November 2012

Integrated Financial Forecast (IFF12)

2012/13 - 2031/32

Financial Planning
Finance & Administration

Manitoba Hydro

INTEGRATED FINANCIAL FORECAST (IFF12)

2012/13 – 2031/32

FINANCIAL PLANNING DEPARTMENT
CORPORATE CONTROLLER DIVISION
FINANCE & ADMINISTRATION

November, 2012

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INTEGRATED FINANCIAL FORECAST (IFF12)

Section 1

KEY FINANCIAL RESULTS
(Dollars are in millions)

	Actual	IFF12 Forecast			
	2011/12	2012/13	2013/14	2014/15	2021/22
PROJECTED RATE INCREASES					
- ELECTRIC	2.00%	3.57%[1]	3.50%	3.95%	3.95%
- GAS (non-commodity)	-	-	2.00%	-	0.75%
NET INCOME					
- ELECTRIC[2]	$ 62	$ 53	$ 60	$ 50	$ 52
- GAS	(6)	2	6	9	4
- SUBSIDIARIES	5	6	6	7	9
CAPITAL EXPENDITURES					
- ELECTRIC	$ 1 033	$ 1 343	$ 1 859	$ 2 009	$ 2 319
- GAS	38	36	36	33	37
DEBT/EQUITY RATIO	74:26	75:25	78:22	83:17	90:10
INTEREST COVERAGE RATIO	1.10	1.10	1.11	1.09	1.05
CAPITAL COVERAGE RATIO (excl. major new generation & transmission)	1.13	1.16	0.89	0.83	1.60
RETAINED EARNINGS	$2 450	$ 2 510	$ 2 583	$ 2 314	$2 528

[1] Includes the 2.0% interim rate increase effective April 1, 2012 and the 2.5% interim rate increase effective September 1, 2012.
[2] Assumes the reinstatement of the 1.0% rate roll-back directed in PUB Order 5/12.

1.0 OVERVIEW

The Consolidated Integrated Financial Forecast (IFF12) projects Manitoba Hydro's financial results over the 20-year period 2012/13 to 2031/32. Segmented forecasts are also provided for the electricity (MH12), natural gas (CGM12), and corporate subsidiaries (CS12).

Financial results projected in IFF12 are less favourable than the financial results projected in IFF11-2. The projection of less favourable results is largely attributable to the following:

a) Lower projected extraprovincial revenues (lower by $2.9 billion over the 20-year forecast period) due to lower spot market prices in the MISO region and the one-year deferral of Conawapa; and
b) Higher projected capital costs for Conawapa (up $2.4 billion) and Keeyask (up $0.6 billion) due largely to updated estimates and the addition of management reserves to allow for increased construction cost risks.

As a consequence of the deterioration in projected financial results, moderately higher domestic rate increases will be required in order to restore the debt/equity ratio to the target level of 75:25 by the end of the 20-year forecast period. In addition to the requirement for a 3.5% rate increase effective April 1, 2013 (which is currently being considered by the PUB as part of Manitoba Hydro's General Rate Application), it is projected that rate increases of 3.95% will be required in each of the remaining 18 years of the 20-year forecast.

Net income is projected to remain relatively low (averaging about $40 million per year) for the first 10 years of the forecast and the equity ratio is reduced from the current 25% level to 10% equity at the end of 10 years (before gradually beginning to recover to reach 25% equity at the end of 20 years). Should a severe drought be encountered during the first 10-year period, net income and the equity ratio would be further challenged.

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 projection of less favourable 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 higher rate increases 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 witnessed in Manitoba. For this reason, even with the rate increases being projected in IFF12, 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 2031/32:

Years Ending March 31	Electric Rate Increases	Net Income	Retained Earnings	Debt / Equity	Interest Coverage	Capital Coverage
		(Millions)				
2013	-	$60	$2,510	75:25	1.10	1.16
2014	3.50%	72	2,583	78:22	1.11	0.89
2015	3.95%	66	2,314	83:17	1.09	0.83
2016	3.95%	90	2,403	85:15	1.11	0.94
2017	3.95%	70	2,473	86:14	1.07	1.22
2018	3.95%	32	2,505	87:13	1.03	1.39
2019	3.95%	(54)	2,452	88:12	0.95	1.15
2020	3.95%	5	2,457	89:11	1.00	1.54
2021	3.95%	6	2,463	89:11	1.00	1.50
2022	3.95%	65	2,528	90:10	1.05	1.60
2023	3.95%	177	2,705	90:10	1.12	1.63
2024	3.95%	242	2,947	89:11	1.15	1.74
2025	3.95%	315	3,262	89:11	1.19	1.88
2026	3.95%	373	3,634	88:12	1.22	2.16
2027	3.95%	432	4,067	87:13	1.25	2.71
2028	3.95%	385	4,452	85:15	1.22	2.41
2029	3.95%	550	5,001	84:16	1.32	2.54
2030	3.95%	725	5,726	82:18	1.43	2.69
2031	3.95%	850	6,577	79:21	1.52	2.80
2032	3.95%	1,069	7,646	75:25	1.68	3.65

2.0 FORECAST ASSUMPTIONS

2.1 Electricity Rates

IFF12 assumes that the Manitoba Public Utilities Board (PUB) reinstates the 1.0% interim average rate increase rolled back in PUB Order 5/12. The base forecast also includes the approved interim average rate increases of 2.0% effective April 1, 2012 and 2.5% effective September 1, 2012 as well as the proposed 3.5% rate increase effective April 1, 2013. Additional average rate increases of 3.95% per year are projected to the end of the forecast period.

2.2 Gas Rates

The forecast assumes a 2.0% non-gas rate increase effective May 1, 2013. Subsequent non-gas rate increases are sufficient to generate Centra Gas net income of approximately $5 million each year beginning in 2016/17 and thereafter.

2.3 Economic Variables

The economic assumptions used in the forecast are based upon Manitoba Hydro's Economic Outlook updated in October 2012 to reflect current economic conditions. Projected rates for key economic indicators are listed below with the 2011 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
2012/13	1.7% (2.0%)	1.00% (1.25%)	3.15% (3.70%)	1.00 (0.99)
2013/14	1.8% (2.0%)	1.30% (2.20%)	3.30% (4.05%)	0.99 (0.99)
2014/15	1.8% (2.0%)	2.10% (3.80%)	3.85% (5.40%)	1.02 (1.05)
2015/16	1.8% (2.0%)	2.95% (4.05%)	4.55% (5.90%)	1.03 (1.06)
2021/22	1.9% (2.1%)	3.80% (4.30%)	5.30% (6.40%)	1.04 (1.06)

* Excludes the 1% Provincial guarantee fee.

2.4 Manitoba Electricity Load Forecast

General consumers revenue is forecast based on the future load requirements in Manitoba as projected in the 2012 Electric Load Forecast.

The 2012 Electric Load Forecast projects that average annual growth in Manitoba load will be 1.6% for both gross firm energy and gross total peak over the 20-year forecast period to 2031/32 (compared to 1.5% in IFF11). Gross firm energy supplied to the Manitoba load is projected to grow from 24 961 GW.h in 2012/13 to 33 425 GW.h by 2031/32. Over the same 20-year period, total system peak is projected to grow from 4 491 MW in 2012/13 to 6 032 MW in 2031/32. The system load factor is projected to remain relatively constant at approximately 63%.

Compared to the 2011 forecast, gross firm energy is 212 GW.h lower in 2012/13 due mainly to lower forecasted industrial and general service loads. Over the 10-year forecast, the difference narrows due to the increased forecast of customers and by 2021/22 the forecast is only lower by 28 GW.h. By 2030/31, the gross firm energy forecast is higher by 359 GW.h. Gross total peak is lower throughout the forecast due to a lower estimate of distribution losses at peak of 4.5% of sales.

2.5 Extraprovincial Revenue

IFF12 includes the following existing and proposed long-term firm export sales:

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

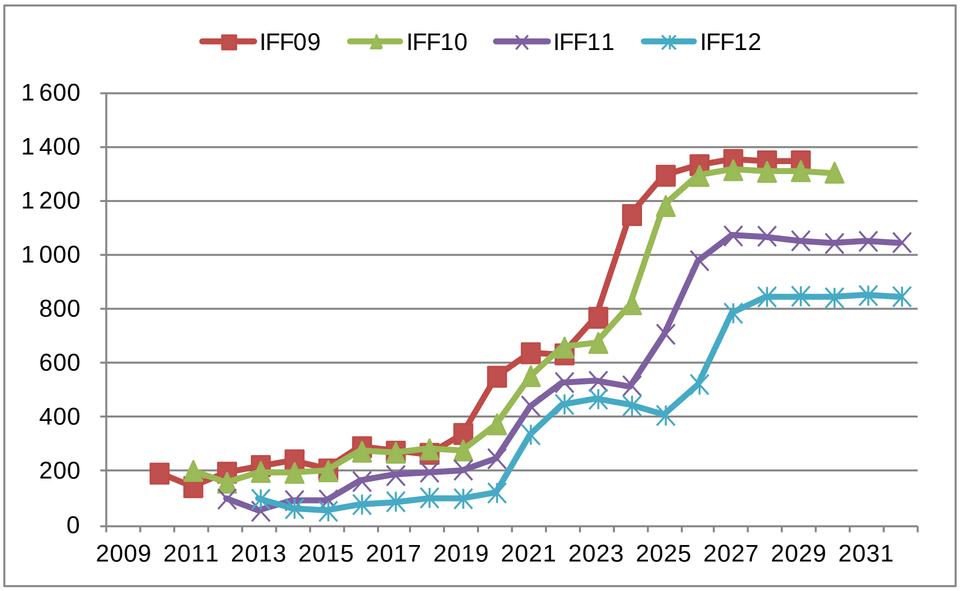
* Proposed

Extraprovincial sales volumes are forecast for the first forecast year (2012/13) based upon the expected inflow conditions as of August 2012 and actual reservoir and lake level elevations as of July 2012. The second forecast year uses the median of 80 years of historic inflows and initial reservoir and lake level elevations carried forward from the 2012/13 forecast. For subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 99 years (1912/13 to 2010/11).

For the third consecutive forecast, extraprovincial revenues (net of water rentals and fuel and power purchases) are projected to be lower than previous forecasts. The decreases in projected net extraprovincial revenues can be attributed to the decreases in forecast electricity export prices and the one-year deferral of Conawapa. Figure 2-1 below shows the comparative net extraprovincial revenues from IFF09 through IFF12.

Figure 2-1: Extraprovincial Revenues

(Net of Water Rentals and Fuel and Power Purchases)



Electricity export opportunity prices have been declining since 2008. The 2012 forecast for short-term and new long-term sales is depressed relative to previous forecasts mainly due to excess capacity in the MISO region, continued slow economic recovery, delays in implementation and lower values of carbon pricing, delays in environmental regulation, 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 2011 price forecast, the 2012 forecast projects on-peak prices to decrease on average approximately 20% over the period 2014/15 to 2022/23 and decrease on average approximately 10% in the period 2023/24 to 2035/36.

Compared to IFF11-2, net extraprovincial revenues are $2.9 billion lower in IFF12 by 2031/32. Just over 80% of the decrease can be attributed to the reduction in forecast electricity export prices described above. The remaining approximate 20% reduction is due mainly to the deferral of Conawapa's in-service date by one year to 2025/26 as well as slightly increased Manitoba load.

2.6 Electricity Supply

Manitoba Hydro's 2012/13 Power Resource Plan indicates new generation is required by 2022/23 to meet the current projection of Manitoba load requirements under dependable energy conditions. New capacity resources are forecast to be required by 2025/26.

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

	MW	**Dependable GW.h**	**In-Service Date**
Wuskwatim	200	1250	2012/13
Keeyask	695	2 900	2019/20
Conawapa	1 485	4 550	2025/26
Kelsey Re-runnering	77	-	2012/13
Enhancements of Winnipeg River Plants	20 - 30	30	2013/14 – 2018/19
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	174	815	By 2026/27

2.7 International Financial Reporting Standards

On September 19, 2012, the Canadian Accounting Standards Board (AcSB) extended the optional transition date for rate-regulated entities an additional year to January 1, 2014 in consideration of the recent commitment of the International Accounting Standards Board (IASB) to review issues related to rate-regulated accounting. Manitoba Hydro will adopt the optional transition date deferral and will be transitioning to IFRS for its 2014/15 fiscal period with comparative information presented for 2013/14.

The primary impacts of IFRS that are included in IFF12 are as follows:

- Rate-regulated assets and liabilities do not currently satisfy the recognition criteria under IFRS and as such any unamortized balances will 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 mostly offset by corresponding reductions in Depreciation and Amortization. The impact of the transition to IFRS on net income for 2014/15 is expected to be an increase of $8 million. The most significant impact of the transition to IFRS for Manitoba Hydro will be a projected reduction to retained earnings of approximately $335 million. The following Table 2-1 outlines the composition of these impacts.

