April 2012

Integrated Financial Forecast (IFF11-2)

2011/12 - 2031/32

Financial Planning
Finance & Administration

Manitoba Hydro

INTEGRATED FINANCIAL FORECAST (IFF11-2)

2011/12 – 2031/32

FINANCIAL PLANNING DEPARTMENT
CORPORATE CONTROLLER DIVISION
FINANCE & ADMINISTRATION

April, 2012

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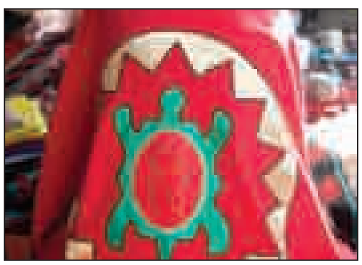
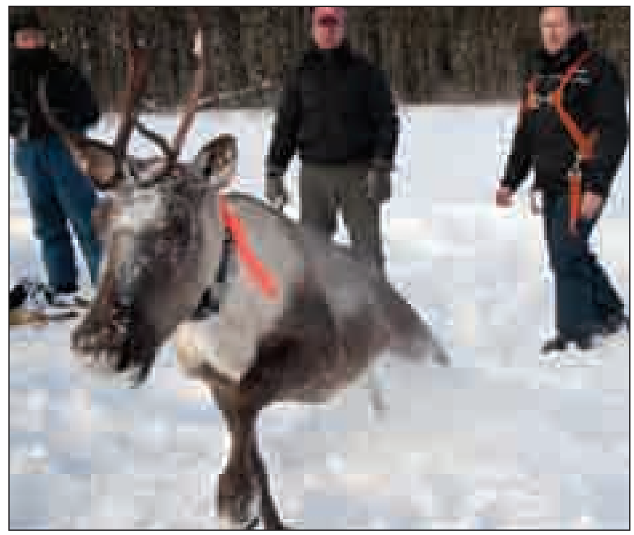
INTEGRATED FINANCIAL FORECAST (IFF11-2)

KEY FINANCIAL RESULTS
(Dollars are in millions)

	Actual	Prelim. Actual	IFF11-2 Forecast		
	2010/11	2011/12	2012/13	2013/14	2021/22
PROJECTED RATE INCREASES - ELECTRIC* - GAS (non-commodity)	 2.8% 0.7%	 2.0% -	 3.57% 2.0%	 3.5% 1.75%	 3.5% 0.5%
NET INCOME - ELECTRIC - GAS - SUBSIDIARIES	 $139 $7 $4	 $64 $(6) $5	 $20 $5 $6	 $68 $5 $7	 $113 $4 $10
CAPITAL EXPENDITURES - ELECTRIC - GAS	 $1 100 $34	 $1 022 $37	 $1 201 $43	 $1 518 $32	 $1 767 $35
DEBT/EQUITY RATIO	73:27	75:25	76:24	82:18	88:12
INTEREST COVERAGE RATIO	1.27	1.11	1.05	1.12	1.09
CAPITAL COVERAGE RATIO (excl. major new generation & transmission)	1.20	0.93	1.19	1.18	1.85
RETAINED EARNINGS	$2 389	$2 453	$2 483	$2 203	$2 924

*Assumes proposed reinstatement of the PUB Order 5/12 1% rate roll-back, the 2% interim rate increase effective April 1, 2012 approved in PUB Order 32/12 and a further proposed interim rate increase of 2.5% effective September 1, 2012.





Section 1

1.0 OVERVIEW

The 2011 Integrated Financial Forecast (IFF11-2) projects Manitoba Hydro's financial results for the 20-year period to 2031/32. IFF11-2 is an update to IFF11 which was approved by the Board on February 28, 2012.

Since IFF11 was last approved by the Board, the following changes have impacted the projected financial results of Manitoba Hydro:

- Preliminary actual net income for 2011/12 is approximately $36 million lower than projected in IFF11 due mainly to lower general consumers revenue resulting from warmer than normal winter weather and the revenue reduction associated with the 1% rate roll-back directed in PUB Order 5/12.
- Net extraprovincial revenues have decreased by approximately $32 million in 2012/13 compared to IFF11 largely due to lower projected export sales volumes and higher projected generation costs resulting from lower than forecast water supply conditions.
- In Order 32/12, the PUB approved an interim rate increase of 2.0% effective April 1, 2012. IFF11-2 proposes an additional 2.5% interim rate increase effective September 1, 2012 required to deal with the further deterioration in net income since IFF11 was approved.
- The Canadian Accounting Standards Board (AcSB) issued a decision on March 30, 2012 to provide an option to extend the mandatory International Financial Reporting Standards (IFRS) changeover date by one year to April 1, 2013. As a result, net income and retained earnings impacts of the transition to IFRS are deferred from 2012/13 to 2013/14 in IFF11-2.

Table 1 below shows the changes in net income in IFF11-2 compared to IFF11.

Table 1

CONSOLIDATED NET INCOME
(in millions)

	2011/12	2012/13	2013/14	Cumulative to 2021/22
IFF11-2	$ 63	* $31	$ 81	$ 895
IFF11	99	17	66	617
Increase/(Decrease)	$ (36)	$ 14	$ 15	$ 278

*Note: includes $23 million in revenue related to the April 2010 rate increase rollback. The PUB denied MH's request to include this revenue in 2011/12 and MH will be applying to the PUB to include this amount in revenue in 2012/13.

2.0 FORECAST ASSUMPTIONS

2.1 Manitoba Electricity Load Forecast

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

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

2.2 Electricity Supply

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

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

2.3 Extraprovincial Sales

IFF11-2 provides an update to IFF11 extraprovincial sales and generation costs to reflect actual results for 2011/12 and actual reservoir and lake level conditions at April 1, 2012.

The projected net extraprovincial revenue for 2012/13 has decreased $32 million compared to IFF11. Precipitation across Manitoba Hydro's watersheds from September, 2011 to April, 2012 was among the lowest on record over the last thirty years and the resulting snowmelt runoff is projected to be below average for this spring. As a result, hydraulic generation is projected to be nearly 3,000 GWh lower for 2012/13 compared to IFF11. This reduces the energy available for export sales and increases the requirements from thermal generation and imports.

All forecast assumptions for 2013/14 and on remain the same as IFF11 and are described further below.

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

IFF11-2 includes the following new or proposed dependable sales transactions:

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

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

IFF11-2 projects a decrease in extraprovincial revenues (net of water rentals and fuel and power purchases) over the 10-year forecast to 2021/22 of $1.1 billion compared to IFF10 which is mainly attributable to lower export prices.

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

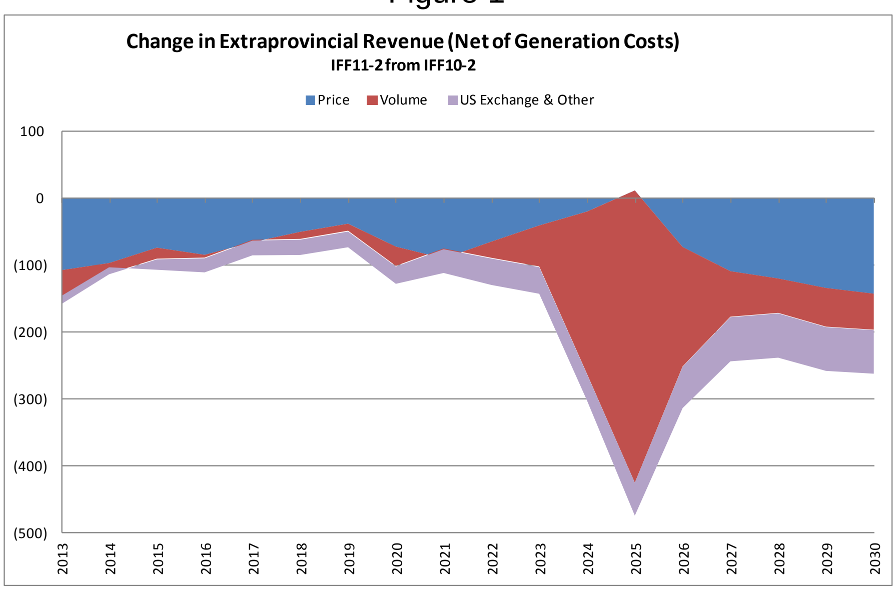
Over the 20-year forecast period, net extraprovincial revenues are projected to be $4.0 billion lower in IFF11-2 compared to IFF10. Approximately half of the decrease can be attributed to the decrease in export prices.

The remaining decrease over the 20-year forecast can be attributed to the following factors:

- Deferral of Conawapa by one year to 2024/25;
- Reduction in transfer capability for the new interconnection to the U.S. (400 MW for the period 2019/20 to 2024/25 upgraded to 1000 MW for 2024/25 and on);
- Reduction in the contracted energy delivered to Wisconsin Public Service (100 MW for the period 2019/20 to 2025/26);
- Increased Manitoba load; and
- Strengthened Canadian dollar relative to IFF10.

Figure 1 below shows the relative impacts of changes in price, volume and U.S. exchange on IFF11-2 extraprovincial revenues compared to IFF10.

Figure 1



2.4 Non-Controlling Interest

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

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

2.5 International Financial Reporting Standards

IFF11-2 assumes that Manitoba Hydro will adopt the additional one-year deferral of IFRS recently announced by the AcSB on March 30, 2012 and the Corporation will transition to IFRS effective April 1, 2013. IFF11-2 reflects the net income and retained earnings impacts of the transition to IFRS in 2013/14.

