INTEGRATED FINANCIAL FORECAST (IFF11)

2011/12 – 2031/32

FINANCIAL PLANNING DEPARTMENT
CORPORATE CONTROLLER DIVISION
FINANCE & ADMINISTRATION

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INTEGRATED FINANCIAL FORECAST (IFF11)

KEY FINANCIAL RESULTS

(Dollars are in millions)

	Actual	IFF11 Forecast			
	2010/11	2011/12	2012/13	2013/14	2021/22
PROJECTED RATE INCREASES					
- ELECTRIC	2.8%	2.0%	3.5%	3.5%	3.5%
- GAS (non-commodity)	0.7%	-	2.5%	1.0%	1.0%
NET INCOME					
- ELECTRIC	$139	$94	$7	$53	$57
- GAS	$7	-	$4	$5	$5
- SUBSIDIARIES	$4	$5	$6	$7	$10
CAPITAL EXPENDITURES					
- ELECTRIC	$1 100	$1 074	$1 166	$1 518	$1 767
- GAS	$34	$40	$29	$32	$35
DEBT/EQUITY RATIO	73:27	74:26	80:20	81:19	89:11
INTEREST COVERAGE RATIO	1.27	1.17	1.03	1.10	1.05
CAPITAL COVERAGE RATIO (excl. major new generation & transmission)	1.20	1.14	0.99	1.14	1.72
RETAINED EARNINGS	$2 389	$2 489	$2 131	$2 196	$2 631

1.0 OVERVIEW

The 2011 Integrated Financial Forecast (IFF11) projects Manitoba Hydro's financial results for the 20-year period to 2031/32.

Since the 20-year IFF was last approved by the Board in March 2011 (and updated in May 2011 for the revised Bipole III cost estimate), there have been a number of changes which have impacted the projected financial results of Manitoba Hydro. Most significantly, extraprovincial revenues have fallen from record high levels since 2008 largely due to reductions in export prices. Lower export prices can be attributed to the reduced value of capacity in the near term resulting from the carryover of excess capacity from the economic recession in the MISO market area, a delay in the implementation of and the value of carbon pricing, as well as lower natural gas prices.

Table 1 below provides the changes from the previous forecast, May 2011 20 Year Financial Forecast (referenced as IFF10). In comparison to IFF10, consolidated net income is projected to be approximately $1.3 billion lower over the 10-year period to 2021/22 mainly due to lower electricity export prices.

Table 1
CONSOLIDATED NET INCOME
(in millions)

	2011/12	2012/13	2013/14	Cumulative to 2021/22
IFF11	$ 99	17	66	$ 617
IFF10	134	132	198	1,928
Decrease	$ (35)	(115)	(132)	$ (1,311)

Over the 20-year period to 2031/32, consolidated net income is projected to be approximately $3.4 billion lower than IFF10 with net extraprovincial revenues $3.9 billion lower over the same period. Almost half of the reduction can be attributed to the lower projected electric export prices over the entire forecast period. In addition to lower export prices, over one-third of the decreased net extraprovincial revenue in the 20-year period is related to lower projected deliveries to customers outside Manitoba. Lower projected deliveries can be attributed to the 1-year deferral of the Conawapa generating station, reduction in the new U.S. interconnection capability from 1000 MW to 400 MW in the period 2021/22 to 2025/26, reduction in the contracted energy delivered to Wisconsin Public Service in the period 2019/20 to 2025/26, and increased domestic Manitoba load demand which reduces exportable surplus energy.

2.0 FORECAST ASSUMPTIONS

2.1 Manitoba Electricity Load Forecast

General consumers revenue is forecast based on the future load requirements in Manitoba as projected in the 2011 Electric Load Forecast.

The 2011 Electric Load Forecast projects that average annual growth in Manitoba load will be 1.6% for net firm energy and 1.7% for net total peak over the forecast period to 2021/22 (compared to 1.6% and 1.4%, respectively, in IFF10). Net firm energy supplied to the Manitoba load is projected to grow from 24 475 GW.h in 2011/12 to 28 744 GW.h by 2021/22. Over that same 10-year period, total system peak is projected to grow from 4 530 MW in 2011/12 to 5 347 MW in 2021/22. The system load factor is projected to remain relatively constant at approximately 61%.

2.2 Electricity Supply

Manitoba Hydro's 2011/12 Power Resource Plan indicates new generation is required in 2020/21 to meet the current projection of Manitoba load requirements under dependable energy conditions. The following major new resource assumptions provide energy to meet Manitoba requirements as well as surplus available for exports under normal flow conditions.

	MW	Dependable GW.h	In-Service Date
Wuskwatim	200	1 250	2011/12
Keeyask	695	2 900	2019/20
Conawapa	1 485	4 550	2024/25
St. Leon Wind Farm II	-	65	2011/12
Kelsey Re-runnering	77	-	2012/13
Enhancements of Winnipeg River Plants	30	30	2014/15 – 2016/17
HVDC Bipole III Line & 2000 MW of Converter Capability	89	243	2017/18
Pointe du Bois Powerhouse Rebuild	43	150	2030/31
Demand Side Management Program			
Planned Additional	256	1 008	By 2025/26

2.3 Extraprovincial Sales

Extraprovincial sales volumes are forecast in the 2011 Forecast of Generation Costs and Interchange Revenues based upon generation estimates utilizing the expected inflow conditions during the first forecast year and using median inflow conditions during the second forecast year. For the subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 96 years.

IFF 11 includes the following new or proposed dependable sales transactions:

- A new 250 MW system power sale to Minnesota Power from June 1, 2020 to May 31, 2035;
- A new 100 MW system power sale to Wisconsin Public Service from June 1, 2021 to May 31, 2025; and
- A proposed 500 MW export sale to Wisconsin Public Service from June 1, 2025 to March 31, 2039.

In July 2011, Manitoba Hydro entered into a purchase agreement with Algonquin Power to purchase the output from the new 16.5-megawatt St. Leon II Wind Energy farm.

Over the 10-year forecast to 2021/22, there is a projected decrease in extraprovincial revenues (net of water rentals and fuel and power purchases) of $1.1 billion compared to the previous forecast which is mainly attributable to lower export prices.

Electricity export prices have been declining since 2008. The 2011 forecast is depressed relative to previous forecasts mainly due to the reduced value of capacity in the near term resulting from the carryover of excess capacity from the economic recession in the MISO market area, a delay in the implementation of and the value of carbon pricing, as well as lower natural gas prices. Natural gas prices have a direct effect on electricity prices since the market clearing price in MISO for a significant portion of the time may be derived from the cost of producing electricity from gas-fired generation. In comparison to the 2010 Electric Export Price Forecast, the 2011 forecast projects prices to decrease on average 16% over the period 2013/14 to 2021/22 and decrease on average 8% in the period 2022/23 to 2036/37.

Over the 20-year forecast period, net extraprovincial revenues are $3.9 billion lower compared to IFF10. Almost half of the decrease can be attributed to the decrease in export prices.

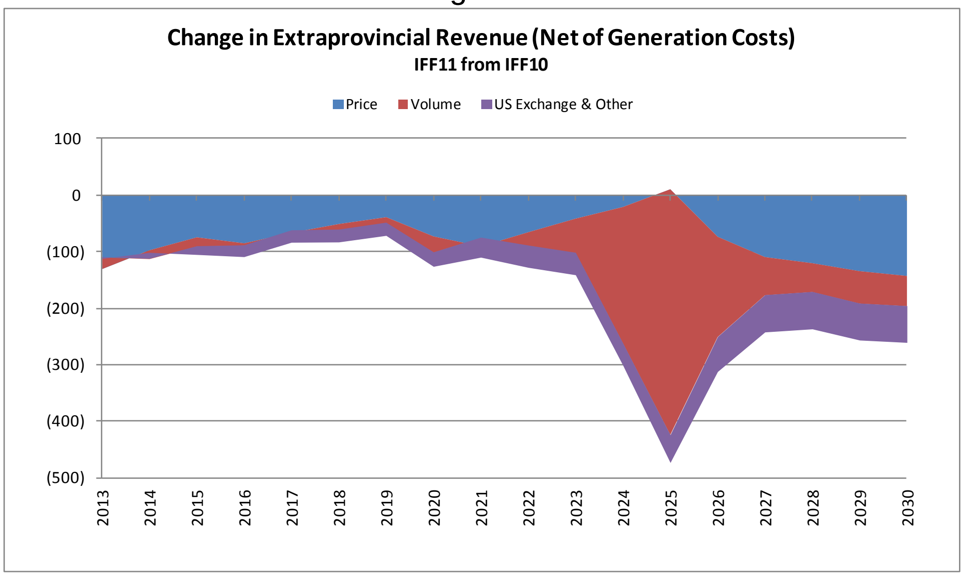
Over one-third of the decrease over the 20-year forecast can be attributed to the following factors affecting deliveries:

- Deferral of Conawapa by one year to 2024/25;

- Reduction in transfer capability for the new interconnection to the U.S. (400 MW for the period 2019/20 to 2024/25 upgraded to 1000 MW for 2024/25 and on);
- Reduction in the contracted energy delivered to Wisconsin Public Service (100 MW for the period 2019/20 to 2025/26); and
- Increased Manitoba load.

Figure 1 below shows the relative impacts of changes in price, volume and U.S. exchange on extraprovincial revenues compared to IFF10.

Figure 1



2.4 Non-Controlling Interest

Non-controlling interest represents the projected distributions paid from the Wuskwatim Power Limited Partnership (WPLP) and Keeyask Hydropower Limited Partnership (KHLP) to Nisichawayasihk Cree Nation (NCN) and Keeyask Cree Nations (KCN), respectively. NCN may acquire up to a 33% interest in the Wuskwatim generating station and KCN may acquire up to a 25% interest in the Keeyask generating station.

Manitoba Hydro will construct, operate and maintain the Wuskwatim and Keeyask generating stations and will purchase all of the output under power purchase agreements with the respective partnerships. Manitoba Hydro's income statement reflects all of the partnership revenues and costs with NCN and KCN's share of distributions shown as a deduction before net income. The partnerships' net assets are offset by an amount for NCN's and KCN's non-controlling equity interest on Manitoba Hydro's balance sheet.

2.5 International Financial Reporting Standards

IFF11 assumes that Manitoba Hydro will fully adopt International Financial Reporting Standards (IFRS) effective April 1, 2012. The primary impacts of IFRS that are included in IFF11 are as follows:

- Rate-regulated assets and liabilities do not satisfy the recognition criteria under IFRS and as such any unamortized balances with be adjusted to retained earnings on transition to IFRS and future expenditures on these items will be expensed as incurred.
- Administrative and other general overhead costs are not eligible for capitalization under IFRS and must be expensed as incurred.
- IFRS is more rigorous in terms of the componentization of assets and the recognition of gains and losses on the disposal/retirement of assets and does not allow the inclusion of asset retirement costs in depreciation rates.