Table 2-1: IFRS Impacts on Retained Earnings and Net Income

Increase/(Decrease)
($Millions)

	Retained Earnings	Net Income 2014/15
Power Smart Programs	(220)	7
Site Remediation	(34)	(1)
Acquisition Costs	(19)	1
Regulatory Costs	(3)	1
Deferred Taxes	(27)	2
Capital Taxes	-	3
Administrative Overhead and Other	(38)	(38)
Pension & Employee Benefits	(21)	4
Removal of Negative Salvage	65	68
Change to Equal Life Group Depreciation	(37)	(38)
Total	(335)	8

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

2.8 Operating & Administrative Expense

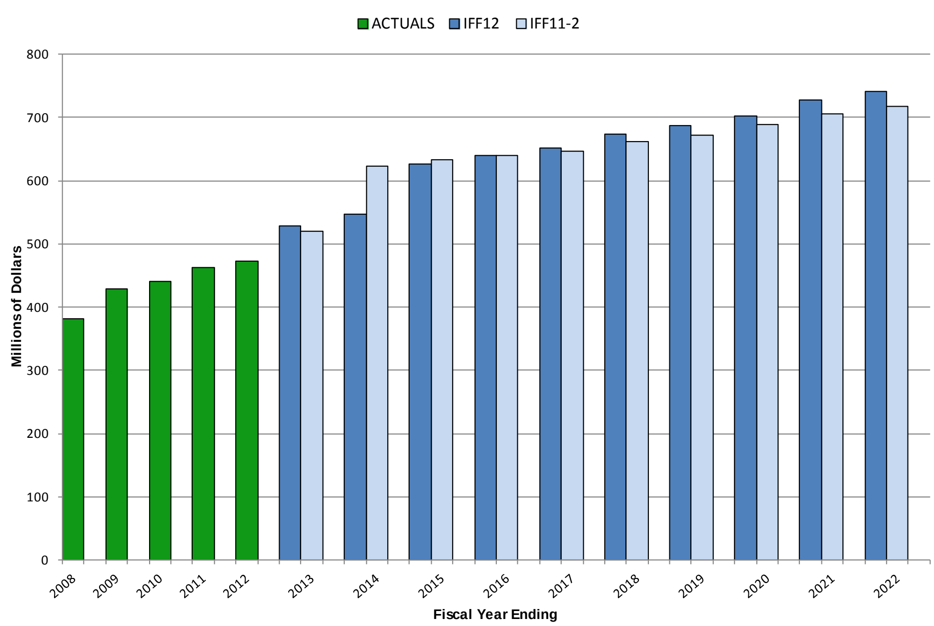
Operating, Maintenance & Administrative (OM&A) Expenses in IFF12 include only those expenditures necessary to provide for the safe and reliable operation and maintenance of the generation, transmission and gas and electric distribution systems.

Figure 2-2 below shows the OM&A expense projected in IFF12 compared to IFF11-2. Over the 10 year period to 2021/22, OM&A is projected to increase by approximately $10 million annually on average compared to IFF11-2 primarily due to accounting changes related to the reduction in the discount rate used for the valuation of pension and benefit obligations.

IFF12 also incorporates the deferral of IFRS implementation to 2014/15 as discussed in Section 2.7 which results in the reduction in OM&A that can be seen in 2013/14 compared to IFF11-2.

Beyond 2014/15, OM&A costs rise at the same level of inflation except in years where major new generation and transmission comes into service in 2017/18 (Bipole III), 2019/20 (Keeyask) and 2025/26 (Conawapa).

Figure 2-2: Operating, Maintenance and Administrative Expense



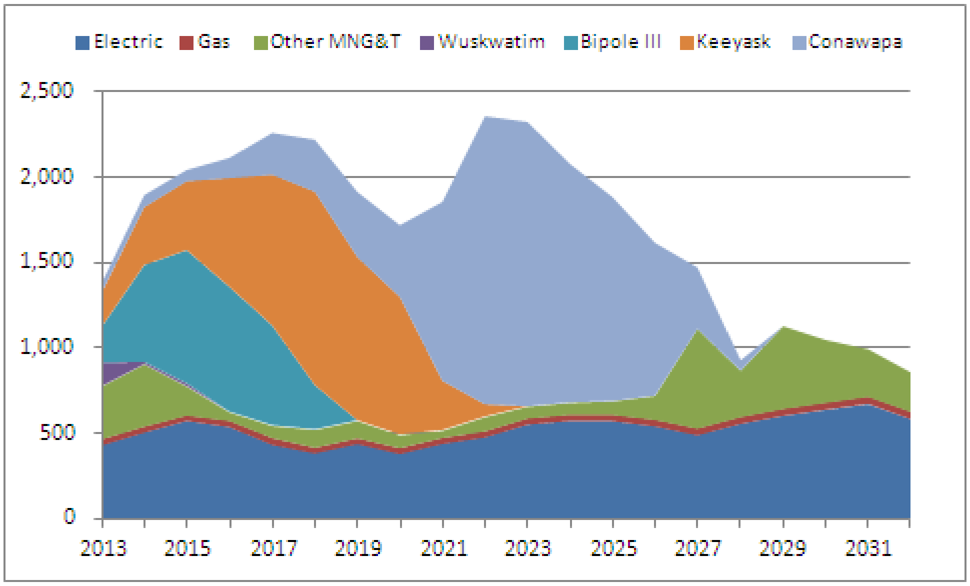
2.9 Non-Controlling Interest

IFF12 assumes that Nisichawayasihk Cree Nation (NCN) will acquire up to a 33% interest in the Wuskwatim generating station. Manitoba Hydro will construct, operate and maintain the Wuskwatim generating station and will purchase all of the output under a power purchase agreement. Manitoba Hydro's income statement reflects all of the partnership revenues and costs with NCN's share of net income shown as a deduction before net income. The partnerships' net assets are offset by an amount for NCN's non-controlling equity interest on Manitoba Hydro's balance sheet.

3.0 CAPITAL EXPENDITURE FORECAST

Capital expenditures are forecast to be $34 070 million to 2031/32. Figure 3-1 below illustrates projected capital expenditures by major category.

Figure 3-1: Capital Expenditure Forecast CEF12



Over the 20-year forecast to 2031/32, capital expenditures are $3 969 million higher compared to the previous capital expenditure forecast, CEF11-2, mainly due to cost estimate increases for the Keeyask and Conawapa projects. The following Table 3-1 provides a summary of CEF12 and the revisions from CEF11-2.

Table 3-1: Summary of Projected Capital Expenditures

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10 Year Total
CEF11-2	1,244	1,550	1,700	2,023	2,077	2,433	1,668	1,914	1,914	1,802	18,324
Incr (Decr)	135	345	341	89	181	(214)	245	(195)	(59)	554	1,422
CEF12	1,379	1,895	2,042	2,112	2,258	2,219	1,913	1,718	1,854	2,356	19,746

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	20 Year Total
CEF11-2	1,615	1,511	1,691	1,004	861	952	1,124	1,073	1,002	945	30,102
Incr (Decr)	708	566	192	611	610	(24)	3	(25)	(8)	(86)	3,969
CEF12	2,323	2,077	1,883	1,615	1,471	928	1,127	1,047	994	859	34,070

The revised Keeyask project cost increased $583 million over the previous forecast due to inclusion of a management reserve to address the risk of higher than projected skilled labour costs as well as rates of inflation higher than the projected Canadian consumer price index.

The revised Conawapa project cost increased $2 422 billion over the previous forecast. Slightly more than half of this increase can be attributed to the inclusion of a management reserve for the labour and inflation risks as described above for Keeyask. The remaining increase is due to the deferral of the Conawapa in-service date to 2025/26.

The following Table 3-2 provides a summary of the total changes to the forecast for the Keeyask and Conawapa projects as well as other major changes.

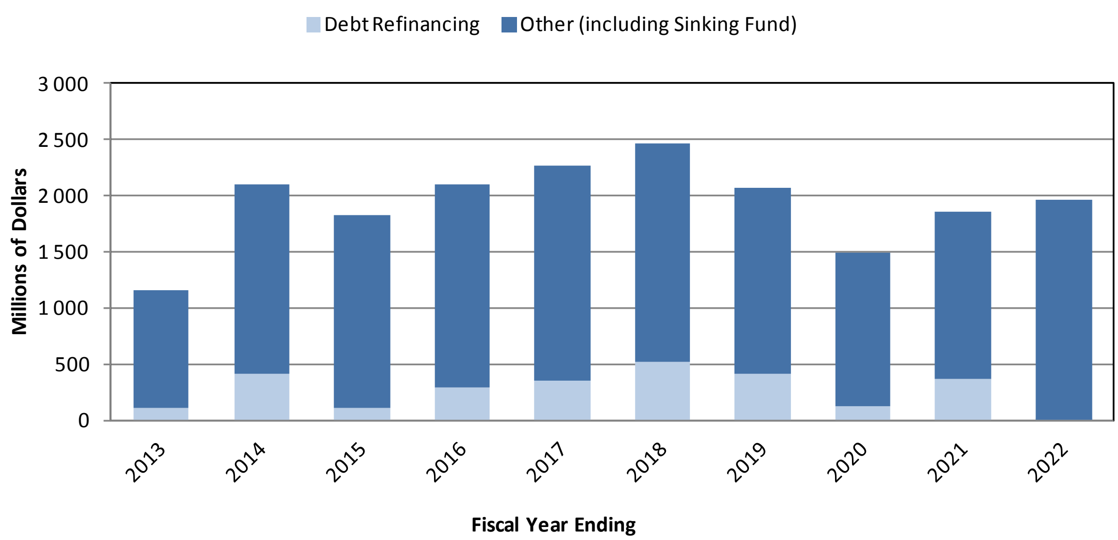
Table 3-2: Summary of CEF12 Project Increases/(Decreases)

	Total Projected Cost	**Total Project Increase / (Decrease)**
	($ Millions	
Conawapa - Generation	10,192	2,422
Keeyask - Generation	6,220	583
Gillam Redevelopment and Expansion Program	366	366
Bipole 2 Thyristor Valve Replacement	234	234
Pointe du Bois Spillway Replacement	560	161
Pointe Du Bois GS Rehabilitation	183	133
Wuskwatim - Generation	1,449	74
Letellier - St. Vital 230kV Transmission	59	59
Rockwood East 230-115kV Station	53	53
Brandon Units 6 & 7 "C" Overhaul Program	50	50
Generation Townsite Infrastructure	74	22
13.2kV Shunt Reactor Replacements	16	(17)

4.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast consolidated borrowing requirements are portrayed in Figure 4-1 below.

Figure 4-1: 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.

5.0 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 95% of customers representing approximately 69% 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 2012 Natural Gas Volume Forecast is higher than last year's forecast. The total natural gas sales volume forecast is up approximately 2% annually gradually increasing to approximately 3% annually by 2021/22. The increase in the 2012 forecast is primarily attributed to a change in the expected proportion of Small General Service Commercial to Large General Service customers. There is a greater proportion of Large General Service customers forecasted, which have a much higher average use per customer, resulting in an increase in volumes. In addition, there is an increase in the forecasted customer growth rate in the Residential customer class resulting in an increase in volumes.

6.0 FINANCIAL TARGETS

Manitoba Hydro has the following financial targets for consolidated operations:

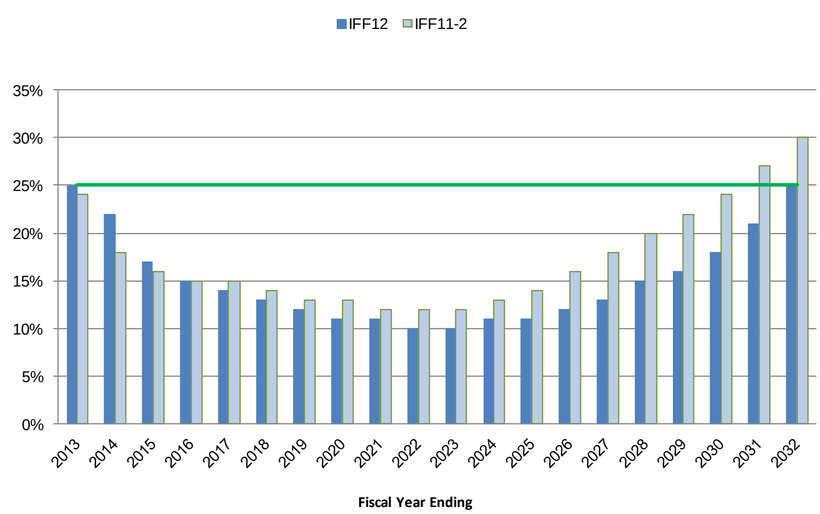
Debt/Equity Ratio	Achieve and maintain a minimum debt/equity ratio of 75:25
Interest Coverage	Maintain an annual gross interest coverage ratio of greater than 1.20
Capital Coverage	Maintain a capital coverage ratio of greater than 1.20 (excepting major new generation and transmission)

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

6.1 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 6-1 below shows the projected consolidated equity ratio for IFF12 compared to IFF11-2. Further reductions in net extraprovincial revenue relative to IFF11-2 combined with capital cost increases result in a deterioration of the equity ratio to 10% by 2021/22. Higher projected rate increases are necessary to prevent further deterioration of the debt/equity ratio. The equity ratio is projected to show improvement following the in-service of Keeyask and Conawapa generating stations and returns to the target 25% by 2031/32.