The primary impacts of IFRS that are included in IFF11-2 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 for the most part offset by corresponding reductions in Depreciation and Amortization. The impact of the transition to IFRS on net income for 2013/14 is expected to be a reduction of $14 million. The most significant impact of the transition to IFRS for Manitoba Hydro will be a reduction to retained earnings of approximately $361 million. The following table outlines the impacts of IFRS on retained earnings and net income:

Table 2
IFRS Impacts
Increase/(Decrease)
($Millions)

	Retained Earnings	Net Income 2013/14
Power Smart Programs	(236)	(7)
Site Remediation	(38)	2
Acquisition Costs	(20)	1
Regulatory Costs	(3)	(0)
Deferred Taxes	(29)	2
Administrative Overhead	(38)	(38)
Employee Benefits	(22)	2
Removal of Negative Salvage	58	60
Change to Equal Life Group Depreciation	(33)	(35)
Total	(361)	(14)

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

2.6 Economic Variables

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

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

*Excluding Provincial Guarantee Fee of 1.0%

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

3.0 NATURAL GAS DEMAND AND SUPPLY

The Corporation sells primary gas to Manitobans in a market which also includes a small number of brokers and marketers, and is the gas distribution utility for all customers in Manitoba. Currently, approximately 90% of customers representing approximately 60% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

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

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

The 2011 Natural Gas Volume Forecast is lower than last year's forecast. The total natural gas sales volume forecast is down approximately 2% annually gradually decreasing to approximately 1% annually by 2021/22. The decrease in the 2011 forecast is primarily attributed to lower consumption expectations for the Special Contract customer class resulting from decreased historical usage.

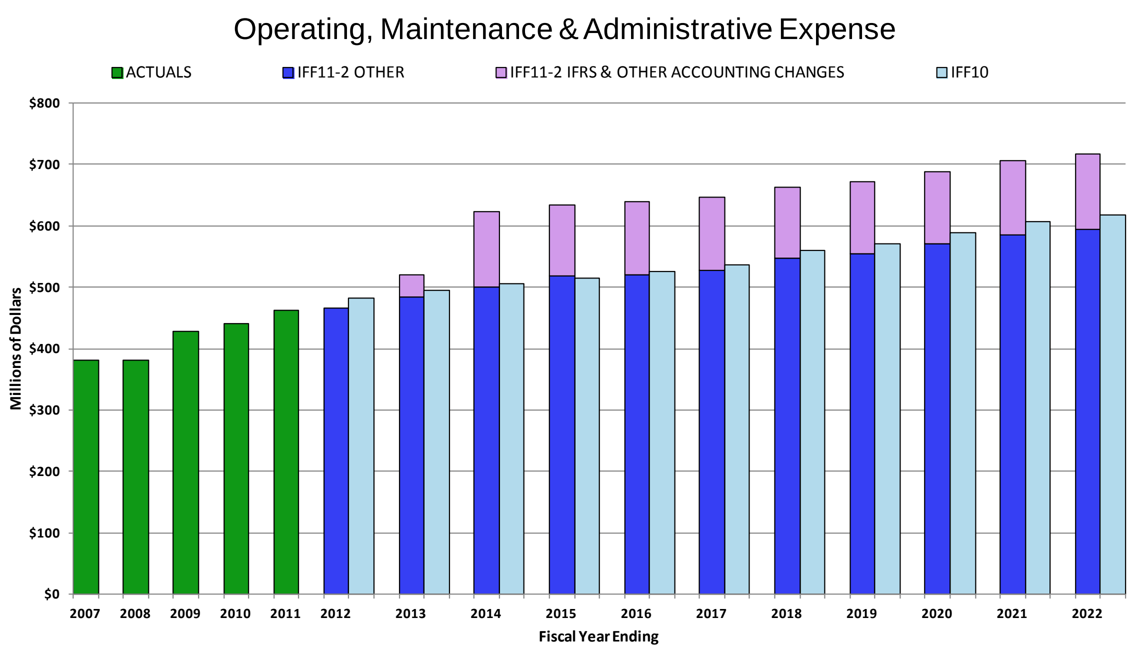
4.0 OPERATING, MAINTENANCE & ADMINISTRATIVE EXPENSE

Operating, Maintenance & Administrative (OM&A) Expenses in IFF11-2 include only those expenditures necessary to provide for the safe and reliable operation and maintenance of the generation, transmission and gas and electric distribution systems.

Compared to 2011/12, OM&A increases due to inflation plus the incremental operating costs as Wuskwatim comes into service partially offset by other productivity improvements and cost savings. Manitoba Hydro will also be implementing accounting changes such that $28 million of costs that were previously capitalized will be charged to OM&A commencing in 2012/13. Thereafter, OM&A rises each year at the same level as inflation except in years where major new generation and transmission comes into service in 2017/18 (Bipole III), 2019/20 (Keeyask) and 2024/25 (Conawapa).

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

Figure 2



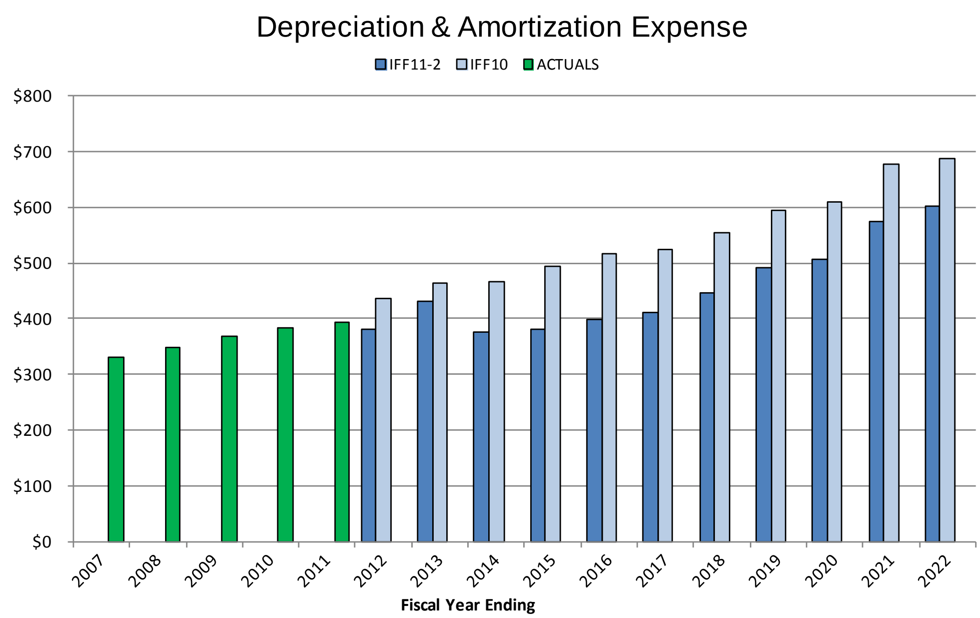
5.0 DEPRECIATION & AMORTIZATION EXPENSE

The Depreciation and Amortization Expense included in IFF11-2 is based on a comprehensive depreciation study that was completed in November of 2011. In addition to the update of service lives of assets, this depreciation study also involved the establishment of new asset component groupings and changes to Manitoba Hydro's depreciation methods to ensure compliance with IFRS requirements.

Figure 3 below provides a comparison of the Depreciation and Amortization expense between IFF11-2 and IFF10. The reduction in 2011/12 and 2012/13 is primarily related to the implementation of the updated asset service lives as a result of the depreciation study. The further reductions in 2013/14 to 2021/22 reflect the removal of asset retirement costs from depreciation rates and the elimination of the amortization of rate-regulated assets, partially offset by the change to the Equal Life Group methodology for calculating depreciation rates.

Similar to OM&A, depreciation expense for 2012/13 increases as it includes depreciation related to the Wuskwatim Generating Station.

