MIPUG/MH I-1

Subject: Letter of Application and Summary & Reasons for Application

a) Please confirm that the letter contained at Tab 1 fully itemizes at paragraph one, bullets a) through j) the requested approvals Manitoba Hydro is seeking as part of its 2012/13 and 2013/14 General Rate Application.

ANSWER:

Please see Manitoba Hydro’s response to CAC/MH I-1(a).

MIPUG/MH I-1

Subject: Letter of Application and Summary & Reasons for Application

b) In the event that part a) above cannot be confirmed, please provide a full and complete list of all requested approvals Manitoba Hydro is seeking as part of its 2012/13 and 2013/14 General Rate Application.

ANSWER:

Please see Manitoba Hydro's response to CAC/MH I-1(a).

MIPUG/MH I-1

Subject: Letter of Application and Summary & Reasons for Application

c) Please confirm that the interim rates approved April 1, 2012 and September 1, 2012 will be sought to be made final as a result of this application. Additionally, confirm that the 3.5% increase to overall revenues will be on top of the increases to revenues already occurring from the interim rate increases as of April 1, 2013.

ANSWER:

Confirmed.

MIPUG/MH I-2

Subject: Financial Targets

a) Please update the response to MIPUG/MH I-3 (a) from the 2010 General Rate Application regarding financial target changes, if any.

ANSWER:

There have been no changes to Manitoba Hydro's financial targets since 2009 as reported in the response to MIPUG/MH I-3(a) from the 2010 GRA. However, financial targets are currently under review and a report is expected to be presented to the Manitoba Hydro Board in November 2012 (in conjunction with IFF12).

<u>MIPUG/MH I-3</u>

Subject: July 20, 2012 Interim Rates Filing, Attachment 3

a) If not completed, please indicate the expected date for finalization of the 2012/13 Power Resource Plan and confirm it will be filed in this hearing upon completion.

<u>ANSWER</u>:

The preparation of Manitoba Hydro's power resource plan for 2012/13 is in progress. Should the 2012/13 power resource plan be completed and approved for public release prior to the completion of 2012/13 Electric Rate Application process, it will be filed.

MIPUG/MH I-3

Subject: July 20, 2012 Interim Rates Filing, Attachment 3

b) If completed, please file the 2012/13 Power Resource Plan.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-3(a).

MIPUG/MH I-4

Subject: July 20, 2012 Interim Rates Filing, Attachment 3 – Wuskwatim

a) Please confirm that per page 34 of Attachment 3, under current load forecast and supply conditions, Wuskwatim generation is not required for domestic supply until 2019/20.

ANSWER:

Not confirmed.

At the time of 2003 Clean Environment Committee submission, Manitoba Hydro's forecast of electrical supply and demand indicated a requirement for new generation to meet firm requirements in the year 2020. Considering supply and demand changes since then, new generation would have been required prior to 2011/12.

Manitoba Hydro's expectations for the need for Wuskwatim generation have changed as load forecasts have been updated. In addition, 250 MW of wind power has been purchased under Power Purchase Agreements, which has deferred the need for new energy sources to meet Manitoba load to 2020/21.

MIPUG/MH I-4

Subject: July 20, 2012 Interim Rates Filing, Attachment 3 – Wuskwatim

b) Please confirm that as of the 2009/10 Power Resource Plan, the level of committed exports as of 2019/20 was 1352 GW.h (page 16).

ANSWER:

In the 2009/10 Power Resource Plan total exports which included both committed and proposed exports totaled 1352 GW.h in 2019/20.

MIPUG/MH I-4

Subject: July 20, 2012 Interim Rates Filing, Attachment 3 – Wuskwatim

c) Please confirm that in the 2011/12 Power Resource Plan, the level of committed exports as of 2019/20 is 2012 GW.h, less 370 GW.h for "Adverse Water" (page 34). Please explain in detail the basis for the changes from the 2009/10 Power Resource Plan to the 2011/12 Power Resource Plan in respect of committed exports and the adverse water clause.

ANSWER:

Manitoba Hydro confirms that in the 2011/12 Power Resource Plan, the level of committed exports as of 2019/20 is 2012 GWh, less 370 GWh for "Adverse Water".

The 2009/10 Power Resource Plan included export sales based on signed Term Sheets with NSP and WPS. The terms of the final contract signed with NSP and the current negotiations with WPS are reflected in the 2011/12 Power Resource plan.

MIPUG/MH I-5

Subject: July 20, 2012 Interim Rates Filing, Attachment 3 – Brandon

a) Please explain the basis and rationale for the "Brandon Unit 5 Licence Review" in CEF 11, including $10.4 million in spending in 2015, in light of the apparent planned retirement of the facility in 2019 per the 2011/12 Power Resource Plan (page 38).

ANSWER:

The planned expenditure of $10.4 million for the Brandon Unit 5 Licence Review is under review by Manitoba Hydro in consideration of the remaining planned service life of this unit and the requirements of the Manitoba Conservation licence for Brandon Unit 5.

MIPUG/MH I-5

Subject: July 20, 2012 Interim Rates Filing, Attachment 3 – Brandon

b) Please describe the current role and relevance of the Brandon Unit 5 plant in light of legislative restrictions on operation.

ANSWER:

Brandon G.S. Unit 5 operates under an Environment Act Licence and is subject to operational restrictions under the Climate Change and Emissions Reductions Act and its associated regulation, MR 186/2009. The operating restrictions on Brandon Unit 5 associated with this regulation permit operation of the unit to supply system energy, in any month of the year, to maintain system reliability, including operation in drought conditions. Subject to the conditions of MR 186/2009, Brandon Unit 5 serves three critical system functions:

1. It assists in ensuring resource adequacy by providing 105 MW of capacity as well as 811 GW.h/yr of dependable energy during drought conditions. Actual day to day operation of Unit 5 under drought conditions will occur according to specific real-time load requirements including energy commitments, the availability of alternative sources of supply including import energy, and the need for Brandon area generation to support the transmission system.

2. It helps provide local area support by providing local capacity and/or voltage support to the Brandon area.

3. It provides southern system generation in the event of a major transmission outage.

MIPUG/MH I-5

Subject: July 20, 2012 Interim Rates Filing, Attachment 3 – Brandon

c) Please indicate whether any assessment is planned of life extension options for Brandon Unit 5 and its potential continuing role in providing reliability beyond 2019. What is the timing for any such assessment?

ANSWER:

Manitoba Hydro is in the early stages of an internal assessment of the future of Brandon G.S. Unit 5 beyond 2019. Manitoba Hydro does not anticipate operation of Brandon Unit 5 on coal beyond this time period and will be considering alternatives including fuel switching and repowering.

MIPUG/MH I-6

Subject: Appendix 10.10: Bill Comparisons

a) Please provide all calculations and evidence in support of the Newfoundland and Labrador Hydro average rate (cents/kW.h) of 3.968 cents for large Industrial Customers of 100 kVA (page 32-33)

ANSWER:

Newfoundland and Labrador Hydro's average rate of 3.968¢/kWh for the large Industrial Customer of 100,000 kVA served at 100 kV is based on the calculation provided by Newfoundland and Labrador Hydro which includes:

Base Rate of 3.676¢/kWh (not customer specific)
RSP adjustment of (0.785)¢/kWh.
Demand charge of $6.68 /kW/month of billing demand

Energy: 62,000,000 kWh @ 3.676¢/kWh	$2,279,120.00
Rate Stabilization Plan: 62,000,000 kW.h @ (0.785)¢/kWh	($486,700.00)
Total Energy Cost	$1,792,420.00
Demand Cost: 100,000 kW @ $6.68/kW	668,000.00
Total	$2,460,420.00
Revenue/kWh: $2,460,420/62,000,000 kWh	3.968¢/kWh

The rates were confirmed using their January 1, 2012 rate schedules available on the utility's website.

MIPUG/MH I-6

Subject: Appendix 10.10: Bill Comparisons

b) Please indicate if Manitoba Hydro reviewed Newfoundland Public Utilities Board Order P.U.6-2012 (March 9, 2012) in determining the average rate for Newfoundland and Labrador Hydro.

ANSWER:

Manitoba Hydro was aware of Newfoundland Public Utilities Board Order P.U.6-2012, however determination of the average rate for Newfoundland and Labrador was based on the bill calculations provided by Newfoundland and Labrador themselves and supported by their January 1, 2012 rate schedules.

MIPUG/MH I-7

Subject: Appendix 7.1: Power Smart Resource Plan

a) In a format similar to RCM/TREE-MH-1-10 from the 2010 GRA (March 11, 2010), please provide the "marginal value" (cents/kW.h) used in the analysis of the 2011 Power Smart Plan, along with the equivalent values used in the Power Smart Plans for the preceding 10 years.

ANSWER:

The following table provides the levelized marginal value (cents/kW.h) used in the analysis of the 2011 Power Smart Plan, along with the equivalent values used in each of the Power Smart Plans for the preceding ten years. Marginal values have been levelized over a 30-year period using Manitoba Hydro's weighted average cost of capital in place at the time of the respective Power Smart Plan.

Power Smart Plan	Marginal Value (cents/kWh) (nominal dollars)
2011	8.52
2010	8.95
2009	8.26
2008	8.08
2007	7.81
2006	7.93
2005	7.80
2004	7.56
2003	7.29
2002	6.99
2001	6.76

<u>MIPUG/MH I-7</u>

Subject: Appendix 7.1: Power Smart Resource Plan

b) Please indicate when the 2012 Power Smart Plan will be completed.

