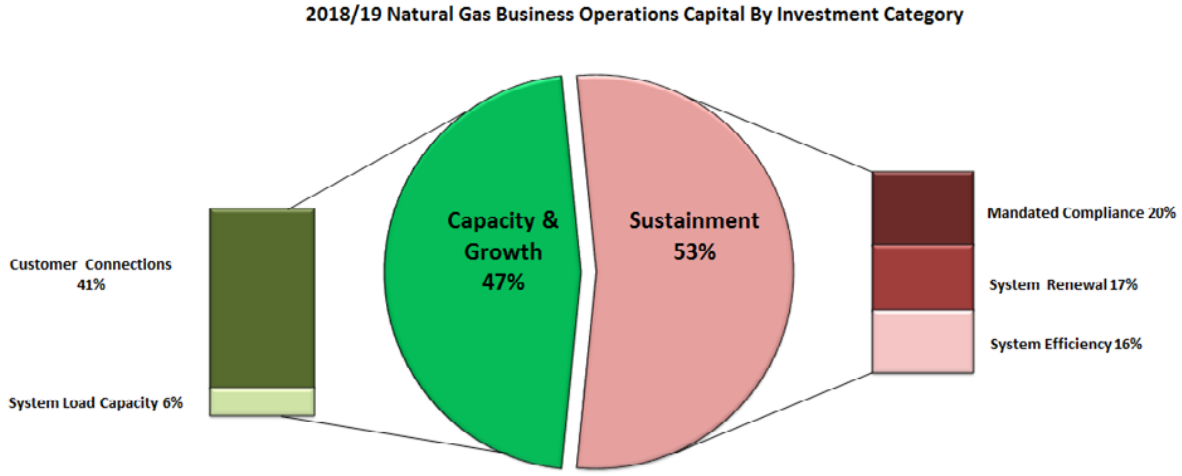
There are no corporate infrastructure projects with a total project forecast greater than $50 million.

2.2 – Business Operations Capital – Natural Gas

2.2.1 – Distribution System & Corporate Infrastructure

The Manitoba Hydro natural gas distribution system consists of approximately 17 000 km of pipelines, 400 pressure regulating stations and 270 000 services to deliver natural gas service to residential, commercial and industrial customers.

The natural gas distribution system capital expenditure forecast for 2018/19 is comprised entirely of capacity & growth and sustainment projects and programs to address customer connection requirements as well as system upgrades reflecting those as a result of compliance, renewal and efficiency requirements as shown in the graph that follows.



Investment category and cashflow details for natural gas projects with a total project forecast between $1 million and $15 million can be found in Appendix II – Projects Greater than $1 Million and Less than $15 Million.

There are no distribution system or corporate infrastructure projects with a total project forecast greater than $50 million.

3.0 – Demand Side Management (DSM)

CEF18 includes demand side management investments for both Electric and Natural Gas operations designed to manage the demand for energy. These expenditures relate to programs that provide education, incentives and expertise to achieve energy savings in an effort to offset growing demand.

Demand Side Management ($ Millions)	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
Electric Programs	62.5	94.3	88.9	86.9	66.5	399.1	733.7
Natural Gas Programs	9.4	10.8	10.8	10.9	10.4	52.2	103.7
Total	**71.9**	**105.1**	**99.6**	**97.8**	**77.0**	**451.4**	**837.4**

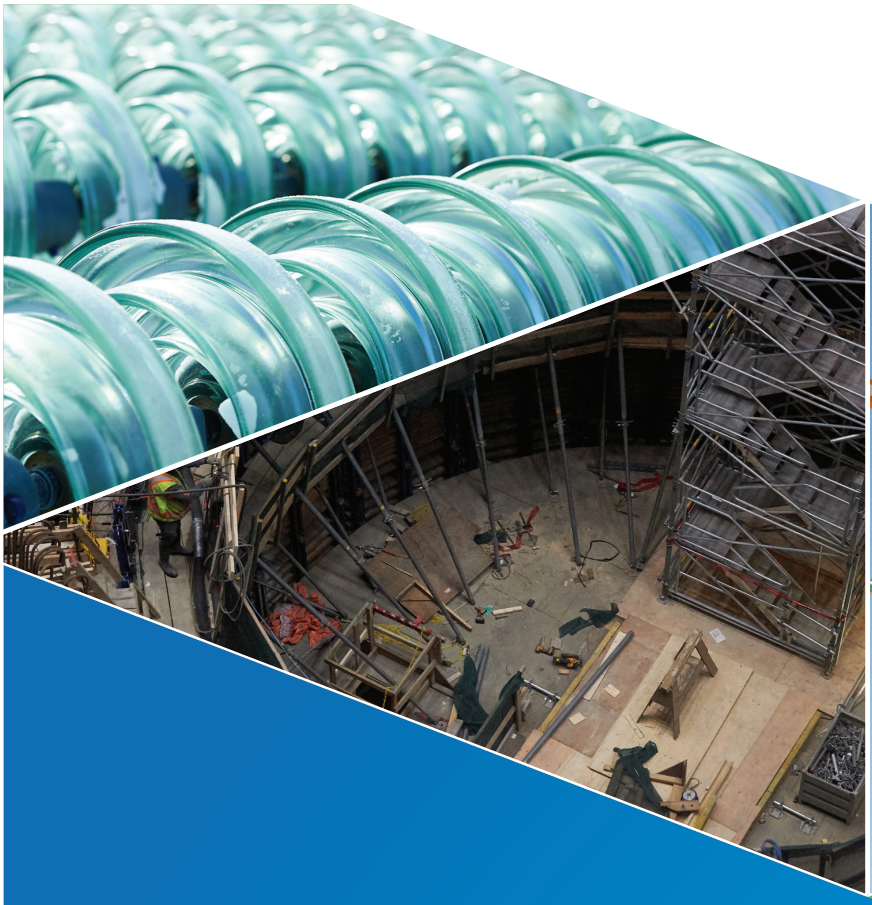
3.1 – Electric DSM Programs

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	NA	$ 99.4	$ 94.3	$ 88.9	$ 86.9	$ 66.5	$ 334.6
Increase (Decrease)		(36.9)	-	-	-	-	$ -
Revised Forecast	NA	$ 62.5	$ 94.3	$ 88.9	$ 86.9	$ 66.5	$ 334.6

3.2 – Natural Gas DSM Programs

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	NA	$ 11.7	$ 10.8	$ 10.8	$ 10.9	$ 10.4	$ 51.4
Increase (Decrease)		(2.3)	-	-	-	-	$ -
Revised Forecast	NA	$ 9.4	$ 10.8	$ 10.8	$ 10.9	$ 10.4	$ 51.4

The reduction of the 2018/19 forecast as compared to CEF16 is primarily due to a change in the mix of programs and updates to customer activity projections for the Load Displacement program.







Section C

Comparison to CEF16

C – Comparison to CEF16

The following table summarizes the changes in capital expenditures between CEF16 and CEF18 over the 10 year period.

CEF18 vs CEF16 ($ Millions)	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
1.0 MAJOR NEW GENERATION & TRANSMISSION	**(33.5)**	**(59.6)**	**(107.5)**	**30.9**	**(46.7)**	**(216.4)**	**(266.9)**
1.1 Keeyask - Generation	(25.1)	(100.2)	(21.0)	56.9	(18.7)	(108.1)	(133.8)
1.2 Bipole III Reliability	5.4	16.3	0.1	-	-	21.9	21.9
1.3 Manitoba-Minnesota Transmission Project	47.7	61.5	(55.7)	0.0	-	53.6	53.6
1.4 Birtle Transmission	0.2	1.4	0.5	2.2	-	4.4	4.4
Other Major New Generation & Transmission	(61.7)	(38.6)	(31.5)	(28.3)	(28.0)	(188.0)	(212.9)
2.0 BUSINESS OPERATIONS CAPITAL	**(2.1)**	**1.1**	**15.6**	**37.8**	**45.1**	**97.4**	**28.9**
2.1 Electric Business Operations Capital	**(1.8)**	**(5.5)**	**10.2**	**33.3**	**42.3**	**78.5**	**0.2**
2.1.1 Generation System	(5.0)	(5.0)	(2.9)	(5.4)	(5.0)	(23.3)	(65.3)
2.1.2 Transmission System	(4.0)	(10.0)	(10.0)	(10.0)	(10.0)	(44.0)	(123.7)
2.1.3 Distribution System	(25.4)	-	13.7	47.6	29.8	65.7	175.5
2.1.4 Corporate Infrastructure	25.0	-	-	(1.1)	(2.2)	21.7	6.4
Unallocated Target Adjustment	7.6	9.5	9.4	2.3	29.7	58.4	7.2
2.2 Natural Gas Business Operations Capital	**(0.3)**	**6.6**	**5.4**	**4.4**	**2.8**	**18.9**	**28.7**
2.2.1 Distribution System & Corporate Infrastructure	(0.3)	6.6	5.4	4.4	2.8	18.9	28.7
3.0 DEMAND SIDE MANAGEMENT	**(39.1)**	**0.0**	**0.0**	**(0.0)**	**0.0**	**(39.1)**	**(39.1)**
3.1 Electric DSM Program	(36.9)	0.0	0.0	(0.0)	0.0	(36.9)	(36.9)
3.2 Natural Gas DSM Program	(2.3)	0.0	0.0	(0.0)	0.0	(2.3)	(2.3)
CONSOLIDATED CAPITAL EXPENDITURE & DSM FORECAST TOTAL	**(74.7)**	**(58.5)**	**(91.9)**	**68.6**	**(1.6)**	**(158.1)**	**(277.2)**
ELECTRIC CAPITAL & DSM FORECAST TOTAL	(72.1)	(65.1)	(97.3)	64.2	(4.4)	(174.8)	(303.6)
NATURAL GAS CAPITAL & DSM FORECAST TOTAL	(2.6)	6.6	5.4	4.4	2.8	16.7	26.4

Over the 10 year period from 2018/19 to 2027/28, forecast cash flow expenditures are $277 million lower as compared to CEF16. The decrease over the 10 year period is primarily associated with Other Major New Generation & Transmission projects included in CEF16. Several of these projects were completed in 2017/18 including: Wuskwatim – Generation, Pointe du Bois Spillway Replacement, Kelsey Improvements & Upgrades, Riel 230/500kV Station, Kettle Improvements & Upgrades and Pointe du Bois Transmission. The Grand Rapids Fish Hatchery Upgrade & Expansion project has been reclassified to Business Operations Capital and all future investment requirements related to the Gillam Redevelopment and Expansion Project (GREP) will also be included as Business Operations Capital items.

Annual cost flow adjustments in the Keeyask Generation project due to scheduling changes and DSM cash flow decreases resulting from a change in the mix of the programs and updates to the projected customer activity for the Load Displacement program further contributed to the 10 year decrease. Annual cost flow adjustments for the Bipole III Reliability Project and Manitoba-Minnesota Transmission Project partially offset the noted reductions.

Appendix I – Investment Category Definitions

The following provides a detailed description of level 1 primary investment categories along with their respective level 2 sub-categories.

Capacity & Growth

Investments required for the expansion of Manitoba Hydro's generation, transmission or HVDC systems, gas transmission main and station assets, gas distribution main and station assets as well as cathodic protection assets. Forecasted investments under capacity and growth are categorized as follows:

- NEW ENERGY – Addition of new generating assets, or upgrades to existing generating assets for the purpose of increasing generation capacity or energy including the associated new or upgraded infrastructure. Also includes new or upgraded transmission assets required to deliver the new or increased energy into the grid.
- SYSTEM LOAD CAPACITY – Addition of new or upgrades to existing transmission or distribution assets for the purpose of increasing the system's capacity to address anticipated load growth not driven by one large customer.
- GRID INTERCONNECTIONS – IMPORT / EXPORT – New assets to deliver energy associated with requests for transmission service (import, export and through-flow requirements).
- CUSTOMER CONNECTIONS – RESIDENTIAL, COMMERCIAL & INDUSTRIAL – New customer-driven connections for domestic service resulting from residential, commercial and/or industrial customer load.
- GRID INTERCONNECTIONS – INDEPENDENT POWER PRODUCERS – New assets to deliver energy associated with requests for transmission service for connections to independent power producers.

Sustainment

Investments to sustain the current and future performance capability of Manitoba Hydro's generation, transmission, HVDC, electric distribution assets, gas transmission main and station assets, gas distribution main and station assets as well as cathodic protection assets. Forecasted investments under sustainment are categorized as follows:

- SYSTEM RENEWAL – Work performed to either replace, refurbish or remove an existing asset as the asset is approaching or is at the end of its useful life, the existing technology is approaching obsolescence, spare parts are not available, and/or the technology is/will be no longer supported. Includes repairs or replacement of assets due to damage caused by the public.
- SYSTEM EFFICIENCY – Addition of new assets or work performed on existing assets in order to improve the operation of the system. Such enhancements are aimed at reducing costs, minimizing the frequency and duration of outages and/or preventing equipment damage.

- MANDATED COMPLIANCE – Investments required to address application of legislative, legal, regulatory or corporate policy, or to address requests from government or other agencies to relocate Manitoba Hydro assets to accommodate other infrastructure.
- DECOMMISSIONING – Expenditures associated with the permanent decommissioning of a Manitoba Hydro generation, transmission, or distribution asset as well as gas transmission or distribution assets. The removal of an asset which is preparation for the construction of an asset in its place is categorized with system renewal.

Business Operations Support

Investments to support business operations and are shared or common throughout the corporation including:

- INFORMATION TECHNOLOGY – Expenditures associated with information technology assets for the data centres, network connectivity, infrastructure, security and business systems including hardware and printers, software licenses, installation and implementation. This category does not include technology assets which operate the electric or natural gas systems.
- FLEET – Expenditures associated with corporate vehicles, mobile equipment and trailers. Primarily includes cars, vans, SUVs, trucks, aerial devices, radial boom diggers, cranes, construction equipment, and all recreation equipment and trailers. These assets typically transport people or goods over land (both on and off road) or water, or are pieces of mobile equipment.
- CORPORATE FACILITIES – Expenditures associated with corporate buildings and properties and the required telecommunications. Corporate buildings are facilities where the primary function is to house staff or storage of equipment/inventory, and include customer service centres, office buildings, warehouses, storage facilities and vehicle service garages. They do not include buildings which have a direct association with the generation, transmission or distribution of energy.
- TOOLS AND EQUIPMENT – Expenditures on tools and equipment used by maintenance crews and/or field staff while working on maintenance or capital projects. Also includes specialized tools and equipment used by design staff to test apparatus and systems.
- GENERATION BUILDINGS AND GROUNDS – Expenditures associated with site buildings related to generating station assets which are primarily designed for operations, as well as property, fencing, roads, railway spurs, water & sewer, public safety, security, PCB, fire suppression and drainage.
- TOWNSITE INFRASTRUCTURE – Expenditures associated with community infrastructure including staff houses, housing and permanent camps. Costs for infrastructure associated with the first-time construction of new or incremental generation, transmission, HVDC or distribution asset would typically be included with the corresponding project and not classified as Business Operations Support.

Demand Side Management

Expenditures related to pursuit of electric energy conservation and efficiency activities designed to manage the demand for energy.

Appendix II – Projects Greater than $1 Million and Less than $15 Million

In accordance with Directive #15/Board Order 73/15, details are provided in CEF18 for individual capital projects with a value greater than $1 million. Projects greater than $15 million appear in the body of the CEF18 booklet with projects greater than $1 million and less than $15 million included in this appendix.

Individual projects in this appendix are grouped by system and two levels of investment category which details what work is being done, where it is being done and why it is required. Together these details provide significantly more information than historically included in response to the directive. This appendix should be read in conjunction with the overview of the investments by system and category as introduced in Section B – Capital Expenditure & Demand Side Management Forecast as well as the descriptions of the investment categories provided in Appendix I – Investment Category Definitions.

The individual project details are further enhanced through the inclusion of Project Status in this appendix to differentiate Executing Projects from those about to begin in the first year of the CEF, which are described as New Projects.

This appendix also includes total project cost, annual forecast cashflows for fiscal years 2019 through 2021, as well as a summarized cashflow projection from 2022 to 2028 for each project.

Directive #15/Board Order 73/15: Manitoba Hydro shall identify and provide details of individual capital projects with a value greater than $1 million in future Capital Expenditure Forecasts. (Board Order 73/15 page 98)

PROJECTS GREATER THAN $1 MILLION AND LESS THAN $15 MILLION

Project Details ($ Millions)	Project Status	Total Project Cost	2019	2020	2021	2022 to 2028
Generation System						
Sustainment						
System Renewal						
Limestone Unit Control Monitoring Upgrade	Executing Project	9.3	2.5	1.3	1.3	-
Grand Rapids Exciter Replacement	Executing Project	8.9	0.2	1.3	-	-
Notigi Marine Vessel Replacement & Infrastructure Improvement	Executing Project	8.7	1.9	0.2	-	-
Jenpeg Unit Control & Monitoring	Executing Project	6.5	1.5	1.3	1.1	0.4
Laurie River Switchyard Bank 2 Replacement	Executing Project	5.9	1.4	-	-	-
Great Falls Stator Frame Spare	Executing Project	5.6	3.0	-	-	-
Great Falls Exciter Replacement	Executing Project	5.4	0.8	-	-	-
Grand Rapids 230kV Reactors Replacement	Executing Project	4.1	0.7	-	-	-
Missi Fuel Tank Installation	Executing Project	3.2	0.2	-	-	-
Slave Falls 129V DC System Upgrade	Executing Project	1.9	0.7	-	-	-
Selkirk 250VDC Battery & Inverter Upgrade	Executing Project	1.5	-	1.1	0.1	-
Slave Falls Cranes Refurbishment	Executing Project	1.5	0.2	-	-	-
Grand Rapids Zebra Mussels Mitigation	Executing Project	1.4	0.8	-	-	-
Slave Falls Cranes, Gate, & Room Refurbishment	Executing Project	1.1	0.2	0.8	-	-
Slave Falls Transformer Banks Replacement & Spare Purchase	New Project	12.0	0.5	3.8	4.2	3.2
Long Spruce Generator Protection Replacement	New Project	10.8	1.2	3.6	1.4	4.2
Seven Sisters Transformer Banks 5 and 6 Replacement	New Project	6.8	0.2	3.5	3.0	-
Great Falls Flow Augmentation	New Project	4.7	1.7	1.3	1.4	-
Grand Rapids PLC 90-70 Upgrade	New Project	3.9	0.2	1.8	1.9	-
Long Spruce Fire Water System Replacement	New Project	3.7	0.6	2.6	0.3	-
Kettle Fire Protection System Replacement	New Project	3.6	0.6	2.6	0.1	-
Limestone Fire Detection Code Upgrade	New Project	3.5	2.8	0.5	-	-
Seven Sisters Intake Frost Protection	New Project	2.4	0.1	2.2	-	-
Missi Accommodations Upgrade & Replacement	New Project	1.5	0.5	0.9	-	-
Slave Falls 7 Bay Sluiceway Pier 1 Refurbishment	New Project	1.1	1.0	-	-	-
Great Falls Water Supply Connection to RM of Alexander	New Project	1.0	1.0	-	-	-
System Renewal Total			**24.4**	**28.5**	**15.0**	**7.9**
Mandated Compliance						
Selkirk Generating Station Environmental Enhancement	Executing Project	14.9	0.1	-	-	-
Brandon Unit 5 License Review	Executing Project	11.5	0.6	2.7	2.0	0.3
Gen South PCB Regulation Compliance	Executing Project	4.5	0.4	0.2	1.4	-
Mandated Compliance Total			**1.0**	**2.9**	**3.5**	**0.3**
System Efficiency						
Kelsey Re-runnering Project Deficiencies & Lagoon Completion	New Project	6.5	6.4	0.1	-	-
System Efficiency Total			**6.4**	**0.1**	**-**	**-**
Sustainment Total			**31.8**	**31.6**	**18.4**	**8.1**

Project Details ($ Millions)	Project Status	Total Project Cost	2019	2020	2021	2022 to 2028
Generation System						
Business Operations Support						
Townsite Infrastructure						
Trailer Court Sewer Linear Infrastructure	Executing Project	11.0	7.1	-	-	-
Gillam Housing Retrofit Program	Executing Project	10.7	0.3	-	-	-
Wuskwatim - Accommodation & Infrastructure	Executing Project	10.0	1.4	2.6	-	-
Kelsey Airport Upgrade	Executing Project	9.7	3.8	4.9	-	-
Town of Gillam 2016 Sewer and Water	Executing Project	9.1	0.3	-	-	-
Manitoba Infrastructure P280 Upgrade	Executing Project	6.9	3.2	1.4	-	-
Seven Sisters Townsite	Executing Project	4.7	0.3	-	-	-
Gillam Single Detach Housing Upgrade	Executing Project	3.1	2.0	0.2	0.2	0.3
Gillam Fencing Replace and Install	Executing Project	2.7	0.7	-	-	-
Gillam Landscape Upgrade	Executing Project	1.2	0.7	-	-	-
Gillam Apartment Rehabilitation	New Project	6.5	4.2	1.8	-	-
Gillam Outdoor Recreation & Beautification	New Project	4.3	1.8	0.7	0.8	0.8
Gillam Airport Airside Improvement	New Project	2.3	2.2	0.1	-	-
Radisson Apartment Repair	New Project	2.1	0.2	1.9	-	-
Townsite Infrastructure Total			**28.3**	**13.7**	**1.0**	**1.1**
Business Operations Support Total			**28.3**	**13.7**	**1.0**	**1.1**
Generation System Total			**60.1**	**45.2**	**19.4**	**9.3**

Project Details ($ Millions)	Project Status	Total Project Cost	2019	2020	2021	2022 to 2028
Transmission System						
Capacity & Growth						
System Load Capacity						
Ashern Station Bank Addition	Executing Project	10.5	0.1	0.1	0.1	9.2
Brandon Victoria Avenue Breaker Replacement	Executing Project	5.1	1.1	1.0	-	-
Whiteshell Bank 1 Replacement	Executing Project	3.0	0.6	-	-	-
System Load Capacity Total			**1.8**	**1.0**	**0.1**	**9.2**
Customer Connections - Residential, Commercial & Industrial						
Poplar Bluff Transmission Project	Executing Project	14.6	12.4	0.4	-	-
Customer Connections - Residential, Commercial & Industrial Total			**12.4**	**0.4**	**-**	**-**
Capacity & Growth Total			**14.1**	**1.4**	**0.1**	**9.2**

Project Details ($ Millions)	Project Status	Total Project Cost	2019	2020	2021	2022 to 2028
Transmission System						
Sustainment						
System Renewal						
HVDC Circuit Breaker Operating Mechanisms Replacement	Executing Project	13.2	0.1	-	-	-
HVDC Fire Protection Projects	Executing Project	7.2	0.1	0.3	2.4	1.4
HVDC Bipole 2 Refurbish Thyristor Module Cooling Components	Executing Project	7.0	0.1	-	-	-
HVDC Transformer Marshalling Kiosk Replacement	Executing Project	7.0	0.9	0.9	0.6	-
Energy Management System Upgrade version 3.2	Executing Project	6.1	3.5	-	-	-
HVDC Auxiliary Power Supply Upgrade	Executing Project	6.1	0.1	0.1	0.5	-
HVDC Bipole 1 Disconnect Replacement	Executing Project	5.5	1.4	1.7	1.0	0.4
HVDC Stations Ground Grid Refurbishment	Executing Project	4.2	0.1	0.5	0.9	-
HVDC Transformer Bushing Draw Rod & Cap Replacement	Executing Project	3.3	-	-	0.4	-
HVDC Domestic Water Treatment Upgrade and Replacement	Executing Project	3.1	1.2	-	-	-
Diesel Upgrade - Brochet	Executing Project	2.5	1.3	0.9	-	-
Dorsey Joint VAR Control Replacement	Executing Project	2.1	0.9	1.0	-	-
Diesel Upgrade - Shamattawa	Executing Project	1.0	0.2	0.5	-	-
Transmission Breaker Sustainment	New Project	13.8	-	0.4	-	3.2
HVDC Bipole 1 Direct Current-Current Transformers Transductor Replacement	New Project	12.2	0.8	1.7	-	6.7
Diesel Upgrade - Lac Brochet	New Project	8.1	0.4	1.8	3.9	1.8
System Renewal Total			**11.2**	**9.9**	**9.8**	**13.5**
Mandated Compliance						
Line V38R - 230kV Transmission Line Right-Of-Way in Riding Mountain National Park	Executing Project	2.2	1.2	0.2	-	-
230kV Protection Additions	New Project	6.1	-	-	-	5.9
Reston Station New 230kV Ring Breaker	New Project	2.5	0.8	1.0	0.6	-
Mandated Compliance Total			**2.0**	**1.2**	**0.6**	**5.9**
System Efficiency						
Virden West & Reston 66kV Capacitors	Executing Project	11.5	8.3	0.1	-	-
Hot Line Tagging Replay Replacement	Executing Project	2.5	0.5	-	-	-
HVDC Controls & System Replicas Development	Executing Project	1.6	0.4	0.8	-	-
System Efficiency Total			**9.2**	**0.9**	**-**	**-**
Sustainment Total			**22.4**	**11.9**	**10.4**	**19.4**
Transmission System Total			**36.5**	**13.3**	**10.4**	**28.6**

Project Details ($ Millions)	Project Status	Total Project Cost	2019	2020	2021	2022 to 2028
Distribution System						
Capacity & Growth						
System Load Capacity						
Heaslip Distribution Supply Centre and 8-25kV Conversion	Executing Project	13.7	8.5	-	-	-
66kV Capacity Additions Stanley Station & Area	Executing Project	8.1	3.7	-	-	-
Norris Road Distribution Supply Centre	Executing Project	4.2	0.1	-	-	-
Norway House Station Bank Addition	Executing Project	4.0	2.5	-	-	-
Shilo Distribution Supply Centre Capacity Increase & Area Voltage	Executing Project	3.5	1.4	-	-	-
Whiteshell 33kV System Improvement	Executing Project	2.4	0.9	-	-	-
Ste Agathe Station Bank Addition	Executing Project	2.3	0.4	-	-	-
LaVerendrye Station 66kV Line 161 Addition	New Project	6.1	2.4	3.6	-	-
Portage la Reine Station Capacity Increase	New Project	4.5	0.1	4.2	-	-
Winkler North Station Bank Addition	New Project	4.3	0.2	4.1	-	-
Morden Cheval Station Bank Addition	New Project	4.0	3.8	-	-	-
Morden Ninth Station Bank Addition	New Project	4.0	0.2	3.8	-	-
Portage Saskatchewan Station Bank Addition & Feeder Relocation	New Project	3.7	3.5	-	-	-
System Load Capacity Total			**27.7**	**15.7**	**-**	**-**
Customer Connections - Residential, Commercial & Industrial						
University Station Replacement	New Project	7.6	1.0	5.9	0.4	-
Enbridge Gretna Distribution Supply Centre & Capacity Bank	New Project	4.0	1.0	2.9	-	-
Customer Connections - Residential, Commercial & Industrial Total			**2.0**	**8.8**	**0.4**	**-**
Capacity & Growth Total			**29.7**	**24.5**	**0.4**	**-**
Sustainment						
Mandated Compliance						
Distribution Hot Line Tag Relay Program	Executing Project	4.9	1.1	-	-	-
Winnipeg Area 66kV Line Upgrade	Executing Project	2.6	0.5	-	-	-
Waverley Underpass	Executing Project	1.0	0.1	-	-	-
Mandated Compliance Total			**1.7**	**-**	**-**	**-**
System Efficiency						
Advanced Information Management	Executing Project	10.4	5.5	-	-	-
French Station Feeder Upgrade	Executing Project	1.3	0.7	-	-	-
Dunraven Feeder Conversions (DN232/233)	New Project	5.4	5.1	-	-	-
System Efficiency Total			**11.4**	**-**	**-**	**-**
Sustainment Total			**13.1**	**-**	**-**	**-**
Distribution System Total			**42.8**	**24.5**	**0.4**	**-**

Project Details ($ Millions)	Project Status	Total Project Cost	2019	2020	2021	2022 to 2028
Corporate Infrastructure						
Business Operations Support						
Corporate Facilities						
820 Taylor - Protection of Critical Infrastructure	New Project	12.0	11.5	-	-	-
Corporate Facilities Total			**11.5**	**-**	**-**	**-**
Information Technology						
Facility Ratings System - 2 projects	Executing Project	1.8	0.8	-	-	-
Banner Forms Upgrade	Executing Project	1.4	1.2	-	-	-
Information Technology Total			**1.9**	**-**	**-**	**-**
Business Operations Support Total			**13.4**	**-**	**-**	**-**
Corporate Infrastructure Total			**13.4**	**-**	**-**	**-**

Project Details ($ Millions)	Project Status	Total Project Cost	2019	2020	2021	2022 to 2028
Gas Distribution System & Corporate Infrastructure						
Capacity & Growth						
System Load Capacity						
St-Pierre Transmission Pipeline Upgrade	Executing Project	2.7	0.4	-	-	-
Steinbach Natural Gas System Upgrade	New Project	4.5	0.4	1.4	1.9	0.3
Waverley West Upgrade	New Project	3.7	0.9	2.0	0.5	-
System Load Capacity Total			**1.7**	**3.4**	**2.5**	**0.3**
Capacity & Growth Total			**1.7**	**3.4**	**2.5**	**0.3**
Sustainment						
System Renewal						
Brandon Primary Generating Station Re-Construction	Executing Project	2.5	1.1	0.5	-	-
System Renewal Total			**1.1**	**0.5**	**-**	**-**
Mandated Compliance						
Medium Pressure Monitoring System Replacement	Executing Project	2.5	1.2	-	-	-
Winnipeg Natural Gas Transmission Easement Widening	Executing Project	1.4	0.5	-	-	-
Letellier-Red River Transmission Upgrade	New Project	1.6	0.3	1.3	-	-
Mandated Compliance Total			**2.0**	**1.3**	**-**	**-**
System Efficiency						
Natural Gas Transmission Pipeline System In-Line Inspection	New Project	6.4	2.5	1.6	1.7	0.5
Provision of Secure Gas Supply-Portage	New Project	1.6	0.1	0.4	0.1	1.0
St. Andrews Distribution System Upgrade	New Project	1.3	1.2	-	-	-
System Efficiency Total			**3.9**	**2.1**	**1.8**	**1.5**
Sustainment Total			**6.9**	**4.0**	**1.8**	**1.5**
Gas Distribution System & Corporate Infrastructure Total			**8.6**	**7.4**	**4.3**	**1.8**
Consolidated Business Operations Capital Projects Total			**161.5**	**90.4**	**34.5**	**39.6**

RESPONSE TO DIRECTIVE #13 - ORDER 73/15

For the Quarter Ended March 31, 2018

13. Manitoba Hydro shall file detailed quarterly reports for all Major New Generation and Transmission projects, including the ones currently under development. These reports are to outline the proposed budget (at time of contract), budget changes and reasons for such changes, and the revised projected in-service costs. Where capital costs have increased materially, Manitoba Hydro is to explain how such increases will impact domestic revenue requirements and projected impacts on Manitoba Hydro's financial forecasts and targets.

Response:

The following figure summarizes the total project costs for the Major New Generation & Transmission Projects (MNG&T) in CEF16 and CEF18, as well as the reasons for revisions between the forecasts. The table also provides the actual project costs and status for each project to March 31, 2018.

Several MNG&T projects included in CEF16 have now been completed (with remaining project completion activities transferred to Business Operations Capital, where applicable) and as such are not classified as MNG&T in CEF18, including Wuskwatim – Generation, Kelsey Improvements & Upgrades, Kettle Improvements & Upgrades, and Pointe du Bois Spillway Replacement.

In addition, the Grand Rapids Fish Hatchery Upgrade & Expansion project has been reclassified to Business Operations Capital in CEF18, as this project is required for licensing of existing generating stations and new national and provincial regulatory requirements for water quality and biosecurity applicable to the integrated system in addition to the licensing requirements for Keeyask. Therefore, it is best considered as a project in support of ongoing operations.

Similarly, all future investment requirements related to the Gillam Redevelopment and Expansion Project (GREP) will also be raised as Business Operations Capital items. The scope of GREP is anticipated to be reduced and any future Gillam townsite maintenance or expansion requirements will be justified as projects on their own and brought

forward for approval under Business Operations Capital. Therefore, it is best considered as a project in support of ongoing operations.

Accordingly, the table below does not include updated forecast amounts for completed projects, the Grand Rapids Fish Hatchery or GREP, as they are no longer included in MNG&T. Commencing in the first quarterly report for 2018/19, Manitoba Hydro will no longer provide the summary table below and will provide project reports for Bipole III, Keeyask, the Manitoba-Minnesota Transmission Line, and the Birtle Transmission line.

Appendices I, II and III provide information on the budgets and current status for the Bipole III, Keeyask, and the Manitoba-Minnesota Transmission Line, respectively.

Figure 1. Total Project Costs for Major New Generation & Transmission Projects in CEF18
March 2018 Quarterly Report
(in millions of dollars)

-	Total Project CEF16	Total Project CEF18	Change in Total Project Inc/(Dec)	Reasons for Revision	Actual to Date	Project Status
Wuskwatim - Generation	1,421.6	N/A	-	The project was complete in 2017/18.	1,416.8	The project is now complete. The decommissioning of the temporary power supply substation in 2018/19 will be raised within Generation's Business Operations Capital.
Keeyask	Refer to Keeyask Quarterly Report Update (Appendix II).					
Grand Rapids Fish Hatchery Upgrade & Expansion	23.5	N/A	-	The Grand Rapids Fish Hatchery Upgrade & Expansion has been transferred to Business Operations Capital in Generation in CEF18, effective April 1, 2018.	4.4	A review of project alternatives has been completed and the refined project scope has been established, with completion scheduled for the third quarter of 2018/19.
Kelsey Improvements & Upgrades	336.9	N/A	-	The project was complete in 2017/18.	325.6	The project is now complete. Future expenditure requirements associated with the sewage lagoon will be justified and approved within Generation's Business Operations Capital.
Kettle Improvements & Upgrades	112.2	N/A	-	The project was complete in 2017/18.	106.4	The project is now complete.

-	Total Project CEF16	Total Project CEF18	Change in Total Project Inc/(Dec)	Reasons for Revision	Actual to Date	Project Status
Pointe du Bois Spillway Replacement	575.7	N/A	-	The project was complete in 2017/18.	567.5	Minor deficiency work was completed. The project is now complete. Any future work requirements will be raised within Generation's Business Operations Capital.
Gillam Redevelopment and Expansion Program (GREP)	266.5	N/A	-	The Gillam Redevelopment and Expansion Program (GREP) is considered complete as at March 31/18. The Gillam Community Centre Redevelopment was transferred to the Human Resources & Corporate Facilities Business Operations Capital effective April 1, 2018 and all other future upgrades and enhancements within the Town of Gillam will be justified and approved within Generation Business Operations Capital.	73.0	Work continued on the replacement of 3 double wide trailers and a housing retrofit during the fourth quarter. Fire remediation work and redevelopment of the Gillam Community Centre began in January and is being completed in unison to minimize the impact to the project schedule. Substantial building completion is scheduled for March 2019. Insurance is expected to cover all costs resulting from the fire.
Bipole III Transmission Reliability Project	Refer to Bipole III Quarterly Report Update (Appendix I).					
Manitoba-Minnesota Transmission Project	Refer to Manitoba-Minnesota Transmission Quarterly Report Update (Appendix III).					

-	Total Project CEF16	Total Project CEF18	Change in Total Project Inc/(Dec)	Reasons for Revision	Actual to Date	Project Status
Birtle Transmission	56.5	56.5	-	No Change. The project, previously titled Manitoba-Minnesota Transmission Project, was renamed to Birtle Transmission.	2.5	The environmental assessment was filed with the Manitoba Environmental Approvals Branch on January 31, 2018. Design activities for Transmission Line B71T are continuing, precise mapping is complete. Birtle South Station design and procurement activities are in progress with most major apparatus have been ordered.

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Bipole III, Keeyask and MMTP Project Reports

Given the size and importance of these projects, Manitoba Hydro is providing additional information on the current status of its largest active Major New Generation and Transmission Projects, namely Bipole III, Keeyask, and the Manitoba-Minnesota Transmission Line projects, in Appendices I, II and III, respectively.

The contingency amounts contained within the control budget, and the information on contract values and capital expenditures by contract to date that is found in Appendices I and II, are highly confidential and commercially sensitive. Manitoba Hydro is filing this information in confidence as public disclosure would harm Manitoba Hydro's ability to manage and execute the work according to the commercial terms agreed to by contract and would certainly affect future negotiations.

Manitoba Hydro's contingency budget is applied to the construction contracts in a manner that reflects the risks and probable occurrence of those risks. Should the risks materialize, the contingency is available to cover additional costs; however, should the risks not materialize, the contingency would not be spent and the funds would be available for other potential risk events in subsequent stages of the project.

Manitoba Hydro Update on Major Projects to the Public Utilities Board

Bipole III Project Update

Q4 Update ending March 31, 2018



Bipole III S2 Final Jumper Connection outside Riel Converter Station

EXECUTIVE SUMMARY

Project Description

Bipole III is a high voltage direct current transmission project under construction that will deliver renewable energy to southern Manitoba once complete later this year.

The Bipole III project includes:

- A 1,384-kilometre, 500,000-volt direct current transmission line;
- The Keewatinohk Converter Station in northern Manitoba, northeast of Gillam;
- The Riel Converter Station, east of Winnipeg;
- 230 kV collector lines (5); and,
- Two ground electrodes at each of the new converter stations.

Bipole III adds 2,000 megawatts to Manitoba Hydro's high voltage direct transmission and will strengthen the reliability of Manitoba's electricity supply by reducing dependency on existing high voltage direct current transmission lines and the Dorsey Converter Station. Currently, the two existing Bipole lines deliver over 70 per cent of the electricity produced in the province.

Due to its heavy reliance on one transmission corridor and a single converter station in the south (Dorsey), Manitoba Hydro's electricity system is vulnerable to extensive power outages from severe weather (major ice storm, extreme wind event, tornado), fires, or other events. The Riel Converter Station will establish a second converter station in southern Manitoba, to provide another major point of power injection into the transmission and distribution system.

Background

The Bipole III Project Environment Act Licence was issued August 14, 2013. In fall 2016, a review of the Bipole III budget and schedule was conducted and the budget was increased to $5.04 billion with an in-service date of July 2018.

Keewatinohk and Riel Converter Stations

The Bipole III transmission line originates at a new northern converter facility, the Keewatinohk Converter Station, and terminates at a new southern converter facility, the Riel Converter Station. In addition to the new transmission line and the new converter stations, the project includes new collector lines linking the Keewatinohk Converter Station to the northern collector system at the existing switchyards at Henday Converter Station and Long Spruce Generating Stations. Each of those facilities required some modifications for these new "collector lines". Each of the new converter stations required the development of a separate ground electrode, connected to the station by a low voltage feeder line.

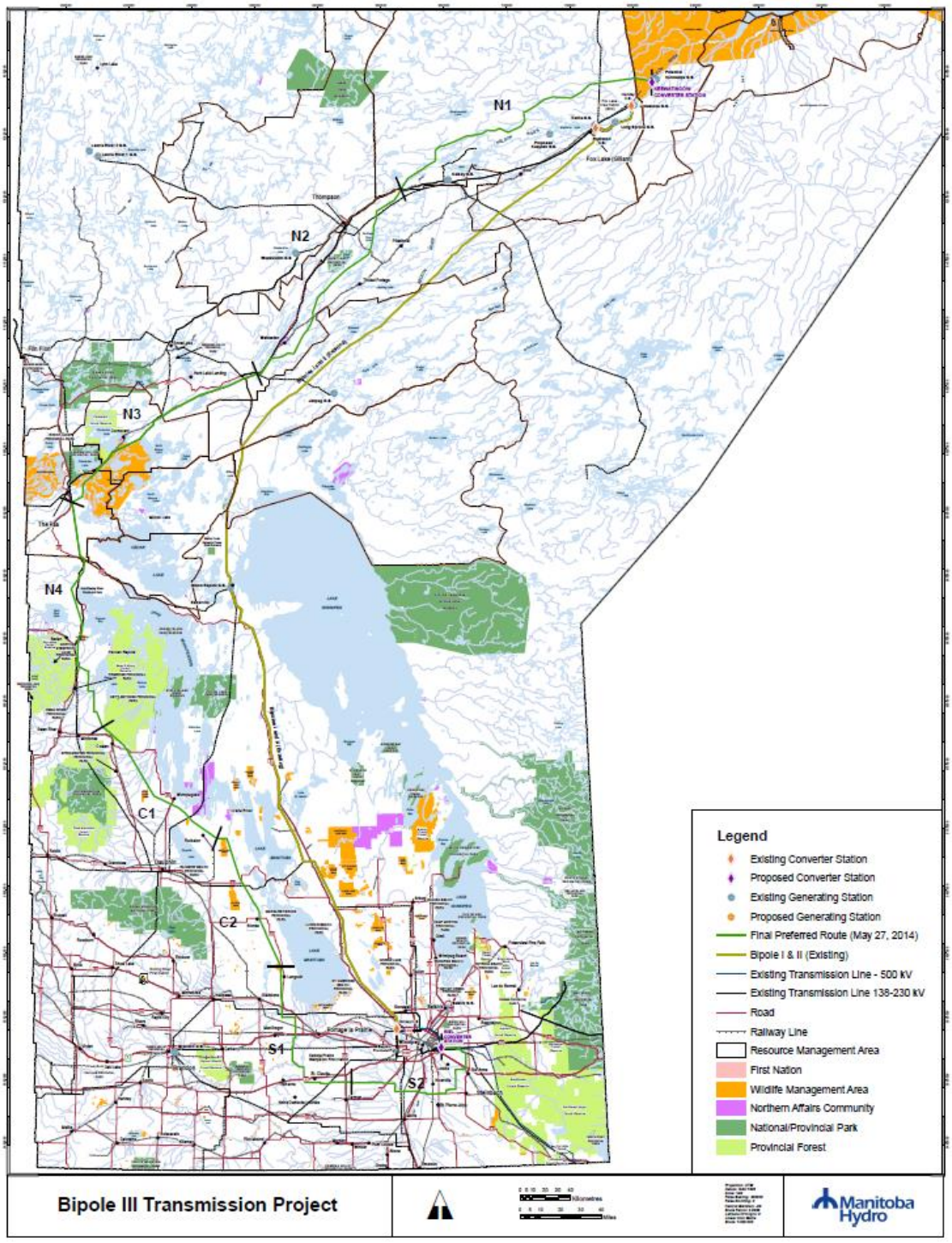
The Keewatinohk Construction Power Station and line went into service July 2014. The Keewatinohk Lodge, a 600 person work camp to house the required construction workforce for the converter station has been fully operational since 2015.

The Riel Converter Station is being constructed at the same site as the Riel Sectionalization Project.

Transmission Line Construction
The Keewatinohk Converter Station and the Riel Converter Station will be linked by a new +/- 500 kV HVDC transmission line approximately 1,384 km in length, centered on a 66 meter wide right-of-way following a route west of lakes Winnipegosis and Manitoba. This new transmission line has been routed as far as practical, sufficiently far from the existing Bipole I and II lines so as to decrease the probability that a single catastrophic weather event or natural disaster would damage both the new transmission line and Bipoles I and II.

Below please find a map of the transmission line segments.

Map of the Bipole III Project



PROJECT UPDATE

Converter Station Construction:

- Construction of the Bipole III converter stations is approximately 97% complete with work focused on the remaining work for the synchronous condensers at the Riel Converter Station, deficiency work at both stations and commissioning of the project to fully integrate it into the Manitoba Hydro system.