Overall, the transition to IFRS will not have a significant impact on the annual net income of Manitoba Hydro. Increases to Operating, Maintenance and Administrative costs due to reduced capitalization and elimination of regulatory deferrals will be for the most part offset by corresponding reductions in Depreciation and Amortization. The impact of the transition to IFRS on net income for 2012/13 is expected to be a reduction of $10 million. The most significant impact of the transition to IFRS for Manitoba Hydro will be a reduction to retained earnings of approximately $375 million. The following table outlines the impacts of IFRS on retained earnings and net income:

Table 2

IFRS Impacts
Increase/(Decrease)
($Millions)

	Retained Earnings	Net Income 2012/13
Power Smart Programs	(224)	(12)
Site Remediation	(39)	(1)
Acquisition Costs	(21)	1
Regulatory Costs	(5)	1
Deferred Taxes	(31)	2
Administrative Overhead	(65)	(65)
Employee Benefits	(12)	-
Change in Service Lives	-	39
Removal of Negative Salvage	52	58
Change to Equal Life Group Depreciation	(30)	(33)
Total	(375)	(10)

2.6 Economic Variables

The economic assumptions used in the forecast are based upon Manitoba Hydro's Economic Outlook updated in October 2011 for current economic conditions. Projected rates for key economic indicators are listed below with the 2010 projected rates in brackets.

	Manitoba Consumer Price Index	MH CDN New Short Term Debt Rate *	MH CDN New Long Term Debt Rate *	$US/$CDN Exchange Rate
2011/12	2.0% (1.9%)	0.90% (2.10%)	3.75% (4.35%)	0.98 (1.02)
2012/13	2.0% (2.2%)	1.25% (3.30%)	3.70% (5.25%)	0.99 (1.04)
2013/14	2.0% (2.1%)	2.20% (3.85%)	4.05% (5.55%)	0.99 (1.05)
2014/15	2.0% (2.1%)	3.80% (4.30%)	5.40% (5.90%)	1.05 (1.09)
2020/21	2.1% (2.1%)	4.30% (4.65%)	6.40% (6.60%)	1.06 (1.11)

*Excluding Provincial Guarantee Fee of 1.0%

The Canadian dollar is projected to remain strong (below par) relative to the U.S. dollar in the early years of the forecast reflecting higher commodity and oil prices and the relatively healthy fiscal situation compared to the U.S. and Europe. In the longer term, the Canadian dollar is projected to weaken to 1.06 (C$/US$) but is stronger than last year's forecast. The Foreign Exchange Exposure Management Program establishes a natural hedge between the U.S. dollar (USD) cash inflows from USD export revenues and USD cash outflows (from USD interest & principal payments and USD purchases), such that changes in foreign exchange rates will be offset on the income statement to the extent that period cash flows are in balance.

3.0 NATURAL GAS DEMAND AND SUPPLY

The Corporation sells primary gas to Manitobans in a market which also includes a small number of brokers and marketers, and is the gas distribution utility for all customers in Manitoba. Currently, approximately 91% of customers representing approximately 60% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

The volume forecast incorporates Manitoba Hydro's Fixed Price Offering for primary gas, which was introduced in 2009 and offers customers one, three, and five-year fixed price contracts.

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

The 2011 Natural Gas Volume Forecast is lower than last year's forecast. The total natural gas sales volume forecast is down 46 million cubic meters (2%) in 2011/12 and down 25 million cubic meters (1%) in 2020/21. The decrease in the 2011 forecast is primarily attributed to lower consumption expectations for the Special Contract customer class resulting from decreased historical usage.

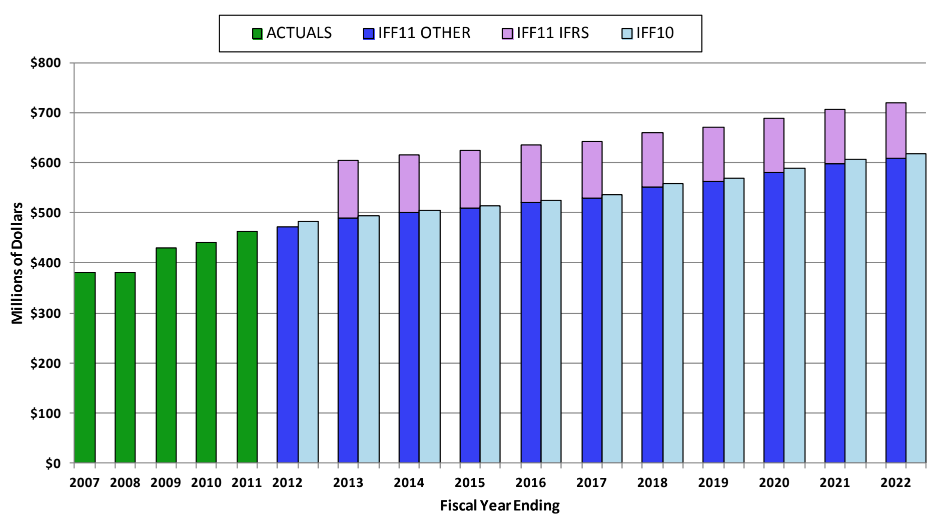
4.0 OPERATING, MAINTENANCE & ADMINISTRATIVE EXPENSE

Operating, Maintenance & Administrative (OM&A) Expenses in IFF11 include only those expenditures necessary to provide for the safe and reliable operation and maintenance of the generation, transmission and gas and electric distribution systems.

Compared to 2011/12, OM&A rises by $134 million in 2012/13 primarily due to the IFRS accounting changes. OM&A also rises in 2012/13 due to inflation plus the incremental operating costs as Wuskwatim comes into service partially offset by other productivity improvements and cost savings. Thereafter, OM&A rises each year at the same level as inflation except in years where major new generation and transmission comes into service in 2017/18 (Bipole III), 2019/20 (Keeyask) and 2024/25 (Conawapa).

Figure 2 below shows the OM&A expense projected in IFF11 compared to IFF10. Over the 10-year period to 2021/22, OM&A increased by approximately $100 million annually on average compared to IFF10. The increase can mainly be attributed to costs that are no longer eligible for capitalization which are expensed under IFRS and are partially offset by cost constraints.

Figure 2
Operating, Maintenance & Administrative Expense

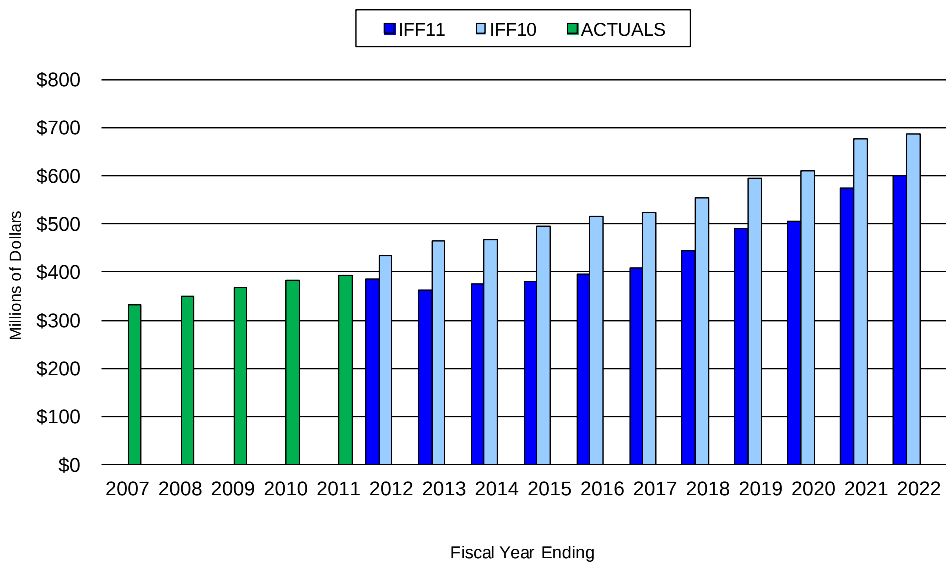


5.0 DEPRECIATION & AMORTIZATION EXPENSE

The Depreciation and Amortization Expense included in IFF11 is based on a comprehensive deprecation study that was completed in November of 2011. In addition to the update of services lives of assets, this depreciation study also involved the establishment of new asset component groupings and changes to Manitoba Hydro's depreciation methods to ensure compliance with IFRS requirements.

Figure 3 below provides a comparison of the Depreciation and Amortization expense between IFF11 and IFF10. The reduction in 2011/12 is primarily related to the implementation of the updated asset service lives as a result of the depreciation study. The further reductions in 2012/13 to 2021/22 reflect the removal of asset retirement costs from depreciation rates and the elimination of the amortization of rate-regulated assets partially offset by the change to the Equal Life Group methodology for calculating depreciation rates.

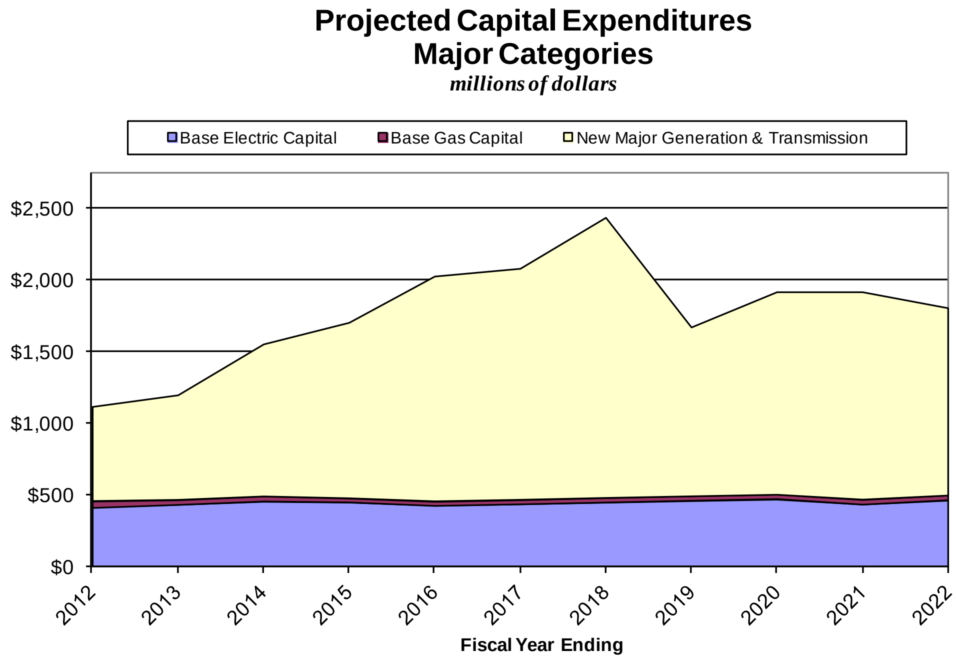
Figure 3
Depreciation & Amortization Expense



6.0 CAPITAL EXPENDITURE FORECAST (CEF11)

Over the 10-year forecast period to 2021/22, projected capital expenditures are $19.4 billion comprised of $5.3 billion in base electric and gas capital expenditures and $14.1 billion in major new generation and transmission expenditures. Figure 4 below illustrates projected capital expenditures by major category.