<u>ANSWER</u>:

In accordance with Bill 24, *The Energy Savings Act*, Manitoba Hydro is required to prepare an energy efficiency plan by March 31, 2013.

MIPUG/MH I-7

Subject: Appendix 7.1: Power Smart Resource Plan

c) If currently known, please provide the marginal value that is to be used in the 2012 Power Smart Plan evaluations.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-7(b).

MIPUG/MH I-7

Subject: Appendix 7.1: Power Smart Resource Plan

d) Please provide a full description and summary of the Bioenergy program, including present status, number of participants, present forecasts and how these compare to the 2010 and 2011 Power Smart Plans, any barriers to customer participation and how these are being addressed.

ANSWER:

The following table provides an update on Program activity to-date, with the program targets for participation in 2010/11 and 2011/12 provided for comparison purposes.

Participation	08/09 Results	09/10 Results	10/11 Results	2010 Plan	2011 Plan
Program Sales	1	1	1	3	6
Total Program Costs ($)	1,932,877	1,487,636	1,604,743	3,463,955	2,539,757
Demand Savings (MW)	15.7	15.7	15.7	8.0	8.5
Energy Savings (GW.h/yr)	103.4	88.1	95.3	76.5	77.9

Manitoba Hydro's Bioenergy Optimization Program (the "Program") encourages customers to install, operate, and maintain customer-sited generation systems that employ combined heat and power and renewable biomass fuels to displace site specific load that would otherwise be served by the Corporation. Technical and financial components of the program provide support intended to accelerate the development of a Manitoba market for bioenergy systems and strives to provide a platform for customers to assemble a benefit stream significant enough to warrant investment in customer-owned generation systems fueled by low-cost, readily-available, sources of biomass fuel. The customer's benefit stream is composed of avoided electricity purchases, avoided fossil fuel purchases, avoided waste disposal costs, greenhouse gas emission reduction credits, financial and tax incentives, and other environmental benefits.

Several barriers were foreseen when the Program was launched in 2008. The primary barriers were related to the high capital cost of generation systems used for site-specific load displacement and the perceived technical and operational risk associated with new technologies. High capital costs are addressed with incentives offered through the Program and the assembly of sustainable benefit streams for participating customers. Perceived technical and operational risks are being addressed by showcasing a series of customer-based, load displacement, self-generation demonstration projects across the Province. The demonstration projects are designed to validate the performance of these newer technologies and form a key component of the overall marketing effort for promoting the use of bioenergy systems.

A significant barrier that was not foreseen at the time the Program was launched was the global economic downturn, which impacted funding priorities for many customers and resulted in many customers suspending or delaying capital expenditures, including investment in self-generation systems. .

MIPUG/MH I-7

Subject: Appendix 7.1: Power Smart Resource Plan

e) As per the 2011 Power Smart Plan, page 49, please confirm that Natural Resources Canada funding for the Bioenergy Optimization Program will end in 2013/14.

ANSWER:

Funding from Natural Resources Canada has been extended until 2016. The funded projects are anticipated to be completed by March 2014.

MIPUG/MH I-7

Subject: Appendix 7.1: Power Smart Resource Plan

f) How is Manitoba Hydro intending to address the loss of Natural Resources Canada funding for the Bioenergy Optimization Program?

ANSWER:

The Bioenergy Optimization Program was originally designed without the expectation of funding being available from Natural Resources Canada. As such, Manitoba Hydro has no plans to replace the Federal Government funding.

The funding made available by Natural Resources Canada created an opportunity to enhance Manitoba Hydro's Bioenergy Optimization Program through the demonstration component of the Program.

MIPUG/MH I-8

Subject: RCM/TREE-MH-1-27 from the 2010 GRA (March 11, 2010)

a) Please provide an updated version of the information from RCM/TREE-MH-1-27 from the 2010 GRA regarding long-term contracts.

ANSWER:

Please see Manitoba Hydro's response to CAC/MH I-115(a) for a listing of MH's current firm export contracts.

MIPUG/MH I-9

Subject: **PUB/MH-II-23(a) from the 2010 GRA (June 24, 2010) and PUB/MH/PRE-ASK-15 (REVISED)**

a) Please update these responses for the most recent 5 years of actuals and 3 years of forecasts.

ANSWER:

The attached table provides the information requested.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	Fiscal 2007/08-2011/12 Compounded Annual Growth	2012/13 Forecast	2013/14 Forecast	Fiscal 2011/12-2013/14 Compounded Annual Growth
Wages & Salaries	$ 359,249	$ 380,031	$ 407,988	$ 425,158	$ 451,925	5.9	$ 476,887	$ 486,425	3.7
Overtime	41,781	45,890	50,307	50,704	54,987	7.1	56,005	57,126	1.9
Employee Benefits	76,807	83,671	83,013	95,376	104,444	8.0	109,649	111,842	3.5
Employee Safety & Training	3,646	4,145	4,284	3,863	3,909	1.8	4,914	5,013	13.2
Travel Expenses	28,331	31,812	32,435	32,594	31,266	2.5	32,405	33,053	2.8
Motor Vehicle	22,423	24,126	24,281	24,436	28,676	6.3	24,784	25,280	(6.1)
Materials & Tools	27,824	29,345	26,897	28,105	26,663	(1.1)	27,173	27,716	2.0
Consulting & Professional Fees	7,503	9,704	14,814	11,157	10,250	8.1	11,639	11,872	7.6
Construction & Maintenance Services	15,938	18,378	20,109	22,657	21,228	7.4	18,706	19,080	(5.2)
Building & Property Services	25,740	28,947	22,931	21,944	21,387	(4.5)	22,399	22,843	3.4
Equipment Maintenance & Rentals	11,719	13,029	14,379	14,165	13,388	3.4	14,476	14,766	5.0
Consumer Services	4,651	5,284	5,798	5,086	5,365	3.6	5,284	5,389	0.2
Collection Costs	5,256	5,019	4,599	4,497	4,035	(6.4)	4,347	4,434	4.8
Customer & Public Relations	6,664	6,901	8,155	7,905	8,093	5.0	6,949	7,088	(6.4)
Sponsored Memberships	1,192	1,465	1,325	1,917	1,608	7.8	1,081	1,103	(17.2)
Office & Administration	14,427	14,652	15,320	14,316	14,277	(0.3)	15,263	15,569	4.4
Computer Services	1,131	858	983	1,003	861	(6.6)	909	927	3.8
Communication Systems	1,353	1,449	1,772	1,678	1,683	5.6	1,683	1,717	1.0
Research & Development Costs	2,979	3,059	3,952	3,651	2,797	(1.6)	3,509	3,579	13.1
Miscellaneous Expense	3,292	903	1,190	1,264	2,032	(11.4)	1,213	1,237	(22.0)
Contingency Planning	-	-	-	-	-		275	2,875	
Operating Expense Recovery	(23,314)	(21,519)	(21,580)	(23,004)	(21,716)	(1.8)	(9,787)	(9,983)	(32.2)
Total Costs	638,594	687,149	722,951	748,471	787,156	5.4	829,765	848,951	3.9
Capital Order Activities	(192,338)	(203,077)	(224,298)	(243,545)	(268,651)	8.7	(246,065)	(250,986)	(3.3)
Capitalized Overhead	(67,289)	(65,743)	(60,151)	(47,336)	(53,084)	(5.8)	(69,434)	(70,823)	15.5
Operating and Administration Charged to Centra	(56,270)	(59,042)	(60,951)	(60,645)	(62,117)	2.5	(67,300)	(68,646)	5.1
Subsidiaries	1,485	4,816	2,146	6,121	7,414	49.5	6,531	6,945	(3.2)
IFRS Accounting Changes								71,574	
CICA Accounting Changes		5,000	-	-	-		-		
Wuskatim GS for Full Year In-Service			-	-	-		-	1,754	
OM&A Attributable to Electric Operations per Annual Report	**$ 324,181**	**$ 369,103**	**$ 379,697**	**$ 403,067**	**$ 410,718**	6.1	**$ 453,497**	**$ 538,770**	14.5
Less:									
Subsidiaries	1,485	4,816	2,146	6,121	7,414	49.5	6,531	6,945	(3.2)
Accounting Changes			11,240	30,910	34,973		67,059	139,974	100.1
Wuskwatim			-	-	-		7,881	9,635	
OM&A Attributable to Electric Operations after adjusting for subsidiaries, accounting changes and Wuskwatim	**$ 322,697**	**$ 364,287**	**$ 366,311**	**$ 366,036**	**$ 368,330**	3.4	**$ 372,026**	**$ 382,216**	1.9

* Other CICA Accounting Changes totalling $4.6 million in 2008/09 and $4.0 million in 2009/10 & future years are embedded within the Total Costs

Labour	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	Fiscal 2007/08-2011/12 Compounded Annual Growth	2012/13 Forecast	2013/14 Forecast	Fiscal 2011/12-2013/14 Compounded Annual Growth
Subtotal - Labour and Benefits	**477,838**	**509,592**	**541,307**	**571,238**	**611,356**	6.4	**642,542**	**655,393**	3.5
EFTs (Straight Time + Overtime, including Subsidiaries)	6,090	6,312	6,465	6,625	6,634	2.2	6,865	6,865	1.7
Labour & Benefits per EFT	**78**	**81**	**84**	**86**	**92**	4.1	**94**	**95**	1.8

MIPUG/MH I-10

Subject: Depreciation by Function

a) In order to help understand the depreciation changes proposed in the GRA, please provide the correct Schedule C6 from PCOSS13 (which is titled "Depreciation Costs" but contains an apparently incorrect table which portrays "Operating Costs").