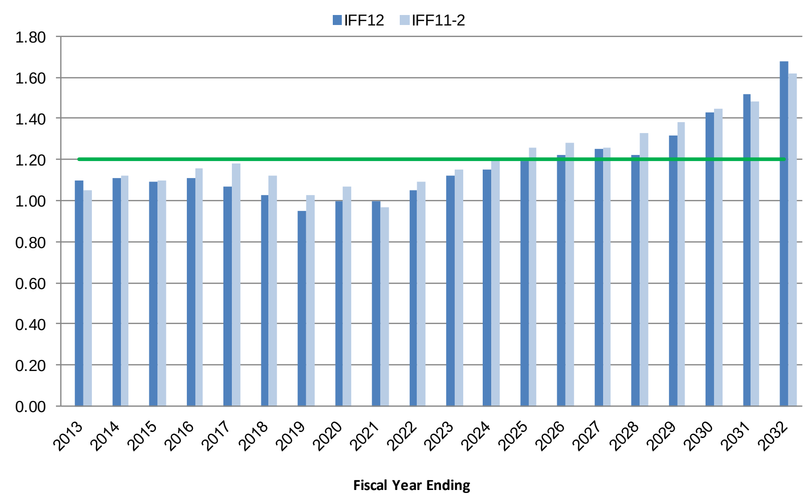
Figure 6-1: Projected Consolidated Equity Ratio



6.2 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 6-2 below shows that the reductions in net extraprovincial revenues compared to IFF11-2 results in interest coverage ratios lower than target for the first 13 years of the forecast. In the longer term, interest coverage is projected to return to the 1.20 target level following Conawapa generating station in-service in 2025/26 and grows thereafter.

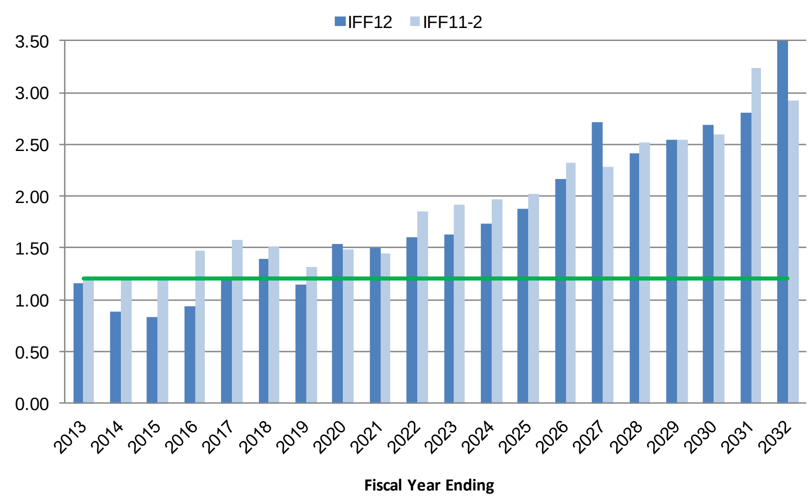
Figure 6-2: Projected Consolidated Interest Coverage Ratio



6.3 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 6-3 below shows the comparative capital coverage ratios for IFF12 and IFF11-2.

Figure 6-3: Projected Consolidated Capital Coverage Ratio



7.0 SENSITIVITY ANALYSIS

The 20-Year Financial Outlook includes a number of key assumptions as described in section 2.0. 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 flow conditions

Table 7-1 below shows the change in retained earnings in selected years over the forecast period (assuming no change to rate increases relative to IFF12).

Table 7-1: Financial Impacts of Sensitivity Analysis

	2014/15	2018/19	2021/22
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)		
High Domestic Load Growth	18	102	229
+ 1% Interest	(20)	(233)	(707)
- 1% Interest	0	136	545
US $ up 10¢	19	57	24
US $ down 10¢	(19)	(59)	(30)
Low Export Price	(8)	(160)	(420)
High Export Price	13	159	425
Capital Expenditures + $100M	(10)	(153)	(392)
5 Year Drought (starting in 2014/15)	N/A	(1,553)	N/A

7.1 Domestic Load Growth Sensitivity

The 2012 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.

Under a high load forecast (90th percentile of load forecasts), gross firm energy could increase by 2 555 GW.h or 7.6% by 2031/32. Although not specifically analyzed, the following factors (with their estimated energy effects by 2031/32) could contribute to overall variability in the load forecast:

- Climate change (+100 GW.h per degree Celsius warmer)
- Large industrial customer addition or loss (±1 500 GW.h)

- Electric vehicle 70% saturation (+1 666 GW.h)
- 10% switch to electric heat (+746 GW.h)
- 10% switch to electric water heaters (+202 GW.h)

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 impacts of higher domestic load are partially offset by the addition of a simple cycle gas turbine, a shorter lead time resource option, in 2022/23 to address energy shortfalls resulting from the higher Manitoba load.

Due to the longer lead time required for hydro resource options, there would be no change to the resource plan assumed in IFF12 under a low load forecast and would result in only minimal financial impacts due to the marginal differences in export and domestic revenues.

7.2 Interest Rates Sensitivity

Interest rates assumed in IFF12 are projected to rise gradually over the first seven years of the forecast. The interest rate sensitivity looks at 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.

7.3 Foreign Exchange Rates Sensitivity

The Canadian dollar is projected to remain at or around par with the U.S. dollar for the first few years of IFF12. Thereafter, the Canadian dollar is projected to weaken slightly to $1.04 (C$/US$). In the short to medium term of the forecast, net income is relatively neutral to changes in the exchange rate, due to the effective hedge provided by Manitoba Hydro's exposure management program.

7.4 Export Prices Sensitivity

IFF12 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.

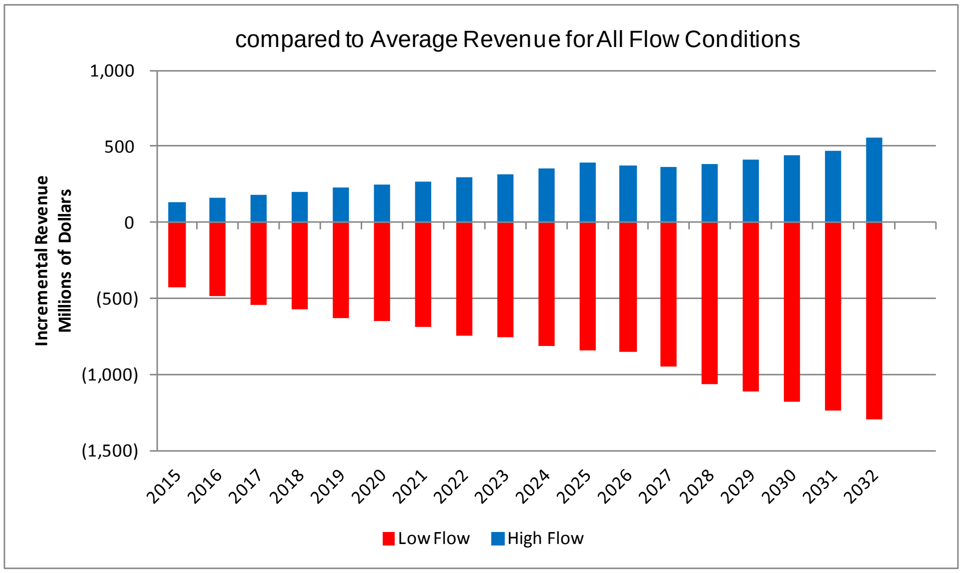
7.5 Capital Expenditures Sensitivity

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.

7.6 Drought/Water Flow Sensitivity

IFF12 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 7-1. 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 7-1: 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 2018/19. This represents the deviation in net interchange revenues and generation costs if the five-year drought begins in 2014/15 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.

7.7 Rate Increase Sensitivity

Table 7-2 on the next page shows the financial effects of various rate increase alternatives.

Table 7-2: Impacts of Rate Increase Alternatives

Fiscal Years Ending	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2032**
IFF12 - 3.95% 2014/15 to 2031/32										
Rate Increases	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Retained Earnings	2 583	2 314	2 403	2 473	2 505	2 452	2 457	2 463	2 528	7 646
Equity	22%	17%	15%	14%	13%	12%	11%	11%	10%	25%
Interest Coverage	1.11	1.09	1.11	1.07	1.03	0.95	1.00	1.00	1.05	1.68
Capital Coverage	0.89	0.83	0.94	1.22	1.39	1.15	1.54	1.50	1.60	3.65
3.0% 2014/15 to 2021/22 & 6.1% thereafter										
Rate Increases	3.50%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	6.06%
Retained Earnings	2 583	2 300	2 361	2 383	2 347	2 201	2 087	1 942	1 820	7 770
Equity	22%	17%	15%	14%	12%	11%	10%	9%	7%	25%
Interest Coverage	1.11	1.07	1.07	1.02	0.97	0.87	0.91	0.89	0.91	1.96
Capital Coverage	0.89	0.81	0.89	1.12	1.22	0.94	1.24	1.15	1.22	4.45
3.0% 2014/15 to 2021/22 & 4.45% thereafter										
Rate Increases	3.50%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	4.45%
Retained Earnings	2 583	2 300	2 361	2 383	2 347	2 201	2 087	1 942	1 820	4 577
Equity	22%	17%	15%	14%	12%	11%	10%	9%	7%	15%
Interest Coverage	1.11	1.07	1.07	1.02	0.97	0.87	0.91	0.89	0.91	1.46
Capital Coverage	0.89	0.81	0.89	1.12	1.22	0.94	1.24	1.15	1.22	3.19
4.0% 2014/15 to 2018/19 & 3.5% thereafter										
Rate Increases	3.50%	4.00%	4.00%	4.00%	4.00%	4.00%	3.50%	3.50%	3.50%	3.50%
Retained Earnings	2 583	2 315	2 406	2 478	2 514	2 465	2 467	2 462	2 503	6 324
Equity	22%	17%	15%	14%	13%	12%	11%	11%	10%	20%
Interest Coverage	1.11	1.09	1.11	1.08	1.03	0.96	1.00	1.00	1.03	1.50
Capital Coverage	0.89	0.83	0.94	1.22	1.40	1.16	1.54	1.47	1.56	3.20
4.5% 2014/15 to 2018/19 & 3.5% thereafter										
Rate Increases	3.50%	4.50%	4.50%	4.50%	4.50%	4.50%	3.50%	3.50%	3.50%	3.50%
Retained Earnings	2 583	2 322	2 429	2 528	2 601	2 603	2 661	2 718	2 829	7 813
Equity	22%	17%	15%	14%	13%	13%	12%	12%	11%	25%
Interest Coverage	1.11	1.10	1.13	1.10	1.07	1.00	1.05	1.04	1.08	1.63
Capital Coverage	0.89	0.84	0.97	1.28	1.50	1.27	1.68	1.61	1.70	3.49
IFF11-2 Rates - 3.5% to 2023/24 & 2.0% thereafter										
Rate Increases	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	2.00%
Retained Earnings	2 583	2 307	2 383	2 430	2 430	2 332	2 279	2 213	2 187	3 081
Equity	22%	17%	15%	14%	13%	11%	10%	10%	9%	10%
Interest Coverage	1.11	1.08	1.09	1.05	1.00	0.91	0.96	0.95	0.98	1.10
Capital Coverage	0.89	0.82	0.91	1.17	1.30	1.05	1.41	1.33	1.43	2.12
3.50% 2013/14 to 2031/32										
Rate Increases	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Retained Earnings	2 583	2 307	2 383	2 430	2 430	2 332	2 279	2 213	2 187	4 857
Equity	22%	17%	15%	14%	13%	11%	10%	10%	9%	16%
Interest Coverage	1.11	1.08	1.09	1.05	1.00	0.91	0.96	0.95	0.98	1.38
Capital Coverage	0.89	0.82	0.91	1.17	1.30	1.05	1.41	1.33	1.43	2.92
Rate Increases Required to Maintain a Minimum 1.00 Interest Coverage										
Rate Increases	3.50%	0.00%	2.15%	5.89%	6.76%	8.99%	0.54%	3.90%	1.19%	0.00%
Retained Earnings	2 583	2 257	2 257	2 257	2 257	2 257	2 257	2 257	2 257	2 346
Equity	22%	16%	14%	13%	12%	11%	10%	10%	9%	8%
Interest Coverage	1.11	1.01	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
Capital Coverage	0.89	0.74	0.78	1.08	1.31	1.26	1.54	1.48	1.47	1.83

Section 2

8.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF12)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF12)
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers	1 649	1 727	1 841	1 912	1 988	2 078	2 177	2 271	2 380	2 493
Extraprovincial	357	344	343	380	406	435	441	464	711	839
	2 006	2 072	2 184	2 292	2 394	2 513	2 618	2 735	3 090	3 332
Cost of Gas Sold	175	168	212	203	201	201	201	201	201	201
	1 831	1 904	1 973	2 089	2 193	2 312	2 418	2 535	2 890	3 131
Other	30	31	33	33	34	34	35	36	36	37
	1 861	1 935	2 005	2 123	2 226	2 347	2 453	2 570	2 926	3 168
EXPENSES										
Operating and Administrative	529	546	628	641	653	676	688	705	729	743
Finance Expense	489	481	532	565	628	700	812	826	1 047	1 144
Depreciation and Amortization	430	463	394	414	434	472	518	534	607	646
Water Rentals and Assessments	117	116	112	112	112	112	112	113	121	126
Fuel and Power Purchased	143	166	179	191	206	221	230	231	253	264
Capital and Other Taxes	106	115	116	126	135	145	153	160	167	176
	1 815	1 887	1 961	2 049	2 169	2 325	2 513	2 568	2 924	3 100
Non-controlling Interest	14	24	21	16	13	10	6	3	4	(3)
Net Income	60	72	66	90	70	32	(54)	5	6	65
Additional General Consumers Revenue										
General electricity rate increases	3.57%	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
General gas rate increases	0.00%	2.00%	0.00%	0.00%	0.00%	0.50%	0.75%	0.50%	0.50%	0.75%
Financial Ratios										
Equity	25%	22%	17%	15%	14%	13%	12%	11%	11%	10%
Interest Coverage	1.10	1.11	1.09	1.11	1.07	1.03	0.95	1.00	1.00	1.05
Capital Coverage	1.16	0.89	0.83	0.94	1.22	1.39	1.15	1.54	1.50	1.60