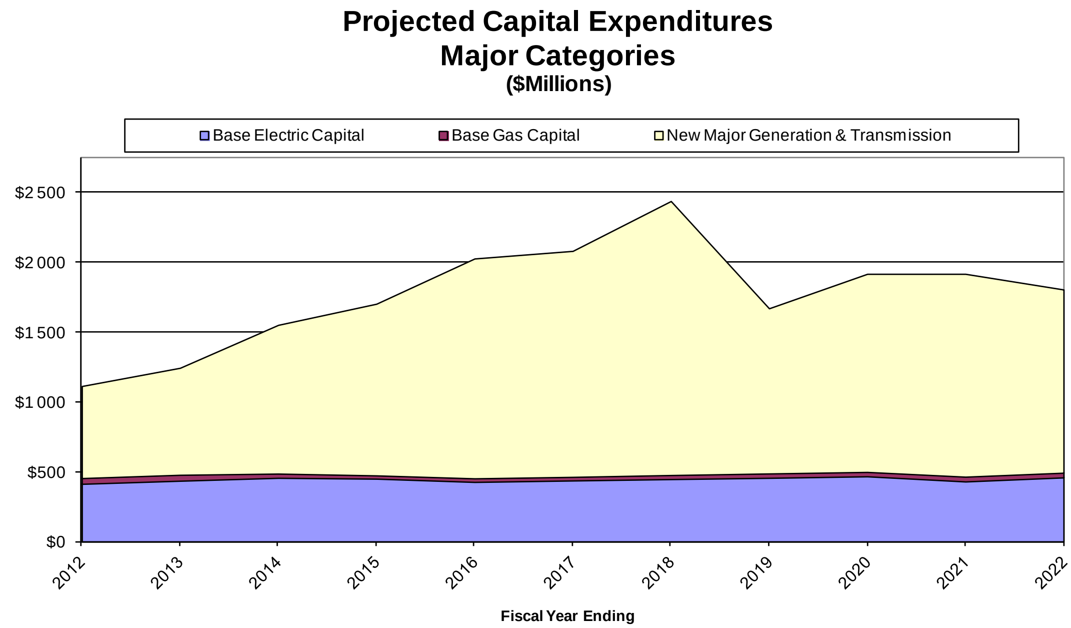
Figure 3



6.0 CAPITAL EXPENDITURE FORECAST (CEF11-2)

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

Figure 4

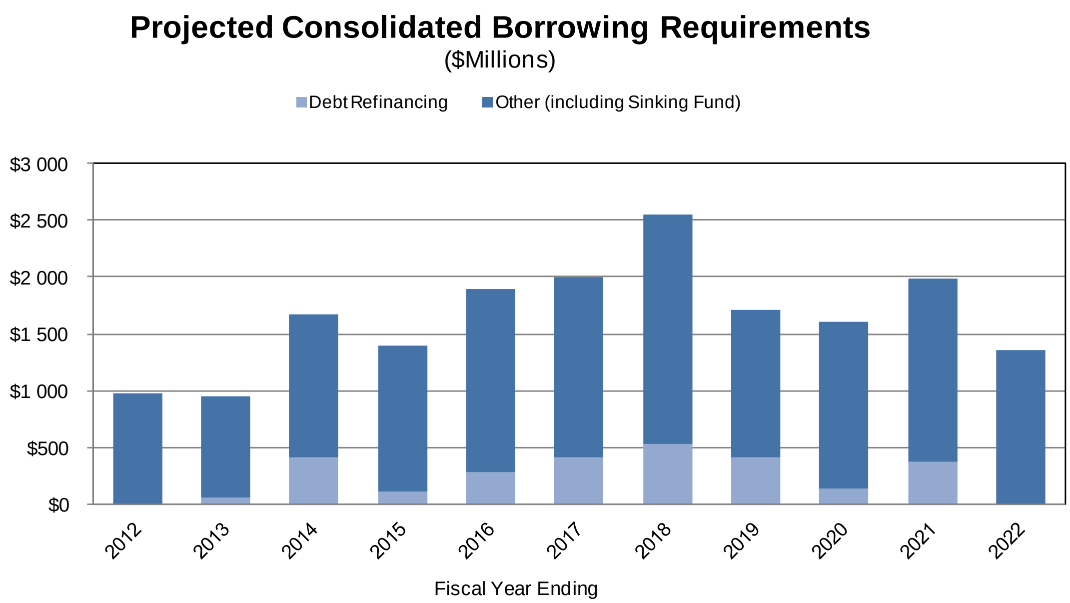


Over the 10-year forecast period to 2021/22, capital expenditures are nearly $1 billion lower compared to the previous capital expenditure forecast, CEF10-2. The decrease can be attributed to the reclassification of demand side management expenditures to OM&A in accordance with IFRS and the timing of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

7.0 BORROWING REQUIREMENTS

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

Figure 5



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

8.0 FINANCIAL TARGETS

Manitoba Hydro has the following financial targets for consolidated operations:

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

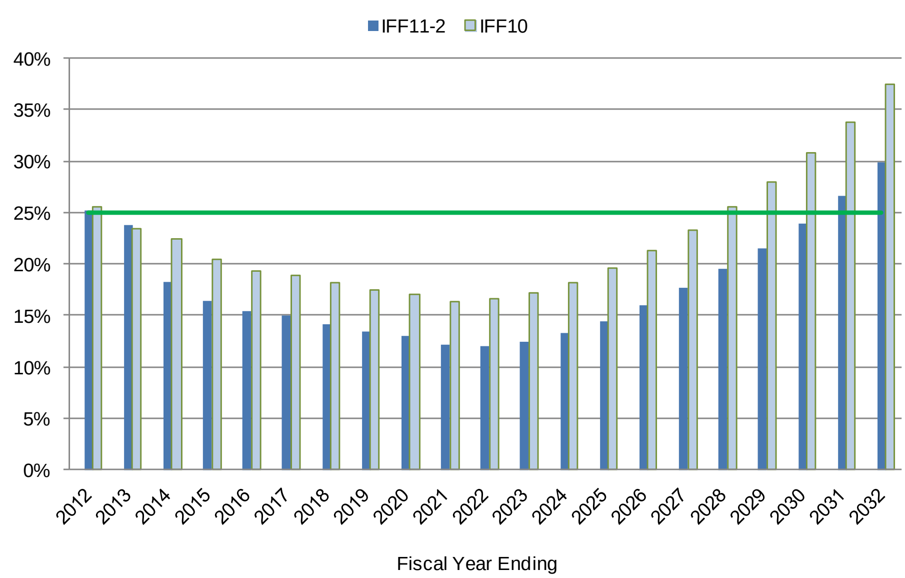
It is recognized that it may not be possible to maintain financial targets during years of major investment in the generation and transmission system.

8.1 Debt/Equity Ratio

The debt/equity ratio indicates the portion of Manitoba Hydro's assets that have been financed by internally generated funds rather than through debt. Figure 6 below shows the projected consolidated equity ratio for IFF11-2 compared to IFF10. High levels of capital investment in major new generation and transmission combined with reduced net extraprovincial revenues result in a deterioration of the equity ratio to 12% by 2021/22. In the longer term, the equity ratio is projected to show steady improvement following the in-service of Keeyask and Conawapa generating stations and returns to the target 25% by 2030/31.

Figure 6

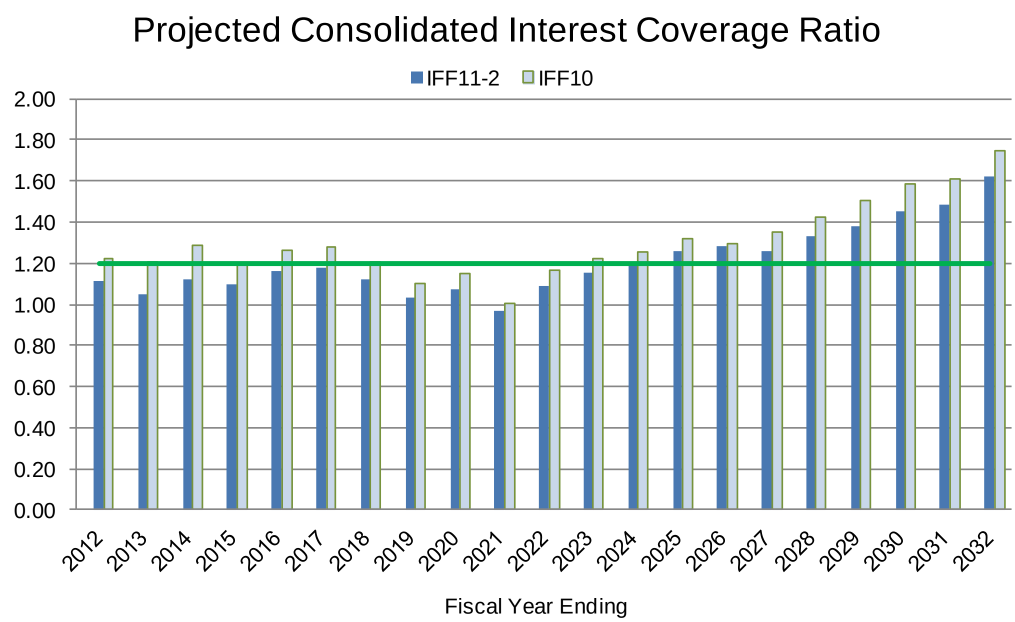
Projected Consolidated Equity Ratio



8.2 Interest Coverage Ratio

The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. Figure 7 below shows that the reduction in net extraprovincial revenues compared to IFF10 results in interest coverage ratios lower than target for the first 13 years the forecast. In the longer term, interest coverage is projected to return to the 1.20 target level immediately following Conawapa generating station in-service in 2024/25 and grows steadily thereafter.

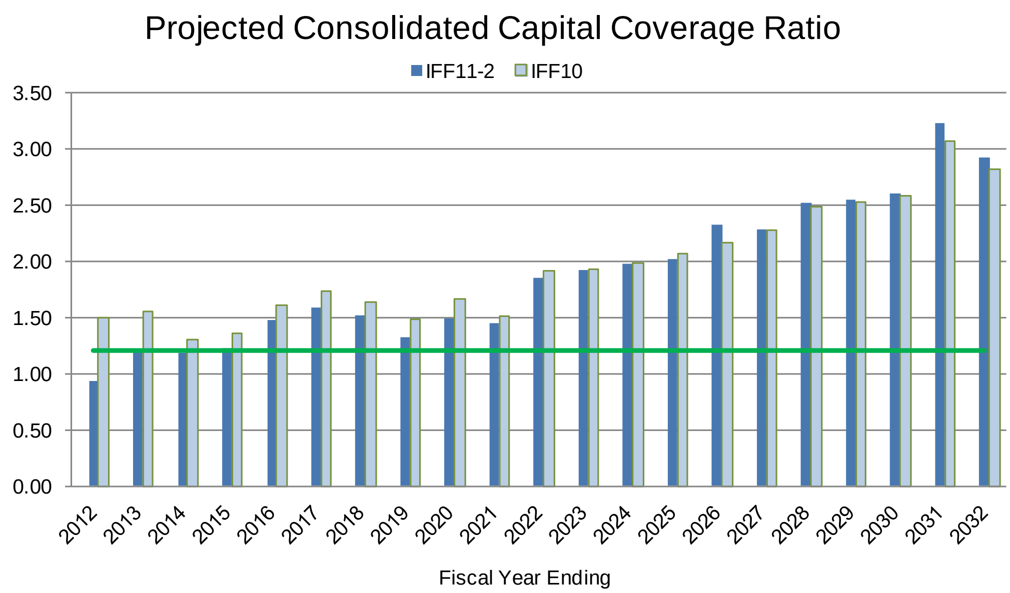
Figure 7



8.3 Capital Coverage Ratio

The capital coverage ratio measures the ability of current period internally generated funds to finance capital expenditures excluding major new generation and related transmission. Capital coverage is below target for the first three years of the forecast and then projected cash flows are sufficient to enable this target to be met in remaining years of the forecast. Figure 8 below shows the comparative capital coverage ratios for IFF11-2 and IFF10.