ANSWER:

Schedule C6 'Functionalization of Depreciation Costs' attached is based on existing April 1, 2011 depreciation rates.

2013 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2013
Functionalization of Depreciation Costs

SCC	Description	Depreciation	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancilary Services	Diesel	Street Lighting	Exports
	Common Generation Costs	40,859,124	31,573,377								9,285,747
	Generating Station Costs	16,010,663	16,010,663								-
	Other Generation Related Costs	343,741	343,741	-	-	-	-		-	-	
	Dedicated Gen. Facilities	16,354,404	16,354,404						-	-	-
	Hydraulic Generating Stations	73,278,303	73,278,303								
	Other Hydraulic Generation Related Cost	17,691,474	17,691,474								
	Hydraulic Generation Costs	90,969,777	90,969,777								
	Thermal Generating Station	18,208,448	18,208,448								
	Non-Dedicated Gen. Facilities	109,178,225	109,178,225								-
	Generation Facilities Costs	125,532,629	125,532,629						-	-	-
	Purchased Power/Export Costs	-	-								-
	Generation Facilities & Costs	***166,391,753***	***157,106,005***						-	-	***9,285,747***
	Common Trans. Costs/Revenues	2,425,546	-	1,867,921	557,625						-
	Generation Switching Stations	4,348,088	-	4,348,088							
	HVDC & Collector Facilities	49,908,052	26,322,464	23,585,589							
	Networked AC Facilities	13,218,365	-	13,218,365							
	Generation Access Transmission	67,474,505	26,322,464	41,152,041							
	Regional Networked Trans.	12,297,536	-	12,297,536	-	-					
	Transmission Common	2,044,451	-	1,655,711	252,595	-	-	136,144	-		
	Transmission Facilities/Costs	***84,242,038***	***26,322,464***	***56,973,210***	***810,220***	-	-	***136,144***	-		-
	Common Subtransmission Costs	601,565	-	-	601,565						
	Subtrans. Facilities & Costs	***18,572,599***	-	-	***16,906,593***	***1,666,006***	-		-	-	-
	Dist. Facilities & Costs	***81,736,257***	-	-	-	***77,640,634***	-		-	***4,095,623***	-
	Customer Service Costs	***10,917,759***	-	-	-	-	***10,917,759***		-	-	-
	Isolated Diesel Facilities	***3,374,036***	***1,744,375***	-	-	***44,622***	-		***1,585,038***		
	Communication & Control System	***28,388,559***	***13,952,437***	-	***5,533,638***	***2,564,774***	-	***6,337,711***	-	-	-
		393,623,000	**199,125,281**	**56,973,210**	**23,250,451**	**81,916,036**	**10,917,759**	**6,473,855**	**1,585,038**	**4,095,623**	**9,285,747**

MIPUG/MH I-10

Subject: Depreciation by Function

b) Please provide a version of Schedule C6 from PCOSS13 based on existing depreciation rates.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-10(a).

MIPUG/MH I-11

Subject: CACMSOS/MH-1-116 from the 2010 GRA (March 11, 2010) re: Financial Targets and AOCI

a) Please confirm as per part (b) of CACMSOS/MH-1-116 from the 2010 GRA that Manitoba Hydro continues to include AOCI in its calculation of the debt:equity ratio.

ANSWER:

The calculation of the debt/equity ratio continues to include accumulated other comprehensive income (AOCI) as a component of equity.

MIPUG/MH I-11

Subject: CACMSOS/MH-1-116 from the 2010 GRA (March 11, 2010) re: Financial Targets and AOCI

b) Please update part (c) of CACMSOS/MH-1-116 from the 2010 GRA showing the debt:equity ratio for actual years with and without inclusion of AOCI in the ratio.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH-I-11(c).

MIPUG/MH I-11

Subject: CACMSOS/MH-1-116 from the 2010 GRA (March 11, 2010) re: Financial Targets and AOCI

c) Please update MIPUG/MH-1-3(a), (b) and (c) from the 2010 GRA showing the calculation of the forecast financial targets as per IFF11-2. For debt:equity calculations, please show the debt:equity with and without inclusion of AOCI in the ratio.

ANSWER:

The following tables provide the calculations requested.

Debt Ratio - Consolidated
($ millions)

	A	B	C	D	E	F	G	H	(E+F+G+H) / (A+B+C+D+E+F+G+H)	(E+F+G+H) / (A+B+D+E+F+G+H)
Fiscal Year Ended	Retained Earnings	Contributions in Aid of Construction	Accumulated Other Comprehensive Income	Non-Controlling Interest	Long-Term Debt	Sinking Fund Investment	Short-Term Debt	Short-Term Investments	Debt Ratio w/ AOCI	Debt Ratio w/o AOCI
2008	1,822	300	305	24	7,571	(718)	-	(133)	0.73	0.76
2009	2,076	296	(169)	39	8,187	(666)	100	(159)	0.77	0.76
2010	2,239	295	285	62	8,538	(822)	-	(174)	0.73	0.74
2011	2,389	295	367	87	8,647	(282)	-	(70)	0.73	0.75
2012	2,450	318	327	100	9,382	(372)	-	(50)	0.74	0.76
2013	2,483	332	302		10,295	(327)	41	-	0.76	0.78
2014	2,203	345	(79)		11,140	(137)	58	-	0.82	0.81
2015	2,277	352	(209)		12,498	(160)	8	-	0.84	0.82
2016	2,414	359	(261)		14,214	(325)	-	(98)	0.85	0.83
2017	2,587	370	(279)		15,808	(493)	-	(96)	0.85	0.84
2018	2,722	381	(306)		17,879	(718)	-	(149)	0.86	0.85
2019	2,754	391	(322)		18,844	(502)	-	(237)	0.87	0.85
2020	2,839	401	(338)		20,137	(542)	-	(234)	0.87	0.86
2021	2,796	411	(356)		21,700	(568)	-	(444)	0.88	0.87
2022	2,924	422	(379)		22,610	(233)	-	(691)	0.88	0.87
2023	3,150	432	(392)		23,454	(307)	-	(765)	0.88	0.86
2024	3,455	443	(391)		24,257	(556)	-	(828)	0.87	0.85
2025	3,872	453	(391)		25,060	(819)	-	(845)	0.86	0.84
2026	4,338	464	(391)		24,812	(699)	-	(989)	0.84	0.83
2027	4,768	476	(391)		24,814	(976)	-	(1,151)	0.82	0.81
2028	5,292	487	(391)		24,815	(1,261)	-	(1,320)	0.80	0.79
2029	5,898	499	(391)		24,756	(1,498)	-	(1,404)	0.78	0.77
2030	6,607	512	(391)		24,508	(1,554)	-	(1,643)	0.76	0.75
2031	7,350	524	(391)		24,410	(1,859)	-	(1,958)	0.73	0.72
2032	8,245	537	(391)		24,199	(2,163)	-	(2,359)	0.70	0.69

Calculation of "Long Term Debt" component for input into Debt:Equity ratio

($ millions)

Fiscal Year Ended	I Long-Term Debt	J Current Portion Long-Term Debt	E = (I+J) Long-Term Debt
2008	7 218	353	7 571
2009	7 668	519	8 187
2010	8 228	310	8 538
2011	8 617	30	8 647
2012	9 101	281	9 382
2013	9 487	808	10 295
2014	10 926	214	11 140
2015	12 186	312	12 498
2016	13 806	408	14 214
2017	15 278	530	15 808
2018	17 043	837	17 879
2019	18 535	309	18 844
2020	19 497	640	20 137
2021	21 007	692	21 700
2022	22 451	159	22 610
2023	23 454	-	23 454
2024	24 257	-	24 257
2025	24 610	450	25 060
2026	24 812	-	24 812
2027	24 814	-	24 814
2028	24 755	60	24 815
2029	24 506	250	24 756
2030	24 408	100	24 508
2031	24 197	213	24 410
2032	23 169	1 030	24 199

Interest Coverage Ratio - Consolidated
($ millions)

	A	B	C	(A+B+C) / (B+C)
Fiscal Year Ended	Net Income	Finance Expense	Capitalized Interest	Interest Coverage Ratio
2008	346	440	62	1.69
2009	266	471	78	1.49
2010	163	410	105	1.32
2011	150	425	142	1.27
2012	61	423	173	1.10
2013	31	478	142	1.05
2014	81	493	178	1.12
2015	74	547	221	1.10
2016	137	581	280	1.16
2017	172	615	365	1.18
2018	135	684	403	1.12
2019	32	809	387	1.03
2020	85	849	447	1.07
2021	(42)	1 194	285	0.97
2022	127	1 156	291	1.09
2023	226	1 139	378	1.15
2024	305	1 129	452	1.19
2025	417	1 223	403	1.26
2026	465	1 449	203	1.28
2027	431	1 596	31	1.26
2028	524	1 564	45	1.33
2029	605	1 526	68	1.38
2030	709	1 476	95	1.45
2031	743	1 491	45	1.48
2032	896	1 392	47	1.62

Capital Coverage Ratio - Consolidated
Excluding Major New Generation & Transmission

Fiscal Year Ended	A Funds from Operations	B Consolidated Capital Expenditures	A/B Capital Coverage
2008	633	391	1.62
2009	688	388	1.77
2010	589	452	1.30
2011	595	477	1.25
2012	567	503	1.13
2013	537	453	1.19
2014	497	423	1.18
2015	496	408	1.22
2016	569	386	1.47
2017	624	395	1.58
2018	615	407	1.51
2019	552	416	1.32
2020	633	426	1.49
2021	568	390	1.45
2022	770	417	1.85
2023	887	462	1.92
2024	978	495	1.97
2025	1 125	556	2.02
2026	1 236	533	2.32
2027	1 255	549	2.28
2028	1 359	539	2.52
2029	1 455	572	2.54
2030	1 570	604	2.60
2031	1 667	516	3.23
2032	1 819	622	2.92

MIPUG/MH I-12

Subject: PUB/MH-II-45(a) from the 2010 GRA (June 24, 2010)

a) Please update PUB/MH-II-45(a) from the 2010 GRA (June 24, 2010) for IFF11-2.