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF12)
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers	2 614	2 742	2 877	3 017	3 164	3 320	3 485	3 658	3 839	4 030
Extraprovincial	873	863	851	937	1 209	1 288	1 304	1 312	1 331	1 341
	3 488	3 605	3 728	3 954	4 373	4 608	4 789	4 970	5 170	5 371
Cost of Gas Sold	201	201	201	200	201	201	201	202	202	202
	3 287	3 404	3 528	3 754	4 173	4 407	4 588	4 768	4 968	5 168
Other	38	38	39	40	41	41	42	43	44	45
	3 324	3 443	3 567	3 793	4 213	4 448	4 630	4 811	5 012	5 213
EXPENSES										
Operating and Administrative	760	777	793	826	842	861	880	897	915	935
Finance Expense	1 134	1 135	1 126	1 243	1 491	1 674	1 642	1 599	1 605	1 536
Depreciation and Amortization	657	665	674	720	800	859	869	883	915	929
Water Rentals and Assessments	128	127	126	134	147	151	151	151	152	153
Fuel and Power Purchased	278	292	318	281	277	291	304	318	328	341
Capital and Other Taxes	185	195	202	207	212	213	217	219	224	224
	3 142	3 191	3 239	3 411	3 770	4 049	4 064	4 066	4 139	4 119
Non-controlling Interest	(5)	(10)	(13)	(9)	(11)	(14)	(16)	(20)	(22)	(25)
Net Income	177	242	315	373	432	385	550	725	850	1 069
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%	1.25%	1.00%	1.25%	1.00%	1.00%	1.00%	0.75%	1.00%	1.00%
Financial Ratios										
Equity	10%	11%	11%	12%	13%	15%	16%	18%	21%	25%
Interest Coverage	1.12	1.15	1.19	1.22	1.25	1.22	1.32	1.43	1.52	1.68
Capital Coverage	1.63	1.74	1.88	2.16	2.71	2.41	2.54	2.69	2.80	3.65

CONSOLIDATED PROJECTED BALANCE SHEET (IFF12)
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
ASSETS										
Plant in Service	15 997	17 087	17 787	18 972	19 561	23 129	23 590	26 663	30 767	31 331
Accumulated Depreciation	(5 333)	(5 710)	(6 039)	(6 419)	(6 831)	(7 286)	(7 791)	(8 310)	(8 901)	(9 534)
Net Plant in Service	10 664	11 377	11 748	12 553	12 731	15 843	15 799	18 353	21 866	21 797
Construction in Progress	2 110	2 880	4 200	5 130	6 796	5 444	6 885	5 430	3 046	4 829
Current and Other Assets	1 388	1 197	827	983	1 152	1 384	1 293	1 292	1 474	940
Goodwill and Intangible Assets	256	239	222	205	192	182	174	167	160	156
Regulated Assets	310	303	-	-	-	-	-	-	-	-
	14 728	15 997	16 997	18 871	20 871	22 852	24 151	25 241	26 547	27 722
LIABILITIES AND EQUITY										
Long-Term Debt	9 445	11 216	12 758	14 631	16 322	18 094	19 989	20 756	22 079	23 429
Current and Other Liabilities	2 132	1 560	1 712	1 667	1 941	2 138	1 609	1 942	1 935	1 718
Contributions in Aid of Construction	341	350	355	359	363	373	379	385	391	397
Retained Earnings	2 510	2 583	2 314	2 403	2 473	2 505	2 452	2 457	2 463	2 528
Accumulated Other Comprehensive Income	299	287	(142)	(189)	(228)	(259)	(278)	(298)	(321)	(349)
	14 728	15 997	16 997	18 871	20 871	22 852	24 151	25 241	26 547	27 722

CONSOLIDATED PROJECTED BALANCE SHEET (IFF12)
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	31 892	32 487	33 207	38 935	44 103	45 641	46 414	46 997	49 014	49 772
Accumulated Depreciation	(10 178)	(10 832)	(11 495)	(12 204)	(12 993)	(13 841)	(14 697)	(15 562)	(16 459)	(17 370)
Net Plant in Service	21 714	21 656	21 712	26 731	31 110	31 800	31 717	31 435	32 555	32 401
Construction in Progress	6 584	8 057	9 209	5 087	1 374	747	1 081	1 525	476	551
Current and Other Assets	998	1 698	1 802	1 638	1 819	2 355	2 813	3 138	3 224	4 371
Goodwill and Intangible Assets	153	152	151	150	149	148	147	146	145	144
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	29 449	31 562	32 875	33 606	34 452	35 051	35 758	36 244	36 400	37 467
LIABILITIES AND EQUITY										
Long-Term Debt	25 432	27 234	27 787	28 589	28 991	29 132	29 083	28 386	28 375	27 948
Current and Other Liabilities	1 275	1 337	1 774	1 324	1 329	1 395	1 594	2 045	1 354	1 771
Contributions in Aid of Construction	403	410	417	423	430	437	444	452	459	467
Retained Earnings	2 705	2 947	3 262	3 634	4 067	4 452	5 001	5 726	6 577	7 646
Accumulated Other Comprehensive Income	(365)	(365)	(365)	(365)	(365)	(365)	(365)	(365)	(365)	(365)
	29 449	31 562	32 875	33 606	34 452	35 051	35 758	36 244	36 400	37 467

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF12)
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
OPERATING ACTIVITIES										
Cash Receipts from Customers	2 093	2 173	2 290	2 395	2 498	2 618	2 725	2 844	3 200	3 444
Cash Paid to Suppliers and Employees	(1 095)	(1 181)	(1 283)	(1 315)	(1 350)	(1 395)	(1 423)	(1 448)	(1 509)	(1 548)
Interest Paid	(482)	(492)	(526)	(574)	(627)	(720)	(837)	(848)	(1 072)	(1 168)
Interest Received	28	17	24	26	31	39	41	39	35	32
	544	517	504	531	552	542	506	586	655	761
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 096	2 000	1 800	2 200	2 200	2 600	2 200	1 400	2 000	1 800
Sinking Fund Withdrawals	129	393	102	26	-	16	416	187	269	676
Retirement of Long-Term Debt	(242)	(808)	(211)	(312)	(347)	(530)	(829)	(306)	(635)	(679)
Other	(42)	(7)	(17)	(19)	(17)	(13)	(24)	(13)	(34)	(9)
	941	1 578	1 675	1 896	1 837	2 073	1 763	1 268	1 600	1 787
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 420)	(1 962)	(2 061)	(2 121)	(2 254)	(2 207)	(1 896)	(1 699)	(1 833)	(2 333)
Sinking Fund Payment	(107)	(208)	(124)	(188)	(166)	(227)	(219)	(224)	(248)	(343)
Other	(21)	(20)	(21)	(20)	(32)	(43)	(29)	(29)	(33)	(38)
	(1 548)	(2 190)	(2 207)	(2 328)	(2 452)	(2 476)	(2 144)	(1 952)	(2 113)	(2 714)
Net Increase (Decrease) in Cash	(64)	(95)	(28)	99	(63)	139	125	(98)	141	(166)
Cash at Beginning of Year	50	(14)	(109)	(137)	(38)	(101)	37	162	64	205
Cash at End of Year	(14)	(109)	(137)	(38)	(101)	37	162	64	205	39

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF12)
(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	3 601	3 721	3 846	4 073	4 495	4 731	4 914	5 097	5 300	5 502
Cash Paid to Suppliers and Employees	(1 587)	(1 626)	(1 672)	(1 679)	(1 706)	(1 742)	(1 777)	(1 807)	(1 840)	(1 872)
Interest Paid	(1 140)	(1 126)	(1 135)	(1 267)	(1 518)	(1 718)	(1 698)	(1 671)	(1 692)	(1 599)
Interest Received	18	19	29	34	42	57	73	81	92	73
	892	988	1 068	1 162	1 313	1 328	1 513	1 700	1 860	2 104
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 000	1 800	1 000	800	400	200	200	-	-	-
Sinking Fund Withdrawals	156	-	-	450	-	-	60	250	700	13
Retirement of Long-Term Debt	(452)	-	-	(450)	-	-	(60)	(250)	(700)	(13)
Other	(1)	(0)	(1)	(1)	(0)	0	2	2	3	(16)
	1 703	1 800	999	799	400	200	202	2	3	(16)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 303)	(2 053)	(1 858)	(1 590)	(1 440)	(897)	(1 094)	(1 017)	(959)	(823)
Sinking Fund Payment	(249)	(269)	(295)	(317)	(316)	(334)	(348)	(359)	(361)	(341)
Other	(29)	(32)	(25)	(25)	(28)	(26)	(26)	(26)	(26)	(26)
	(2 581)	(2 355)	(2 178)	(1 933)	(1 784)	(1 256)	(1 468)	(1 403)	(1 346)	(1 190)
Net Increase (Decrease) in Cash	14	433	(111)	27	(72)	273	246	299	516	898
Cash at Beginning of Year	39	53	486	375	402	331	603	850	1 149	1 665
Cash at End of Year	53	486	375	402	331	603	850	1 149	1 665	2 563

9.0 CAPITAL EXPENDITURE FORECAST (CEF12)

CAPITAL EXPENDITURE FORECAST (CEF12)

(in millions of dollars)

	Total Project Cost	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ELECTRIC											
Major New Generation & Transmission											
Wuskwatim - Generation	1 448.6	123.9	12.3	16.2	-	-	-	-	-	-	-
Wuskwatim - Transmission	322.9	13.4	-	-	-	-	-	-	-	-	-
Herblet Lake – The Pas 230 kV Transmission	76.6	0.6	-	-	-	-	-	-	-	-	-
Keeyask - Generation	6 220.1	201.8	339.0	405.1	636.5	883.9	1 132.1	955.4	804.1	288.2	71.9
Conawapa - Generation	10 192.4	56.0	72.0	66.3	118.9	245.3	305.1	381.4	420.5	1 046.8	1 685.4
Kelsey Improvements & Upgrades	301.7	28.5	8.9	9.5	-	-	-	-	-	-	-
Kettle Improvements & Upgrades	165.7	2.4	4.0	19.4	16.0	19.8	16.4	7.7	7.9	8.0	8.2
Pointe du Bois Spillway Replacement	559.6	150.0	248.5	81.0	2.3	-	-	-	-	-	-
Pointe du Bois - Transmission	85.9	10.2	14.2	20.0	0.0	-	-	-	-	-	-
Pointe du Bois Powerhouse Rebuild	1 538.3	-	-	-	-	-	-	-	-	-	0.5
Gillam Redevelopment and Expansion Program	366.5	-	-	27.0	30.2	30.5	29.5	27.9	26.3	29.1	28.7
Bipole III - Transmission Line	1 259.9	46.6	251.3	325.4	320.5	176.2	77.9	-	-	-	-
Bipole III - Converter Stations	1 828.5	143.0	231.1	408.9	379.2	394.3	177.3	-	-	-	-
Bipole III - Collector Lines	191.4	18.3	84.0	43.6	30.0	11.1	2.0	-	-	-	-
Riel 230/ 500 kV Station	267.6	84.5	47.3	3.5	2.0	-	-	-	-	-	-
Firm Import Upgrades	19.9	-	11.7	8.2	-	-	-	-	-	-	-
Dorsey - US Border New 500 kV Transmission Line	204.8	0.3	0.4	2.0	3.7	25.2	61.8	64.7	41.0	4.7	0.1
St. Joseph Wind Transmission	11.2	1.3	-	-	-	-	-	-	-	-	-
Demand Side Management	NA	28.5	28.0	-	-	-	-	-	-	-	-
Generating Station Improvements & Upgrades	649.0	-	-	-	-	-	-	-	-	-	45.0
Additional North South Transmission	395.6	-	-	-	-	-	-	-	-	-	-
G911 Fall Update MNG&T Capitalized Interest Revision	NA	0.0	(1.2)	(1.6)	(3.8)	(5.3)	(4.9)	(0.3)	(0.4)	(0.1)	(0.1)
		909.3	1 351.6	1 434.6	1 535.3	1 781.0	1 797.2	1 436.8	1 299.4	1 376.6	1 839.7

CAPITAL EXPENDITURE FORECAST (CEF12)

(in millions of dollars)

