February 2014

Integrated Financial Forecast (IFF13)

2013/14 - 2032/33

Financial Planning
Finance & Regulatory

Manitoba Hydro

INTEGRATED FINANCIAL FORECAST (IFF13)

2013/14 – 2032/33

FINANCIAL PLANNING DEPARTMENT
FINANCE & REGULATORY

February, 2014

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INTEGRATED FINANCIAL FORECAST (IFF13)

KEY FINANCIAL RESULTS
(Dollars are in millions)

	Actual	IFF13 Forecast			
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2022/23**
PROJECTED RATE INCREASES					
- ELECTRIC	4.50%[1]	3.50%[2]	3.95%	3.95%	3.95%
- GAS (non-commodity)	-	1.07%	-	0.50%	0.00%
NET INCOME					
- ELECTRIC	$ 78	$ 116	$ 55	$ 12	$ 6
- GAS	8	12	1	4	3
- SUBSIDIARIES	6	8	6	8	12
CAPITAL EXPENDITURES					
- ELECTRIC	$ 1 033	$ 1 597	$ 2 013	$ 2 422	$ 2 280
- GAS	39	49	48	61	38
DEBT/EQUITY RATIO	75:25	76:24	78:22	82:18	89:11
INTEREST COVERAGE RATIO	1.15	1.22	1.09	1.03	1.01
CAPITAL COVERAGE RATIO (excl. major new generation & transmission)	1.25	1.06	0.87	0.80	1.52
RETAINED EARNINGS	$2 542	$ 2 678	$ 2 739	$ 2 705	$2 575

[1] Includes a 2.0% rate increase effective April 1, 2012 and a 2.5% rate increase effective September 1, 2012.
[2] The 3.5% rate increase was implemented effective May 1, 2013. In accordance with PUB Order 43/13, 1.5% of the rate increase will be accrued to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service.

EXECUTIVE SUMMARY

The Consolidated Integrated Financial Forecast (IFF13) projects Manitoba Hydro's financial results and financial position for the 20-year period from 2013/14 to 2032/33. Segmented forecasts are also provided for the electricity (MH13), natural gas (CGM13), and corporate subsidiaries (CS13).

Financial results projected in IFF13 are less favourable than the financial results projected in IFF12. The projection of less favourable results is largely attributable to the following:

- Lower projected net revenue ($1.0 billion) due to lower projected domestic Manitoba load somewhat offset by higher net extra-provincial revenue; and
- Higher projected capital costs ($1.6 billion) due to the one year deferral of the Conawapa Generating Station, the re-instatement of Electric and Gas demand side management costs in the capital forecast and the update of a number of project cost estimates.

IFF13 includes further internal cost constraint provisions to mitigate the rate pressures as a result of the reduction in net revenue and capital requirements. These initiatives assist in offsetting the incremental rate impacts and therefore the projected even annual electric rate increases in IFF13 for each year up to 2031/32 are the same as projected in IFF12 at 3.95%, with one more additional year of 3.95% in 2032/33.

Consistent with IFF12, the equity ratio is reduced from the current 24% level to 11% equity by 2021/22 before gradually beginning to recover to reach the 25% equity target by 2033/34. This represents a two year deferral in attaining the 25% equity target compared to IFF12.

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

Notwithstanding the changes in the projected financial results, Manitoba Hydro's proposed major capital expansion program remains as the best plan to meet the future electricity requirements of the Province in the most reliable, economic and environmentally sustainable way. While rate increases that are higher than inflation will be necessary to maintain a reasonable financial structure, the revenue generated by those rate increases will, in part, represent an investment in the future of the Province. This investment will pay dividends to current and future generations of Manitobans over the approximate 100-year service lives of the new generation and transmission facilities.

Also contributing to the need for higher rate increases is the requirement to replace distribution, transmission and substation assets that were installed up to 60 years ago. The aging infrastructure issue is facing all utilities in North America and is resulting in considerably higher rate increases than are being projected in Manitoba. For this reason, even with the rate increases being projected in IFF13, it is expected that

Manitoba Hydro will maintain its status as having the lowest overall rate structure in North America.

The following is a summary of projected net income and key financial ratios over the 20-year period to 2032/33:

Years Ending March 31	Electric Rate Increases	Net Income	Retained Earnings	Debt / Equity	Interest Coverage	Capital Coverage
		(Millions)				
2014	-	$136	$2 678	76:24	1.22	1.06
2015	3.95%	62	2 739	78:22	1.09	0.87
2016	3.95%	24	2 705	82:18	1.03	0.80
2017	3.95%	31	2 736	84:16	1.03	0.87
2018	3.95%	(0)	2 736	85:15	1.00	1.17
2019	3.95%	(55)	2 681	86:14	0.95	1.07
2020	3.95%	(19)	2 662	87:13	0.98	1.18
2021	3.95%	(62)	2 600	88:12	0.95	1.20
2022	3.95%	(45)	2 555	89:11	0.97	1.35
2023	3.95%	20	2 575	89:11	1.01	1.52
2024	3.95%	82	2 658	89:11	1.05	1.68
2025	3.95%	148	2 806	89:11	1.09	1.79
2026	3.95%	184	2 990	89:11	1.10	1.86
2027	3.95%	297	3 287	89:11	1.16	2.14
2028	3.95%	293	3 579	88:12	1.15	2.27
2029	3.95%	275	3 854	87:13	1.14	2.32
2030	3.95%	425	4 280	86:14	1.22	2.59
2031	3.95%	550	4 830	84:16	1.29	2.81
2032	3.95%	760	5 589	82:18	1.42	3.18
2033	3.95%	970	6 560	78:22	1.56	3.53

Section 1

1.0 INTRODUCTION

The Consolidated Integrated Financial Forecast (IFF13) provides projections of Manitoba Hydro's financial results and financial position for the 20-year period from 2013/14 to 2032/33. Its purpose is to project the Corporation's long-term financial direction and to serve as a baseline for the evaluation of Corporate Strategic Initiatives.

The detailed forecasts in the first two years of the IFF are used for monthly reporting and variance analysis. The IFF serves as the primary forecast to determine the need for rate increases that are necessary for the Corporation to attain its financial targets and objectives.

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

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

This forecast supersedes the 2012 Integrated Financial Forecast (IFF12) which was finalized in November of 2012.

2.0 RATES and ECONOMIC VARIABLES

2.1 Electricity Rates

In accordance with Manitoba Public Utilities Board (PUB) Order 43/13, IFF13 assumes that 1.5% of the 3.5% Electric rate increase that was approved effective May 1, 2013 will be accrued to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in service. IFF13 further assumes that the 1.5% of the rate increase will continue to accrue until the time when Bipole III is placed in service (October 2017) and that the cumulative amount in this deferral account will be amortized to income over a three year period thereafter. After the Bipole III in-service date, the 1.5% rate increase will revert to general consumers revenue.

Additional average electric rate increases of 3.95% per year are projected each April from 2014/15 through 2032/33.

The rate increase proposed for 2014/15 has been approved by the Manitoba Hydro-Electric Board (MHEB) for submission to the PUB. Proposed rate increases subsequent to 2014/15 may be changed in future forecasts and are presented for illustrative purposes only. Each year's revision to the Integrated Financial Forecast is based on the current year's assumptions including energy supply and demand, projected interest and escalation rates, projected prices for exported energy, operating and capital forecasts and other factors. Changes in any of these assumptions will have an impact on the projected future results. Actual rate applications made in future years will depend upon the circumstances and outlook at that time and will be subject to the review and approval of the MHEB.

2.2 Gas Rates

There is no non-gas rate increase proposed for the 2014/15 fiscal year. IFF13 assumes non-gas rate increases commencing on May 1, 2015 sufficient to generate Centra Gas net income of approximately $3 million each year beginning in 2015/16 and thereafter. Gas general rate applications are also subject to review and approval by the MHEB prior to filing with the PUB.

2.3 Economic Variables

The economic assumptions used in the forecast are based upon Manitoba Hydro's Economic Outlook, with certain key variables updated as of November 2013 to reflect current economic conditions at that time. Projected rates for key economic indicators are listed below with the 2012 projected rates in brackets.

	Manitoba Consumer Price Index	MH CDN New Short Term Debt Rate *	MH CDN New Long Term Debt Rate *	US-CDN Exchange Rate (C$/US$)
2013/14	1.8% (1.8%)	1.00% (1.30%)	3.75% (3.30%)	1.04 (0.99)
2014/15	2.0% (1.8%)	1.15% (2.10%)	4.05% (3.85%)	1.03 (1.02)
2015/16	2.0% (1.8%)	2.10% (2.95%)	4.35% (4.55%)	1.01 (1.03)
2016/17	2.0% (1.8%)	3.10% (3.65%)	4.60% (4.95%)	1.01 (1.04)
2022/23	2.0% (1.9%)	3.90% (3.80%)	5.75% (5.30%)	1.03 (1.04)

* Excludes the 1% Provincial guarantee fee.

3.0 Manitoba Electricity Load Forecast

General consumers revenue is forecast based on the future load requirements in Manitoba as projected in the 2013 Electric Load Forecast.

The 2013 Electric Load Forecast projects that average annual growth in Manitoba load will be 1.5% for both gross firm energy and gross total peak over the 20-year forecast period to 2032/33 (compared to 1.6% in IFF12). Gross firm energy supplied to the Manitoba load is projected to grow from 25 239 GW.h in 2013/14 to 32 667 GW.h by 2032/33. Over the same 20-year period, total system peak is projected to grow from 4 601 MW in 2013/14 to 5 959 MW in 2032/33. The system load factor is projected to remain relatively constant at approximately 63%.

Compared to the 2012 forecast, gross firm energy is 495 GW.h lower in 2013/14 due mainly to lower forecasted industrial and general service loads. Gross firm energy is projected to be down 717 GW.h in 2022/23 and 1 159 GW.h in 2031/32 primarily due to a decrease in the forecast of residential customers resulting from a lower Manitoba population growth rate and initiatives being undertaken to reduce the number of customers choosing electric space and water heat. The gross total peak forecast is 8 MW lower in 2013/14 and 146 MW lower than the 2012 forecast in 2031/32, for similar reasons to the change in energy.