Figure 8



9.0 RISK ANALYSIS

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

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

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

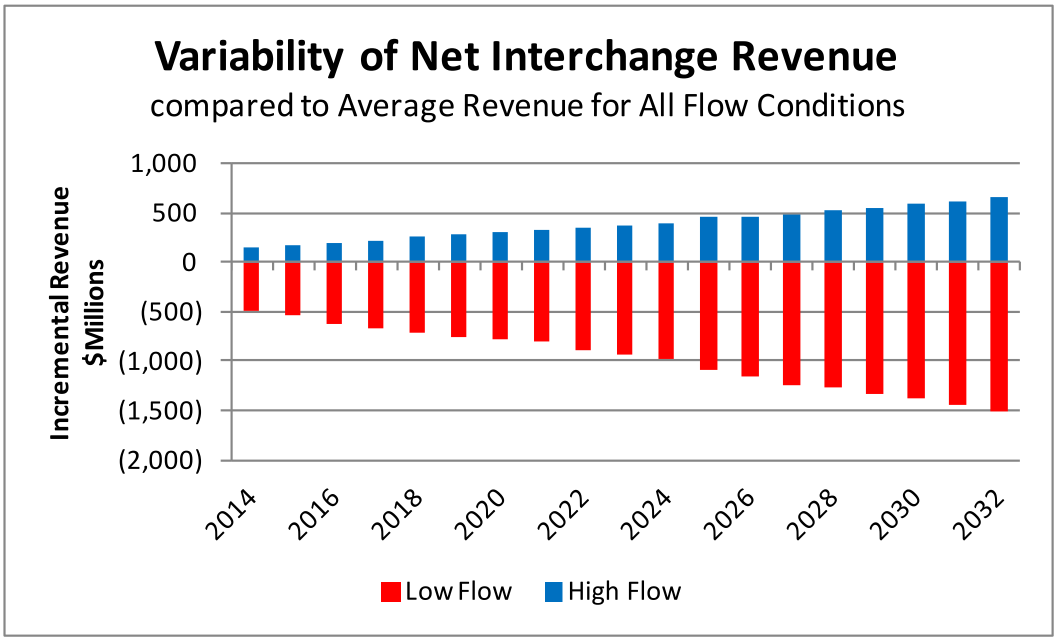
	2013/14	2017/18	2021/22	Incremental Annual Rate Increase/(Decrease)*
	Incremental Increase/(Decrease) in Retained Earnings			
High Domestic Load Growth	7	10	(119)	0.15%
+1% Interest	3	(116)	(724)	0.91%
-1% Interest	(2)	113	671	-0.90%
US $ up 10¢	(7)	(12)	64	-0.08%
US $ down 10¢	8	10	(73)	0.10%
Low Export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

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

9.1 Five Year Drought

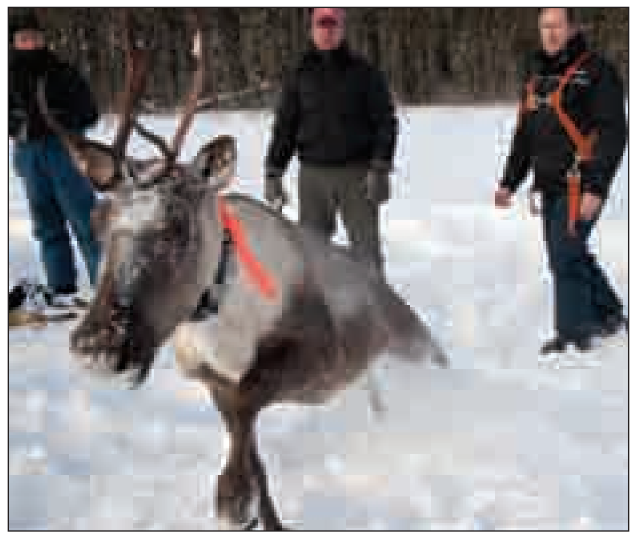
IFF11 reflects average net interchange revenues and variable generation costs associated with 96 different potential system inflow conditions. The actual inflow that occurs in any given year can vary significantly as shown in Figure 9 below. The impact of the lowest flows are asymmetrically greater than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

Figure 9



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



Section 2

10.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF11-2)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF11-2)
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers	1 507	1 767	1 806	1 870	1 928	2 002	2 082	2 156	2 246	2 341	2 438
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
	1 870	2 108	2 169	2 264	2 397	2 504	2 613	2 710	2 857	3 162	3 351
Cost of Gas Sold	197	288	258	254	252	251	250	250	249	249	249
	1 673	1 820	1 912	2 010	2 145	2 253	2 362	2 461	2 608	2 913	3 102
Other	27	39	41	42	42	43	44	45	46	47	48
	1 700	1 858	1 952	2 052	2 187	2 296	2 407	2 506	2 654	2 960	3 150
EXPENSES											
Operating and Administrative	466	521	623	633	640	647	662	672	688	705	718
Finance Expense	423	478	493	547	581	615	684	809	849	1 194	1 156
Depreciation and Amortization	381	432	376	381	398	410	446	492	507	575	601
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	102	108	108	115	124	133	143	150	157	146	153
	1 637	1 827	1 871	1 976	2 048	2 122	2 269	2 471	2 566	2 999	3 013
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	63	31	81	74	137	172	135	32	85	(42)	127
Additional General Consumers Revenue											
General electricity rate increases	0.00%	3.57%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
General gas rate increases	0.00%	2.00%	1.75%	0.00%	0.50%	0.50%	0.00%	0.50%	0.50%	0.50%	0.50%
Financial Ratios											
Equity	25%	24%	18%	16%	15%	15%	14%	13%	13%	12%	12%
Interest Coverage	1.11	1.05	1.12	1.10	1.16	1.18	1.12	1.03	1.07	0.97	1.09
Capital Coverage	0.93	1.19	1.18	1.22	1.47	1.58	1.51	1.32	1.49	1.45	1.85

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF11-2)
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers	2 540	2 646	2 724	2 804	2 892	2 980	3 069	3 161	3 252	3 349
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
	3 470	3 593	3 848	4 212	4 418	4 523	4 608	4 705	4 817	4 923
Cost of Gas Sold	248	248	248	247	247	247	247	248	248	248
	3 222	3 345	3 600	3 965	4 170	4 276	4 361	4 457	4 569	4 675
Other	49	50	51	52	53	54	55	56	57	58
	3 271	3 395	3 651	4 017	4 223	4 330	4 416	4 513	4 626	4 734
EXPENSES										
Operating and Administrative	732	745	769	779	792	807	822	837	853	869
Finance Expense	1 139	1 129	1 223	1 449	1 596	1 564	1 526	1 476	1 491	1 392
Depreciation and Amortization	606	610	643	711	763	772	785	795	828	850
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	160	165	171	174	175	177	180	182	184	186
	3 034	3 078	3 223	3 540	3 781	3 794	3 798	3 791	3 870	3 824
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	226	305	417	465	431	524	605	709	743	896
Additional General Consumers Revenue										
General electricity rate increases	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
General gas rate increases	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	0.50%	1.00%
Financial Ratios										
Equity	12%	13%	14%	16%	18%	20%	22%	24%	27%	30%
Interest Coverage	1.15	1.19	1.26	1.28	1.26	1.33	1.38	1.45	1.48	1.62
Capital Coverage	1.92	1.97	2.02	2.32	2.28	2.52	2.54	2.60	3.23	2.92

CONSOLIDATED PROJECTED BALANCE SHEET (IFF11-2)
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS											
Plant in Service	14 393	15 839	16 375	17 156	18 100	18 703	22 149	22 663	26 307	29 089	29 479
Accumulated Depreciation	(5 067)	(5 429)	(5 754)	(6 098)	(6 472)	(6 851)	(7 293)	(7 782)	(8 286)	(8 856)	(9 454)
Net Plant in Service	9 326	10 410	10 621	11 058	11 628	11 851	14 856	14 882	18 021	20 233	20 025
Construction in Progress	2 445	2 198	3 150	3 999	5 015	6 412	5 348	6 449	4 560	3 597	4 966
Current and Other Assets	1 456	1 357	779	793	1 047	1 204	1 471	1 328	1 465	1 735	1 611
Goodwill and Intangible Assets	256	252	235	220	205	194	185	178	171	166	162
Regulated Assets	321	326	-	-	-	-	-	-	-	-	-
	13 803	14 543	14 785	16 070	17 895	19 661	21 860	22 837	24 217	25 731	26 763
LIABILITIES AND EQUITY											
Long-Term Debt	9 270	9 487	10 926	12 186	13 806	15 278	17 043	18 535	19 497	21 007	22 451
Current and Other Liabilities	1 425	1 939	1 390	1 463	1 577	1 706	2 020	1 478	1 819	1 872	1 345
Contributions in Aid of Construction	320	332	345	352	359	370	381	391	401	411	422
Retained Earnings	2 453	2 483	2 203	2 277	2 414	2 587	2 722	2 754	2 839	2 796	2 924
Accumulated Other Comprehensive Income	335	302	(79)	(209)	(261)	(279)	(306)	(322)	(338)	(356)	(379)
	13 803	14 543	14 785	16 070	17 895	19 661	21 860	22 837	24 217	25 731	26 763
Equity Ratio	25%	24%	18%	16%	15%	15%	14%	13%	13%	12%	12%

CONSOLIDATED PROJECTED BALANCE SHEET (IFF11-2)
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
ASSETS										
Plant in Service	29 916	30 512	34 954	39 061	40 352	41 013	41 609	42 165	44 213	44 957
Accumulated Depreciation	(10 058)	(10 667)	(11 311)	(12 022)	(12 786)	(13 557)	(14 338)	(15 128)	(15 952)	(16 798)
Net Plant in Service	19 858	19 845	23 644	27 038	27 566	27 455	27 271	27 037	28 261	28 159
Construction in Progress	6 101	6 971	4 172	1 024	547	788	1 261	1 724	621	760
Current and Other Assets	1 721	1 990	2 226	2 208	2 601	3 007	3 276	3 517	4 080	4 743
Goodwill and Intangible Assets	159	158	156	154	153	151	150	149	148	148
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27 839	28 963	30 198	30 424	30 866	31 401	31 958	32 427	33 110	33 811
LIABILITIES AND EQUITY										
Long-Term Debt	23 454	24 257	24 610	24 812	24 814	24 755	24 506	24 408	24 197	23 169
Current and Other Liabilities	1 195	1 200	1 654	1 201	1 200	1 258	1 446	1 292	1 430	2 250
Contributions in Aid of Construction	432	443	453	464	476	487	499	512	524	537
Retained Earnings	3 150	3 455	3 872	4 338	4 768	5 292	5 898	6 607	7 350	8 245
Accumulated Other Comprehensive Income	(392)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)
	27 839	28 963	30 198	30 424	30 866	31 401	31 958	32 427	33 110	33 811
Equity Ratio	12%	13%	14%	16%	18%	20%	22%	24%	27%	30%