	Total Project Cost	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Power Supply											
HVDC Auxiliary Power Supply Upgrades	5.3	0.3	0.4	-	-	-	-	-	-	-	-
Dorsey Synchronous Condenser Refurbishment	73.3	4.0	5.8	8.7	11.0	7.6	5.4	4.8	-	-	-
HVDC System Transformer & Reactor Fire Protection & Prevention	10.3	0.2	0.3	0.0	-	-	-	-	-	-	-
HVDC Transformer Replacement Program	171.2	9.5	10.1	23.3	16.9	13.8	-	-	-	-	-
HVDC Transformer Replacement Program Extended	449.7	-	-	-	-	-	-	-	-	-	0.5
Dorsey 230 kV Relay Building Upgrade	80.9	0.4	0.0	2.1	2.5	0.4	16.5	33.1	9.6	3.8	-
HVDC Stations Ground Grid Refurbishment	4.1	0.4	0.4	0.3	0.5	0.3	-	-	-	-	-
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	13.9	0.7	0.6	0.3	0.2	0.1	0.0	0.1	-	-	-
HVDC Bipole 1 Pole Differential Protection	3.3	-	0.4	0.9	2.1	-	-	-	-	-	-
HVDC Bipole 1 By-Pass Vacuum Switch Removal	19.2	0.2	4.5	8.7	5.0	-	-	-	-	-	-
HVDC Bipole 2 Refrigerant Condenser Replacement	12.9	-	0.3	3.0	2.6	7.1	-	-	-	-	-
HVDC Smoothing Reactor Replacements	46.2	4.5	4.0	-	-	-	-	-	-	-	-
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Separation	3.0	0.2	1.2	1.5	-	-	-	-	-	-	-
HVDC Bipole 1 DCCT Transductor Replacement	11.4	0.1	1.2	1.0	2.8	3.5	2.7	-	-	-	-
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Replacements	8.7	0.0	0.8	2.0	4.8	1.1	-	-	-	-	-
HVDC Bipole 2 Valve Wall Bushing Replacements	19.1	0.1	-	3.3	4.8	3.9	4.1	2.3	-	-	-
HVDC Bipole 2 Upgrades & Replacements	210.5	-	-	-	-	-	-	-	-	-	12.3
HVDC Bipole 1 CQ Disconnect Replacement	4.9	0.5	1.3	1.6	0.9	0.5	-	-	-	-	-
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	7.8	1.1	0.4	0.4	0.3	0.3	0.1	-	-	-	-
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.6	0.8	1.0	1.0	2.2	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	-	2.1	13.3	23.1	57.4	58.3
HVDC Gapped Arrestor Replacement	15.9	0.4	3.6	3.2	6.7	1.3	-	-	-	-	-
Winnipeg River Riverbank Protection Program	19.7	1.3	1.2	1.3	1.2	1.0	-	-	-	-	-
Power Supply Hydraulic Controls	26.8	0.6	3.0	3.4	1.9	-	1.6	2.2	0.9	-	-
Slave Falls GS Creek Spillway Rehab	10.7	1.0	1.7	8.0	-	-	-	-	-	-	-
Slave Falls Rehabilitation	229.9	0.7	0.3	9.0	9.2	9.5	9.9	10.6	10.3	26.6	25.7
Great Falls Unit 4 Major Overhaul	43.2	7.2	19.9	0.2	-	-	-	-	-	-	-
Great Falls Unit 5 Discharge Ring Replacement and Major Overhaul	24.8	-	-	-	2.3	17.8	3.5	1.2	-	-	-
Generation South Overhauls & Improvements	384.8	-	-	-	-	-	-	-	-	-	4.7
Pine Falls Rehabilitation	158.5	5.3	7.1	9.2	27.8	27.6	24.9	28.8	7.9	2.2	-
Generation South Transformer Refurbish & Spares	25.9	0.1	2.3	10.4	9.3	2.5	-	-	-	-	-
Water Licenses & Renewals	53.5	6.5	8.2	5.6	5.9	6.2	1.6	-	-	-	-
Generation South PCB Regulation Compliance	4.5	0.7	0.2	0.2	2.7	-	-	-	-	-	-
Kettle Transformer Overhaul Program	45.2	10.3	10.0	4.0	0.0	-	-	-	-	-	-
Generation South Breaker Replacements	10.7	3.8	0.9	0.7	0.1	0.8	-	-	-	-	-
Seven Sisters Upgrades	14.1	0.7	1.1	-	-	-	-	-	-	-	-
Generation South Excitation Upgrades	16.3	1.3	0.6	1.8	3.8	1.5	0.6	5.1	-	-	-
Generation South Excitation Program Extended	14.0	-	-	-	-	-	-	-	-	-	4.4
Laurie River/Churchill River Diversion (CRD) Comm and Annunciation Upgrad	6.7	3.1	1.0	-	-	-	-	-	-	-	-
Notigi Marine Vessel Replacement and Infrastructure Improvements	4.6	1.3	2.9	-	-	-	-	-	-	-	-
Limestone Stilling Basin Rehabilitation	1.9	0.2	1.7	-	-	-	-	-	-	-	-
Pointe Du Bois GS Rehabilitation	182.9	7.1	7.1	9.0	18.8	23.0	21.3	18.8	24.6	23.1	10.6
Kettle Wicket Gates Lever Refurbishments	2.2	0.4	0.9	0.8	-	-	-	-	-	-	-
Limestone Governor Control Repl	2.3	0.1	0.4	1.6	0.3	-	-	-	-	-	-
Limestone GSCADA Replacement	4.7	0.3	1.1	0.7	0.8	0.3	1.6	-	-	-	-
Jenpeg Unit Overhauls	128.1	(0.0)	-	-	2.3	2.5	18.2	24.0	24.5	24.9	19.5
Power Supply Dam Safety Upgrades	64.5	3.6	5.0	10.4	-	-	-	-	-	-	-
Brandon Unit 5 License Review	10.3	0.2	0.2	1.7	1.9	1.0	-	-	-	-	-
Selkirk Enhancements	14.2	0.5	0.4	-	-	-	-	-	-	-	-
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	5.9	0.4	23.3	2.0	18.9	-
Fire Protection Projects - HVDC	6.9	0.3	1.2	2.6	-	-	-	-	-	-	-
Halon Replacement Project	36.0	2.3	2.6	2.3	2.8	1.7	2.8	-	-	-	-
Grand Rapids Townsite House Renovations	12.2	0.9	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0
Grand Rapids Fish Hatchery	2.2	1.7	-	-	-	-	-	-	-	-	-
Generation Townsite Infrastructure	74.1	11.5	16.2	-	-	-	-	-	-	-	-
Site Remediation of Contaminated Corporate Facilities	33.4	1.1	1.1	-	-	-	-	-	-	-	-
High Voltage Test Facility	40.6	2.3	-	-	-	-	-	-	-	-	-
Power Supply Security Installations / Upgrades	42.9	5.4	8.6	8.8	2.0	-	-	-	-	-	-
Power Supply Sewer & Domestic Water System Install and Upgrade	45.2	4.8	6.1	3.7	2.1	2.2	2.5	-	-	-	-
Power Supply Domestic	NA	20.1	20.5	21.0	21.4	21.8	22.2	22.7	23.1	23.6	24.1
Target Adjustment	NA	7.5	(20.5)	-	-	-	-	-	-	-	-
		137.6	150.4	178.4	180.5	166.1	143.0	191.1	127.0	181.3	161.0

CAPITAL EXPENDITURE FORECAST (CEF12)

(in millions of dollars)

	Total Project Cost	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Transmission											
Winnipeg - Brandon Transmission System Improvements	43.1	0.9	2.0	27.7	5.3	-	-	-	-	-	-
Transcona East 230 - 66 kV Station	37.6	13.4	0.1	-	-	-	-	-	-	-	-
Brandon Area Transmission Improvements	11.5	6.4	2.7	-	-	-	-	-	-	-	-
V38R 230kV Transmission Line ROW in RMNP	2.6	0.5	0.6	1.0	0.4	-	-	-	-	-	-
Neepawa 230 - 66 kV Station	29.1	8.0	11.0	1.2	0.0	-	-	-	-	-	-
Transmission Line Re-Rating	31.7	6.9	-	-	-	-	-	-	-	-	-
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	0.8	0.9	2.5	6.0	9.4	12.7	-
Transcona Station 66 kV Breaker Replacement	5.6	-	-	0.8	2.5	2.3	-	-	-	-	-
13.2kV Shunt Reactor Replacements	15.9	2.1	2.0	1.9	2.1	2.1	2.2	1.3	-	-	-
Rockwood East 230-115kV Station	53.3	2.4	15.1	27.1	7.9	-	-	-	-	-	-
Lake Winnipeg East System Improvements	64.6	2.6	22.4	23.8	13.0	2.3	-	-	-	-	-
Canexus Load Addition	(0.3)	(1.3)	-	-	-	-	-	-	-	-	-
Letellier - St. Vital 230kV Transmission	59.0	0.5	2.2	7.6	30.8	17.9	0.0	-	-	-	-
Breaker Failure Protection Implementation	4.4	0.8	1.6	1.4	0.6	-	-	-	-	-	-
D602F 500kV T/L Footing Replacements	4.4	1.8	-	-	-	-	-	-	-	-	-
Stanley Station 230-66 kV Transformer Addition	19.4	-	0.6	5.2	9.3	4.5	-	-	-	-	-
Enbridge Pipelines: Clipper Project Load Addition Phase 2	7.4	1.8	-	-	-	-	-	-	-	-	-
Ashern Station Bank Addition	10.0	0.2	0.5	6.7	2.5	-	-	-	-	-	-
Ashern Station 230 kV Shunt Reactor Replacement	1.2	0.3	-	-	-	-	-	-	-	-	-
Tadoule Lake DGS Diesel Tank Farm Upgrade	0.9	0.5	0.0	0.0	-	-	-	-	-	-	-
Energy Management System (EMS) Upgrade	6.5	1.2	-	-	-	-	-	-	-	-	-
Transmission Line Protection & Teleprotection Replacement	20.5	5.1	6.2	1.4	2.1	-	-	-	-	-	-
Mobile Radio System Modernization	30.6	1.5	13.0	6.3	9.2	-	-	-	-	-	-
Site Remediation of Diesel Generating Stations	13.3	1.8	-	-	-	-	-	-	-	-	-
Oil Containment - Transmission	7.4	0.1	-	-	-	-	-	-	-	-	-
Station Battery Bank Capacity & System Reliability Increase	46.4	4.2	4.1	4.3	4.4	3.7	-	-	-	-	-
Waverley Service Centre Oil Tank Farm Replacement	2.9	0.4	0.1	-	-	-	-	-	-	-	-
115 kV Transmission Lines	298.9	-	-	-	-	-	-	-	-	-	10.3
230 kV Transmission Lines	171.1	-	-	-	-	-	-	-	-	-	5.9
Sub-Transmission	124.8	-	-	-	-	-	-	-	-	-	4.3
Communications	425.8	-	-	-	-	-	-	-	-	-	14.7
Transmission Domestic	NA	31.2	31.8	32.5	33.1	33.8	34.5	35.1	35.9	36.6	37.3
Target Adjustment	NA	(14.6)	(9.4)	-	-	-	-	-	-	-	-
		78.7	106.5	149.0	124.0	67.5	39.1	42.4	45.3	49.2	72.4
Customer Service & Distribution											
Winnipeg Distribution Infrastructure Requirements	24.5	1.5	1.8	2.4	-	-	-	-	-	-	-
Rover Substation Replace 4 kV Switchgear	12.7	0.0	0.0	0.0	6.9	0.6	-	-	-	-	-
Martin New Outdoor Station	27.3	1.0	10.8	9.9	-	-	-	-	-	-	-
Burrows New 66 kV/ 12 kV Station	42.6	15.2	4.2	2.2	-	-	-	-	-	-	-
Winnipeg Central 12&4kV Manhole Oil Switches	9.8	0.5	-	-	-	-	-	-	-	-	-
William New 66 kV/ 12 kV Station	10.3	0.1	2.7	4.2	3.0	-	-	-	-	-	-
Waverley West Sub Division Supply - Stage 1	6.5	0.1	-	-	-	-	-	-	-	-	-
St. James New Station & 24 kV Conversion	65.9	0.4	18.4	20.8	22.3	0.4	-	-	-	-	-
Distribution	887.5	-	-	-	-	-	-	-	-	-	30.5
Health Sciences Centre Service Consolidation & Distribution Upgrade	13.9	-	9.4	3.3	-	-	-	-	-	-	-
Waverley South DSC Installation	3.9	1.3	-	-	-	-	-	-	-	-	-
Southdale DK732 Cable Replacement	2.6	1.1	-	-	-	-	-	-	-	-	-
Royal canadian Mint Expansion	2.3	1.2	-	-	-	-	-	-	-	-	-
IKEA/Seasons of Tuxedo DSC Installation	4.6	3.3	1.2	-	-	-	-	-	-	-	-
Line 27 66 kV Extension and Arborg North Distribution Supply Centre	6.0	1.0	2.5	-	-	-	-	-	-	-	-
Melrose DSC	3.5	1.6	-	-	-	-	-	-	-	-	-
Starbuck DSC	3.0	1.5	-	-	-	-	-	-	-	-	-
Blumenort Distribution Supply Centre	3.0	2.8	-	-	-	-	-	-	-	-	-
Teulon East 66-12 kV Station	4.6	1.2	-	-	-	-	-	-	-	-	-
Kleefeld Distribution Supply Centre	2.8	0.2	2.6	-	-	-	-	-	-	-	-
Cromer North Station & Reston RE12-4 25kV Conversion	4.2	0.3	-	-	-	-	-	-	-	-	-
Brandon Crocus Plains 115-25 kV Bank Addition	5.8	0.0	0.0	5.7	-	-	-	-	-	-	-
Brandon Highland Park Station Capacity Increase	3.2	1.5	1.7	-	-	-	-	-	-	-	-
Birtle South - Rossburn 66kV Line	4.9	0.0	0.0	1.0	3.9	-	-	-	-	-	-
TCPL Keystone Project	8.0	1.8	2.3	-	-	-	-	-	-	-	-
Line 98 Rebuild melita to Waskada	3.8	0.0	-	-	-	-	-	-	-	-	-
Waskada North-Line 98 2X8MVAR Cap Bank	3.9	3.0	0.9	-	-	-	-	-	-	-	-
Steinbach Area 66kV Capacity Upgrade	6.3	3.0	1.5	-	-	-	-	-	-	-	-
Enbridge Pipelines Clipper-66kV Supply I	0.9	1.9	-	-	-	-	-	-	-	-	-
Waverley West 66 kV Supply Upgrade	3.2	0.3	2.9	-	-	-	-	-	-	-	-
Winpac 7 MVA Expansion	9.4	3.1	3.0	-	-	-	-	-	-	-	-
Bissett L48-DSC & Cap Bank Installation	3.9	2.8	-	-	-	-	-	-	-	-	-
Customer Service & Distribution Domestic	NA	130.5	133.2	136.3	139.0	141.8	144.7	147.5	150.5	153.5	156.6
Target Adjustment	NA	(15.6)	-	-	-	-	-	-	-	-	-
		166.8	199.0	185.8	175.1	142.8	144.7	147.5	150.5	153.5	187.1