This reduced load translates to a reduction in General Consumer Revenue of $1 185 million to the end of 2032/33 at IFF12 forecasted rates.

4.0 Extra-provincial Revenue

IFF13 includes the following existing and proposed long-term firm export sales:

Northern States Power 150 MW Seasonal Diversity	To April 2015
Northern States Power 200 MW Seasonal Diversity	To April 2016
Northern States Power 500 MW Power Sale	To April 2014
Minnesota Power 50 MW System Participation Sale	May 2009 to April 2015
Minnesota Power 50 MW System Participation Sale*	May 2015 to May 2020
Minnesota Power 250 MW System Participation Sale	June 2020 to May 2035
Great River Energy 150 MW Seasonal Diversity Sale	May 1995 to April 2015
Great River Energy 200 MW Seasonal Diversity Sale	May 2015 to April 2025
Northern States Power 125 MW System Power Sale	May 2021 to April 2025
Northern States Power 375/325 MW System Power Sale	May 2015 to April 2025
Northern States Power 350 MW Seasonal Diversity Sale	May 2015 to April 2025
Wisconsin Public Service 100 MW Sale	June 2021 to May 2027
Wisconsin Public Service 300 MW Term Sheet Sale*	June 2026 to May 2036
Wisconsin Public Service 108 MW System Participation*	June 2014 to May 2021
Wisconsin Public Service 200 MW System Participation*	June 2020 to May 2026 June 2036 to May 2040

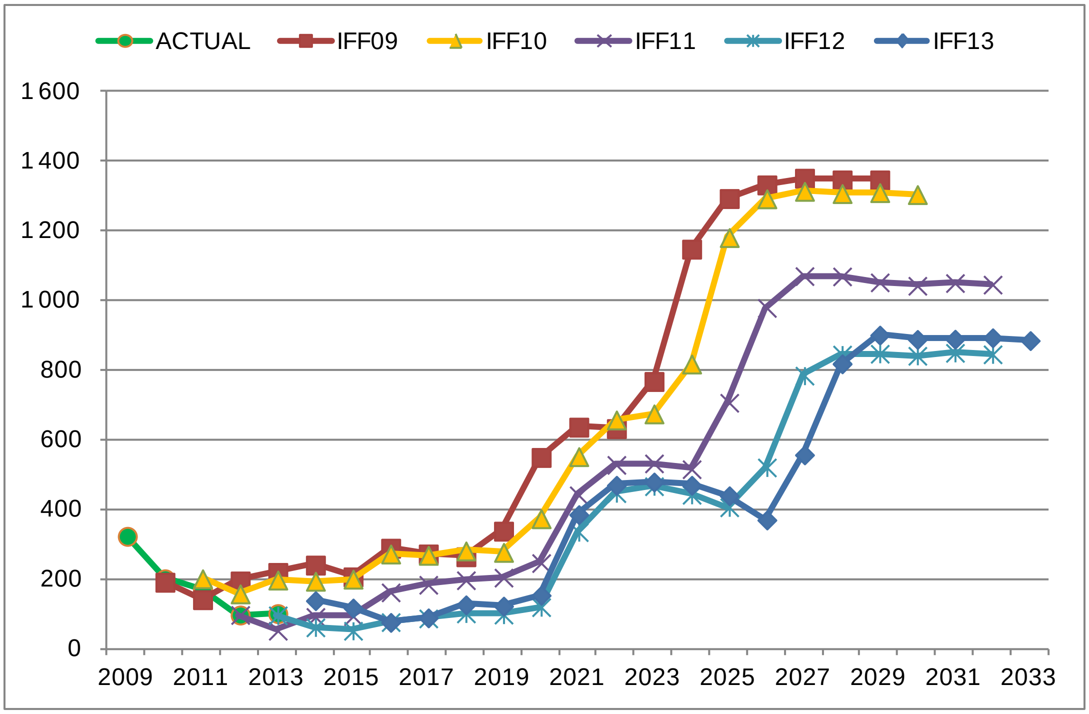
* Proposed

Extra-provincial sales volumes are forecast for the first forecast year (2013/14) based upon the expected inflow conditions as of December 2013 and actual reservoir and lake level elevations as of November 2012. The second forecast year (2014/15) uses the expected river inflows and initial reservoir and lake level elevations carried forward from the 2013/14 forecast. For 2015/16 and subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 99 years (1912/13 to 2010/11).

Over the twenty year forecast period, net extra-provincial revenue (extra-provincial revenue net of water rentals and fuel and power purchased) increases $203 million compared to IFF12. The increase is mainly due to higher volumes of energy available for export as a result of a reduction in the Manitoba domestic load forecast, partially offset by decreased volumes associated with the deferral of the Conawapa Generating Station in-service date by one year to 2026/27. Figure 4-1: Extra-provincial Revenues below shows the comparative net extra-provincial revenues from IFF09 through IFF13.

Figure 4-1: Extra-provincial Revenues

(Net of Water Rentals and Fuel and Power Purchases)



In comparison to the 2012 Electric Export Price Forecast, the 2013 forecast projects on-peak prices to decrease on average 3% over the period 2014/15 to 2032/33. The small decrease reflects the forecast for lower natural gas prices, somewhat offset by the stabilizing effects of relatively flat year over year coal and carbon price forecasts along with upward pressure on prices being provided by clarity on US environmental regulation and resulting coal fleet retirements.

5.0 Electricity Supply

Manitoba Hydro's 2013/14 Power Resource Plan indicates new generation is required by 2023/24 to meet the current projection of Manitoba load requirements under dependable energy conditions. New capacity resources are forecast to be required by 2026/27.

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

	MW	**Dependable GW.h**	**In-Service Date**
Keeyask	695	2 900	2019/20
Conawapa	1 485	4 550	2026/27
HVDC Bipole III Line & 2000 MW of Converter Capability	86	190	2017/18
Pointe du Bois Powerhouse Rebuild	45	150	2030/31
Demand Side Management Program			
Planned Additional	166	773	By 2027/28

6.0 International Financial Reporting Standards (IFRS)

In February of 2013, the Canadian Accounting Standards Board (AcSB) extended the optional IFRS transition date for rate-regulated entities an additional year to January 1, 2015 in consideration of the commitment of the International Accounting Standards Board (IASB) to review issues related to rate-regulated accounting.

In April of 2013, the IASB issued the Exposure Draft – Regulatory Deferral Accounts. The Exposure Draft proposed an interim standard intended to allow entities that are first-time adopters of IFRS and that currently recognize regulatory deferral accounts (i.e. regulatory assets and liabilities) in accordance with their existing GAAP, to continue to do so upon transition. The IASB finalized the interim standard on January 30, 2014. Under the interim standard, entities will be able to avoid making major changes in accounting for regulatory assets and liabilities on transition to IFRS until the IASB can provide more guidance through its Rate-regulated Activities project. While it is uncertain as to the final position the IASB will take as part of its Rate regulated Activities project, it has been assumed in IFF13 that regulatory deferral accounts will continue to be recognized throughout the forecast period to 2032/33.

Manitoba Hydro will adopt the optional transition date deferral and will be transitioning to IFRS for its 2015/16 fiscal period with comparative information presented for 2014/15.

The primary impacts of IFRS that are included in IFF13 are as follows:

- Administrative and other general overhead costs are not eligible for capitalization under IFRS and must be expensed as incurred;
- IFRS is more rigorous in terms of the componentization of assets and the recognition of gains and losses on the disposal/retirement of assets and does not allow the inclusion of asset retirement costs in depreciation rates; and

- Unamortized experience gains and losses on pension balances will be reclassified to accumulated other comprehensive income (AOCI) upon transition to IFRS.

The following table Figure 6-1 outlines the projected IFRS impacts to retained earnings, AOCI and net income:

Figure 6-1: IFRS Impacts on Retained Earnings and Net Income

Increase/(Decrease)
($Millions)

	Retained Earnings	AOCI	Net Income 2015/16
Capital Taxes	-	-	2
Administrative Overhead *	(53)	-	(53)
Pension & Employee Benefits	(30)	(332)	6
Removal of Negative Salvage	62	-	64
Change to Equal Life Group Depreciation	(36)	-	(37)
Total	(57)	(332)	(18)

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

7.0 Operating & Administrative Expense

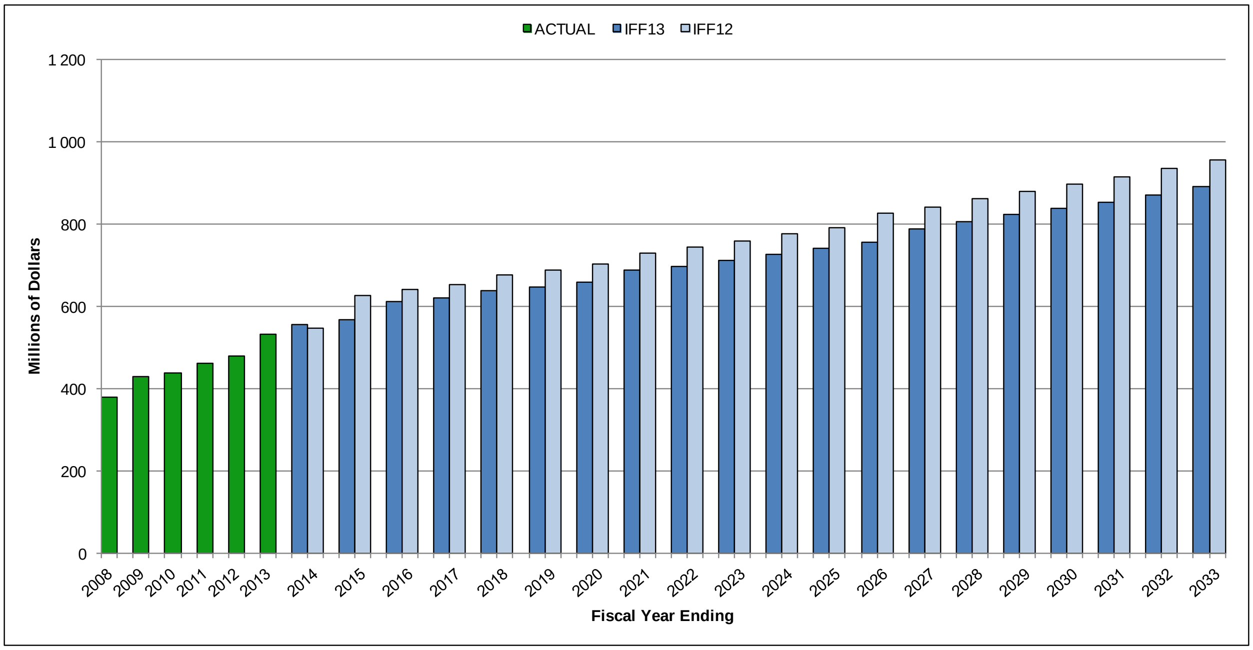
Operating, Maintenance & Administrative (OM&A) Expenses in IFF13 include only those expenditures necessary to provide for the safe and reliable operation and maintenance of the generation, transmission and electric and gas distribution systems.