ANSWER:

Please see Manitoba Hydro's response to CAC/MH I-3(a).

MIPUG/MH I-12

Subject: PUB/MH-II-45(a) from the 2010 GRA (June 24, 2010)

b) To the extent that transmission charges are netted to export sales in part (a), please provide a detailed calculation showing the derivation of the export values.

ANSWER:

Please see the attached table detailing the transmission charges and credits.

(in Millions of Dollars)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Export Sales	$ 322	$ 282	$ 325	$ 374	$ 449	$ 482	$ 510	$ 532	$ 589	$ 798	$ 891	$ 908
Transmission and Environmental Credits	20	19	17	18	19	19	20	20	20	21	21	22
Transmission and Environmental Charges	(41)	(46)	(39)	(42)	(43)	(44)	(45)	(46)	(47)	(47)	(48)	(49)
Total Export Sales	$ 300	$ 255	$ 303	$ 351	$ 424	$ 457	$ 485	$ 507	$ 563	$ 772	$ 863	$ 880

	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Export Sales	$ 923	$ 1 100	$ 1 383	$ 1 501	$ 1 518	$ 1 513	$ 1 518	$ 1 538	$ 1 538
Transmission and Environmental Credits	22	22	23	23	24	24	25	25	25
Transmission and Environmental Charges	(50)	(51)	(52)	(53)	(54)	(55)	(56)	(57)	(57)
Total Export Sales	$ 895	$ 1 071	$ 1 354	$ 1 471	$ 1 488	$ 1 482	$ 1 486	$ 1 506	$ 1 506

MIPUG/MH I-12

Subject: PUB/MH-II-45(a) from the 2010 GRA (June 24, 2010)

c) To the extent that merchant sales and purchases are excluded from the calculation in part (a), please provide a detailed calculation showing the derivation of the sales and purchase values.

ANSWER:

Please see the table below calculating Export Sales and Import Purchases including System Merchant Sales and Purchases. Note that System Merchant Purchases and Sales are not forecasted beyond the second year of the forecast.

	2011/12	2012/13
Total Export Sales excluding System Merchant Sales	$ 322	$ 282
System Merchant Sales	17	21
Total Export Sales including System Merchant Sales	338	303

	2011/12	2012/13
Total Import Purchases excluding System Merchant Purchases	$ 78	$ 115
System Merchant Purchases	12	17
Total Import Purchases including System Merchant Purchases	90	132

MIPUG/MH I-13

Subject: Exhibit MH-81 from the 2010 GRA

a) Please confirm that the $153 million "present value basis" cited in the undertaking is with reference to solely the financial evaluation component of the 2008/09 Power Resource Plan.

ANSWER:

Confirmed.

MIPUG/MH I-13

Subject: Exhibit MH-81 from the 2010 GRA

b) Please provide the equivalent "present value basis" for each subsequent Power Resource Plan (2009/10, 2010/11, and 2011/12), comparing the preferred plan to the alternative plan (or in the case of 2011/12 Power Resource Plan, each of the alternative plans).

ANSWER:

Manitoba Hydro expects that these matters will be fully canvassed during the upcoming Needs For and Alternatives To proceeding. Accordingly, Manitoba Hydro respectfully declines to provide the requested information.

MIPUG/MH I-13

Subject: Exhibit MH-81 from the 2010 GRA

c) Please provide the discount rate applied in deriving each of the values in part (b) above.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-13(b).

MIPUG/MH I-14

Subject: IFF11-2 page 31 and Appendix 5.7 Depreciation Study

a) Please provide a detailed description of the changes in Depreciation expenses at IFF11-2 page 31 between 2012, 2013 and 2014, showing separately: the impacts of addition of general assets; Wuskwatim; and the depreciation study.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-15(p).

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

a) Please provide a listing of all major Canadian Crown utilities for which Gannett Fleming has prepared depreciation studies over the past 4 years. Please provide the date of the study, whether the study is now or has previously been reviewed by a rate regulator, and whether Gannett Fleming has prepared evidence or testified in support of the depreciation studies or utility proposals.

ANSWER:

The following response was prepared by Gannett Fleming.

Please refer to the attachment to this response, which is a summary of proceedings where Mr. Kennedy has provided evidence.

LARRY E. KENNEDY

SUMMARY OF APPEARANCES BEFORE REGULATORY BOARDS

Year	Client	Applicant	Regulatory Board	Proceeding Number
1999	ENMAX Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2003	AltaLink Management Ltd	AltaLink Management Ltd	Alberta Energy and Utilities Board	1279345
2003	TransCanada PipeLines Limited	TransCanada PipeLines Limited	National Energy Board of Canada	RH-1-2002
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Westridge Utilities Inc	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation- Distribution Assets	Alberta Energy and Utilities Board	1380613
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A

LARRY E. KENNEDY

SUMMARY OF APPEARANCES BEFORE REGULATORY BOARDS

Year	Client	Applicant	Regulatory Board	Proceeding Number
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822
2011	Gaz Metro	Gaz Metro	La Regie de L'Energie	R-3752-2011
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink	AltaLink	Alberta Utilities Commission	1606895
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	TransAlta Utilities Corpotration	TransAlta Utilities Corpotration	Municipal Government Board of Alberta	N/A
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	TransCanada PipeLines Limited	TransCanada PipeLines Limited	National Energy Board of Canada	RH-003-2011
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilties Board	Appearance Pending
2012	NL Hydro	NL Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	Appearance Pending
2012	Manitoba Hydro	Manitoba Hydro	Maniitoba Public Utilities Board	Appearance Pending
2012	IntraGaz Incorporated	IntraGaz Incorporated	La Regie de L'Energie	Appearance Pending

LARRY E. KENNEDY

SUMMARY OF CASES WHERE EVIDENCE WAS PROVIDED BUT APPEARANCES WERE NOT REQUIRED

Year	Client	Applicant	Regulatory Board	Proceeding Number
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc	Alberta Energy and Utilities Board	Decision 2002-43
2001	ENMAX Power Corporation	ENMAX Power Corporation – Electric Transmission Assets	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation – Electric Transmission Assets	Alberta Department of Energy	N/A
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric –ISO Issues	Alberta Energy and Utilities Board	N/A
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	The City of Red Deer	The City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc	Northwest Territories Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation- Transmission Assets	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc	FortisBC, Inc	British Columbia Utilities Commission	N/A
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	Study Submitted
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005				
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A

LARRY E. KENNEDY

SUMMARY OF CASES WHERE EVIDENCE WAS PROVIDED BUT APPEARANCES WERE NOT REQUIRED

Year	Client	Applicant	Regulatory Board	Proceeding Number
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCOGas	ATCOGas	Alberta Utilities Commission	1553052
2008	Heritage Gas	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2010	Enbridge Pipelines Limited - Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	FortisAlberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1607159
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utlilty Board	N/A

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

b) For each study identified in part (a), please indicate whether the referenced study is intended to provide IFRS-compliant methods of depreciation. If not, please indicate whether the study is intended for use only for rate regulation purposes (and a separate method or approach for depreciation will be applied in financial reporting) or whether the same Gannett Fleming method is intended for financial reporting.

ANSWER:

The following response was prepared by Gannett Fleming.

It is the experience of Mr. Kennedy that generally, the depreciation studies are used for both regulatory and financial reporting purposes.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

c) For each study identified in part (a), please indicate if the study is fully consistent with the proposed Manitoba Hydro approach in respect of:

i. service lives being determined with "less reliance on statistical developed asset lives and more reliance on the enhanced operational information" (page 3 of Appendix 5.7)

ii. Use of an "ELG" procedure (as opposed to an "ASL" procedure)

iii. Removal of asset retirement costs from depreciation expense

ANSWER:

The following response was prepared by Gannett Fleming.

In most studies prepared by Gannett Fleming, the use of professional judgment which includes operational and management interviews, peer experience and industry experience are all considerations in the determination of the Life estimates. The weighting of these considerations is dependent on the facts and circumstances of each case.

Please refer to the attachment to PUB/MH I-85(a) for a summary of utilities that use the ELG procedure.

The inclusion of net negative salvage/asset retirement obligations is used by some regulated Canadian electric Utilities.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

d) Please provide a copy of the relevant portions of IAS 16 that Manitoba Hydro and Gannett Fleming are relying upon in proposing the depreciation changes noted in part (c) above (e.g., use of ELG versus ASL).

ANSWER:

Please see Manitoba Hydro's response to CAC/MH I-47(a).