CAPITAL EXPENDITURE FORECAST (CEF12)

(in millions of dollars)

	Total Project Cost	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Customer Care & Marketing											
Advanced Metering Infrastructure	30.9	-	-	4.0	5.4	5.5	5.6	4.4	3.9	-	-
Customer Care & Marketing Domestic	NA	3.0	3.1	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-
		3.0	3.1	7.9	9.3	9.4	9.7	8.5	8.2	4.3	4.4
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
1840 Chevrier Apparatus Maintenance Shop Ancilliary Processing Facility	4.0	-	1.3	1.8	0.9	-	-	-	-	-	-
EAM Phase 2	18.6	5.0	5.1	2.6	-	-	-	-	-	-	-
Workforce Management (Phase 1 to 4)	17.7	1.4	-	-	-	-	-	-	-	-	-
Fleet	NA	13.0	14.3	14.6	14.9	15.2	15.5	15.8	16.2	16.5	16.8
Finance & Administration Domestic	NA	22.0	25.9	26.5	27.0	27.5	28.1	28.7	29.2	29.8	30.4
Target Adjustment	NA	(1.9)	(6.5)	-	-	-	-	-	-	-	-
		47.5	48.3	53.5	50.8	50.8	51.6	52.5	53.4	54.3	55.2
ELECTRIC CAPITAL SUBTOTAL		**1,342.9**	**1,858.8**	**2,009.2**	**2,075.0**	**2,217.6**	**2,185.3**	**1,878.8**	**1,683.7**	**1,819.3**	**2,319.9**
GAS											
Customer Service & Distribution											
Ile Des Chenes NG Transmission Network Upgrade	1.2	1.1	-	-	-	-	-	-	-	-	-
Gas SCADA Replacement	4.6	2.6	-	-	-	-	-	-	-	-	-
Customer Service & Distribution Domestic	NA	22.1	26.2	26.7	27.3	27.8	28.4	28.9	29.5	30.1	30.7
Target Adjustment	NA	(3.8)	(3.7)	-	-	-	-	-	-	-	-
		22.1	22.5	26.7	27.3	27.8	28.4	28.9	29.5	30.1	30.7
Customer Care & Marketing											
Advanced Metering Infrastructure	15.0	-	-	1.0	5.4	8.3	-	-	-	-	-
Demand Side Management	NA	9.3	8.8	-	-	-	-	-	-	-	-
Customer Care & Marketing Domestic	NA	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.7	5.8
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-
		14.2	13.7	6.0	10.6	13.5	5.3	5.4	5.5	5.7	5.8
GAS CAPITAL SUBTOTAL		**36.3**	**36.2**	**32.8**	**37.8**	**41.3**	**33.7**	**34.4**	**35.1**	**35.8**	**36.5**
CONSOLIDATED CAPITAL		**1,379.1**	**1,895.0**	**2,041.9**	**2,112.8**	**2,258.9**	**2,219.0**	**1,913.2**	**1,718.8**	**1,855.1**	**2,356.4**
G911 Fall Update Base Capitalized Interest Revision	NA	-	(0.3)	(0.4)	(0.6)	(0.4)	(0.4)	(0.5)	(0.5)	(0.6)	(0.6)
CEF12 TOTAL		**1,379.1**	**1,894.7**	**2,041.5**	**2,112.2**	**2,258.5**	**2,218.6**	**1,912.7**	**1,718.3**	**1,854.4**	**2,355.8**

CAPITAL EXPENDITURE FORECAST (CEF12)

(in millions of dollars)

	Total Project Cost	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	20 Year Total
ELECTRIC												
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	152.4
Wuskwatim - Transmission	322.9	-	-	-	-	-	-	-	-	-	-	13.4
Herblet Lake – The Pas 230 kV Transmission	76.6	-	-	-	-	-	-	-	-	-	-	0.6
Keeyask - Generation	6 220.1	-	-	-	-	-	-	-	-	-	-	5 718.0
Conawapa - Generation	10 192.4	1 663.6	1 395.3	1 192.1	893.9	359.5	60.4	-	-	-	-	9 962.5
Kelsey Improvements & Upgrades	301.7	-	-	-	-	-	-	-	-	-	-	46.9
Kettle Improvements & Upgrades	165.7	7.7	-	-	-	-	-	-	-	-	-	117.5
Pointe du Bois Spillway Replacement	559.6	-	-	-	-	-	-	-	-	-	-	481.8
Pointe du Bois - Transmission	85.9	-	-	-	-	-	-	-	-	-	-	44.5
Pointe du Bois Powerhouse Rebuild	1 538.3	2.2	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	366.5	26.8	32.3	32.1	34.0	11.9	-	-	-	-	-	366.5
Bipole III - Transmission Line	1 259.9	-	-	-	-	-	-	-	-	-	-	1 197.9
Bipole III - Converter Stations	1 828.5	-	-	-	-	-	-	-	-	-	-	1 733.6
Bipole III - Collector Lines	191.4	-	-	-	-	-	-	-	-	-	-	189.0
Riel 230/ 500 kV Station	267.6	-	-	-	-	-	-	-	-	-	-	137.3
Firm Import Upgrades	19.9	-	-	-	-	-	-	-	-	-	-	19.9
Dorsey - US Border New 500 kV Transmission Line	204.8	-	-	-	-	-	-	-	-	-	-	203.7
St. Joseph Wind Transmission	11.2	-	-	-	-	-	-	-	-	-	-	1.3
Demand Side Management	NA	-	-	-	-	-	-	-	-	-	-	56.6
Generating Station Improvements & Upgrades	649.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	56.6	62.7	174.5	536.3
Additional North South Transmission	395.6	-	-	-	-	395.6	-	-	-	-	-	395.6
G911 Fall Update MNG&T Capitalized Interest Revision	NA	(0.1)	(0.1)	(0.2)	(0.3)	(0.7)	(1.2)	(2.2)	(3.1)	(0.8)	(0.3)	(26.7)
		1 732.5	1 464.6	1 271.3	1 032.6	939.3	329.9	481.1	366.2	278.1	229.8	22 887.0

CAPITAL EXPENDITURE FORECAST (CEF12)

(in millions of dollars)

	Total Project Cost	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	20 Year Total
Power Supply												
HVDC Auxiliary Power Supply Upgrades	5.3	-	-	-	-	-	-	-	-	-	-	0.7
Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	47.3
HVDC System Transformer & Reactor Fire Protection & Prevention	10.3	-	-	-	-	-	-	-	-	-	-	0.6
HVDC Transformer Replacement Program	171.2	-	-	-	-	-	-	-	-	-	-	73.5
HVDC Transformer Replacement Program Extended	449.7	4.6	6.4	32.9	6.7	7.0	50.3	22.5	77.8	88.1	39.3	336.2
Dorsey 230 kV Relay Building Upgrade	80.9	-	-	-	-	-	-	-	-	-	-	68.3
HVDC Stations Ground Grid Refurbishment	4.1	-	-	-	-	-	-	-	-	-	-	1.9
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	13.9	-	-	-	-	-	-	-	-	-	-	2.0
HVDC Bipole 1 Pole Differential Protection	3.3	-	-	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	19.2	-	-	-	-	-	-	-	-	-	-	18.5
HVDC Bipole 2 Refrigerant Condenser Replacement	12.9	-	-	-	-	-	-	-	-	-	-	12.9
HVDC Smoothing Reactor Replacements	46.2	-	-	-	-	-	-	-	-	-	-	8.5
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Separation	3.0	-	-	-	-	-	-	-	-	-	-	2.9
HVDC Bipole 1 DCCT Transductor Replacement	11.4	-	-	-	-	-	-	-	-	-	-	11.3
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Replacements	8.7	-	-	-	-	-	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	19.1	-	-	-	-	-	-	-	-	-	-	18.6
HVDC Bipole 2 Upgrades & Replacements	210.5	52.7	57.4	64.1	24.1	-	-	-	-	-	-	210.5
HVDC Bipole 1 CQ Disconnect Replacement	4.9	-	-	-	-	-	-	-	-	-	-	4.9
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	7.8	-	-	-	-	-	-	-	-	-	-	2.5
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.6	-	-	-	-	-	-	-	-	-	-	5.0
Bipole 2 Thyristor Valve Replacement	233.7	59.3	20.2	-	-	-	-	-	-	-	-	233.7
HVDC Gapped Arrestor Replacement	15.9	-	-	-	-	-	-	-	-	-	-	15.2
Winnipeg River Riverbank Protection Program	19.7	-	-	-	-	-	-	-	-	-	-	6.1
Power Supply Hydraulic Controls	26.8	-	-	-	-	-	-	-	-	-	-	13.6
Slave Falls GS Creek Spillway Rehab	10.7	-	-	-	-	-	-	-	-	-	-	10.7
Slave Falls Rehabilitation	229.9	26.5	26.9	13.1	-	-	-	-	-	-	-	178.3
Great Falls Unit 4 Major Overhaul	43.2	-	-	-	-	-	-	-	-	-	-	27.4
Great Falls Unit 5 Discharge Ring Replacement and Major Overhaul	24.8	-	-	-	-	-	-	-	-	-	-	24.8
Generation South Overhauls & Improvements	384.8	10.2	40.3	29.4	48.6	28.5	33.3	82.8	53.3	53.7	-	384.8
Pine Falls Rehabilitation	158.5	-	-	-	-	-	-	-	-	-	-	140.9
Generation South Transformer Refurbish & Spares	25.9	-	-	-	-	-	-	-	-	-	-	24.7
Water Licenses & Renewals	53.5	-	-	-	-	-	-	-	-	-	-	33.9
Generation South PCB Regulation Compliance	4.5	-	-	-	-	-	-	-	-	-	-	3.7
Kettle Transformer Overhaul Program	45.2	-	-	-	-	-	-	-	-	-	-	24.3
Generation South Breaker Replacements	10.7	-	-	-	-	-	-	-	-	-	-	6.3
Seven Sisters Upgrades	14.1	-	-	-	-	-	-	-	-	-	-	1.8
Generation South Excitation Upgrades	16.3	-	-	-	-	-	-	-	-	-	-	14.7
Generation South Excitation Program Extended	14.0	5.0	3.4	1.2	-	-	-	-	-	-	-	14.0
Laurie River/Churchill River Diversion (CRD) Comm and Annunciation Upgrad	6.7	-	-	-	-	-	-	-	-	-	-	4.1
Notigi Marine Vessel Replacement and Infrastructure Improvements	4.6	-	-	-	-	-	-	-	-	-	-	4.2
Limestone Stilling Basin Rehabilitation	1.9	-	-	-	-	-	-	-	-	-	-	1.9
Pointe Du Bois GS Rehabilitation	182.9	8.6	6.1	4.4	-	-	-	-	-	-	-	182.5
Kettle Wicket Gates Lever Refurbishments	2.2	-	-	-	-	-	-	-	-	-	-	2.1
Limestone Governor Control Repl	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Limestone GSCADA Replacement	4.7	-	-	-	-	-	-	-	-	-	-	4.7
Jenpeg Unit Overhauls	128.1	-	-	-	-	-	-	-	-	-	-	115.9
Power Supply Dam Safety Upgrades	64.5	-	-	-	-	-	-	-	-	-	-	19.1
Brandon Unit 5 License Review	10.3	-	-	-	-	-	-	-	-	-	-	5.0
Selkirk Enhancements	14.2	-	-	-	-	-	-	-	-	-	-	0.9
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	-	-	-	-	50.4
Fire Protection Projects - HVDC	6.9	-	-	-	-	-	-	-	-	-	-	4.1
Halon Replacement Project	36.0	-	-	-	-	-	-	-	-	-	-	14.5
Grand Rapids Townsite House Renovations	12.2	1.0	-	-	-	-	-	-	-	-	-	9.8
Grand Rapids Fish Hatchery	2.2	-	-	-	-	-	-	-	-	-	-	1.7
Generation Townsite Infrastructure	74.1	-	-	-	-	-	-	-	-	-	-	27.8
Site Remediation of Contaminated Corporate Facilities	33.4	-	-	-	-	-	-	-	-	-	-	2.2
High Voltage Test Facility	40.6	-	-	-	-	-	-	-	-	-	-	2.3
Power Supply Security Installations / Upgrades	42.9	-	-	-	-	-	-	-	-	-	-	24.8
Power Supply Sewer & Domestic Water System Install and Upgrade	45.2	-	-	-	-	-	-	-	-	-	-	21.4
Power Supply Domestic	NA	24.6	25.0	25.5	26.1	26.6	27.1	27.7	28.2	28.8	29.3	489.5
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	(13.0)
		192.5	185.8	170.6	105.5	62.1	110.8	133.0	159.3	170.6	68.7	2 975.0