Commissioning of the Keewatinohk and Riel Converter Stations:

- HVDC Commissioning:
  - The Bipole III transmission line was linked to the Riel and Keewatinohk Converter Stations on March 31st.
  - As part of the testing process, commissioning crews successfully energized each station fully from the converter transformers to the valve hall to the DC yard on April 2nd, for the first time delivering 50 megawatts from the Keewatinohk Converter Station to the Riel Converter Station.
- Synchronous Condenser Commissioning:
  - The four synchronous condensers are 360,000-kg machines that rotate at 1,200 rpm and help stabilize Manitoba Hydro's system.
  - Synchronous Condenser 1- reached full speed during testing in March, performing as expected even at over-speed testing.
  - Synchronous Condenser 2 – Load tests, load rejection and reactive capability tests have now been completed.
  - Synchronous Condenser 3 – Completion of the start/stop sequence testing and ongoing unit pressure tests. Hydrogen filling is scheduled for mid-April, with online testing to follow.
  - Synchronous Condenser 4 – Unit transformer pre-energized testing and ground fault testing are underway.
- Keewatinohk 230 kV Switchyard:
  - The switchyard was successfully energized, some deficiency correction work remains.
  - All five collector lines are now in service for full AC inlet to Keewatinohk, which is required for HVDC commissioning over the next few months.

Transmission Line:

- As of March 31, 2018 the construction of the Bipole III 500kV Transmission Line was completed and turned over for commissioning on March 31, 2018. By reallocating work between resources, and through rigorous monitoring and control, Manitoba Hydro was able to ensure successful completion of construction in time for commissioning.

- Forbes Brothers Ltd. (FBL) - Sections N2, N3, S1 and S2:
  - Stringing work resumed in January for Sections N2, N3, and S1 (S2 previously completed). Remaining tower assembly and erection activities (primarily in N3) were completed in February.

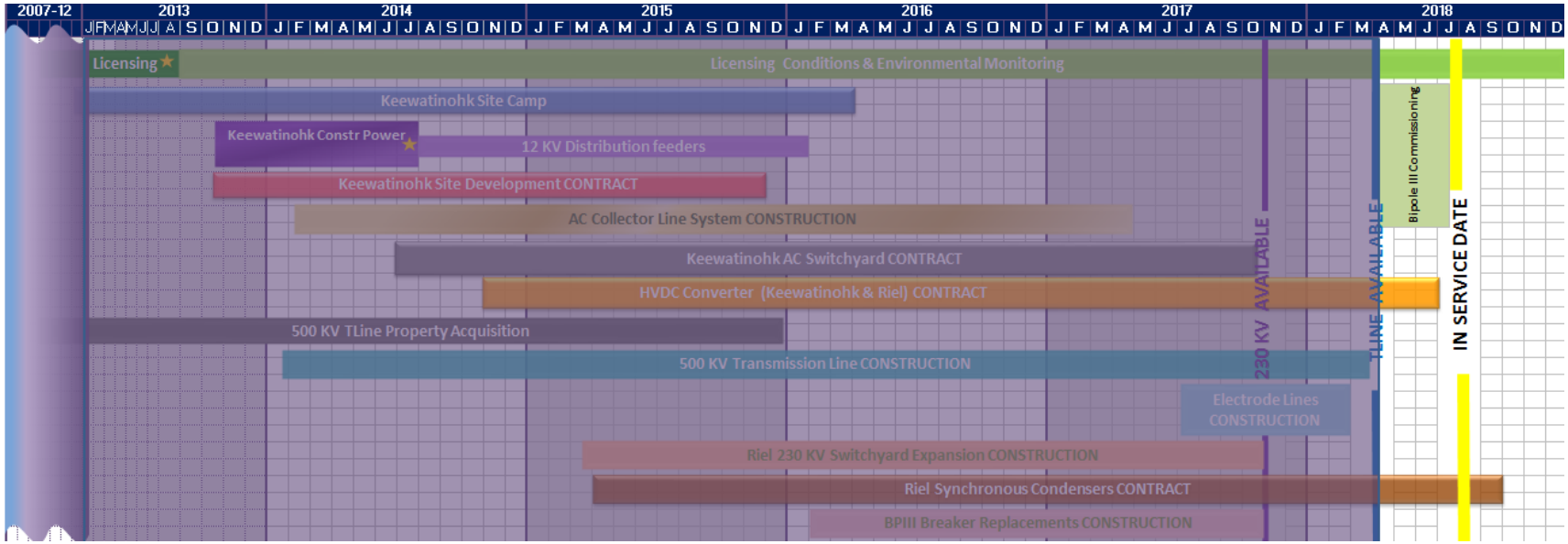
  - January was a slow start, but work progressed through February and March. Overall, despite being behind plan and pushing schedule completion dates further into March than targeted, the work was completed (as a result of less deficiencies) before the end of March. Final inspections and all deficiencies that would impact the start of commissioning activities were corrected enabling the issuance of the Taking Over Certificate March 31st. Outstanding deficiency remediation work is ongoing.

- Rokstad Power Company (RPC) - Sections N1, N4, C1 and C2:
  - Work this quarter continued with tower assembly operations in N1 and N4, the last of which was completed the 3rd week of March.
  - Stringing activities and final inspection for section C2 were completed in January, enabling RPC stringing crews from C2 to return to section C1. However, RPC's rate of progress continued to lag plan on overall stringing scope, and although a significant amount of conductor was in the air, back end stringing activities and spacer damper crews struggled to maintain pace. Further notice to correct was issued to RPC, and by February 23rd an additional segment of stringing work was removed from their scope in section N1.
  - Construction activities concluded with the balance of stringing completed in late March, behind target and plan, but in time to turn over for commissioning. Final inspections and all deficiencies that would impact the start of commissioning activities were corrected enabling the issuance of the Taking Over Certificate March 31st. Outstanding deficiency remediation work is ongoing.
- Valard – Section N1:
  - Work resumed in January with installation of foundations, and tower assembly and erection. Foundations were completed in early February.
  - Stringing operations commenced in January. Slower than planned progress experienced in January, in combination with the additional work awarded to Valard during February, impacted the planned completion date, shifting it from early to mid-March.
  - Construction activities concluded with the balance of stringing completed during March. Final inspections and all deficiencies that would impact the start of commissioning activities were corrected enabling the issuance of the Taking Over Certificate March 31st, with the remaining deficiencies for correction expected to be completed in April.
- Non-destructive testing of all tower sleeves was completed for the whole line; a total of 11,496 sleeves were inspected. Findings overall included a 1.1% failure rate, or 120 non-conformant guy cable sleeves, all of which have been replaced.

Collector Lines:

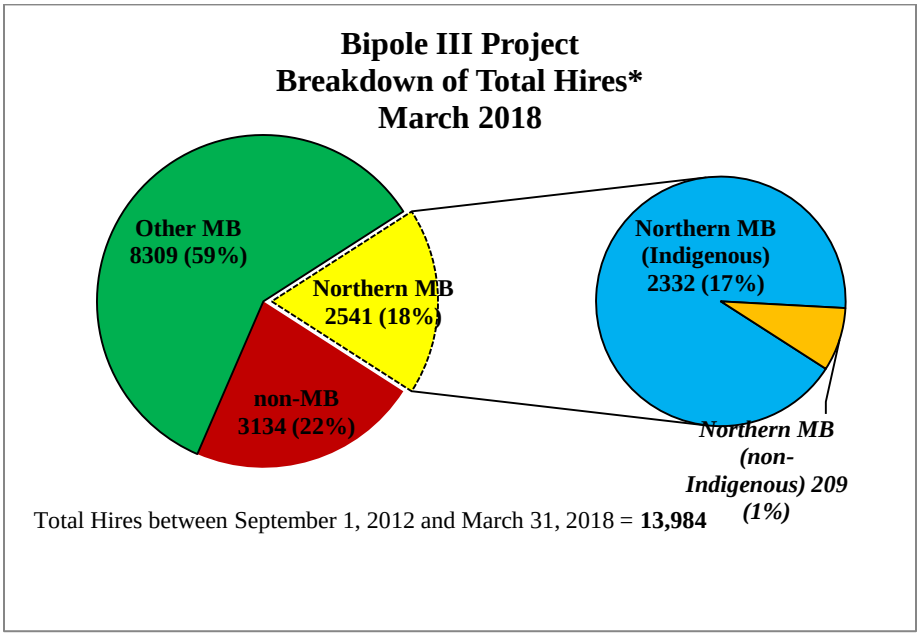
- AC Collector Lines (5 - 230 KV transmission lines):
  - TCN/Forbes Bros. Joint Venture completed the assembly all remaining towers for L61K during January. In addition, stringing the remaining spans also resumed in January. The final stringing of the L61K line was completed during mid-February.
  - 5 spans of the L61K line had to be re-strung in March, as the conductor used in the original installation was defective. The line has since been re-commissioned and placed back into service.
- Henday station upgrades:
  - Work completed during February included the installation of the final jumpers.
  - Only minor deficiency clean-up remains.
- Long Spruce station upgrades:
  - The new L46H cable was tested, commissioned and energized in February.
  - Only minor deficiency clean-up remains.
- Riel and Keewatinohk Electrode lines:
  - Work completed.
- Limestone to Keewatinohk Secondary Communication Line:
  - Crown Utilities completed the installation of the conduit.
  - Works remaining include pulling the balance of fibre and installing the remaining vaults. Telecommunications has begun to splice the installed fibre.
- R49R Sectionalization:
  - Sectionalization of the line is complete.
- Dorsey PCM Upgrades:
  - Remaining work includes the salvage of the Dorsey to Whiteshell Cross Trip scheme – scheduled for completion 6 months post BPIII in-service date.

Bipole III Schedule Overview – March 31, 2018



Total Hires: – as of March 31, 2018

- Since September 2012 there have been a total of 13,984 hires for the Bipole III Project.
- Of the total hires, 78% are Manitobans, including 18% northern Manitobans.
- Active hires: 3,235.



FINANCIAL SUMMARY

- Construction is progressing to be on budget of $5.042 billion.
- Expenditures were $4.289 billion to the end of March 31, 2018.

Table A - Bipole III Budget Summary (in Billions $)

Item #	Item	Current Approved Budget (2016$)	Actuals to Mar 31, 2018
1.1	Transmission Line	1.457	1.479
1.2	Converter Stations	2.285	2.181
1.3	Collector Lines	0.199	0.191
1.4	Community Development Initiative	0.053	0.052
1.5	Escalation @ CPI	0.052	0.000
1.6	Interest (Capitalized)	0.487	0.386
1.7	Contingency	0.509	0.000
1.8	Total	5.042	4.289

Table A Notes:

1. The Escalation and Contingency Components (1.5 and 1.7) will have no actual costs incurred against them; these costs will form part of the actual costs in the Transmission Line, Converter Stations, Collector Lines, Community Development Initiative and Interest Components (1.1, 1.2, 1.3, 1.4 and 1.6).

PICTURES

Photo 1: Final Jumper connections, N1 Tower #1 at Keewatinohk Converter Station



Photo 2: Riel Converter Station



Photo 3: Bipole III N1 Stringing Operations – Implosive Sleeve Detonation



Photo 4: S2 Tower #7338 RCS Final Jumper Installations March 31, 2018



Manitoba Hydro Update on Major Projects to the Public Utilities Board

Keeyask Project Update

Q4 Update ending March 31, 2018



EXECUTIVE SUMMARY

- Despite improvements and achieving critical milestones in the 2017 season, further improvement in performance of approximately 10% by the General Civil Contractor (GCC) is still required on the Keeyask Project to meet control budget ($8.7B) and achieve in service dates for the units that are in advance of the control schedule of August 2021. This also assumes that no significant risks materialize with other contracts or risks that could impact the critical path. Manitoba Hydro is confident that this rate of improvement is attainable as it is similar to the year-over-year improvement between 2016 and 2017.
- The control budget for the project remains at $8.7B. There are no changes in budget that would impact domestic revenue requirements or Manitoba Hydro's financial forecasts.
- In the last quarter, concrete placements on the Powerhouse Complex and work on the South Dyke were completed as planned.
- At the end of March 2018, approximately half of the concrete required for the Keeyask Project was placed.
- Actual expenditures to the end of March 31, 2018 were $4.51 billion.

PROJECT UPDATE

Background

- The Keeyask Generating Station is a 7 unit, 695-megawatt hydroelectric generating station under construction at Gull Rapids on the lower Nelson River in northern Manitoba.
- The Keeyask Project includes construction of the generating station as well as construction of supporting infrastructure. Most of the infrastructure was constructed in advance of the generating station under the Keeyask Infrastructure Project (KIP). The Keeyask Project is a collaborative effort between Manitoba Hydro and four Manitoba First Nations, working together as the Keeyask Hydropower Limited Partnership.
- Keeyask will be Manitoba's fourth largest generating station and the sixth on the Nelson River.
- Construction of the Keeyask Generating Station commenced on July 16, 2014 after receipt of all required licenses and approvals.
- The General Civil Works contract, the largest contract on the project, was awarded to BBE Hydro Constructors Limited Partnership consisting of Bechtel Canada Co., Barnard Construction of Canada Ltd. and EllisDon Civil Ltd. The General Civil Works contractor is responsible for rock excavation, concrete for the powerhouse and spillway, earth structures, electrical and mechanical work, and the construction and removal of temporary cofferdams needed to manage the river flow during construction.

Generating Station

- Manitoba Hydro in conjunction with the major construction contractors finished developing the project plan for 2018. This plan includes production goals/milestones for the season and actions targeted at improving performance.
- Manitoba Hydro and the GCC implemented a winter concrete plan in early 2018 to help recover a portion of the concrete quantities that were not achieved by the end of December 2017. This winter work allows for key areas to be advanced during the coldest winter months. The GCC executed the winter concrete work as planned, placing more than 9,000 m^3 of concrete between January 1 and March 31, 2018. In total there has been approximately 172,000 m^3 of concrete placed on the project; more than half the total volume of concrete required for the Keeyask Project.
- To help reduce risk to the project schedule, construction of the South Dyke was advanced by a year and began in late 2017. Work on the South Dyke included excavation, fill placement and sourcing of granular material. The winter work portion on the South Dyke was completed as planned.
- Work by the GCC over the winter was generally completed more efficiently than planned indicating that the initiatives targeted at driving positive change are beginning to show success.

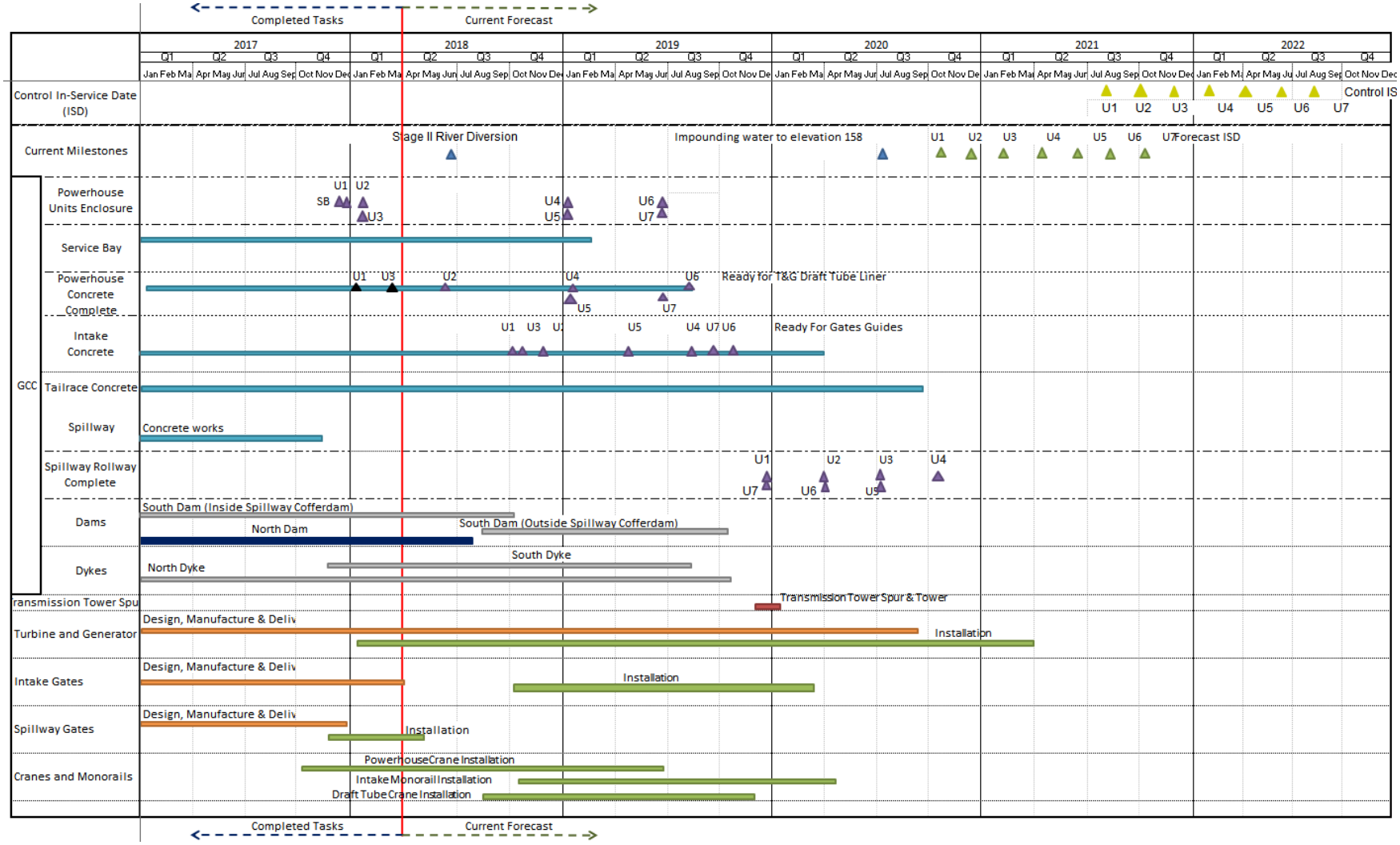
- Canmec continued to install the gates, guides and hoists on the Spillway. The installation work will continue until early May. The Spillway is on track for completion prior to river diversion in summer 2018.
- The Turbine and Generator (T&G) contractor installed the unit 1 and unit 3 draft tube liners and is assembling the stay ring in the Service Bay. Manitoba Hydro continues to work with the GCC and T&G contractors to resolve interface issues that are impacting the schedule. These issues are not expected to impact achievement of the control schedule.
- Despite improvements and achieving critical milestones in the 2017 season, further improvement in performance of approximately 10% by the GCC is still required on the Keeyask Project to meet control budget ($8.7B) and achieve in service dates for the units that are in advance of the control schedule of August 2021. This also assumes that no significant risks materialize with other contracts or risks that could impact the critical path. Manitoba Hydro is confident that this rate of improvement is attainable as it is similar to the year-over-year improvement between 2016 and 2017.
- The top risks include:
    - Execution/productivity rates of the GCC.
    - Loss of site access/work stoppages - Any civil disorder could significantly impact Manitoba Hydro's ability to construct the Keeyask Generating Station on time and on budget.
    - Unexpected geotechnical/geological conditions at the South Dam/Dyke.
    - Unseasonable weather that shortens the warm construction season.

Infrastructure

- Work is underway to expand the Keeyask main camp by an additional 152 rooms to accommodate the workforce required in 2018. The main camp contractor returned to site in winter 2018 to begin installation of the additional dorm units. These units will be available to support ramp up of the craft workforce in spring 2018. When expansion to the main camp is complete the Keeyask site will be able to accommodate over 2,500 workers.

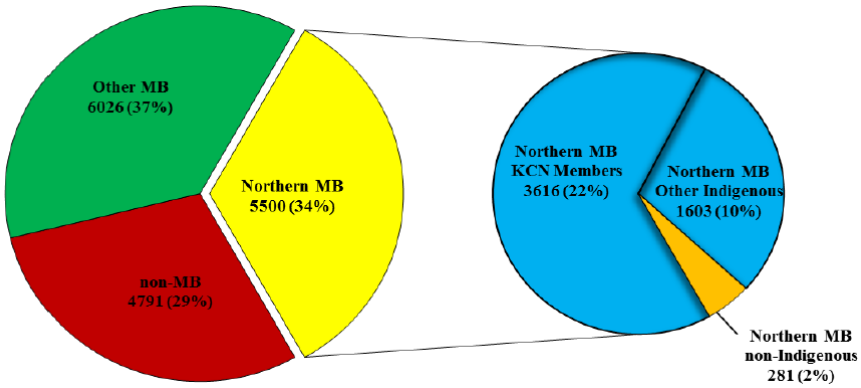
Project Schedule Overview – March 31, 2018

Note: Construction activities, milestones and unit In Service Dates (ISDs) reflect Manitoba Hydro's current forecast schedule. Presently, the forecast for the unit ISDs is in advance of the Control ISDs (August 2021 for first unit ISD).



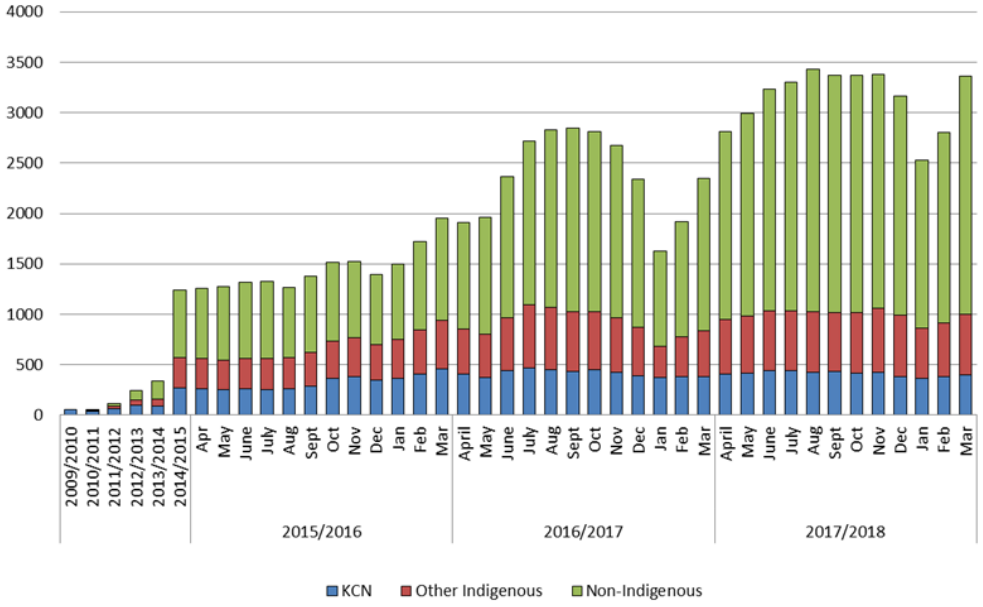
* This is a summary of our current plan broken down to the major component of construction and significant contractors, and how these components and milestones relate to river management and impoundment.
* "Control ISD" reflects MH communicated ISD dates, while "Current ISD" reflects current plan ISD dates which are currently 10 months ahead of the control ISD.
* Powerhouse concrete remains the project critical path driving the water impoundment. Construction of the dams and dykes are currently off the critical path.

Total Project Hires – as of March 31, 2018



- As of March 31, 2018, there have been a total of 16,317 hires on the Keeyask Project. Of these total hires, 71% (11,526) are Manitobans, 44% (7,234) have self-declared as being Indigenous persons and 22% (3,638) of the total hires are Keeyask Cree Nation ("KCN") members.

Active Hires – as of March 31, 2018



- As of March 31, 2018 there were 3,365 active hires on the Keeyask Project. Of these active hires, 54% (1,815) are Manitobans, 30% (1,001) have self-declared as being Indigenous persons and 12% (401) are KCN members.

FINANCIAL SUMMARY

- Actual expenditures to the end of March 31, 2018 were $4.51 billion.

Table A - Keeyask Budget Summary (in Billions $)

Item #	Item	Current Approved Budget (2016$)	Actuals to March 31, 2018
1.1	Generating Station	5.948	3.785
1.2	Generation Outlet Transmission (GOT)	0.202	0.107
1.3	Escalation @ CPI	0.249	0.000
1.4	Interest (including Interest on Equity)	1.749	0.615
1.5	Contingency	0.578	0.000
	Total	**8.726**	**4.508**

Table A Notes:

1. The Escalation and Contingency Components (1.3 and 1.5) will have no actual costs incurred against them; these costs will form part of the actual costs in the Generating Station, Generation Outlet Transmission and Interest Components (1.1, 1.2 and 1.4).

RECENT PHOTOS

Photo #1: Unit 1 Draft Tube Liner in the Service Bay Preparing to be Installed – January 21, 2018

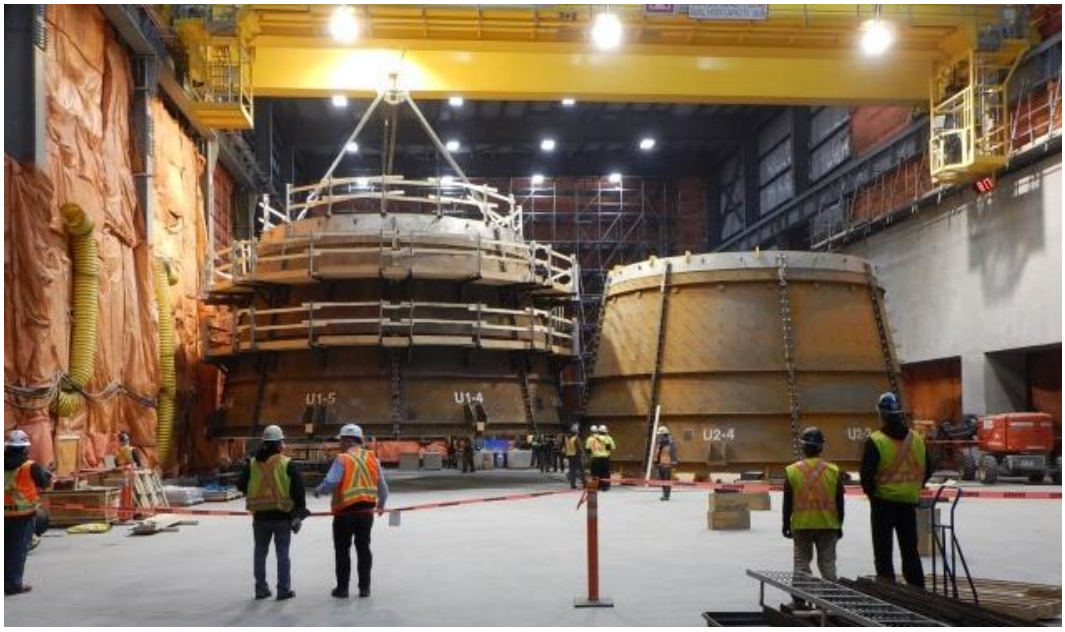


Photo #2: Unit 1 Draft Tube Liner Installation by the Turbine and Generator Contractor – January 21, 2018



Photo #3: Spillway Gate, Guide and Hoist Installation – March 20, 2018



Photo #4: Powerhouse Complex with Service Bay and Units 1-3 Enclosed – March 20, 2018

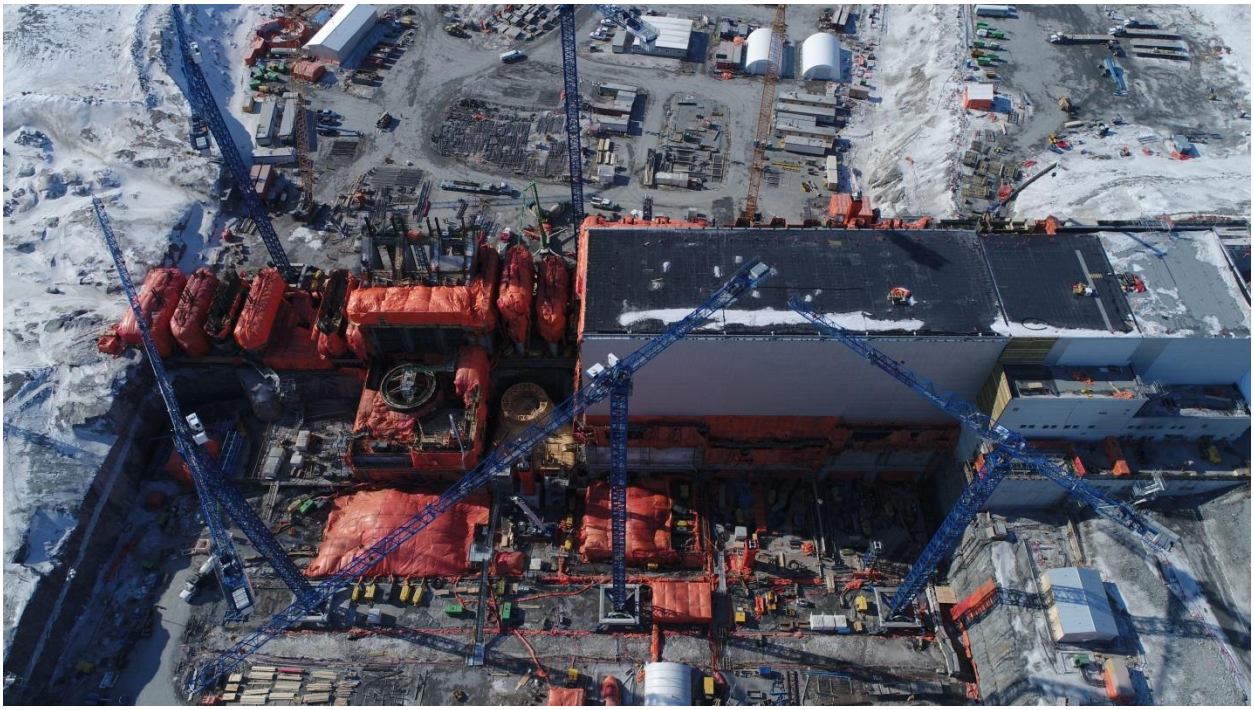
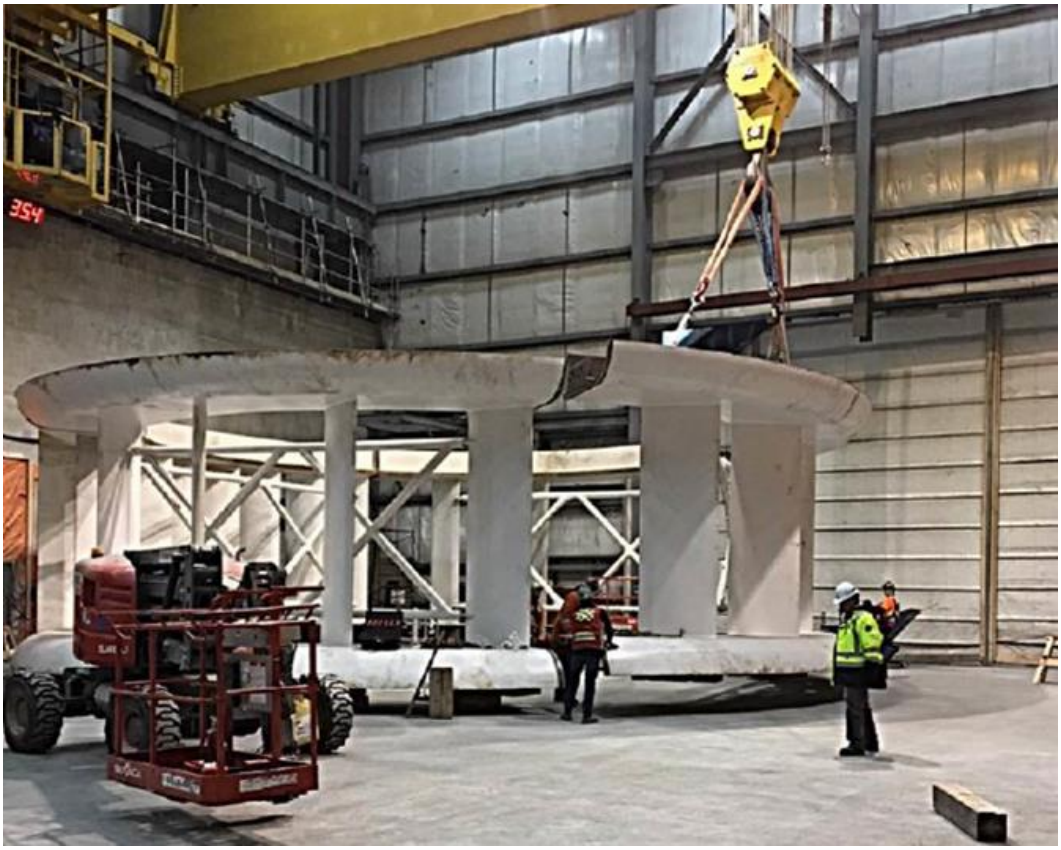


Photo #5: Stay Ring Assembly by the Turbine and Generator Contractor – March 29, 2018



MANITOBA – MINNESOTA TRANSMISSION PROJECT

Q4 Update ending March 31, 2018

MMTP Project Description

Manitoba Hydro's capital expenditure forecast includes the construction of a new 500kV Transmission Line between Winnipeg and Duluth, Minnesota (MMTP).

The MMTP transmission line will originate at Dorsey Converter station located near Rosser, northwest of Winnipeg and extend 213 km south around Winnipeg to the Manitoba-Minnesota border, near Piney, Manitoba. The MMTP also includes associated upgrades at Dorsey, Riel and Glenboro stations.

The U.S. portion of the 500 kV line will initiate at the border and terminate at Iron Range Station near Grand Rapids, Minnesota. This project is known as the Great Northern Transmission Line (GNTL), and will be constructed by Minnesota Power.

MMTP Project Update

- A decision from the Minister of Sustainable Development regarding an Environment Act Licence for the project has yet to be made. Sagkeeng First Nation has filed a request for judicial review of the provincial licensing decision stemming from concerns around section 35 Consultation (aboriginal rights). Dates and next steps of this review are yet to be determined.
- On December 21, 2017 the NEB issued an Order setting out the procedures for a public hearing to review the MMTP project, and associated timelines. The order also specified the maximum time for an NEB decision of no later than March 2019. The NEB certificate process is essential to the timely completion of the project.
- The hearing process is underway, with the oral portion and cross examination scheduled to begin in late June 2018. Oral traditional evidence will be presented by aboriginal intervenors in early June 2018.
- A number of Intervenors have requested additional time be added to the hearing process to allow time to prepare both expert evidence and oral traditional evidence from aboriginal participants. Manitoba Hydro has argued that this is not necessary. The NEB has yet to issue a decision related to this request.
- Property Acquisition is continuing and 68% of the private land required along the proposed transmission line route between Vivian, Manitoba and the U.S. Border has been secured.
- In order to secure the project in-service date Manitoba Hydro must move forward with long lead time items such as the material contracts prior to receiving Provincial and Federal regulatory approvals. Failure to do so would result in substantial project delays, as such two contracts for tower steel have been awarded to SA-RA Energy, Construction, Trade & Industry Inc., and MITAS Industry Inc. Each contract will supply 50% of the tower steel, with a delivery date for all tower steel by end of October. Should Manitoba Hydro receive notification that the project will not receive its necessary regulatory approvals materials may be re-used on future transmission projects in order to recover sunk costs.
- Work began on the Request for Proposal (RFP) documents for two construction contracts (one for Section 1, Dorsey Station to Vivian Corner and one for Section 2, Vivian Corner to the U.S. Border), in order to post the RFP for bids to be received through the summer and protect an estimated construction start date of December 2018. This contract will be structured such that construction

MANITOBA – MINNESOTA TRANSMISSION PROJECT

Q4 Update ending March 31, 2018

efforts will be pending the regulatory approvals to ensure there is minimal costs to Manitoba Hydro should the project not proceed due to decision regarding the environmental license.

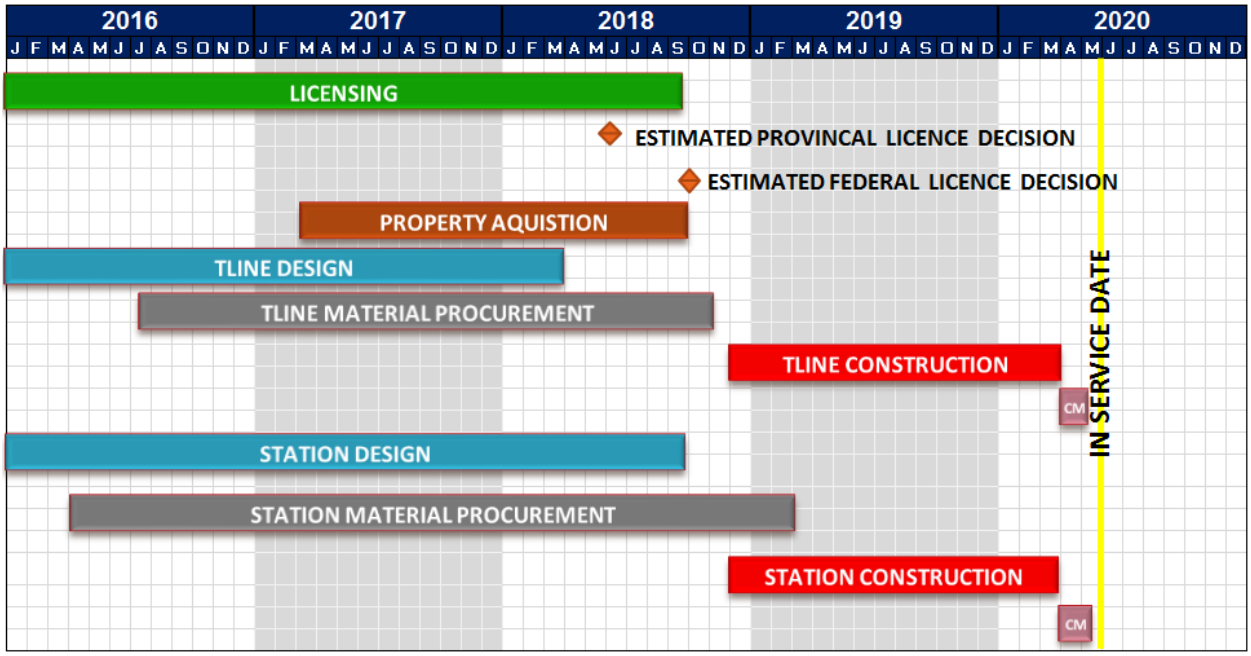
- Phase conductor material was delivered, and will continue through the spring of 2018.
- Pre-cast foundation material is being ordered and deliveries will begin in the spring.

MMTP Budget

Item #	Item	Control Budget	Actuals to March 31, 2018
1.1	Licensing & Environmental	$ 31.5M	$ 19.3M
1.2	500 kV Transmission Line *	$ 213.6M	$ 26.0M
1.3	Station Upgrades*	$ 112.8M	$ 13.3M
1.4	Contingency	$ 95.3M	$0
1.5	**Total**	**$ 453.2M**	**$ 58.6M**

*No construction contracts are currently in place.

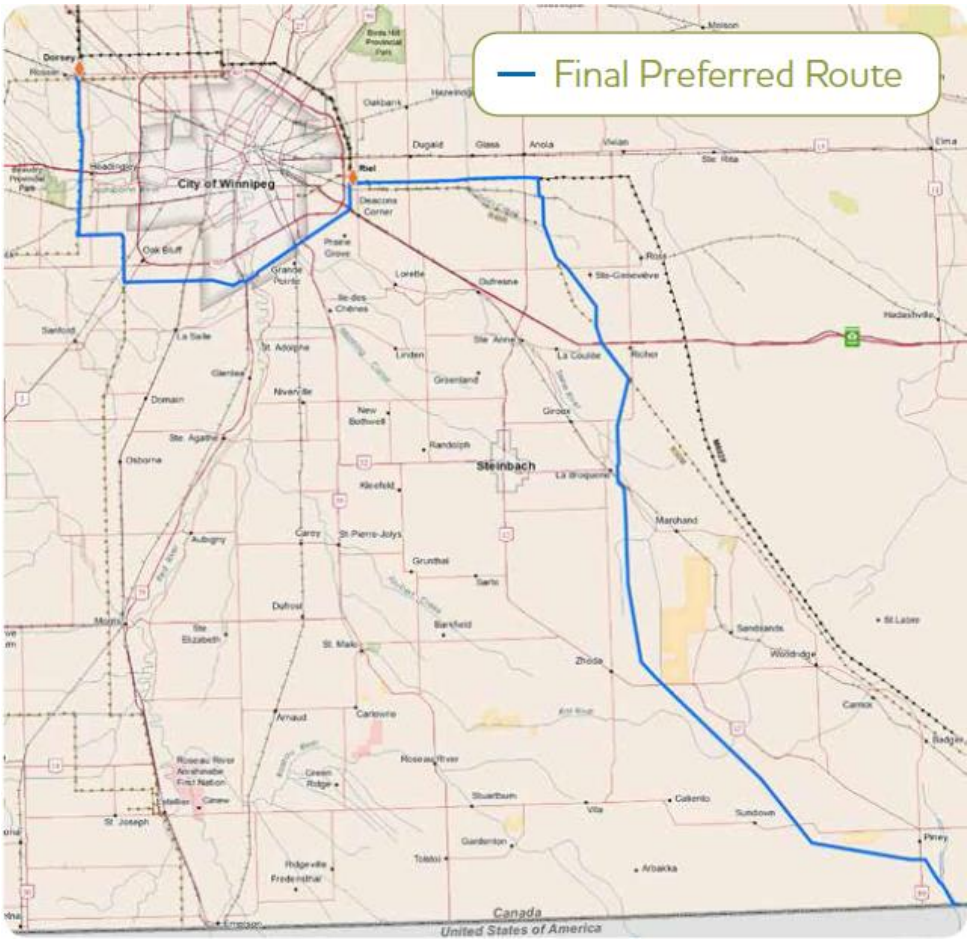
MMTP Project Schedule



MANITOBA – MINNESOTA TRANSMISSION PROJECT

Q4 Update ending March 31, 2018

MMTP Project Route



Manitoba Hydro Update on Major Projects to the Public Utilities Board

Bipole III Project Update

Q1 Update ending June 30, 2018



Bipole III sunset at Keewatinohk Converter Station

EXECUTIVE SUMMARY

Project Description

Bipole III is a high voltage direct current transmission project under construction that will deliver renewable energy to southern Manitoba once in-service in the next quarter.

The Bipole III project includes:

- A 1,384-kilometre, 500,000-volt direct current transmission line;
- The Keewatinohk Converter Station in northern Manitoba, northeast of Gillam;
- The Riel Converter Station, east of Winnipeg;
- 230 kV collector lines (5); and,
- Two ground electrodes at each of the new converter stations.

Bipole III adds 2,000 megawatts to Manitoba Hydro's high voltage direct transmission and will strengthen the reliability of Manitoba's electricity supply by reducing dependency on existing high voltage direct current transmission lines and the Dorsey Converter Station. Currently, the two existing Bipole lines deliver over 70 per cent of the electricity produced in the province.

Due to its heavy reliance on one transmission corridor and a single converter station in the south (Dorsey), Manitoba Hydro's electricity system is vulnerable to extensive power outages from severe weather (major ice storm, extreme wind event, tornado), fires, or other events. The Riel Converter Station will establish a second converter station in southern Manitoba, to provide another major point of power injection into the transmission and distribution system.