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

e) Please confirm that on the basis of the ASL procedure (Gannett Fleming January 13, 2012 study), Manitoba Hydro's plant in service as at March 31, 2010 shows a negative depreciation variances of $552 million (i.e., is over-depreciated by $552 million).

ANSWER:

The calculated accumulated depreciation balance determined by Gannett Fleming using the ASL procedure with updated service life assumptions indicates a surplus of booked accumulated costs of $552 million.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

f) Please indicate if the analysis in part (e) above includes asset retirement costs, or whether these are removed from the January 13, 2012 study.

ANSWER:

With respect to the referenced January 13, 2012 depreciation study, the book accumulated depreciation balances include historical retirement costs realized on the disposition of assets up to March 31, 2010. The calculated accumulated depreciation balances include a provision for future retirement costs based on the net salvage percentages indicated in Schedule 1- (Use of the ASL Procedure) Pages 1 – 8.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

g) Please indicate which study is the "last depreciation study" referred to in the second paragraph of Gannett Fleming's letter of January 13, 2012, and if not on the record of this proceeding please provide a copy of that study. If this does not refer to the depreciation study completed in 2005, please also provide a copy of the 2005 study.

ANSWER:

The last depreciation study referred to in the second paragraph of Gannett Fleming's letter on January 13, 2012 is the 2005 depreciation study, which was completed by Gannett Fleming based on plant account balances as at March 31, 2005.

Please refer to Appendix 24 titled Manitoba Hydro - Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant at March 31, 2005.

MIPUG/MH I-15

Subject: **Appendix 5.7 Depreciation Study**

h) Please confirm that upon adoption of ELG with no asset retirement costs, the negative depreciation variance increases to $594 million.

ANSWER:

The calculated accumulated depreciation balance determined by Gannett Fleming using the ELG Procedure without provision for future retirement costs indicates a surplus of booked accumulated costs of $594 million.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

i) Please confirm that under Hydro's proposed approach, the $594 million negative variance is amortized to the benefit of customers via a depreciation "true-up" equalling $6.8 million per year (a rate of 1.1% of the variance amortized per year).

ANSWER:

Under Manitoba Hydro's proposed approach, the $594 million surplus of booked accumulated costs is amortized to the benefit of customers over the remaining life of the specific depreciable asset accounts to which it pertains, by adjusting the depreciation rate for each account to include a "true-up" component.

All else being equal, if there were no additions to the asset pool after March 31, 2010, and provided retirements adhered to those predicted by the assigned depreciable life and IOWA curve, Manitoba Hydro would expect to amortize 10 % of the variance within 6 years, 25% within 10 years, 50% within 18 years, 75% within 30 years, and 90% within 40 years, with full amortization by 85 years.

The actual annual amount and percentage of the depreciation variance amortized will change from year to year. In the short term, the amount to be amortized annually will vary from that shown in the depreciation study as the rates will not be implemented until April 1, 2013. The surviving asset cost base for each account will have changed from that reflected in the depreciation study, and will continue to change over time in response to ongoing addition and retirement activity. Over the longer term, depreciation rates will be adjusted through depreciation studies and interim depreciation rate reviews as the variance for each account becomes fully amortized.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

j) Please indicate whether any alternative approaches to addressing the $594 million depreciation variance, including the adoption of shorter periods for amortization of the variance, were considered by Hydro or in discussions with Gannett Fleming. Please list all such alternative approaches considered or analyzed and provide the analysis and implications of the alternative approaches.

ANSWER:

By its nature, depreciation is an accounting estimate, which is subject to periodic revision. Given the long-term nature of Manitoba Hydro's property, plant and equipment assets, surpluses or deficits in accumulated depreciation are built up over long periods of time. The $594 million surplus has been accumulated over a long period of time, using depreciation rates that were based on the information available at the time.

Manitoba Hydro prefers a rational and systematic approach to handling the surplus, that recognizes the long-term nature of the assets and the fact that depreciation estimates will change over time. In this depreciation study, as in the past, the approach has been to amortize surpluses and deficits over the remaining life of the accounts to which they pertain, which is consistent with the objective of maintaining rate stability for customers.

If the net surplus in accumulated depreciation was to be amortized over a shorter period of time, revenue requirements could be reduced during the timeframe of the amortization, but a significant increase in revenue requirement would be experienced when the net surplus was depleted. Such a treatment would contribute to rate volatility for customers, which would be compounded if circumstances change such that it becomes necessary to shorten asset lives in a future depreciation study.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

k) Please provide a copy of the tables from the Gannett Fleming January 13, 2012 analysis, and the November 2, 2011 analysis, assuming no change in asset lives from the previous depreciation rates.

ANSWER:

The tables referred to in the question were not required for the completion of the depreciation study and are not available. For Gannett Fleming to produce these tables would require a significant work effort and cost.

The current depreciation study included the implementation of componentization changes which involved significant adjustments to the quantity and content of the individual asset accounts. The asset lives from the previous depreciation study do not directly relate to the revised component breakdown, and as such, applying the previous asset lives to the new components would not produce meaningful results.

Please refer to the response to MIPUG/MH I-15(p) for quantification of the impact of the change in asset lives on depreciation expense by asset category.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

l) Please provide a copy of the Gannett Fleming January 13, 2012 analysis (Schedule 1 and Schedule 2) separating out the life/original cost analysis from the net salvage analysis.

ANSWER:

The tables referred to in the question were not required for the completion of the depreciation study and are not available. For Gannett Fleming to produce these tables would require a significant work effort and cost.

Please refer to the response to MIPUG/MH I-15(p) for quantification of the impact on depreciation expense of the change in asset lives versus the removal of the provision for net salvage by asset category.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

m) Please indicate why the componentization of each of the hydraulic generation facilities does not include a depreciable group for overhauls, or equivalent periodic major servicing and inspections of the turbine and/or generator, per IAS 16, paragraphs 13-14. Please indicate if Gannett Fleming has established depreciable groups for overhauls for other utilities with hydraulic generation.

ANSWER:

The following response was prepared by Gannett Fleming.

The componentization was completed through an extensive process wherein Manitoba Hydro engineering and operating staff members were consulted to determine the significant components of the hydraulic generation plants. Each of the resulting components is depreciated through the use of an Iowa retirement dispersion curve which provides for interim retirement activity early in the asset life. To the extent that the overhaul and major servicing will be capitalized, the associated retirement activity is inherent in the interim retirement expectations of the Iowa curves.

Manitoba Hydro is proposing to use the ELG procedure for determination of the depreciation rate. The ELG procedure provides for the direct depreciation of the assets that retire prior to the average service life based on the expected interim retirement activity inherent in the Iowa curve. As such, it is not a requirement to specifically componentize the expected capital overhauls when the ELG procedure is used.

Notwithstanding the above, Gannett Fleming notes that a number of electric generation utilities (particularly those not using the ELG procedure) have separately componentized an account for overhauls.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

n) Please indicate, for distribution plant, the lives and survivor curves that would have been used based on statistical methods, had the "enhanced operations information" (per page 3 of Appendix 5.7) not been available. Please provide the numerical analysis for the distribution sections of Schedule 1 and Schedule 2 from Gannett Fleming's November 2, 2011 study had distribution lives and survivor curves based on statistics methods been used.

ANSWER:

The following response was prepared by Gannett Fleming.

Please refer to the attachment to PUB-MH 1-84(d) being a summary of the retirement rate analysis that was completed for all accounts. The attachment identifies the fit of the smoothed Iowa curves as recommended by Gannett Fleming plotted against the actual retirement experience of the company. Gannett Fleming considered a number of factors in the determination of the average service life for each account, including the statistical analysis of mortality history, the typical industry lives used by peer companies, Gannett Fleming experience, and information gained from management and operational staff.

Gannett Fleming has not developed a view of the life estimates for each account excluding only the information gained in the operational interviews. For Gannett Fleming to complete such a task and redo the average service life estimation phase of the study would require a significant work effort and cost. However, it is noted that the degree to which other factors have been considered is apparent from a review of the material supplied in the attachment to PUB-MH 1-84(d).

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

o) Please provide a narrative description as to why the major accumulated depreciation variances have arisen in the following accounts (e.g., large numbers of early retirements, losses on disposal, shorter asset lives, etc.):

i. 9000k Computer Equipment
ii. 8000c Building Renovations
iii. 5000j Carrier Equipment
iv. 4000j Poles and Fixtures
v. 4000l Overhead Conductors and Devices

ANSWER:

The following responses relate to the accumulated depreciation variance amounts for the specified accounts shown on pages III-18 and III-19 of the referenced depreciation study:

i) **9000K Computer Equipment:** The positive variance is due to mainly to: losses incurred on retirement of assets and the reclassification of items as computer equipment which were originally capitalized into & depreciated in accounts with longer service lives.

ii) **8000C Building Renovations:** With componentization, building renovations were segregated from the buildings themselves into a separate overhaul component. The positive variance has arisen primarily because the renovation assets were previously amortized over a much longer period of time (55-60 years) as part of the source building accounts.

iii) **5000J Carrier Equipment:** With componentization, communication assets were split out into a number of new accounts. The book accumulated depreciation balance was distributed among the new components based on the calculated accrued depreciation using the ASL procedure. For the Carrier Equipment account, the positive variance is due mainly to: the change to the ELG procedure for group depreciation; inclusion of a pro-rata share of losses incurred on retirement of assets for the communication group of accounts; with a partial offset related to the removal of net salvage.

iv) **4000J Poles and Fixtures:** The negative variance is due primarily to an increase to the estimated average service life and the removal of net salvage with a partial offset attributable to the change to the ELG procedure for group depreciation.

v) **4000L Overhead Conductors and Devices:** The negative variance is due primarily to an increase to the estimated average service life and the removal of net salvage with a partial offset attributable to the change to the ELG procedure for group depreciation.