Figure 7-1 below shows the OM&A expense projected in IFF13 compared to IFF12. Over the 10 year period to 2022/23, OM&A is projected to decrease by approximately $37 million annually on average compared to IFF12 primarily due to the assumption in IFF13 that regulatory deferral accounts will continue to be recognized throughout the forecast period. This decrease is partially offset by an increase in the amount of administrative and other general overhead costs that must be expensed under IFRS from $39 million to $54 million.

IFF13 also incorporates the deferral of IFRS implementation to 2015/16 as discussed in Section 6.0 which results in the reduction in OM&A that can be seen in 2014/15 compared to IFF12.

For the period from 2015/16 to 2020/21, it is assumed that OM&A cost increases will be limited to below inflationary levels of 1%. For the remainder of the forecast, O&A rises 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), 2020/21 (500kV tie line) and 2026/27 (Conawapa). Increases associated with load growth over the forecast period are assumed to be achieved through continuing productivity improvements.

Figure 7-1: Operating, Maintenance and Administrative Expense



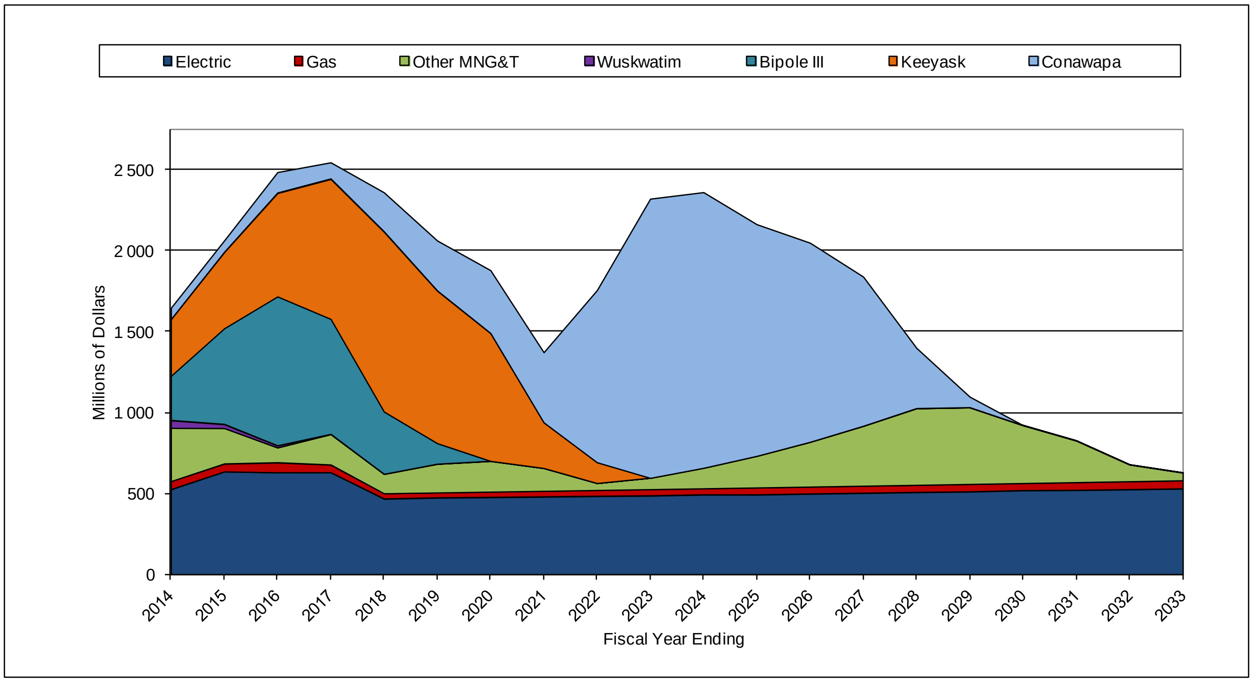
8.0 Non-Controlling Interest

IFF13 assumes that the Nisichawayasihk Cree Nation (NCN) will acquire up to a 33% common equity interest in the Wuskwatim Power Limited Partnership (WPLP) and that the Keeyask Cree Nations (KCN) invest in the Keeyask Hydropower Limited Partnership (KHLP) under a preferred equity ownership arrangement. The Non-controlling interest represents NCN’s share of the projected net income or losses in WPLP and the projected distributions paid from the KHLP to KCN. 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’s share of net income or losses 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.

9.0 CAPITAL EXPENDITURE FORECAST

Capital expenditures are forecast to be $34 442 million to 2032/33. Figure 9-1 below illustrates projected capital expenditures by major category.

Figure 9-1: Capital Expenditure Forecast CEF13



Over the 20-year forecast to 2032/33, capital expenditures are $1 629 million higher compared to the previous capital expenditure forecast (CEF12) including the overhead adjustment incorporated in IFF12. The increase is mainly the result of the one year deferral of the Conawapa Generating Station to 2026/27, the re-instatement of Electric and Gas Demand Side Management costs in the forecast under the assumption that regulatory deferral accounts will continue to be recognized upon transition to IFRS and the update of a number of project cost estimates (see Table 9-2). The following Table 9-1 provides a summary of CEF13 and the revisions from CEF12.

Table 9-1: Summary of Projected Capital Expenditures

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
CEF12	1 895	2 042	2 112	2 258	2 219	1 913	1 718	1 854	2 356	2 323	20 689
Incr (Decr)	(248)	20	371	285	140	148	160	(482)	(601)	(4)	(211)
CEF13	1 647	2 062	2 483	2 543	2 358	2 061	1 878	1 372	1 755	2 319	20 478

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
CEF12	2 077	1 883	1 615	1 471	928	1 127	1 047	994	859	834	33 526
Incr (Decr)	282	279	432	367	470	(29)	(125)	(166)	(179)	(204)	916
CEF13	2 359	2 162	2 048	1 838	1 399	1 098	922	828	680	630	34 442

The following Table 9-2 provides a summary of the total changes to the twenty year forecast.

Table 9-2: Summary of CEF13 Project Increases/(Decreases)

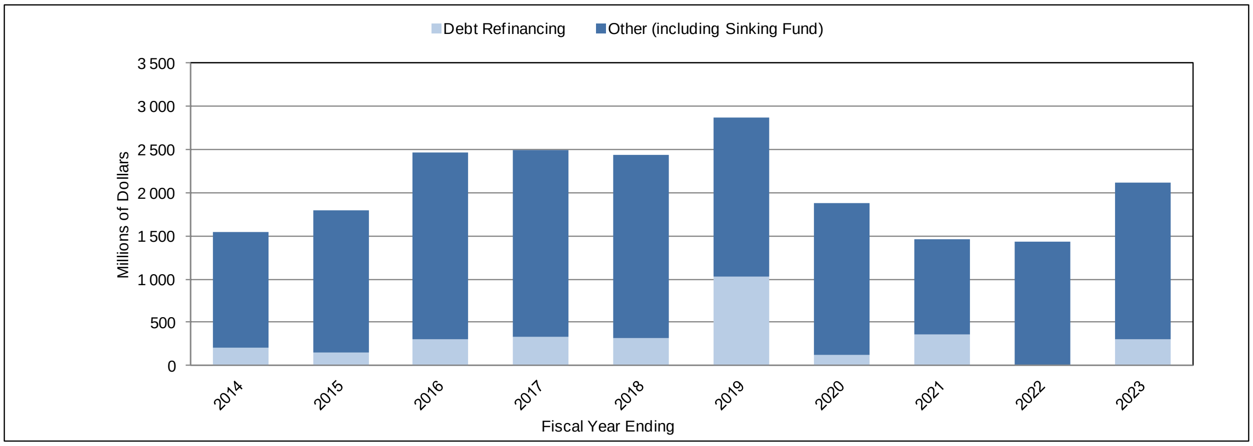
	Total Projected Cost	20 Year Increase (Decrease)
	($ Millions)	
Electric Demand Side Management*	NA	367
Conawapa - Generation	10 492	324
Transmission Line Upgrades for NERC Alert	151	151
Dorsey - US Border New 500kV Transmission Line	350	146
Electric Base Capital	NA	136
Gas Demand Side Management*	NA	71
Keeyask - Generation	6 220	64
Bipole III - Converter Stations	1 829	63
Riel 230/500kV Station	330	63
Community Development Initiative	61	61
Pointe du Bois Spillway Replacement	560	60
Wuskwatim - Generation	1 449	52
Dawson Road Station - 115/24kV Station	52	52
St. Vital Station - 115/24kV Station	51	51
Gas Base Capital	NA	45
Other Changes	NA	(77)
Sub-total		1 629
CEF12 Overhead Adjustment	NA	(713)
		916

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

10.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast consolidated borrowing requirements are portrayed in Figure 10-1 below.

Figure 10-1: Projected Consolidated Borrowing Requirements



Manitoba Hydro arranges long-term financing in the form of advances from the Province of Manitoba. Both long and short-term borrowings are guaranteed by the Province (except for mitigation bonds issued by the Manitoba Hydro-Electric Board). Manitoba Hydro's 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.