CAPITAL EXPENDITURE FORECAST (CEF12)

(in millions of dollars)

	Total Project Cost	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	20 Year Total
Transmission												
Winnipeg - Brandon Transmission System Improvements	43.1	-	-	-	-	-	-	-	-	-	-	35.9
Transcona East 230 - 66 kV Station	37.6	-	-	-	-	-	-	-	-	-	-	13.5
Brandon Area Transmission Improvements	11.5	-	-	-	-	-	-	-	-	-	-	9.1
V38R 230kV Transmission Line ROW in RMNP	2.6	-	-	-	-	-	-	-	-	-	-	2.6
Neepawa 230 - 66 kV Station	29.1	-	-	-	-	-	-	-	-	-	-	20.2
Transmission Line Re-Rating	31.7	-	-	-	-	-	-	-	-	-	-	6.9
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	-	-	-	-	-	-	32.2
Transcona Station 66 kV Breaker Replacement	5.6	-	-	-	-	-	-	-	-	-	-	5.6
13.2kV Shunt Reactor Replacements	15.9	-	-	-	-	-	-	-	-	-	-	13.7
Rockwood East 230-115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	52.5
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	64.1
Canexus Load Addition	(0.3)	-	-	-	-	-	-	-	-	-	-	(1.3)
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	58.9
Breaker Failure Protection Implementation	4.4	-	-	-	-	-	-	-	-	-	-	4.4
D602F 500kV T/L Footing Replacements	4.4	-	-	-	-	-	-	-	-	-	-	1.8
Stanley Station 230-66 kV Transformer Addition	19.4	-	-	-	-	-	-	-	-	-	-	19.4
Enbridge Pipelines: Clipper Project Load Addition Phase 2	7.4	-	-	-	-	-	-	-	-	-	-	1.8
Ashern Station Bank Addition	10.0	-	-	-	-	-	-	-	-	-	-	9.9
Ashern Station 230 kV Shunt Reactor Replacement	1.2	-	-	-	-	-	-	-	-	-	-	0.3
Tadoule Lake DGS Diesel Tank Farm Upgrade	0.9	-	-	-	-	-	-	-	-	-	-	0.5
Energy Management System (EMS) Upgrade	6.5	-	-	-	-	-	-	-	-	-	-	1.2
Transmission Line Protection & Teleprotection Replacement	20.5	-	-	-	-	-	-	-	-	-	-	14.8
Mobile Radio System Modernization	30.6	-	-	-	-	-	-	-	-	-	-	30.0
Site Remediation of Diesel Generating Stations	13.3	-	-	-	-	-	-	-	-	-	-	1.8
Oil Containment - Transmission	7.4	-	-	-	-	-	-	-	-	-	-	0.1
Station Battery Bank Capacity & System Reliability Increase	46.4	-	-	-	-	-	-	-	-	-	-	20.7
Waverley Service Centre Oil Tank Farm Replacement	2.9	-	-	-	-	-	-	-	-	-	-	0.4
115 kV Transmission Lines	298.9	16.1	19.8	21.1	25.8	23.7	25.5	28.4	28.9	31.5	32.9	264.1
230 kV Transmission Lines	171.1	9.2	11.3	12.1	14.8	13.6	14.6	16.3	16.5	18.0	18.8	151.2
Sub-Transmission	124.8	6.7	8.3	8.8	10.8	9.9	10.6	11.9	12.1	13.1	13.7	110.3
Communications	425.8	23.0	28.2	30.0	36.8	33.8	36.3	40.5	41.2	44.8	46.9	376.2
Transmission Domestic	NA	38.0	38.8	39.6	40.4	41.2	42.0	42.8	43.7	44.6	45.5	758.3
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	(24.0)
		93.1	106.4	111.6	128.6	122.2	129.1	139.9	142.4	152.1	157.9	2 057.3
Customer Service & Distribution												
Winnipeg Distribution Infrastructure Requirements	24.5	-	-	-	-	-	-	-	-	-	-	5.7
Rover Substation Replace 4 kV Switchgear	12.7	-	-	-	-	-	-	-	-	-	-	7.5
Martin New Outdoor Station	27.3	-	-	-	-	-	-	-	-	-	-	21.7
Burrows New 66 kV/ 12 kV Station	42.6	-	-	-	-	-	-	-	-	-	-	21.6
Winnipeg Central 12&4kV Manhole Oil Switches	9.8	-	-	-	-	-	-	-	-	-	-	0.5
William New 66 kV/ 12 kV Station	10.3	-	-	-	-	-	-	-	-	-	-	9.9
Waverley West Sub Division Supply - Stage 1	6.5	-	-	-	-	-	-	-	-	-	-	0.1
St. James New Station & 24 kV Conversion	65.9	-	-	-	-	-	-	-	-	-	-	62.4
Distribution	887.5	47.9	58.8	62.6	76.7	70.5	75.7	84.4	85.8	93.5	97.8	784.1
Health Sciences Centre Service Consolidation & Distribution Upgrade	13.9	-	-	-	-	-	-	-	-	-	-	12.7
Waverley South DSC Installation	3.9	-	-	-	-	-	-	-	-	-	-	1.3
Southdale DK732 Cable Replacement	2.6	-	-	-	-	-	-	-	-	-	-	1.1
Royal canadian Mint Expansion	2.3	-	-	-	-	-	-	-	-	-	-	1.2
IKEA/Seasons of Tuxedo DSC Installation	4.6	-	-	-	-	-	-	-	-	-	-	4.6
Line 27 66 kV Extension and Arborg North Distribution Supply Centre	6.0	-	-	-	-	-	-	-	-	-	-	3.5
Melrose DSC	3.5	-	-	-	-	-	-	-	-	-	-	1.6
Starbuck DSC	3.0	-	-	-	-	-	-	-	-	-	-	1.5
Blumenort Distribution Supply Centre	3.0	-	-	-	-	-	-	-	-	-	-	2.8
Teulon East 66-12 kV Station	4.6	-	-	-	-	-	-	-	-	-	-	1.2
Kleefeld Distribution Supply Centre	2.8	-	-	-	-	-	-	-	-	-	-	2.8
Cromer North Station & Reston RE12-4 25kV Conversion	4.2	-	-	-	-	-	-	-	-	-	-	0.3
Brandon Crocus Plains 115-25 kV Bank Addition	5.8	-	-	-	-	-	-	-	-	-	-	5.7
Brandon Highland Park Station Capacity Increase	3.2	-	-	-	-	-	-	-	-	-	-	3.1
Birtle South - Rossburn 66kV Line	4.9	-	-	-	-	-	-	-	-	-	-	4.9
TCPL Keystone Project	8.0	-	-	-	-	-	-	-	-	-	-	4.0
Line 98 Rebuild melita to Waskada	3.8	-	-	-	-	-	-	-	-	-	-	0.0
Waskada North-Line 98 2X8MVAR Cap Bank	3.9	-	-	-	-	-	-	-	-	-	-	3.9
Steinbach Area 66kV Capacity Upgrade	6.3	-	-	-	-	-	-	-	-	-	-	4.5
Enbridge Pipelines Clipper-66kV Supply I	0.9	-	-	-	-	-	-	-	-	-	-	1.9
Waverley West 66 kV Supply Upgrade	3.2	-	-	-	-	-	-	-	-	-	-	3.2
Winpac 7 MVA Expansion	9.4	-	-	-	-	-	-	-	-	-	-	6.0
Bissett L48-DSC & Cap Bank Installation	3.9	-	-	-	-	-	-	-	-	-	-	2.8
Customer Service & Distribution Domestic	NA	159.7	162.9	166.2	169.5	172.9	176.3	179.9	183.5	187.1	190.9	3 182.4
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	(15.6)
		207.6	221.7	228.8	246.2	243.4	252.0	264.3	269.2	280.6	288.6	4 155.0

CAPITAL EXPENDITURE FORECAST (CEF12)

(in millions of dollars)

	Total Project Cost	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	20 Year Total
Customer Care & Marketing												
Advanced Metering Infrastructure	30.9	-	-	-	-	-	-	-	-	-	-	28.8
Customer Care & Marketing Domestic	NA	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	88.2
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	-
		4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	117.1
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	160.0
1840 Chevrier Apparatus Maintenance Shop Ancilliary Processing Facility	4.0	-	-	-	-	-	-	-	-	-	-	4.0
EAM Phase 2	18.6	-	-	-	-	-	-	-	-	-	-	12.7
Workforce Management (Phase 1 to 4)	17.7	-	-	-	-	-	-	-	-	-	-	1.4
Fleet	NA	17.1	17.5	17.8	18.2	18.6	18.9	19.3	19.7	20.1	20.5	340.6
Finance & Administration Domestic	NA	31.0	31.6	32.3	32.9	33.6	34.2	34.9	35.6	36.3	37.1	614.7
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	(8.3)
		56.2	57.1	58.1	59.1	60.1	61.2	62.2	63.3	64.4	65.5	1 125.0
ELECTRIC CAPITAL SUBTOTAL		**2 286.3**	**2 040.1**	**1 845.1**	**1 576.7**	**1 431.9**	**887.9**	**1 085.5**	**1 005.5**	**951.0**	**815.9**	**33 316.4**
GAS												
Customer Service & Distribution												
Ile Des Chenes NG Transmission Network Upgrade	1.2	-	-	-	-	-	-	-	-	-	-	1.1
Gas SCADA Replacement	4.6	-	-	-	-	-	-	-	-	-	-	2.6
Customer Service & Distribution Domestic	NA	31.3	31.9	32.6	33.2	33.9	34.6	35.3	36.0	36.7	37.4	620.6
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	(7.4)
		31.3	31.9	32.6	33.2	33.9	34.6	35.3	36.0	36.7	37.4	616.9
Customer Care & Marketing												
Advanced Metering Infrastructure	15.0	-	-	-	-	-	-	-	-	-	-	14.7
Demand Side Management	NA	-	-	-	-	-	-	-	-	-	-	18.1
Customer Care & Marketing Domestic	NA	5.9	6.0	6.1	6.2	6.4	6.5	6.6	6.8	6.9	7.0	117.4
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	-
		5.9	6.0	6.1	6.2	6.4	6.5	6.6	6.8	6.9	7.0	150.2
GAS CAPITAL SUBTOTAL		**37.2**	**37.9**	**38.7**	**39.5**	**40.3**	**41.1**	**41.9**	**42.7**	**43.6**	**44.5**	**767.1**
CONSOLIDATED CAPITAL		**2 323.5**	**2 078.1**	**1 883.8**	**1 616.2**	**1 472.2**	**929.0**	**1 127.4**	**1 048.3**	**994.6**	**860.4**	**34 083.5**
G911 Fall Update Base Capitalized Interest Revision	NA	(0.8)	(1.0)	(1.2)	(0.9)	(0.9)	(0.5)	(0.7)	(0.8)	(0.9)	(1.0)	(13.2)
CEF12 TOTAL		**2 322.7**	**2 077.0**	**1 882.6**	**1 615.3**	**1 471.3**	**928.5**	**1 126.7**	**1 047.5**	**993.7**	**859.4**	**34 070.4**

10.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH12)

ELECTRIC OPERATIONS (MH12)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
REVENUES										
General Consumers										
at approved rates	1 331	1 361	1 374	1 390	1 404	1 424	1 447	1 462	1 485	1 506
additional*	0	48	104	165	228	297	371	447	531	619
Extraprovincial	357	344	343	380	406	435	441	464	711	839
Other	14	15	15	15	15	16	16	16	17	17
	1 702	1 768	1 836	1 950	2 054	2 172	2 274	2 390	2 743	2 981
EXPENSES										
Operating and Administrative	455	471	544	556	567	590	601	617	639	653
Finance Expense	452	444	492	524	586	656	767	781	1 001	1 097
Depreciation and Amortization	399	430	372	391	410	447	494	508	580	619
Water Rentals and Assessments	117	116	112	112	112	112	112	113	121	126
Fuel and Power Purchased	143	166	179	191	206	221	230	231	253	264
Capital and Other Taxes	88	96	101	110	119	129	136	143	149	158
Corporate Allocation	9	9	8	8	8	8	8	8	8	8
	1 664	1 732	1 808	1 892	2 009	2 163	2 349	2 401	2 753	2 926
Non-controlling Interest	14	24	21	16	13	10	6	3	4	(3)
Net Income	53	60	50	73	57	19	(68)	(9)	(7)	52
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.50%	7.59%	11.84%	16.26%	20.85%	25.62%	30.58%	35.74%	41.10%

ELECTRIC OPERATIONS (MH12)
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	1 529	1 552	1 575	1 598	1 621	1 644	1 669	1 693	1 717	1 741
additional*	713	814	921	1 035	1 155	1 283	1 419	1 564	1 716	1 878
Extraprovincial	873	863	851	937	1 209	1 288	1 304	1 312	1 331	1 341
Other	17	18	18	18	19	19	19	20	20	21
	3 133	3 246	3 366	3 588	4 003	4 234	4 411	4 588	4 784	4 980
EXPENSES										
Operating and Administrative	667	681	696	727	741	757	775	789	805	823
Finance Expense	1 087	1 086	1 076	1 193	1 440	1 622	1 589	1 546	1 552	1 482
Depreciation and Amortization	630	637	645	690	770	828	837	849	880	893
Water Rentals and Assessments	128	127	126	134	147	151	151	151	152	153
Fuel and Power Purchased	278	292	318	281	277	291	304	318	328	341
Capital and Other Taxes	167	176	183	188	192	193	196	198	203	203
Corporate Allocation	8	8	8	8	8	8	8	8	7	7
	2 964	3 008	3 052	3 220	3 575	3 850	3 860	3 859	3 926	3 901
Non-controlling Interest	(5)	(10)	(13)	(9)	(11)	(14)	(16)	(20)	(22)	(25)
Net Income	163	228	301	358	418	370	534	710	835	1 054
* 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	46.68%	52.47%	58.49%	64.75%	71.26%	78.03%	85.06%	92.37%	99.97%	107.86%