Figure 4

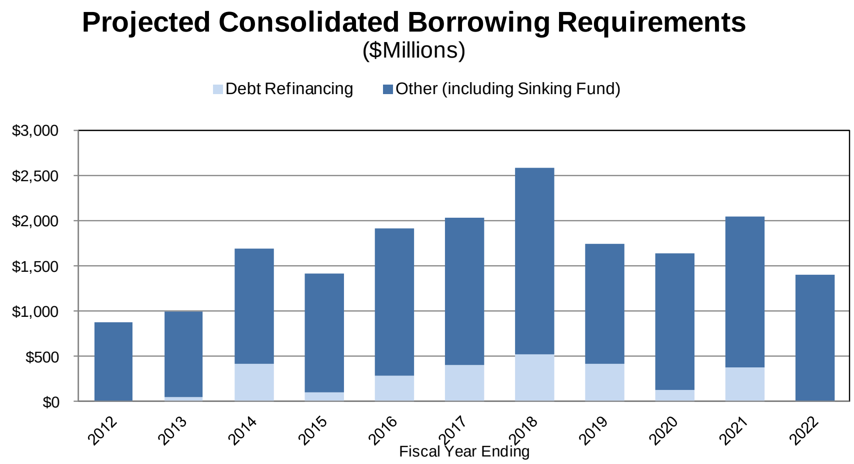


Over the 10-year forecast period to 2021/22, capital expenditures are nearly $1 billion lower compared to the previous capital expenditure forecast, CEF10-2. The decrease can be attributed to the reclassification of demand side management expenditures to OM&A in accordance with IFRS and the timing of the project expenditures resulting from the one-year deferral of Conawapa generating station to 2024/25 which are partially offset by a moderate increase to Wuskwatim reflecting anticipated costs to completion.

7.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast consolidated borrowing requirements are portrayed in Figure 5 below.

Figure 5



Manitoba Hydro arranges long term financing in the form of advances from the Province of Manitoba. Both long and short-term borrowings are guaranteed by the Province (except for mitigation bonds issued by the Manitoba Hydro-Electric Board). Manitoba Hydro's target range is to hold 15% to 25% of debt in floating rate instruments in order to minimize debt costs without undue interest rate exposure. Currently, about 20% of Manitoba Hydro's debt is in floating rate instruments.

8.0 FINANCIAL TARGETS

Manitoba Hydro has the following financial targets for consolidated operations:

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

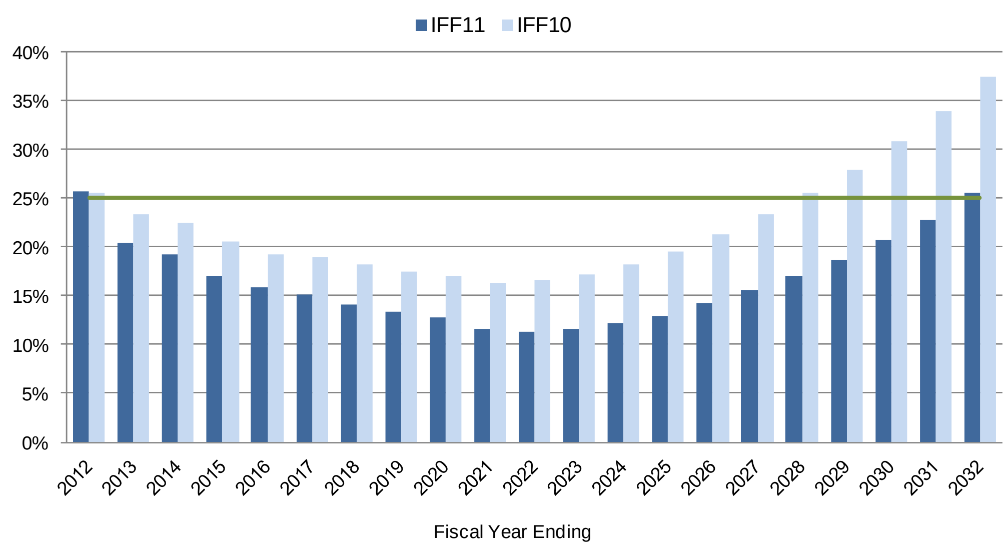
It is recognized that it may not be possible to maintain financial targets during years of major investment in the generation and transmission system.

8.1 Debt/Equity Ratio

The debt/equity ratio indicates the portion of Manitoba Hydro's assets that have been financed by internally generated funds rather than through debt. Figure 6 below shows the projected consolidated equity ratio for IFF11 compared to IFF10. High levels of capital investment in major new generation and transmission combined with reduced net extraprovincial revenues result in a deterioration of the equity ratio to 11% by 2021/22. In the longer term, the equity ratio is projected to show steady improvement following the in-service of Keeyask and Conawapa generating stations and returns to the target 25% by 2031/32.

Figure 6

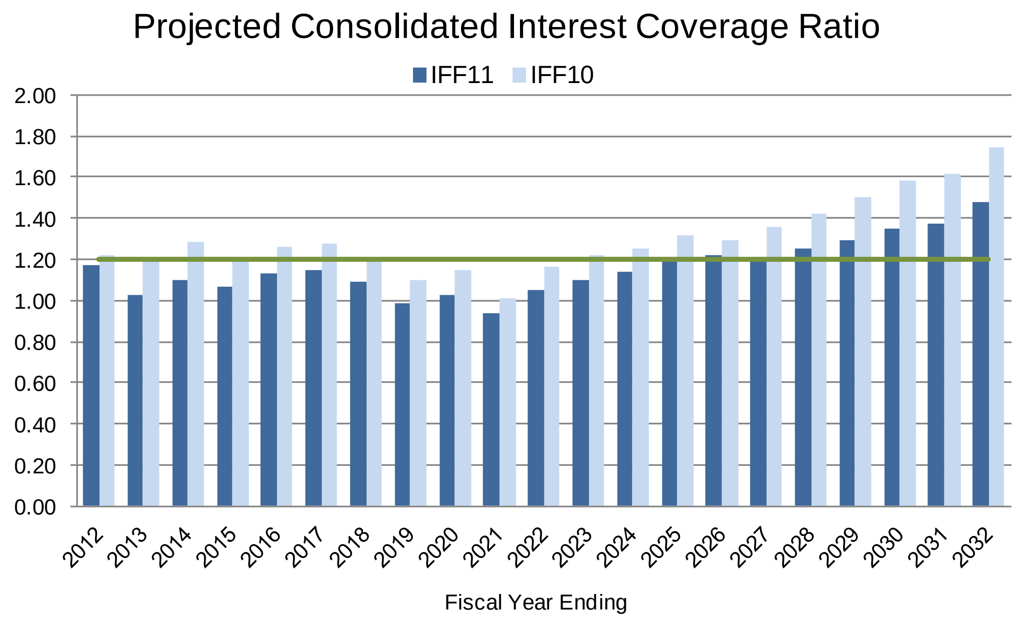
Projected Consolidated Equity Ratio



8.2 Interest Coverage Ratio

The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. Figure 7 below shows that the reduction in net extraprovincial revenues compared to the previous forecast results in interest coverage ratios lower than target for most of the 10-year forecast period. In the longer term, interest coverage is projected to return to the 1.2 target level immediately following Conawapa generating station in-service in 2024/25 and grows steadily thereafter.

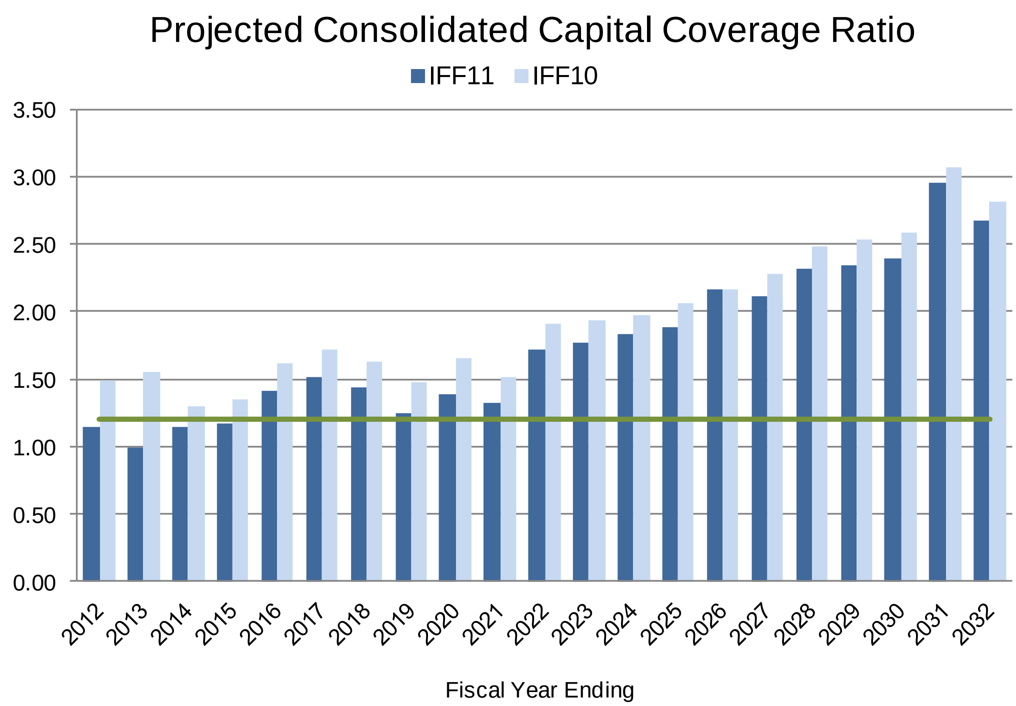
Figure 7



8.3 Capital Coverage Ratio

The capital coverage ratio measures the ability of current period internally generated funds to finance capital expenditures excluding major new generation and related transmission. Capital coverage is below target for the first four years of the forecast and then projected cash flows are sufficient to enable this target to be met in remaining years of the forecast. Figure 8 below shows the comparative capital coverage ratios for IFF11 and IFF10.

Figure 8



9.0 RISK ANALYSIS

The 20 Year Financial Outlook includes a number of key assumptions as described in section 1.0. A change to one or more of those assumptions could have a significant impact on projected financial results. This section provides an indication of the financial impact of changes in the following assumptions:

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

The table below shows the change in retained earnings in selected years over the forecast period assuming no change to rate increases relative to IFF11.