11.0 NATURAL GAS DEMAND & SUPPLY

The Corporation sells primary gas to Manitobans in a market which also includes a small number of brokers and marketers, and is the gas distribution utility for all customers in Manitoba. Currently, approximately 94% of customers representing approximately 61% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

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

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

The 2013 Natural Gas Volume Forecast is lower than last year's forecast. The total natural gas sales volume forecast is down 20 million cubic meters (1%) in 2013/14 and down 3 million cubic meters (0.1%) in 2022/23. The decrease in the 2013 forecast is primarily attributed to a change in the expected usage of the Top Consumer groups.

12.0 FINANCIAL TARGETS

Manitoba Hydro has the following financial targets for consolidated operations:

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

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

12.1 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 12-1 below shows the projected consolidated equity ratio for IFF13 compared to IFF12. High levels of capital investment over the next ten years combined with reduced revenues result in deterioration of the equity ratio to 11% by 2021/22. The equity ratio shows improvement following the in-service of Keeyask and Conawapa generating stations and is projected to return to the target 25% within one year (2033/34) of the 20-year forecast period.

Figure 12-1: Projected Consolidated Equity Ratio

12.2 Interest Coverage Ratio

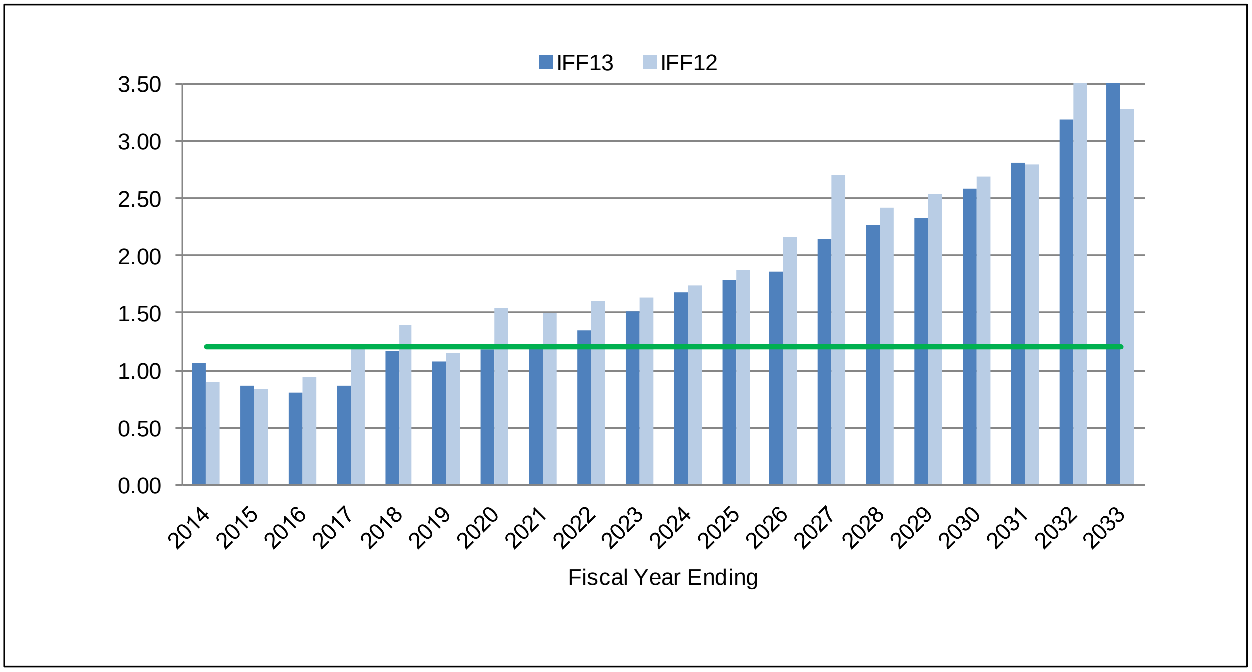
The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. Figure 12-2 below shows that the reduction in net income compared to the previous forecast IFF12 and increase in capital requirements to replace aging infrastructure results in interest coverage ratios lower than target for a period of fifteen years. In the longer term, interest coverage is projected to return to the 1.20 target level following in-service of the Conawapa Generating Station.

Figure 12-2: Projected Consolidated Interest Coverage Ratio

12.3 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. Figure 12-3 below shows the comparative capital coverage ratios between IFF13 and IFF12. Capital coverage is below target for the first seven years of the forecast and then projected cash flows are sufficient to enable this target to be met in the remaining years of the forecast after the in-service of the Keeyask Generating Station.

Figure 12-3: Projected Consolidated Capital Coverage Ratio



13.0 SENSITIVITY ANALYSIS

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

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

Table 13-1 below shows the change in retained earnings and incremental even annual rate increases/(decreases) required to achieve the same level of retained earnings in 2022/23 as forecast in IFF13.

Table 13-1: Financial Impacts of Sensitivity Analysis

	2015/16	2019/20	2022/23	
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)			Incremental Annual Electric Rate Increase/(Decrease)
Low Domestic Load Growth	(15)	(64)	(103)	0.11%
+ 1% Interest	(41)	(299)	(891)	0.99%
- 1% Interest	40	286	827	-1.02%
C$/US$ Down 0.10 (C$ Strengthening)	4	23	(79)	0.14%
C$/US$ Up 0.10 (C$ Weakening)	(4)	(23)	77	-0.14%
Low Export Price	(6)	(143)	(426)	0.50%
High Export Price	(5)	119	348	-0.41%
Capital Expenditures + $100M	(14)	(183)	(463)	0.50%
5 Year Drought (starting in 2015/16)	N/A	(1 583)	N/A	1.81%
+ 1% Rate Increase in 2015	29	110	195	-0.22%
- 1% Rate Increase in 2015	(29)	(110)	(197)	0.22%

13.1 Domestic Load Growth Sensitivity

The 2013 Electric Load Forecast is prepared with the expectation that there is a 50% chance that actual Manitoba energy requirements could be higher or lower than forecast.

Historically, domestic load requirements higher than forecast would result in greater adverse financial impacts than lower domestic loads due to the higher value of opportunity export sales compared to domestic revenues. With the weakening of export electricity prices over the last several years, wholesale market export and domestic retail rates have inverted and the resulting revenue impacts are positive to Manitoba Hydro. The risk represented is the low domestic load growth or the 10th percentile where gross firm energy could decrease by 1 928 GW.h by 2032/33 or 492 MW in system peak energy.

13.2 Interest Rates Sensitivity

Interest rates assumed in IFF13 are projected to rise gradually over the first six years of the forecast. The interest rate sensitivity indicates the financial impacts of interest rates one percent higher or lower than forecast on short-term, long-term and floating rate debt, as well as sinking funds.

13.3 Foreign Exchange Rates Sensitivity

The Canadian dollar is projected to be slightly weaker than the US$ with some gains in the short term and returning to $1.03 (C$/US$) for the remainder of the forecast. In the short to medium term of the forecast, net income is relatively neutral to changes in the exchange rate, due to the effective hedge provided by Manitoba Hydro's exposure management program. The exchange rate sensitivity indicates the financial impacts of the C$/US$ exchange rate being 0.10 higher (C$ weakening) or lower (C$ strengthening) than forecast.

13.4 Export Prices Sensitivity

IFF13 reflects the expected electricity export prices derived from several independent price forecasts for the Midwest independent System Operator (MISO) region. Each price forecast consultant has their own electricity price forecast models, assumptions and view of the future. In preparing their forecasts, the consultants prepare their own internal estimates for a number of pricing factors. These factors include:

- Thermal fuel forecasts (coal and natural gas);
- Future load growth forecasts;
- Profile of existing generation (fuel type, efficiency and operating parameters);
- Profile of potential new generation (fuel type, efficiency, capital cost and required rates of return);
- Generation requirements;
- Power market rules; and

- Future regulation/legislation related to SO_2 (sulfur dioxide), NO_X (nitrous oxide), Hg (mercury) and CO_2 (carbon dioxide) emissions, as well as cooling water releases and coal ash handling.

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

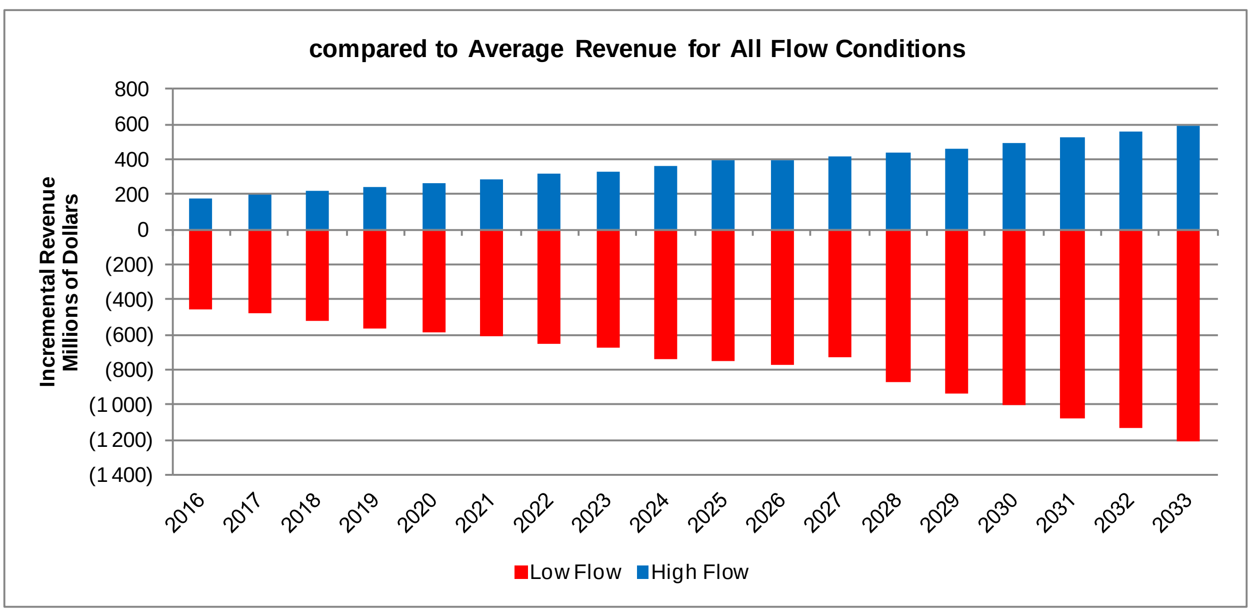
13.5 Capital Expenditures Sensitivity

The capital expenditure sensitivity reflects the financial effects of inflationary increases in excess of general inflation levels and/or additional expenditures necessary to meet reliability, safety, regulatory or customer requirements. In this sensitivity, increases of $100 million per year for electric and $10 million per year for gas have been assumed for non-specified projects.