Background

The Bipole III Project Environment Act Licence was issued August 14, 2013. In fall 2016, a review of the Bipole III budget and schedule was conducted and the budget was increased to $5.04 billion with an in-service date of July 2018.

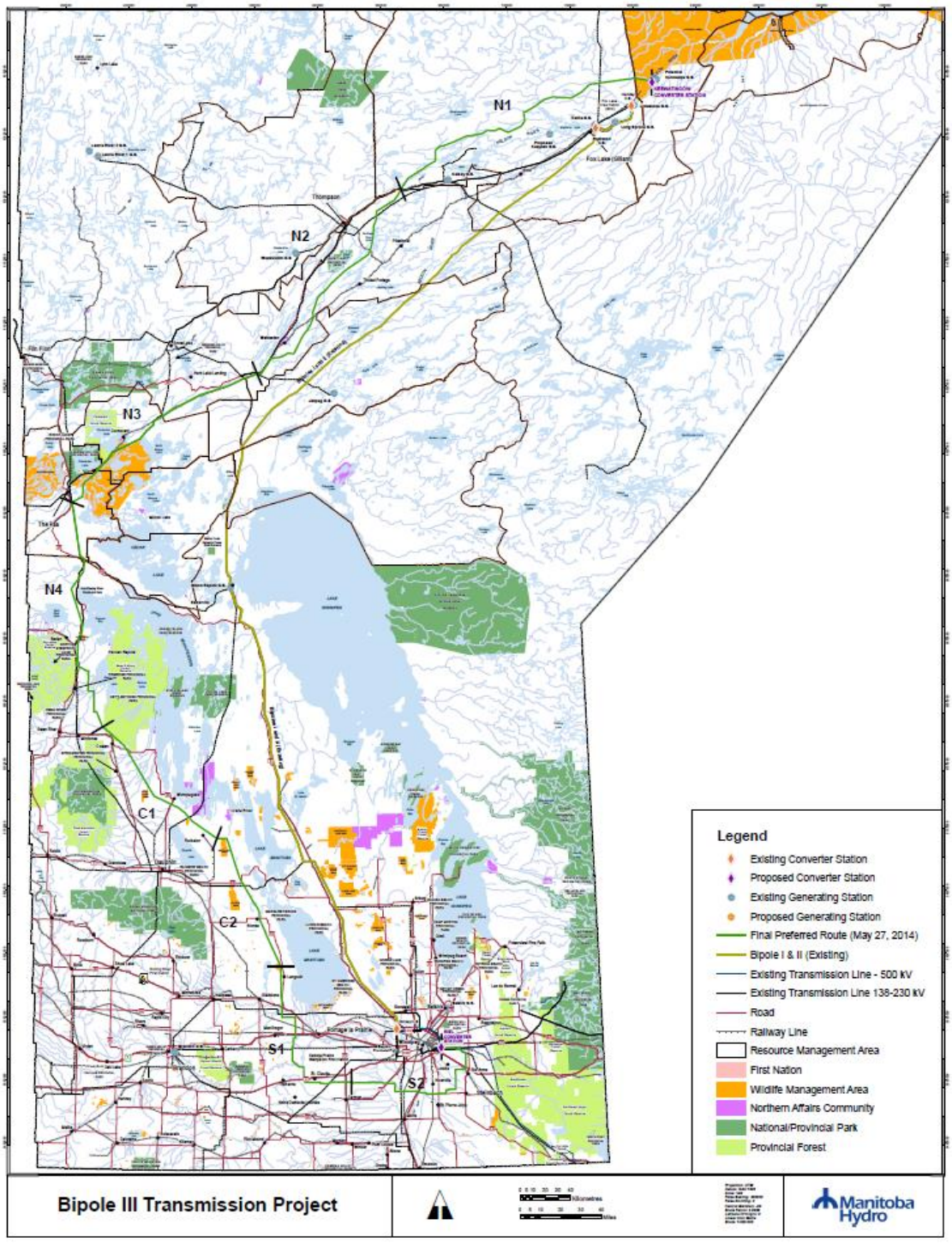
Keewatinohk and Riel Converter Stations
The Bipole III transmission line originates at a new northern converter facility, the Keewatinohk Converter Station, and terminates at a new southern converter facility, the Riel Converter Station. In addition to the new transmission line and the new converter stations, the project includes new collector lines linking the Keewatinohk Converter Station to the northern collector system at the existing switchyards at Henday Converter Station and Long Spruce Generating Stations. Each of those facilities required some modifications for these new "collector lines". Each of the new converter stations required the development of a separate ground electrode, connected to the station by a low voltage feeder line.

Transmission Line Construction

The Keewatinohk Converter Station and the Riel Converter Station will be linked by a new +/- 500 kV HVDC transmission line approximately 1,384 km in length, centered on a 66 meter wide right-of-way following a route west of lakes Winnipegosis and Manitoba. This new transmission line has been routed as far as practical, sufficiently far from the existing Bipole I and II lines so as to decrease the probability that a single catastrophic weather event or natural disaster would damage both the new transmission line and Bipoles I and II.

Below please find a map of the transmission line segments.

Map of the Bipole III Project



PROJECT UPDATE

Construction work on the Bipole III HVDC transmission line was completed on March 31, 2018 enabling Manitoba Hydro to release the Bipole III Transmission Line for commissioning. Construction at the converter stations is nearly complete and the HVDC line was connected to both the Riel and Keewatinohk Converter Stations on March 31, 2018.

On April 2, 2018 as part of the test process, commissioning crews successfully energized each station fully from the converter transformers to the valve hall to the DC yard for the first time, delivering 50 megawatts from the Keewatinohk Converter Station to the Riel Converter Station.

On April 23, 2018 the Bipole III, Pole 6 was loaded to 1150 MW, full loading in metallic return on one pole for the first time. Bipole III HVDC power was uninterrupted for all tests, performing as expected.

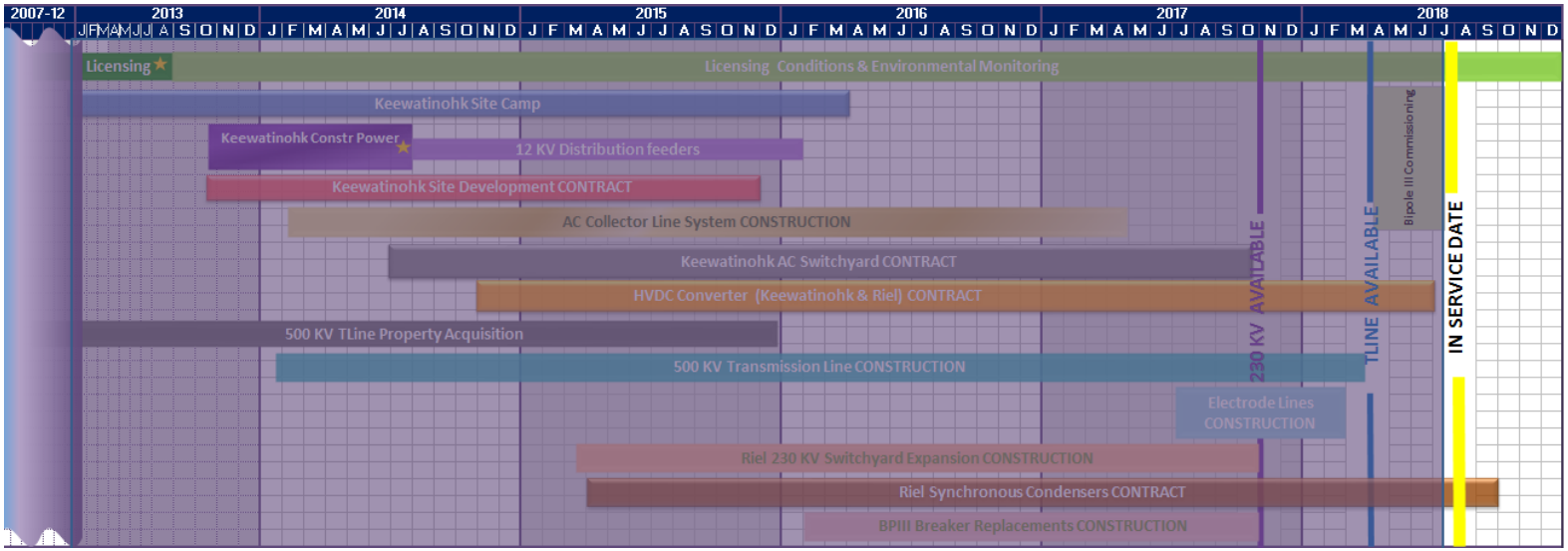
The first three synchronous condensers – 360,000 kg machines that rotate at 1,200 rpm and help stabilize Manitoba Hydro's system are complete and available to support the system.

As part of the commissioning process, the HVDC system including both converter stations and the transmission line had to run for 30 consecutive days to confirm reliability prior to going into commercial service. That trial operating period successfully concluded on June 26, 2018. The trial operation was followed by a seven day period to address deficiencies noted during commissioning and the 30-day trial.

On July 4, 2018 Bipole III was turned over for commercial service to Manitoba Hydro operations.

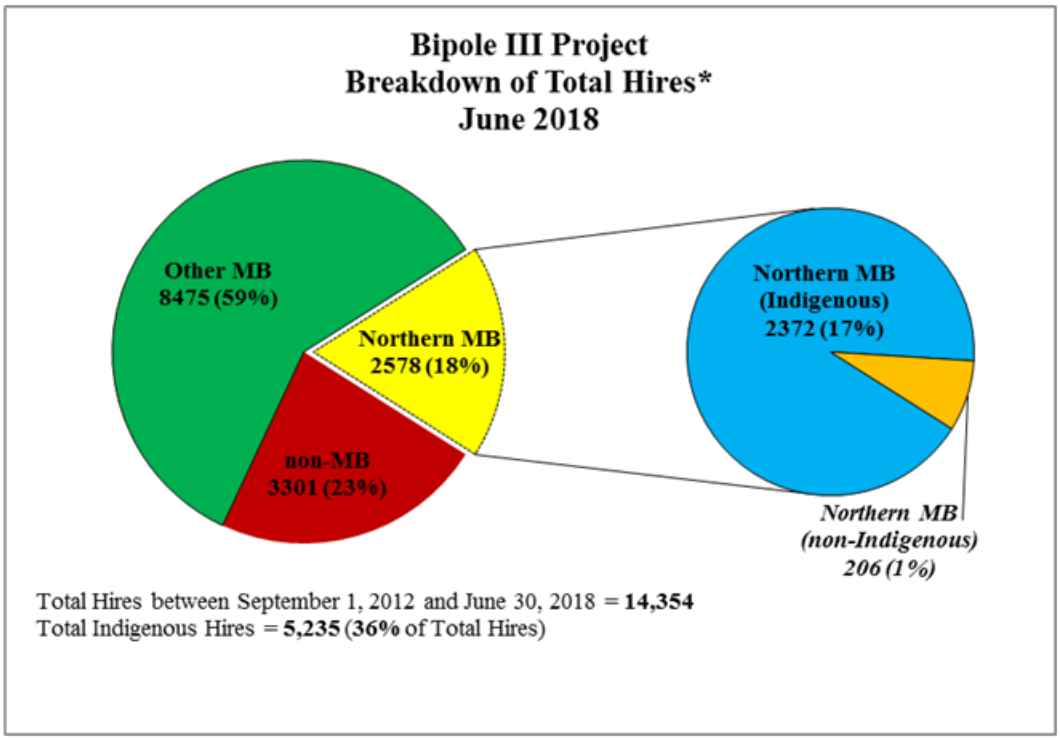
The work remaining on the Bipole III project includes the completion of the final synchronous condenser at the Riel Converter Station, decommissioning of the Keewatinohk lodge and associated temporary construction infrastructure and final Bipole III project close out activities.

Bipole III Schedule Overview – June 30, 2018



Total Hires: – as of June 30, 2018

- Since September 2012 there have been a total of 14,354 hires for the Bipole III Project.
- Of the total hires, 77% (11,053) are Manitobans, including 18% (2,578) northern Manitobans, 36% (5,235) have self-declared as being Indigenous persons.
- Active hires: 2,253.



FINANCIAL SUMMARY

- Construction is progressing to be on budget of $5.042 billion.
- Expenditures were $4.4 billion to the end of June 30, 2018.

Table A - Bipole III Budget Summary (in Billions $)

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1.3	Collector Lines	0.199	0.193
1.4	Community Development Initiative	0.053	0.053
1.5	Escalation @ CPI	0.052	0.000
1.6	Interest (Capitalized)	0.487	0.434
1.7	Contingency	0.509	0.000
1.8	Total	5.042	4.400

Table A Notes:

1. The Escalation and Contingency Components (1.5 and 1.7) will have no actual costs incurred against them; these costs will form part of the actual costs in the Transmission Line, Converter Stations, Collector Lines, Community Development Initiative and Interest Components (1.1, 1.2, 1.3, 1.4 and 1.6).

Pictures

Photo 1: Riel Converter Station, spare transformer deluge testing



Photo 2: Bipole III Commissioning, DC line fault testing

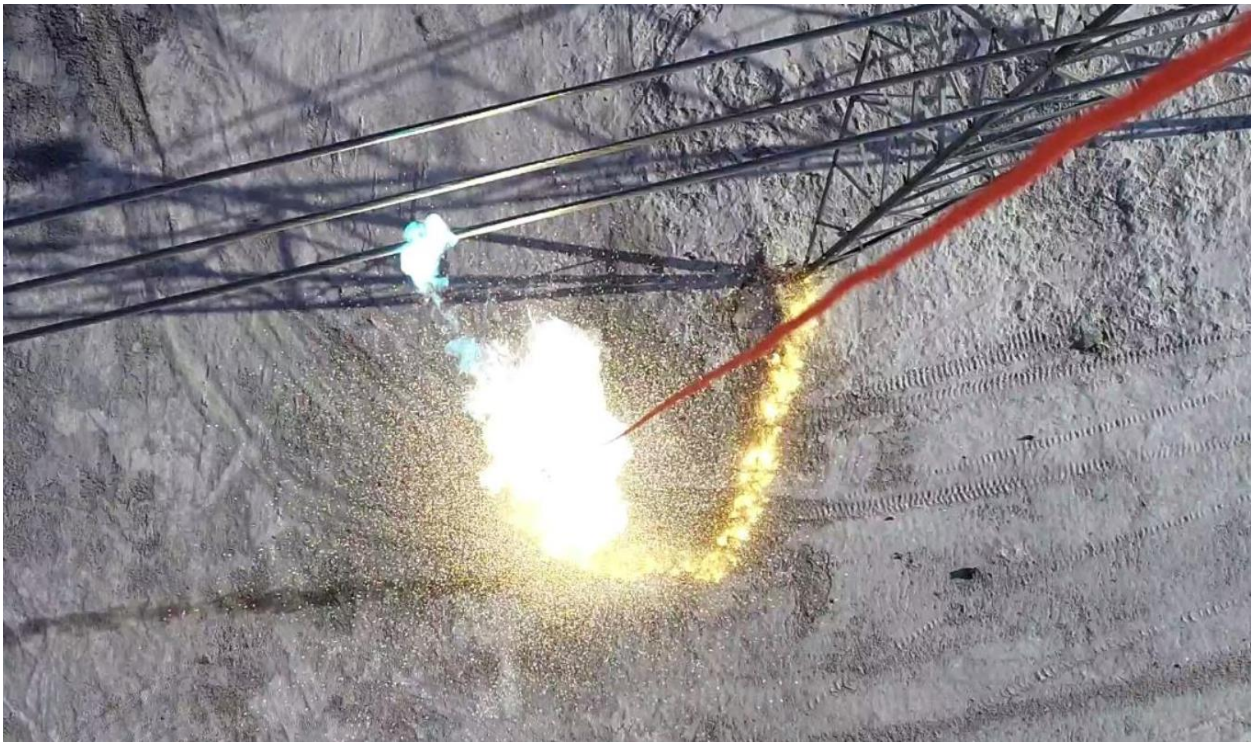


Photo 3: N1 – Environmental Inspection STR 516



Photo: **N1 – Environmental Inspection STR 517**



Photo 5: N1 – C530 Guyed Tower



Photo 6: N1 – Keewatinohk Converter Station



Manitoba Hydro Update on Major Projects to the Public Utilities Board

Keeyask Project Update

Q1 Update ending June 30, 2018



EXECUTIVE SUMMARY

- In 2018, the project requires at least a 10% improvement in the General Civil Contract ("GCC") performance for the remainder of their work and no substantive risks to materialize to achieve the control budget. The schedule is trending towards 10 months ahead of schedule, however, there is still much work remaining this year.
- The control budget for the project remains at $8.7B. There are currently no changes in budget that would impact domestic revenue requirements or Manitoba Hydro's financial forecasts.
- In the last quarter, concrete placements on the Powerhouse Complex and earthworks on the north and south side of the river were completed as planned.
- Actual expenditures to the end of June 30, 2018 were $4.86 billion.

PROJECT UPDATE

Background

- The Keeyask Generating Station is a 7 unit, 695-megawatt hydroelectric generating station under construction at Gull Rapids on the lower Nelson River in northern Manitoba.
- The Keeyask Project is a collaborative effort between Manitoba Hydro and four Manitoba First Nations, working together as the Keeyask Hydropower Limited Partnership.
- Keeyask will be Manitoba's fourth largest generating station and the sixth on the Nelson River.
- Construction of the Keeyask Generating Station commenced on July 16, 2014 after receipt of all required licenses and approvals.
- The Keeyask Project includes construction of the generating station as well as construction of supporting infrastructure. Most of the supporting infrastructure was constructed in advance of commencement of construction of the generating station under the Keeyask Infrastructure Project (KIP).
- The General Civil Works contract, the largest contract on the project, was awarded to BBE Hydro Constructors Limited Partnership consisting of Bechtel Canada Co., Barnard Construction of Canada Ltd. and EllisDon Civil Ltd. The General Civil Works contractor is responsible for rock excavation, concrete for the powerhouse and spillway, earth structures, electrical and mechanical work, and the construction and removal of temporary cofferdams needed to manage the river flow during construction.

Generating Station

- The General Civil Contractor is on track with concrete placements on the Powerhouse complex. Approximately 38,000 m^3 of concrete was placed between April 1 and June 30, 2018. In total there has been approximately 210,000 m^3 of concrete placed on the project; approximately 65 per cent of the total volume of concrete required for the Keeyask Project.
- The Spillway gates, guides and hoist work has been substantially completed which is required to support river diversion activities.
- The project is on track to achieve the river diversion milestone in late summer 2018 where the entire flow of the Nelson River will be channeled through the Spillway. River diversion is a significant milestone for the project and the partner First Nations.
- Work on the South Dyke, North Dam, and Central Dam continues to progress as planned.
- In 2018, the project requires at least a 10% improvement in the GCC performance for the remainder of their work and no substantive risks to materialize to achieve control. The schedule is trending towards 10 months ahead of schedule, however, there is still much work remaining this year.

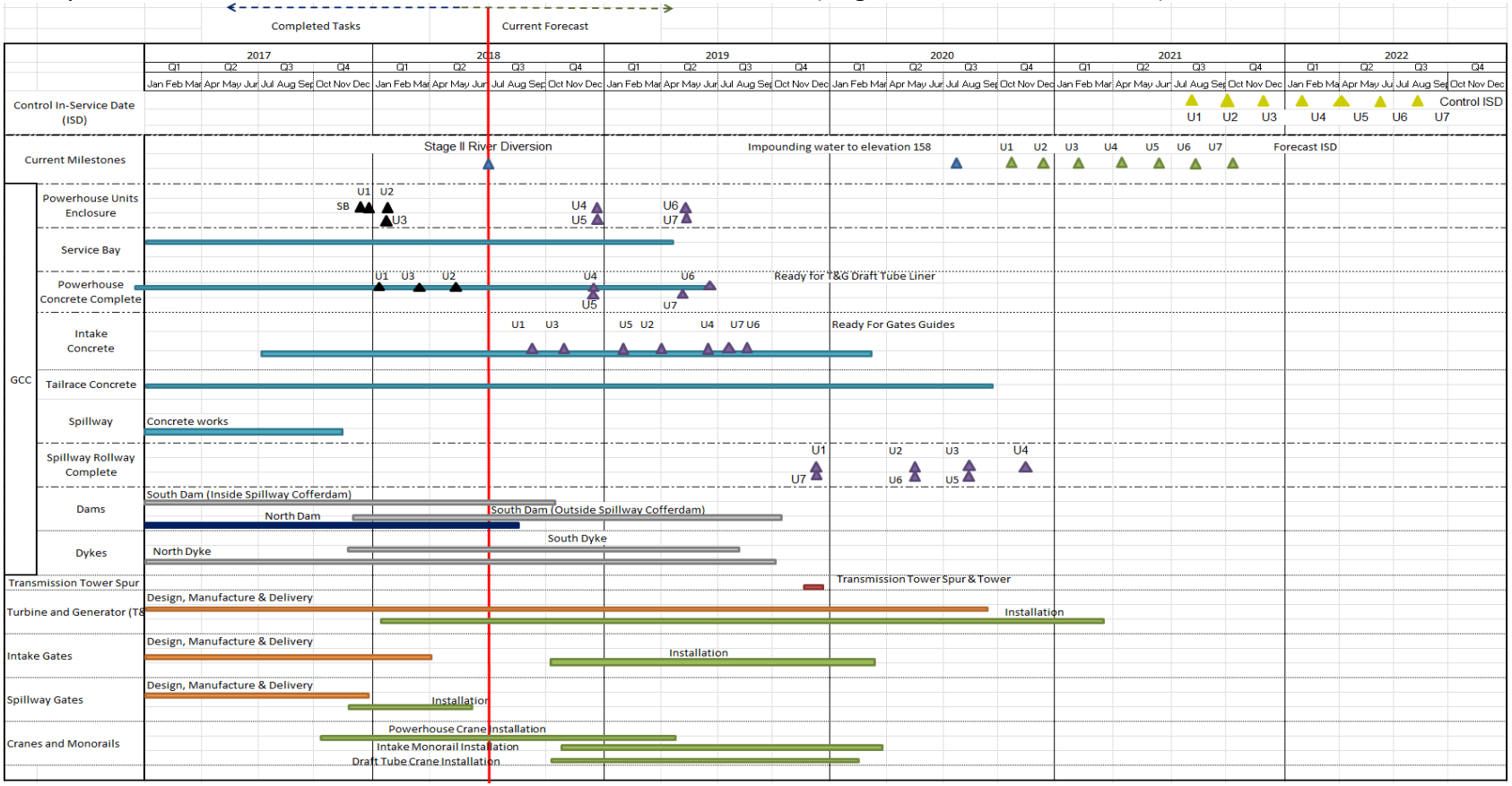
- The top risks include:
    - Execution/productivity rates of the GCC.
    - Loss of site access/work stoppages - Any civil disorder could significantly impact Manitoba Hydro's ability to construct the Keeyask Generating Station on time and on budget.
    - Unexpected geotechnical/geological conditions at the South Dam/Dyke.
    - Unseasonable weather that shortens the warm construction season.

Infrastructure

- Expansion of the main camp by an additional 152 rooms has been completed and will allow the project to accommodate up to 2,500 workers.

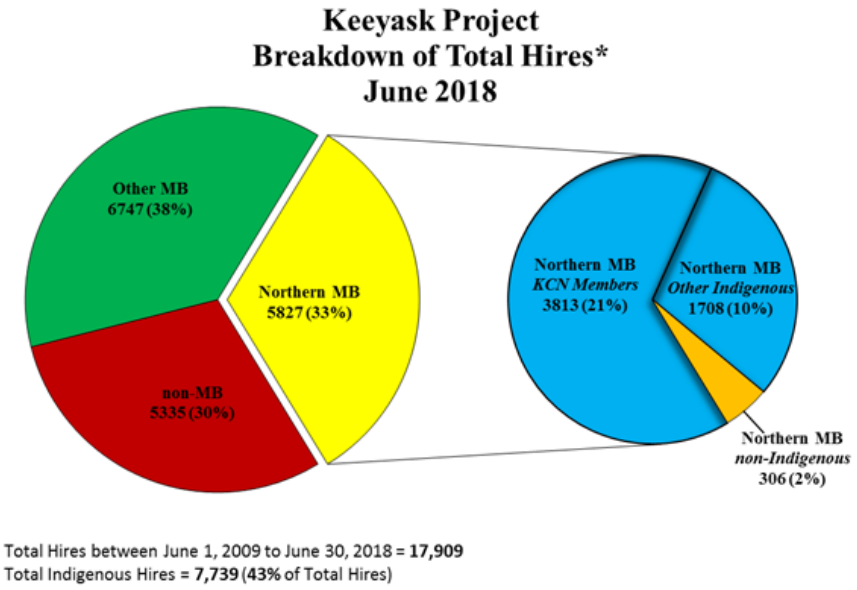
Project Schedule Overview – June 30, 2018

Note: Construction activities, milestones and unit In Service Dates (ISDs) reflect Manitoba Hydro's current forecast schedule. Presently, the forecast for the unit ISDs is in advance of the Control ISDs (August 2021 for first unit ISD).



* This is a summary of MH's current plan broken down to the major component of construction and significant contractors, and how these components and milestones relate to river management and impoundment.
* "Control ISD" reflects MH communicated In-Service-Date ("ISD") dates, while "Current ISD" reflects current planned ISD dates which are currently 10 months ahead of the control ISD.
* Powerhouse concrete remains the project critical path driving the water impoundment. Construction of the dams and dykes are currently off the critical path.

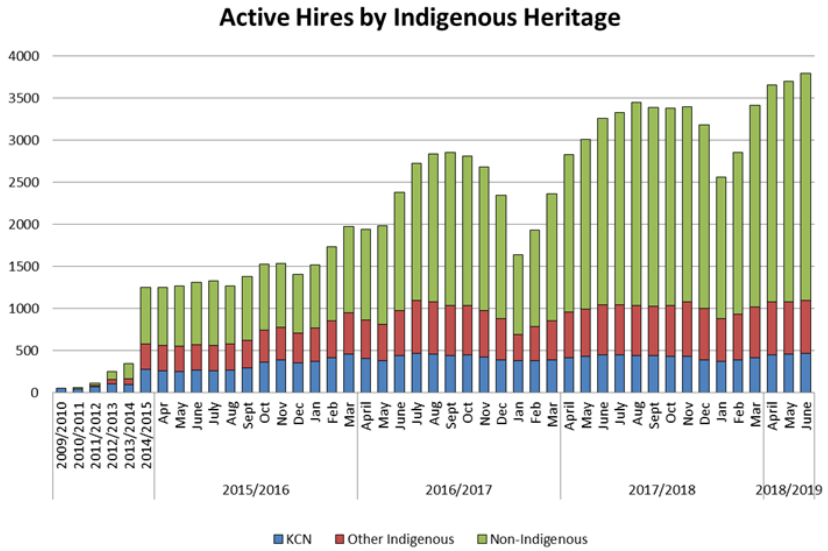
Total Project Hires – as of June 30, 2018



Total Hires between June 1, 2009 to June 30, 2018 = **17,909**
Total Indigenous Hires = **7,739** (**43%** of Total Hires)

- As of June 30, 2018, there have been a total of 17,909 hires on the Keeyask Project. Of these total hires, 70% (12,574) are Manitobans, 43% (7,739) have self-declared as being Indigenous persons and 21% (3,813) of the total hires are Keeyask Cree Nation ("KCN") members.

Active Hires – as of June 30, 2018



- As of June 30, 2018 there were 3,796 active hires on the Keeyask Project. Of these active hires, 54% (2,049) are Manitobans, 29% (1,093) have self-declared as being Indigenous persons and 12% (462) are KCN members.

FINANCIAL SUMMARY

- Actual expenditures to the end of June 30, 2018 were $4.86 billion.

Table A - Keeyask Budget Summary (in Billions $)

Item #	Item	Current Approved Budget (2016$)	Actuals to June 30, 2018
1.1	Generating Station	5.948	4.077
1.2	Generation Outlet Transmission (GOT)	0.202	0.124
1.3	Escalation @ CPI	0.249	0.000
1.4	Interest (including Interest on Equity)	1.749	0.661
1.5	Contingency	0.578	0.000
	Total	**8.726**	**4.862**

Table A Notes:
1. The Escalation and Contingency Components (1.3 and 1.5) will have no actual costs incurred against them; these costs will form part of the actual costs in the Generating Station, Generation Outlet Transmission and Interest Components (1.1, 1.2 and 1.4).

RECENT PHOTOS

Photo #1: Completed Spillway Structure – May 23, 2018



Photo #2: Aerial View of the Spillway and Spillway Cofferdam Removal "in the dry" – June 18, 2018



Photo #3: Central Dam Construction – June 2018



Photo #4: Installed Unit 1 Stay Ring – May 23, 2018

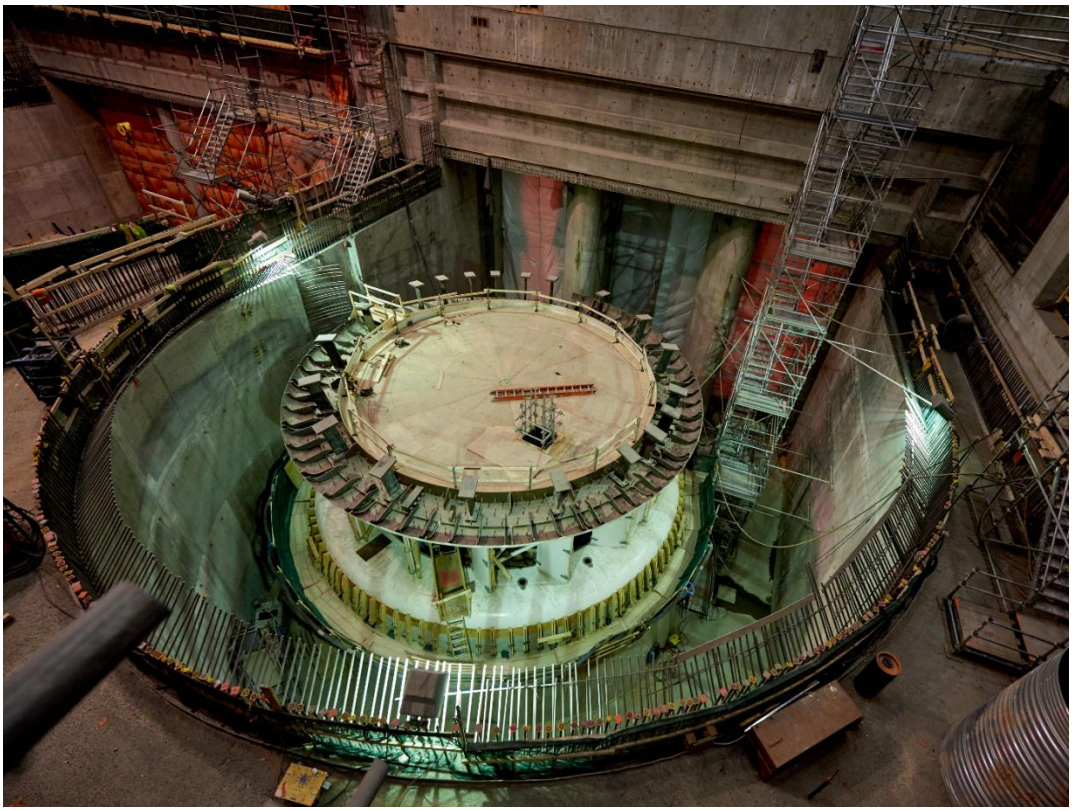


Photo #5 – Lowering Unit 3 Stay Ring into Place – June 11, 2018



Photo #6: Powerhouse Complex – June 15, 2018



MANITOBA – MINNESOTA TRANSMISSION PROJECT

Q1 Update ending June 30, 2018

MMTP Project Description

Manitoba Hydro's capital expenditure forecast includes the construction of a new 500kV Transmission Line between Winnipeg and Duluth, Minnesota (MMTP).

The MMTP transmission line will originate at Dorsey Converter station located near Rosser, northwest of Winnipeg and extend 213 km south around Winnipeg to the Manitoba-Minnesota border, near Piney, Manitoba. The MMTP also includes associated upgrades at Dorsey, Riel and Glenboro stations.

The U.S. portion of the 500 kV line will initiate at the border and terminate at Iron Range Station near Grand Rapids, Minnesota. This project is known as the Great Northern Transmission Line (GNTL), and is being constructed by Minnesota Power.

MMTP Project Update

- Manitoba Hydro is awaiting a licensing decision by Manitoba Sustainable Development, after receiving a positive recommendation from the Manitoba Clean Environment Commission following its environmental hearing.
- Sagkeeng First Nation has filed a request for judicial review of the provincial licensing decision stemming from concerns around section 35 Consultation. Since no license has been issued to date, next steps of this review are yet to be determined.
- The National Energy Board (NEB) hearings for the Project are complete. Oral cross examination took place June 18th-22nd, and the record for the proceedings officially closed June 25th.
- Manitoba Hydro awaits a decision by the NEB on whether to issue a Certificate, which decision is then subject to the approval of the Governor in Council.
- Property acquisition is continuing and as of June 30th, 75% of the private land required along the proposed transmission line route between Vivian, Manitoba and the U.S. Border has been secured.
- In order to secure the project in-service date Manitoba Hydro must move forward with long lead time items such as the material contracts prior to receiving Provincial and Federal regulatory approvals. Failure to do so would result in substantial project delays. Should Manitoba Hydro receive notification that the project will not receive its necessary regulatory approvals, materials may be re-used on future transmission projects in order to recover sunk costs.
- Phase conductor material has been delivered to an existing storage yard, and pre-cast foundation material deliveries have begun.
- Meetings with the tower steel vendors have begun to review manufacturing process and delivery. Manufacturing process has begun in order to meet the delivery date for all tower steel by this fall.
- The Request for Proposal (RFP) documents for two construction contracts were posted on MERX on June 13th, with a closing date of late August, in order to protect an estimated construction start date of December 2018. These contracts will be structured such that construction efforts will be subject to the regulatory approvals.

MANITOBA – MINNESOTA TRANSMISSION PROJECT

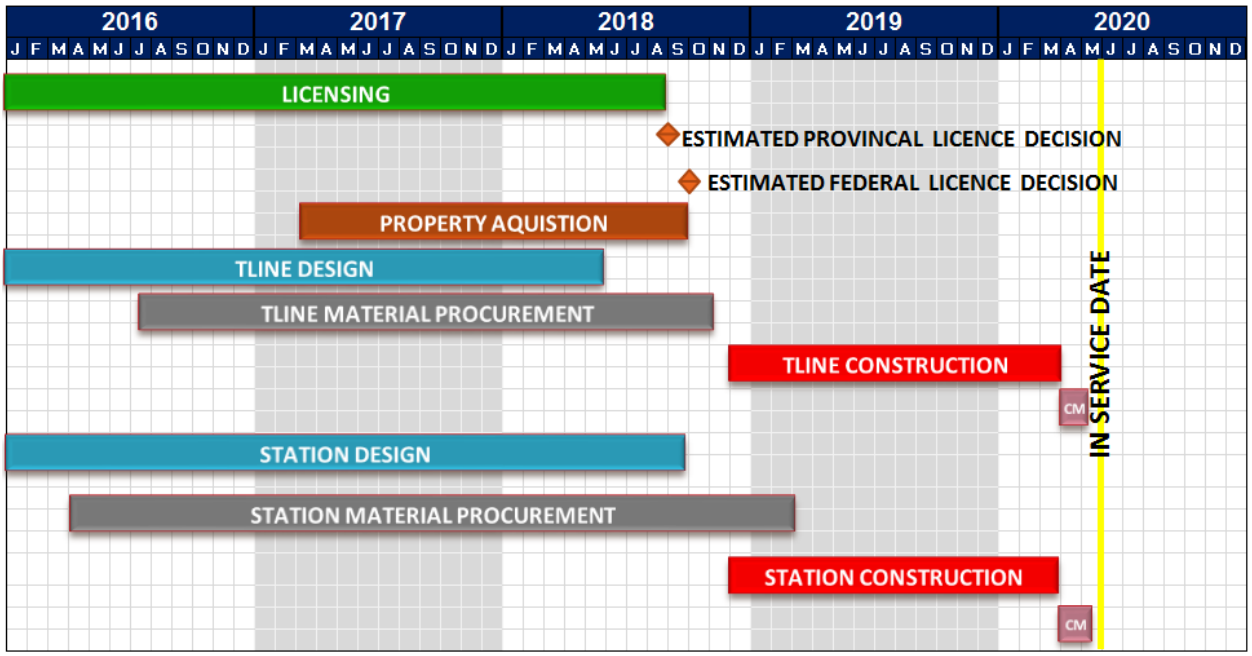
Q1 Update ending June 30, 2018

MMTP Budget

MMTP Budget Summary (in Millions $)			
Item #	**Item**	**Total Project Control Budget**	**Actual costs to June 30, 2018**
1.1	Licensing & Environmental	31.5	20.8
1.2	500 kV Transmission Line *	213.6	44.9
1.3	Station Upgrades*	112.8	8.3
1.4	Contingency	95.3	-
1.5	Total	453.2	73.9

*No construction contracts or contracts above $50 million are currently in place.

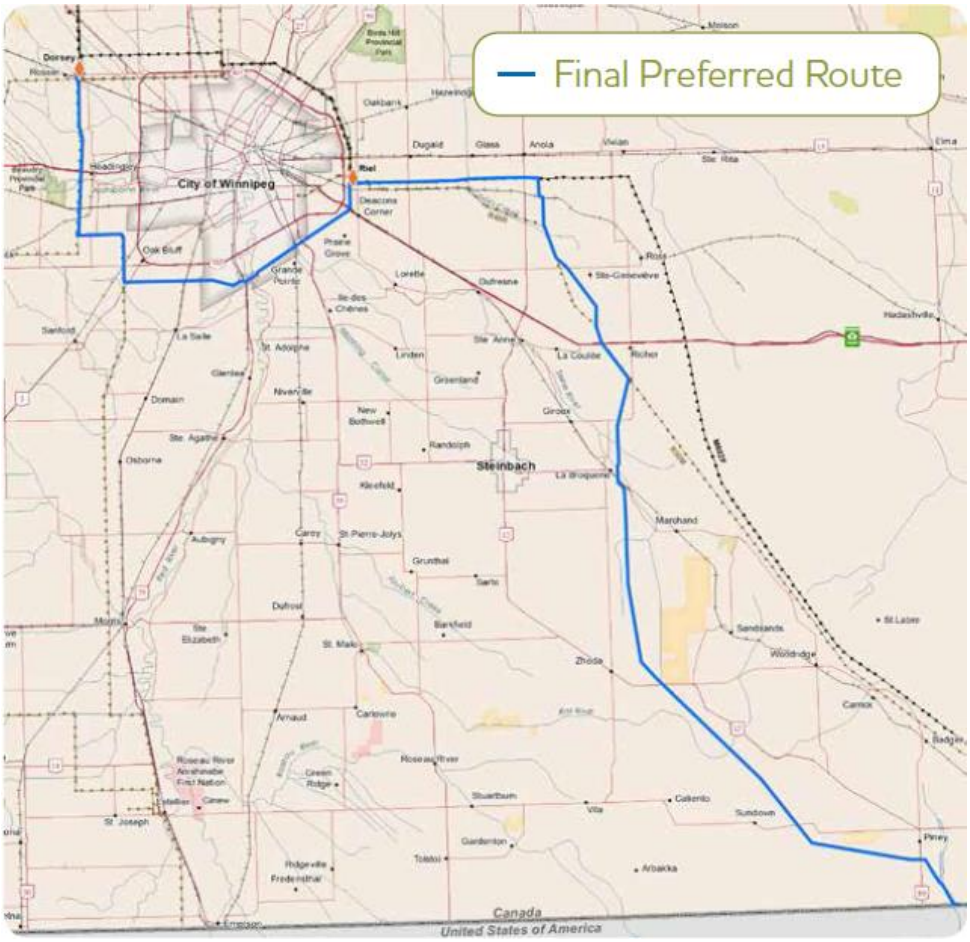
MMTP Project Schedule



MANITOBA – MINNESOTA TRANSMISSION PROJECT

Q1 Update ending June 30, 2018

MMTP Project Route



BIRTLE TRANSMISSION PROJECT

Q1 Update ending June 30, 2018

As noted in the fourth quarter report for the 2017/18 fiscal year, Manitoba Hydro is now providing detailed reports for all projects classified as MNG&T in its Capital Expenditure Forecast. As such, Manitoba Hydro is now filing a separate report on the Birtle Project, in addition to the Bipole, Keeyask, MMTP and GNTL Reports.

Birtle Project Description

Construction of the Manitoba portion of a new 230kV Transmission Line between Birtle, Manitoba and Tantallon, Saskatchewan and additional miscellaneous upgrades to the Manitoba transmission grid is known as the Birtle Transmission Project.

The Birtle transmission line (B71T) will originate at Birtle South Station and extend 46 km to the Manitoba-Saskatchewan border. The Birtle Transmission Project also includes upgrades to transmission line P52E as well as upgrades at Raven Lake, Virden West, and The Pas Ralls Island stations.

Birtle Project Update

- Manitoba Hydro (MH) filed the Environmental Act Proposal for the project on January 30, 2018. The Environmental Approvals Branch (EAB), Technical Advisory Committee submitted Information Requests (IRs) to MH on June 1st. MH met with Provincial regulators on June 27th to describe the routing and border crossing selection process. MH anticipates filing responses to IRs by mid-July. Communication with Provincial regulators will resume over the coming months to ensure they are informed on all aspects of the proposed Project.
- Transmission line design activities are ongoing.
- Land title searches have been largely completed by MH with completion scheduled by July 2018.
- Design for structures, equipment and grounding at Birtle South Station commenced in June and the major apparatus for Birtle South Station has been ordered.

Birtle Budget

Birtle Budget Summary (in Millions $)

Item #	Item	Total Project Control Budget	Actual costs to June 30, 2018
1.1	Licensing & Environmental	4.65	2.07
1.2	Transmission line	43.83	0.49
1.3	Station Upgrades	7.94	0.22
1.4	**Total**[1]	**56.5**	**2.78**

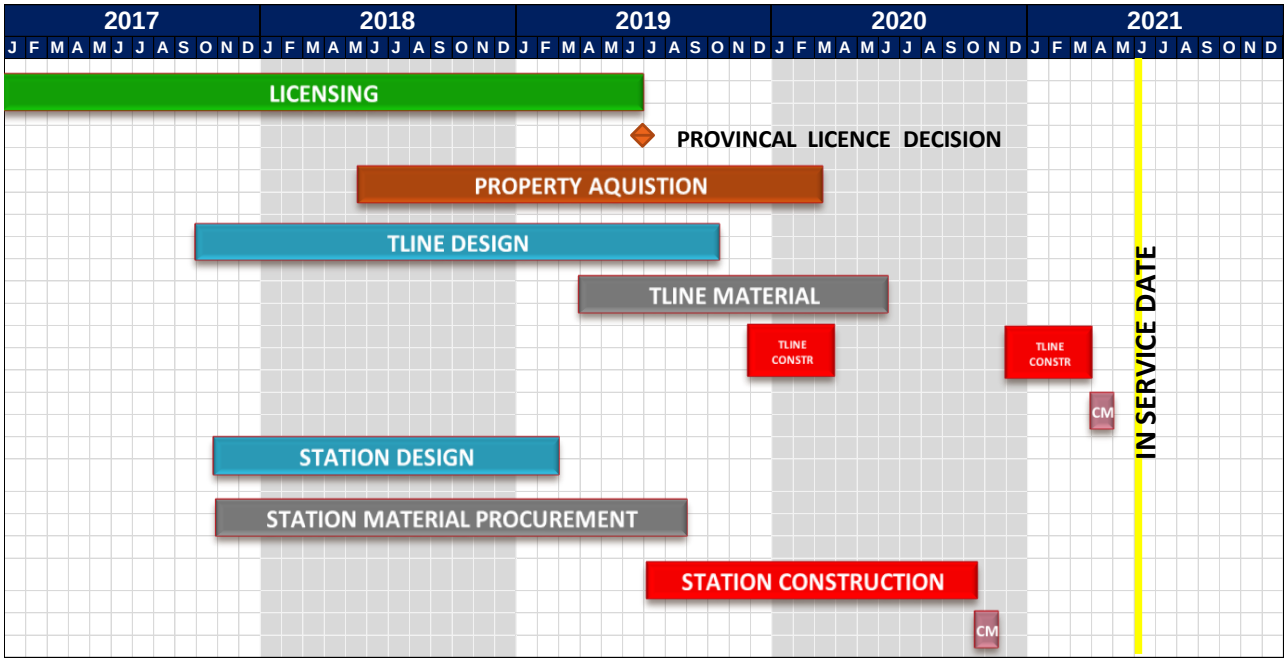
1. In the current control budget contingency is built into the project costs.