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

p) Please update PUB/MH-1-37(a) Revised re: depreciation expenses for actuals and forecasts through 2013/14. For each year, please separately identify the impacts of addition of assets; Wuskwatim; the new depreciation study lives; the impacts of the adoption of the ELG approach; and the impact of the elimination of asset retirement costs.

ANSWER:

For the requested update to 2008/09 Information Request PUB/MH I-37(a), please refer to PUB/MH I-81(a).

The attached schedule identifies the incremental impact of the specified items for each of the years included in PUB/MH I-81(a).

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE

	2007/08 Actual	Net Additions	2008/09 Actual	Net Additions	2009/10 Actual	Net Additions	2010/11 Actual	Year over Year Change			2011/12 Actual
								Net Additions	Depreciation Study Component Reclass	Depreciation Study Change in Asset Life	
Generation											
Hydraulic Generating Stations	68 451	2 460	70 911	3 399	74 310	1 818	76 128	3 692	(352)	(4 404)	75 064
Thermal Generating Stations	17 170	106	17 276	336	17 612	(7 842)	9 771	1 180	(426)	(1 845)	8 680
Amortization of Planning Studies	2 366	(2 366)	-	-	-	-		-	-	-	-
Demand Side Management	11 357	7 800	19 157	2 907	22 064	1 930	23 994	2 197	-	-	26 191
Diesel Generating Stations	4 067	(134)	3 933	(381)	3 552	139	3 691	1 685	-	(4 017)	1 359
Amortization of Contributions	(2 774)	(22)	(2 796)	-	(2 796)	-	(2 796)	(247)	-	2 325	(718)
	$ 100 637	$ 7 844	$ 108 481	$ 6 262	$ 114 743	$ (3 955)	$ 110 788	$ 8 507	$ (778)	$ (7 941)	$ 110 576
Transmission											
Transmission	14 120	197	14 317	11	14 328	143	14 471	74	-	(625)	13 920
Amortization of Contributions	(1 631)	(6)	(1 638)	-	(1 638)	9	(1 629)	1	-	271	(1 357)
	$ 12 489	$ 191	$ 12 680	$ 11	$ 12 690	$ 152	$ 12 842	$ 75	$ -	$ (354)	$ 12 563
Stations											
Substations	70 616	1 896	72 512	1 611	74 123	2 624	76 747	5 060	1 909	(4 558)	79 157
Transformers	3 681	(1 393)	2 288	(167)	2 121	(468)	1 653	316	-	(278)	1 691
Amortization of Contributions	(1 461)	(1)	(1 462)	(2)	(1 464)	(6)	(1 470)	(29)	-	251	(1 247)
	$ 72 836	$ 502	$ 73 338	$ 1 442	$ 74 780	$ 2 150	$ 76 930	$ 5 347	$ 1 909	$ (4 585)	$ 79 601
Distribution											
Subtransmission Lines	8 905	261	9 166	303	9 469	423	9 892	714	-	(4 632)	5 974
Distribution Lines	72 410	5 320	77 730	4 949	82 679	4 515	87 194	4 999	-	(36 646)	55 547
Meters & Metering Transformers	1 551	46	1 597	(7)	1 590	25	1 615	(176)	-	2 766	4 205
Amortization of Contributions	(9 769)	(411)	(10 180)	(263)	(10 443)	(267)	(10 710)	(401)	-	6 337	(4 774)
	$ 73 097	$ 5 215	$ 78 312	$ 4 983	$ 83 295	$ 4 696	$ 87 991	$ 5 136	$ -	$ (32 175)	$ 60 952
Other											
Communications	17 636	1 837	19 473	1 474	20 947	1 571	22 518	(7 768)	-	5 368	20 118
Motor Vehicles	8 275	416	8 691	69	8 760	740	9 500	1 736	-	(862)	10 374
Structures & Improvements	3 216	2 476	5 692	898	6 590	832	7 422	403	(1 131)	924	7 618
General Equipment	20 572	(2 898)	17 674	332	18 006	(834)	17 172	826	-	5 495	23 493
Computer Development	13 582	499	14 081	373	14 454	799	15 253	3 485	-	157	18 895
Affordable Energy Fund	625	816	1 441	1 617	3 058	410	3 468	4 004	-	-	7 472
Miscellaneous	2 701	(238)	2 463	532	2 995	(372)	2 623	797	-	-	3 420
Corporate Allocation	(2 093)	81	(2 012)	(127)	(2 139)	359	(1 780)	-	-	74	(1 706)
Target Adjustment									-		-
	$ 64 514	$ 2 989	$ 67 503	$ 5 168	$ 72 671	$ 3 505	$ 76 176	$ 3 483	$ (1 131)	$ 11 156	$ 89 684
Total Depreciation and Amortization Expense	$ 323 573	$ 16 741	$ 340 314	$ 17 865	$ 358 179	$ 6 547	$ 364 727	$ 22 548	$ -	$ (33 899)	$ 353 376

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE

	2011/12 Actual	Year over Year Change (Forecast) Net Additions	Wuskwatim	Depn Study Change in Asset Life	2012/13 Forecast	Year over Year Change (Forecast) Net Additions	Wuskwatim	Depreciation Study Change in Asset Life	Depreciation Study ELG	Depreciation Study Removal of Net Salvage	IFRS Remove Indirect Overhead	Remove Rate Regulated Assets	2013/14 Forecast
Generation													
Hydraulic Generating Stations	75 064	3 758	19 993	(1 561)	97 254	3 963	2 445	(414)	8 826	(14 222)	-	-	97 852
Thermal Generating Stations	8 680	7 397	-	(40)	16 036	441	-	(52)	1 333	(1 262)	-	-	16 496
Amortization of Planning Studies	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	26 191	2 474	-	-	28 664	2 731	-	-	-	-	-	(31 395)	-
Diesel Generating Stations	1 359	(173)	-	221	1 407	197	-	(154)	106	(123)	-	(64)	1 368
Amortization of Contributions	(718)	(602)	-	287	(1 033)	(135)	-	76	-	-	-	-	(1 092)
	$ 110 576	$ 12 854	$ 19 993	$ (1 094)	$ 142 328	$ 7 196	$ 2 445	$ (543)	$ 10 266	$ (15 608)	$ -	$ (31 459)	$ 114 624
Transmission													
Transmission	13 920	929	2 261	(115)	16 995	541	-	(25)	1 405	(4 737)	-	-	14 179
Amortization of Contributions	(1 357)	86	-	(87)	(1 358)	(20)	-	19	-	-	-	-	(1 360)
	$ 12 563	$ 1 015	$ 2 261	$ (202)	$ 15 636	$ 520	$ -	$ (6)	$ 1 405	$ (4 737)	$ -	$ -	$ 12 819
Stations													
Substations	79 157	5 206	3 261	(442)	87 181	3 453	-	(195)	4 743	(14 289)	-	-	80 893
Transformers	1 691	311	-	(19)	1 983	538	-	(30)	145	(436)	-	-	2 200
Amortization of Contributions	(1 247)	105	-	(93)	(1 235)	(16)	-	16	-	-	-	-	(1 235)
	$ 79 601	$ 5 622	$ 3 261	$ (554)	$ 87 929	$ 3 975	$ -	$ (209)	$ 4 888	$ (14 725)	$ -	$ -	$ 81 858
Distribution													
Subtransmission Lines	5 974	553	-	(312)	6 215	556	-	(224)	703	(1 827)	-	-	5 423
Distribution Lines	55 547	6 629	38	(2 394)	59 820	5 494	-	(2 214)	6 743	(17 534)	-	-	52 309
Meters & Metering Transformers	4 205	842	-	(28)	5 019	(14)	-	(26)	624	-	-	-	5 603
Amortization of Contributions	(4 774)	(812)	-	268	(5 318)	(551)	-	318	-	-	-	-	(5 551)
	$ 60 952	$ 7 212	$ 38	$ (2 467)	$ 65 736	$ 5 486	$ -	$ (2 147)	$ 8 069	$ (19 361)	$ -	$ -	$ 57 784
Other													
Communications	20 118	4 391	32	613	25 153	1 331	-	455	5 316	(2 622)	-	-	29 634
Motor Vehicles	10 374	(386)	-	(53)	9 935	342	-	(27)	1 760	-	-	-	12 010
Structures & Improvements	7 618	718	-	173	8 509	360	-	106	321	199	-	-	9 495
General Equipment	23 493	(642)	-	161	23 011	(1 361)	-	(424)	-	-	-	-	21 226
Computer Development	18 895	(2 473)	-	(46)	16 376	1 594	-	(52)	1 019	-	-	-	18 937
Affordable Energy Fund	7 472	1 398	-	-	8 870	(160)	-	-	-	-	-	-	8 710
Miscellaneous	3 420	339	-	-	3 760	(1 845)	-	-	-	-	-	(5 333)	(3 418)
Corporate Allocation	(1 706)	(1)	-	-	(1 707)	499	-	-	-	-	-	-	(1 208)
Target Adjustment	-	(5 163)	-	472	(4 691)	(4 408)	-	614	(737)	1 280	(221)	-	(8 163)
	$ 89 684	$ (1 820)	$ 32	$ 1 321	$ 89 217	$ (3 648)	$ -	$ 671	$ 7 679	$ (1 143)	$ (221)	$ (5 333)	$ 87 223
Total Depreciation and Amortization Expense	$ 353 376	$ 24 882	$ 25 584	$ (2 996)	$ 400 846	$ 13 530	$ 2 445	$ (2 234)	$ 32 307	$ (55 574)	$ (221)	$ (36 792)	$ 354 307

MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

q) For an illustrative sample of the comparison of the ASL approach and the ELG approach, please provide all input data and calculations in support of 2 asset accounts (e.g., 1175D and 2000L, or two alternatives that are likely to serve as illustrative examples) to indicate all calculations required to reach the values shown in both Schedule 1 and Schedule 2 of November 2, 2011 Gannett Fleming report, and the January 13, 2012 Gannett Fleming report.