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF11-2)
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 975	2 238	2 305	2 397	2 531	2 640	2 750	2 849	2 997	3 304	3 496
Cash Paid to Suppliers and Employees	(1 150)	(1 245)	(1 341)	(1 385)	(1 405)	(1 431)	(1 471)	(1 502)	(1 540)	(1 561)	(1 586)
Interest Paid	(423)	(484)	(494)	(536)	(585)	(619)	(704)	(839)	(863)	(1 212)	(1 175)
Interest Received	26	28	27	20	27	34	41	43	40	36	35
	427	537	497	496	569	624	615	552	633	568	770
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	1 000	1 650	1 450	2 000	2 000	2 600	1 800	1 600	2 200	1 600
Sinking Fund Withdrawals	23	129	395	105	24	-	4	424	177	265	689
Retirement of Long-Term Debt	(25)	(181)	(808)	(214)	(312)	(408)	(530)	(837)	(309)	(640)	(692)
Other	(81)	(21)	(14)	(5)	(7)	(7)	(7)	(16)	(5)	26	(6)
	729	926	1 223	1 336	1 705	1 585	2 067	1 371	1 462	1 851	1 591
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1 204)	(1 270)	(1 510)	(1 637)	(1 956)	(2 009)	(2 362)	(1 596)	(1 850)	(1 887)	(1 728)
Sinking Fund Payment	(98)	(117)	(208)	(124)	(192)	(157)	(231)	(209)	(219)	(288)	(346)
Other	(20)	(21)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(35)	(40)
	(1 322)	(1 408)	(1 738)	(1 782)	(2 168)	(2 212)	(2 629)	(1 835)	(2 098)	(2 210)	(2 114)
Net Increase (Decrease) in Cash	(166)	56	(18)	51	106	(2)	53	87	(2)	210	247
Cash at Beginning of Year	70	(96)	(41)	(58)	(8)	98	96	149	237	234	444
Cash at End of Year	(96)	(41)	(58)	(8)	98	96	149	237	234	444	691

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF11-2)
(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	3 617	3 742	3 999	4 366	4 574	4 682	4 770	4 869	4 983	5 092
Cash Paid to Suppliers and Employees	(1 618)	(1 667)	(1 683)	(1 705)	(1 747)	(1 782)	(1 811)	(1 844)	(1 873)	(1 904)
Interest Paid	(1 133)	(1 118)	(1 222)	(1 460)	(1 610)	(1 590)	(1 563)	(1 519)	(1 514)	(1 453)
Interest Received	20	21	31	36	38	49	60	64	71	84
	887	978	1 125	1 236	1 255	1 359	1 455	1 570	1 667	1 819
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 000	800	800	200	-	-	-	-	-	-
Sinking Fund Withdrawals	159	-	-	401	-	-	60	250	-	13
Retirement of Long-Term Debt	(159)	-	-	(450)	-	-	(60)	(250)	(100)	(213)
Other	(7)	(6)	(6)	(8)	(8)	(7)	(7)	(6)	(4)	(19)
	993	794	794	143	(8)	(7)	(7)	(6)	(104)	(219)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 542)	(1 434)	(1 612)	(925)	(781)	(869)	(1 039)	(990)	(914)	(853)
Sinking Fund Payment	(234)	(246)	(263)	(282)	(274)	(285)	(297)	(306)	(305)	(317)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1 805)	(1 710)	(1 903)	(1 235)	(1 085)	(1 183)	(1 365)	(1 325)	(1 248)	(1 199)
Net Increase (Decrease) in Cash	74	62	17	144	162	169	84	239	315	401
Cash at Beginning of Year	691	765	828	845	989	1 151	1 320	1 404	1 643	1 958
Cash at End of Year	765	828	845	989	1 151	1 320	1 404	1 643	1 958	2 359

11.0 CAPITAL EXPENDITURE FORECAST (CEF11-2)

CAPITAL EXPENDITURE FORECAST (CEF11-2)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
ELECTRIC													
Major New Generation & Transmission													
Wuskwatim - Generation	1 374.6	181.1	65.3	5.9	-	-	-	-	-	-	-	-	252.3
Wuskwatim - Transmission	297.4	31.6	-	-	-	-	-	-	-	-	-	-	31.6
Herblet Lake – The Pas 230 kV Transmission	74.9	6.4	0.7	-	-	-	-	-	-	-	-	-	7.2
Keeyask - Generation	5 636.9	115.6	163.4	198.2	401.1	662.9	895.6	1 041.0	786.3	716.4	189.2	45.4	5 215.1
Conawapa - Generation	7 770.8	104.4	105.2	66.1	67.2	188.1	235.4	296.8	322.6	764.7	1 229.5	1 222.9	4 603.0
Kelsey Improvements & Upgrades	301.7	34.4	24.8	20.2	0.4	-	-	-	-	-	-	-	79.7
Kettle Improvements & Upgrades	165.7	13.7	22.9	20.4	20.7	7.3	7.4	7.6	7.7	7.9	8.0	8.2	131.9
Pointe du Bois Spillway Replacement	398.2	41.1	113.6	100.4	77.1	13.0	-	-	-	-	-	-	345.2
Pointe du Bois - Transmission	85.9	14.5	11.1	18.2	16.4	-	-	-	-	-	-	-	60.2
Pointe du Bois Powerhouse Rebuild	1 538.3	-	-	-	-	-	-	-	-	-	-	0.5	0.5
Bipole III - Transmission Line	1 259.9	31.0	52.8	135.4	330.9	353.9	239.0	73.4	-	-	-	-	1 216.3
Bipole III - Converter Stations	1 828.5	50.7	141.6	315.4	330.6	353.5	356.3	163.2	58.8	-	-	-	1 770.0
Bipole III - Collector Lines	191.4	9.9	57.8	46.9	22.6	25.2	18.5	10.1	-	-	-	-	191.1
Riel 230/ 500 kV Station	267.6	74.8	67.7	47.5	-	-	-	-	-	-	-	-	190.0
Firm Import Upgrades	19.9	0.2	19.7	-	-	-	-	-	-	-	-	-	19.9
Dorsey - US Border New 500kV Transmission Line	204.8	0.1	0.8	0.4	2.0	3.6	34.0	84.0	79.0	-	-	-	203.9
St. Joseph Wind Transmission	11.2	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Demand Side Management	NA	31.8	33.6	-	-	-	-	-	-	-	-	-	65.4
Generating Station Improvements & Upgrades	649.0	-	-	-	-	-	-	-	-	-	45.0	32.2	77.3
Single Cycle Gas Turbines	65.6	-	-	-	-	-	-	-	-	-	-	-	-
Additional North South Trasmission	318.2	-	-	-	-	-	-	-	-	-	-	-	-
Target Adjustment	(317.2)	(87.8)	(118.3)	85.0	(45.4)	(40.7)	(175.7)	277.0	(77.3)	(77.0)	(26.0)	(3.2)	(289.4)
		656.1	762.6	1 060.0	1 223.4	1 566.9	1 610.5	1 953.0	1 177.1	1 412.0	1 445.8	1 306.0	14 173.5