Note, there are no construction contracts or contracts above $50 million currently in place.

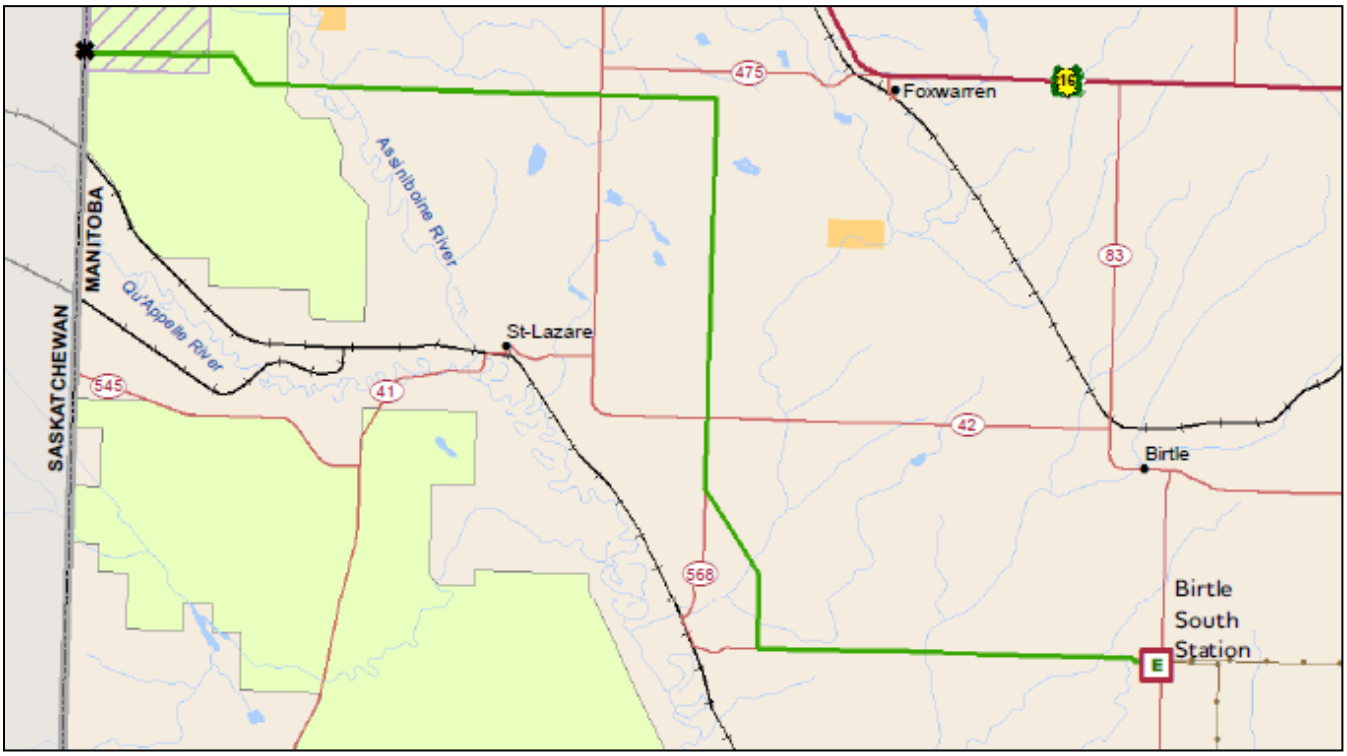
BIRTLE TRANSMISSION PROJECT

Q1 Update ending June 30, 2018

Birtle Project Schedule



Birtle Final Preferred Route Map



Manitoba Hydro Update on Major Projects to the Public Utilities Board

Bipole III Project Update

Q2 Update ending September 30, 2018



Riel Converter Station – Synchronous Condenser

EXECUTIVE SUMMARY

Project Description

Bipole III is a high voltage direct current transmission line that delivers renewable energy to southern Manitoba. Bipole III went into operation in July of 2018.

The Bipole III project included:

- A 1,384-kilometre, 500,000-volt direct current transmission line;
- The Keewatinohk Converter Station in northern Manitoba, northeast of Gillam;
- The Riel Converter Station, east of Winnipeg;
- 230 kV collector lines (5); and,
- Two ground electrodes at each of the new converter stations.

Bipole III adds 2,000 megawatts to Manitoba Hydro's high voltage direct transmission and strengthens the reliability of Manitoba's electricity supply by reducing dependency on existing high voltage direct current transmission lines and the Dorsey Converter Station. Prior to Bipole III, the two existing Bipole lines delivered over 70 per cent of the electricity produced in the province.

Due to its heavy reliance on one transmission corridor and a single converter station in the south (Dorsey), Manitoba Hydro's electricity system was vulnerable to extensive power outages from severe weather (major ice storm, extreme wind event, tornado), fires, or other events. The Riel Converter Station established a second converter station in southern Manitoba, to provide another major point of power injection into the transmission and distribution system.

Background

The Bipole III Project Environment Act Licence was issued August 14, 2013. In fall 2016, a review of the Bipole III budget and schedule was conducted and the budget was increased to $5.04 billion with an in-service date of July 2018.

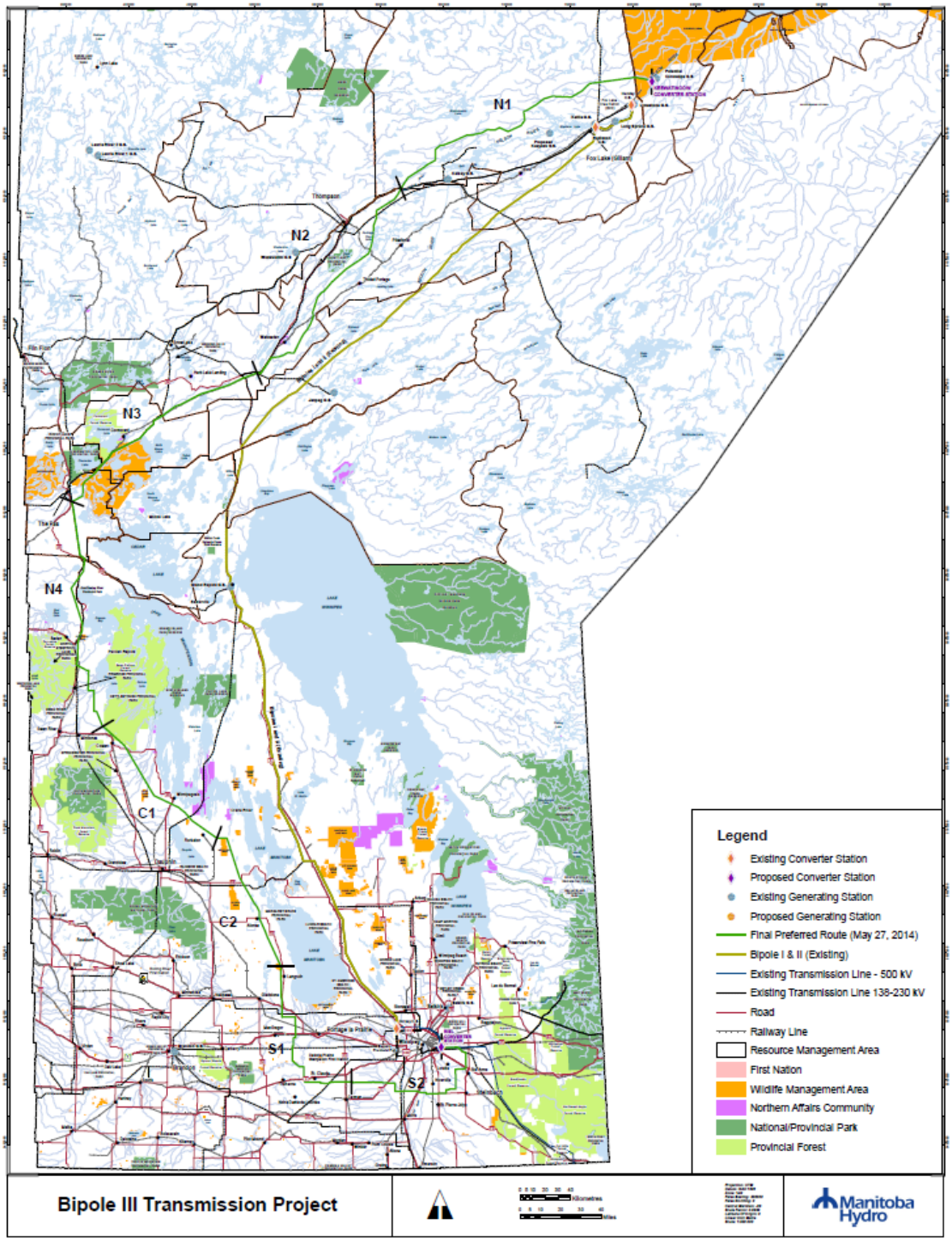
Keewatinohk and Riel Converter Stations
The Bipole III transmission line originates at a new northern converter facility, the Keewatinohk Converter Station, and terminates at a new southern converter facility, the Riel Converter Station. In addition to the new transmission line and the new converter stations, the project included new collector lines linking the Keewatinohk Converter Station to the northern collector system at the existing switchyards at Henday Converter Station and Long Spruce Generating Stations. Each of those facilities required some modifications for these new "collector lines". Each of the new converter stations required the development of a separate ground electrode, connected to the station by a low voltage feeder line.

Transmission Line Construction

The Keewatinohk Converter Station and the Riel Converter Station are linked by a new +/- 500 kV HVDC transmission line approximately 1,384 km in length, centered on a 66 meter wide right-of-way following a route west of lakes Winnipegosis and Manitoba. This new transmission line has been routed as far as practical, sufficiently far from the existing Bipole I and II lines so as to decrease the probability that a single catastrophic weather event or natural disaster would damage both the new transmission line and Bipoles I and II.

Below please find a map of the transmission line segments.

Map of the Bipole III Project



PROJECT UPDATE

On July 4, 2018 Bipole III was turned over for commercial service to Manitoba Hydro operations. With Bipole III now in-service, Manitoba Hydro has been balancing the transmission of HVDC power from northern Manitoba across Bipoles I, II and III.

A Recommendation was approved by Manitoba Hydro's Major Projects Executive Committee (MPEC) on August 28, 2018 to reduce the Bipole III control budget $271.8 million from $5.04 billion to approximately $4.77 billion. The new control budget, will be updated to reflect this number in IFF/CEF19.

The remaining work on the project includes the completion of the fourth and final synchronous condenser which is expected to be completed in November of 2018, the decommissioning of the temporary infrastructure at the Keewatinohk site, construction of a permanent water treatment plant and staff facilities at Keewatinohk.

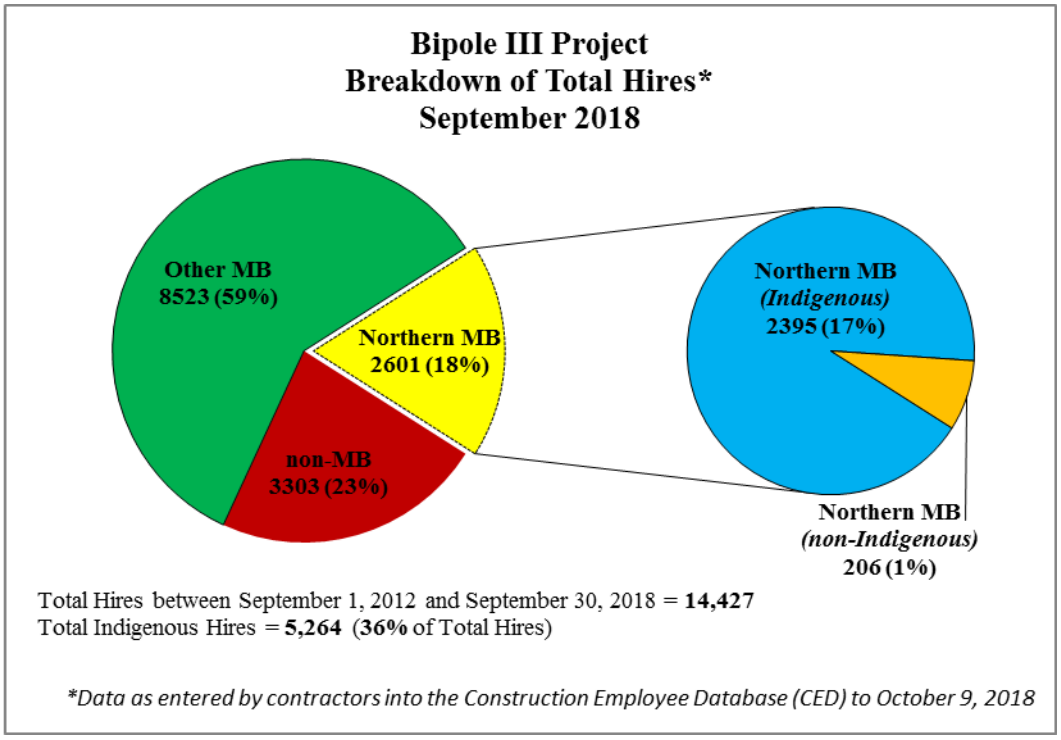
At the Keewatinohk Converter Station, A KWIS KI MAHKA, a joint venture company with Fox Lake Cree Nation has mobilized to site as part of the direct negotiated contract for the decommissioning and remediation of the site and the sewage lagoon.

Total Hires: – as of September 30, 2018

- Since September 2012 there have been a total of 14,427 hires to the Bipole III project.
- Of the total hires, 77% have been Manitoban, including 18% northern Manitobans.
- 36% of total hires have self-declared as being Indigenous.
    - 39% of Keewatinohk, 16% of Riel and 46% of the transmission line have self-declared as being Indigenous.

Active hires will no longer be reported under the Project. With the construction and commissioning phases near completion, the number of active hires is minimal.

Additional information is provided below regarding the percentage of project hires (Manitoban – both Northern and Other, along with non-Manitobans).



FINANCIAL SUMMARY

- A Recommendation was approved by Manitoba Hydro's MPEC on August 28, 2018 to reduce the Bipole III control budget $271.8 million from $5.04 billion to approximately $4.77 billion. The new control budget, will be updated to reflect this number in IFF/CEF19.
- Expenditures were $4.43 billion to the end of September 30, 2018.

Table A - Bipole III Budget Summary (in Billions $)

Item #	Item	Current Approved Budget (2016$)	Actuals to Sept 30, 2018
1.1	Transmission Line	1.457	1.505
1.2	Converter Stations	2.285	2.247
1.3	Collector Lines	0.199	0.193
1.4	Community Development Initiative	0.053	0.053
1.5	Escalation @ CPI	0.052	0.000
1.6	Interest (Capitalized)	0.487	0.435
1.7	Contingency	0.509	0.000
1.8	Total	5.042	4.433

Table A Notes:

1. The Escalation and Contingency Components (1.5 and 1.7) will have no actual costs incurred against them; these costs will form part of the actual costs in the Transmission Line, Converter Stations, Collector Lines, Community Development Initiative and Interest Components (1.1, 1.2, 1.3, 1.4 and 1.6).

Manitoba Hydro Update on Major Projects to the Public Utilities Board

Keeyask Project Update

Q2 Update ending September 30, 2018



EXECUTIVE SUMMARY

- Entering the 2018 construction season, the project required at least a 10% improvement in the General Civil Contract ("GCC") performance for the remainder of their work and no substantive risks to materialize to achieve the control budget. This year's progress to date has been positive and the cost of the project is tracking to the $8.7B control budget. The first unit In-Service Date (ISD) is trending towards 10 months ahead of schedule. While these results are positive, there is still a lot of work remaining.
- The control budget for the project remains at $8.7B. There are currently no changes in budget that would impact domestic revenue requirements or Manitoba Hydro's financial forecasts.
- In late August 2018, the Nelson River was successfully diverted through the spillway on schedule. River diversion is a significant milestone for the project and our First Nation partners. Concrete and earthworks placements were completed as planned.
- Actual expenditures to the end of September 30, 2018 were $5.21 billion.

PROJECT UPDATE

Background

- The Keeyask Generating Station is a 7 unit, 695-megawatt hydroelectric generating station under construction at Gull Rapids on the lower Nelson River in northern Manitoba.
- The Keeyask Project is a collaborative effort between Manitoba Hydro and four Manitoba First Nations, working together as the Keeyask Hydropower Limited Partnership.
- Keeyask will be Manitoba's fourth largest generating station and the sixth on the Nelson River.
- Construction of the Keeyask Generating Station commenced on July 16, 2014 after receipt of all required licenses and approvals.
- The Keeyask Project includes construction of the generating station as well as construction of supporting infrastructure. Most of the supporting infrastructure was constructed in advance of commencement of construction of the generating station under the Keeyask Infrastructure Project (KIP).
- The General Civil Works contract, the largest contract on the project, was awarded to BBE Hydro Constructors Limited Partnership consisting of Bechtel Canada Co., Barnard Construction of Canada Ltd. and EllisDon Civil Ltd. The General Civil Works contractor is responsible for rock excavation, concrete for the powerhouse and spillway, earth structures, electrical and mechanical work, and the construction and removal of temporary cofferdams needed to manage the river flow during construction.

Generating Station

- The General Civil Works Contractor (GCC) is on track for concrete placements on the Powerhouse complex. Approximately 87,000 m^3 of concrete has been placed so far in 2018. In total there has been approximately 250,000 m^3 of concrete placed on the project; approximately 77 per cent of the total volume of concrete required for the Keeyask Project.
    - The production rate and cost performance for concrete placements has improved in 2018 over the rates achieved in 2017 and the project is tracking to surpass the 2018 concrete production target.
- Unit 4 & 5 structural steel framing has been completed and the project is on track to enclose units 4 & 5 by the end of the year. Enclosure of these units will allow the Turbine and Generator contractor to install the embedded parts on units 4 & 5 this winter.
- Earthworks continued throughout the quarter as planned on the North Dam, Central Dam, South Dam Cofferdam and South Dyke. The North Dam was completed in the quarter to its final elevation. To the end of September 2018, approximately 94% of the planned 2018 earthworks quantities have been placed.

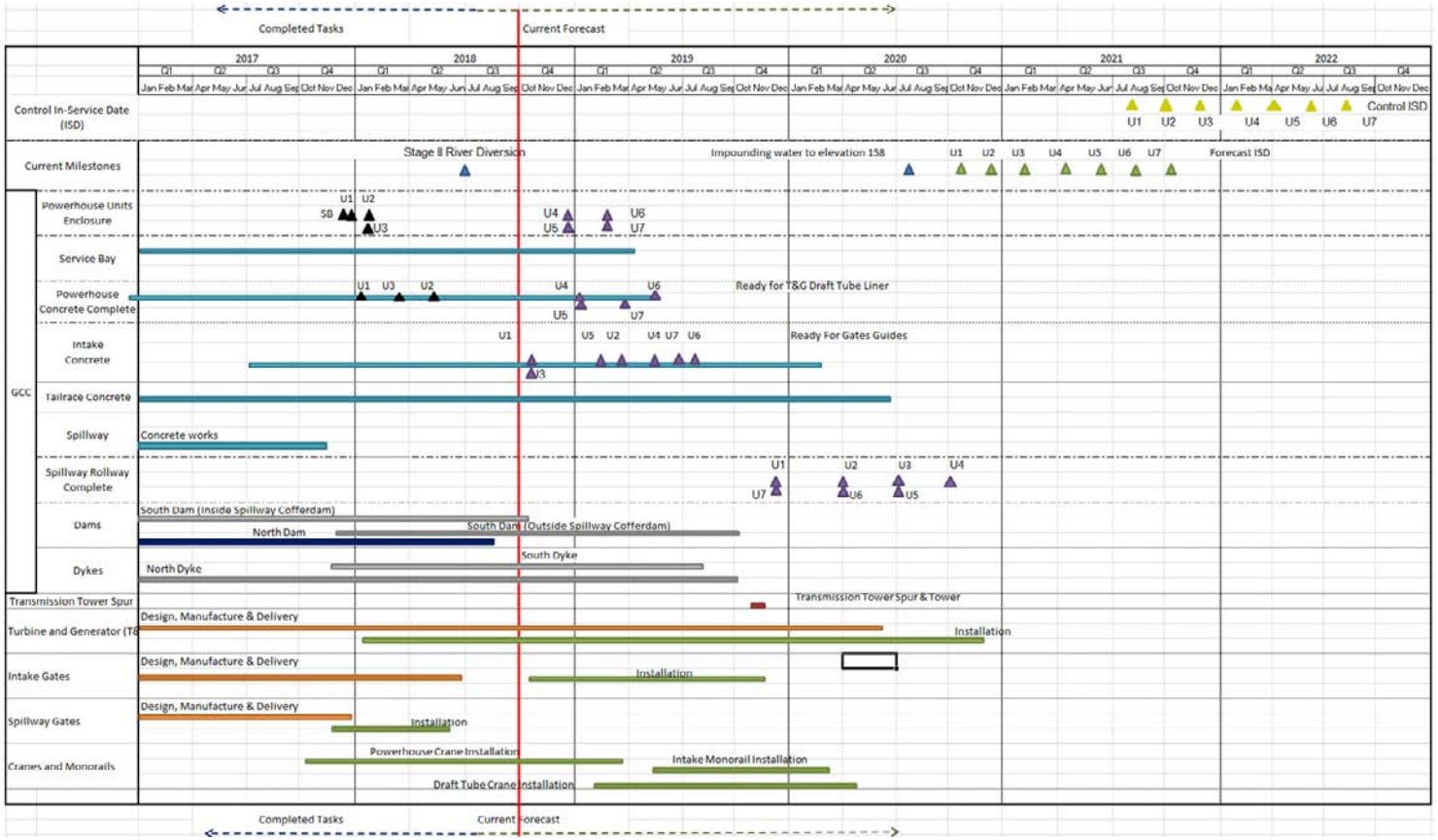
  - The production rate and cost performance for earthworks has improved in 2018 over the rates achieved in 2017 and the project is tracking to surpass the 2018 earthworks production goal.
- The Spillway gates, guides and hoists were commissioned over the summer allowing for the Nelson River to be successfully diverted through the Spillway in August 2018. The rock groins for the South Dam Cofferdam were constructed in August allowing for the entire flow of the river to be passed through the Spillway. Achievement of river diversion is an important milestone for both construction as well as for our First Nation partners. A river diversion ceremony was held with our First Nation partners at site on August 31 to recognize the significance of the permanent change to the waterway.
- Work is progressing on the turbines and generators. The unit 2 stay ring was installed and handed back to the GCC to complete the remaining concrete work. The assembly of the units 4 and 5 draft tube liners continues and are on track for installation this winter within the enclosed section of the Powerhouse.
- The top risks include:
  - Execution/productivity rates of the GCC.
  - Loss of site access/work stoppages - Any civil disorder could significantly impact Manitoba Hydro's ability to construct the Keeyask Generating Station on time and on budget.
  - Unexpected geotechnical/geological conditions at the South Dam/Dyke.
  - Unseasonable weather that shortens the warm construction season.

Infrastructure

- The construction of the rock groins across the south channel of the Nelson River allows construction traffic to travel across the river for the first time. Direct access from the project site to Gillam via the South Access Road is now possible, reducing travel time between Gillam and the project site by over 1 hour.

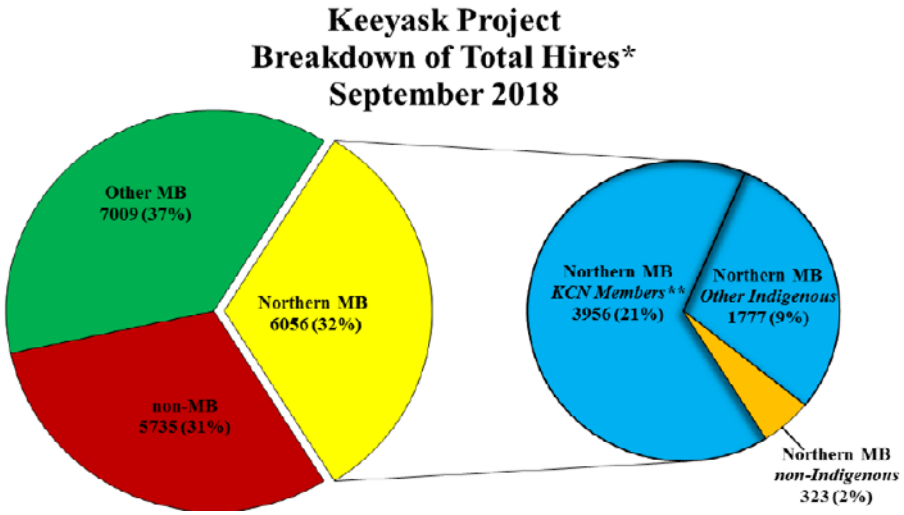
Project Schedule Overview – September 30, 2018

Note: Construction activities, milestones and unit ISDs reflect Manitoba Hydro's current forecast schedule. Presently, the forecast for the unit ISDs is in advance of the Control ISDs (August 2021 for first unit ISD).



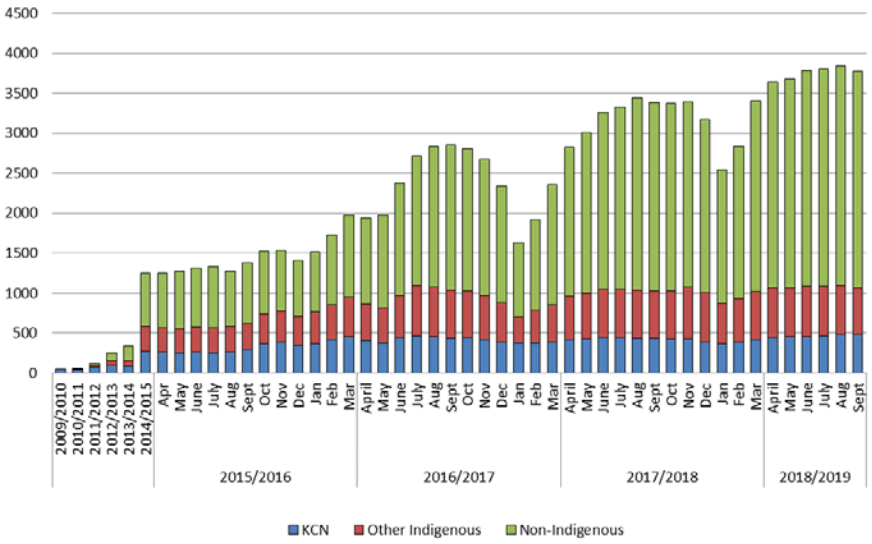
* This is a summary of MH's current plan broken down to the major component of construction and significant contractors, and how these components and milestones relate to river management and impoundment.
* "Control ISD" reflects MH communicated In-Service-Date ("ISD") dates, while "Current ISD" reflects current planned ISD dates which are currently 10 months ahead of the control ISD.
* Powerhouse concrete remains the project critical path driving the water impoundment. Construction of the dams and dykes are currently off the critical path.
*MH and Voith are working together to rework the Turbine and Generator schedule.

Total Project Hires – as of September 30, 2018



- As of September 30, 2018, there have been a total of 18,800 hires on the Keeyask Project. Of these total hires, 69% (13,065) are Manitobans, 43% (8,049) have self-declared as being Indigenous persons and 21% (3,976) of the total hires are Keeyask Cree Nation ("KCN") members.

Active Hires – as of September 30, 2018



- As of September 30, 2018 there were 3,771 active hires on the Keeyask Project. Of these active hires, 52% (1,979) are Manitobans, 28% (1,065) have self-declared as being Indigenous persons and 13% (481) are KCN members.

FINANCIAL SUMMARY

- Actual expenditures to the end of September 30, 2018 were $5.21 billion.

Table A - Keeyask Budget Summary (in Billions $)			
Item #	Item	Current Approved Budget (2016$)	Actuals to September 30, 2018
1.1	Generating Station	5.948	4.363
1.2	Generation Outlet Transmission (GOT)	0.202	0.136
1.3	Escalation @ CPI	0.249	0.000
1.4	Interest (including Interest on Equity)	1.749	0.709
1.5	Contingency	0.578	0.000
	Total	**8.726**	**5.208**

Table A Notes:
1. The Escalation and Contingency Components (1.3 and 1.5) will have no actual costs incurred against them; these costs will form part of the actual costs in the Generating Station, Generation Outlet Transmission and Interest Components (1.1, 1.2 and 1.4).

RECENT PHOTOS

Photo #1: Powerhouse Construction – September 30, 2018



Photo #2: Installation of the Unit 2 Stay Ring (Turbine and Generator embedded component) – September 18, 2018



Photo #3: Aerial View of the Spillway and Spillway Cofferdam Removal "in the wet" pre-river diversion – July 5, 2018



Photo #4: River Diversion Ceremony – August 31, 2018



Photo #5: Aerial view of the Nelson River post River Diversion – August 28, 2018



Photo #6: Dewatering and Excavation within the South Dam Cofferdam – September 30, 2018



Photo #7: North Dam at Final Elevation – September 1, 2018



Photo #8: Central Dam Construction – September 30, 2018



MMTP Project Description

Manitoba Hydro's capital expenditure forecast includes the construction of a new 500kV Transmission Line between Winnipeg and Duluth, Minnesota (MMTP).

The MMTP transmission line will originate at Dorsey Converter station located near Rosser, northwest of Winnipeg and extend 213 km south around Winnipeg to the Manitoba-Minnesota border, near Piney, Manitoba. The MMTP also includes associated upgrades at Dorsey, Riel and Glenboro stations.

The U.S. portion of the 500 kV line will initiate at the border and terminate at Iron Range Station near Grand Rapids, Minnesota. This project is known as the Great Northern Transmission Line (GNTL), and is being constructed by Minnesota Power.

MMTP Project Update

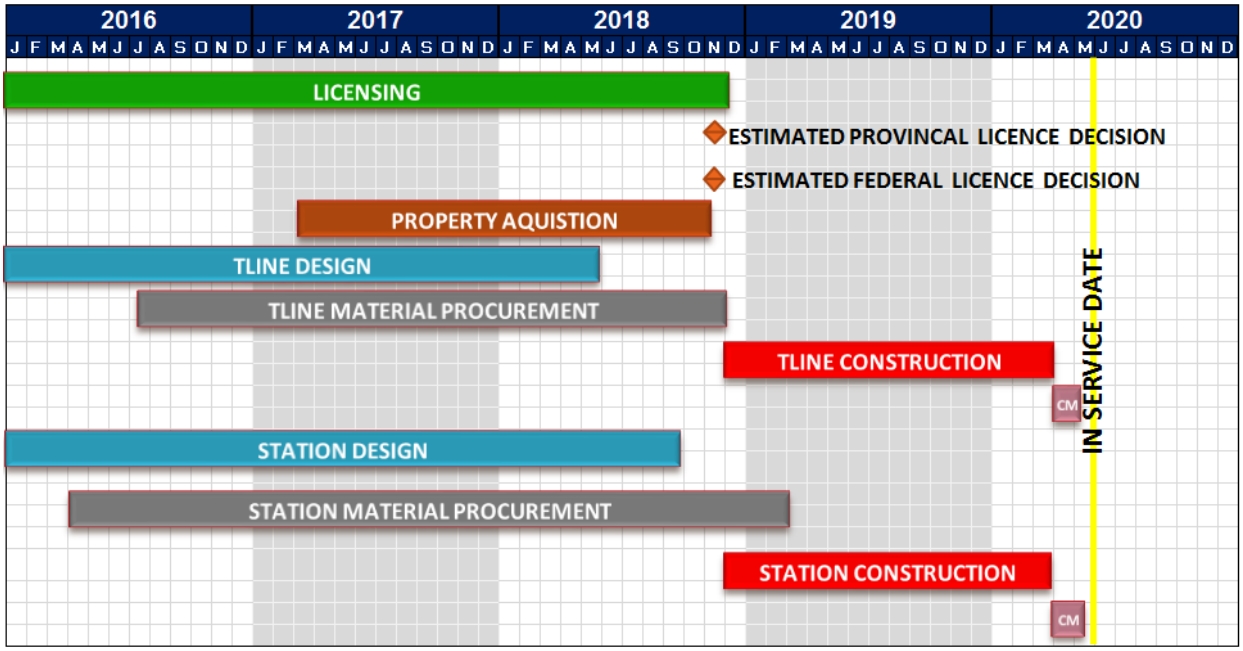
- Manitoba Hydro is awaiting a licensing decision by Manitoba Sustainable Development. Sagkeeng First Nation has filed a request for judicial review of the provincial licensing decision stemming from concerns around section 35 Consultation (aboriginal rights). Sagkeeng First Nation has put their judicial review of MMTP into abeyance until licensing decisions have been made.
- The National Energy Board (NEB) hearings for the Project were completed in June.
- Manitoba Hydro now awaits a decision and recommendation by the NEB on whether to issue a Certificate, which decision is then subject to the approval of the Governor in Council.
- Property acquisition is continuing and as of September 30th, just over 75% of the private land required along the proposed transmission line route between Vivian, Manitoba and the U.S. Border has been secured.
- In order to secure the project in-service date Manitoba Hydro must move forward with long lead time items such as the material contracts prior to receiving Provincial and Federal regulatory approvals. Failure to do so would result in substantial project delays. Should Manitoba Hydro receive notification that the project will not receive its necessary regulatory approvals, materials may be re-used on future transmission projects in order to recover sunk costs.
- Pre-cast foundation material deliveries are continuing to the existing material storage yard, and tower steel manufacturing is on track for deliveries to begin later this fall.
- The Request for Proposal (RFP) documents for two construction contracts were posted on MERX on June 13th, in order to protect an estimated construction start date of December 2018. The RFP closed on August 20th and bid submissions are being evaluated. Contracts will be awarded following receipt of regulatory approvals.

MMTP Budget

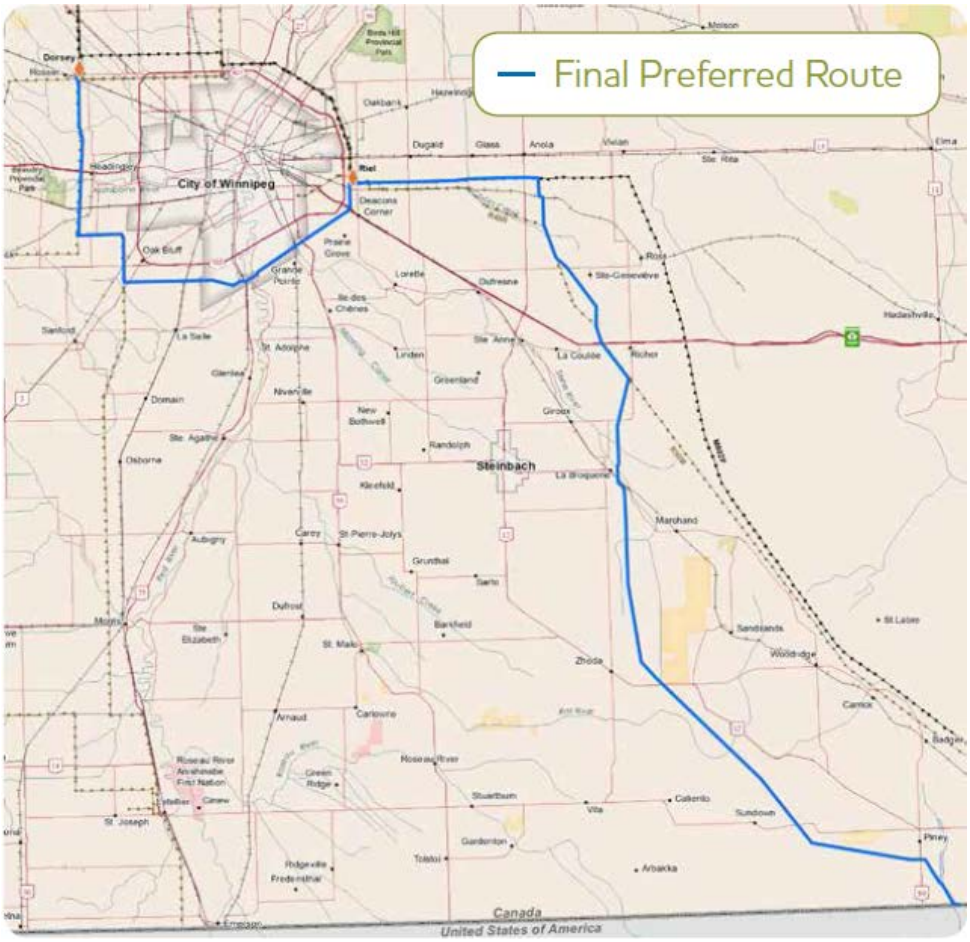
MMTP Budget Summary (in Millions $)			
Item #	**Item**	**Total Project Control Budget**	**Actual costs to Sept 30, 2018**
1.1	Licensing & Environmental	31.5	22.0
1.2	500 kV Transmission Line *	213.6	46.8
1.3	Station Upgrades*	112.8	11.7
1.4	Contingency	95.3	-
1.5	**Total**	**453.2**	**80.6**

*No construction contracts above $50 million are currently in place.

MMTP Project Schedule



MMTP Project Route



Birtle Project Description

Construction of the Manitoba portion of a new 230kV Transmission Line between Birtle, Manitoba and Tantallon, Saskatchewan is known as the Birtle Transmission Project. The Birtle transmission line (B71T) will originate at Birtle South Station and extend 46 km to the Manitoba-Saskatchewan border. The Birtle Transmission Project also includes upgrades to transmission line P52E as well as upgrades at Raven Lake, Virden West, and The Pas Ralls Island stations.

Birtle Project Update

- Manitoba Hydro (MH) filed the Environmental Act Proposal for the project on January 30, 2018. The license is anticipated to be received in June, 2019. Manitoba Sustainable Development is no longer considering changes to the Final Preferred Route to avoid the Spy Hill-Ellice Community Pasture and have moved forward with Section 35 consultation planning.
- Transmission line design activities are ongoing, with preliminary tower spotting completed. Material procurement for towers is expected commence in spring 2019.
- Land title searches have been completed for property acquisition. Land appraisals will be initiated in November 2018 and landowner discussions with property land agents are scheduled to begin in December 2018.
- Station Design activities for Birtle South Station are continuing. All major apparatus has been ordered with deliveries expected by August 2019.

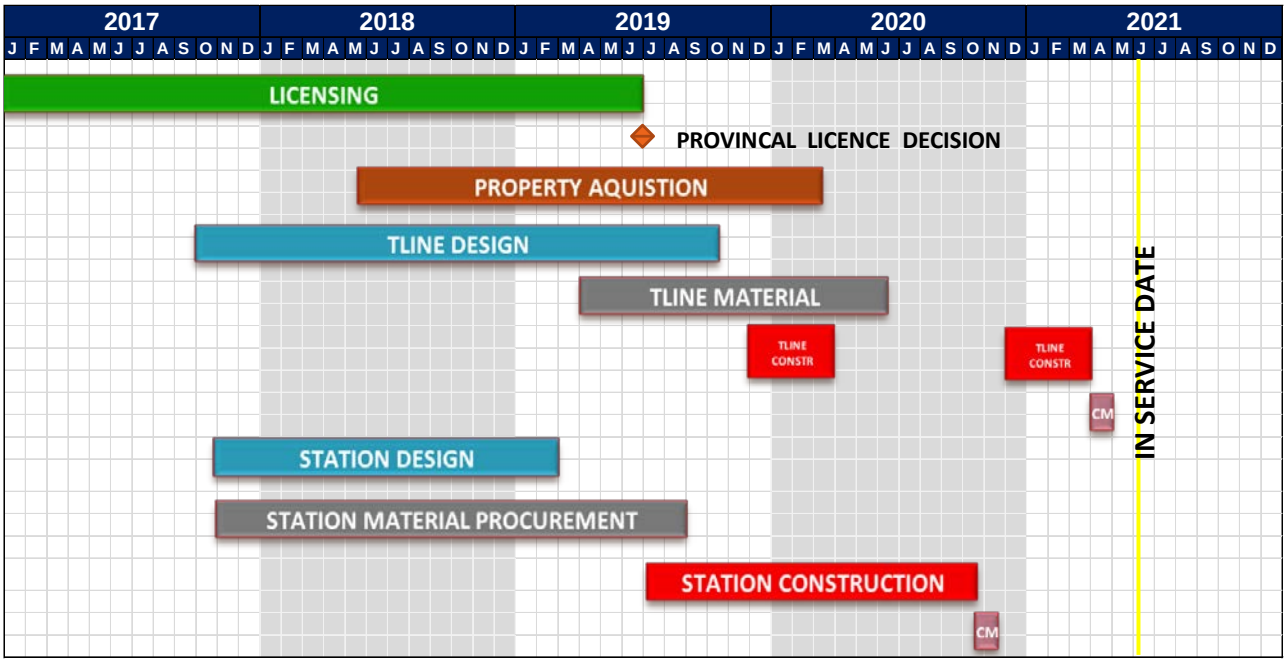
Birtle Budget

Birtle Budget Summary (in Millions $)			
Item #	**Item**	**Total Project Control Budget**	**Actual costs to Sept 30, 2018**
1.1	Licensing & Environmental	4.65	2.14
1.2	Transmission line[1]	43.83	0.54
1.3	Station Upgrades	7.94	0.28
1.4	**Total[2]**	**56.5**	**2.96**

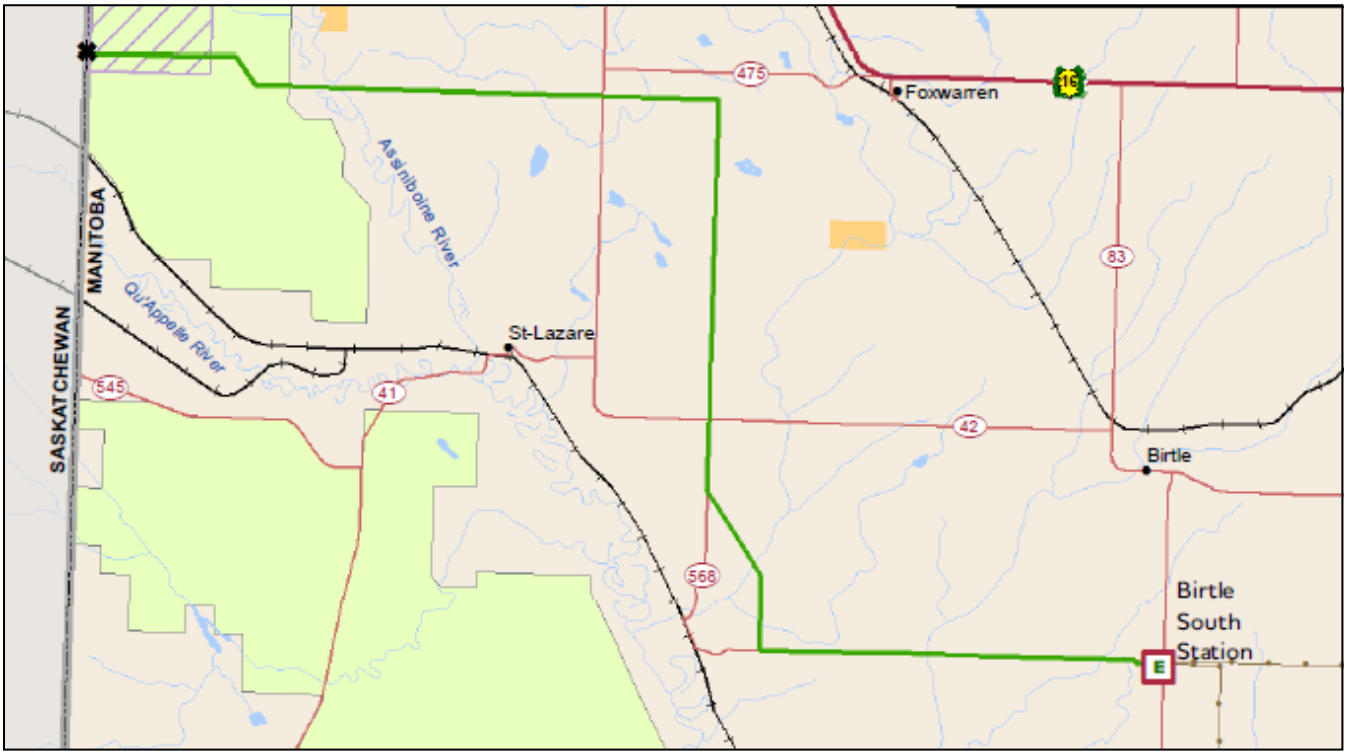
1. In the current control budget contingency is built into the project costs.