ANSWER:

The following response was prepared by Gannett Fleming.

Please refer to the following attachments:

Attachment 1 shows the calculation of annual and accrued depreciation for account 1175D using the ELG procedure.

Attachment 2 shows the calculation of annual and accrued depreciation for account 2000L using the ELG procedure.

Attachment 3 shows the calculation of composite remaining life for account 1175D using the ELG procedure.

Attachment 4 shows the calculation of composite remaining life for account 2000L using the ELG procedure.

Attachment 5 shows the calculation of annual and accrued depreciation for account 1175D using the ASL procedure.

Attachment 6 shows the calculation of annual and accrued depreciation for account 2000L using the ASL procedure.

Attachment 7 shows the calculation of composite remaining life for account 1175D using the ASL procedure.

Attachment 8 shows the calculation of composite remaining life for account 2000L using the ASL procedure.

MANITOBA HYDRO

ACCOUNT 1175D - SPILLWAY

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 75-R2					
PROBABLE RETIREMENT YEAR.. 12-2131					
1991	80,430,469.28	1.50	1,206,457.04	0.2925	23,525,912
1992	80,430,469.28	1.51	1,214,500.09	0.2794	22,472,273
1993	40,215,234.64	1.52	611,271.57	0.2660	10,697,252
2007	68,329.54	1.77	1,209.43	0.0620	4,236
2008	94,022.89	1.82	1,711.22	0.0455	4,278
2010	2,246.89	2.06	46.29	0.0103	23
	201,240,772.52		3,035,195.64		56,703,974

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 1.51

MANITOBA HYDRO

ACCOUNT 2000L - OVERHEAD CONDUCTOR AND DEVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
SURVIVOR CURVE.. IOWA 65-R4					
NET SALVAGE PERCENT.. 0					
1911	225,000.00			1.0000	225,000
1923	51,028.75	1.11	566.42	0.9712	49,559
1926	62,927.80	1.14	717.38	0.9633	60,618
1927	314,857.21	1.15	3,620.86	0.9602	302,326
1928	39,363.53	1.16	456.62	0.9570	37,671
1930	522,063.55	1.18	6,160.35	0.9499	495,908
1931	1,500,000.00	1.19	17,850.00	0.9460	1,419,000
1939	446.20	1.28	5.71	0.9152	408
1946	1,053.27	1.36	14.32	0.8772	924
1948	596.21	1.38	8.23	0.8625	514
1949	439,651.86	1.39	6,111.16	0.8548	375,814
1950	516,410.37	1.40	7,229.75	0.8470	437,400
1951	411,102.89	1.41	5,796.55	0.8390	344,915
1952	623,823.40	1.41	8,795.91	0.8248	514,530
1953	184,704.93	1.42	2,622.81	0.8165	150,812
1955	214,227.77	1.44	3,084.88	0.7992	171,211
1956	1,017,699.36	1.45	14,756.64	0.7902	804,186
1957	244,145.73	1.45	3,540.11	0.7758	189,408
1958	11,557.33	1.46	168.74	0.7665	8,859
1959	45,931.38	1.47	675.19	0.7570	34,770
1960	9,105.00	1.48	134.75	0.7474	6,805
1961	1,271,931.21	1.49	18,951.78	0.7376	938,176
1962	2,239,550.14	1.49	33,369.30	0.7226	1,618,299
1963	110,859.67	1.50	1,662.90	0.7125	78,988
1964	76,762.00	1.51	1,159.11	0.7022	53,902
1965	1,325,873.24	1.51	20,020.69	0.6870	910,875
1966	577,503.19	1.52	8,778.05	0.6764	390,623
1967	10,483,558.18	1.53	160,398.44	0.6656	6,977,856
1968	749,644.48	1.53	11,469.56	0.6502	487,419
1969	1,855,561.71	1.54	28,575.65	0.6391	1,185,889
1970	1,197,235.01	1.54	18,437.42	0.6237	746,715
1971	1,766,128.46	1.55	27,374.99	0.6122	1,081,224
1972	3,539,695.96	1.56	55,219.26	0.6006	2,125,941
1973	1,861,910.17	1.56	29,045.80	0.5850	1,089,217
1974	3,198,096.34	1.57	50,210.11	0.5730	1,832,509
1975	3,554,160.95	1.57	55,800.33	0.5574	1,981,089
1976	3,033,727.44	1.58	47,932.89	0.5451	1,653,685
1977	5,270,392.40	1.58	83,272.20	0.5293	2,789,619
1978	2,634,319.79	1.58	41,622.25	0.5135	1,352,723
1979	606,840.63	1.59	9,648.77	0.5008	303,906
1980	6,807,630.10	1.59	108,241.32	0.4850	3,301,701
1981	436,619.15	1.59	6,942.24	0.4690	204,774
1982	57,853,123.93	1.60	925,649.98	0.4560	26,381,025
1983	84,846.80	1.60	1,357.55	0.4400	37,333
1984	362,239.79	1.60	5,795.84	0.4240	153,590

MANITOBA HYDRO

ACCOUNT 2000L - OVERHEAD CONDUCTOR AND DEVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
SURVIVOR CURVE.. IOWA 65-R4					
NET SALVAGE PERCENT.. 0					
1985	22,264,507.75	1.61	358,458.57	0.4106	9,141,807
1986	19,805.94	1.61	318.88	0.3944	7,811
1987	13,031.21	1.61	209.80	0.3784	4,931
1988	421,948.99	1.61	6,793.38	0.3622	152,830
1989	6,555,982.36	1.62	106,206.91	0.3483	2,283,449
1990	9,394,025.98	1.62	152,183.22	0.3321	3,119,756
1991	2,617,663.25	1.62	42,406.14	0.3159	826,920
1992	3,793,724.33	1.62	61,458.33	0.2997	1,136,979
1993	2,462,562.70	1.62	39,893.52	0.2835	698,137
1994	1,868,678.63	1.62	30,272.59	0.2673	499,498
1995	4,369,494.93	1.62	70,785.82	0.2511	1,097,180
1996	445,858.55	1.63	7,267.49	0.2364	105,401
1997	18,664,969.99	1.63	304,239.01	0.2200	4,106,293
1998	14,863,385.61	1.63	242,273.19	0.2038	3,029,158
1999	16,583,325.93	1.63	270,308.21	0.1874	3,107,715
2000	3,795,733.12	1.63	61,870.45	0.1712	649,830
2001	11,356,603.50	1.63	185,112.64	0.1548	1,758,002
2002	13,860,228.87	1.63	225,921.73	0.1386	1,921,028
2003	13,387,009.11	1.63	218,208.25	0.1222	1,635,893
2004	6,813,310.01	1.63	111,056.95	0.1060	722,211
2005	6,212,543.46	1.63	101,264.46	0.0896	556,644
2006	2,272,917.45	1.63	37,048.55	0.0734	166,832
2007	16,445,139.06	1.63	268,055.77	0.0570	937,373
2008	4,416,009.70	1.64	72,422.56	0.0410	181,056
2009	2,021,804.32	1.64	33,157.59	0.0246	49,736
2010	2,322,979.57	1.64	38,096.86	0.0082	19,048
	304,577,151.60		4,878,543.68		101,223,234

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 1.60

MANITOBA HYDRO

ACCOUNT 1175D - SPILLWAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS AT MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 75-R2						
PROBABLE RETIREMENT YEAR.. 12-2131						
1991	80,430,469.28	23,525,912	20,429,847	60,000,622	47.17	1,272,008
1992	80,430,469.28	22,472,273	19,514,869	60,915,600	47.72	1,276,521
1993	40,215,234.64	10,697,252	9,289,468	30,925,767	48.29	640,418
2007	68,329.54	4,236	3,679	64,651	52.99	1,220
2008	94,022.89	4,278	3,715	90,308	52.45	1,722
2010	2,246.89	23	20	2,227	48.04	46
	201,240,772.52	56,703,974	49,241,598	151,999,175		3,191,935