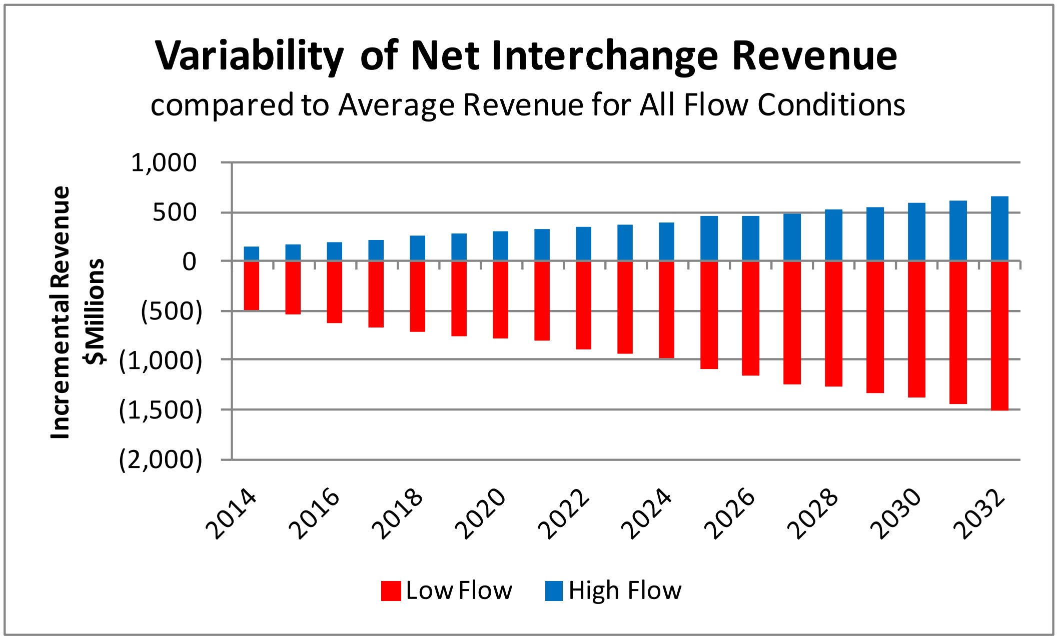
	2013/14	2017/18	2021/22	Incremental Annual Rate Increase/(Decrease)*
	Incremental Increase/(Decrease) in Retained Earnings			
IFF11	2,196	2,616	2,631	N/A
High Domestic Load Growth	7	10	(119)	0.15%
+1% Interest	3	(116)	(724)	0.91%
-1% Interest	(2)	113	671	-0.90%
US $ up 10¢	(7)	(12)	64	-0.08%
US $ down 10¢	8	10	(73)	0.10%
Low Export Price	1	(184)	(684)	0.89%
High Export Price	20	129	401	-0.53%
Capital Expenditures + $100M	(11)	(165)	(551)	0.65%
5 Year Drought (starting in 2013/14)	N/A	(1,570)	N/A	2.53%

***NOTE** – the rate increases represent the additional identical annual percentage (incremental to the base case annual rate increases) required to achieve the same level of retained earnings in 2021/22 as in the base MH11.

9.1 Five Year Drought

IFF11 reflects average net interchange revenues and variable generation costs associated with 96 different potential system inflow conditions. The actual inflow that occurs in any given year can vary significantly as shown in Figure 9 below. The impact of the lowest flows are asymmetrically greater than the highest flows due to the requirements for thermally generated and imported energy in low flow years and spilling of water beyond system constraints in high years.

Figure 9



A prolonged period of low flows has a significant financial impact on financial projections. The 2011 estimate of a recurrence of the historic five-year drought period from 1987/88 to 1991/92 commencing in 2013/14 is about $1.4 billion by 2017/18. After finance charges, this estimate grows to nearly $1.6 billion and could be higher as projected in previous forecasts due to higher prices for thermal generation and import purchases.

10.0 ALTERNATIVE SCENARIOS

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
IFF11 Base Case											
Interest Coverage Ratio	1.17	1.03	1.10	1.07	1.13	1.15	1.09	0.99	1.03	0.94	1.05
Rate Increases Required to Achieve 1.20 Interest Coverage by 2021											
Interest Coverage Ratio	1.17	1.06	1.16	1.17	1.26	1.30	1.28	1.20	1.28	1.20	1.36
Incremental Rate Increases	0.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	3.50%
4.00% Rate Increases to 2021											
Interest Coverage Ratio	1.17	1.04	1.12	1.10	1.17	1.19	1.15	1.06	1.10	1.01	1.13
Incremental Rate Increases	0.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	3.50%
Inflationary Rate Increases											
Interest Coverage Ratio	1.17	1.00	1.04	0.99	1.02	1.02	0.94	0.83	0.85	0.75	0.82
Rate Increases	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.10%	2.10%	2.10%	2.10%	2.10%
PUB Order 5/12											
Interest Coverage Ratio	1.13	1.01	1.07	1.05	1.11	1.12	1.07	0.97	1.01	0.92	1.02
GCR Reductions	(22)	(13)	(14)	(14)	(15)	(16)	(17)	(17)	(18)	(19)	(20)
Net Income (Loss)	77	4	50	40	94	123	78	(32)	11	(125)	35
Retained Earnings	2,467	2,095	2,145	2,185	2,278	2,401	2,480	2,448	2,459	2,334	2,368
OM&A Reductions Required to Maintain Minimum 1.20 Interest Coverage											
Interest Coverage Ratio	1.17	1.20	1.27	1.24	1.29	1.31	1.25	1.20	1.24	1.20	1.35
Total OM&A (IFF11)	472	606	616	624	635	643	660	670	688	706	719
OM&A Reductions*	-	(109)	(111)	(113)	(115)	(118)	(120)	(181)	(185)	(280)	(285)
Capital Expenditure Reductions											
Interest Coverage Ratio	1.17	1.04	1.12	1.09	1.17	1.20	1.14	1.04	1.09	1.00	1.13
Capital Expenditures (IFF11)	1,114	1,195	1,550	1,700	2,023	2,077	2,433	1,668	1,914	1,914	1,802
Capital Expenditure Reductions**	-	(110)	(110)	(110)	(110)	(110)	(110)	(110)	(110)	(110)	(110)

* OM&A reductions are projected for illustrative purposes only. It would not be possible to reduce OM&A by these amounts and still maintain safety, reliability and efficiency fo the electric system. There are, however, and number of OM&A initatives currently underway which will result in cost savings without jeopardizing system security.

** Similar to OM&A initiatives, a review is currently underway to determine the extent, if any, capital expenditure reductions (or deferrals) that may be possible.

11.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF11)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF11)
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers	1,620	1,697	1,792	1,855	1,913	1,986	2,065	2,139	2,228	2,322	2,419
Extraprovincial	370	359	363	394	469	502	531	554	611	821	913
	1,990	2,056	2,155	2,249	2,382	2,488	2,596	2,693	2,838	3,142	3,333
Cost of Gas Sold	245	240	257	254	252	251	250	250	249	249	249
	1,745	1,816	1,898	1,995	2,130	2,237	2,346	2,443	2,589	2,894	3,084
Other	27	39	41	42	42	43	44	45	46	47	48
	1,772	1,854	1,938	2,037	2,172	2,280	2,390	2,488	2,635	2,940	3,132
EXPENSES											
Operating and Administrative	472	606	616	624	635	643	660	670	688	706	719
Finance Expense	436	492	502	560	595	630	703	832	876	1,225	1,193
Depreciation and Amortization	385	364	375	380	397	409	445	491	506	574	601
Water Rentals and Assessments	120	116	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	157	158	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	103	101	108	115	124	132	143	149	157	146	153
	1,673	1,836	1,872	1,978	2,057	2,133	2,284	2,492	2,591	3,029	3,050
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	99	17	66	57	113	146	104	(6)	41	(92)	72
Additional General Consumers Revenue											
General electricity rate increases	0.00%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
General gas rate increases	0.00%	2.50%	1.00%	0.00%	0.50%	0.50%	0.00%	0.50%	0.50%	0.50%	1.00%
Financial Ratios											
Equity	26%	20%	19%	17%	16%	15%	14%	13%	13%	12%	11%
Interest Coverage	1.17	1.03	1.10	1.07	1.13	1.15	1.09	0.99	1.03	0.94	1.05
Capital Coverage	1.14	0.99	1.14	1.17	1.41	1.51	1.44	1.25	1.39	1.32	1.72

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF11)
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers	2,520	2,626	2,703	2,783	2,868	2,955	3,043	3,134	3,226	3,323
Extraprovincial	931	946	1,124	1,408	1,526	1,544	1,539	1,544	1,565	1,574
	3,451	3,573	3,827	4,191	4,394	4,498	4,583	4,678	4,791	4,897
Cost of Gas Sold	248	248	248	247	247	247	247	248	248	248
	3,203	3,325	3,580	3,943	4,146	4,251	4,335	4,430	4,543	4,649
Other	49	50	51	52	53	54	55	56	57	58
	3,252	3,374	3,630	3,995	4,199	4,305	4,390	4,486	4,601	4,708
EXPENSES										
Operating and Administrative	733	747	773	783	797	813	828	845	862	879
Finance Expense	1,184	1,178	1,278	1,510	1,667	1,642	1,610	1,572	1,596	1,506
Depreciation and Amortization	605	609	643	710	762	772	784	794	827	849
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	160	165	171	174	175	177	180	182	184	186
	3,079	3,129	3,281	3,604	3,855	3,877	3,888	3,893	3,983	3,947
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	162	235	338	380	332	416	489	581	604	746
Additional General Consumers Revenue										
General electricity rate increases	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
General gas rate increases	1.00%	1.00%	1.00%	1.00%	0.50%	1.00%	1.00%	1.00%	1.00%	1.00%
Financial Ratios										
Equity	12%	12%	13%	14%	16%	17%	19%	21%	23%	26%
Interest Coverage	1.10	1.14	1.20	1.22	1.20	1.25	1.29	1.35	1.37	1.48
Capital Coverage	1.77	1.84	1.88	2.16	2.11	2.32	2.34	2.39	2.96	2.68