CAPITAL EXPENDITURE FORECAST (CEF11-2)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Power Supply													
HVDC Auxiliary Power Supply Upgrades	5.3	0.5	0.4	-	-	-	-	-	-	-	-	-	0.9
Dorsey Synchronous Condenser Refurbishment	78.3	4.6	5.3	5.1	7.7	11.7	11.4	8.3	-	-	-	-	54.2
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	0.5	0.3	0.3	0.1	-	-	-	-	-	-	-	1.2
HVDC Transformer Replacement Program	171.7	4.6	17.6	15.5	17.2	14.0	9.7	-	-	-	-	-	78.5
HVDC Transformer Replacement Program Extended	449.7	-	-	-	-	-	-	-	-	-	0.5	4.6	5.2
Dorsey 230 kV Relay Building Upgrade	82.2	1.6	2.2	17.7	35.1	12.5	3.1	-	-	-	-	-	72.2
HVDC Stations Ground Grid Refurbishment	4.3	0.4	0.4	0.4	0.3	0.5	-	-	-	-	-	-	2.1
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	15.9	2.1	1.1	1.0	0.2	0.5	0.1	0.1	0.0	-	-	-	5.2
HVDC Bipole 1 Pole Differential Protection	3.3	-	-	1.1	2.2	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.4	2.3	11.1	6.0	-	-	-	-	-	-	-	19.8
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	0.2	2.7	2.4	5.6	-	-	-	-	-	-	11.0
HVDC Smoothing Reactor Replacements	39.3	20.6	1.8	0.7	-	-	-	-	-	-	-	-	23.1
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Separation	3.2	0.4	1.2	1.5	-	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	0.2	1.3	1.1	3.0	3.8	2.4	-	-	-	-	-	11.7
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Replacements	8.7	0.6	1.0	1.7	5.3	0.0	-	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	19.2	0.1	-	3.3	4.8	4.0	4.2	2.3	-	-	-	-	18.7
HVDC Bipole 2 Upgrades & Replacements	444.2	-	-	-	-	-	-	-	-	-	12.3	52.7	65.0
HVDC Bipole 1 CQ Disconnect Replacement	5.2	0.3	0.9	1.5	1.0	1.1	0.3	-	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	4.7	1.2	-	-	-	-	-	-	-	-	-	-	1.2
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.8	0.4	2.7	1.2	1.2	-	-	-	-	-	-	-	5.5
HVDC Gapped Arrestor Replacement	16.3	0.2	1.0	3.9	3.4	7.0	0.1	-	-	-	-	-	15.7
Converter Transformer Bushing Replacement	5.9	0.4	1.0	0.5	-	-	-	-	-	-	-	-	1.9
Winnipeg River Riverbank Protection Program	19.7	1.5	1.4	1.3	1.3	1.3	0.8	-	-	-	-	-	7.5
Power Supply Hydraulic Controls	20.5	1.0	0.7	1.3	-	-	-	2.1	2.6	0.9	-	-	8.6
Slave Falls GS Creek Spillway Rehab	11.1	0.0	1.0	1.9	8.1	-	-	-	-	-	-	-	11.1
Slave Falls Rehabilitation	230.2	9.0	2.6	4.3	31.7	40.6	45.8	42.0	11.3	-	-	-	187.3
Great Falls Unit 4 Major Overhaul	43.5	11.4	21.6	0.8	-	-	-	-	-	-	-	-	33.8
Great Falls Unit 5 Discharge Ring Replacement and Major Overhaul	24.8	-	-	-	2.2	17.1	5.4	-	-	-	-	-	24.8
Generation South Overhauls & Improvements	384.8	-	-	-	-	-	-	-	-	-	4.7	10.2	14.8
Pine Falls Rehabilitation	166.7	4.0	21.0	26.9	40.3	46.8	14.0	0.1	-	-	-	-	153.0
Generation South Transformer Refurbish & Spares	27.6	0.6	7.0	13.8	4.3	0.5	0.5	-	-	-	-	-	26.6
Water Licenses & Renewals	54.6	5.2	5.6	6.2	6.3	6.5	6.5	3.9	-	-	-	-	40.2
Generation South PCB Regulation Compliance	4.7	0.5	0.4	0.4	0.2	2.7	-	-	-	-	-	-	4.1
Kettle Transformer Overhaul Program	35.6	9.1	7.1	7.9	0.7	-	-	-	-	-	-	-	24.8
Generation South Breaker Replacements	11.1	1.7	3.8	0.5	1.0	0.4	1.2	-	-	-	-	-	8.5
Seven Sisters Upgrades	14.4	4.4	1.6	0.6	-	-	-	-	-	-	-	-	6.6
Generation South Excitation Upgrades	18.3	1.3	1.5	2.3	1.9	2.5	1.0	0.7	6.9	0.2	-	-	18.3
Generation South Excitation Program Extended	14.0	-	-	-	-	-	-	-	-	-	4.4	5.0	9.4
Laurie River/Churchill River Diversion (CRD) Comm and Annunciation Upgrad	4.8	2.1	1.9	-	-	-	-	-	-	-	-	-	4.0
Notigi Marine Vessel Replacement and Infrastructure Improvements	4.6	0.3	4.1	-	-	-	-	-	-	-	-	-	4.4
Limestone Stilling Basin Rehabilitation	2.0	0.0	0.4	1.6	-	-	-	-	-	-	-	-	2.0
Pointe Du Bois GS Rehabilitation	50.0	6.3	19.8	19.5	4.4	-	-	-	-	-	-	-	49.9
Kettle Wicket Gates Lever Refurbishments	2.3	-	1.1	1.2	-	-	-	-	-	-	-	-	2.3
Limestone Governor Control Repl	2.5	-	0.3	1.3	0.9	-	-	-	-	-	-	-	2.5
Limestone GSCADA Replacement	5.3	-	0.4	1.3	0.8	0.9	0.4	1.5	-	-	-	-	5.3
Jenpeg Unit Overhauls	128.1	-	-	-	-	2.2	2.5	18.0	23.7	24.2	24.6	20.8	115.9
Power Supply Dam Safety Upgrades	64.5	7.4	10.6	5.0	-	-	-	-	-	-	-	-	23.1
Brandon Unit 5 License Review	18.7	0.2	0.2	2.6	10.4	0.0	-	-	-	-	-	-	13.4
Selkirk Enhancements	14.2	0.4	0.9	-	-	-	-	-	-	-	-	-	1.3
Fire Protection Projects - HVDC	7.2	0.4	0.2	1.2	2.9	-	-	-	-	-	-	-	4.7
Halon Replacement Project	36.4	1.6	5.2	2.6	3.5	2.2	0.9	-	-	-	-	-	16.0
Oil Containment – Power Supply	19.1	0.7	0.5	0.7	0.4	0.6	0.3	-	-	-	-	-	3.1
Grand Rapids Townsite House Renovations	5.2	1.1	0.9	0.9	0.9	0.0	-	-	-	-	-	-	3.9
Grand Rapids Fish Hatchery	2.2	1.2	0.8	-	-	-	-	-	-	-	-	-	2.0
Generation Townsite Infrastructure	52.1	9.0	1.9	-	-	-	-	-	-	-	-	-	10.9
Site Remediation of Contaminated Corporate Facilities	32.8	1.6	1.1	-	-	-	-	-	-	-	-	-	2.7
High Voltage Test Facility	40.6	13.7	0.4	-	-	-	-	-	-	-	-	-	14.1
Power Supply Security Installations / Upgrades	43.2	5.6	7.9	9.7	4.7	-	-	-	-	-	-	-	27.8
Power Supply Sewer & Domestic Water System Install and Upgrade	37.9	6.4	2.9	1.0	2.4	1.6	2.4	3.1	0.1	-	-	-	19.9
Power Supply Domestic	509.2	19.7	20.1	20.5	21.0	21.4	21.8	22.2	22.7	23.1	23.6	24.1	240.3
Target Adjustment	(335.8)	(10.7)	(60.3)	(57.3)	(76.4)	(77.5)	(30.6)	(19.6)	(1.6)	0.5	0.8	(2.8)	(335.5)
		155.6	137.6	150.4	163.9	130.5	104.1	84.8	65.6	48.9	70.8	114.6	1 226.7

CAPITAL EXPENDITURE FORECAST (CEF11-2)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Transmission													
Winnipeg - Brandon Transmission System Improvements	44.8	3.0	0.8	4.1	28.7	3.7	-	-	-	-	-	-	40.3
Transcona East 230 - 66 kV Station	33.1	24.1	-	-	-	-	-	-	-	-	-	-	24.1
Brandon Area Transmission Improvements	11.8	4.4	6.3	1.0	-	-	-	-	-	-	-	-	11.6
Neepawa 230 - 66 kV Station	30.0	14.1	8.0	4.5	-	-	-	-	-	-	-	-	26.6
Transmission Line Re-Rating	31.8	2.9	6.4	-	-	-	-	-	-	-	-	-	9.3
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	0.8	0.9	2.6	6.1	9.7	12.1	-	32.2
Transcona Station 66 kV Breaker Replacement	6.0	0.4	2.9	1.5	1.1	0.0	-	-	-	-	-	-	6.0
13.2kV Shunt Reactor Replacements	33.0	2.2	4.9	0.9	0.8	2.2	2.3	2.3	17.5	-	-	-	33.0
Lake Winnipeg East System Improvements	66.9	2.3	5.7	15.4	29.2	14.2	0.1	-	-	-	-	-	66.8
Canexus Load Addition	(0.2)	0.9	0.1	-	-	-	-	-	-	-	-	-	1.0
D602F 500kV T/L Footing Replacements	4.4	4.4	-	-	-	-	-	-	-	-	-	-	4.4
Stanley Station 230-66 kV Transformer Addition	21.1	0.0	1.8	7.3	7.9	4.0	-	-	-	-	-	-	21.1
Enbridge Pipelines: Clipper Project Load Addition Phase 2	7.5	1.8	1.9	0.0	-	-	-	-	-	-	-	-	3.7
Ashern Station Bank Addition	10.6	0.2	1.6	1.5	7.0	0.2	-	-	-	-	-	-	10.6
Ashern Station 230 kV Shunt Reactor Replacement	2.7	0.9	1.8	-	-	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Diesel Tank Farm Upgrade	1.1	(1.0)	0.7	-	-	-	-	-	-	-	-	-	(0.4)
Energy Management System (EMS) Upgrade	6.6	2.8	2.0	-	-	-	-	-	-	-	-	-	4.8
Transmission Line Protection & Teleprotection Replacement	21.1	3.1	3.4	2.8	2.8	2.9	2.4	-	-	-	-	-	17.5
Winnipeg Central Protection Wireline Replacement	10.5	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Mobile Radio System Modernization	30.7	1.9	6.4	2.8	11.6	7.9	-	-	-	-	-	-	30.5
Site Remediation of Diesel Generating Stations	13.3	2.3	0.7	-	-	-	-	-	-	-	-	-	3.0
Oil Containment - Transmission	7.4	0.4	0.0	-	-	-	-	-	-	-	-	-	0.4
Station Battery Bank Capacity & System Reliability Increase	46.5	4.8	5.1	4.9	5.0	5.2	-	-	-	-	-	-	25.0
Waverley Service Centre Oil Tank Farm Replacement	3.0	0.5	0.4	0.7	-	-	-	-	-	-	-	-	1.6
115 kV Transmission Lines	298.9	-	-	-	-	-	-	-	-	-	10.3	16.1	26.4
230 kV Transmission Lines	171.1	-	-	-	-	-	-	-	-	-	5.9	9.2	15.1
Sub-Transmission	124.8	-	-	-	-	-	-	-	-	-	4.3	6.7	11.0
Communications	425.8	-	-	-	-	-	-	-	-	-	14.7	23.0	37.6
Site Remediation	NA	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Domestic	788.9	30.6	31.2	31.8	32.5	33.1	33.8	34.5	35.1	35.9	36.6	37.3	372.3
Target Adjustment	(41.6)	(24.3)	(13.4)	27.3	(38.2)	(13.6)	(0.1)	2.2	(14.6)	0.0	1.0	1.8	(71.9)
		83.1	78.7	106.5	88.6	60.7	39.3	41.6	44.1	45.6	84.8	94.1	767.0
Customer Service & Distribution													
Winnipeg Distribution Infrastructure Requirements	24.5	2.3	2.3	2.9	-	-	-	-	-	-	-	-	7.5
Rover Substation Replace 4 kV Switchgear	12.7	0.0	0.1	1.7	2.5	2.8	0.5	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	1.2	11.9	8.1	2.2	-	-	-	-	-	-	-	23.3
Frobisher Station Upgrade	14.4	0.5	1.0	-	-	-	-	-	-	-	-	-	1.5
Burrows New 66 kV/ 12 kV Station	28.6	12.1	6.7	-	-	-	-	-	-	-	-	-	18.9
Winnipeg Central 12&4kV Manhole Oil Switches	9.8	1.4	-	-	-	-	-	-	-	-	-	-	1.4
William New 66 kV/ 12 kV Station	10.3	0.5	2.2	2.9	3.2	1.1	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply - Stage 1	6.5	0.7	-	-	-	-	-	-	-	-	-	-	0.7
St. James New Station & 24 kV Conversion	65.9	0.6	6.3	3.9	9.5	21.8	23.6	-	-	-	-	-	65.7
Distribution	887.5	-	-	-	-	-	-	-	-	-	30.5	47.9	78.4
York Station Bank & Switchgear Addition	6.0	1.4	-	-	-	-	-	-	-	-	-	-	1.4
Defective RINJ Cable Replacement	8.7	1.3	1.3	-	-	-	-	-	-	-	-	-	2.7
Health Sciences Centre Service Consolidation & Distribution Upgrade	15.8	2.0	5.0	3.6	4.0	0.6	-	-	-	-	-	-	15.2
Waverley South DSC Installation	3.9	2.7	-	-	-	-	-	-	-	-	-	-	2.7
Southdale DK732 Cable Replacement	2.6	0.9	1.2	-	-	-	-	-	-	-	-	-	2.1
Steinbach Area 66kV Capacity Upgrade	6.3	5.9	0.3	-	-	-	-	-	-	-	-	-	6.2
Line 27 66 kV Extension and Arborg North Distribution Supply Centre	6.0	4.3	1.2	-	-	-	-	-	-	-	-	-	5.4
AECL Station Switchgear Replacement	2.4	0.8	-	-	-	-	-	-	-	-	-	-	0.8
Melrose DSC	3.5	3.5	-	-	-	-	-	-	-	-	-	-	3.5
Starbuck DSC	3.0	3.0	-	-	-	-	-	-	-	-	-	-	3.0
Enbridge Pipelines Clipper-66kV Supply I	0.9	2.1	-	-	-	-	-	-	-	-	-	-	2.1
Teulon East 66-12 kV Station	4.6	4.2	-	-	-	-	-	-	-	-	-	-	4.2
Waskada New 66-25kV Distrib'n Supply Ctr	3.9	3.9	-	-	-	-	-	-	-	-	-	-	3.9
Cromer North Station & Reston RE12-4 25kV Conversion	4.3	0.2	1.2	-	-	-	-	-	-	-	-	-	1.3
Brandon Crocus Plains 115-25 kV Bank Addition	6.3	0.0	0.0	0.0	6.2	-	-	-	-	-	-	-	6.2
Birtle South - Rossburn 66kV Line	4.9	-	-	0.1	0.3	4.5	-	-	-	-	-	-	4.9
TCPL Keystone Project	8.0	2.1	2.4	-	-	-	-	-	-	-	-	-	4.5
Line 98 Rebuild Melita to Waskada	3.8	3.8	-	-	-	-	-	-	-	-	-	-	3.8
Customer Service & Distribution Domestic	3 310.3	127.9	130.5	133.2	136.3	139.0	141.8	144.7	147.5	150.5	153.5	156.6	1 561.5
Target Adjustment	(257.5)	(30.3)	(6.8)	(11.2)	(21.6)	(18.7)	(14.8)	(9.6)	(9.8)	(10.0)	(10.2)	(10.4)	(153.6)
		159.0	166.8	145.1	142.5	151.1	151.2	135.0	137.7	140.5	173.8	194.0	1 696.6