13.6 Drought/Water Flow Sensitivity

IFF13 reflects the average revenues and expenses of 99 different potential system inflow conditions that occurred historically from 1912/13 to 2010/11. Although the forecast inherently includes the revenues and expenses associated with both the highest and lowest inflow conditions, the actual inflow could vary significantly from forecast in any given year as shown in Figure 13-1. The impact of low flows are greater than high flows due to the requirements for thermally generated and imported energy in low flow years and spilling of water beyond system constraints in high flow years.

Figure 13-1: Variability of Net Interchange Revenue



A prolonged period of low flows has a significant financial impact. The current estimate of a recurrence of the historic five-year drought from 1987/88 to 1991/92 is approximately $1.6 billion by the end of the drought period in 2019/20. This represents the deviation in net interchange revenues and generation costs if the five-year drought begins in 2015/16 compared to the average net revenues resulting from all historic flow cases. The costs of drought could rise under a scenario of higher electricity export and thermal fuel prices.

13.7 Rate Increase Sensitivity

Table 13-1 indicates the financial impact of a +/-1% change in the proposed electric rate increase in 2014/15.

Section 2

14.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF13)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF13)
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUES										
General Consumers	1 763	1 824	1 914	1 994	2 076	2 168	2 264	2 364	2 471	2 583
BPIII Reserve Account	(18)	(21)	(22)	(23)	(13)	0	0	0	0	0
Extraprovincial	408	383	362	390	441	448	484	760	862	880
	2 153	2 185	2 253	2 360	2 505	2 616	2 748	3 124	3 333	3 464
Cost of Gas Sold	213	213	227	224	224	224	225	225	226	226
	1 939	1 972	2 026	2 136	2 281	2 392	2 523	2 899	3 108	3 237
Other	29	27	29	30	30	31	32	33	33	34
	1 968	2 000	2 055	2 166	2 311	2 423	2 555	2 931	3 141	3 271
EXPENSES										
Operating and Administrative	556	568	613	620	640	648	660	688	696	712
Finance Expense	472	534	551	607	699	827	881	1 148	1 239	1 240
Depreciation and Amortization	446	474	470	482	520	534	556	634	701	708
Water Rentals and Assessments	125	123	111	111	112	111	113	124	127	127
Fuel and Power Purchased	144	142	174	189	203	214	217	250	265	273
Capital and Other Taxes	112	121	130	141	152	155	156	157	159	190
	1 856	1 962	2 049	2 151	2 325	2 488	2 582	3 001	3 187	3 249
Non-controlling Interest	24	24	18	16	13	10	8	7	0	(2)
Net Income	136	62	24	31	(0)	(55)	(19)	(62)	(45)	20
Additional General Consumers Revenue										
General electricity rate increases	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
General gas rate increases	0.00%	0.00%	0.50%	0.50%	0.50%	0.50%	0.00%	0.00%	0.50%	0.00%
Financial Ratios										
Equity	24%	22%	18%	16%	15%	14%	13%	12%	11%	11%
Interest Coverage	1.22	1.09	1.03	1.03	1.00	0.95	0.98	0.95	0.97	1.01
Capital Coverage	1.06	0.87	0.80	0.87	1.17	1.07	1.18	1.20	1.35	1.52

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF13)
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
REVENUES										
General Consumers	2 704	2 830	2 964	3 100	3 246	3 402	3 565	3 736	3 915	4 103
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	881	867	795	976	1 238	1 344	1 342	1 342	1 358	1 360
	3 586	3 698	3 759	4 077	4 483	4 746	4 907	5 078	5 274	5 463
Cost of Gas Sold	227	227	227	227	228	228	229	229	230	230
	3 359	3 471	3 532	3 849	4 256	4 518	4 678	4 849	5 044	5 233
Other	35	35	36	37	37	38	39	40	40	41
	3 394	3 506	3 568	3 886	4 293	4 556	4 717	4 888	5 084	5 274
EXPENSES										
Operating and Administrative	726	741	756	790	807	824	839	854	872	891
Finance Expense	1 256	1 256	1 251	1 373	1 673	1 851	1 824	1 835	1 776	1 722
Depreciation and Amortization	713	718	728	775	865	922	932	949	958	960
Water Rentals and Assessments	127	127	127	135	148	151	151	152	153	153
Fuel and Power Purchased	284	300	298	283	271	291	301	299	311	321
Capital and Other Taxes	200	208	216	223	227	230	230	231	235	234
	3 305	3 350	3 376	3 579	3 990	4 268	4 276	4 320	4 305	4 281
Non-controlling Interest	(6)	(8)	(8)	(10)	(11)	(13)	(16)	(18)	(20)	(23)
Net Income	82	148	184	297	293	275	425	550	760	970
Additional General Consumers Revenue										
General electricity rate increases	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
General gas rate increases	1.00%	0.75%	1.00%	0.50%	1.00%	0.75%	0.75%	1.00%	1.00%	1.00%
Financial Ratios										
Equity	11%	11%	11%	11%	12%	13%	14%	16%	18%	22%
Interest Coverage	1.05	1.09	1.10	1.16	1.15	1.14	1.22	1.29	1.42	1.56
Capital Coverage	1.68	1.79	1.86	2.14	2.27	2.32	2.59	2.81	3.18	3.53

CONSOLIDATED PROJECTED BALANCE SHEET (IFF13)
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS										
Plant in Service	16 904	18 087	19 060	19 887	23 496	24 246	27 774	31 855	32 437	32 950
Accumulated Depreciation	(5 608)	(6 003)	(6 367)	(6 776)	(7 230)	(7 749)	(8 276)	(8 881)	(9 524)	(10 178)
Net Plant in Service	11 296	12 084	12 694	13 111	16 267	16 497	19 498	22 974	22 913	22 772
Construction in Progress	2 427	3 298	4 745	6 456	5 203	6 528	4 783	1 972	3 159	4 984
Current and Other Assets	1 147	1 123	939	1 118	1 572	1 381	1 787	1 956	1 518	1 421
Goodwill and Intangible Assets	262	245	225	209	197	187	175	165	156	150
Regulated Assets	299	290	277	261	244	228	209	194	180	168
	15 432	17 041	18 880	21 155	23 482	24 820	26 453	27 260	27 926	29 495
LIABILITIES AND EQUITY										
Long-Term Debt	10 481	11 921	14 140	16 214	17 443	19 943	21 315	22 248	23 224	24 920
Current and Other Liabilities	1 685	1 762	1 703	1 825	2 860	1 732	2 053	2 035	1 791	1 649
Contributions in Aid of Construction	365	375	384	393	403	418	431	442	453	465
BPIII Reserve Account	18	40	62	85	98	65	33	-	-	-
Retained Earnings	2 678	2 739	2 705	2 736	2 736	2 681	2 662	2 600	2 555	2 575
Accumulated Other Comprehensive Income	204	204	(115)	(98)	(57)	(19)	(41)	(66)	(97)	(114)
	15 432	17 041	18 880	21 155	23 482	24 820	26 453	27 260	27 926	29 495

CONSOLIDATED PROJECTED BALANCE SHEET (IFF13)
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
ASSETS										
Plant in Service	33 553	34 244	34 893	41 380	46 094	47 848	48 329	50 225	51 009	51 487
Accumulated Depreciation	(10 840)	(11 509)	(12 183)	(12 905)	(13 717)	(14 588)	(15 469)	(16 368)	(17 275)	(18 185)
Net Plant in Service	22 714	22 735	22 710	28 475	32 377	33 260	32 860	33 857	33 734	33 302
Construction in Progress	6 755	8 242	9 653	5 018	1 717	1 076	1 537	485	396	568
Current and Other Assets	1 786	2 039	2 029	2 229	2 548	2 746	3 086	3 007	3 982	5 195
Goodwill and Intangible Assets	145	140	136	131	127	122	117	113	108	103
Regulated Assets	158	150	142	134	126	120	117	115	114	113
	31 559	33 307	34 670	35 987	36 895	37 325	37 717	37 576	38 334	39 282
LIABILITIES AND EQUITY										
Long-Term Debt	27 114	28 268	29 872	30 874	31 416	31 398	30 871	30 861	30 864	30 677
Current and Other Liabilities	1 425	1 861	1 427	1 436	1 500	1 663	2 148	1 458	1 445	1 605
Contributions in Aid of Construction	477	489	501	513	525	538	550	563	576	590
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 658	2 806	2 990	3 287	3 579	3 854	4 280	4 830	5 589	6 560
Accumulated Other Comprehensive Income	(114)	(117)	(120)	(123)	(126)	(129)	(132)	(135)	(141)	(150)
	31 559	33 307	34 670	35 987	36 895	37 325	37 717	37 576	38 334	39 282