CONSOLIDATED PROJECTED BALANCE SHEET (IFF11)
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS											
Plant in Service	14,393	15,736	16,310	17,091	18,035	18,638	22,084	22,599	26,242	29,025	29,414
Accumulated Depreciation	(5,071)	(5,386)	(5,735)	(6,078)	(6,451)	(6,829)	(7,270)	(7,758)	(8,261)	(8,831)	(9,427)
Net Plant in Service	9,322	10,351	10,575	11,013	11,585	11,809	14,815	14,841	17,981	20,194	19,987
Construction in Progress	2,445	2,198	3,150	3,999	5,015	6,412	5,348	6,449	4,560	3,597	4,966
Current and Other Assets	1,455	1,138	923	937	1,174	1,304	1,540	1,367	1,662	1,880	1,905
Goodwill and Intangible Assets	256	252	235	220	205	194	185	178	171	166	162
Regulated Assets	321	-	-	-	-	-	-	-	-	-	-
	13,798	13,938	14,883	16,169	17,979	19,719	21,888	22,834	24,374	25,837	27,019
LIABILITIES AND EQUITY											
Long-Term Debt	9,270	9,487	10,926	12,209	13,833	15,304	17,070	18,562	19,724	21,234	22,878
Current and Other Liabilities	1,384	1,895	1,336	1,427	1,549	1,679	1,995	1,461	1,804	1,856	1,334
Contributions in Aid of Construction	320	332	345	352	358	370	381	391	401	411	421
Retained Earnings	2,489	2,131	2,196	2,254	2,367	2,513	2,616	2,610	2,651	2,559	2,631
Accumulated Other Comprehensive Income	335	95	80	(73)	(129)	(147)	(174)	(190)	(206)	(224)	(246)
	13,798	13,938	14,883	16,169	17,979	19,719	21,888	22,834	24,374	25,837	27,019
Equity Ratio	26%	20%	19%	17%	16%	15%	14%	13%	13%	12%	11%

CONSOLIDATED PROJECTED BALANCE SHEET (IFF11)
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	29,852	30,447	34,890	38,996	40,287	40,948	41,544	42,100	44,148	44,892
Accumulated Depreciation	(10,030)	(10,638)	(11,281)	(11,992)	(12,754)	(13,525)	(14,305)	(15,094)	(15,917)	(16,762)
Net Plant in Service	19,821	19,809	23,608	27,004	27,532	27,423	27,239	27,006	28,231	28,130
Construction in Progress	6,101	6,971	4,172	1,024	547	788	1,261	1,724	621	760
Current and Other Assets	1,744	2,146	2,306	2,201	2,699	2,996	3,148	3,464	3,888	4,401
Goodwill and Intangible Assets	159	158	156	154	153	151	150	149	148	148
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27,825	29,083	30,242	30,383	30,931	31,358	31,798	32,344	32,888	33,439
LIABILITIES AND EQUITY										
Long-Term Debt	23,681	24,684	25,037	25,239	25,441	25,382	25,133	25,235	25,024	23,963
Current and Other Liabilities	1,178	1,188	1,645	1,193	1,196	1,255	1,442	1,294	1,432	2,284
Contributions in Aid of Construction	432	442	453	464	475	487	499	511	524	537
Retained Earnings	2,793	3,028	3,366	3,746	4,078	4,493	4,982	5,563	6,167	6,913
Accumulated Other Comprehensive Income	(259)	(259)	(259)	(259)	(259)	(259)	(259)	(259)	(259)	(259)
	27,825	29,083	30,242	30,383	30,931	31,358	31,798	32,344	32,888	33,439
Equity Ratio	12%	12%	13%	14%	16%	17%	19%	21%	23%	26%

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF11)
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	2,102	2,186	2,290	2,382	2,516	2,624	2,733	2,831	2,979	3,285	3,477
Cash Paid to Suppliers and Employees	(1,169)	(1,331)	(1,346)	(1,389)	(1,413)	(1,441)	(1,484)	(1,517)	(1,557)	(1,580)	(1,607)
Interest Paid	(437)	(487)	(491)	(535)	(584)	(620)	(705)	(837)	(870)	(1,225)	(1,188)
Interest Received	26	28	27	20	27	34	41	43	40	36	35
	522	397	480	478	545	597	585	521	591	516	718
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	1,000	1,650	1,450	2,000	2,000	2,600	1,800	1,800	2,200	1,800
Sinking Fund Withdrawals	23	129	395	105	24	-	5	424	178	265	689
Retirement of Long-Term Debt	(25)	(181)	(808)	(214)	(312)	(408)	(530)	(837)	(309)	(640)	(692)
Other	(81)	(21)	(14)	(5)	(7)	(7)	(7)	(16)	(5)	26	(6)
	729	926	1,223	1,336	1,705	1,585	2,067	1,371	1,663	1,851	1,791
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1,204)	(1,182)	(1,510)	(1,637)	(1,956)	(2,009)	(2,362)	(1,596)	(1,850)	(1,887)	(1,728)
Sinking Fund Payment	(98)	(117)	(208)	(124)	(192)	(157)	(231)	(210)	(219)	(288)	(346)
Other	(20)	(21)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(35)	(40)
	(1,322)	(1,319)	(1,738)	(1,782)	(2,168)	(2,212)	(2,629)	(1,836)	(2,098)	(2,210)	(2,114)
Net Increase (Decrease) in Cash	(70)	4	(36)	32	82	(30)	23	56	157	158	395
Cash at Beginning of Year	70	(0)	3	(32)	0	82	52	75	131	287	445
Cash at End of Year	(0)	3	(32)	0	82	52	75	131	287	445	840

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF11)
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,598	3,722	3,978	4,344	4,549	4,657	4,743	4,841	4,957	5,066
Cash Paid to Suppliers and Employees	(1,642)	(1,693)	(1,712)	(1,737)	(1,780)	(1,818)	(1,851)	(1,886)	(1,919)	(1,954)
Interest Paid	(1,160)	(1,138)	(1,250)	(1,494)	(1,646)	(1,637)	(1,616)	(1,575)	(1,583)	(1,530)
Interest Received	20	22	32	36	38	49	61	66	73	86
	816	912	1,049	1,150	1,160	1,250	1,338	1,446	1,528	1,668
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	800	1,000	800	200	200	-	-	200	-	-
Sinking Fund Withdrawals	159	-	-	414	-	-	60	250	-	13
Retirement of Long-Term Debt	(159)	-	-	(450)	-	-	(60)	(250)	(100)	(213)
Other	(7)	(6)	(6)	(8)	(8)	(7)	(7)	(6)	(4)	(19)
	793	994	794	156	192	(7)	(7)	194	(104)	(219)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,542)	(1,434)	(1,612)	(925)	(781)	(869)	(1,039)	(990)	(914)	(853)
Sinking Fund Payment	(238)	(250)	(268)	(288)	(280)	(292)	(304)	(313)	(315)	(327)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1,809)	(1,713)	(1,907)	(1,241)	(1,091)	(1,190)	(1,372)	(1,332)	(1,258)	(1,209)
Net Increase (Decrease) in Cash	(200)	192	(64)	65	262	53	(41)	307	166	241
Cash at Beginning of Year	840	640	832	768	833	1,095	1,148	1,107	1,414	1,580
Cash at End of Year	640	832	768	833	1,095	1,148	1,107	1,414	1,580	1,821

12.0 CAPITAL EXPENDITURE FORECAST (CEF11)

CAPITAL EXPENDITURE FORECAST (CEF11)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
ELECTRIC													
Major New Generation & Transmission													
Wuskwatim - Generation	1,374.6	181.1	65.3	5.9	-	-	-	-	-	-	-	-	252.3
Wuskwatim - Transmission	297.4	31.6	-	-	-	-	-	-	-	-	-	-	31.6
Herblet Lake – The Pas 230 kV Transmission	74.9	6.4	0.7	-	-	-	-	-	-	-	-	-	7.2
Keeyask - Generation	5,636.9	115.6	163.4	198.2	401.1	662.9	895.6	1,041.0	786.3	716.4	189.2	45.4	5,215.1
Conawapa - Generation	7,770.8	104.4	105.2	66.1	67.2	188.1	235.4	296.8	322.6	764.7	1,229.5	1,222.9	4,603.0
Kelsey Improvements & Upgrades	301.7	34.4	24.8	20.2	0.4	-	-	-	-	-	-	-	79.7
Kettle Improvements & Upgrades	165.7	13.7	22.9	20.4	20.7	7.3	7.4	7.6	7.7	7.9	8.0	8.2	131.9
Pointe du Bois Spillway Replacement	398.2	41.1	113.6	100.4	77.1	13.0	-	-	-	-	-	-	345.2
Pointe du Bois - Transmission	85.9	14.5	11.1	18.2	16.4	-	-	-	-	-	-	-	60.2
Pointe du Bois Powerhouse Rebuild	1,538.3	-	-	-	-	-	-	-	-	-	-	0.5	0.5
Bipole III - Transmission Line	1,259.9	31.0	52.8	135.4	330.9	353.9	239.0	73.4	-	-	-	-	1,216.3
Bipole III - Converter Stations	1,828.5	50.7	141.6	315.4	330.6	353.5	356.3	163.2	58.8	-	-	-	1,770.0
Bipole III - Collector Lines	191.4	9.9	57.8	46.9	22.6	25.2	18.5	10.1	-	-	-	-	191.1
Riel 230/ 500 kV Station	267.6	74.8	67.7	47.5	-	-	-	-	-	-	-	-	190.0
Firm Import Upgrades	19.9	0.2	19.7	-	-	-	-	-	-	-	-	-	19.9
Dorsey - US Border New 500kV Transmission Line	204.8	0.1	0.8	0.4	2.0	3.6	34.0	84.0	79.0	-	-	-	203.9
St. Joseph Wind Transmission	11.2	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Demand Side Management	NA	31.8	-	-	-	-	-	-	-	-	-	-	31.8
Generating Station Improvements & Upgrades	649.0	-	-	-	-	-	-	-	-	-	45.0	32.2	77.3
Single Cycle Gas Turbines	65.6	-	-	-	-	-	-	-	-	-	-	-	-
Additional North South Trasmission	318.2	-	-	-	-	-	-	-	-	-	-	-	-
Target Adjustment	(317.2)	(87.8)	(118.3)	85.0	(45.4)	(40.7)	(175.7)	277.0	(77.3)	(77.0)	(26.0)	(3.2)	(289.4)
		656.1	729.0	1,060.0	1,223.4	1,566.9	1,610.5	1,953.0	1,177.1	1,412.0	1,445.8	1,306.0	14,139.8