ELECTRIC OPERATIONS (MH12)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	15 374	16 435	17 104	18 255	18 807	22 348	22 781	25 825	29 899	30 432
Accumulated Depreciation	(5 173)	(5 536)	(5 856)	(6 223)	(6 622)	(7 064)	(7 553)	(8 057)	(8 632)	(9 248)
Net Plant in Service	10 201	10 899	11 248	12 032	12 185	15 285	15 228	17 769	21 267	21 184
Construction in Progress	2 108	2 878	4 198	5 128	6 794	5 439	6 879	5 422	3 038	4 821
Current and Other Assets	1 869	1 735	1 391	1 578	1 790	2 027	1 844	1 974	2 059	1 725
Goodwill and Intangible Assets	180	165	150	134	123	113	105	98	92	88
Regulated Assets	231	225	-	-	-	-	-	-	-	-
	14 590	15 902	16 988	18 873	20 892	22 864	24 056	25 262	26 456	27 816
LIABILITIES AND EQUITY										
Long-Term Debt	9 428	11 199	12 741	14 614	16 304	18 077	19 972	20 739	22 062	23 412
Current and Other Liabilities	2 086	1 569	1 743	1 726	2 032	2 233	1 610	2 073	1 966	1 945
Contributions in Aid of Construction	336	345	350	355	359	369	375	382	389	396
Retained Earnings	2 442	2 502	2 295	2 368	2 425	2 444	2 376	2 368	2 361	2 413
Accumulated Other Comprehensive Income	299	287	(142)	(189)	(228)	(259)	(278)	(298)	(321)	(349)
	14 590	15 902	16 988	18 873	20 892	22 864	24 056	25 262	26 456	27 816

ELECTRIC OPERATIONS (MH12)
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	30 962	31 525	32 212	37 906	43 040	44 544	45 284	45 838	47 824	48 551
Accumulated Depreciation	(9 876)	(10 512)	(11 157)	(11 848)	(12 618)	(13 446)	(14 284)	(15 135)	(16 016)	(16 911)
Net Plant in Service	21 086	21 013	21 055	26 059	30 422	31 098	31 000	30 703	31 808	31 640
Construction in Progress	6 576	8 048	9 200	5 077	1 364	737	1 070	1 513	464	539
Current and Other Assets	1 802	2 215	2 362	2 205	2 492	2 880	3 337	3 663	3 749	4 896
Goodwill and Intangible Assets	85	83	82	82	81	80	79	78	77	76
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	29 548	31 359	32 699	33 422	34 359	34 794	35 486	35 957	36 099	37 151
LIABILITIES AND EQUITY										
Long-Term Debt	25 414	27 217	27 770	28 572	28 974	29 115	29 066	28 369	28 358	27 931
Current and Other Liabilities	1 520	1 293	1 771	1 325	1 436	1 352	1 551	2 001	1 310	1 726
Contributions in Aid of Construction	403	411	418	426	433	441	449	457	466	474
Retained Earnings	2 576	2 804	3 105	3 463	3 881	4 251	4 785	5 495	6 330	7 384
Accumulated Other Comprehensive Income	(365)	(365)	(365)	(365)	(365)	(365)	(365)	(365)	(365)	(365)
	29 548	31 359	32 699	33 422	34 359	34 794	35 486	35 957	36 099	37 151

ELECTRIC OPERATIONS (MH12)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 692	1 768	1 836	1 950	2 054	2 172	2 274	2 390	2 743	2 981
Cash Paid to Suppliers and Employees	(782)	(822)	(909)	(941)	(975)	(1 020)	(1 047)	(1 069)	(1 126)	(1 162)
Interest Paid	(466)	(476)	(509)	(556)	(608)	(700)	(816)	(826)	(1 050)	(1 144)
Interest Received	28	17	24	26	31	39	41	39	35	32
	472	486	442	478	502	491	453	533	602	707
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 036	1 970	1 760	2 190	2 180	2 580	2 190	1 390	1 980	1 790
Sinking Fund Withdrawals	129	393	102	26	-	16	416	187	269	676
Retirement of Long-Term Debt	(180)	(808)	(176)	(312)	(347)	(530)	(829)	(306)	(635)	(679)
Other	(42)	(7)	(17)	(19)	(17)	(13)	(24)	(13)	(34)	(9)
	943	1 548	1 670	1 886	1 817	2 053	1 753	1 258	1 580	1 777
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 381)	(1 922)	(2 028)	(2 083)	(2 214)	(2 174)	(1 863)	(1 666)	(1 799)	(2 299)
Sinking Fund Payment	(107)	(208)	(124)	(188)	(166)	(227)	(219)	(224)	(248)	(343)
Other	(21)	(20)	(21)	(20)	(32)	(42)	(28)	(28)	(33)	(38)
	(1 509)	(2 151)	(2 173)	(2 291)	(2 412)	(2 443)	(2 111)	(1 919)	(2 080)	(2 679)
Net Increase (Decrease) in Cash	(94)	(117)	(62)	73	(94)	101	96	(128)	102	(195)
Cash at Beginning of Year	43	(51)	(168)	(230)	(157)	(251)	(150)	(54)	(182)	(80)
Cash at End of Year	(51)	(168)	(230)	(157)	(251)	(150)	(54)	(182)	(80)	(275)

ELECTRIC OPERATIONS (MH12)
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	3 133	3 246	3 366	3 588	4 003	4 234	4 411	4 588	4 784	4 980
Cash Paid to Suppliers and Employees	(1 198)	(1 233)	(1 276)	(1 281)	(1 305)	(1 337)	(1 368)	(1 394)	(1 422)	(1 450)
Interest Paid	(1 115)	(1 101)	(1 108)	(1 239)	(1 490)	(1 689)	(1 668)	(1 640)	(1 661)	(1 567)
Interest Received	18	19	29	34	42	57	73	81	92	73
	837	932	1 011	1 102	1 251	1 265	1 448	1 635	1 793	2 037
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 970	1 780	990	790	390	190	190	(50)	(10)	(10)
Sinking Fund Withdrawals	156	-	-	450	-	-	60	250	700	13
Retirement of Long-Term Debt	(432)	-	-	(450)	-	-	(60)	(220)	(700)	(13)
Other	(1)	(0)	(1)	(1)	(0)	0	2	2	3	(16)
	1 693	1 780	989	789	390	190	192	(18)	(7)	(26)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 268)	(2 018)	(1 822)	(1 553)	(1 403)	(858)	(1 054)	(977)	(918)	(781)
Sinking Fund Payment	(249)	(269)	(295)	(317)	(316)	(334)	(348)	(359)	(361)	(341)
Other	(29)	(32)	(25)	(25)	(28)	(26)	(26)	(26)	(26)	(26)
	(2 546)	(2 319)	(2 142)	(1 896)	(1 746)	(1 217)	(1 428)	(1 362)	(1 305)	(1 148)
Net Increase (Decrease) in Cash	(16)	393	(141)	(5)	(106)	238	211	254	481	862
Cash at Beginning of Year	(275)	(291)	102	(39)	(44)	(150)	89	300	555	1 036
Cash at End of Year	(291)	102	(39)	(44)	(150)	89	300	555	1 036	1 898

11.0 GAS OPERATIONS FINANCIAL FORECAST (CGM12)

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers										
at approved rates	319	312	356	351	349	348	349	349	350	350
additional revenue requirement*	0	7	7	7	7	9	11	13	15	18
	319	319	363	358	356	357	360	362	365	368
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	151	155	154	156	159	161	164	167
Other	2	2	2	2	2	2	2	2	2	2
	145	153	153	156	156	158	161	163	166	169
EXPENSES										
Operating and Administrative	67	69	77	77	78	78	79	79	81	82
Finance Expense	18	17	21	22	23	25	25	26	27	28
Depreciation and Amortization	28	30	20	21	22	22	23	23	24	25
Capital and Other Taxes	18	19	15	15	16	16	16	17	17	17
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	147	144	147	151	153	155	158	161	165
Net Income	2	6	9	9	5	5	6	6	5	4

* Additional Revenue Requirement	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Percent Increase		2.00%	0.00%	0.00%	0.00%	0.50%	0.75%	0.50%	0.50%	0.75%
Cumulative Percent Increase		2.00%	2.00%	2.00%	2.00%	2.51%	3.28%	3.80%	4.31%	5.10%

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	656	679	705	735	767	788	811	835	860	886
Accumulated Depreciation	(232)	(240)	(245)	(252)	(260)	(269)	(278)	(288)	(299)	(310)
Net Plant in Service	424	439	460	483	507	520	533	546	561	576
Construction in Progress	2	2	2	2	2	4	6	8	8	8
Current and Other Assets	73	68	68	68	68	68	68	68	68	68
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3
Regulated Assets	79	78	-	-	-	-	-	-	-	-
	586	594	536	557	580	595	610	625	640	655
LIABILITIES AND EQUITY										
Long-Term Debt	295	290	330	340	360	380	390	400	420	410
Current and Other Liabilities	99	96	67	69	68	56	57	57	48	69
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	36	41	(27)	(18)	(13)	(7)	(2)	4	9	13
	586	594	536	557	580	595	610	625	640	655

GAS OPERATIONS (CGM12)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES										
Cash Receipts from Customers	355	357	401	392	390	391	394	397	399	403
Cash Paid to Suppliers and Employees	(291)	(335)	(347)	(347)	(348)	(347)	(348)	(349)	(352)	(354)
Interest Paid	(19)	(19)	(20)	(21)	(23)	(24)	(25)	(26)	(26)	(27)
	45	3	33	23	20	20	21	22	21	21
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	60	30	40	10	20	20	10	10	20	10
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(3)	30	5	10	20	20	10	10	20	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(37)	(39)	(33)	(37)	(40)	(32)	(33)	(33)	(34)	(34)
Other	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	(37)	(39)	(33)	(38)	(41)	(34)	(34)	(34)	(34)	(35)
Net Increase (Decrease) in Cash	5	(7)	5	(4)	(1)	7	(2)	(3)	7	(4)
Cash at Beginning of Year	(13)	(9)	(15)	(10)	(15)	(16)	(9)	(12)	(14)	(7)
Cash at End of Year	(9)	(15)	(10)	(15)	(16)	(9)	(12)	(14)	(7)	(11)

12.0 CORPORATE SUBSIDIARIES FINANCIAL FORECAST (CS12)

CORPORATE SUBSIDIARIES (CS12)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
Revenue	45	48	52	53	54	55	56	57	59	60
Cost of Operations	25	27	29	30	30	31	32	32	33	33
	20	22	23	24	24	24	25	25	26	26
EXPENSES										
Operating and Administrative	13	14	14	15	15	15	16	16	16	16
Finance Expense	(0)	(0)	0	-	-	-	-	-	-	-
Depreciation and Amortization	1	1	1	1	1	1	1	1	1	1
Capital and Other Taxes	0	0	0	0	0	0	0	1	1	1
	14	15	16	16	17	17	17	17	17	18
Net Income	6	6	7	7	7	8	8	8	8	9

CORPORATE SUBSIDIARIES (CS12)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	11	11	12	12	12	12	12	12	12	12
Accumulated Depreciation	(3)	(4)	(5)	(6)	(7)	(8)	(8)	(9)	(10)	(10)
Net Plant in Service	8	7	7	6	5	4	3	3	2	2
Construction in Progress	-	-	-	-	-	-	-	-	-	-
Current and Other Assets	30	37	44	53	61	70	79	88	97	106
Goodwill and Intangible Assets	1	1	1	1	0	0	0	0	0	0
Regulated Assets	0	0	-	-	-	-	-	-	-	-
	39	45	52	59	67	75	83	91	99	108
LIABILITIES AND EQUITY										
Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Current and Other Liabilities	6	6	6	6	6	6	6	6	6	6
Contributions in Aid of Construction	0	0	0	0	0	0	0	0	0	0
Share Captial	0	0	0	0	0	0	0	0	0	0
Retained Earnings	33	39	46	53	61	69	77	85	93	102
	39	45	52	59	67	75	83	91	99	108

CORPORATE SUBSIDIARIES (CS12)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
OPERATING ACTIVITIES										
Cash Receipts from Customers	45	48	52	53	54	55	56	57	59	60
Cash Paid to Suppliers and Employees	(39)	(41)	(44)	(45)	(46)	(47)	(48)	(48)	(49)	(50)
Interest Paid	0	0	(0)	-	-	-	-	-	-	-
	7	7	8	8	9	9	9	9	9	9
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1)	(0)	(1)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(1)	(0)	(1)	-	-	-	-	-	-	-
Net Increase (Decrease) in Cash	5	7	8	8	9	9	9	9	9	9
Cash at Beginning of Year	7	13	20	27	36	44	53	62	71	80
Cash at End of Year	13	20	27	36	44	53	62	71	80	89