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF13)
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
OPERATING ACTIVITIES										
Cash Receipts from Customers	2 278	2 312	2 386	2 491	2 627	2 728	2 861	3 239	3 450	3 582
Cash Paid to Suppliers and Employees	(1 185)	(1 207)	(1 294)	(1 325)	(1 365)	(1 385)	(1 403)	(1 474)	(1 502)	(1 556)
Interest Paid	(506)	(523)	(552)	(603)	(710)	(841)	(890)	(1 180)	(1 274)	(1 246)
Interest Received	26	13	16	23	34	37	35	32	29	16
	612	596	556	587	585	539	603	616	703	796
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 346	1 800	2 600	2 400	2 600	2 800	2 000	1 600	1 400	2 000
Sinking Fund Withdrawals	410	103	16	-	13	412	186	270	670	155
Retirement of Long-Term Debt	(610)	(252)	(312)	(336)	(330)	(1 442)	(305)	(633)	(673)	(451)
Other	(116)	(11)	(12)	(12)	(11)	(22)	(11)	(57)	15	(6)
	1 030	1 641	2 291	2 053	2 271	1 748	1 870	1 180	1 412	1 698
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 630)	(2 090)	(2 502)	(2 559)	(2 446)	(2 105)	(2 094)	(1 388)	(1 771)	(2 339)
Sinking Fund Payment	(194)	(114)	(184)	(159)	(224)	(218)	(225)	(245)	(338)	(245)
Other	(14)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(1 838)	(2 226)	(2 707)	(2 739)	(2 691)	(2 358)	(2 349)	(1 663)	(2 140)	(2 614)
Net Increase (Decrease) in Cash	(196)	11	140	(99)	165	(72)	124	134	(25)	(120)
Cash at Beginning of Year	32	(164)	(153)	(12)	(111)	54	(18)	106	240	214
Cash at End of Year	(164)	(153)	(12)	(111)	54	(18)	106	240	214	94

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF13)
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 707	3 820	3 884	4 204	4 612	4 878	5 040	5 214	5 412	5 604
Cash Paid to Suppliers and Employees	(1 590)	(1 627)	(1 647)	(1 680)	(1 701)	(1 744)	(1 767)	(1 780)	(1 813)	(1 838)
Interest Paid	(1 243)	(1 259)	(1 259)	(1 397)	(1 720)	(1 917)	(1 901)	(1 935)	(1 852)	(1 819)
Interest Received	17	26	32	42	59	78	87	101	82	102
	890	960	1 009	1 169	1 251	1 295	1 460	1 600	1 829	2 048
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 200	1 600	1 600	1 000	600	200	200	-	-	-
Sinking Fund Withdrawals	29	-	437	-	-	60	250	700	13	30
Retirement of Long-Term Debt	(300)	-	(450)	-	-	(60)	(250)	(700)	(13)	(30)
Other	1	1	0	1	1	1	2	3	(16)	(16)
	1 931	1 601	1 587	1 001	601	201	202	3	(16)	(16)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 376)	(2 179)	(2 065)	(1 856)	(1 417)	(1 117)	(945)	(847)	(699)	(654)
Sinking Fund Payment	(265)	(294)	(321)	(326)	(350)	(370)	(384)	(388)	(368)	(382)
Other	(30)	(31)	(26)	(26)	(26)	(27)	(27)	(27)	(27)	(27)
	(2 671)	(2 503)	(2 412)	(2 209)	(1 793)	(1 513)	(1 356)	(1 262)	(1 095)	(1 064)
Net Increase (Decrease) in Cash	149	58	184	(39)	58	(17)	306	340	719	968
Cash at Beginning of Year	94	244	302	486	446	505	488	794	1 134	1 853
Cash at End of Year	244	302	486	446	505	488	794	1 134	1 853	2 821

15.0 CAPITAL EXPENDITURE FORECAST (CEF13)

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	44.8	23.8	12.1	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	2.3	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	0.3	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	350.1	471.0	639.3	865.1	1 111.4	942.3	789.5	282.4	129.3	-	5 580.2
Conawapa - Generation	10 491.5	69.8	70.1	125.9	99.4	240.6	308.1	387.5	432.5	1 061.6	1 722.1	4 517.5
Kelsey Improvements & Upgrades	301.7	16.0	2.2	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	3.2	7.7	23.7	17.3	1.0	31.7	29.5	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	260.5	125.3	5.5	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	12.7	8.6	12.3	21.9	7.4	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	-	-	-	-	-	-	-	-	0.5	2.2	2.7
Gillam Redevelopment and Expansion Program (GREP)	366.5	-	27.0	30.2	30.5	29.5	27.9	26.3	29.1	28.7	26.8	256.0
Bipole III - Transmission Line	1 259.9	66.2	265.9	381.9	263.7	195.2	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	179.0	262.6	493.2	410.2	181.5	127.4	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	28.8	63.5	46.2	37.7	8.5	-	-	-	-	-	184.6
Community Development Initiative	60.8	53.9	2.2	2.0	1.8	0.9	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	74.1	40.8	0.7	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	0.0	10.8	8.9	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	0.4	3.8	29.7	101.1	58.7	63.5	91.7	0.1	-	-	349.0
St. Joseph Wind Transmission	10.0	0.0	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	28.1	25.3	24.6	23.9	22.6	21.7	19.9	18.9	18.8	18.7	222.4
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	-	2.8	33.0	33.6	34.3	103.7
Additional North South Transmission	475.0	-	-	-	-	-	-	-	4.1	4.4	51.6	60.2
Target Adjustment (Cost Flow)	NA	(119.0)	(33.9)	(46.0)	(8.2)	0.7	33.6	20.9	56.8	(42.0)	(62.1)	(199.3)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 071.1**	**1 376.5**	**1 790.2**	**1 864.4**	**1 858.1**	**1 556.0**	**1 368.1**	**856.8**	**1 234.8**	**1 793.6**	**14 769.6**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	14.2	8.0	5.0	21.9	30.2	27.0	16.0	-	-	-	122.3
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	-	-
Slave Falls Major Overhauls	126.1	-	0.2	0.9	5.3	26.6	30.3	31.8	26.9	4.2	-	126.1
Water Licenses & Renewals	56.8	7.6	7.0	7.0	6.5	2.4	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	10.2	10.3	15.3	21.7	19.5	20.4	24.2	19.5	17.1	9.6	167.9
Great Falls Unit 4 Overhaul	53.6	4.6	16.5	11.9	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	6.0	0.4	17.5	7.8	31.7
		36.7	42.1	40.2	55.3	78.6	77.7	78.0	46.7	38.8	17.5	511.6
Transmission												
Rockwood East 230/115kV Station	53.3	13.1	29.1	8.6	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	15.2	30.0	17.2	0.0	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	1.2	3.0	34.9	18.1	1.6	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	1.1	8.9	9.0	9.1	23.7	24.2	24.7	25.1	25.6	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	6.7	7.9	8.9	8.5	5.9	3.4	0.8	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	0.4	16.5	33.2	9.9	3.5	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	2.1	13.3	23.1	57.4	58.5	59.6	213.9
		36.2	71.0	78.4	36.0	35.2	73.6	57.9	85.5	83.6	85.1	642.6
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	2.1	20.0	25.6	16.1	1.3	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	0.1	0.3	3.0	20.0	20.0	7.9	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	0.0	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	51.8
Burrows New 66/12kV Station	54.7	8.7	5.1	-	-	-	-	-	-	-	-	13.8
		10.9	27.9	29.1	39.1	37.8	27.9	9.3	-	-	-	182.1
MAJOR CAPITAL TOTAL		**83.8**	**141.1**	**147.7**	**130.5**	**151.7**	**179.2**	**145.1**	**132.3**	**122.4**	**102.6**	**1 336.3**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Base Capital												
Electric												
Generation Operations	NA	98.2	94.2	87.7	101.8	63.9	59.6	67.2	70.5	73.2	77.8	794.1
Transmission	NA	104.1	114.9	126.1	112.0	70.3	65.6	73.9	77.5	80.5	85.6	910.6
Customer Service & Distribution	NA	175.4	207.6	211.8	229.2	143.8	134.3	151.2	158.6	164.8	175.2	1 751.9
Customer Care & Energy Conservation	NA	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	33.6
Human Resources & Corporate Services	NA	61.4	75.7	54.8	54.8	34.4	32.1	36.2	37.9	39.4	41.9	468.6
Finance & Regulatory	NA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2
		442.4	495.8	483.7	501.3	316.0	295.2	332.1	348.3	361.8	384.4	3 961.0
Gas												
Customer Service & Distribution	NA	35.7	34.9	49.0	34.9	22.3	21.2	24.4	26.1	27.7	30.0	306.2
Customer Care & Energy Conservation	NA	13.7	13.4	12.3	12.1	10.1	9.3	8.5	8.5	8.4	8.5	104.8
		49.4	48.3	61.3	47.0	32.4	30.6	32.8	34.6	36.1	38.5	411.0
BASE CAPITAL TOTAL		**491.8**	**544.1**	**545.1**	**548.3**	**348.3**	**325.8**	**364.9**	**382.9**	**397.9**	**422.9**	**4 372.0**
CONSOLIDATED CEF13 TOTAL		**1 646.6**	**2 061.7**	**2 482.9**	**2 543.1**	**2 358.1**	**2 061.0**	**1 878.1**	**1 372.0**	**1 755.1**	**2 319.1**	**20 477.9**
ELECTRIC CAPITAL TOTAL		**1 597.2**	**2 013.4**	**2 421.6**	**2 496.1**	**2 325.7**	**2 030.5**	**1 845.3**	**1 337.4**	**1 719.1**	**2 280.6**	**20 066.8**
GAS CAPITAL TOTAL		**49.4**	**48.3**	**61.3**	**47.0**	**32.4**	**30.6**	**32.8**	**34.6**	**36.1**	**38.5**	**411.0**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	-	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	-	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	-	-	-	-	-	-	-	-	-	-	5 580.2
Conawapa - Generation	10 491.5	1 700.2	1 428.7	1 228.1	920.1	371.2	65.0	-	-	-	-	10 230.8
Kelsey Improvements & Upgrades	301.7	-	-	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	-	-	-	-	-	-	-	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	-	-	-	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	16.0	37.8	90.7	157.8	245.0	403.9	312.7	216.2	55.6	-	1 538.3
Gillam Redevelopment and Expansion Program (GREP)	366.5	32.3	32.1	34.0	11.9	-	-	-	-	-	-	366.5
Bipole III - Transmission Line	1 259.9	-	-	-	-	-	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	-	-	-	-	-	-	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	-	-	-	-	-	-	-	-	-	-	184.6
Community Development Initiative	60.8	-	-	-	-	-	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	-	-	-	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	-	-	-	-	-	-	-	-	-	-	349.0
St. Joseph Wind Transmission	10.0	-	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	19.1	18.7	17.9	16.2	16.0	16.3	16.6	16.9	17.3	17.6	395.1
Generating Station Improvements & Upgrades	NA	35.0	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	373.8
Additional North South Transmission	475.0	29.8	49.9	85.7	116.8	132.7	-	-	-	-	-	475.0
Target Adjustment (Cost Flow)	NA	(3.9)	22.6	13.3	23.8	49.5	34.0	20.2	11.1	17.1	6.2	(5.5)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 828.5**	**1 625.5**	**1 506.1**	**1 291.6**	**846.5**	**540.2**	**358.9**	**258.7**	**105.2**	**49.6**	**23 180.3**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	122.3
Jenpeg Overhaul Program	115.9	2.7	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	115.9
Slave Falls Major Overhauls	126.1	-	-	-	-	-	-	-	-	-	-	126.1
Water Licenses & Renewals	56.8	-	-	-	-	-	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	7.4	3.3	0.2	0.1	-	-	-	-	-	-	178.9
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	18.8	-	-	-	-	-	-	-	-	-	50.4
		28.8	6.3	21.7	21.8	23.3	1.2	45.4	(3.4)	0.6	-	657.3
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	-	-	-	-	-	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	19.8	-	-	-	-	-	-	-	-	-	233.7
		19.8	-	-	-	-	-	-	-	-	-	662.4
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	-	-	-	-	-	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	13.8
		-	-	-	-	-	-	-	-	-	-	182.1
MAJOR CAPITAL TOTAL		**48.6**	**6.3**	**21.7**	**21.8**	**23.3**	**1.2**	**45.4**	**(3.4)**	**0.6**	**-**	**1 501.8**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Base Capital												
Electric												
Generation Operations	NA	71.7	83.9	81.5	81.1	81.0	83.7	76.5	84.0	84.5	84.6	1 606.6
Transmission	NA	78.8	92.3	89.7	89.3	89.1	92.1	84.2	92.4	93.0	93.1	1 804.4
Customer Service & Distribution	NA	251.7	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	4 506.1
Customer Care & Energy Conservation	NA	3.7	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	4.5	74.6
Human Resources & Corporate Services	NA	38.6	45.1	43.9	43.7	43.6	45.0	41.2	45.2	45.5	45.5	905.9
Finance & Regulatory	NA	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	4.8
		444.7	486.9	477.0	481.6	485.2	510.8	474.5	524.8	525.3	530.6	8 902.4
Gas												
Customer Service & Distribution	NA	28.3	33.7	33.5	34.0	34.7	36.6	34.1	38.2	39.3	40.2	658.8
Customer Care & Energy Conservation	NA	9.1	9.2	9.3	9.4	9.1	9.2	9.3	9.5	9.6	9.7	198.2
		37.4	42.9	42.8	43.4	43.8	45.8	43.5	47.7	48.9	49.9	857.0
BASE CAPITAL TOTAL		**482.1**	**529.8**	**519.7**	**525.0**	**529.1**	**556.6**	**518.0**	**572.5**	**574.1**	**580.5**	**9 759.4**
CONSOLIDATED CEF13 TOTAL		**2 359.3**	**2 161.5**	**2 047.5**	**1 838.5**	**1 398.8**	**1 098.1**	**922.3**	**827.7**	**679.9**	**630.1**	**34 441.6**
ELECTRIC CAPITAL TOTAL		**2 321.9**	**2 118.6**	**2 004.7**	**1 795.1**	**1 355.0**	**1 052.3**	**878.8**	**780.0**	**631.0**	**580.2**	**33 584.5**
GAS CAPITAL TOTAL		**37.4**	**42.9**	**42.8**	**43.4**	**43.8**	**45.8**	**43.5**	**47.7**	**48.9**	**49.9**	**857.0**