Note: there are no construction contracts or contracts above $50 million currently in place.

Birtle Project Schedule



Birtle Final Preferred Route Map



RESPONSE TO DIRECTIVE #14 – BOARD ORDER 73/15

For Year Ended March 31, 2018

14. *Manitoba Hydro shall file quarterly updates regarding its Operation, Maintenance & Administration (OM&A) expenditures and the actual OM&A expenditures compared to Manitoba Hydro's target.*

Manitoba Hydro's Operating and Administrative (O&A) expenses for Electric Operations for the year-ended 2017/18 were $516.8 million, a decrease of $19.0 million or 3.5% as compared to year ended 2016/17. The decrease is primarily due to a reduction in employee-related expenditures resulting from the corporate restructuring initiative, as well as a reduction in consulting and professional fees related to the completion of the strategic initiative funding program in 2017, and other work such as Wuskwatim Aquatic Monitoring, interconnection studies, power sale negotiations and ARC flash studies. This is partially offset by an increase in uncollectible accounts reflecting a change in the collectability for certain accounts, an increase in construction and maintenance services as a result of increased vegetation management treatment costs, and an increase in maintenance requirements at Jenpeg associated with water head bearing repairs and airport road maintenance.

O&A expenses for the year ending March 31, 2018 were on target with forecast reflecting a minimal variance of $1.5 million lower than forecast or 0.3%.

A summary of Manitoba Hydro's actual 2017/18 O&A expenditures by cost element with a comparison to the 2016/17 year end expenditures and 2017/18 forecast has been provided in the table below.

ELECTRIC OPERATIONS
OPERATING & ADMINISTRATIVE COSTS BY COST ELEMENT
FOR THE YEAR ENDING MARCH 31
(in Thousands of Dollars)

	2016/17 Actual	2017/18 Actual	2017/18 Forecast	Favourable (Unfavourable) Variance
Employee Related Expenditures				
Wages & salaries	$517 311	$493 691		
Overtime	72 256	75 095		
Employee benefits	165 924	156 884		
Other	71 944	68 232		
Total Employee Related Expenditures	827 435	793 902		
Less: Capitalized labour and overhead	(345 763)	(336 400)		
Operational Employee Related Expenditures	481 672	457 502		
External services and materials	126 024	122 842		
Donations, sponsorships & grants	2 134	2 434		
Uncollectible accounts	4 266	12 375		
Other	2 820	1 202		
Cost recoveries	(15 706)	(16 387)		
O&A charged to gas operations	(65 384)	(63 113)		
Operating & Administrative Expenses	**535 826**	**516 855**	**518 340**	**1 485**

RESPONSE TO DIRECTIVE #14 – BOARD ORDER 73/15

For Three Quarter Ended June 30, 2018

14. *Manitoba Hydro shall file quarterly updates regarding its Operation, Maintenance & Administration (OM&A) expenditures and the actual OM&A expenditures compared to Manitoba Hydro's target.*

Manitoba Hydro's Operating and Administrative (O&A) expenses for Electric Operations for the first quarter of 2018/19 were $123.1 million, a decrease of $14.8 million or 10.7% as compared to the first quarter of 2017/18. The decrease is primarily due to a reduction in employee related expenditures as a result of the voluntary departure program.

O&A expenses for the first quarter of 2018/19 were $4.3 million or 3.4% lower than forecast primarily due to primarily due to an unallocated contingency forecast for transitional business requirements which may be required as a result of the VDP, the timing of requirements for consulting and professional services and delays in awarding vegetation management contracts.

A summary of Manitoba Hydro's actual and forecast O&A expenditures by cost element with a comparison to the 2017/18 first quarter expenditures has been provided in the table below.

ELECTRIC OPERATIONS
OPERATING & ADMINISTRATIVE COSTS BY COST ELEMENT
FOR THE QUARTER ENDED JUNE 30
(in Thousands of Dollars)

	2017/18 Actual	2018/19 Actual	2018/19 Forecast	Favourable (Unfavourable) Variance
Employee Related Expenditures				
Wages & salaries	$129 393	$114 967	$116 922	$1 955
Overtime	20 730	20 138	21 069	931
Employee benefits	45 579	38 477	38 877	400
Other	17 262	17 092	18 276	1 184
Total Employee Related Expenditures	212 964	190 674	195 144	4 470
Less: Capitalized labour and overhead	(85 132)	(78 846)	(83 815)	(4 969)
Operational Employee Related Expenditures	127 832	111 828	111 329	(499)
External services and materials	28 968	29 456	32 226	2 770
Donations, sponsorships & grants	661	546	535	(11)
Uncollectible accounts	1 093	1 079	1 066	(13)
Other	76	121	2 005	1 884
Cost recoveries	(3 817)	(4 267)	(3 648)	619
O&A charged to gas operations	(16 917)	(15 679)	(16 111)	(432)
Operating & Administrative Expenses	**137 896**	**123 084**	**127 403**	**4 319**

RESPONSE TO DIRECTIVE #14 – BOARD ORDER 73/15

For the Quarter Ended September 30, 2018

14. *Manitoba Hydro shall file quarterly updates regarding its Operation, Maintenance & Administration (OM&A) expenditures and the actual OM&A expenditures compared to Manitoba Hydro's target.*

Manitoba Hydro's Operating and Administrative (O&A) expenses for Electric Operations for the second quarter of 2018/19 was $249.5 million, as compared to a forecast of $249.3 million. The minor variance is attributable to higher employee related expenditures primarily due to lower than anticipated capitalization of resources, offset by unallocated contingency funds for transitional requirements which may be required as a result of the Voluntary Departure Program (VDP), as well as the timing of consulting and professional fee requirements.

Compared to the same 6 month period last year, O&A expenditures were lower by $16.4 million or 6.1%. The decrease is primarily due to a reduction in employee related expenditures as a result of the VDP and management reductions.

A summary of Manitoba Hydro's actual and forecast O&A expenditures by cost element with a comparison to the 2017/18 second quarter expenditures has been provided in the table below, as well as the annual O&A forecast for 2018/19.

ELECTRIC OPERATIONS
OPERATING & ADMINISTRATIVE COSTS BY COST ELEMENT
FOR THE QUARTER ENDED SEPTEMBER 30

(in Thousands of Dollars)

	2017/18 Q2 Actual	2018/19 Annual Forecast	2018/19 Q2 Actual	2018/19 Q2 Forecast	Favourable (Unfavourable) Variance
Employee Related Expenditures					
Wages & salaries	$254 647	$469 597	$230 728	$235 672	$4 944
Overtime	36 744	76 642	35 395	39 423	4 028
Employee benefits	82 769	145 225	73 067	71 778	(1 289)
Other	33 188	73 421	33 952	36 345	2 393
Total Employee Related Expenditures	407 348	764 885	373 142	383 218	10 076
Less: Capitalized labour and overhead	(163 797)	(332 292)	(150 109)	(167 570)	(17 461)
Operational Employee Related Expenditu	243 551	432 593	223 033	215 648	(7 385)
External services and materials	58 909	130 905	62 323	65 041	2 718
Donations, sponsorships & grants	1 060	2 140	905	1 070	165
Uncollectible accounts	2 180	4 265	2 182	2 133	(49)
Other	308	9 188	225	4 396	4 171
Cost recoveries	(7 420)	(14 593)	(8 626)	(7 295)	1 331
O&A charged to gas operations	(32 668)	(63 315)	(30 511)	(31 676)	(1 165)
Operating & Administrative Expenses	**265 920**	**501 183**	**249 531**	**249 318**	**(213)**

Note: recent data is provisional and subject to change, however large changes are not common.

Table (a) - Hydraulic Generation

Month	Hydraulic Gross Generation (GWh)				
	Winnipeg River	Grand Rapids GS	Upper Nelson	Lower Nelson	Wuskwatim GS
Nov-2017	337	175	254	1765	136
Dec-2017	330	208	263	2166	136
Jan-2018	324	241	255	1874	132
Feb-2018	316	158	214	1750	122
Mar-2018	338	156	249	1988	140
Apr-2018	244	86	253	1717	135
May-2018	212	82	262	1856	125
Jun-2018	232	188	254	1643	143
Jul-2018	216	170	276	1980	148
Aug-2018	170	181	247	1813	146
Sep-2018	144	83	202	1550	141
Oct-2018	212	129	224	1514	131

Chart (b) - Energy in Storage

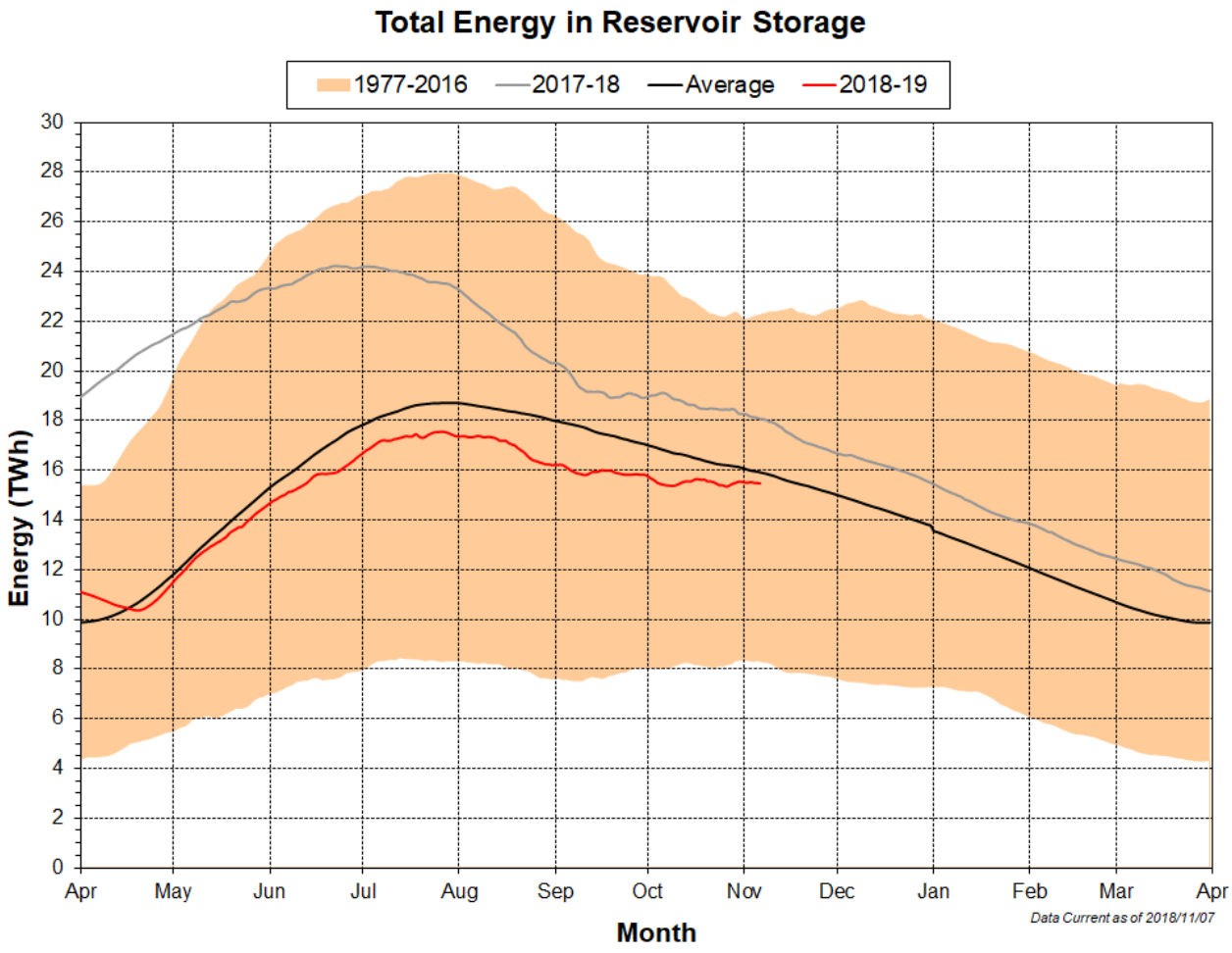


Table (b) – Wind Eliminated Lake Winnipeg Water Level

Month	Lake Winnipeg Water Level (m)
Nov-01-2017	217.51
Dec-01-2017	217.43
Jan-01-2018	217.38
Feb-01-2018	217.39
Mar-01-2018	217.36
Apr-01-2018	217.33
May-01-2018	217.30
Jun-01-2018	217.32
Jul-01-2018	217.40
Aug-01-2018	217.41
Sep-01-2018	217.33
Oct-01-2018	217.27

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
Nov-2017	1114	98	721	2288	993	3217
Dec-2017	902	80	842	2629	966	3853
Jan-2018	840	63	1015	2390	952	3382
Feb-2018	947	50	743	2401	970	3510
Mar-2018	908	66	661	2326	992	3556
Apr-2018	611	496	377	2036	980	3178
May-2018	513	505	338	1832	1070	3301
Jun-2018	584	300	795	1844	1089	3000
Jul-2018	520	206	686	2068	1113	3490
Aug-2018	389	93	734	1840	1069	3201
Sep-2018	327	76	347	1486	1075	2802
Oct-2018	549	111	516	1491	1044	2663

Notes:

1. Data may be subject to change until finalised.

Table (d.1) - Sales and Purchases Filed with NEB

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh
Nov-17	355									
	374	94,524	11,301,640	119.56						
	387									
	392	24,000	1,780,695	74.20						
	393	761	61,195	80.41						
	404	39,108	2,879,705	73.63						
	404				131,710	4,268,979	32.41			
								31,099	939,556	30.21
Dec-17	355									
	374	97,774	11,287,251	115.44						
	387									
	392	24,880	1,834,357	73.73						
	393	898	74,237	82.67						
	402	9,300	1,344	0.14						
	404	37,985	2,793,201	73.53						
	404				187,455	6,233,689	33.25			
								30,319	1,377,519	45.43

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh
Jan-18	355									
	374	93,982	11,332,473	120.58						
	387									
	392	24,890	1,786,890	71.79						
	393	1,454	111,484	76.67						
	404	39,431	2,887,488	73.23						
	404				30,149	2,273,419	53.18			
								151,300	5,646,920	37.32
Feb-18	355									
	374	81,142	10,297,185	126.90						
	387									
	392	22,376	1,654,264	73.93						
	393	1,277	99,280	80.90						
	404	34,863	2,644,254	75.85						
	404				9,205	1,119,832	48.37			
								139,188	3,783,679	27.18
Mar-18	374	108,371	11,882,911	109.65						
	387									
	392	25,239	1,868,914	74.05						
	393	811	70,759	87.23						
	404	42,254	3,041,627	71.98						
	404				305,256	9,932,483	32.54			
								12,002	167,790	13.98

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh
Apr-18	374	100,102	11,409,810	113.98						
	387									
	392	24,150	1,782,879	73.83						
	393	743	61,932	83.38						
	404	39,097	2,878,662	73.63						
	404				201,915	8,830,027	40.37			
								32,608	665,317	20.40
May-18	374	188,005	19,409,098	103.24						
	387	23,422	1,105,806	47.21						
	392	24,772	1,844,339	743.45						
	393	517	43,875	84.90						
	404	40,664	3,022,268	74.32						
	404				356,108	13,816,971	36.88			
								1,722	35,863	20.83
Jun-18	374	175,908	18,402,458	104.61						
	387	22,484	980,576	43.61						
	392	23,968	1,861,343	77.66						
	393	399	35,366	88.65						
	402	4	672	172.22						
	404	39,317	3,360,350	85.47						
	404				358,245	12,913,777	34.28			
								3,233	34,798	10.76

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh
Jul-18	374	187,853	19,287,818	102.68						
	387	23,519	1,050,043	44.65	200	10,958	54.79			
	392	24,559	1,900,564	77.39						
	393	490	41,142	83.89						
	404	40,569	3,406,824	83.98						
	404				626,950	20,482,805	31.66			
								1,402	(8,735)	(6.23)
Aug-18	374	190,354	19,592,327	102.93						
	387	23,891	1,095,172	45.67	200	11,447	57.23			
	392	24,569	1,888,192	76.85						
	393	505	40,050	79.38						
	404	42,663	3,573,194	83.75						
	404				443,589	16,261,242	35.24			
								4,278	264,524	61.83
Sep-18	374	164,015	17,432,401	106.29						
	387	18,185	788,273	43.35	200	8,109	40.55			
	392	23,975	1,848,744	77.11						
	393	385	35,955	93.39						
	404	36,680	3,118,461	85.02						
	404				176,358	7,239,589	41.05			
								38,497	981,511	61.83

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh	MWh	Revenue (CAN$)	$/MWh
Oct-18	374	164,067	18,504,246	112.78						
	387	11,373	564,719	49.65						
	392	24,800	1,898,876	76.57						
	393	596	51,316	86.10						
	404	41,532	3,529,414	84.98						
	404				58,268	3,506,695	60.18			
								140,791	4,616,277	61.83

Notes:
1. Data for October 2018 is preliminary

Table (d.2) - MISO Sales

Month	MWh	$Cdn	Avg Price $/MWh
Nov-2017	64,265	1,773,231	28.56
Dec-2017	124,256	3,417,993	27.67
Jan-2018	25,120	1,461,323	58.06
Feb-2018	7,550	418,698	50.50
Mar-2018	295,454	8,980,264	30.46
Apr-2018	193,893	1,660,261	42.06
May-2018	346,813	12,914,161	37.18
Jun-2018	350,532	12,158,259	34.61
Jul-2018	613,111	19,301,437	31.58
Aug-2018	434,215	15,375,219	35.49
Sep-2018	169,504	6,418,021	38.66
Oct-2018	56,055	2,848,410	49.73

Notes:
1. MISO Sales include Real Time and Day Ahead transactions.

Table (d.3) - Canadian Extraprovincial Sales

Month	MWh	$Cdn	Avg Price $/MWh
Nov-2017	112,666	6,861,629	31.65
Dec-2017	89,341	4,492,841	31.49
Jan-2018	51,958	3,596,589	49.11
Feb-2018	51,902	3,133,562	40.18
Mar-2018	70,650	3,371,487	30.26
Apr-2018	66,702	3,764,498	40.08
May-2018	75,783	4,832,381	39.40
Jun-2018	61,855	3,440,588	39.25
Jul-2018	32,404	2,178,161	56.93
Aug-2018	53,236	3,661,871	65.20
Sep-2018	64,543	4,328,200	50.33
Oct-2018	69,109	6,816,016	88.82

Table (d.4) - Purchases

Month	MWh	$Cdn	Avg Price $/MWh
Nov-2017	135,160	8,731,817	64.60
Dec-2017	117,953	7,790,909	66.05
Jan-2018	251,443	12,980,057	51.62
Feb-2018	219,682	9,404,155	42.81
Mar-2018	87,063	5,411,967	62.16
Apr-2018	109,098	6,028,517	55.26
May-2018	66,678	4,948,018	74.21
Jun-2018	65,592	4,760,498	72.58
Jul-2018	67,054	4,924,887	73.45
Aug-2018	62,630	4,721,043	75.38
Sep-2018	107,372	6,212,782	57.86
Oct-2018	228,664	9,595,660	41.96

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.

PROOF OF REVENUE

June 1, 2018 Rates vs April 1, 2019 Rates
Fiscal year ending March 31, 2020
($000s)

	Calculated Revenue June 1, 2018 Rates	Calculated Revenue April 1, 2019 Rates	Diff. in Revenue Dollars	Diff. in Revenue Percent
Basic	647,160	669,953	22,793	3.5%
Residential on Reserve	47,059	48,712	1,653	3.5%
Diesel	798	826	28	3.5%
Seasonal	8,085	8,370	285	3.5%
FRWH	1,237	1,281	44	3.5%
Residential	$ 704,339	$ 729,141	$ 24,802	3.5%
Small Non-Demand	156,163	161,656	5,493	3.5%
Small Demand	182,198	188,609	6,411	3.5%
Seasonal	729	754	26	3.5%
FRWH	502	519	18	3.5%
GS Small	$ 339,591	$ 351,538	$ 11,947	3.5%
GS Medium	$ 210,903	$ 218,334	$ 7,430	3.5%
Large 750 V - 30 kV	113,320	117,294	3,974	3.5%
Large 30 - 100 kV	88,144	91,261	3,117	3.5%
Large > 100 kV	184,347	190,849	6,503	3.5%
GS Large	$ 385,810	$ 399,404	$ 13,594	3.5%
Diesel GS & Gov.	7,700	7,706	6	0.1%
SEP	860	860	-	0.0%
General Service	$ 944,865	$ 977,842	$ 32,977	3.5%
Area & Roadway Lighting	$ 22,765	$ 23,562	$ 797	3.5%
Misc & Adjs	$ 6,451	$ 6,677	$ 226	3.5%
DOMESTIC REVENUE	**$ 1,678,420**	**$ 1,737,223**	**$ 58,802**	**3.5%**

Note: Calculated Class Revenues now include the impact of DSM savings, which were previously reported on a consolidated basis as a separate line item entitled DSM Reduction.

PROPOSED RATE SCHEDULES

TO BE EFFECTIVE

April 1, 2019

Manitoba Hydro

Available in accessible formats upon request

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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. % 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. 2019-01

Basic Charge:	$ 8.71
PLUS	
Energy Charge:	
All kWh	@ 8.827 ¢ / kWh
Minimum Bill:	$ 8.71

Services over 200 amps will have $8.71 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. 2019-02

Annual Basic Charge:	$ 104.52
PLUS	
Energy Charge:	
All kWh	@ 8.827 ¢ / kWh
Minimum Annual Bill:	$ 104.52

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. 2019-03

Basic Charge:	$ 8.36
PLUS	
Energy Charge:	
All kWh	@ 8.484 ¢ / kWh
Minimum Bill:	$ 8.36

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.

ON-RESERVE - TARIFF NO. 2019-04

Basic Charge:	$ 8.36
PLUS	
Energy Charge:	
All kWh	@ 8.484 ¢ / kWh
Minimum Bill:	$ 8.36

Services over 200 amps will have $8.36 added to the Basic Charge.

Applicability:

The Residential rate applies to all residential services on First Nations Reserve land.

RESIDENTIAL

FLAT RATE WATER HEATING RATES

(NOT available for new services)

	TARIFF NO. 2019-09	***TARIFF NO. 2019-10***
Element Size	**Controlled**	**Uncontrolled**
500 W	$ 13.59	$ 17.96
600 W	$ 16.10	$ 21.37
750 W	$ 19.77	$ 26.36
900 W	$ 23.50	$ 31.32
1,000 W	$ 25.92	$ 34.68
1,200 W	$ 29.43	$ 38.92
1,250 W	$ 30.30	$ 40.03
1,500 W	$ 34.68	$ 45.16
2,000 W	$ 41.73	$ 54.45
2,500 W	$ 46.99	$ 61.01
3,000 W	$ 51.43	$ 67.65
3,500 W	$ 57.82	$ 75.34
4,000 W	$ 64.10	$ 83.05
4,500 W	$ 71.58	$ 92.21
6,000 W		$ 119.45
1,500 / 1,000 W	$ 26.97	$ 36.07
2,000 / 1,000 W	$ 27.68	$ 36.97
3,000 / 1,000 W	$ 28.27	$ 38.28
2,000 / 1,500 W	$ 37.55	$ 50.20
3,000 / 1,500 W	$ 38.43	$ 51.14
4,500 / 1,500 W	$ 39.74	$ 53.18
3,000 / 2,000 W	$ 46.15	$ 61.87

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. 2019-20

Basic Charge:	$ 21.81
PLUS	
Energy Charge:	
First 11,000 kWh	@ 9.209 ¢ / kWh
Next 8,500 kWh	@ 6.542 ¢ / kWh
Balance of kWh	@ 4.253 ¢ / kWh
	PLUS
Demand Charge:	
First 50 kVA of Monthly Billing Demand	No Charge
Balance of Billing Demand	@ $ 10.89 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge

SMALL THREE PHASE - TARIFF NO. 2019-21

Basic Charge:	$ 30.74
PLUS	
Energy Charge:	
First 11,000 kWh	@ 9.209 ¢ / kWh
Next 8,500 kWh	@ 6.542 ¢ / kWh
Balance of kWh	@ 4.253 ¢ / kWh
	PLUS
Demand Charge:	
First 50 kVA of Monthly Billing Demand	No Charge
Balance of Billing Demand	@ $ 10.89 / 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 @ 6.542 ¢ / 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. 2019-22

Annual Basic Charge:	$ 261.72
PLUS	
First 66,000 kWh	@ 9.209 ¢ / kWh
Balance of kWh	@ 6.542 ¢ / kWh
Minimum Annual Bill:	$ 261.72

SEASONAL THREE PHASE - TARIFF NO. 2019-27

Annual Basic Charge:	$ 368.88
PLUS	
First 66,000 kWh	@ 9.209 ¢ / kWh
Balance of kWh	@ 6.542 ¢ / kWh
Minimum Annual Bill:	$ 368.88

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. 2019-23

Basic Charge:	$ 21.81
PLUS	
Energy Charge:	
First 11,000 kWh	@ 9.209 ¢ / kWh
Balance of kWh	@ 6.542 ¢ / kWh
Minimum Bill:	$ 21.81

COOKING AND HEATING SEASONAL - TARIFF NO. 2019-24

Annual Basic Charge:	$ 261.72
PLUS	
Energy Charge:	
First 66,000 kWh	@ 9.209 ¢ / kWh
Balance of kWh	@ 6.542 ¢ / kWh
Minimum Annual Bill:	$ 261.72

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. 2019-40

Basic Charge:	$ 21.81
PLUS	
Energy Charge:	
First 2,000 kWh	@ 9.209 ¢ / kWh
Balance of kWh	@ 42.617 ¢ / kWh
Minimum Bill:	$ 21.81

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. 2019-41

Basic Charge:	$ 21.81
PLUS	
Energy Charge:	@ $2.59382 / kWh
Minimum Bill:	$ 21.81

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. 2019-30

Basic Charge:	$ 32.45
PLUS	
Energy Charge:	
First 11,000 kWh	@ 9.209 ¢ / kWh
Next 8,500 kWh	@ 6.542 ¢ / kWh
Balance of kWh	@ 4.253 ¢ / kWh
PLUS	
* Demand Charge:	
First 50 kVA of Monthly Billing Demand	No Charge
Balance of Billing Demand	@ $ 10.89 / 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 17.

GENERAL SERVICE

(Customer-Owned Transformation)

LARGE 750 V TO NOT EXCEEDING 30 KV - TARIFF NO. 2019-60

	Energy Charge:	@ 3.995 ¢ / kWh
	PLUS	
*	Demand Charge:	@ $ 9.23 / kVA

Minimum Bill: Demand Charge

LARGE 30 KV TO NOT EXCEEDING 100 KV - TARIFF NO. 2019-61

	Energy Charge:	@ 3.675 ¢ / kWh
	PLUS	
*	Demand Charge:	@ $ 7.83 / kVA

Minimum Bill: Demand Charge

LARGE EXCEEDING 100 KV - TARIFF NO. 2019-62

	Energy Charge:	@ 3.564 ¢ / kWh
	PLUS	
*	Demand Charge:	@ $ 6.97 / 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.

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. 2019-50

Basic Charge:	$ 21.81
PLUS	
Energy Charge:	@ 10.536 ¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Recorded Demand	No Charge
Balance of Recorded Demand	@ $ 2.72 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge:

LUBD SMALL THREE PHASE - TARIFF NO. 2019-51

Basic Charge:	$ 30.74
PLUS	
Energy Charge:	@ 10.536 ¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Recorded Demand	No Charge
Balance of Recorded Demand	@ $ 2.72 / 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. 2019-52

	Basic Charge:	$ 32.45
	PLUS	
	Energy Charge:	@ 10.536 ¢ / kWh
	PLUS	
*	Demand Charge:	
	First 50 kVA of Monthly Recorded Demand	No Charge
	Balance of Recorded Demand	@ $ 2.72 / 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. 2019-53

	Energy Charge:	@ 9.320 ¢ / kWh
	PLUS	
*	Demand Charge:	@ $ 2.31 / kVA

Minimum Bill: Demand Charge

LUBD LARGE 30 KV TO NOT EXCEEDING 100 KV - TARIFF NO. 2019-54

	Energy Charge:	@ 8.192 ¢ / kWh
	PLUS	
*	Demand Charge:	@ $ 1.96 / kVA

Minimum Bill: Demand Charge

LUBD LARGE EXCEEDING 100 KV - TARIFF NO. 2019-55

	Energy Charge:	@ 7.585 ¢ / kWh
	PLUS	
*	Demand Charge:	@ $ 1.74 / 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. 2019-29

Element Size	Uncontrolled
500 W	$ 18.88
600 W	$ 22.58
750 W	$ 28.17
1,000 W	$ 37.88
1,200 W	$ 45.32
1,500 W	$ 56.38
2,000 W	$ 70.68
2,500 W	$ 84.98
3,000 W	$ 98.89
3,500 W	$ 112.80
3,800 W	$ 124.68
4,000 W	$ 126.70
4,500 W	$ 140.63
5,000 W	$ 154.52
6,000 W	$ 182.35
6,500 W	$ 201.89
7,000 W	$ 210.13
7,500 W	$ 230.48
8,000 W	$ 237.94
9,000 W	$ 265.72
10,000 W	$ 293.56
10,500 W	$ 307.52
12,000 W	$ 349.20
12,500 W	$ 363.11
13,000 W	$ 377.03
13,500 W	$ 390.77
14,500 W	$ 418.59
15,000 W	$ 432.62
16,000 W	$ 460.43
16,500 W	$ 487.92
18,000 W	$ 516.11
19,000 W	$ 559.36
20,000 W	$ 571.70
23,000 W	$ 673.81
24,000 W	$ 702.45
25,000 W	$ 710.66
3,000 / 1,000 W	$ 46.15
2,000 / 1,500 W	$ 58.43
3,000 / 1,500 W	$ 59.08
4,500 / 1,500 W	$ 60.52

GENERAL SERVICE

SHORT-TERM POWER RATE

pause

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. 2018-20 or 2018-21:

a) The Unmetered Service rate is applicable 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. 2019-80:

Watts			Rate Per Month	
			Shared Pole/Luminaire	Exclusive Pole/Luminaire
200	F		-	$ 11.88
20	CF		-	$ 2.55
100	I		$ 5.45	$ 11.88
150	I		-	$ 11.88
300	I		-	$ 16.92
500	I		$ 14.30	$ 23.32
400	MH		-	$ 28.43
175	MV		$ 10.58	$ 16.92
250	MV		$ 12.10	$ 19.17
400	MV		$ 16.59	$ 22.93
70	HPS		$ 9.09	$ 14.92
70	HPS	24 hours	-	$ 16.78
100	HPS		$ 9.43	$ 15.74
150	HPS		$ 11.56	$ 17.78
250	HPS		$ 14.23	$ 20.49
400	HPS		$ 16.90	$ 28.43
400	HPS	2/100'	-	$ 43.95
400	HPS	4/100'	-	$ 32.27
750	HPS		$ 26.21	$ 41.56
1 000	HPS		-	$ 48.22
1 000	HPS	1/60'	-	$ 49.33
1 000	HPS	2/100'	-	$ 59.12
1 000	HPS	4/100'	-	$ 50.69

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

OUTDOOR LIGHTING RATE - *TARIFF NO. 2019-80:*

Watts	Rate Per Month	
	Shared Pole/Luminaire	Exclusive Pole/Luminaire
10 LED (1 – 30 W)	-	$ 2.32
40 LED (> 30 – 50 W)	$ 7.81	$ 13.64
40 LED 24 hr (> 30 – 50 W)	-	$ 15.49
60 LED (> 50 – 80 W)	$ 7.98	$ 14.28
90 LED (> 80 – 120 W)	$ 9.55	$ 15.76
150 LED (> 120 – 180 W)	$ 11.37	$ 17.13
150 LED 2/100' (>120 – 180)	-	$ 27.73
150 LED 4/100' (>120 – 180)	-	$ 19.34
250 LED (> 180 – 280 W)	$ 11.53	$ 23.05
250 LED 2/100' (> 180 – 280 W)	-	$ 38.56
250 LED 4/100' (> 180 – 280 W)	-	$ 26.90

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. 2019-81:*

Watts	Rate Per Month	
	Shared Pole/Luminaire	**Exclusive Pole/Luminaire**
100 I	$ 6.19	-
150 I	$ 6.19	$ 12.83
300 I	$ 11.28	-
500 I	$ 15.19	$ 24.87
250 MV	$ 13.98	$ 20.47
400 MV	$ 17.10	$ 22.96
500 Q	$ 23.50	$ 29.79

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. 2019-82:*

Watts	Rate Per Month	
	Shared Pole/Luminaire	**Exclusive Pole/Luminaire**
70 HPS	$ 9.09	$ 14.92
100 HPS	$ 9.43	$ 15.74
150 HPS	$ 11.56	$ 17.78
250 HPS	$ 14.73	$ 20.49
40 LED (> 30 – 50 W)	$ 7.81	$ 13.64
60 LED (> 50 – 80 W)	$ 7.98	$ 14.28
90 LED (> 80 – 120 W)	$ 9.55	$ 15.76
150 LED (> 120 – 180 W)	$ 11.37	$ 17.13
250 LED (> 180 – 280 W)	$ 11.53	$ 23.05

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. 2019-83:*

Watts	Rate Per Month	
	Flat Rate (Energy and Rental)	**Metered (Rental Only)**
100 HPS	$ 11.70	$ 8.06
150 HPS	$ 15.49	$ 11.00
175 MV	$ 12.07	$ 8.06
400 MV	$ 19.98	$ 11.00
60 LED	$ 10.24	$ 8.06
90 LED	$ 13.49	$ 11.00

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

DECORATIVE LIGHTING - *TARIFF NO. 2019-85*

Connected load @ $1.041/kW per night of scheduled use:

Minimum Monthly Bill: $ 21.28

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.

Bill Comparison

Residential

Forecast Customers: 475,219

kWh	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
250	$29.73	$30.78	$1.05	3.53%
750	$72.36	$74.91	$2.55	3.52%
1 000	$93.68	$96.98	$3.30	3.52%
2 000	$178.95	$185.25	$6.30	3.52%
5 000	$434.76	$450.06	$15.30	3.52%

Residential
First Nations On Reserve

Forecast Customers: 18,478

kWh	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference $ / Month	Percent Change
250	$28.57	$29.57	$1.00	3.50%
750	$69.55	$71.99	$2.44	3.51%
1 000	$90.04	$93.20	$3.16	3.51%
2 000	$172.00	$178.04	$6.04	3.51%
5 000	$417.88	$432.56	$14.68	3.51%

Residential
Seasonal

Forecast Customers: 19,114

kWh	June 1, 2018 $ / Summer	April 1, 2019 $ / Month	Difference in $ / Summer	Percent Change
250	$122.24	$126.59	$4.35	3.56%
750	$164.87	$170.72	$5.85	3.55%
1 000	$186.19	$192.79	$6.60	3.54%
2 000	$271.46	$281.06	$9.60	3.54%
5 000	$527.27	$545.87	$18.60	3.53%

Residential
Diesel

Forecast Customers: 596

kWh	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
250	$28.57	$29.57	$1.00	3.50%
750	$69.55	$71.99	$2.44	3.51%
1 000	$90.04	$93.20	$3.16	3.51%
2 000	$172.00	$178.04	$6.04	3.51%
5 000	$417.88	$432.56	$14.68	3.51%

Bill Comparison

General Service Small
< 50 kVA

Forecast Customers: 53,188

kWh	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
750	$87.79	$90.88	$3.09	3.52%
2 000	$198.99	$205.99	$7.00	3.52%
5 000	$465.87	$482.26	$16.39	3.52%
10 000	$910.67	$942.71	$32.04	3.52%
36 500	$2,619.86	$2,711.94	$92.08	3.51%

General Service Small
51 kVA

Forecast Customers: 13,639

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
25%	$868.26	$898.80	$30.54	3.52%
50%	$1,500.05	$1,552.79	$52.74	3.52%
75%	$1,902.00	$1,968.92	$66.92	3.52%
100%	$2,284.33	$2,364.75	$80.42	3.52%

General Service Small
100 kVA

Forecast Customers: 13,639

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
25%	$1,992.46	$2,062.53	$70.07	3.52%
50%	$2,769.82	$2,867.31	$97.49	3.52%
75%	$3,519.53	$3,643.48	$123.95	3.52%
100%	$4,269.24	$4,419.66	$150.42	3.52%

Bill Comparison

General Service
Seasonal

Mthly Avg Custs 965

kWh	June 1, 2018 $ / Summer	April 1, 2019 $ / Month	Difference in $ / Summer	Percent Change
750	$319.56	$330.79	$11.23	3.51%
2 000	$430.76	$445.90	$15.14	3.51%
5 000	$697.64	$722.17	$24.53	3.52%
10 000	$1,142.44	$1,182.62	$40.18	3.52%

General Service
Diesel

Forecast Customers: 117

kWh	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
750	$87.79	$90.88	$3.09	3.52%
2 000	$198.99	$205.99	$7.00	3.52%
5 000	$1,477.50	$1,484.50	$7.00	0.47%
10 000	$3,608.35	$3,615.35	$7.00	0.19%

General Service
Government and First Nation Education

Forecast Customers: 68

kWh	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
750	$1,966	$1,967	$0.74	0.04%
2 000	$5,209	$5,209	$0.74	0.01%
5 000	$12,990	$12,991	$0.74	0.01%
10 000	$25,959	$25,960	$0.74	0.00%

Bill Comparison

General Service Medium
500 kVA

Forecast Customers: 1968

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
25%	$9,229	$9,554	$325	3.52%
50%	$12,977	$13,434	$457	3.52%
75%	$16,726	$17,315	$589	3.52%
100%	$20,474	$21,196	$722	3.53%

General Service Medium
1 000 kVA

Forecast Customers: 1968

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
25%	$18,237	$18,879	$642	3.52%
50%	$25,734	$26,641	$907	3.52%
75%	$33,231	$34,403	$1,172	3.53%
100%	$40,728	$42,165	$1,437	3.53%

Bill Comparison

General Service Large - 750 V to 30 kV
5 000 kVA

Forecast Customers: 333

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
25%	$79,813	$82,604	$2,791	3.50%
50%	$115,027	$119,059	$4,032	3.51%
75%	$150,240	$155,513	$5,273	3.51%
100%	$185,454	$191,968	$6,514	3.51%

General Service Large - 30 kV to 100 kV
10 000 kVA

Forecast Customers: 44

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
25%	$140,388	$145,369	$4,981	3.55%
50%	$205,175	$212,438	$7,263	3.54%
75%	$269,963	$279,506	$9,543	3.53%
100%	$334,750	$346,575	$11,825	3.53%

General Service Large - Over 100 kV
50 000 kVA

Forecast Customers: 15

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
25%	$650,674	$673,715	$23,041	3.54%
50%	$964,848	$998,930	$34,082	3.53%
75%	$1,279,021	$1,324,145	$45,124	3.53%
100%	$1,593,195	$1,649,360	$56,165	3.53%

Bill Comparison

Limited Use Billing Demand - General Service Small
100 kVA

Forecast Customers: 531

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
5%	$529	$542	$13	2.54%
10%	$900	$926	$27	2.95%
15%	$1,271	$1,311	$40	3.12%
20%	$1,643	$1,696	$53	3.21%

Limited Use Billing Demand - General Service Medium
500 kVA

Forecast Customers: 19

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
5%	$3,072	$3,180	$108	3.52%
10%	$4,929	$5,103	$174	3.52%
15%	$6,787	$7,026	$239	3.53%
20%	$8,644	$8,949	$305	3.53%

Bill Comparison

Limited Use Billing Demand - General Service Large - 750 V to 30 kV
5 000 kVA

Forecast Customers: 2

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
5%	$27,584	$28,547	$963	3.49%
10%	$44,018	$45,556	$1,538	3.49%
15%	$60,452	$62,565	$2,113	3.50%
20%	$76,887	$79,574	$2,687	3.49%

Limited Use Billing Demand - General Service Large - 30 kV to 100 kV
10 000 kVA

Forecast Customers: 0

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
5%	$47,779	$49,476	$1,697	3.55%
10%	$76,658	$79,377	$2,719	3.55%
15%	$105,536	$109,277	$3,741	3.54%
20%	$134,415	$139,178	$4,763	3.54%

Limited Use Billing Demand - General Service Large - Over 100 kV
50 000 kVA

Forecast Customers: 3

Load Factor	June 1, 2018 $ / Month	April 1, 2019 $ / Month	Difference in $ / Month	Percent Change
5%	$217,825	$225,551	$7,726	3.55%
10%	$351,524	$363,978	$12,454	3.54%
15%	$485,224	$502,404	$17,180	3.54%
20%	$618,923	$640,830	$21,907	3.54%

2018/19

DEMAND SIDE MANAGEMENT PLAN






MARCH 2018

MANITOBA HYDRO – HELPING MANITOBANS MOVE TOWARD A MORE SUSTAINABLE ENERGY FUTURE

Manitoba Hydro POWER SMART*

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Message from Manitoba Hydro's CEO



2018-19 will be a year of significant changes for Manitoba Hydro Power Smart and the delivery of demand side management services.