CAPITAL EXPENDITURE FORECAST (CEF11-2)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Customer Care & Marketing													
Advanced Metering Infrastructure	30.9	-	4.0	5.3	5.4	5.6	4.3	4.2	-	-	-	-	28.8
Customer Care & Marketing Domestic	91.2	3.0	3.0	3.1	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	42.0
Target Adjustment	(22.3)	3.6	1.0	(0.3)	(0.9)	(2.3)	(1.2)	(5.4)	(1.1)	(1.2)	(1.2)	(1.2)	(10.2)
		6.6	8.0	8.1	8.4	7.2	7.1	2.9	3.0	3.1	3.1	3.2	60.7
Finance & Administration													
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
EAM Phase 2	19.3	6.1	8.9	2.3	-	-	-	-	-	-	-	-	17.3
Workforce Management (Phase 1 to 4)	15.7	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Fleet	NA	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	16.5	16.8	167.7
Finance & Administration Domestic	643.1	24.9	25.4	25.9	26.5	27.0	27.5	28.1	28.7	29.2	29.8	30.4	303.5
Target Adjustment	(20.2)	(8.4)	(8.9)	(2.3)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(19.8)
		46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	54.3	55.2	559.0
ELECTRIC CAPITAL SUBTOTAL		**1 107.1**	**1 201.1**	**1 518.2**	**1 675.9**	**1 966.2**	**1 962.9**	**2 268.9**	**1 480.0**	**1 703.3**	**1 832.6**	**1 767.1**	**18 483.4**
GAS													
Customer Service & Distribution													
Ile Des Chenes NG Transmission Network Upgrade	1.2	0.3	0.9	-	-	-	-	-	-	-	-	-	1.2
Gas SCADA Replacement	4.6	3.6	-	-	-	-	-	-	-	-	-	-	3.6
Buncloudy Natural Gas Crossing at Souris River	1.6	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Customer Service & Distribution Domestic	649.4	25.2	25.7	26.2	26.7	27.3	27.8	28.4	28.9	29.5	30.1	30.7	306.5
Target Adjustment	(94.4)	(6.2)	(4.5)	(3.7)	(3.7)	(3.8)	(3.9)	(4.0)	(4.0)	(4.1)	(4.2)	(4.3)	(46.4)
		24.6	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	25.9	26.4	266.5
Customer Care & Marketing													
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.4	-	-	-	-	-	-	-	14.7
Demand Side Management	NA	12.6	13.4	-	-	-	-	-	-	-	-	-	26.1
Customer Care & Marketing Domestic	122.1	4.8	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.7	5.8	57.7
Target Adjustment	(52.5)	(1.5)	1.4	(1.2)	(11.9)	(2.9)	(2.9)	(2.1)	(2.7)	(2.8)	(2.3)	(2.3)	(31.1)
		15.9	20.7	9.1	1.5	2.3	2.4	3.3	2.7	2.7	3.4	3.5	67.3
GAS CAPITAL SUBTOTAL		**40.5**	**42.8**	**31.6**	**24.5**	**25.7**	**26.3**	**27.7**	**27.6**	**28.1**	**29.3**	**29.9**	**333.9**
CONSOLIDATED CAPITAL		**1 147.6**	**1 243.9**	**1 549.8**	**1 700.4**	**1 991.9**	**1 989.1**	**2 296.6**	**1 507.6**	**1 731.5**	**1 861.9**	**1 797.0**	**18 817.3**
Target Adjustment	NA	(33.6)	(0.0)	0.0	0.0	31.1	87.9	135.9	160.3	182.2	51.8	5.2	620.8
CEF11-2 TOTAL		**1 114.1**	**1 243.9**	**1 549.8**	**1 700.4**	**2 022.9**	**2 077.0**	**2 432.5**	**1 667.9**	**1 913.6**	**1 913.7**	**1 802.1**	**19 438.1**

12.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH11-2)

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
REVENUES											
General Consumers											
at approved rates	1 186	1 290	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	45	106	156	208	265	325	387	455	527	603
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 693	1 778	1 873	2 007	2 114	2 224	2 320	2 466	2 769	2 957
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	452	504	537	570	640	763	803	1 147	1 109
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 672	1 709	1 810	1 881	1 952	2 100	2 300	2 393	2 823	2 833
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	68	62	124	159	121	18	70	(57)	113
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase	0.00%	4.50%	8.16%	11.94%	15.86%	19.92%	24.11%	28.46%	32.95%	37.61%	42.42%

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
REVENUES										
General Consumers										
at approved rates	1 441	1 460	1 479	1 498	1 521	1 541	1 562	1 582	1 602	1 622
additional*	683	767	822	880	941	1 004	1 069	1 136	1 205	1 277
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
Other	19	20	20	20	21	21	22	22	23	23
	3 074	3 193	3 445	3 806	4 008	4 110	4 191	4 284	4 394	4 497
EXPENSES										
Operating and Administrative	634	646	669	676	688	700	713	727	741	755
Finance Expense	1 091	1 079	1 173	1 398	1 545	1 512	1 473	1 424	1 438	1 338
Depreciation and Amortization	579	583	615	682	733	741	753	761	793	814
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	156	158	160	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2 850	2 891	3 032	3 345	3 582	3 591	3 591	3 580	3 655	3 604
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	213	291	402	450	415	507	588	691	726	878
* Additional General Consumers Revenue										
Percent Increase	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.41%	52.57%	55.62%	58.73%	61.91%	65.14%	68.45%	71.82%	75.25%	78.76%