CAPITAL EXPENDITURE FORECAST (CEF11)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Power Supply													
HVDC Auxiliary Power Supply Ugrades	5.3	0.5	0.4	-	-	-	-	-	-	-	-	-	0.9
Dorsey Synchronous Condenser Refurbishment	78.3	4.6	5.3	5.1	7.7	11.7	11.4	8.3	-	-	-	-	54.2
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	0.5	0.3	0.3	0.1	-	-	-	-	-	-	-	1.2
HVDC Transformer Replacement Program	171.7	4.6	17.6	15.5	17.2	14.0	9.7	-	-	-	-	-	78.5
HVDC Transformer Replacement Program Extended	449.7	-	-	-	-	-	-	-	-	-	0.5	4.6	5.2
Dorsey 230 kV Relay Building Upgrade	82.2	1.6	2.2	17.7	35.1	12.5	3.1	-	-	-	-	-	72.2
HVDC Stations Ground Grid Refurbishment	4.3	0.4	0.4	0.4	0.3	0.5	-	-	-	-	-	-	2.1
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	15.9	2.1	1.1	1.0	0.2	0.5	0.1	0.1	0.0	-	-	-	5.2
HVDC Bipole 1 Pole Differential Protection	3.3	-	-	1.1	2.2	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.4	2.3	11.1	6.0	-	-	-	-	-	-	-	19.8
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	0.2	2.7	2.4	5.6	-	-	-	-	-	-	11.0
HVDC Smoothing Reactor Replacements	39.3	20.6	1.8	0.7	-	-	-	-	-	-	-	-	23.1
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Separation	3.2	0.4	1.2	1.5	-	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	0.2	1.3	1.1	3.0	3.8	2.4	-	-	-	-	-	11.7
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Replacements	8.7	0.6	1.0	1.7	5.3	0.0	-	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	19.2	0.1	-	3.3	4.8	4.0	4.2	2.3	-	-	-	-	18.7
HVDC Bipole 2 Upgrades & Replacements	444.2	-	-	-	-	-	-	-	-	-	12.3	52.7	65.0
HVDC Bipole 1 CQ Disconnect Replacement	5.2	0.3	0.9	1.5	1.0	1.1	0.3	-	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	4.7	1.2	-	-	-	-	-	-	-	-	-	-	1.2
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.8	0.4	2.7	1.2	1.2	-	-	-	-	-	-	-	5.5
HVDC Gapped Arrestor Replacement	16.3	0.2	1.0	3.9	3.4	7.0	0.1	-	-	-	-	-	15.7
Converter Transformer Bushing Replacement	5.9	0.4	1.0	0.5	-	-	-	-	-	-	-	-	1.9
Winnipeg River Riverbank Protection Program	19.7	1.5	1.4	1.3	1.3	1.3	0.8	-	-	-	-	-	7.5
Power Supply Hydraulic Controls	20.5	1.0	0.7	1.3	-	-	-	2.1	2.6	0.9	-	-	8.6
Slave Falls GS Creek Spillway Rehab	11.1	0.0	1.0	1.9	8.1	-	-	-	-	-	-	-	11.1
Slave Falls Rehabilitation	230.2	9.0	2.6	4.3	31.7	40.6	45.8	42.0	11.3	-	-	-	187.3
Great Falls Unit 4 Major Overhaul	43.5	11.4	21.6	0.8	-	-	-	-	-	-	-	-	33.8
Great Falls Unit 5 Discharge Ring Replacement and Major Overhaul	24.8	-	-	-	2.2	17.1	5.4	-	-	-	-	-	24.8
Generation South Overhauls & Improvements	384.8	-	-	-	-	-	-	-	-	-	4.7	10.2	14.8
Pine Falls Rehabilitation	166.7	4.0	21.0	26.9	40.3	46.8	14.0	0.1	-	-	-	-	153.0
Generation South Transformer Refurbish & Spares	27.6	0.6	7.0	13.8	4.3	0.5	0.5	-	-	-	-	-	26.6
Water Licenses & Renewals	54.6	5.2	5.6	6.2	6.3	6.5	6.5	3.9	-	-	-	-	40.2
Generation South PCB Regulation Compliance	4.7	0.5	0.4	0.4	0.2	2.7	-	-	-	-	-	-	4.1
Kettle Transformer Overhaul Program	35.6	9.1	7.1	7.9	0.7	-	-	-	-	-	-	-	24.8
Generation South Breaker Replacements	11.1	1.7	3.8	0.5	1.0	0.4	1.2	-	-	-	-	-	8.5
Seven Sisters Upgrades	14.4	4.4	1.6	0.6	-	-	-	-	-	-	-	-	6.6
Generation South Excitation Upgrades	18.3	1.3	1.5	2.3	1.9	2.5	1.0	0.7	6.9	0.2	-	-	18.3
Generation South Excitation Program Extended	14.0	-	-	-	-	-	-	-	-	-	4.4	5.0	9.4
Laurie River/Churchill River Diversion (CRD) Comm and Annunciation Upgrades	4.8	2.1	1.9	-	-	-	-	-	-	-	-	-	4.0
Notigi Marine Vessel Replacement and Infrastructure Improvements	4.6	0.3	4.1	-	-	-	-	-	-	-	-	-	4.4
Limestone Stilling Basin Rehabilitation	2.0	0.0	0.4	1.6	-	-	-	-	-	-	-	-	2.0
Pointe Du Bois GS Rehabilitation	50.0	6.3	19.8	19.5	4.4	-	-	-	-	-	-	-	49.9
Kettle Wicket Gates Lever Refurbishments	2.3	-	1.1	1.2	-	-	-	-	-	-	-	-	2.3
Limestone Governor Control Repl	2.5	-	0.3	1.3	0.9	-	-	-	-	-	-	-	2.5
Limestone GSCADA Replacement	5.3	-	0.4	1.3	0.8	0.9	0.4	1.5	-	-	-	-	5.3
Jenpeg Unit Overhauls	128.1	-	-	-	-	2.2	2.5	18.0	23.7	24.2	24.6	20.8	115.9
Power Supply Dam Safety Upgrades	64.5	7.4	10.6	5.0	-	-	-	-	-	-	-	-	23.1
Brandon Unit 5 License Review	18.7	0.2	0.2	2.6	10.4	0.0	-	-	-	-	-	-	13.4
Selkirk Enhancements	14.2	0.4	0.9	-	-	-	-	-	-	-	-	-	1.3
Fire Protection Projects - HVDC	7.2	0.4	0.2	1.2	2.9	-	-	-	-	-	-	-	4.7
Halon Replacement Project	36.4	1.6	5.2	2.6	3.5	2.2	0.9	-	-	-	-	-	16.0
Oil Containment – Power Supply	19.1	0.7	0.5	0.7	0.4	0.6	0.3	-	-	-	-	-	3.1
Grand Rapids Townsite House Renovations	5.2	1.1	0.9	0.9	0.9	0.0	-	-	-	-	-	-	3.9
Grand Rapids Fish Hatchery	2.2	1.2	0.8	-	-	-	-	-	-	-	-	-	2.0
Generation Townsite Infrastructure	52.1	9.0	1.9	-	-	-	-	-	-	-	-	-	10.9
Site Remediation of Contaminated Corporate Facilities	31.7	1.6	-	-	-	-	-	-	-	-	-	-	1.6
High Voltage Test Facility	40.6	13.7	0.4	-	-	-	-	-	-	-	-	-	14.1
Power Supply Security Installations / Upgrades	43.2	5.6	7.9	9.7	4.7	-	-	-	-	-	-	-	27.8
Power Supply Sewer & Domestic Water System Install and Upgrade	37.9	6.4	2.9	1.0	2.4	1.6	2.4	3.1	0.1	-	-	-	19.9
Power Supply Domestic	509.2	19.7	20.1	20.5	21.0	21.4	21.8	22.2	22.7	23.1	23.6	24.1	240.3
Target Adjustment	(335.8)	(10.7)	(60.3)	(57.3)	(76.4)	(77.5)	(30.6)	(19.6)	(1.6)	0.5	0.8	(2.8)	(335.5)
		155.6	136.4	150.4	163.9	130.5	104.1	84.8	65.6	48.9	70.8	114.6	1,225.6