16.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH13)

ELECTRIC OPERATIONS (MH13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
REVENUES										
General Consumers										
at approved rates	1 396	1 408	1 423	1 438	1 452	1 471	1 490	1 508	1 528	1 548
additional*	0	56	115	177	243	314	390	470	555	646
BPIII Reserve Account	(18)	(21)	(22)	(23)	(13)	0	0	0	0	0
Extraprovincial	408	383	362	390	441	448	484	760	862	880
Other	13	13	13	14	14	14	14	15	15	15
	1 799	1 838	1 890	1 995	2 138	2 247	2 378	2 753	2 960	3 089
EXPENSES										
Operating and Administrative	485	494	542	548	567	574	586	612	620	633
Finance Expense	437	499	514	567	657	784	838	1 105	1 195	1 195
Depreciation and Amortization	415	440	437	448	485	499	521	600	667	675
Water Rentals and Assessments	125	123	111	111	112	111	113	124	127	127
Fuel and Power Purchased	144	142	174	189	203	214	217	250	265	273
Capital and Other Taxes	93	101	109	121	131	134	135	136	138	168
Corporate Allocation	9	9	9	9	9	9	9	9	9	9
	1 707	1 807	1 896	1 992	2 163	2 324	2 417	2 835	3 020	3 081
Non-controlling Interest	24	24	18	16	13	10	8	7	0	(2)
Net Income	116	55	12	19	(12)	(67)	(31)	(75)	(60)	6
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%

ELECTRIC OPERATIONS (MH13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
REVENUES										
General Consumers										
at approved rates	1 568	1 588	1 609	1 629	1 649	1 672	1 694	1 715	1 737	1 758
additional*	742	844	952	1 067	1 188	1 317	1 454	1 599	1 751	1 913
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	881	867	795	976	1 238	1 344	1 342	1 342	1 358	1 360
Other	16	16	16	16	17	17	17	18	18	19
	3 206	3 315	3 373	3 688	4 091	4 350	4 507	4 674	4 865	5 050
EXPENSES										
Operating and Administrative	646	660	673	705	720	735	748	762	778	794
Finance Expense	1 210	1 210	1 204	1 325	1 623	1 801	1 772	1 784	1 724	1 670
Depreciation and Amortization	679	684	694	741	829	886	895	911	918	921
Water Rentals and Assessments	127	127	127	135	148	151	151	152	153	153
Fuel and Power Purchased	284	300	298	283	271	291	301	299	311	321
Capital and Other Taxes	178	185	194	200	204	206	208	208	212	211
Corporate Allocation	9	9	9	9	9	9	9	7	6	6
	3 132	3 175	3 197	3 397	3 803	4 079	4 083	4 123	4 102	4 075
Non-controlling Interest	(6)	(8)	(8)	(10)	(11)	(13)	(16)	(18)	(20)	(23)
Net Income	68	133	168	281	277	259	408	532	742	952
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	93.20%	100.84%	108.77%

ELECTRIC OPERATIONS (MH13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS										
Plant in Service	16 237	17 381	18 305	19 095	22 681	23 407	26 910	30 963	31 516	31 998
Accumulated Depreciation	(5 434)	(5 814)	(6 168)	(6 564)	(7 003)	(7 508)	(8 019)	(8 609)	(9 236)	(9 875)
Net Plant in Service	10 803	11 568	12 137	12 531	15 677	15 900	18 891	22 355	22 280	22 124
Construction in Progress	2 425	3 296	4 743	6 454	5 200	6 525	4 779	1 967	3 154	4 978
Current and Other Assets	1 649	1 669	1 534	1 742	2 172	2 055	2 375	2 440	2 057	2 111
Goodwill and Intangible Assets	188	172	154	139	127	118	107	96	87	81
Regulated Assets	220	213	203	190	180	169	159	149	142	134
	15 285	16 918	18 770	21 056	23 357	24 767	26 310	27 007	27 720	29 428
LIABILITIES AND EQUITY										
Long-Term Debt	10 464	11 904	14 123	16 197	17 426	19 926	21 298	22 231	23 207	24 903
Current and Other Liabilities	1 653	1 760	1 726	1 870	2 890	1 848	2 093	1 978	1 795	1 805
Contributions in Aid of Construction	362	372	382	391	401	413	425	437	449	462
BPIII Reserve Account	18	40	62	85	98	65	33	-	-	-
Retained Earnings	2 584	2 638	2 592	2 611	2 599	2 533	2 502	2 427	2 366	2 372
Accumulated Other Comprehensive Income	204	204	(115)	(98)	(57)	(19)	(41)	(66)	(97)	(114)
	15 285	16 918	18 770	21 056	23 357	24 767	26 310	27 007	27 720	29 428

ELECTRIC OPERATIONS (MH13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
ASSETS										
Plant in Service	32 572	33 228	33 848	40 307	44 992	46 716	47 170	49 034	49 786	50 231
Accumulated Depreciation	(10 520)	(11 173)	(11 836)	(12 546)	(13 347)	(14 206)	(15 074)	(15 960)	(16 853)	(17 749)
Net Plant in Service	22 052	22 055	22 012	27 760	31 645	32 510	32 095	33 074	32 933	32 482
Construction in Progress	6 748	8 235	9 645	5 009	1 707	1 065	1 525	472	382	553
Current and Other Assets	2 348	2 583	2 493	2 700	3 015	3 250	3 556	3 477	4 454	5 669
Goodwill and Intangible Assets	77	72	68	63	58	54	49	45	40	36
Regulated Assets	129	123	119	112	107	103	100	99	98	98
	31 353	33 069	34 336	35 645	36 533	36 982	37 325	37 166	37 906	38 837
LIABILITIES AND EQUITY										
Long-Term Debt	27 097	28 251	29 854	30 857	31 399	31 381	30 853	30 843	30 847	30 660
Current and Other Liabilities	1 456	1 874	1 360	1 376	1 434	1 632	2 084	1 392	1 378	1 538
Contributions in Aid of Construction	475	488	501	514	527	540	553	567	581	596
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 440	2 572	2 741	3 022	3 299	3 558	3 967	4 499	5 241	6 193
Accumulated Other Comprehensive Income	(114)	(117)	(120)	(123)	(126)	(129)	(132)	(135)	(141)	(150)
	31 353	33 069	34 336	35 645	36 533	36 982	37 325	37 166	37 906	38 837