As part of the Efficiency Manitoba Act, a new standalone Crown corporation — Efficiency Manitoba — is being established with the accountability to deliver electric and natural gas demand side management programs and services to consumers, businesses and industry. This will include most of the current programs and initiatives offered through Power Smart. As such, Manitoba Hydro will work closely with Efficiency Manitoba over the coming months to effect a transition to the new entity, while minimizing impacts on the delivery of services during the transition period.

More than 82,000 customers are expected to save $17 million on their collective energy bills by participating in Power Smart this year. To meet our targets, we must continue to focus on engaging customers and working with communities to promote energy efficiency. In addition to incentives, such as rebates and free energy-saving devices, we offer technical guidance and on-bill financing to make saving energy as easy and convenient as possible. Thanks to Power Smart, many customers are realizing benefits that go far beyond lower energy bills—including more comfortable homes and businesses, and improved air quality.

Manitobans who take advantage of Power Smart are also minimizing their impact on the environment. Thanks to these programs, it's estimated that greenhouse gas emissions will be reduced by approximately 256,000 tonnes in 2018-19 alone — the equivalent of taking 51,000 cars off the road for one year.

Although the delivery of demand side management to Manitobans is entering a period of change, Manitoba Hydro will continue to support our customers in meeting their energy needs. We look forward to continuing to work with government, consumers, businesses, industry partners and Efficiency Manitoba as we continue to move our province towards achieving greater energy efficiency.



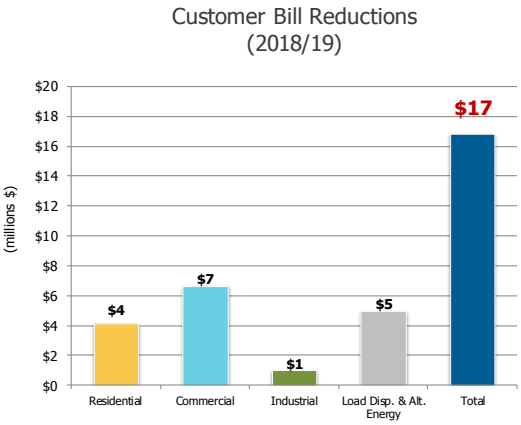
Kelvin Shepherd,
President & Chief Executive Officer, Manitoba Hydro

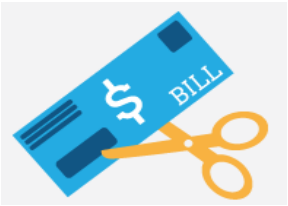
HIGHLIGHTS

This report outlines Manitoba Hydro's Demand Side Management (DSM) plan for the 2018/19 fiscal year. The plan involves activity related to incentive-based programs and efforts associated with energy codes, performance standards and energy efficiency regulations. Manitoba Hydro has a strong commitment to DSM with a focus intent on pursuing all cost effective opportunities and continually monitoring the market for emerging trends and additional opportunities. Manitoba Hydro updates its DSM plan every year to reflect current market conditions and additional experience gained on customer response.

Helping our Customers Save

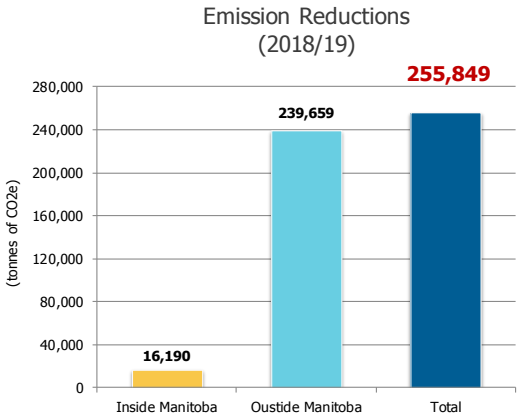
In 2018/19, customers who participate in Manitoba Hydro's Demand Side Management Programs are anticipated to enjoy a reduction of $17 million on their energy bills; $4 million for residential customers, $7 million for commercial customers, $1 million for industrial customers, and $5 million for load displacement and alternative energy customers. These are dollars that customers can choose to invest in their homes, businesses or to spend elsewhere in Manitoba.





Reducing Environmental Impacts

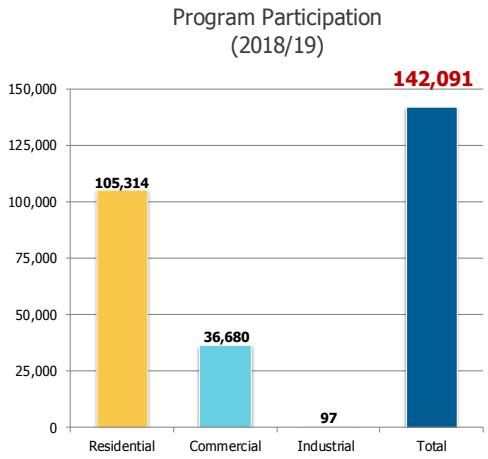
Greenhouse gas emission reductions arising from Manitoba Hydro's DSM investments are expected to be approximately 256,000 tonnes from 2018/19 activity alone. This is equivalent to taking over 51,000 cars off the road for one year.





Partnering with Customers for Deeper Savings

Manitoba Hydro has been offering DSM programming to residential, commercial and industrial customers for over two and a half decades. In 2018/19, it is forecast that there will be over 142,000 participants in Manitoba Hydro's DSM incentive-based and support programs, representing approximately 105,000 residential customers, 37,000 commercial customers, and 97 industrial customers who will benefit through lower bills through their participation in Manitoba Hydro's DSM programs.



Manitoba Hydro will continue to leverage customer and stakeholder relationships to create partnerships that provide deeper energy savings and encourage harder-to-reach customers to take advantage of Power Smart opportunities and programs.

The following are examples of initiatives driving increased customer engagement and deeper energy savings:

Achieving Deeper Savings with Hard-to-Reach Customers

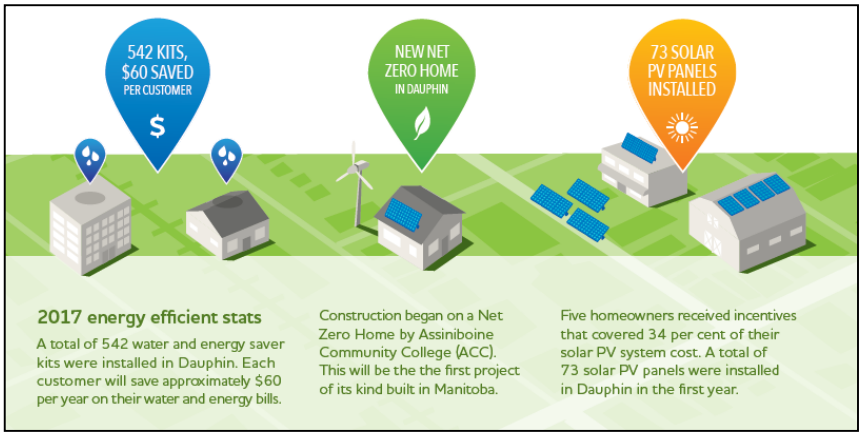


The Affordable Energy Program has long recognized the value in partnering with a number of different government and non-government groups, including; First Nation Communities, Indigenous groups, social enterprise groups and community-based organizations. Through these partnerships, many hard to reach lower income customers have benefitted from energy efficiency upgrades. Partnerships established with the North End Community Renewal Corporation will continue through 2018/19 to promote the Affordable Energy Program.

Through the Indigenous Power Smart Program, staff members work directly with local Band leadership and Housing Coordinators to improve the energy efficiency of homes in the community. Working with these communities, 2018/19 will see approximately 1,400 homes receive energy efficiency upgrades.

Partnering at the Community Level with Energy Plans

Manitoba Hydro is working with local municipal officials in Dauphin to carry out a Community Energy Plan to help the communities achieve deeper energy efficiency improvements across all sectors (residential, commercial and industrial). Supported by energy advocates from within the communities, their community energy plan will identify and prioritize each town's energy efficiency goals and objectives, leveraging existing programs and industry partners to achieve these goals. Taking a community approach to energy efficiency allows community members to become active participants by working together to achieve a common goal.



Partnerships and Collaboration will Drive Race to Reduce to the Finish Line

The first behavioural energy efficiency initiative of its kind in Manitoba, Race to Reduce successfully demonstrates collaboration among customers, industry associations, and other key stakeholders while working in partnership with Manitoba Hydro to find even greater levels of savings than ever before. Launched on January 18, 2017, the program has secured almost seven million square feet of office space to participate in the innovative energy reduction competition.

RACE TO REDUCE

Race to Reduce encourages landlords and tenants to publicly commit to working together to reduce their buildings' total energy use by 10 per cent over the four year race. Race to Reduce participants will be publicly recognized and celebrated during the initiative's annual award ceremonies.

Helping Customers Build Efficiency Expertise "In-House"



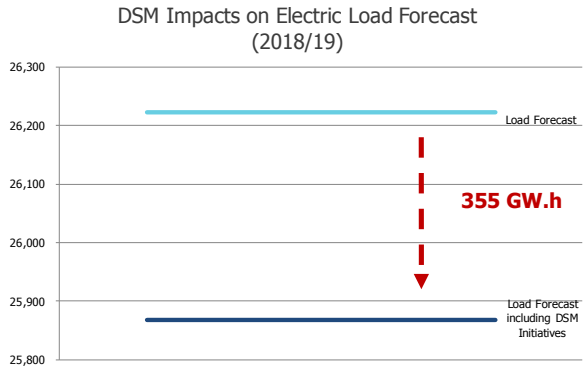
Recent enhancements to Manitoba Hydro's Performance Optimization Program, which targets large institutions, commercial and industrial buildings and processes, provide support for embedded energy managers to advocate and lead energy efficiency improvements from within the customer's operations.

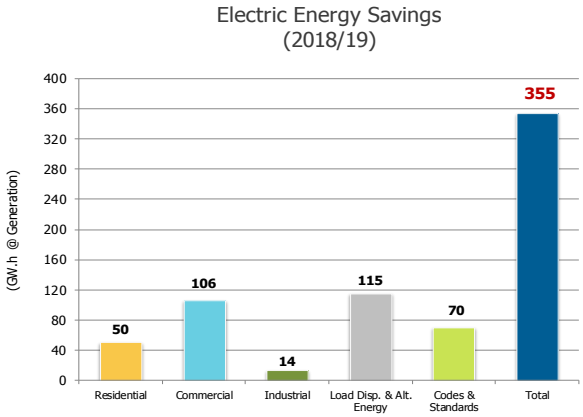
The expanded programming, known as the Energy Manager Initiative provides support for embedded energy manager salary costs; organizational, planning and technical support; energy management training, scoping and feasibility studies; and advanced energy monitoring dashboards with real time control messaging and with customized linking of energy consumption to key customer performance metrics. These enhancements provide proactive customer engagement and strengthen executive level commitment within organizations that supports critical investment in energy efficiency and productivity.

Meeting Future Energy Needs of Manitobans

Electric Energy Savings

In 2018/19, Manitoba Hydro plans to capture electricity savings of 240 MW and 355 GW.h. Along with constructing new renewable hydro generation, Demand Side Management is a key component of Manitoba Hydro's strategy for meeting the province's future energy needs. The energy savings achieved through DSM will represent 1.4% of the actual Manitoba electric load for 2017/18. In 2018/19, Manitoba Hydro plans to capture electricity energy savings of 13 MW and 50 GW.h in the residential sector, 23 MW and 106 GW.h in the commercial sector, 170 MW and 14 GW.h in the industrial sector, 16 MW and 115 GW.h through load displacement and alternative energy opportunities and 18 MW and 70 GW.h resulting from efforts relating to codes and standards.



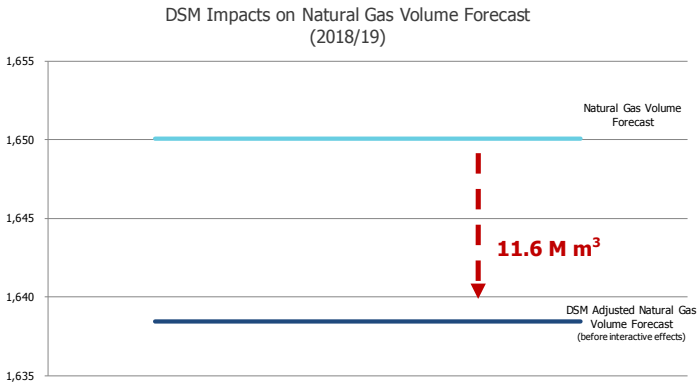




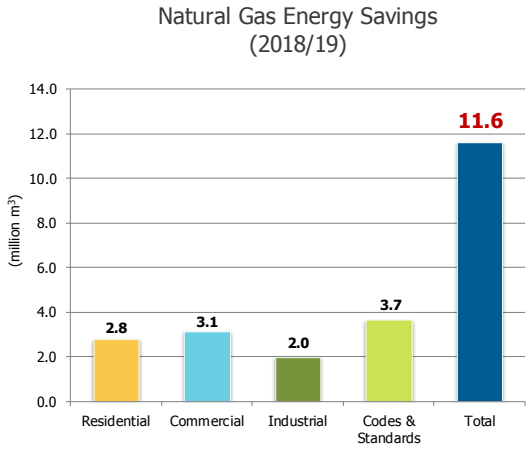
Natural Gas Savings

In 2018/19, the plan sets out to capture natural gas savings of 11.6 million cubic metres before interactive effects which represents 0.71% of the natural gas consumption for 2017/18, further reducing natural gas consumption in Manitoba. The percentage of volume calculation excludes the natural gas consumption of both Manitoba Hydro Power Stations and Special Contracts in the volume forecast.

In 2018/19, Manitoba Hydro plans to capture natural gas savings of 2.8 million cubic metres in the residential sector, 3.1 million cubic metres in the commercial sector, 2.0 million cubic metres in the industrial sector, and 3.7 million cubic metres resulting from efforts relating to codes and standards.

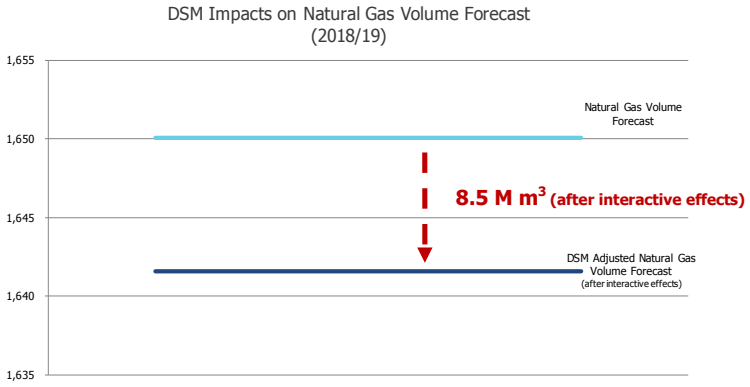


Note: The above graph excludes the natural gas consumption of both Manitoba Hydro Power Stations and Special Contracts in the volume forecast.

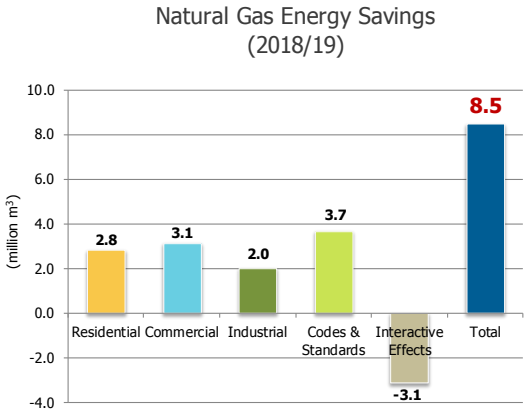


As a result of some electric DSM programming, there is an increase in natural gas consumption for space heating purposes – interactive effects. The interactive effects result from the need to replace heat lost from the use of more efficient lighting and other interior equipment that use electricity.

Including an increase of 3.1 million cubic metres in natural gas consumption due to interactive effects, the plan is expected to result in net natural gas savings of 8.5 million cubic metres which represents 0.52% of the natural gas consumption for 2017/18. This percentage of volume calculation also excludes the natural gas consumption of both Manitoba Hydro Power Stations and Special Contracts in the volume forecast.



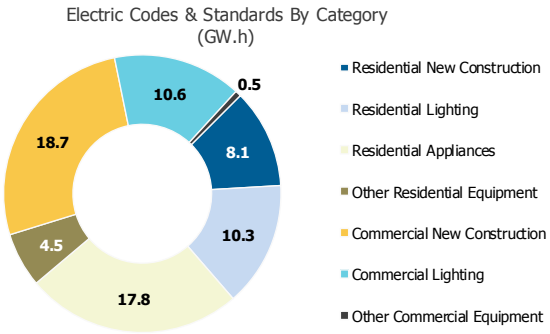
Note: The above graph excludes the natural gas consumption of both Manitoba Hydro Power Stations and Special Contracts in the volume forecast.

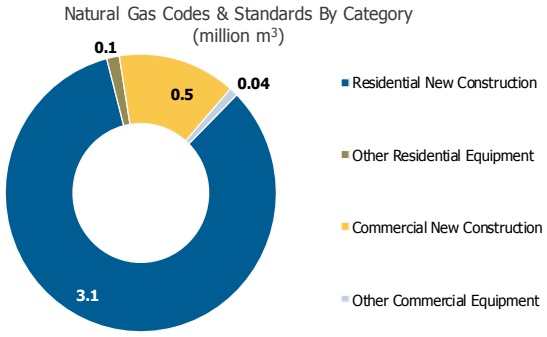


Codes, Standards & Regulations Savings

In addition to utility-directed 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 building codes and performance 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 which are then incorporated into Manitoba Power Smart programs, and subsequent energy efficiency regulations and building codes proposed by national and provincial regulators.

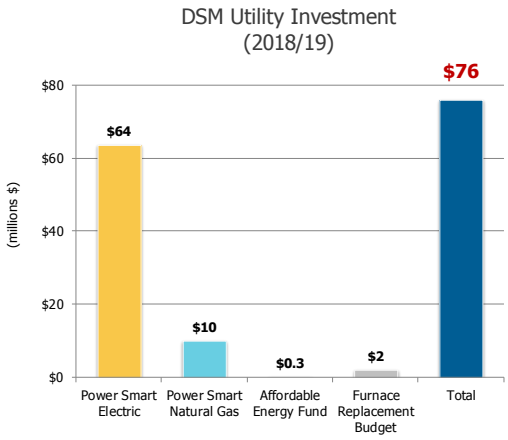
Efforts to achieve energy savings through Codes, Standards and Regulations are forecast to achieve capacity savings of 18 MW, energy savings of 70 GW.h and 3.7 million cubic metres of natural gas in 2018/19.

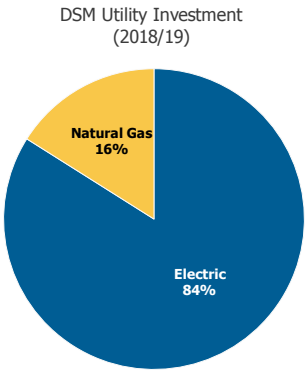




Investing in Demand Side Management

Over the next year, Manitoba Hydro expects to invest $76 million in Demand Side Management initiatives with $64 million of the costs funded through Manitoba Hydro's DSM electricity budget, $10 million funded through Manitoba Hydro's DSM natural gas budget, $0.3 million funded through the Affordable Energy Fund and $2 million funded through the Lower Income Natural Gas Furnace Replacement budget. Actual expenditures are significantly dependent on customer's decisions to participate.





Building Manitoba's Green Economy

The economic benefits of energy efficiency and alternative energy extend far beyond lowering energy bills for households and businesses in Manitoba. These investments contribute to local economic development and job creation through investments by customers and services provided by Manitoba businesses. As cited by the well-known energy efficiency industry advocate, The American Council for an Energy-Efficient Economy (ACEEE);

"Energy efficiency investments create jobs in two ways. First, the investment itself creates jobs. Often, as in construction work for a building upgrade, these projects create local jobs that cannot be outsourced. Second, the energy savings due to the investment create more jobs for years afterward as people spend the money they save on energy bills."

This year's Demand Side Management Plan is projecting activity related to energy efficient construction, retrofits and other Demand Side Management initiatives to total over 120 million dollars in 2018/19 alone. In addition, this investment in demand side management is anticipated to generate bill savings of 17 million dollars in 2018/19 alone. When a household or business lowers their energy costs, they are then able to spend that money elsewhere in the economy.

In addition to the economy wide creation of jobs arising from this local construction and renovation activity, Manitoba Hydro's programs have and will result in the direct creation of green jobs through the service providers delivering the following Power Smart programs. The following are examples of these initiatives:

Supporting Social Enterprises through the Affordable Energy Program



The Affordable Energy Program continues to support the efforts of Building Urban Industries for Local Development (BUILD) and Brandon Energy Efficiency Program (BEEP), Manitoba social enterprise contractors. Both organizations are non-profit contractors who provide training programs for people who face barriers to employment and have limited experience in the formal labour market to retrofit housing stock in a fashion that reduces poverty and benefits the environment. Through this partnership, BUILD and BEEP will employ 27 individuals, developing candidates for future job opportunities in the social enterprise and private sector overall.

Working with First Nation Communities, the Indigenous Power Smart Program provides free basic energy saving measures and free insulation along with funding which creates employment for members in the community to complete the installation. Over 5,900 total homes have been retrofitted through the program, generating 27 equivalent full time jobs of First Nation employment.

Power Smart Partners with Retailers to Offer Rebates on LEDs and Energy Efficient Products



The Residential LED Lighting Program continues to offer instant rebates on ENERGY STAR® certified lighting products province-wide at participating retailers. In 2018/19, a contract service provider is again coordinating retailer promotions, and hiring energy efficiency ambassadors to staff in-store engagement events during campaigns. One full time project manager and up to 15 part time ambassadors are employed in Manitoba as a result of the program.

Water and Energy Saver Program, Creating Savings and Jobs

The ongoing Water and Energy Saver Program employs technicians, through the contracted service provider, to coordinate community events and go door-to-door promoting the program and installing water saving devices. A total of three full time staff and up to 20 part time technicians are currently employed in Manitoba.



Retiring Old Fridges, Hiring New Faces



The Refrigerator Retirement Program continues to positively contribute to the local economy through the establishment of a local recycling facility and processing centre. Up to 20 full time green collar jobs have been created in the province as a direct result of the Power Smart Refrigerator Retirement Program. Since the program launched in 2011, approximately 63,000 refrigerators and freezers have been collected, decommissioned, and recycled by the program's contracted service provider who employs service professionals, warehouse workers, and field staff.

Installing Geothermal Systems in First Nations with First Nations



The Community Geothermal Program converts electric furnaces to geothermal heat pump systems in First Nation communities. The program supports and provides funding for Aki Energy, a non-profit social enterprise group working as liaison with individual communities to promote and coordinate installations. Jobs are created within the participating First Nation Community through the installation of the geothermal systems in the communities' homes. This community approach creates meaningful employment as they install green heating systems in their communities. To date, approximately 55 band members have received various training as it relates to GSHP systems, including installation, maintenance, and fusion certification; 21 have received full installer accreditation granted by the International Ground Source Heat Pump Association (IGSHPA).

Power Smart Shops Program Creates Jobs While Helping Small Businesses and Communities Thrive



The Power Smart Shops Program for small businesses is a full-service program that offers direct installation of a variety of water and energy-saving measures, lighting walkthroughs, and enhanced incentives for lighting retrofits.

The program is delivered by a contracted service provider that employs one regional manager, one account coordinator, and four technicians, all who directly support the program. Electrical services for lighting projects requiring a licensed electrician are subcontracted to seven electrical companies based in Winnipeg, Portage la Prairie, Dauphin, Brandon and The Pas, to support projects across Manitoba. Altogether, these subcontractors have a team of over 45 electricians and apprentices working on Power Smart Shops projects. Since launching in October 2015, over 1,400 businesses in 43 communities across Manitoba have participated in the program.

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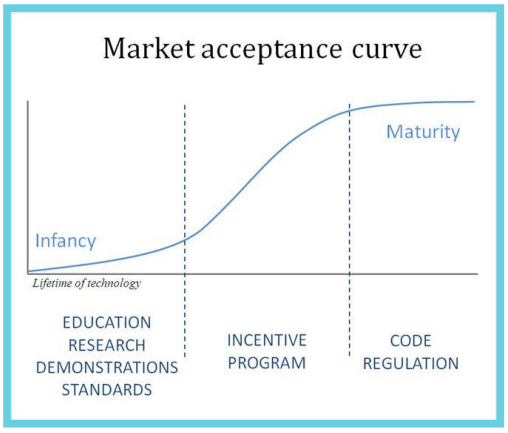
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DSM STRATEGY

Manitoba Hydro's DSM initiative, marketed under the Power Smart brand, is designed to encourage the efficient use of energy in residential, commercial, and industrial customer sectors. Manitoba Hydro's overall DSM strategy involves taking a broad approach to capturing energy efficiency opportunities: educating customers and industry to build awareness and understanding, creating foundations through the support of standards, motivating customers with the aid of financial tools, and entrenching energy savings through the support of federal and provincial codes and regulations.

In assessing options for pursing a DSM opportunity, Manitoba Hydro uses a number of metrics as guidelines to assess energy efficient 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. These metrics include the Total Resource Cost, Societal Cost, Rate Impact Measure, Levelized Utility Cost, and Customer Simple Payback. 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.



As outlined in the following graph, Manitoba Hydro takes a three stage approach to achieving market transformation. In the infancy stage of emerging opportunities, Manitoba Hydro supports these technologies by building customer awareness, funding demonstration projects, and investing in research and development. As market acceptance increases and the opportunity becomes cost-effective, financial incentives and/or other market intervention strategies are pursued to encourage customers to install the technology. As the product matures and market adoption grows, incentive-based programming generally becomes uneconomic. During this phase, Manitoba Hydro's strategy involves pursuing the remaining opportunities through the adoption of codes and regulations. This latter strategy also ensures permanent market transformation for the specific energy efficiency opportunity.

An Example: Changing Furnace Efficiencies in Manitoba
In 2001, only 30% of all natural gas furnaces being installed in Manitoba were high-efficient models and customer awareness of higher efficiency options was low. In response to this market situation, Manitoba Hydro launched the Power Smart Residential Loan and supporting Home Comfort and Energy Savings campaign to educate and promote the installation of high efficient natural gas furnaces. This approach laid the foundation for customers to consider the energy efficient alternative, and provided a tool for contractors to promote this technology. In 2005, to further increase market acceptance, a $245 incentive was introduced to encourage customers to choose high efficient natural gas furnaces over the less efficient alternative. By 2007, high efficiency furnaces had grown to represent 76% of all furnaces being replaced in Manitoba homes. In 2008, to accelerate the number of customers upgrading their furnaces, Manitoba Hydro increased their rebate to $500 for a limited time offering and aggressively promoted the financial and comfort benefits of upgrading a furnace. As market acceptance increased, Manitoba Hydro worked with the Province of Manitoba to develop the framework to regulate the minimum efficiency of all natural gas furnaces installed in Manitoba. On December 30, 2009, with market penetration of 86%, the Power Smart incentive ended and the Provincial regulation took effect requiring a minimum 92% AFUE for natural gas furnaces installed in Manitoba.

DEMAND SIDE MANAGEMENT PLAN

The 2018/19 DSM Plan was developed through an intensive planning process and it offers programs and initiatives to pursue opportunities in all market sectors; residential, commercial, and industrial. These programs are designed based on in-depth knowledge of the technology and the market environment. An in-depth understanding is essential to ensure that the program design is adequately and effectively addressing the appropriate target market and contains the tools and strategies to address market barriers. The following table outlines the forecasted achievements for 2018/19:

Programs	Participation Definition	2018/19 Participation	Capacity Savings (MW)	Energy Savings (GW.h)	Natural Gas Savings (million m^3)	Utility Investment (millions $)
New Homes Program	No. of houses	400	1.6	3.1	0.1	$1.3
Home Insulation Program	No. of houses	1,718	1.5	3.3	0.5	$2.7
Water and Energy Saver Program	No. of houses	14,975	0.2	2.2	0.7	$1.4
Affordable Energy Program	No. of retrofits	3,428	1.3	3.9	0.9	$6.5
Refrigerator Retirement Program	No. of appliances	7,215	0.8	7.6	-	$1.6
Residential LED Lighting Program	No. of bulbs	710,783	5.6	17.8	-	$2.1
Community Geothermal Program	No. of systems	125	1.0	2.0	-	$0.9
Appliances	No. of appliances	5,800	0.1	1.3	0.0	$0.5
Power Bars	No. of power bars	600	0.0	0.0	-	$0.0
Smart Thermostats	No. of thermostats	2,500	0.2	0.5	0.3	$0.3
Plug-in Timers	No. of timers	5,000	0.0	0.3	-	$0.0
Power Smart Residential Loan	No. of loans	3,726	0.1	0.3	0.3	$0.0
Power Smart PAYS Financing	No. of loans	166	0.0	0.1	0.0	$0.0
Residential Earth Power Loan	No. of loans	90	0.3	0.7	0.0	$0.0
Residential Programs			**12.8**	**42.9**	**2.8**	**$17.3**
Commercial Lighting Program	No. of projects	1,700	15.0	60.9	-	$11.0
LED Roadway Lighting Conversion Program	No. of conversions	33,030	2.1	14.4	-	$11.5
Commercial Building Envelope - Windows Program	No. of projects	150	0.4	1.0	0.6	$0.9
Commercial Building Envelope - Insulation Program	No. of projects	270	1.5	3.2	1.1	$1.8
Commercial Geothermal Program	No. of buildings	7	0.2	0.4	-	$0.3
Commercial HVAC Program - Boilers	No. of boilers	112	-	-	0.6	$0.6
Commercial HVAC Program - CO2 Sensors	No. of sensors	65	0.1	0.1	0.0	$0.1
Commercial HVAC Program - HRV/ERV	No. of units	11	0.1	0.2	0.1	$0.3
Commercial HVAC Program - Water Heaters	No. of water heaters	27	-	-	0.1	$0.1
Commercial Custom Measures Program	No. of projects	25	0.3	2.0	0.3	$0.6
Enhanced Building Operations Program	No. of buildings	5	0.2	1.0	0.2	$0.3
New Buildings Program	No. of buildings	15	0.8	2.8	0.1	$1.5
Commercial Refrigeration Program	No. of locations	265	1.2	8.8	0.0	$0.5
Commercial Kitchen Appliance Program	No. of appliances	19	0.0	0.1	0.0	$0.1
Network Energy Management Program	No. of licenses	1,000	0.0	0.2	0.0	$0.0
Internal Retrofit Program	No. of projects	53	0.8	4.8	0.1	$0.8
Power Smart Shops	No. of projects	807	0.3	2.1	0.0	$0.9
Race to Reduce	No. of buildings	6	0.1	0.9	0.1	$0.2
Parking Lot Controller	No. of controllers	54	0.0	1.0	-	$0.2
Power Smart for Business PAYS Financing	No. of loans	28	0.0	0.0	0.0	$0.0
Commercial Programs			**23.0**	**103.8**	**3.1**	**$31.7**
Performance Optimization Program	No. of projects	80	1.4	13.6	-	$2.5
Natural Gas Optimization Program	No. of projects	10	-	-	2.0	$0.7
Industrial Programs			**1.4**	**13.6**	**2.0**	**$3.2**
Energy Efficiency Subtotal			**37.3**	**160.3**	**8.0**	**$52.2**
Curtailable Rate Program	No. of customers	3	168.7	-	-	$6.1
Load Management			**168.7**	**0.0**	**0.0**	**$6.1**
Bioenergy Optimization Program	No. of projects	2	0.4	1.0	-	$0.5
Customer Sited Load Displacement	No. of customers	2	15.3	113.9	-	$7.1
Load Displacement & Alternative Energy			**15.7**	**114.9**	**0.0**	**$7.6**
Residential Solar Photovoltaics Program (PV)	No. of systems	264	0.0	7.4	0.0	$5.1
Commercial Solar Photovoltaics Program (PV)	No. of systems	28	0.0	2.0	0.0	$1.3
Other Emerging Technologies			**0.0**	**9.4**	**0.0**	**$6.4**
Codes, Standards & Regulations			17.9	70.5	3.7	-
Interactive Effects			-	-	-3.1	-
Program Support			-	-	-	$3.7
Demand Side Management Plan - 2018/19			**240**	**355**	**8.5**	**$76.0**

Residential

Manitoba Hydro offers a number of innovative programs, using a variety of market intervention tools including but not limited to, incentives, financing, education, and energy assessments to address opportunities in the residential market.

New Homes Program

Power Smart for New Homes is a residential new construction program providing incentives to builders and customers for the optimized design and construction of energy-efficient homes.

To be eligible for incentives, the home must be at least 20 per cent more energy efficient than a conventional new home. Completed Power Smart homes automatically qualify for the Canada Mortgage and Housing Corporation (CMHC) mortgage premium refund program, and homeowners receive an official Power Smart certificate and an EnerGuide label, if applicable.

Power Smart for New Homes offers two participation paths and will accept applications for homes built under a variety of energy efficient, sustainable, or green construction programs. In the 2018/19 year, the program will absorb the Advanced HRV Control program and begin to offer incentives on advanced HRV controls to builders who have chosen not to participate in the whole-home rebate stream.

In 2018/19, program participation is expected to be 400 new residential dwellings, which includes 300 single detached and 100 multi attached units, resulting in 3.1 GW.h and 1.6 MW of electric savings and over 84,000 cubic metres of natural gas savings. Combined with achievements to date, approximately 648 new residential dwellings will have participated resulting in 4.1 GW.h and 2.3 MW of electric savings and 0.1 million cubic metres of natural gas by the end of 2018/19.





	2015/16 to 2017/18*	2018/19	Total to 2018/19
No. of Houses	248	400	**648**
Capacity Savings (MW)	0.7	1.6	**2.3**
Energy Savings (GW.h)	1.0	3.1	**4.1**
Natural Gas Savings (million m^3)	0.1	0.1	**0.1**
Utility Investment (Millions, $)	$0.9	$1.3	**$2.2**
Customer Investment (Millions, $)	$0.9	$3.6	**$4.4**
Total DSM Investment (Millions, $)	$1.7	$4.8	**$6.6**
Estimated Average Annual Bill Reduction per Customer (Electric Home): $556			
Estimated Average Annual Bill Reduction per Customer (Natural Gas Home): $203			

*Includes estimates for 2017/18

Home Insulation Program



The program encourages owners of electric and natural gas heated homes built before 1999 to upgrade their insulation to Power Smart levels and perform air sealing in their attics, walls, and foundations. The overall target market for the program is approximately 48,600 electric and 81,500 natural gas homes. The program addresses the multiple barriers to completing these upgrades, focusing on the lack of customer awareness regarding the financial and comfort benefits of increased insulation levels, the upfront capital cost of the upgrade, and the lack of priority when compared to more aesthetic and visible renovation projects. These market barriers are addressed through a comprehensive strategy that includes financial incentives to reduce the cost of the upgrade, informational materials in the form of advertising campaigns, and renovation "how to" booklets that provide technical guidance for upgrading insulation to Power Smart levels. The program is delivered through a large network of industry contractors and retailers across the province. Home owners can qualify for incentives covering up to 100% of the cost of their insulation materials on projects that meet Power Smart insulation levels.



A targeted outreach initiative, offering free in-home energy assessments, assists customers in identifying opportunities for qualifying insulation upgrades. The program also offers rebates during the spring and fall residential campaigns on weather stripping and window kits at participating retailers.

The Home Insulation Program was launched in May 2004. In 2018/19, the program is targeted to retrofit 708 electrically heated homes and 1,010 natural gas heated homes, achieving 3.3 GW.h and 1.5 MW of electric savings and 0.5 million cubic metres of natural gas savings. Combined with achievements to date, approximately 15,300 electrically heated homes and 28,500 natural gas heated homes will be retrofitted, resulting in 78.9 GW.h and 38.4 MW of electric savings and 15.4 million cubic metres of natural gas savings by the end of 2018/19. The program is forecast to reach 31% of targeted electric customers and 35% of targeted natural gas customers by the end of 2018/19.

	2004/05 to 2017/18*	2018/19	Total to 2018/19
No. of Houses	42,134	1,718	**43,852**
Capacity Savings (MW)	36.9	1.5	**38.4**
Energy Savings (GW.h)	75.7	3.3	**78.9**
Natural Gas Savings (million m^3)	14.9	0.5	**15.4**
Utility Investment (Millions, $)	$44.0	$2.7	**$46.7**
Customer Investment (Millions, $)	$24.2	$1.0	**$25.2**
Total DSM Investment (Millions, $)	$68.2	$3.7	**$71.9**
Estimated Average Annual Bill Reduction per Customer (Electric): $360			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $115			

*Includes estimates for 2017/18

Affordable Energy Program



The Affordable Energy Program (AEP) was launched in December 2007. In 2018/19, program participation is expected to be 3,428 customers, resulting in 3.9 GW.h and 1.3 MW of electric savings and 0.9 million cubic metres of gas savings. Combined with achievements to date, approximately 25,797 customers will have participated resulting in 36.2 GW.h and 16.5 MW of electric savings and 11.4 million cubic metres of natural gas savings by the end of 2018/19.

The program is designed to assist lower income homeowners and renters in implementing energy efficiency upgrades, such as improved insulation, high efficiency natural gas furnaces and various basic energy efficiency measures. These upgrades can provide significant energy savings, decreasing the customer's monthly energy bills while increasing the comfort of their home. The criteria for determining program eligibility are the Low Income Cut-Off (LICO) thresholds set by Statistics Canada; customers' total household income must fall below 125% of the LICO thresholds for inclusion in the program. Based on the Power Smart Residential End Use Survey data, there are approximately 115,000 homes in Manitoba, excluding multi-unit residential buildings, which fall below the LICO 125% threshold; 97,630 customers own their home, while 17,512 customers rent. The primary targets within this market are homes with poor or fair insulation levels and standard efficient natural gas furnaces. As of 2018/19, the program projects that there are approximately 15,500 insulation customers and 3,250 standard furnace customers remaining in the market. In addition, the Affordable Energy Program targets multi-unit residential buildings (apartment style) for basic energy efficiency upgrades. There are approximately 24,300 remaining apartment suites which fall within the LICO 125% market. The program is currently working with landlords and property managers to retrofit suites with basic energy efficiency measures.

The program was designed recognizing the unique barriers lower income customers face in completing energy efficiency retrofits. Manitoba Hydro assists and encourages participation in this market by minimizing the financial burden with free insulation upgrades, a high efficiency natural gas furnace for $9.50/month for 5 years, and free basic energy efficiency measures (e.g. LEDs, showerheads, faucet aerators, etc.). The program expansion to include landlords has been successful in helping reach lower income Manitobans who rent in reducing their utility bills. The program is delivered through a number of approaches including direct participation with individual customers, through social enterprise contractors Brandon Energy Efficiency Program (BEEP) and Building Urban Industries for Local Development (BUILD), or through community groups (e.g. First Nation communities and neighbourhood or community associations). Through these approaches, customers are made aware of the value of energy efficiency retrofits, along with the benefits of participating in the program. Customers are targeted through advertising and community-based campaigns, customized information sessions, and community networks.

A community-led initiative, the Neighbourhood Approach, began in fall 2012 with the goal of completing energy efficiency upgrades on a block-by-block basis in lower income neighbourhoods. Under this approach, North End Community Renewal Corporation employs local residents BUILD to bring energy efficiency upgrade opportunities direct to the customer's door.

To date, an estimated 22,369 homes have completed energy efficiency retrofits. Of the total retrofits, approximately 11,464 insulation projects have been completed, and 5,730 furnace replacements have been completed. The program is forecast to reach 6% (898) of the remaining targeted homes with poor or fair insulation levels within the total LICO 125% market in 2018/19. The program is forecast to reach 16% (510) of the remaining standard furnaces in the LICO 125% market in 2018/19.

	2007/08 to 2017/18*	2018/19	Total to 2018/19
Total Participation	22,369	3,428	**25,797**
No. of Insulation Projects	11,464	898	**12,362**
No. of Furnaces Installed	5,730	510	**6,240**
No. of Boilers Installed	130	10	**140**
Capacity Savings (MW)	15.2	1.3	**16.5**
Energy Savings (GW.h)	32.3	3.9	**36.2**
Natural Gas Savings (million m^3)	10.4	0.9	**11.4**
Utility Investment (Millions, $)	$63.0	$6.5	**$69.5**
Customer Investment (Millions, $)	$4.5	$0.2	**$4.6**
Total DSM Investment (Millions, $)	$67.5	$6.7	**$74.2**
Estimated Average Annual Bill Reduction per Customer - Basic Measures (Electric): $70			
Estimated Average Annual Bill Reduction per Customer - Basic Measures (Natural Gas): $34			
Estimated Average Annual Bill Reduction per Customer (Electric) - Insulation: $643			
Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Insulation: $194			
Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Furnace: $189			

*Includes estimates for 2017/18

Water and Energy Saver Program

The Water and Energy Saver program was launched in September 2010. The program reduces residential water heating energy consumption through the use of low flow, energy efficient plumbing fixtures. Customers are offered a free water and energy saver kit with program messaging focused on the energy and water benefits and bill reductions associated with energy efficient plumbing fixtures. The program offers five channels of participation: mail, targeted direct installation, a bulk mail or installation option for multi-unit residential facilities, community events, as well as a limited time in-store rebate on qualifying showerheads.





Program participation in 2018/19 is expected to be 14,975 households, resulting in 2.2 GW.h and 0.2 MW of electric savings and 0.7 million cubic metres of gas savings. Combined with achievements to date, 213,672 customers will have participated resulting in 32.8 GW.h and 5.7 MW of electric savings and 6.4 million cubic metres of natural gas savings by the end of 2018/19. The program is forecast to reach 60% of targeted customers by the end of 2018/19.

The target market includes residential dwellings (non-LICO) that use electricity or natural gas to heat water, totaling approximately 355,000 customers.

The program continues to engage and educate customers about the environmental benefits of energy and water conservation and bill saving opportunities for customers. The program is scheduled to run until the end of March 2019.

	2010/11 to 2017/18*	2018/19	Total to 2018/19
No. of Houses	198,697	14,975	**213,672**
Capacity Savings (MW)	5.4	0.2	**5.7**
Energy Savings (GW.h)	30.6	2.2	**32.8**
Natural Gas Savings (million m³)	5.7	0.7	**6.4**
Utility Investment (Millions, $)	$11.6	$1.4	**$13.0**
Customer Investment (Millions, $)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, $)	$11.6	$1.4	**$13.0**
Estimated Average Annual Bill Reduction per Kit (Electric): $30			
Estimated Average Annual Bill Reduction per Kit (Natural Gas): $19			

*Includes estimates for 2017/18

Refrigerator Retirement Program

The Refrigerator Retirement program was launched in June 2011. In 2018/19, the program expects to retire 5,000 refrigerators and 1,500 freezers and has been expanded to also retire 715 window air conditioners, dehumidifiers and bar fridges or small freezers. This results in an estimated 7.6 GW.h and 0.8 MW of electric savings. Combined with achievements to date, 69,785 customers will have participated resulting in 84.3 GW.h and 8.5 MW of electric savings by the end of 2018/19. The program is forecast to reach an additional 2% of the remaining potential market by the end of 2018/19, bringing the total market penetration to 16%.