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS											
Plant in Service	13 795	15 212	15 723	16 485	17 410	17 993	21 415	21 904	25 521	28 275	28 636
Accumulated Depreciation	(4 917)	(5 266)	(5 581)	(5 911)	(6 272)	(6 638)	(7 065)	(7 539)	(8 028)	(8 583)	(9 165)
Net Plant in Service	8 878	9 947	10 142	10 574	11 138	11 355	14 351	14 365	17 492	19 692	19 472
Construction in Progress	2 443	2 196	3 149	3 997	5 014	6 410	5 346	6 447	4 558	3 595	4 964
Current and Other Assets	1 906	1 864	1 327	1 372	1 559	1 740	1 987	1 779	1 951	2 171	2 048
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	241	-	-	-	-	-	-	-	-	-
	13 648	14 426	14 780	16 092	17 847	19 631	21 800	22 701	24 105	25 555	26 577
LIABILITIES AND EQUITY											
Long-Term Debt	9 253	9 469	10 909	12 169	13 789	15 260	17 025	18 518	19 480	20 990	22 434
Current and Other Liabilities	1 351	1 917	1 407	1 520	1 574	1 736	2 035	1 432	1 810	1 814	1 289
Contributions in Aid of Construction	317	328	341	348	355	365	376	386	396	407	418
Retained Earnings	2 391	2 411	2 203	2 265	2 389	2 548	2 669	2 687	2 757	2 700	2 814
Accumulated Other Comprehensive Income	335	302	(79)	(209)	(261)	(279)	(306)	(322)	(338)	(356)	(379)
	13 648	14 426	14 780	16 092	17 847	19 631	21 800	22 701	24 105	25 555	26 577

ELECTRIC OPERATIONS (MH11-2)
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	29 045	29 610	34 023	38 098	39 357	39 988	40 557	41 087	43 107	43 823
Accumulated Depreciation	(9 752)	(10 344)	(10 970)	(11 663)	(12 407)	(13 160)	(13 926)	(14 701)	(15 509)	(16 338)
Net Plant in Service	19 293	19 267	23 053	26 435	26 951	26 828	26 631	26 386	27 599	27 485
Construction in Progress	6 099	6 969	4 170	1 022	545	786	1 259	1 722	618	758
Current and Other Assets	2 158	2 426	2 660	2 640	3 029	3 431	3 695	3 929	4 486	5 143
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27 641	28 752	29 972	30 183	30 609	31 128	31 667	32 118	32 783	33 466
LIABILITIES AND EQUITY										
Long-Term Debt	23 437	24 240	24 593	24 795	24 796	24 738	24 489	24 391	24 180	23 152
Current and Other Liabilities	1 140	1 146	1 599	1 146	1 145	1 203	1 390	1 236	1 374	2 193
Contributions in Aid of Construction	429	440	451	463	475	487	499	512	525	538
Retained Earnings	3 026	3 317	3 719	4 170	4 584	5 092	5 679	6 370	7 096	7 974
Accumulated Other Comprehensive Income	(392)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)
	27 641	28 752	29 972	30 183	30 609	31 128	31 667	32 118	32 783	33 466

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 556	1 693	1 778	1 873	2 007	2 114	2 224	2 320	2 466	2 769	2 957
Cash Paid to Suppliers and Employees	(742)	(816)	(886)	(931)	(951)	(976)	(1 018)	(1 048)	(1 084)	(1 103)	(1 125)
Interest Paid	(406)	(466)	(475)	(516)	(564)	(598)	(683)	(817)	(841)	(1 188)	(1 151)
Interest Received	26	28	27	20	27	34	41	43	40	36	35
	434	439	444	447	519	574	564	499	580	514	717
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	900	1 630	1 405	1 990	2 000	2 590	1 800	1 590	2 190	1 590
Sinking Fund Withdrawals	23	129	395	105	24	-	4	424	177	265	689
Retirement of Long-Term Debt	(25)	(119)	(808)	(179)	(312)	(408)	(530)	(837)	(309)	(640)	(692)
Other	(81)	(21)	(14)	(5)	(7)	(7)	(7)	(16)	(5)	26	(6)
	729	889	1 203	1 326	1 695	1 585	2 057	1 371	1 452	1 841	1 581
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1 163)	(1 226)	(1 481)	(1 616)	(1 934)	(1 986)	(2 336)	(1 567)	(1 820)	(1 856)	(1 697)
Sinking Fund Payment	(98)	(117)	(208)	(124)	(192)	(157)	(231)	(209)	(219)	(288)	(346)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1 280)	(1 363)	(1 709)	(1 761)	(2 146)	(2 189)	(2 603)	(1 806)	(2 069)	(2 179)	(2 083)
Net Increase (Decrease) in Cash	(116)	(36)	(62)	12	68	(29)	18	64	(36)	176	215
Cash at Beginning of Year	66	(50)	(86)	(148)	(135)	(67)	(96)	(79)	(15)	(51)	126
Cash at End of Year	(50)	(86)	(148)	(135)	(67)	(96)	(79)	(15)	(51)	126	340

ELECTRIC OPERATIONS (MH11-2)
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	3 074	3 193	3 445	3 806	4 008	4 110	4 191	4 284	4 394	4 497
Cash Paid to Suppliers and Employees	(1 154)	(1 201)	(1 215)	(1 234)	(1 272)	(1 303)	(1 329)	(1 358)	(1 383)	(1 410)
Interest Paid	(1 108)	(1 092)	(1 196)	(1 433)	(1 582)	(1 561)	(1 534)	(1 490)	(1 484)	(1 423)
Interest Received	20	21	31	36	38	49	60	64	71	84
	832	921	1 066	1 175	1 192	1 295	1 388	1 501	1 598	1 748
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	980	790	790	190	(10)	-	(10)	(10)	(30)	(10)
Sinking Fund Withdrawals	159	-	-	401	-	-	60	250	-	13
Retirement of Long-Term Debt	(159)	-	-	(450)	-	-	(60)	(220)	(100)	(213)
Other	(7)	(6)	(6)	(8)	(8)	(7)	(7)	(6)	(4)	(19)
	973	784	784	133	(18)	(7)	(17)	14	(134)	(229)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 510)	(1 401)	(1 578)	(891)	(746)	(834)	(1 003)	(953)	(876)	(814)
Sinking Fund Payment	(234)	(246)	(263)	(282)	(274)	(285)	(297)	(306)	(305)	(317)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1 773)	(1 677)	(1 869)	(1 201)	(1 051)	(1 148)	(1 328)	(1 288)	(1 211)	(1 160)
Net Increase (Decrease) in Cash	32	28	(19)	108	124	140	43	227	253	359
Cash at Beginning of Year	340	372	400	381	489	613	752	796	1 023	1 276
Cash at End of Year	372	400	381	489	613	752	796	1 023	1 276	1 635

13.0 GAS OPERATIONS FINANCIAL FORECAST (CGM11-2)

GAS OPERATIONS (CGM11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
REVENUES											
General Consumers											
at approved rates	328	431	400	400	398	397	396	396	395	395	395
additional revenue requirement*	0	7	14	15	16	18	18	20	22	24	26
	328	438	414	415	415	415	414	416	417	419	422
Cost of Gas Sold	197	288	258	254	253	251	250	250	249	249	249
Gross Margin	131	150	157	161	162	164	164	166	168	170	173
Other	1	2	2	2	2	2	2	2	2	2	2
	132	152	159	163	164	166	166	168	170	172	175
EXPENSES											
Operating and Administrative	62	67	84	85	85	85	84	84	85	86	88
Finance Expense	18	19	22	24	25	25	26	26	27	27	28
Depreciation and Amortization	26	28	20	20	21	21	21	22	23	24	25
Capital and Other Taxes	19	20	16	16	16	17	17	17	18	18	18
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	138	147	153	157	159	161	160	162	164	167	171
Net Income	(6)	5	5	5	5	5	6	6	5	5	4

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
* Additional Revenue Requirement											
Percent Increase		2.00%	1.75%	0.00%	0.50%	0.50%	0.00%	0.50%	0.50%	0.50%	0.50%
Cumulative Percent Increase		2.00%	3.79%	3.79%	4.30%	4.83%	4.83%	5.35%	5.88%	6.41%	6.94%

GAS OPERATIONS (CGM11-2)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS											
Plant in Service	636	658	678	692	707	722	741	762	784	807	830
Accumulated Depreciation	(226)	(234)	(238)	(246)	(254)	(261)	(270)	(279)	(289)	(299)	(310)
Net Plant in Service	410	424	440	446	453	461	471	483	495	508	520
Construction in Progress	2	2	2	2	2	2	2	2	2	2	2
Current and Other Assets	112	114	114	115	123	119	123	114	116	116	115
Goodwill and Intangible Assets	10	8	7	5	4	3	3	3	3	3	3
Regulated Assets	80	85	-	-	-	-	-	-	-	-	-
	614	633	562	568	582	585	599	603	616	629	640
LIABILITIES AND EQUITY											
Long-Term Debt	235	335	320	365	375	375	385	385	395	405	415
Current and Other Liabilities	191	104	116	73	71	68	65	62	61	59	58
Contributions in Aid of Construction	33	34	45	44	44	45	46	46	45	45	44
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	34	39	(40)	(35)	(30)	(25)	(18)	(12)	(7)	(2)	2
	614	633	562	568	582	585	599	603	616	629	640

GAS OPERATIONS (CGM11-2)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
OPERATING ACTIVITIES											
Cash Receipts from Customers	380	504	481	477	477	477	477	478	480	482	485
Cash Paid to Suppliers and Employees	(394)	(412)	(435)	(434)	(433)	(433)	(431)	(432)	(433)	(435)	(437)
Interest Paid	(20)	(21)	(22)	(23)	(24)	(25)	(25)	(26)	(26)	(27)	(28)
	(34)	71	24	20	20	19	20	20	20	21	20
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	-	100	20	45	10	-	10	-	10	10	10
Retirement of Long-Term Debt	-	(63)	-	(35)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-
	-	37	20	10	10	-	10	-	10	10	10
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(41)	(42)	(28)	(21)	(22)	(23)	(26)	(29)	(29)	(30)	(31)
Other	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(41)	(42)	(29)	(21)	(22)	(23)	(26)	(29)	(29)	(31)	(31)
Net Increase (Decrease) in Cash	(75)	65	15	9	8	(4)	4	(8)	1	0	(1)
Cash at Beginning of Year	(19)	(94)	(29)	(14)	(5)	3	(1)	3	(6)	(4)	(4)
Cash at End of Year	(94)	(29)	(14)	(5)	3	(1)	3	(6)	(4)	(4)	(5)

14.0 CORPORATE SUBSIDIARIES FINANCIAL FORECAST (CS11-2)

CORPORATE SUBSIDIARIES (CS11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

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