CAPITAL EXPENDITURE FORECAST (CEF11)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Transmission													
Winnipeg - Brandon Transmission System Improvements	44.8	3.0	0.8	4.1	28.7	3.7	-	-	-	-	-	-	40.3
Transcona East 230 - 66 kV Station	33.1	24.1	-	-	-	-	-	-	-	-	-	-	24.1
Brandon Area Transmission Improvements	11.8	4.4	6.3	1.0	-	-	-	-	-	-	-	-	11.6
Neepawa 230 - 66 kV Station	30.0	14.1	8.0	4.5	-	-	-	-	-	-	-	-	26.6
Transmission Line Re-Rating	31.8	2.9	6.4	-	-	-	-	-	-	-	-	-	9.3
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	0.8	0.9	2.6	6.1	9.7	12.1	-	32.2
Transcona Station 66 kV Breaker Replacement	6.0	0.4	2.9	1.5	1.1	0.0	-	-	-	-	-	-	6.0
13.2kV Shunt Reactor Replacements	33.0	2.2	4.9	0.9	0.8	2.2	2.3	2.3	17.5	-	-	-	33.0
Lake Winnipeg East System Improvements	66.9	2.3	5.7	15.4	29.2	14.2	0.1	-	-	-	-	-	66.8
Canexus Load Addition	(0.2)	0.9	0.1	-	-	-	-	-	-	-	-	-	1.0
D602F 500kV T/L Footing Replacements	4.4	4.4	-	-	-	-	-	-	-	-	-	-	4.4
Stanley Station 230-66 kV Transformer Addition	21.1	0.0	1.8	7.3	7.9	4.0	-	-	-	-	-	-	21.1
Enbridge Pipelines: Clipper Project Load Addition Phase 2	7.5	1.8	1.9	0.0	-	-	-	-	-	-	-	-	3.7
Ashern Station Bank Addition	10.6	0.2	1.6	1.5	7.0	0.2	-	-	-	-	-	-	10.6
Ashern Station 230 kV Shunt Reactor Replacement	2.7	0.9	1.8	-	-	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Diesel Tank Farm Upgrade	1.1	(1.0)	0.7	-	-	-	-	-	-	-	-	-	(0.4)
Energy Management System (EMS) Upgrade	6.6	2.8	2.0	-	-	-	-	-	-	-	-	-	4.8
Transmission Line Protection & Teleprotection Replacement	21.1	3.1	3.4	2.8	2.8	2.9	2.4	-	-	-	-	-	17.5
Winnipeg Central Protection Wireline Replacement	10.5	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Mobile Radio System Modernization	30.7	1.9	6.4	2.8	11.6	7.9	-	-	-	-	-	-	30.5
Site Remediation of Diesel Generating Stations	12.6	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Oil Containment - Transmission	7.4	0.4	0.0	-	-	-	-	-	-	-	-	-	0.4
Station Battery Bank Capacity & System Reliability Increase	46.5	4.8	5.1	4.9	5.0	5.2	-	-	-	-	-	-	25.0
Waverley Service Centre Oil Tank Farm Replacement	3.0	0.5	0.4	0.7	-	-	-	-	-	-	-	-	1.6
115 kV Transmission Lines	298.9	-	-	-	-	-	-	-	-	-	10.3	16.1	26.4
230 kV Transmission Lines	171.1	-	-	-	-	-	-	-	-	-	5.9	9.2	15.1
Sub-Transmission	124.8	-	-	-	-	-	-	-	-	-	4.3	6.7	11.0
Communications	425.8	-	-	-	-	-	-	-	-	-	14.7	23.0	37.6
Site Remediation	NA	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Domestic	788.9	30.6	31.2	31.8	32.5	33.1	33.8	34.5	35.1	35.9	36.6	37.3	372.3
Target Adjustment	(41.6)	(24.3)	(13.4)	27.3	(38.2)	(13.6)	(0.1)	2.2	(14.6)	0.0	1.0	1.8	(71.9)
		83.1	78.0	106.5	88.6	60.7	39.3	41.6	44.1	45.6	84.8	94.1	766.3
Customer Service & Distribution													
Winnipeg Distribution Infrastructure Requirements	24.5	2.3	2.3	2.9	-	-	-	-	-	-	-	-	7.5
Rover Substation Replace 4 kV Switchgear	12.7	0.0	0.1	1.7	2.5	2.8	0.5	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	1.2	11.9	8.1	2.2	-	-	-	-	-	-	-	23.3
Frobisher Station Upgrade	14.4	0.5	1.0	-	-	-	-	-	-	-	-	-	1.5
Burrows New 66 kV/ 12 kV Station	28.6	12.1	6.7	-	-	-	-	-	-	-	-	-	18.9
Winnipeg Central 12&4kV Manhole Oil Switches	9.8	1.4	-	-	-	-	-	-	-	-	-	-	1.4
William New 66 kV/ 12 kV Station	10.3	0.5	2.2	2.9	3.2	1.1	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply - Stage 1	6.5	0.7	-	-	-	-	-	-	-	-	-	-	0.7
St. James New Station & 24 kV Conversion	65.9	0.6	6.3	3.9	9.5	21.8	23.6	-	-	-	-	-	65.7
Distribution	887.5	-	-	-	-	-	-	-	-	-	30.5	47.9	78.4
York Station Bank & Switchgear Addition	6.0	1.4	-	-	-	-	-	-	-	-	-	-	1.4
Defective RINJ Cable Replacement	8.7	1.3	1.3	-	-	-	-	-	-	-	-	-	2.7
Health Sciences Centre Service Consolidation & Distribution Upgrade	15.8	2.0	5.0	3.6	4.0	0.6	-	-	-	-	-	-	15.2
Waverley South DSC Installation	3.9	2.7	-	-	-	-	-	-	-	-	-	-	2.7
Southdale DK732 Cable Replacement	2.6	0.9	1.2	-	-	-	-	-	-	-	-	-	2.1
Steinbach Area 66kV Capacity Upgrade	6.3	5.9	0.3	-	-	-	-	-	-	-	-	-	6.2
Line 27 66 kV Extension and Arborg North Distribution Supply Centre	6.0	4.3	1.2	-	-	-	-	-	-	-	-	-	5.4
AECL Station Switchgear Replacement	2.4	0.8	-	-	-	-	-	-	-	-	-	-	0.8
Melrose DSC	3.5	3.5	-	-	-	-	-	-	-	-	-	-	3.5
Starbuck DSC	3.0	3.0	-	-	-	-	-	-	-	-	-	-	3.0
Enbridge Pipelines Clipper-66kV Supply I	0.9	2.1	-	-	-	-	-	-	-	-	-	-	2.1
Teulon East 66-12 kV Station	4.6	4.2	-	-	-	-	-	-	-	-	-	-	4.2
Waskada New 66-25kV Distrib'n Supply Ctr	3.9	3.9	-	-	-	-	-	-	-	-	-	-	3.9
Cromer North Station & Reston RE12-4 25kV Conversion	4.3	0.2	1.2	-	-	-	-	-	-	-	-	-	1.3
Brandon Crocus Plains 115-25 kV Bank Addition	6.3	0.0	0.0	0.0	6.2	-	-	-	-	-	-	-	6.2
Birtle South - Rossburn 66kV Line	4.9	-	-	0.1	0.3	4.5	-	-	-	-	-	-	4.9
TCPL Keystone Project	8.0	2.1	2.4	-	-	-	-	-	-	-	-	-	4.5
Line 98 Rebuild Melita to Waskada	3.8	3.8	-	-	-	-	-	-	-	-	-	-	3.8
Customer Service & Distribution Domestic	3,310.3	127.9	130.5	133.2	136.3	139.0	141.8	144.7	147.5	150.5	153.5	156.6	1,561.5
Target Adjustment	(257.5)	(30.3)	(6.8)	(11.2)	(21.6)	(18.7)	(14.8)	(9.6)	(9.8)	(10.0)	(10.2)	(10.4)	(153.6)
		159.0	166.8	145.1	142.5	151.1	151.2	135.0	137.7	140.5	173.8	194.0	1,696.6

CAPITAL EXPENDITURE FORECAST (CEF11)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Customer Care & Marketing													
Advanced Metering Infrastructure	30.9	-	4.0	5.3	5.4	5.6	4.3	4.2	-	-	-	-	28.8
Customer Care & Marketing Domestic	91.2	3.0	3.0	3.1	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	42.0
Target Adjustment	(22.3)	3.6	1.0	(0.3)	(0.9)	(2.3)	(1.2)	(5.4)	(1.1)	(1.2)	(1.2)	(1.2)	(10.2)
		6.6	8.0	8.1	8.4	7.2	7.1	2.9	3.0	3.1	3.1	3.2	60.7
Finance & Administration													
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
EAM Phase 2	19.3	6.1	8.9	2.3	-	-	-	-	-	-	-	-	17.3
Workforce Management (Phase 1 to 4)	15.7	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Fleet	NA	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	16.5	16.8	167.7
Finance & Administration Domestic	643.1	24.9	25.4	25.9	26.5	27.0	27.5	28.1	28.7	29.2	29.8	30.4	303.5
Target Adjustment	(20.2)	(8.4)	(8.9)	(2.3)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(19.8)
		46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	54.3	55.2	559.0
ELECTRIC CAPITAL SUBTOTAL		**1,107.1**	**1,165.6**	**1,518.2**	**1,675.9**	**1,966.2**	**1,962.9**	**2,268.9**	**1,480.0**	**1,703.3**	**1,832.6**	**1,767.1**	**18,447.9**
GAS													
Customer Service & Distribution													
Ile Des Chenes NG Transmission Network Upgrade	1.2	0.3	0.9	-	-	-	-	-	-	-	-	-	1.2
Gas SCADA Replacement	4.6	3.6	-	-	-	-	-	-	-	-	-	-	3.6
Buncloudy Natural Gas Crossing at Souris River	1.6	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Customer Service & Distribution Domestic	649.4	25.2	25.7	26.2	26.7	27.3	27.8	28.4	28.9	29.5	30.1	30.7	306.5
Target Adjustment	(94.4)	(6.2)	(4.5)	(3.7)	(3.7)	(3.8)	(3.9)	(4.0)	(4.0)	(4.1)	(4.2)	(4.3)	(46.4)
		24.6	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	25.9	26.4	266.5
Customer Care & Marketing													
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.4	-	-	-	-	-	-	-	14.7
Demand Side Management	NA	12.6	-	-	-	-	-	-	-	-	-	-	12.6
Customer Care & Marketing Domestic	122.1	4.8	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.7	5.8	57.7
Target Adjustment	(52.5)	(1.5)	1.4	(1.2)	(11.9)	(2.9)	(2.9)	(2.1)	(2.7)	(2.8)	(2.3)	(2.3)	(31.1)
		15.9	7.2	9.1	1.5	2.3	2.4	3.3	2.7	2.7	3.4	3.5	53.9
GAS CAPITAL SUBTOTAL		**40.5**	**29.3**	**31.6**	**24.5**	**25.7**	**26.3**	**27.7**	**27.6**	**28.1**	**29.3**	**29.9**	**320.5**
CONSOLIDATED CAPITAL		**1,147.6**	**1,195.0**	**1,549.8**	**1,700.4**	**1,991.9**	**1,989.1**	**2,296.6**	**1,507.6**	**1,731.5**	**1,861.9**	**1,797.0**	**18,768.4**
Target Adjustment	NA	(33.6)	(0.0)	0.0	0.0	31.1	87.9	135.9	160.3	182.2	51.8	5.2	620.8
CEF11 TOTAL		**1,114.1**	**1,195.0**	**1,549.8**	**1,700.4**	**2,022.9**	**2,077.0**	**2,432.5**	**1,667.9**	**1,913.6**	**1,913.7**	**1,802.1**	**19,389.2**

13.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH11)

ELECTRIC OPERATIONS (MH11)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1,243	1,268	1,294	1,306	1,313	1,330	1,350	1,361	1,382	1,403	1,422
additional*	0	44	92	142	194	250	309	371	438	509	584
Extraprovincial	370	359	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1,620	1,686	1,765	1,859	1,992	2,099	2,208	2,304	2,448	2,751	2,938
EXPENSES											
Operating and Administrative	402	517	527	534	544	551	569	579	595	612	624
Finance Expense	399	451	460	516	551	586	658	786	830	1,178	1,145
Depreciation and Amortization	357	343	353	357	374	386	422	467	482	549	575
Water Rentals and Assessments	120	116	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	157	158	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	83	85	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	8	8	8	8	8	8	8	8	8	8
	1,526	1,678	1,711	1,814	1,890	1,964	2,116	2,321	2,418	2,854	2,870
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	94	7	53	44	100	132	89	(21)	27	(106)	57
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase	0.00%	3.50%	7.12%	10.87%	14.75%	18.77%	22.93%	27.23%	31.68%	36.29%	41.06%

ELECTRIC OPERATIONS (MH11)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
REVENUES										
General Consumers										
at approved rates	1,441	1,460	1,479	1,498	1,521	1,541	1,562	1,582	1,602	1,622
additional*	663	746	800	857	918	980	1,044	1,110	1,178	1,250
Extraprovincial	931	946	1,124	1,408	1,526	1,544	1,539	1,544	1,565	1,574
Other	19	20	20	20	21	21	22	22	22	23
	3,053	3,172	3,423	3,784	3,985	4,086	4,166	4,258	4,367	4,469
EXPENSES										
Operating and Administrative	636	649	672	681	693	707	720	735	750	765
Finance Expense	1,135	1,128	1,228	1,459	1,615	1,590	1,557	1,518	1,543	1,451
Depreciation and Amortization	579	582	614	681	732	740	752	760	793	813
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	156	158	160	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2,896	2,942	3,091	3,409	3,657	3,674	3,681	3,682	3,767	3,726
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	147	219	321	363	316	400	472	563	586	728
* Additional General Consumers Revenue										
Percent Increase	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	46.00%	51.11%	54.13%	57.21%	60.36%	63.56%	66.83%	70.17%	73.57%	77.05%