ELECTRIC OPERATIONS (MH13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 818	1 859	1 913	2 019	2 151	2 247	2 378	2 753	2 960	3 089
Cash Paid to Suppliers and Employees	(809)	(817)	(902)	(932)	(971)	(988)	(1 003)	(1 072)	(1 097)	(1 147)
Interest Paid	(491)	(506)	(534)	(582)	(688)	(819)	(868)	(1 157)	(1 251)	(1 222)
Interest Received	26	13	16	23	34	37	35	32	29	16
	544	549	493	528	525	478	542	555	640	735
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 316	1 740	2 570	2 390	2 590	2 800	2 000	1 590	1 390	1 970
Sinking Fund Withdrawals	410	103	16	-	13	412	186	270	670	155
Retirement of Long-Term Debt	(610)	(217)	(312)	(336)	(330)	(1 442)	(305)	(633)	(673)	(431)
Other	(116)	(11)	(12)	(12)	(11)	(22)	(11)	(57)	15	(6)
	1 000	1 616	2 261	2 043	2 261	1 748	1 870	1 170	1 402	1 688
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 578)	(2 039)	(2 439)	(2 511)	(2 413)	(2 074)	(2 061)	(1 352)	(1 735)	(2 300)
Sinking Fund Payment	(194)	(114)	(184)	(159)	(224)	(218)	(225)	(245)	(338)	(245)
Other	(14)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(1 786)	(2 175)	(2 644)	(2 691)	(2 658)	(2 326)	(2 315)	(1 627)	(2 103)	(2 574)
Net Increase (Decrease) in Cash	(243)	(10)	111	(120)	128	(101)	97	99	(61)	(151)
Cash at Beginning of Year	25	(218)	(227)	(117)	(237)	(109)	(209)	(112)	(14)	(74)
Cash at End of Year	(218)	(227)	(117)	(237)	(109)	(209)	(112)	(14)	(74)	(225)

ELECTRIC OPERATIONS (MH13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 206	3 315	3 373	3 688	4 091	4 350	4 507	4 674	4 865	5 050
Cash Paid to Suppliers and Employees	(1 177)	(1 211)	(1 227)	(1 256)	(1 273)	(1 311)	(1 331)	(1 341)	(1 369)	(1 390)
Interest Paid	(1 218)	(1 234)	(1 233)	(1 370)	(1 691)	(1 888)	(1 870)	(1 904)	(1 820)	(1 785)
Interest Received	17	26	32	42	59	78	87	101	82	102
	828	897	945	1 105	1 186	1 229	1 393	1 530	1 758	1 976
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 190	1 580	1 590	980	590	180	160	(10)	(20)	(50)
Sinking Fund Withdrawals	29	-	437	-	-	60	250	700	13	30
Retirement of Long-Term Debt	(290)	-	(450)	-	-	(60)	(220)	(700)	(13)	-
Other	1	1	0	1	1	1	2	3	(16)	(16)
	1 931	1 581	1 577	981	591	181	192	(7)	(36)	(36)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 338)	(2 135)	(2 021)	(1 812)	(1 372)	(1 070)	(901)	(798)	(650)	(603)
Sinking Fund Payment	(265)	(294)	(321)	(326)	(350)	(370)	(384)	(388)	(368)	(382)
Other	(30)	(30)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)
	(2 633)	(2 459)	(2 368)	(2 164)	(1 749)	(1 466)	(1 312)	(1 213)	(1 045)	(1 013)
Net Increase (Decrease) in Cash	125	19	154	(78)	28	(56)	273	310	677	928
Cash at Beginning of Year	(225)	(100)	(81)	73	(6)	23	(33)	240	550	1 228
Cash at End of Year	(100)	(81)	73	(6)	23	(33)	240	550	1 228	2 155

17.0 GAS OPERATIONS FINANCIAL FORECAST (CGM13)

GAS OPERATIONS (CGM13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
REVENUES										
General Consumers										
at approved rates	367	360	374	375	375	376	377	378	380	381
additional revenue requirement*	0	0	2	3	5	7	7	7	9	9
	367	360	376	378	380	383	384	386	389	390
Cost of Gas Sold	213	213	228	224	224	224	225	225	226	226
Gross Margin	153	147	149	154	156	159	159	160	163	164
Other	2	2	2	2	2	2	2	2	2	2
	155	149	150	156	158	160	161	162	164	165
EXPENSES										
Operating and Administrative	67	69	67	68	68	69	70	71	71	73
Finance Expense	16	17	19	21	23	23	24	24	24	25
Depreciation and Amortization	28	31	29	30	31	32	32	31	32	31
Capital and Other Taxes	19	19	20	20	20	20	21	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	148	147	152	155	157	158	159	161	163
Net Income	12	1	4	4	3	3	3	3	4	3

* Additional Revenue Requirement	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Percent Increase		0.00%	0.50%	0.50%	0.50%	0.50%	0.00%	0.00%	0.50%	0.00%
Cumulative Percent Increase		0.00%	0.50%	1.00%	1.51%	2.02%	2.02%	2.02%	2.53%	2.53%

GAS OPERATIONS (CGM13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
ASSETS										
Plant in Service	690	722	764	795	813	830	849	870	893	918
Accumulated Depreciation	(238)	(246)	(248)	(255)	(261)	(269)	(277)	(285)	(294)	(303)
Net Plant in Service	452	476	516	540	552	561	572	585	599	615
Construction in Progress	2	2	2	2	2	3	4	5	5	6
Current and Other Assets	84	84	84	84	84	84	84	84	84	84
Goodwill and Intangible Assets	8	7	5	5	4	4	3	3	3	3
Regulated Assets	79	77	74	70	64	58	50	44	38	34
	625	646	682	702	707	710	715	722	731	743
LIABILITIES AND EQUITY										
Long-Term Debt	290	350	380	390	400	400	400	410	400	420
Current and Other Liabilities	117	77	79	86	77	74	75	70	86	76
Contributions in Aid of Construction	43	43	42	42	43	44	46	45	44	43
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	54	55	59	63	66	70	73	76	80	82
	625	646	682	702	707	710	715	722	731	743

GAS OPERATIONS (CGM13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
OPERATING ACTIVITIES										
Cash Receipts from Customers	403	396	412	410	412	415	417	418	421	423
Cash Paid to Suppliers and Employees	(345)	(358)	(357)	(358)	(359)	(360)	(362)	(364)	(366)	(369)
Interest Paid	(18)	(18)	(20)	(22)	(23)	(24)	(24)	(24)	(25)	(25)
	40	20	35	30	30	31	30	30	30	29
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	30	60	30	10	10	-	-	10	10	30
Retirement of Long-Term Debt	-	(35)	-	-	-	-	-	-	-	(20)
Other	-	-	-	-	-	-	-	-	-	-
	30	25	30	10	10	-	-	10	10	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(51)	(49)	(62)	(48)	(33)	(31)	(33)	(36)	(37)	(40)
Other	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(0)	(0)	(0)
	(51)	(49)	(62)	(48)	(33)	(32)	(34)	(36)	(37)	(40)
Net Increase (Decrease) in Cash	19	(4)	3	(8)	7	(2)	(4)	4	4	(1)
Cash at Beginning of Year	(26)	(7)	(11)	(8)	(16)	(9)	(11)	(14)	(10)	(7)
Cash at End of Year	(7)	(11)	(8)	(16)	(9)	(11)	(14)	(10)	(7)	(8)

18.0 CORPORATE SUBSIDIARIES FINANCIAL FORECAST (CS13)

CORPORATE SUBSIDIARIES (CS13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUES										
Revenue	58	57	62	63	64	65	67	68	69	71
Cost of Operations	33	34	37	37	38	39	40	40	41	42
	24	23	25	25	26	27	27	28	28	29
EXPENSES										
Operating and Administrative	14	15	15	15	15	16	16	16	16	16
Finance Expense	(0)	(0)	(0)	-	-	-	-	-	-	-
Depreciation and Amortization	1	2	2	2	2	2	2	1	0	0
Capital and Other Taxes	0	1	1	1	1	1	1	1	1	1
	16	17	17	18	18	18	18	18	17	17
Net Income	8	6	8	8	8	8	9	10	11	12

CORPORATE SUBSIDIARIES (CS13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS										
Plant in Service	13	14	16	16	16	16	16	16	16	16
Accumulated Depreciation	(5)	(6)	(7)	(9)	(10)	(12)	(14)	(14)	(15)	(15)
Net Plant in Service	8	8	8	7	5	4	2	1	1	1
Construction in Progress	-	-	-	-	-	-	-	-	-	-
Current and Other Assets	43	49	57	66	76	87	98	109	120	132
Goodwill and Intangible Assets	1	1	1	1	0	0	0	0	-	-
Regulated Assets	0	0	0	0	0	0	0	0	0	0
	52	59	66	74	82	91	100	110	121	133
LIABILITIES AND EQUITY										
Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Current and Other Liabilities	11	11	11	11	11	11	11	11	11	11
Contributions in Aid of Construction	0	0	0	0	0	0	0	0	0	0
Share Captial	1	1	1	1	1	1	1	1	1	1
Retained Earnings	40	46	54	62	70	78	88	98	109	121
	52	59	66	74	82	91	100	110	121	133

CORPORATE SUBSIDIARIES (CS13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
OPERATING ACTIVITIES										
Cash Receipts from Customers	58	57	62	63	64	65	67	68	69	71
Cash Paid to Suppliers and Employees	(48)	(49)	(52)	(53)	(54)	(55)	(56)	(57)	(58)	(59)
Interest Paid	0	0	0	-	-	-	-	-	-	-
	10	8	9	10	10	10	11	11	11	12
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1)	(2)	(1)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(1)	(2)	(1)	-	-	-	-	-	-	-
Net Increase (Decrease) in Cash	8	6	8	10	10	10	11	11	11	12
Cash at Beginning of Year	8	16	22	30	39	49	60	70	81	93
Cash at End of Year	16	22	30	39	49	60	70	81	93	105