The program reduces residential energy consumption through the removal of old, inefficient, and often nearly empty refrigerators and freezers. Manitoba Hydro will also collect old window air conditioning units, dehumidifiers and small fridges/freezers if accompanied with a qualifying full size refrigerator or freezer. Customers receive free in-home pick-up of qualifying working units plus a financial incentive of $50 for each qualifying full size fridge or freezer. Pick up and recycling of an air-conditioner and/or dehumidifier and bar fridge or small freezer is complimentary but customers will not receive a financial incentive for these units. The program ensures environmental recycling of each unit retired and encourages customers to retire their secondary units and not replace it in order to maximize their savings.

The remaining target market includes all single family residential homes yielding approximately 160,000 older fridges, and 155,000 older freezers and approximately 70,000 older window air-conditioners and dehumidifiers, bar fridges and small freezers.

Most customers do not know the costs of operating an underutilized refrigerator or freezer, and many lack assistance in removing the appliance from the home. Through the Refrigerator Retirement Program, customers are made aware of the costs of their second appliance and the benefits of "retiring" it. The program makes retiring easy by providing a convenient in-home pickup service and pays them to participate.

	2011/12 to 2017/18*	2018/19	Total to 2018/19
Total Participation	62,570	7,215	**69,785**
No. of Fridges	51,750	5,000	**56,750**
No. of Freezers	10,820	1,500	**12,320**
No. of Dehumidifiers	0	390	**390**
No. of Window Air Conditioning Units	0	325	**325**
Capacity Savings (MW)	7.7	0.8	**8.5**
Energy Savings (GW.h)	76.7	7.6	**84.3**
Utility Investment (Millions, $)	$12.5	$1.6	**$14.1**
Customer Investment (Millions, $)	$5.3	$0.7	**$6.0**
Total DSM Investment (Millions, $)	$17.8	$2.3	**$20.1**
Estimated Average Annual Bill Reduction per Customer (Electric) without fridge replacement: $131			
Estimated Average Annual Bill Reduction per Customer (Electric) without freezer replacement: $100			
Estimated Average Annual Bill Reduction per Customer (Electric) without dehumidifier replacement: $87			
Estimated Average Annual Bill Reduction per Customer (Electric) without AC Unit replacement: $33			

*Includes estimates for 2017/18

Residential LED Lighting Program

The Residential LED Lighting program is designed to encourage residential customers to choose the most energy efficient lighting technology for each application within their home. The program aims to increase the adoption of Light Emitting Diode (LED) technology as a replacement for incandescent and halogen screw-in light bulbs. The program offers two channels of participation: mass market retail rebate campaigns and rebates for property managers of multi-unit residential buildings.



The program was launched in October 2014. In 2018/19, program participation is expected to be over 59,000 residential dwellings (over 710,000 LED bulbs) resulting in 17.8 GW.h and 5.6 MW of electric savings. Combined with achievements to date, program participation will be more than 287,000 residential dwellings (over 3.4 million LED bulbs) resulting in 108.8 GW.h and 34.3 MW of electric savings by the end of 2018/19.

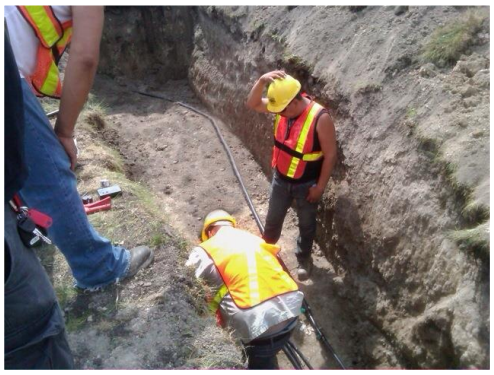
The target market includes 530,000 residential dwellings and approximately 18 million screw-based sockets in which LED bulbs can be used. Consumers are slowly replacing existing incandescent and halogen bulbs with LEDs; however, the high upfront cost and low consumer awareness of specialty LED bulbs remain barriers to widespread adoption.

	2014/15 to 2017/18*	2018/19	Total to 2018/19
No. of Bulbs	2,736,279	710,783	**3,447,062**
Capacity Savings (MW)	28.7	5.6	**34.3**
Energy Savings (GW.h)	91.0	17.8	**108.8**
Utility Investment (Millions, $)	$12.8	$2.1	**$14.9**
Customer Investment (Millions, $)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, $)	$12.8	$2.1	**$14.9**
Estimated Average Annual Bill Reduction per Bulb (Electric): $2			

*Includes estimates for 2017/18



Community Geothermal Program



The Community Geothermal Program aims to reduce customers' electric space heating costs through the adoption of geothermal heat pump systems. The program is designed to offer a customized approach for each community, with the assistance of AKI Energy, a non-profit indigenous social enterprise. To help mitigate the high capital cost barrier, a third-party provider is contracted to conduct a feasibility study and to provide a quote on the bulk purchase of the heat pump units, resulting in a much lower per unit price than the current market average. Another component of the program includes creating job opportunities and training for First Nations to take part in the installation and the on-going maintenance of the geothermal systems, with training funded by the First Nation. Manitoba Hydro provides technical guidance, assesses the energy bills to determine which homes would most benefit from geothermal installations, and explores opportunities to further maximize the number of geothermal installations within the community. Manitoba Hydro's PAYS Financing Program is vital in enabling community members to pay for the majority of the geothermal system through the energy savings which are realized by converting their heating/air conditioning systems to a geothermal system. In homes where the energy savings cannot support financing the full cost of the geothermal system through the PAYS Financing Program, Manitoba Hydro provides financial incentives.

Manitoba Hydro and Aki Energy have assisted four First Nations communities with 385 installs to date. In 2018/19, the program is expected to achieve 2.0 GW.h and 1.0 MW of electric savings. Combined with achievements to date, 510 systems will be installed, resulting in 6.8 GW.h and 2.0 MW of electric savings by the end of 2018/19.

	2013/14 to 2017/18*	2018/19	Total to 2018/19
No. of Geothermal Systems	385	125	**510**
Capacity Savings (MW)	1.0	1.0	**2.0**
Energy Savings (GW.h)	4.8	2.0	**6.8**
Utility Investment (Millions, $)	$2.8	$0.9	**$3.6**
Customer Investment (Millions, $)	$5.1	$1.9	**$7.0**
Total DSM Investment (Millions, $)	$7.9	$2.8	**$10.7**
Estimated Average Annual Bill Reduction per Customer (Electric): $1,061			

*Includes estimates for 2017/18

Appliances and Electronics Initiative

The Residential Appliances and Electronics Initiative will run again in the fall 2018. Instant rebates on Advanced Power Bars and Plug in Timers will be offered during a four week campaign as part of the overall fall 2018 Retail Rebate Campaign, which also includes rebates on LED lighting, weather stripping and other energy saving devices. Bill credits will also be offered for the purchase of designated residential appliances and will run for four months from November 2018 to February 2018. In addition, a clothesline giveaway is planned for spring 2019.

Appliances

The program helps customers reduce their energy consumption by choosing appliances that meet the highest levels of energy efficiency. A financial incentive will be available for top energy performing Clothes Washers, Clothes Washer/Dryer Combinations, and for the most energy efficient refrigerators. Customers will receive the incentive by way of a credit applied directly to their Manitoba Hydro bill.





The target market includes approximately 30,000 customers who will be purchasing a new clothes washer or clothes washer/dryer combo and approximately 20,000 customers who will be purchasing a new refrigerator. The initiative is expected to reach approximately 4% of the market.

Plug-in Timers

Plug-in Timers help customer reduce their energy consumption by using an indoor and/or outdoor plug-in timer for lights, block heaters, pool pumps, etc. Operating household devised with a plug –in timer will help save energy result in lower energy bills.



The target market for plug-in timers including 105,000 residential customers who plug the block heater in their vehicle in for more than seven hours a day and do not use a plug in timer as well as customers who leaving indoor lights on for more than 7 hours per day. The program is expected to reach 3% of the target market through the rebate campaign.

Advanced Power Bars

Advanced Power Bars help customers reduce the amount of electricity their household electronics consume. Electronics that are left plugged in can continue to consume electricity even when not in use. This category of products includes power bars that contain features such as integrated timers or smart features with automatic shut off functions that will help customers save electricity.



Virtually all households operate at least one TV and set top box, representing 470,000 customers. As many as 275,000 of these customers will operate a DVD player, and further 135,000 customers will operating some sort of gaming consoles all which make up the target market. In 2018/19, this initiative aims to reach a small percentage of customers and the focus continues to be to work with retailers to increase the availability on these types of energy saving devices. The target market for Power Bars includes all residential Manitoba Hydro residential customers using electronic devices.

In 2018/19, program participation for all components is expected to be 11,400 units resulting in 1.6 GW.h and 0.1 MW of electric savings and 3,500 cubic metres of natural gas savings. Combined with achievements to date, program participation will be approximately 25,211 units resulting in 3.4 GW.h and 0.4 MW of electric savings and 20,000 cubic metres of natural gas savings by the end of 2018/19.

	2016/17 to 2017/18*	2018/19	Total to 2018/19
No. of Units	13,811	11,400	**25,211**
Capacity Savings (MW)	0.3	0.1	**0.4**
Energy Savings (GW.h)	1.8	1.6	**3.4**
Natural Gas Savings (million m³)	0.0	0.0	**0.0**
Utility Investment (Millions, $)	$1.0	$0.5	**$1.5**
Customer Investment (Millions, $)	$0.8	$0.1	**$1.0**
Total DSM Investment (Millions, $)	$1.8	$0.7	**$2.5**
Estimated Average Annual Bill Reduction per Customer (Electric) - Clothes Washer: $27			
Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Clothes Washer: $2			
Estimated Average Annual Bill Reduction per Customer (Electric) - Clothes Washer & Clothes Dryer: $30			
Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Clothes Washer & Clothes Dryer: $3			
Estimated Average Annual Bill Reduction per Customer (Electric) - Refrigerator: $10			
Estimated Average Annual Bill Reduction per Customer (Electric) - Power Bar: $4			
Estimated Average Annual Bill Reduction per Customer (Electric) - Plug-in Timer: $5			

*Includes estimates for 2017/18

Smart Thermostats



Wi-Fi connected "smart" thermostats have the potential to achieve further energy savings than manual or simple programmable units. Smart thermostats vary in the system's individual algorithms and achieve enhanced savings in several ways: by learning occupant patterns; by coordinating temperature settings with occupancy; by optimizing system performance; and by taking humidity and weather conditions into account, thereby reducing HVAC runtimes. Smart thermostats also give consumers a new level of control over their household climate by enabling remote activation, voice activation, or geo-fencing to modify settings.

Manitoba Hydro ran a Smart Thermostat Pilot study throughout 2016 and into 2017, with the objective of determining the potential savings for gas-heated and electric-heated households across Manitoba. Results are expected to be released at the end of the 2017/18 fiscal year.

In late 2016, ENERGY STAR® began certifying connected thermostats and Natural Resources Canada advises ENERGY STAR certified connected thermostats can save at least 8% of the energy used for space heating and cooling in residential applications. ENERGY STAR certified connected thermostats are automatically eligible for rebates under Manitoba Hydro's Bill Credit Rebate program.

A smart thermostat Bill Credit Rebate campaign was run for four months in the 2016/17 fiscal year and was renewed for the 2017/18 fiscal year. The second campaign is offered from November 1, 2017 to February 28, 2018 and provides a $75 bill credit to residential customers who purchase an eligible smart thermostat device. The product category for smart thermostats is growing rapidly and it is estimated that by the year 2020, as many as 50% of homes will contain a smart or connected thermostat.

The 2018/19 smart thermostat rebate program is estimated to generate sales of 2,500 devices, with annual electric savings of 0.5 GW.h and 0.2 MW and natural gas savings of 0.3 million cubic metres. Combined with achievements to date, program participation will be approximately 4,875 devices resulting in 1.4 GW.h and 0.9 MW of electric savings and 0.6 million cubic metres of natural gas savings by the end of 2018/19.

	2015/16 to 2017/18*	2018/19	Total to 2018/19
No. of Thermostats	2,375	2,500	**4,875**
Capacity Savings (MW)	0.7	0.2	**0.9**
Energy Savings (GW.h)	1.0	0.5	**1.4**
Natural Gas Savings (million m³)	0.3	0.3	**0.6**
Utility Investment (Millions, $)	$0.8	$0.3	**$1.1**
Customer Investment (Millions, $)	$1.3	$0.8	**$2.0**
Total DSM Investment (Millions, $)	$2.1	$1.0	**$3.1**
Estimated Average Annual Bill Reduction per Customer (Electric): $91 Estimated Average Annual Bill Reduction per Customer (Natural Gas): $34			

*Includes estimates for 2017/18

Solar Energy Pilot Program

In April 2016 Manitoba Hydro expanded Manitobans' renewable energy options by introducing the Power Smart Solar Energy Pilot Program (SEP). This two-year pilot program offered a financial incentive towards the purchase of a Solar Photovoltaic (PV) system, and was open to residential, commercial and industrial customers who are connected to the Manitoba Hydro grid. The incentive of $1 per watt covered approximately 37 per cent of the installed cost of the system.



Launching the pilot program offered Manitoba Hydro an excellent opportunity to evaluate the opportunities and challenges of solar PV in the Manitoba market, the processes required to support the technology, and most importantly the effects the distribution grid. The program has resulted in growth in the number of solar industry suppliers, created more jobs for electrical trade workers, provided competition and drove prices down in the market, while growing Manitoba's green economy.

As enrollment in the pilot comes to an end April 30, 2018, program participation is expected to be 264 residential customers and 28 commercial customers, resulting in 9.4 GW.h of electric savings. Combined with achievements to date, 577 customers will have participated resulting in 16.4 GW.h and 0.8 MW of electric savings by the end of 2018/19. This initiative also leverages the existing Earth Power Loan, which offers on-bill financing to residential customers installing solar PV.

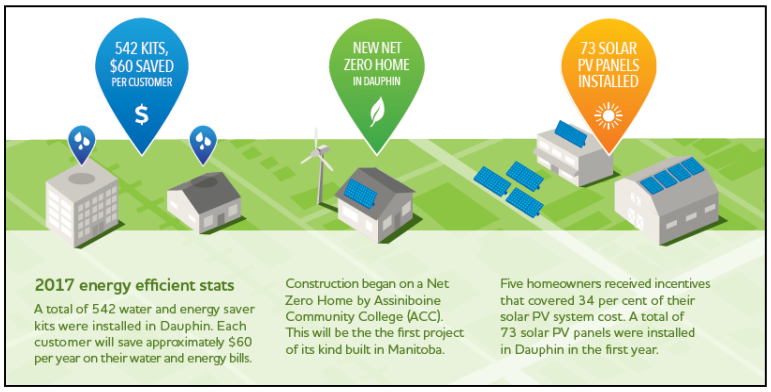
	2016/17 to 2017/18*	2018/19	Total to 2018/19
No. of Systems - Residential	267	264	**531**
No. of Systems - Commercial	18	28	**46**
Capacity Savings (MW)	0.8	0.0	**0.8**
Energy Savings (GW.h)	7.1	9.4	**16.4**
Utility Investment (Millions, $)	$4.9	$6.4	**$11.2**
Customer Investment (Millions, $)	$5.7	$12.1	**$17.8**
Total DSM Investment (Millions, $)	$10.6	$18.5	**$29.0**
Estimated Average Annual Bill Reduction per Customer (Electric) - Residential: $2,167			
Estimated Average Annual Bill Reduction per Customer (Electric) - Commercial: $5,532			

*Includes estimates for 2017/18

Community Energy Plan

Manitoba Hydro continues to promote energy efficiency using a direct and aggressive approach by partnering with communities to establish a Community Energy Program. A two year pilot scheduled to run until the fall of 2018, is currently underway with Dauphin and The Pas aimed at making these communities leaders in energy efficiency. The pilot will serve as a guide for communities to undertake energy efficiency upgrades in the residential, commercial, and industrial sectors to reduce energy consumption, and assist in lowering utility bills and overall operating costs.

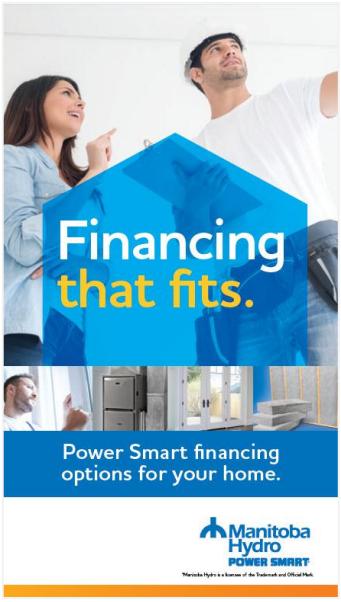
Manitoba Hydro developed an Energy Profile to assist these communities in prioritizing their energy efficiency efforts and establish goals and objectives. The Community Energy Plan will leverage Power Smart programs to assist in achieving these objectives. Taking a community approach to energy efficiency allows for community members to be active participants and work together in achieving a common goal.



The following convenient financing programs offered by Manitoba Hydro supports energy efficiency upgrades by allowing customers to finance initial project costs and pay these costs back on their monthly Manitoba Hydro bill.

Power Smart Residential Loan

The Power Smart Residential Loan (PSRL), launched in March 2001, provides customers with convenient on-bill financing to assist them in making their home more energy efficient. Under the PSRL, the following energy efficiency improvements can be made to the home: insulation, ventilation equipment, air leakage sealing, windows and doors, electric vehicle chargers, and space and water heating equipment. Participants can borrow up to $7,500 (exceptions to this are $5,500 for natural gas furnaces and $3,000 for electric vehicle chargers) and repay the amount on their energy bill over a term of up to 5 years (up to 15 years for natural gas furnaces and boilers). The target market consists of electric and natural gas homeowners in Manitoba.



In 2018/19, the program is expected to finance energy efficient upgrades for 3,726 homes, achieving 0.3 GW.h and 0.1 MW of electric savings and 0.3 million cubic metres of natural gas savings. Combined with achievements to date, 98,280 homes will be retrofitted, resulting in 12.1 GW.h and 6.7 MW of electric savings and 16.7 million cubic metres of natural gas savings by the end of 2018/19.

	2001/02 to 2017/18*	2018/19	Total to 2018/19
No. of Loans	94,554	3,726	**98,280**
Capacity Savings (MW)	6.6	0.1	**6.7**
Energy Savings (GW.h)	11.9	0.3	**12.1**
Natural Gas Savings (million m³)	16.4	0.3	**16.7**
Average Loan Amount: $5,054			

*Includes estimates for 2017/18

Power Smart PAYS Financing

Launched in November 2012, the Power Smart Pay-As-You-Save (PAYS) Financing Program offers low-interest on-bill financing for energy efficient upgrades. This offering complements and supports existing incentive-based programs by assisting customers in managing the installation cost of their upgrade. To qualify, upgrades must have sufficient estimated annual utility bill savings to offset the monthly financing payment, thereby resulting in an energy bill that is less than or equal to the total bill prior to the retrofit. PAYS financing also differs from Manitoba Hydro's other financing programs in that the loan is transferable between homeowners when a property is sold, and is transferable from a landlord to a tenant where the tenant is responsible for paying the energy bill.



Financing is available over a term of up to 25 years (depending on the technology financed) with a 5-year fixed interest rate. Energy efficient upgrades that may qualify for financing are:

- Space heating equipment:
  - High efficiency natural gas furnaces;
  - Natural gas boilers (minimum AFUE of 85%);
  - Geothermal heat pump systems;
- Insulation upgrades;
- Drain water heat recovery systems;
- WaterSense-labeled toilets (in conjunction with energy efficient equipment).

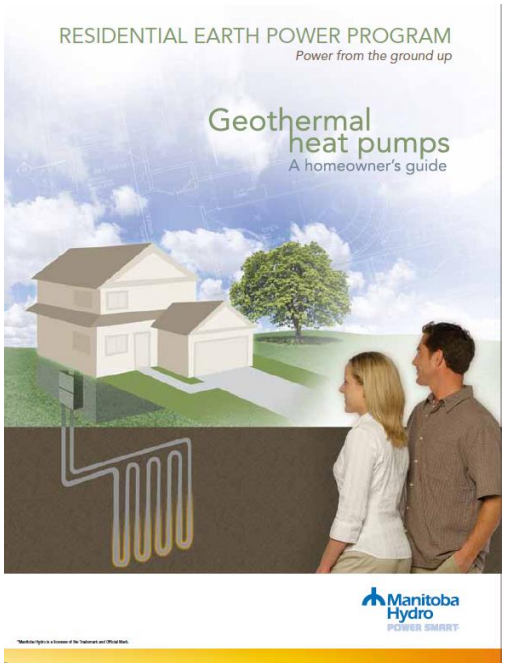
In 2018/19, the program is expected to finance energy efficient upgrades for 166 homes, achieving 0.1 GW.h and 0.03 MW of electric savings. Combined with achievements to date, 1,127 homes will be retrofitted, resulting in 2.1 GW.h and 0.5 MW of electric savings by the end of 2018/19.

	2012/13 to 2017/18*	2018/19	Total to 2018/19
No. of Loans	961	166	**1,127**
Capacity Savings (MW)	0.5	0.0	**0.5**
Energy Savings (GW.h)	2.0	0.1	**2.1**
Natural Gas Savings (million m³)	0.0	0.0	**-0.1**
Average Loan Amount: $8,731			

*Includes estimates for 2017/18

Residential Earth Power Loan

The Residential Earth Power Loan (REPL), launched in April 2002, supports the adoption of geothermal heat pump technology, and fosters awareness and growth of new, emerging technologies through educational materials, technical support, and training workshops. With that goal in mind, solar hot water systems were added to the loan in 2010 and solar photovoltaic (PV) systems and cold climate air source heat pump systems were added to the suite of eligible measures in 2016. Although more expensive to install, these technologies offer significant electricity savings, thereby reducing customers' monthly utility bills. The convenience and flexibility of the on-bill REPL reduces the financial barrier that exists when installing these systems.



Customers are eligible to finance up to $20,000 for geothermal heat pump systems, $7,500 for solar domestic water heating systems, $30,000* for solar PV systems, and $10,000 for cold climate air source heat pump systems. The financial terms include a 5-year fixed interest rate over a 15-year maximum amortization term. The interest rate for the balance of the financing period is established at Manitoba Hydro's cost of borrowing at the time the fixed interest rate term expires.

In 2018/19, the program participation is expected to be 90 loans, resulting in 0.7 GW.h and 0.3 MW of electric savings and 9,900 cubic metres of gas savings. Combined with achievements to date, 1,544 customers will participate resulting in 16.3 GW.h and 4.9 MW of electric savings and 3.1 million cubic metres of natural gas savings by the end of 2018/19. The program is forecasted to reach 0.6% of targeted customers by the end of 2018/19.

*Amount eligible to finance a solar PV system is based on an installed price per watt, up to a maximum of $30,000.

	2002/03 to 2017/18*	2018/19	Total to 2018/19
No. of Loans	1,454	90	**1,544**
Capacity Savings (MW)	4.6	0.3	**4.9**
Energy Savings (GW.h)	15.6	0.7	**16.3**
Natural Gas Savings (million m³)	3.0	0.0	**3.1**
Average Loan Amount: $14,844			

*Includes estimates for 2017/18

Commercial

Manitoba Hydro offers a number of innovative programs, using a variety of market intervention tools including but not limited to, incentives, financing, technical assistance, industry education and training, to address opportunities in the commercial market.

Commercial Lighting Program



The Commercial Lighting Program, launched in May 1992, reduces electricity consumption by accelerating the acceptance and adoption of energy efficient lighting technologies in Manitoba. Commercial, industrial, and agricultural customers are encouraged to install qualifying energy efficient lighting technologies in their facilities to reduce energy bills, improve the quality of lighting, as well as increase safety, security, and productivity.

The target market consists of all existing commercial, industrial, and agricultural buildings with inefficient lighting installations in Manitoba, where lighting systems operate a minimum of 2,000 hours per year. Lighting systems that operate between 1,000 to 1,999 hours per year may qualify for prorated incentives. The estimated market size is 52,500 potential lighting projects overall. Many energy efficient lighting options have higher initial capital costs, and oftentimes customers lack awareness of the technologies available and the non-energy related benefits of energy efficient lighting, thereby creating a barrier to the adoption of higher efficiency systems. In addition, many customers operate in commercial lease space where the person making decisions related to lighting upgrades may not pay the utility bill and therefore, does not realize the direct financial return. Strategies in place to address these market barriers include financial incentives, education and training, as well as technical and customer service support.

In 2018/19, program participation is expected to be 1,700 projects, resulting in 60.9 GW.h and 15.0 MW of electric savings. Combined with achievements to date, 19,910 projects will be completed resulting in 699.4 GW.h and 146.9 MW of electric savings by the end of 2018/19. The program is forecast to reach 38% of the target market by the end of 2018/19.

	1992/93 to 2017/18*	2018/19	Total to 2018/19
No. of Projects	18,210	1,700	**19,910**
Capacity Savings (MW)	131.9	15.0	**146.9**
Energy Savings (GW.h)	638.5	60.9	**699.4**
Utility Investment (Millions, $)	$122.3	$11.0	**$133.3**
Customer Investment (Millions, $)	$47.2	$5.2	**$52.4**
Total DSM Investment (Millions, $)	$169.4	$16.2	**$185.6**
Estimated Average Annual Bill Reduction per Customer (Electric): $191			

*Includes estimates for 2017/18

LED Roadway Lighting Conversion Program



Through the Power Smart LED Roadway Lighting Conversion Program, launched in June 2015, Manitoba Hydro will convert existing High Pressure Sodium (HPS) roadway, decorative, lane and area lights to Light Emitting Diode (LED) lights over a 7-year period. Manitoba Hydro provides energy and maintenance services to over 130,000 roadway lights across the Province of Manitoba.

The current roadway lighting technology is High Pressure Sodium (HPS), which produces a yellow/orange light and has a four-year lamp life. The wattages range from 70 to 1,000 and these light fixtures were originally installed in 1991 under a past Power Smart Roadway Lighting Conversion Program to replace Mercury Vapour and Incandescent lighting.

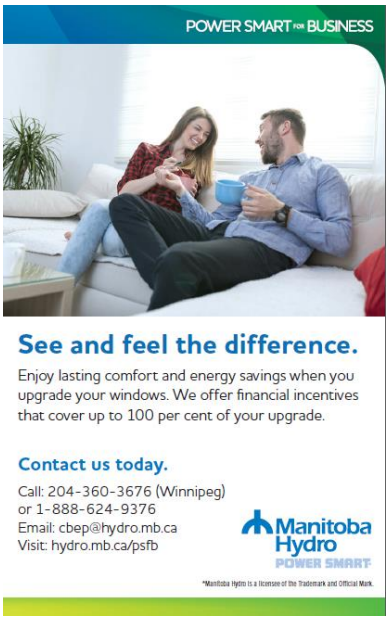
In addition to energy savings, LED roadway lighting has a significantly longer life than HPS lighting, quick turn on and off, and improved contrast and colour rendering due to their white light output. LED lights also provide the added benefit of directing the light downward onto the roadway increasing the amount of light on the road and improving drivers' visibility.

In 2018/19, program participation is expected to be 33,030 conversions, resulting in 14.4 GW.h and 2.1 MW of electric savings. Combined with achievements to date, 117,420 conversions will take place resulting in 50.6 GW.h and 7.8 MW of electric savings by the end of 2018/19. The program is forecast to reach 90% of targeted customers by the end of 2018/19.

	2014/15 to 2017/18*	2018/19	Total to 2018/19
No. of Conversions	84,390	33,030	**117,420**
Capacity Savings (MW)	5.7	2.1	**7.8**
Energy Savings (GW.h)	36.1	14.4	**50.6**
Utility Investment (Millions, $)	$36.1	$11.5	**$47.6**
Customer Investment (Millions, $)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, $)	$36.1	$11.5	**$47.6**

*Includes estimates for 2017/18

Commercial Building Envelope - Windows Program



The Commercial Building Envelope (Windows) Program, launched in 1995, improves building envelope performance and reduces energy consumption through the installation of high performance window and doors in existing commercial buildings. In 2016/17, the program expanded its offering to include financial incentives for doors and extending incentives for curtain wall upgrades to natural gas heated buildings. The target market consists of all existing commercial customers, primarily focused on sectors such as multi-unit residential buildings, schools, hotels/motels, personal care homes, and health care facilities. The program targets facilities planning to replace existing windows and/or doors, thus presenting an economic opportunity to install higher efficiency Power Smart qualifying systems at the time of replacement.

Market barriers include the incremental product cost of high performance windows, along with a lack of awareness of the significant potential energy savings and other non-energy benefits. Windows are also measure that is often deferred if other building maintenance upgrades are required. Providing financial incentives to help offset incremental material costs, working closely with local fabricators and window suppliers and contractors, while promoting the benefits of high performance windows is effectively addressing these barriers.

It is estimated that there are approximately 750 potential window replacement projects in Manitoba each year, of a total overall market of 27,000 potential projects.

In 2018/19, program participation is expected to be 150 projects, resulting in 1.0 GW.h and 0.4 MW of electric savings and 0.6 million cubic metres of gas savings. Combined with achievements to date, participation will be 2,023 projects resulting in 25.1 GW.h and 10.3 MW of electric savings and 3.9 million cubic metres of natural gas savings by the end of 2018/19. The program is forecast to reach 7.5% of the total potential market by the end of 2018/19.

	2006/07 to 2017/18*	2018/19	Total to 2018/19
No. of Projects	1,873	150	**2,023**
Capacity Savings (MW)	10.0	0.4	**10.3**
Energy Savings (GW.h)	24.1	1.0	**25.1**
Natural Gas Savings (million m³)	3.3	0.6	**3.9**
Utility Investment (Millions, $)	$17.3	$0.9	**$18.2**
Customer Investment (Millions, $)	$0.9	$3.9	**$4.8**
Total DSM Investment (Millions, $)	$18.2	$4.9	**$23.1**
Estimated Average Annual Bill Reduction per Customer (Electric): $213			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $412			

*Includes estimates for 2017/18

Commercial Building Envelope - Insulation Program

The Commercial Building Envelope (Insulation) Program, launched in April 2006, improves building envelope performance and reduces energy consumption by upgrading insulation levels in roof and wall areas of existing buildings. In 2016/17, the program expanded its offering to encourage a pilot program for air leakage reduction in commercial buildings.



The target market is comprised of all commercial customers with insulation levels that do not meet Power Smart levels. The program targets facilities planning to undergo extensive repairs to existing roofs and walls, presenting an economic opportunity to improve existing insulation levels at the time of renovation.

Market barriers include the capital cost of major upgrades to roofs and exterior facades, and a lack of awareness of the significant potential energy savings and other non-energy benefits associated with upgraded insulation levels. Insulation upgrades typically happen at the time of renovation, resulting in a lost opportunity if customers do not increase insulation at that time. Providing financial incentives to help offset incremental material costs and promoting the benefits of better insulated buildings are effectively addressing these barriers.

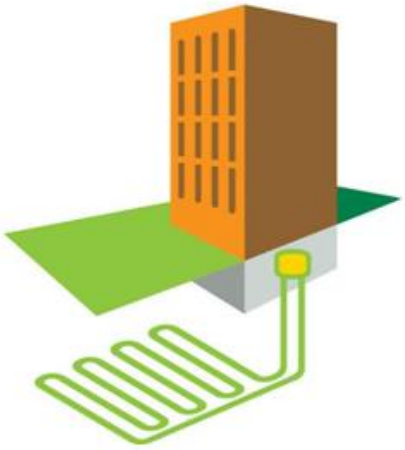
It is estimated that there are approximately 400 potential insulation replacement projects in Manitoba each year, of a total overall market of 15,000 potential projects.

In 2018/19, program participation is expected to be 270 projects, resulting in 3.2 GW.h and 1.5 MW of electric savings and 1.1 million cubic metres of natural gas savings. Combined with achievements to date, participation will be 2,534 projects resulting in 51.3 GW.h and 24.1 MW of electric savings and 16.3 million cubic metres of natural gas savings by the end of 2018/19. The program is forecast to reach 17% of the total potential market by the end of 2018/19.

	2006/07 to 2017/18*	2018/19	Total to 2018/19
No. of Projects	2,264	270	**2,534**
Capacity Savings (MW)	22.6	1.5	**24.1**
Energy Savings (GW.h)	48.1	3.2	**51.3**
Natural Gas Savings (million m^3)	15.2	1.1	**16.3**
Utility Investment (Millions, $)	$21.8	$1.8	**$23.6**
Customer Investment (Millions, $)	$14.9	$0.3	**$15.2**
Total DSM Investment (Millions, $)	$36.6	$2.2	**$38.8**
Estimated Average Annual Bill Reduction per Customer (Electric): $115			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $136			

*Includes estimates for 2017/18

Commercial Geothermal Program



The Commercial Geothermal Program, launched in 2007, encourages the installation of geothermal heat pumps in electrically heated commercial buildings. Through the program, customers are provided with information on how the geothermal heat pump technology works, the energy savings available, and other benefits to increase understanding and acceptance of the technology. Financial incentives are offered to help offset the higher capital costs of the system and increase adoption of this green heating option. The program also financially supports feasibility studies, ensuring the installation of a geothermal heat pump system is an economic option for the customer. Benefits of geothermal systems and program opportunities are communicated through the broad network of engineers, architects, consultants, contractors, and trade allies in Manitoba who have established relationships with the commercial and industrial customer base. The target market consists of existing commercial buildings that use conventional electric technologies for space heating at or approaching end of life. The high capital cost of installing a geothermal heat pump system, combined with the available supply of qualified installers and contractors in some regions of the province; challenging drilling and trenching conditions due to varying geological conditions; limited land area of many properties to accommodate the loop installation; and the proximity to the ground loop of underground facilities and services (water and sewer lines that may freeze, etc.) can make choosing geothermal as a heating/cooling option more challenging for the customer.

In 2018/19, program participation is expected to be 7 customers, resulting in 0.4 GW.h and 0.2 MW of electric savings. Combined with achievements to date, 156 customers will participate resulting in 45.3 GW.h and 17.3 MW of electric savings by the end of 2018/19. The program is forecast to reach 4% of targeted customers by the end of 2018/19.

	2007/08 to 2017/18*	2018/19	Total to 2018/19
No. of Buildings	149	7	**156**
Capacity Savings (MW)	17.2	0.2	**17.3**
Energy Savings (GW.h)	44.9	0.4	**45.3**
Utility Investment (Millions, $)	$5.5	$0.3	**$5.8**
Customer Investment (Millions, $)	$22.0	$0.1	**$22.1**
Total DSM Investment (Millions, $)	$27.5	$0.3	**$27.9**
Estimated Average Annual Bill Reduction per Customer (Electric): $5,609			

*Includes estimates for 2017/18

Commercial HVAC Program – Boilers



Launched in April 2006, the Commercial HVAC Program for Boilers seeks to transform the commercial boiler market in Manitoba by increasing awareness and adoption of energy efficient condensing and near-condensing boilers. Energy efficient boilers offer significant natural gas savings, reducing customers' monthly utility bills. The program focuses on educating building owners and operators about the benefits of energy efficient equipment and works with industry contractors, engineers, consultants, designers, and equipment dealers to promote these systems. Financial incentives ranging from $2/MBH (thousands of BTUs per hour) to $8/MBH are provided for qualifying systems. The program is designed to build market acceptance prior to a proposed minimum efficiency regulation, which is projected for adoption in April 2020.

The program's primary target market consists of commercial buildings with existing heating equipment that is at or nearing end of life. Boiler replacements are not likely to occur until existing equipment is nearing end of life and are often completed in an emergency situation during the heating season. Therefore, purchasing decisions are made with limited lead time and primarily based on the initial capital cost, not considering the annual operating costs of the system over its 25-year life. Condensing or near-condensing natural gas boilers are also more expensive to install than conventional boilers, and require modifications to the ventilation system. Financial incentives, combined with educational materials and information on the lifecycle cost advantage of installing energy efficient systems, endeavor to address these market barriers.

In 2018/19, program participation is expected to be 112 boilers, resulting 0.6 million cubic metres of gas savings. Combined with achievements to date, 1,467 boilers will be installed resulting in 14.2 million cubic metres of natural gas savings by the end of 2018/19.

	2006/07 to 2017/18*	2018/19	Total to 2018/19
No. of Boilers	1,355	112	**1,467**
Natural Gas Savings (million m³)	13.6	0.6	**14.2**
Utility Investment (Millions, $)	$13.0	$0.6	**$13.6**
Customer Investment (Millions, $)	$10.6	$0.5	**$11.1**
Total DSM Investment (Millions, $)	$23.6	$1.1	**$24.6**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $1,346			

*Includes estimates for 2017/18

Commercial HVAC Program - C02 Sensors



Launched in April 2009, the Commercial HVAC Program for CO2 Sensors is designed to increase the awareness and adoption of CO2 sensors in commercial facilities. CO2 sensors reduce energy consumption by matching ventilation supply to occupant demand, reducing customers' monthly utility bills. CO2 sensors also improve occupant comfort by providing more consistent air quality and can extend the life of heating and cooling equipment by putting less demand on these systems.

The program's primary target market consists of over-ventilated commercial facilities with variable occupancy that have, or are considering, direct digital control systems or rooftop units to control heating, cooling, and ventilation. Installations typically occur when other major renovations are being made to the ventilation system.

CO2 sensors are not required in commercial building operation and therefore, are often one of the first retrofit measures to be overlooked, particularly in the presence of budgetary constraints. Also, customers tend to be unfamiliar with the operation of their ventilation systems and therefore, may be unaware when their building is being over-ventilated. Aggressive financial incentives, combined with promoting the lifecycle cost advantage and improved ventilation benefits of CO2 sensor technology, endeavor to address these market barriers.

In 2018/19, program participation is expected to be 65 sensors, resulting in 0.1 GW.h and 0.1 MW of electric savings and 31,000 cubic metres of gas savings. Combined with achievements to date, 511 sensors will be installed resulting in 0.6 GW.h and 0.3 MW of electric savings and 0.7 million cubic metres of natural gas savings by the end of 2018/19.

	2009/10 to 2017/18*	2018/19	Total to 2018/19
No. of Sensors	446	65	**511**
Capacity Savings (MW)	0.2	0.1	**0.3**
Energy Savings (GW.h)	0.5	0.1	**0.6**
Natural Gas Savings (million m³)	0.7	0.0	**0.7**
Utility Investment (Millions, $)	$0.5	$0.1	**$0.6**
Customer Investment (Millions, $)	$0.2	$0.0	**$0.2**
Total DSM Investment (Millions, $)	$0.7	$0.1	**$0.8**
Estimated Average Annual Bill Reduction per Customer (Electric): $174			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $139			

*Includes estimates for 2017/18

Commercial HVAC Program – HRV/ERV



The Commercial HVAC Program for Heat Recovery Ventilators (HRV) and Energy Recovery Ventilators (ERV) was launched in May 2016. An HRV/ERV introduces fresh air by having the stale and polluted air from the building pass through the heat exchanger core with a continuous stream of fresh air. As the stale air being expelled moves through the HRV system and passes the fresh air being drawn in, heat or cold is transferred and recovered. The installation of an HRV/ERV can reduce ventilation heating load from 50 to 80 per cent.

The program's primary target market consists of existing commercial buildings with mechanical ventilation and dense occupancy, such as multi-unit residential buildings, health care facilities, retail spaces, restaurants, offices, and schools. Financial incentives and educational materials serve to build awareness and understanding of HRV/ERV technology and encourage participation in the program.

In 2018/19, program participation is expected to be 11 buildings, resulting in 0.2 GW.h and 0.1 MW of electric savings and 0.1 million cubic metres of gas savings. Combined with achievements to date, 15 buildings will participate resulting in 0.2 GW.h and 0.1 MW of electric savings and 0.1 million cubic metres of natural gas savings by the end of 2018/19.

	2016/17 to 2017/18*	2018/19	Total to 2018/19
No. of Buildings	4	11	**15**
Capacity Savings (MW)	0.0	0.1	**0.1**
Energy Savings (GW.h)	0.0	0.2	**0.2**
Natural Gas Savings (million m³)	0.0	0.1	**0.1**
Utility Investment (Millions, $)	$0.2	$0.3	**$0.4**
Customer Investment (Millions, $)	$0.0	$0.1	**$0.1**
Total DSM Investment (Millions, $)	$0.2	$0.4	**$0.5**
Estimated Average Annual Bill Reduction per Customer (Electric): $2,007			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $1,618			

*Includes estimates for 2017/18

Commercial HVAC Program - Water Heaters



The Commercial HVAC Program for Water Heaters was launched in April 2015. The program is designed to reduce natural gas consumption by accelerating the adoption of high efficiency natural gas water heaters, which are approximately 30% more efficient than standard efficiency units.

The program's primary target market consists of commercial buildings with high levels of domestic hot water consumption where the current water heating system is at or nearing end of life.



High initial product costs and long payback periods serve as barriers to the purchase and installation of condensing water heaters. Financial incentives, educational materials, and information seminars endeavor to address these market barriers.

The program also supports the potential for future regulations by advancing market acceptance of condensing water heating technology in Manitoba. The program will prepare the market for a condensing water heater regulation by educating customers, contractors, and distributors about the benefits of condensing water heaters. Advertising and promotional activities increase consumer and contractor awareness of the program and the benefits of choosing high efficiency water heating options.

In 2018/19, program participation is expected to be 27 water heaters, resulting in 0.1 million cubic metres of gas savings. Combined with achievements to date, 113 water heaters will be installed resulting 0.2 million cubic metres of natural gas savings by the end of 2018/19.

	2015/16 to 2017/18*	2018/19	Total to 2018/19
No. of Water Heaters	86	27	**113**
Natural Gas Savings (million m³)	0.2	0.1	**0.2**
Utility Investment (Millions, $)	$0.4	$0.1	**$0.5**
Customer Investment (Millions, $)	$0.2	$0.1	**$0.3**
Total DSM Investment (Millions, $)	$0.6	$0.2	**$0.8**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $544			

*Includes estimates for 2017/18

Commercial Custom Measures Program

The Power Smart Commercial Custom Measures Program, launched in 2006, is designed to encourage commercial customers to explore and implement energy efficient upgrades of their operations or facilities. This program offers support for customer-specific and unique projects or newer technologies that are not currently eligible under the other Power Smart for Business Program offerings. Technologies and projects may include digital control systems, hot water and space heating equipment, waste energy recovery systems, variable speed drive systems, and solar air and water heating systems. The program provides funding to help cover the cost of feasibility studies that are often required for larger projects and newer or emerging technologies, and implementation incentives based on projected savings from the project.



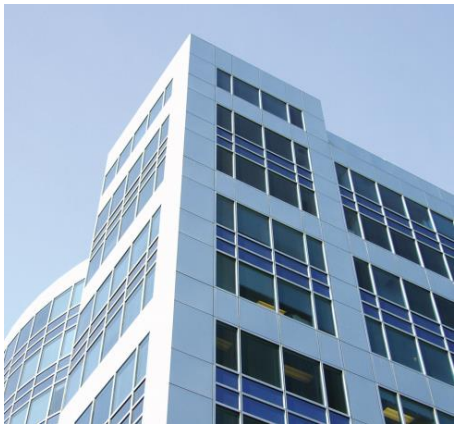
The program targets all commercial customers planning new construction, renovation or expansion projects. Often the high incremental cost of energy efficient technologies and systems, customer uncertainty of payback, and lack of awareness of energy efficient alternatives limit a customer's propensity to invest in an energy efficient project. The Custom Measures Program addresses these barriers by promoting new and innovative technologies, by offering a feasibility study incentive to provide confidence in energy savings estimates, and by offering incentives to help reduce the implementation cost. An enhanced Custom Measures Program was launched in 2015/16 addressing one of the barriers to participation, the cost of identifying and investigating savings opportunities. The cost of feasibility study proposals and reports are now completely funded by the Program for large electric projects.