ELECTRIC OPERATIONS (MH11)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS											
Plant in Service	13,795	15,115	15,661	16,424	17,348	17,931	21,354	21,842	25,459	28,214	28,575
Accumulated Depreciation	(4,921)	(5,227)	(5,564)	(5,894)	(6,253)	(6,618)	(7,044)	(7,518)	(8,006)	(8,560)	(9,141)
Net Plant in Service	8,874	9,888	10,097	10,530	11,095	11,313	14,310	14,325	17,453	19,653	19,434
Construction in Progress	2,443	2,196	3,149	3,997	5,014	6,410	5,346	6,447	4,558	3,595	4,964
Current and Other Assets	1,905	1,641	1,471	1,516	1,693	1,874	2,120	1,924	2,095	2,306	2,330
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	-	-	-	-	-	-	-	-	-	-
	13,643	13,903	14,879	16,192	17,937	19,723	21,893	22,805	24,209	25,652	26,821
LIABILITIES AND EQUITY											
Long-Term Debt	9,253	9,469	10,909	12,192	13,816	15,287	17,052	18,545	19,707	21,217	22,861
Current and Other Liabilities	1,316	1,878	1,363	1,494	1,563	1,754	2,085	1,531	1,753	1,799	1,278
Contributions in Aid of Construction	317	327	340	347	355	365	376	385	396	406	418
Retained Earnings	2,421	2,134	2,187	2,232	2,332	2,464	2,553	2,533	2,560	2,454	2,511
Accumulated Other Comprehensive Income	335	95	80	(73)	(129)	(147)	(174)	(190)	(206)	(224)	(246)
	13,643	13,903	14,879	16,192	17,937	19,723	21,893	22,805	24,209	25,652	26,821

ELECTRIC OPERATIONS (MH11)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	28,984	29,549	33,961	38,036	39,296	39,927	40,496	41,025	43,046	43,762
Accumulated Depreciation	(9,728)	(10,318)	(10,943)	(11,635)	(12,379)	(13,131)	(13,896)	(14,670)	(15,477)	(16,306)
Net Plant in Service	19,256	19,231	23,018	26,401	26,917	26,795	26,600	26,355	27,569	27,456
Construction in Progress	6,099	6,969	4,170	1,022	545	786	1,259	1,722	618	758
Current and Other Assets	2,169	2,569	2,725	2,616	3,111	3,405	3,552	3,863	4,279	4,786
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27,615	28,858	30,001	30,125	30,658	31,069	31,493	32,021	32,547	33,080
LIABILITIES AND EQUITY										
Long-Term Debt	23,664	24,667	25,020	25,222	25,423	25,365	25,116	25,218	25,007	23,946
Current and Other Liabilities	1,124	1,135	1,591	1,138	1,142	1,200	1,387	1,238	1,376	2,228
Contributions in Aid of Construction	429	440	451	462	474	486	499	511	524	538
Retained Earnings	2,658	2,876	3,198	3,561	3,877	4,277	4,750	5,313	5,899	6,627
Accumulated Other Comprehensive Income	(259)	(259)	(259)	(259)	(259)	(259)	(259)	(259)	(259)	(259)
	27,615	28,858	30,001	30,125	30,658	31,069	31,493	32,021	32,547	33,080

ELECTRIC OPERATIONS (MH11)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1,620	1,686	1,765	1,859	1,992	2,099	2,208	2,304	2,448	2,751	2,938
Cash Paid to Suppliers and Employees	(758)	(880)	(893)	(936)	(961)	(988)	(1,032)	(1,064)	(1,102)	(1,123)	(1,147)
Interest Paid	(419)	(469)	(472)	(515)	(563)	(599)	(684)	(815)	(847)	(1,201)	(1,163)
Interest Received	26	28	27	20	27	34	41	43	40	36	35
	469	366	427	428	495	546	533	468	539	463	663
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	900	1,630	1,405	2,000	2,000	2,590	1,790	1,790	2,190	1,790
Sinking Fund Withdrawals	23	129	395	105	24	-	5	424	178	265	689
Retirement of Long-Term Debt	(25)	(119)	(808)	(179)	(312)	(408)	(530)	(837)	(309)	(640)	(692)
Other	(81)	(21)	(14)	(5)	(7)	(7)	(7)	(16)	(5)	26	(6)
	729	889	1,203	1,326	1,705	1,585	2,057	1,361	1,653	1,841	1,781
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1,163)	(1,154)	(1,481)	(1,616)	(1,934)	(1,986)	(2,336)	(1,567)	(1,820)	(1,856)	(1,697)
Sinking Fund Payment	(98)	(117)	(208)	(124)	(192)	(157)	(231)	(210)	(219)	(288)	(346)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1,280)	(1,291)	(1,709)	(1,761)	(2,146)	(2,189)	(2,603)	(1,807)	(2,069)	(2,179)	(2,083)
Net Increase (Decrease) in Cash	(82)	(36)	(80)	(6)	54	(57)	(13)	22	124	125	361
Cash at Beginning of Year	66	(16)	(52)	(132)	(138)	(84)	(141)	(154)	(132)	(8)	118
Cash at End of Year	(16)	(52)	(132)	(138)	(84)	(141)	(154)	(132)	(8)	118	479

ELECTRIC OPERATIONS (MH11)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,053	3,172	3,423	3,784	3,985	4,086	4,166	4,258	4,367	4,469
Cash Paid to Suppliers and Employees	(1,178)	(1,228)	(1,245)	(1,266)	(1,306)	(1,341)	(1,369)	(1,400)	(1,429)	(1,459)
Interest Paid	(1,134)	(1,112)	(1,223)	(1,467)	(1,618)	(1,608)	(1,586)	(1,545)	(1,553)	(1,498)
Interest Received	20	22	32	36	38	49	61	66	73	86
	760	853	987	1,087	1,098	1,186	1,272	1,378	1,457	1,597
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	790	990	790	190	190	(10)	-	190	(40)	(10)
Sinking Fund Withdrawals	159	-	-	414	-	-	60	250	-	13
Retirement of Long-Term Debt	(159)	-	-	(450)	-	-	(60)	(220)	(100)	(213)
Other	(7)	(6)	(6)	(8)	(8)	(7)	(7)	(6)	(4)	(19)
	783	984	784	146	182	(17)	(7)	214	(144)	(229)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,510)	(1,401)	(1,578)	(891)	(746)	(834)	(1,003)	(953)	(876)	(814)
Sinking Fund Payment	(238)	(250)	(268)	(288)	(280)	(292)	(304)	(313)	(315)	(327)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1,778)	(1,680)	(1,874)	(1,207)	(1,056)	(1,154)	(1,335)	(1,295)	(1,220)	(1,170)
Net Increase (Decrease) in Cash	(234)	156	(102)	26	224	15	(70)	296	93	198
Cash at Beginning of Year	479	245	401	299	325	550	564	494	790	884
Cash at End of Year	245	401	299	325	550	564	494	790	884	1,082

14.0 GAS OPERATIONS FINANCIAL FORECAST (CGM11)

GAS OPERATIONS (CGM11)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	383	383	400	400	398	397	396	396	395	395	395
additional revenue requirement*	0	9	13	14	15	17	17	19	21	23	27
	383	392	413	414	414	414	413	415	416	418	422
Cost of Gas Sold	245	241	257	254	253	251	250	250	249	249	249
Gross Margin	138	152	156	160	161	163	163	165	167	169	174
Other	1	2	2	2	2	2	2	2	2	2	2
	140	154	158	162	163	165	165	167	169	171	176
EXPENSES											
Operating and Administrative	64	82	83	83	84	85	83	84	85	86	87
Finance Expense	19	22	23	25	25	25	26	26	27	28	29
Depreciation and Amortization	25	19	19	20	21	21	21	22	23	24	24
Capital and Other Taxes	20	15	16	16	16	17	17	17	18	18	18
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	140	150	153	156	158	160	159	161	164	167	171
Net Income	(0)	4	5	5	5	5	6	6	4	4	5

* Additional Revenue Requirement										
Percent Increase	2.50%	1.00%	0.00%	0.50%	0.50%	0.00%	0.50%	0.50%	0.50%	1.00%
Cumulative Percent Increase	2.50%	3.53%	3.53%	4.04%	4.56%	4.56%	5.09%	5.61%	6.14%	7.20%

GAS OPERATIONS (CGM11)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
ASSETS											
Plant in Service	636	653	674	688	704	719	737	759	781	803	827
Accumulated Depreciation	(226)	(229)	(235)	(243)	(251)	(258)	(267)	(276)	(286)	(296)	(307)
Net Plant in Service	410	424	439	446	453	460	470	483	495	507	520
Construction in Progress	2	2	2	2	2	2	2	2	2	2	2
Current and Other Assets	112	114	116	124	122	118	121	122	123	122	122
Goodwill and Intangible Assets	10	8	7	5	4	3	3	3	3	3	3
Regulated Assets	80	-	-	-	-	-	-	-	-	-	-
	614	547	564	577	580	583	597	610	622	634	647
LIABILITIES AND EQUITY											
Long-Term Debt	235	335	320	365	365	365	375	385	395	405	415
Current and Other Liabilities	185	94	109	73	71	68	65	63	61	59	58
Contributions in Aid of Construction	33	34	45	44	44	45	46	46	45	45	44
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	40	(37)	(32)	(26)	(21)	(16)	(10)	(4)	0	4	9
	614	547	564	577	580	583	597	610	622	634	647

GAS OPERATIONS (CGM11)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	444	458	479	476	476	476	475	477	478	481	486
Cash Paid to Suppliers and Employees	(396)	(434)	(433)	(433)	(432)	(432)	(430)	(431)	(432)	(434)	(437)
Interest Paid	(20)	(21)	(22)	(24)	(24)	(25)	(25)	(26)	(27)	(27)	(28)
	27	3	24	20	19	19	20	20	19	20	21
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	-	100	20	45	-	-	10	10	10	10	10
Retirement of Long-Term Debt	-	(63)	-	(35)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-
	-	37	20	10	-	-	10	10	10	10	10
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(41)	(26)	(28)	(21)	(22)	(23)	(26)	(29)	(29)	(30)	(31)
Other	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(41)	(26)	(29)	(21)	(22)	(23)	(26)	(29)	(29)	(31)	(31)
Net Increase (Decrease) in Cash	(14)	14	15	8	(3)	(4)	4	1	0	(1)	(0)
Cash at Beginning of Year	(19)	(33)	(19)	(4)	4	1	(2)	1	2	3	2
Cash at End of Year	(33)	(19)	(4)	4	1	(2)	1	2	3	2	2

15.0 CORPORATE SUBSIDIARIES FINANCIAL FORECAST (CS11)

CORPORATE SUBSIDIARIES (CS11)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
REVENUES											
Revenue	38	42	46	47	48	49	50	51	52	53	54
Cost of Operations	19	21	23	24	24	24	25	26	26	27	27
	19	21	23	23	24	24	25	25	26	26	27
EXPENSES											
Operating and Administrative	13	13	14	14	14	14	15	15	15	16	16
Finance Expense	(0)	0	0	-	-	-	-	-	-	-	-
Depreciation and Amortization	1	1	1	1	1	1	1	1	0	0	0
Capital and Other Taxes	0	0	0	0	0	0	0	0	0	0	0
	14	15	15	16	16	16	16	17	16	16	17
Net Income	5	6	7	8	8	8	8	9	10	10	10