In 2018/19, program participation is expected to be 25 projects, resulting in 2.0 GW.h and 0.3 MW of electric savings and 0.3 million cubic metres of gas savings. Combined with achievements to date, 144 projects will participate resulting in 29.0 GW.h and 2.5 MW of electric savings and 2.7 million cubic metres of natural gas savings by the end of 2018/19.

	2006/07 to 2017/18*	2018/19	Total to 2018/19
No. of Projects	119	25	**144**
Capacity Savings (MW)	2.2	0.3	**2.5**
Energy Savings (GW.h)	26.9	2.0	**29.0**
Natural Gas Savings (million m^3)	2.4	0.3	**2.7**
Utility Investment (Millions, $)	$5.3	$0.6	**$6.0**
Customer Investment (Millions, $)	$13.0	$0.9	**$14.0**
Total DSM Investment (Millions, $)	$18.3	$1.6	**$19.9**
Estimated Average Annual Bill Reduction per Customer (Electric): $8,088			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $4,886			

*Includes estimates for 2017/18

Enhanced Building Operations Program



The Power Smart Commercial Building Optimization Program (CBOP), launched in 2006, encourages commercial customers with existing buildings to engage in an assessment and adjustment process known as retrocommissioning (RCx) to help return their buildings' mechanical systems to their designed operating characteristics and even further optimize their operation to save energy and improve occupant comfort. The program utilizes local engineering and energy service companies to identify non-capital intensive energy conservation opportunities with relatively short payback periods. Incentives are offered to cover a portion of the cost for hiring the RCx agent as well as for implementation of the energy efficient measures identified through the investigation process.

The market consists of existing commercial buildings larger than 50,000 square feet and between 2 and 25 years of age with direct digital control systems and functioning heating, ventilating and air conditioning mechanical systems. There are approximately 500 buildings in this market, however there are significant barriers that must be overcome to reach these customers including lack of experience and availability of RCx providers in Manitoba, lack of customer awareness of the cost-saving benefits of RCx, and lack of customer time and competing priorities for capital to invest in energy efficiency projects. The program addresses these barriers by providing training and information sessions for potential and existing RCx providers, by promoting RCx at relevant industry events, and by offering incentives to reduce the capital cost and payback cycle of the RCx process. Further addressing these barriers, an enhanced program with increased incentives and revised RCx templates designed to yield more per-project savings was introduced in 2016/2017 and re-named the Enhanced Building Operations Program.

In 2018/19, program participation is expected to be 5 buildings, resulting in 1.0 GW.h and 0.2 MW of electric savings and 0.2 million cubic metres of gas savings. Combined with achievements to date, 23 buildings will participate resulting in 4.6 GW.h and 0.7 MW of electric savings and 1.0 million cubic metres of natural gas savings by the end of 2018/19.

	2006/07 to 2017/18*	2018/19	Total to 2018/19
No. of Buildings	18	5	**23**
Capacity Savings (MW)	0.5	0.2	**0.7**
Energy Savings (GW.h)	3.6	1.0	**4.6**
Natural Gas Savings (million m^3)	0.8	0.2	**1.0**
Utility Investment (Millions, $)	$3.0	$0.3	**$3.3**
Customer Investment (Millions, $)	$0.2	$0.2	**$0.3**
Total DSM Investment (Millions, $)	$3.2	$0.5	**$3.7**
Estimated Average Annual Bill Reduction per Customer (Electric): $11,730			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $9,026			

*Includes estimates for 2017/18

New Buildings Program



The New Buildings Program, introduced in 2010, offers technical assistance and financial incentives for customers designing and constructing new, energy efficient commercial buildings. The program is designed to transform the commercial new construction industry in response to recent building code changes which require significant improvements in overall building energy efficiency.

The first version of the program aimed to prepare the Manitoba commercial building industry for the province's adoption of the National Energy Code of Canada for Buildings (NECB) 2011. Ninety-two buildings have been completed through this program since 2010 and more than 90 new projects are currently in design or under construction. As of December 1, 2014, all commercial buildings in Manitoba must now adhere to the province's version of the NECB called the Manitoba Energy Code for Buildings (MECB).

With the new code in force, the New Buildings Program has evolved to once again seek higher levels of energy performance in new buildings. To qualify as an official Power Smart Building, projects must be designed with an energy target that is at least 10% better than a standard, code-compliant building. Financial incentives range from $0.50/ft2 to $2.00/ft2 depending on the project's overall energy target. An Energy Modeling Assistance Incentive of up to $10,000 is also available to encourage the use of energy modeling early in a building's design process and to help develop the local energy modeling industry in support of the Power Smart and the MECB.

The target market is all new commercial buildings that are bound by the requirements of the MECB. The industry faces fundamental changes to the current methods of designing, constructing, and commissioning commercial buildings. Manitoba Hydro also worked closely with the Province's Green Building Coordination Team to develop the Green Building Policy for Government of Manitoba Funded Projects. This policy ensures the Province's investments in new construction will help transform the local market and will help build industry capacity within Manitoba.

In 2018/19, program participation is expected to be 15 new buildings, resulting in 2.8 GW.h and 0.8 MW of electric savings and 0.1 million cubic metres of gas savings. Combined with achievements to date, 114 new buildings will participate resulting in 32.7 GW.h and 8.5 MW of electric savings and 4.3 million cubic metres of natural gas savings by the end of 2018/19. The program is forecast to reach 7.5% market penetration of the new construction market in 2018/19.

	2009/10 to 2017/18*	2018/19	Total to 2018/19
No. of Buildings	99	15	**114**
Capacity Savings (MW)	7.6	0.8	**8.5**
Energy Savings (GW.h)	29.9	2.8	**32.7**
Natural Gas Savings (million m³)	4.2	0.1	**4.3**
Utility Investment (Millions, $)	$11.5	$1.5	**$13.0**
Customer Investment (Millions, $)	$15.2	$1.2	**$16.4**
Total DSM Investment (Millions, $)	$26.7	$2.7	**$29.4**
Estimated Average Annual Bill Reduction per Customer (Electric): $13,211			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $1,023			

*Includes estimates for 2017/18

Commercial Refrigeration Program

The Commercial Refrigeration Program, launched in 2006, encourages commercial customers to reduce energy consumption by offering over 10 different product incentives for energy efficient upgrades to refrigeration display cases, walk-in boxes, mechanical rooms, and lighting. Savings are achieved by providing customers with information about best practices for maintenance, promoting energy efficient refrigeration technologies, and optimizing the operation of new and existing refrigeration equipment.



The target market is commercial customers with foodservice refrigeration equipment, primarily restaurants, grocery and convenience stores. Many of the qualifying energy efficient refrigeration systems have higher incremental costs, and equipment upgrade decisions are sometimes based on aesthetics over energy efficiency. Offering financial incentives to lower incremental costs and promoting the energy and associated bill savings along with non-energy benefits of efficient refrigeration systems, such as increased comfort in refrigeration aisles for customers and employees, reduced product spoilage, and extended equipment life for refrigeration motors and compressors, is effectively addressing these barriers.

In 2018/19, program participation is expected to be 265 projects, resulting in 8.8 GW.h and 1.2 MW of electric savings. Combined with achievements to date, participation will be 2,797 projects resulting in 87.5 GW.h and 11.9 MW of electric savings by the end of 2018/19. The program is forecast to reach 62% of targeted customers by the end of 2018/19.

	2006/07 to 2017/18*	2018/19	Total to 2018/19
No. of Locations	2,532	265	**2,797**
Capacity Savings (MW)	10.7	1.2	**11.9**
Energy Savings (GW.h)	78.7	8.8	**87.5**
Utility Investment (Millions, $)	$5.5	$0.5	**$6.0**
Customer Investment (Millions, $)	$6.3	$0.2	**$6.4**
Total DSM Investment (Millions, $)	$11.8	$0.7	**$12.5**
Estimated Average Annual Bill Reduction per Customer (Electric): $551			

*Includes estimates for 2017/18

Commercial Kitchen Appliance Program

Launched in January 2008, the Commercial Kitchen Appliances Program encourages restaurants and foodservice establishments to purchase high-efficiency kitchen equipment. The program provides rebates to customers who purchase and install high-efficiency steam cookers (electric and gas) and deep-fat fryers (gas only). To qualify, the model must either be ENERGY STAR® certified or tested for compliance with ENERGY STAR® requirements.





In comparison to standard models, many ENERGY STAR® appliances may have a higher initial purchase cost but many customers are not aware that ENERGY STAR® appliances can improve food quality, decrease cooking times, and lessen operating and maintenance costs. By providing financial incentives and promoting the various energy and non-energy benefits of high-efficiency appliances, the program endeavors to address these market barriers.

In 2018/19, the program is expected to support the installation of 19 appliances, achieving 0.1 GW.h and 0.03 MW of electric savings and 6,000 cubic metres of natural gas savings. Combined with achievements to date, 1,311 appliances will be installed resulting in 3.8 GW.h and 1.1 MW of electric savings and 1.1 million cubic metres of natural gas savings by the end of 2018/19.

	2008/09 to 2017/18*	2018/19	Total to 2018/19
No. of Appliances	1,292	19	**1,311**
Capacity Savings (MW)	1.1	0.0	**1.1**
Energy Savings (GW.h)	3.7	0.1	**3.8**
Natural Gas Savings (million m³)	1.1	0.0	**1.1**
Utility Investment (Millions, $)	$1.1	$0.1	**$1.2**
Customer Investment (Millions, $)	$0.1	$0.0	**$0.1**
Total DSM Investment (Millions, $)	$1.2	$0.1	**$1.3**
Estimated Average Annual Bill Reduction per Customer (Electric): $602			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $282			

*Includes estimates for 2017/18

Network Energy Management Program

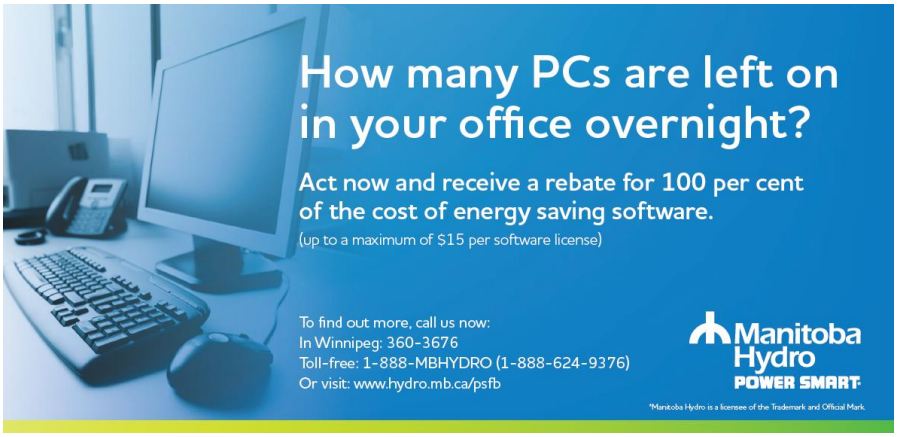
The Network Energy Management Program, launched in 2009, encourages customers to install program-approved software that conserves energy by sending personal computers (PCs) into a mode that consumes less energy when they are not in use. The program is aimed at commercial and institutional organizations that manage a network of PCs.

The target market is comprised of approximately 2,500 physical locations in the school/college and office sectors, representing approximately 300,000 PCs. Installation, configuration, and testing of this new software on existing networks can require a significant time investment. Although management may realize operational cost savings, IT staff is often cautious when implementing software that they perceive may in any way restrict their ability to access individual PCs remotely to perform maintenance and system upgrades. The program provides financial incentives and promotes the product benefits through direct marketing to both management and IT staff in order to address these barriers to adoption.

In 2018/19, program participation is expected to be 1,000 software licenses, resulting in 0.2 GW.h and 0.02 MW of electric savings. Combined with achievements to date, participation will be 6,346 software licenses resulting in 2.8 GW.h and 0.3 MW of electric savings by the end of 2018/19.

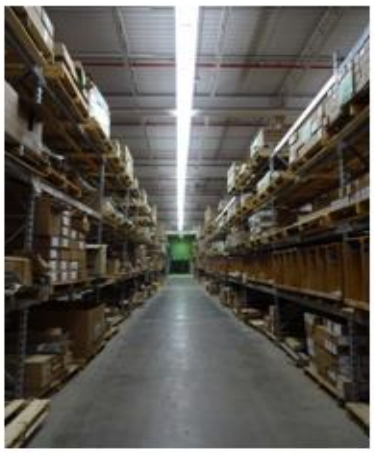
	2009/10 to 2017/18*	2018/19	Total to 2018/19
No. of Licenses	5,346	1,000	**6,346**
Capacity Savings (MW)	0.3	0.0	**0.3**
Energy Savings (GW.h)	2.7	0.2	**2.8**
Utility Investment (Millions, $)	$0.3	$0.0	**$0.3**
Customer Investment (Millions, $)	$0.1	$0.0	**$0.1**
Total DSM Investment (Millions, $)	$0.3	$0.1	**$0.4**
Estimated Average Annual Bill Reduction per Customer (Electric): $4,163			

*Includes estimates for 2017/18



Internal Retrofit Program

The Internal Retrofit Program (IRP), launched in 1993, targets energy efficient upgrades in Manitoba Hydro buildings including, but not limited to, generating stations, commercial facilities, office spaces and corporate housing. The program's efforts demonstrate Manitoba Hydro's commitment to energy conservation at large. The program provides technical assistance and financial support for the installation of Power Smart measures such as lighting, windows, insulation, heating, ventilation, and air conditioning systems and other custom measures.



In addition to achieving energy savings, the IRP strives to improve workplace safety, address operational issues, reduce maintenance costs and optimize employee comfort.

In 2018/19, it is anticipated that the program will complete 53 projects, resulting in 4.8 GW.h and 0.8 MW of electric savings and 0.1 million cubic metres of natural gas savings. Combined with achievements to date, the program will have completed 1,833 projects resulting in 78.1 GW.h and 16.3 MW of electric savings and 0.1 million cubic metres of natural gas savings by the end of 2018/19.

	1992/93 to 2017/18*	2018/19	Total to 2018/19
No. of Projects	1,780	53	**1,833**
Capacity Savings (MW)	15.5	0.8	**16.3**
Energy Savings (GW.h)	73.3	4.8	**78.1**
Natural Gas Savings (million m³)	0.0	0.1	**0.1**
Utility Investment (Millions, $)	$25.2	$0.8	**$26.0**

*Includes estimates for 2017/18

Power Smart Shops Program



Launched in October 2015, the Power Smart Shops Program promotes energy efficiency to the hard-to-reach small commercial market such as small restaurants, offices, clinics, and salons. More recently, the program was also extended to non-profit organizations, charities, and religious facilities across Manitoba. To be eligible, the business must be 10,000 square feet or less in size and a Manitoba Hydro commercial customer with either an electric or natural gas heating system. National chains and new construction projects are not eligible to participate.

The Power Smart Shops Program utilizes a full-service contractor delivery model and consists of a three-part offering: Firstly, the on-site direct installation of various free measures, such as bathroom and kitchen faucet aerators, low-flow pre-rinse spray valves, and basic lighting measures. Secondly, a free lighting assessment that identifies further opportunities to upgrade inefficient lighting. Lastly, the program covers 70% of material and labour costs of qualifying lighting retrofits identified in the assessment. Material sourcing and installation are coordinated by the program contractor.

The small commercial market is a proven late adopter of energy efficient technologies due to a number of unique barriers that have not been specifically addressed by Power Smart for Business programs in the past. Budgetary restrictions, limited resources, and a lack of industry exposure are all barriers that the Power Smart Shops Program endeavors to overcome. The program's aggressive incentives are intended to lessen upfront capital costs to the customer.

In 2018/19, program participation is expected to be 807 projects, resulting in 2.1 GW.h and 0.3 MW of electric savings and 12,000 cubic metres of natural gas savings. Combined with achievements to date, participation will be 3,234 projects resulting in 8.9 GW.h and 1.7 MW of electric savings and 0.1 million cubic metres of natural gas savings by the end of 2018/19.

	2009/10 to 2017/18*	2018/19	Total to 2018/19
No. of Projects	2,427	807	**3,234**
Capacity Savings (MW)	1.4	0.3	**1.7**
Energy Savings (GW.h)	6.9	2.1	**8.9**
Natural Gas Savings (million m³)	0.1	0.0	**0.1**
Utility Investment (Millions, $)	$3.6	$0.9	**$4.5**
Customer Investment (Millions, $)	$0.1	$0.0	**$0.2**
Total DSM Investment (Millions, $)	$3.7	$1.0	**$4.7**
Estimated Average Annual Bill Reduction per Customer (Electric): $26			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $3			

*Includes estimates for 2017/18

Race to Reduce

Manitoba Race to Reduce, launched January 2017, is a competition-based initiative designed to reduce energy consumption in participating commercial buildings by 10 per cent over a four year race. Collaboration among customers, industry associations, and other key stakeholders is an important principle of the race. Encouraged energy reduction behaviours include turning off lights in unoccupied spaces, setting back thermostats, closing window blinds in cooling season, enabling energy-saving features of office equipment, and more.

By increasing the energy efficiency, or simply reducing the energy use in these buildings, landlords and tenants can reduce operating costs while making a direct improvement to Manitoba's environment by reducing carbon emissions and improving air quality. The initiative has secured almost seven million square feet of office space in Manitoba to participate in the competition. Successful Race to Reduce participants will be publicly recognized and celebrated annually during the initiative's award ceremonies.

In 2018/19, it is expected that 6 commercial buildings will participate, resulting in 0.9 GW.h and 0.1 MW of electric savings and 0.1 million cubic metres of natural gas savings. The program is forecast to enroll 66% of targeted customers by the end of 2018/19.

	2016/17 to 2017/18*	2018/19	Total to 2018/19
No. of Buildings	32	6	**38**
Capacity Savings (MW)	0.5	0.1	**0.6**
Energy Savings (GW.h)	4.3	0.9	**5.3**
Natural Gas Savings (million m^3)	0.3	0.1	**0.4**
Utility Investment (Millions, $)	$0.3	$0.2	**$0.5**
Customer Investment (Millions, $)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, $)	$0.3	$0.2	**$0.5**
Estimated Average Annual Bill Reduction per Customer (Electric): $7,390			
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $2,448			

*Includes estimates for 2017/18

Parking Lot Controller

The Parking Lot Controller Program launched in 2016/17, and was a one year initiative designed to reduce energy consumption in parking lots of commercial buildings by providing financial incentives for the installation of qualifying devices. Parking lot controllers are electronic devices that control the electricity going to an outdoor plug, allowing building and property managers to effectively manage electricity usage in their parking lots. Parking lot controllers can reduce electricity costs by up to 50 per cent and ensure trouble-free starts for tenants, staff and guests. The market for the program is comprised of new construction and existing parking lots of multi-unit residential buildings, offices, and institutional and industrial facilities.



The program ended in 2017 and has been successful in achieving its targeted energy savings. It is expected that an additional 54 commercial building will finalize their projects in the 2018/19 year, resulting in 1.0 GW.h of electric savings. The program is forecast to capture 68% of targeted customers by the end of 2018/19.

	2016/17 to 2017/18*	2018/19	Total to 2018/19
No. of Projects	143	54	**197**
Capacity Savings (MW)	0.0	0.0	**0.0**
Energy Savings (GW.h)	2.7	1.0	**3.8**
Utility Investment (Millions, $)	$0.5	$0.2	**$0.7**
Customer Investment (Millions, $)	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, $)	$0.5	$0.2	**$0.7**
Estimated Average Annual Bill Reduction per Customer (Electric): $25			

*Includes estimates for 2017/18

The following convenient financing program offered by Manitoba Hydro supports energy efficiency upgrades by allowing customers to finance initial project costs and pay these costs back on their monthly Manitoba Hydro bill.

Power Smart for Business PAYS Financing



The Power Smart for Business PAYS (Pay As You Save) Financing Program, launched in September 2013, to assist commercial customers in reducing their energy and water consumption by offering extended financing terms for energy efficiency upgrades such as lighting, high efficiency natural gas furnaces, condensing and near-condensing boilers, insulation, geothermal systems, CO2 sensors, custom measures (commercial and industrial applications), and WaterSense® labeled toilets and urinals. This offering complimented and supported the various incentive-based programs by assisting customers in managing the installation cost of their upgrade.

Effective September 8th, 2017, the Program was temporarily suspended from accepting any new applications, however, previously approved applications can still proceed with the financing. Based upon these pre-approvals, the program is expected to finance 28 projects in 2018/19. Combined with achievements to date, 124 technologies will be financed.

Note: Savings are included under the appropriate incentive based program.

	2013/14 to 2017/18*	2018/19	Total to 2018/19
No. of Loans	96	28	**124**
Average Loan Amount: $26,551			

*Includes estimates for 2017/18

Industrial

Manitoba industry competes in a global economy and energy efficiency is often a key indicator of the overall productivity and competitiveness of an industrial customer. Energy consumption is impacted by every aspect of an industrial operation, from the way employees work to the facilities they work in, and the way in which they process, package and deliver raw materials into finished goods for their local, national and international customers.

Manitoba Hydro offers incentive-based programs to address opportunities within the industrial market for energy efficiency improvements and co-generation of electricity. These programs take a customer-focused approach to identifying and addressing operating and production challenges in a manner that not only improves overall energy efficiency, but enhances productivity and competitiveness for Manitoba industry.

Manitoba's industrial market can be characterized as consisting of a large variety of industries with a broad size demographic of customers within each classification. While some sectors are responsible for higher percentages of consumption than others, no one industry sector is dominant within the province. In Manitoba, each sector is typically dominated by less than six customers, with the remaining customers being smaller with more specialized operations or substantively lower outputs. This diversity presents some unique challenges with program delivery as opportunities to capture substantive savings are tied directly to specific industry business cycles within each industry sector that dictate major events such as equipment change-outs, plant overhauls, facility expansions, and new plant construction. These cycles are periodic and can stretch across decades, with timing influenced heavily by market cycles and global competitive pressures.

With industry comprising nearly 40% of Manitoba's total electric and natural gas consumption, Manitoba Hydro's industrial Power Smart programs must have broad appeal in order to be relevant and responsive to the needs of a diverse population of industrial customers.

Investing in the energy efficiency for our industrial customers also increases their competitiveness in the global economy. On average, energy costs account for 5% to 15% of total operating costs for the majority of these companies, while energy intensive resource companies employing thousands of Manitobans across the north and rural regions of southern Manitoba have energy costs that range from 15% to 70% of total operating costs.

Manitoba Hydro's total industrial energy efficiency investment is returned annually to the Province's industrial sector through reduced energy costs. These investments in energy efficiency reduce labor, material and facility costs, further helping to make Manitoba industry increasingly productive and globally competitive, and supporting further investment in energy efficiency and productivity improvements.

Performance Optimization Program



The Performance Optimization Program, launched in June 1993, is designed to promote energy efficiency through the optimization of electric motor-driven industrial systems such as air compressors, pumps, fans and blowers, optimization of industrial refrigeration, process heating, electro-chemical processes systems, and implementation of plant-wide energy management systems. The program supports customers with financial incentives to assist in the identification, investigation, and implementation of system efficiency improvements throughout a facility.

The focused target market consists of approximately 2 000 industrial customers, with the program being available to both existing facilities and new construction projects. Emphasis is placed on the 300 largest customers who represent about 1/3 of the energy consumed in Manitoba. The average duration of a project from identification of the opportunity to implementation ranges from 6 months to 2 years, averaging approximately 18 months.

The actual number of project applications facilitated in any fiscal year and the savings achieved per project can vary dramatically based on project size, equipment age, and remaining life of the individual systems being optimized. However, savings levels are relatively consistent, thereby reflecting the capability within Manitoba Hydro's programs to adapt to available opportunities.

In 2018/19, the program is expected to achieve 13.6 GW.h and 1.4 MW of electric savings. Combined with achievements to date, the program is expected to achieve 595.2 GW.h and 111.5 MW by the end of 2018/19.

	1993/94 to 2017/18*	2018/19	Total to 2018/19
Capacity Savings (MW)	110.1	1.4	**111.5**
Energy Savings (GW.h)	581.6	13.6	**595.2**
Utility Investment (Millions, $)	$35.8	$2.5	**$38.3**
Customer Investment (Millions, $)	$99.3	$2.3	**$101.6**
Total DSM Investment (Millions, $)	$135.1	$4.8	**$139.9**
Estimated Average Annual Bill Reduction per Customer (Electric): $8,436			

*Includes estimates for 2017/18

Natural Gas Optimization Program

The Power Smart Natural Gas Optimization Program (NGOP), launched in September 2006, is designed to support the systematic improvement of natural gas equipment and processes for industrial and large institutional customers. The program supports customers by offering financial incentives for steam trap audits, feasibility studies and for energy efficient project implementation. The program was principally developed to promote custom applications within large industrial, institutional and commercial facilities comprised of roughly 1,400 customers in Manitoba. The scope of the NGOP has been extended to allow the program to respond to all industrial customer inquiries, regardless of the size of the facility or volume of natural gas consumed.



Like the Performance Optimization Program, the NGOP is a custom program that supports a variety of technologies across a wide variety of applications, including; boiler conversions, process water and air heat recovery, process equipment and pipe insulation, boiler economizers, and other available technologies. The program is designed to address key market barriers related to project costs, available benefits, cost/benefit ratios and desired return on investment.

Current low natural gas commodity prices are challenging Manitoba Hydro customers' ability to achieve desired rates of return on investment in conservation initiatives. This highlights the importance of Manitoba Hydro in being actively involved when new facilities and uses of natural gas are being constructed, as any inefficiencies in the original facility or process will be hard to rectify in coming years.

The actual number of project applications facilitated in any fiscal year and the savings achieved per project can vary dramatically based on project size, equipment age, and remaining life of the individual systems being optimized. However, savings levels are relatively consistent, thereby reflecting the capability within Manitoba Hydro's programs to adapt to available opportunities.

In 2018/19, the program is expected to achieve 2.0 million cubic metres in natural gas savings. Combined with achievements to date, the program is expected to achieve 24.2 million cubic metres in natural gas savings by the end of 2018/19.

	2006/07 to 2017/18*	2018/19	Total to 2018/19
Natural Gas Savings (million m^3)	22.2	2.0	**24.2**
Utility Investment (Millions, $)	$6.7	$0.7	**$7.4**
Customer Investment (Millions, $)	$35.5	$2.3	**$37.8**
Total DSM Investment (Millions, $)	$42.2	$3.0	**$45.2**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $37,222			

*Includes estimates for 2017/18

Load Displacement & Alternative Energy

Load Displacement occurs when customer-owned and operated facilities capable of generating heat and/or power are used to displace energy purchases that would otherwise be made from the Manitoba Hydro system in the form of electric and/or natural gas consumption. This displacement is achieved in an environmentally sustainable manner using renewable energy resources such as biomass, waste and by-product streams from common industrial processes.

Displaced energy provided under long-term contracts with customers is used by Manitoba Hydro to serve other customers' energy needs, including the export market, where the sale of renewable electric energy displaces generation that is largely fossil fuel-based. The widely distributed nature of load displacement projects, can in some cases defer the need transmission and distribution infrastructure required to move energy across the Province.

In most instances, the alternate energy resources used to facilitate load displacement are obtained locally, contributing to the Manitoba economy and displacing purchases of fossil fuels from out-of-province suppliers. In other instances, the productive use of waste and by-product streams enhances the economics of local industries and reduces environmental impacts and costs for disposal. In this manner, Manitoba Hydro's Load Displacement and Bioenergy Optimization Programs provide an important opportunity to support and expand the local economic footprint of Manitoba's energy industry in an environmentally sustainable manner.

Manitoba businesses and industry currently consume about 50,000 tonnes of processed biomass annually. Large opportunities exist for significant growth within this industry if local production of high quality refined biomass fuel expands to create a sustainable and reliable supply of biomass that encourages and supports customer investment in biomass heat and power installations.

As an example…

500,000 tonnes of pelleted biomass consumption is capable of displacing the equivalent of nearly 2,000 GW.h in annual electricity purchases for space and hot water heating. This quantity of energy represents nearly 10% of Manitoba consumption of electricity, while also serving as a key contributor to Manitoba Hydro peak winter demand requirements. Achieved over 20 years, this level of biomass consumption could contribute as much as 0.25 – 0.30% of load per year towards Manitoba Hydro's achievement of its demand side management objectives.

Similarly, 500,000 tonnes of pellet biomass consumption is capable of displacing the equivalent of nearly 225 million cubic metres of natural gas consumption for heating, representing nearly 15% of Manitoba natural gas consumption and reducing greenhouse gas emissions by about 425,000 tonnes annually.

Investments in load displacement by Manitoba Hydro and its customers are an important opportunity for Manitoba business to enhance their economic competitiveness and reduce their environmental footprint. Manitoba Hydro's Load Displacement and Bioenergy Optimization Programs are intended to support these investments and capture their associated investments for all Manitobans.

Bioenergy Optimization Program



The Bioenergy Optimization Program, launched in 2006, is designed to encourage customers to install, operate, and maintain customer-sited load displacement generation systems that employ heat only and/or combined heat and power (CHP) applications fueled by renewable energy sources, such as biomass.

To date, the target market has consisted primarily of agricultural customers that have readily available, low-cost sources of biomass, continual needs for heat and power, and the capability to operate and maintain biomass-to-energy conversion systems. The knowledge gained through the delivery of the program has helped to focus the program towards biomass heating applications. Manitoba Hydro's program further supports customers in developing a thorough understanding of the costs and benefits of bioenergy systems.



The Program is targeting schools, institutes, and public buildings in the current plan. The sizes of systems anticipated under the program are less than one MW electrical equivalent capacity.

In 2018/19, the program participation is expected to be 2 projects, resulting in 1.0 GW.h and 0.4 MW of electric savings. Combined with achievements to date, participation will be 48 projects resulting in 85.9 GW.h and 17.4 MW of electric savings by the end of 2018/19.

	2005/06 to 2017/18*	2018/19	Total to 2018/19
No. of Projects	46	2	**48**
Capacity Savings (MW)	17.0	0.4	**17.4**
Energy Savings (GW.h)	84.9	1.0	**85.9**
Utility Investment (Millions, $)	$13.0	$0.5	**$13.5**
Customer Investment (Millions, $)	$66.7	$1.0	**$67.7**
Total DSM Investment (Millions, $)	$79.8	$1.5	**$81.3**
Estimated Average Annual Bill Reduction per Customer (Electric): Variable depending on project size			

*Includes estimates for 2017/18

Load Displacement Program

The Load Displacement Program, launched in 2014, encourages industrial and municipal customers to install, operate, and maintain customer-sited load displacement generation systems that rely on waste streams, by-products and locally-available, low-cost sources of biomass and other renewable energy sources as the fuel source. The target market consists of larger industrial and municipal customers, or customer sectors that are striving to optimize their operations while also achieving reduced energy costs and improved environmental performance.

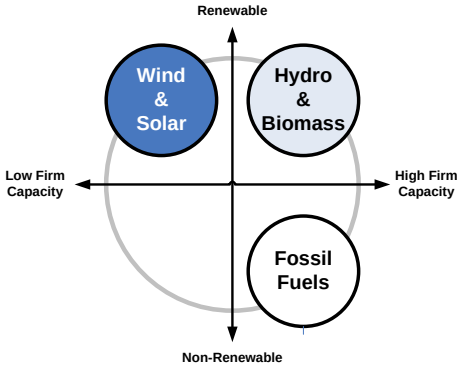


Industrial and municipal operations with waste and by-products streams from manufacturing processes typically incur costs for disposal and treatment required to mitigate environmental liabilities. Converting waste and by-product streams into useful energy for use within the manufacturing operation is often a more sustainable practice environmentally, and a means of reducing overall energy and disposal costs. Similarly, locally-available low-cost sources of biomass such as waste wood and crop residues can be harnessed as a sustainable and economic fuel source for on-site heat and power generation.

Manitoba Hydro's Load Displacement Program supports customers with financial incentives to assist customers in evaluating the feasibility of load displacement projects, and with incentives for the implementation of equipment and systems required for load displacement generation, and maintenance of ongoing, reliable operation ensuring consistent and stable energy production that can rely on by both the customer and Manitoba Hydro.

A typical load displacement generation project can take two to three years for the analysis, design and equipment implementation. To support this process, Manitoba Hydro provides financial incentives to support feasibility studies, engineering design, procurement and installation for customer-sited generation projects on the condition that long-term contractual commitments can be secured. Some projects may also be eligible for operating incentives designed to support the cost of ongoing fuel procurement (i.e. purchased biomass).

Major customer sectors targeted by the program include forestry, chemicals, metals, oil and gas, and municipal wastewater treatment facilities. The capacity of these on-site generation systems is anticipated to provide more than 1 MW of electrical load displacement. Potential projects include existing self-generation systems that can benefit from additional investment to increase stable and reliable long-term output, improved environmental performance, and reduced operating costs.



In 2018/19, the program is expected to achieve 113.9 GW.h and 15.3 MW of new incremental electric savings. Combined with persisting savings achieved to date, the program is expected to achieve 127.2 GW.h and 18.4 MW of electric savings by the end of 2018/19.

	2014/15	2015/16	2016/17	2017/18 *	2018/19	Total to 2018/19
Capacity Savings (MW)	17.9 (1)(2)	13.2 (2)	17.2 (2)	16.6 (2)	**15.3**	**18.4**
Energy Savings (GW.h)	76.3 (1)(2)	83.3 (2)	107.2 (2)	103.4 (2)	**113.9**	**127.2**
Utility Investment (Millions, $)	$0.7 (3)	$4.6 (3)	$3.8 (3)	$0.3 (3)	**$7.1**	**$16.4**
Customer Investment (Millions, $)	$3.3 (4)	$5.3 (4)	$10.1 (4)	$0.0 (4)	**$13.8**	**$32.5**
Total DSM Investment (Millions, $)	$4.0	$9.9	$13.9	$0.3	**$20.8**	**$48.9**
Estimated Average Annual Bill Reduction per Customer (Electric): Variable depending on project size						

*Includes estimates for 2017/18

(1) Savings previously reported as annual savings under the Bioenergy Optimization Program in 2014/15, subject to being re-earned in future years.

(2) Annual capacity and energy savings that are not subject to long-term contractual commitments are not viewed as persistent savings in future years, and are therefore not considered in the cumulative total savings in subsequent years. These savings must therefore be re-earned annually within each year of the program.

(3) Utility investments include expenditures to support feasibility studies, engineering studies and capital investments in customer-owned equipment for generation projects that will be subject to long-term contractual commitments. These investments are not related to non-persistent savings achieved annually in 2014/15, 2015/16, 2016/17 & 2017/18.

(4) Customer investments include expenditures for fuel required to achieve annual non-persistent savings in 2014/15, 2015/16, 2016/17 or 2017/18, in addition to expenditures incurred to support feasibility studies, engineering studies and capital investments in customer-owned equipment for self-generation projects that will be subject to long-term contractual commitments.

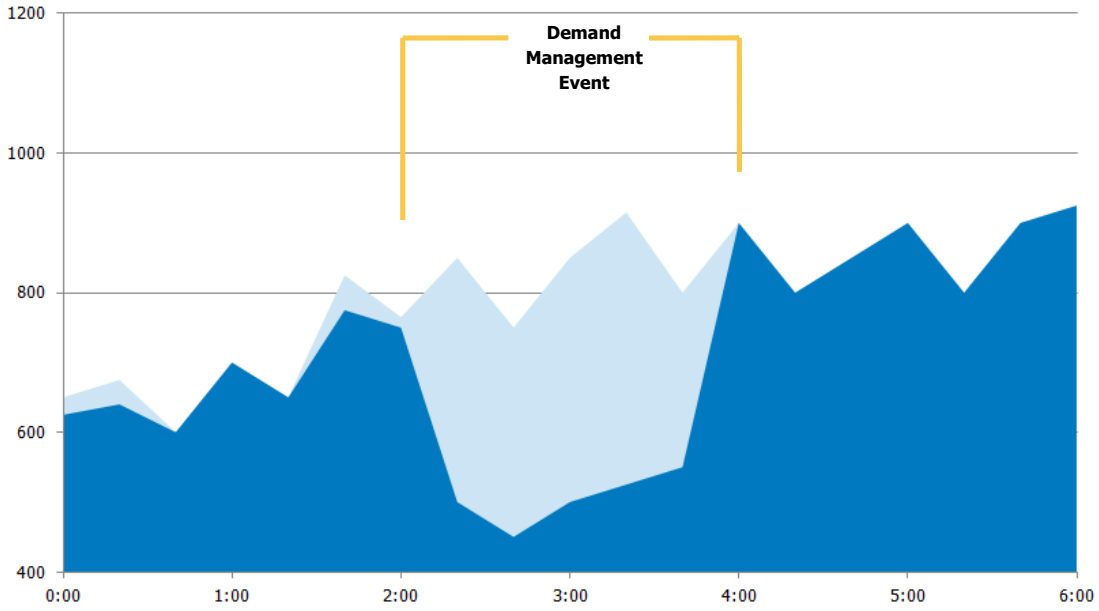
Load Management

Curtailable Rate Program

Under the Curtailable Rate Program, qualifying customers receive a monthly credit on load (kW) which can be curtailed on notice from Manitoba Hydro. To be eligible, customers' load/processes must be configured to allow them to meet the requested curtailment within the notification period as outlined under their chosen contract option.

	1990/00 to 2017/18*	2018/19	Total to 2018/19
No. of Customers	61	3	**64**
Capacity Savings (MW)	162.1	168.7	**168.7**
Utility Investment (Millions, $)	$107.5	$6.1	**$113.6**

*Includes estimates for 2017/18



Codes, Standards & Regulations

In addition to utility-directed 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 building codes and performance 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 which are then incorporated into Manitoba Power Smart programs, and subsequent energy efficiency regulations and building codes proposed by national and provincial regulators.

While the total costs for all participants in achieving codes and standards savings are largely the same as those incurred through other methods of encouraging energy efficiency, the cost for Manitoba Hydro to participate in codes and standards processes is considerably less, as the Corporation is able to leverage efforts from the other stakeholders participating in these processes including consumers, industry, and government.

There are several areas of focus for the 2018/19 year.

Building Energy Codes

The new energy code for commercial buildings, the Manitoba Energy Code for Buildings (MECB 2011), which came into force on December 1, 2014, is now seeing new construction projects submitted for permitting under more stringent requirements for energy performance. For residential construction, section 9.36 of the national building code dealing with energy efficiency in Part 9 buildings came into force on April 1, 2016. To support the market in becoming compliant with the new energy requirements in both of these codes, Manitoba Hydro will continue to offer regular consultation to the various code authorities across the Province, including the Manitoba Office of the Fire Commissioner, City of Winnipeg, and City of Brandon, etc. Widely recognized as the province's experts on energy use, and commercial and residential energy codes, Manitoba Hydro technical personnel will consult on code interpretations and plan reviews to supplement the available resources within the various planning districts and permitting offices throughout Manitoba. In addition, a series of energy code-related training and education sessions will be offered for customers in collaboration with industry and trade associations.

Late in 2016, the 2015 National Building Code was reviewed at the Building Standards Board of Manitoba which included updates to the National Energy Codes for Buildings (NECB) and Section 9.36. The updates were considered to be relatively minor and adoption is expected early in 2018. To support the newest energy code for commercial buildings, Manitoba Hydro technical staff will be chairing the 2015 NECB User's Guide Working Group. This publication will provide an update to the first User's Guide that was developed for the 2011 NECB.

In addition to assisting the market with the current codes, Manitoba Hydro has also increased the requirements for its voluntary based incentive programs in the New Buildings Program and the Power Smart for New Homes Program. The intent is to encourage home builders and commercial building designers to pursue higher levels of energy efficiency and position themselves more favourably for the

next code cycle which will see further improvements to energy efficiency in buildings. A specific program design strategy will be offering incentives to assist with the cost of energy modeling (in the case of commercial buildings) or offering higher levels of incentives for homes that are designed to meet performance thresholds. These strategies are being implemented to address a specific gap in the Manitoba market which is a lack of energy modeling professionals. Early indications are that the codes nationally will be moving towards performance based codes versus prescriptive based requirements. Having a more robust industry in place and experienced to support designing for energy efficiency will assist with this transition.

The Government of Canada released the Pan Canadian Framework in December 2016 which outlined a future strategy pertaining to energy use in buildings and, in particular, a defined path for improving efficiency in buildings through increasingly stringent changes to the National Building Code. With a goal of a "net-zero energy ready" construction mandated across Canada in buildings codes by the year 2030, Manitoba Hydro will play a key role to move both Manitoba industry and customers towards these standards over the next 10 years.

The Federal Government has also signaled the desire to pursue a retrofit code for existing buildings by 2022. A code for existing buildings will help guide energy efficiency improvements that can be made when Canadians renovate their homes and buildings. Other jurisdictions in Canada are at various stages of adoption of energy efficiency and Manitoba has a relatively small population. The aim of Manitoba Hydro staff will be to ensure that the codes that are developed keep pace with the trajectory of adoption that exists in Manitoba due to many years of Power Smart offerings.

Energy Performance Standards

At a national level, Manitoba Hydro continues to be an integral member of the CSA Standing Committee for Performance, Energy Efficiency and Renewables (SCOPEER) providing direct financial support, technical expertise and leadership to the national effort. In 2018/19, efforts will be focused on the development of Energy Performance Standards supporting implementation of Amendments 14 and 15 to Canada's Energy Efficiency Act covering energy consuming products commonly used by the residential, commercial and industrial sectors. In addition, given the direction of the Canadian Energy Strategy (CES), Manitoba Hydro will be providing guidance and support for alignment and harmonization of various Canadian and US standards. Harmonization across North America supports industry attempts to improve the energy efficiency of common energy consuming goods.

Manitoba Hydro's support for this national effort provides important consideration for Manitoba's energy needs, as they relate to our local climate and other energy drivers. As an example, common white goods purchased by Manitoba consumers are imported into Canada by local wholesalers and retailers, who are subject to federal regulations at the point of entry into Canada. Federal regulations that include consideration of Manitoba needs support the goals and objectives of Manitoba Hydro's DSM strategy, and provide an important compliance mechanism to prevent under-performing products from entering the Manitoba market.

Manitoba Hydro's expertise and knowledge surrounding energy consuming equipment and the drivers for the Province's heating and cooling requirements are well respected across Canada, making Manitoba

Hydro's voice an important influence at the federal and provincial level when changes to codes and standards are discussed. In providing this service, Manitoba Hydro projects a strong image of Manitoba's proficiency in supporting energy efficiency and climate change within Canada.

A key component of Manitoba Hydro's national effort in 2018/19 will be continued support for federal amendments 14 and 15 to Canada's Energy Efficiency Act, which is the primary regulation impacting white goods and equipment purchased by Manitoban's. Enactment of these amendments plays a key role in obtaining the savings identified in Manitoba Hydro's DSM Plan.

Energy Efficiency Regulations

As a priority action item under Manitoba's Clean Energy Strategy and Manitoba Climate Change and Green Economy Action Plan, Manitoba Hydro involvement plays an important role in the Provincial regulation of energy consuming products under The Energy Act. The provision of technical support and market data that creates the supporting justification to gain industry acceptance and government approval play a key role in Manitoba Hydro's involvement. Members from Manitoba Hydro's marketing and technical staff have been invited to consult with the Province on the development of "a Framework for Minimum Energy Performance Standards in Manitoba" that will form the basis of the Provincial strategy moving forward.



Demand Side Management Plan | 2018/19

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