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 47.6 1.59

MANITOBA HYDRO

ACCOUNT 2000L - OVERHEAD CONDUCTOR AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
1911	225,000.00	225,000	258,750	33,750-		
1923	51,028.75	49,559	58,683	7,654-		
1926	62,927.80	60,618	72,367	9,439-		
1927	314,857.21	302,326	362,086	47,229-		
1928	39,363.53	37,671	45,268	5,904-		
1930	522,063.55	495,908	600,373	78,309-		
1931	1,500,000.00	1,419,000	1,725,000	225,000-		
1939	446.20	408	513	67-		
1946	1,053.27	924	1,199	146-		
1948	596.21	514	667	71-		
1949	439,651.86	375,814	487,759	48,107-		
1950	516,410.37	437,400	567,690	51,280-		
1951	411,102.89	344,915	447,656	36,553-		
1952	623,823.40	514,530	667,795	43,972-		
1953	184,704.93	150,812	195,735	11,030-		
1955	214,227.77	171,211	222,210	7,982-		
1956	1,017,699.36	804,186	1,043,732	26,033-		
1957	244,145.73	189,408	245,828	1,682-		
1958	11,557.33	8,859	11,498	59	15.99	4
1959	45,931.38	34,770	45,127	804	16.53	49
1960	9,105.00	6,805	8,832	273	17.07	16
1961	1,271,931.21	938,176	1,217,634	54,297	17.61	3,083
1962	2,239,550.14	1,618,299	2,100,347	139,203	18.62	7,476
1963	110,859.67	78,988	102,516	8,344	19.17	435
1964	76,762.00	53,902	69,958	6,804	19.72	345
1965	1,325,873.24	910,875	1,182,200	143,673	20.73	6,931
1966	577,503.19	390,623	506,979	70,524	21.29	3,313
1967	10,483,558.18	6,977,856	9,056,374	1,427,184	21.86	65,287
1968	749,644.48	487,419	632,608	117,036	22.86	5,120
1969	1,855,561.71	1,185,889	1,539,134	316,428	23.44	13,499
1970	1,197,235.01	746,715	969,142	228,093	24.44	9,333
1971	1,766,128.46	1,081,224	1,403,292	362,836	25.02	14,502
1972	3,539,695.96	2,125,941	2,759,202	780,494	25.60	30,488
1973	1,861,910.17	1,089,217	1,413,666	448,244	26.60	16,851
1974	3,198,096.34	1,832,509	2,378,365	819,731	27.20	30,137
1975	3,554,160.95	1,981,089	2,571,203	982,958	28.19	34,869
1976	3,033,727.44	1,653,685	2,146,274	887,453	28.79	30,825
1977	5,270,392.40	2,789,619	3,620,573	1,649,819	29.79	55,382
1978	2,634,319.79	1,352,723	1,755,663	878,657	30.79	28,537
1979	606,840.63	303,906	394,432	212,409	31.40	6,765
1980	6,807,630.10	3,301,701	4,285,190	2,522,440	32.39	77,877
1981	436,619.15	204,774	265,771	170,848	33.40	5,115
1982	57,853,123.93	26,381,025	34,239,232	23,613,892	34.00	694,526
1983	84,846.80	37,333	48,454	36,393	35.00	1,040
1984	362,239.79	153,590	199,340	162,900	36.00	4,525
1985	22,264,507.75	9,141,807	11,864,909	10,399,599	36.61	284,064

MANITOBA HYDRO

ACCOUNT 2000L - OVERHEAD CONDUCTOR AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
1986	19,805.94	7,811	10,138	9,668	37.61	257
1987	13,031.21	4,931	6,400	6,631	38.61	172
1988	421,948.99	152,830	198,354	223,595	39.61	5,645
1989	6,555,982.36	2,283,449	2,963,628	3,592,354	40.23	89,295
1990	9,394,025.98	3,119,756	4,049,048	5,344,978	41.23	129,638
1991	2,617,663.25	826,920	1,073,238	1,544,425	42.23	36,572
1992	3,793,724.33	1,136,979	1,475,655	2,318,069	43.23	53,622
1993	2,462,562.70	698,137	906,093	1,556,470	44.23	35,190
1994	1,868,678.63	499,498	648,285	1,220,394	45.23	26,982
1995	4,369,494.93	1,097,180	1,424,001	2,945,494	46.23	63,714
1996	445,858.55	105,401	136,797	309,062	46.85	6,597
1997	18,664,969.99	4,106,293	5,329,449	13,335,521	47.85	278,694
1998	14,863,385.61	3,029,158	3,931,464	10,931,922	48.85	223,786
1999	16,583,325.93	3,107,715	4,033,421	12,549,905	49.85	251,753
2000	3,795,733.12	649,830	843,397	2,952,336	50.85	58,060
2001	11,356,603.50	1,758,002	2,281,664	9,074,940	51.85	175,023
2002	13,860,228.87	1,921,028	2,493,251	11,366,978	52.85	215,080
2003	13,387,009.11	1,635,893	2,123,182	11,263,827	53.85	209,170
2004	6,813,310.01	722,211	937,338	5,875,972	54.85	107,128
2005	6,212,543.46	556,644	722,454	5,490,089	55.85	98,301
2006	2,272,917.45	166,832	216,527	2,056,390	56.85	36,172
2007	16,445,139.06	937,373	1,216,591	15,228,548	57.85	263,242
2008	4,416,009.70	181,056	234,988	4,181,022	58.48	71,495
2009	2,021,804.32	49,736	64,551	1,957,253	59.48	32,906
2010	2,322,979.57	19,048	24,722	2,298,258	60.48	38,000
	304,577,151.60	101,223,234	131,135,862	173,441,290		3,936,888

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 44.1 1.29

MANITOBA HYDRO

ACCOUNT 1175D - SPILLWAY

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	--ACCRUED DEPREC.-- FACTOR (7)	AMOUNT (8)
INTERIM SURVIVOR CURVE.. IOWA 75-R2							
PROBABLE RETIREMENT YEAR.. 12-2131							
NET SALVAGE PERCENT.. -10							
1991	80,430,469.28	75.00	1.33	1,176,697.77	58.01	0.2265	20,041,906
1992	80,430,469.28	75.00	1.33	1,176,697.77	58.85	0.2153	19,051,002
1993	40,215,234.64	75.00	1.33	588,348.88	59.69	0.2041	9,030,049
2007	68,329.54	74.94	1.33	999.66	71.79	0.0420	3,159
2008	94,022.89	74.92	1.33	1,375.55	72.67	0.0300	3,106
2010	2,246.89	74.88	1.34	33.12	74.43	0.0060	15
	201,240,772.52			2,944,152.75			48,129,237

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 1.46

MANITOBA HYDRO

ACCOUNT 2000L - OVERHEAD CONDUCTOR AND DEVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	--ACCRUED DEPREC.-- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 65-R4							
NET SALVAGE PERCENT.. -15							
1911	225,000.00	65.00				1.0000	258,750
1923	51,028.75	65.00	1.54	903.72	2.51	0.9614	56,417
1926	62,927.80	65.00	1.54	1,114.45	3.26	0.9499	68,738
1927	314,857.21	65.00	1.54	5,576.12	3.52	0.9459	342,479
1928	39,363.53	65.00	1.54	697.13	3.78	0.9419	42,636
1930	522,063.55	65.00	1.54	9,245.75	4.30	0.9339	560,658
1931	1,500,000.00	65.00	1.54	26,565.00	4.57	0.9297	1,603,715
1939	446.20	65.00	1.54	7.90	6.94	0.8932	458
1946	1,053.27	65.00	1.54	18.65	9.75	0.8500	1,030
1948	596.21	65.00	1.54	10.56	10.75	0.8346	572
1949	439,651.86	65.00	1.54	7,786.23	11.30	0.8262	417,701
1950	516,410.37	65.00	1.54	9,145.63	11.86	0.8175	485,514
1951	411,102.89	65.00	1.54	7,280.63	12.45	0.8085	382,214
1952	623,823.40	65.00	1.54	11,047.91	13.06	0.7991	573,258
1953	184,704.93	65.00	1.54	3,271.12	13.69	0.7894	167,673
1955	214,227.77	65.00	1.54	3,793.97	15.00	0.7692	189,509
1956	1,017,699.36	65.00	1.54	18,023.46	15.67	0.7589	888,205
1957	244,145.73	65.00	1.54	4,323.82	16.36	0.7483	210,101
1958	11,557.33	65.00	1.54	204.68	17.05	0.7377	9,805
1959	45,931.38	65.00	1.54	813.44	17.76	0.7268	38,389
1960	9,105.00	65.00	1.54	161.25	18.48	0.7157	7,494
1961	1,271,931.21	65.00	1.54	22,525.90	19.20	0.7046	1,030,662
1962	2,239,550.14	65.00	1.54	39,662.43	19.94	0.6932	1,785,402
1963	110,859.67	65.00	1.54	1,963.32	20.69	0.6817	86,908
1964	76,762.00	65.00	1.54	1,359.46	21.46	0.6699	59,132
1965	1,325,873.24	65.00	1.54	23,481.22	22.23	0.6580	1,003,288
1966	577,503.19	65.00	1.54	10,227.58	23.02	0.6459	428,928
1967	10,483,558.18	65.00	1.54	185,663.82	23.81	0.6337	7,639,825
1968	749,644.48	65.00	1.54	13,276.20	24.62	0.6212	535,557
1969	1,855,561.71	65.00	1.54	32,862.00	25.44	0.6086	1,298,732
1970	1,197,235.01	65.00	1.54	21,203.03	26.27	0.5959	820,378
1971	1,766,128.46	65.00	1.54	31,278.14	27.12	0.5828	1,183,634
1972	3,539,695.96	65.00	1.54	62,688.02	27.97	0.5697	2,319,009
1973	1,861,910.17	65.00	1.54	32,974.43	28.83	0.5565	1,191,490
1974	3,198,096.34	65.00	1.54	56,638.29	29.70	0.5431	1,997,345
1975	3,554,160.95	65.00	1.54	62,944.19	30.58	0.5295	2,164,381
1976	3,033,727.44	65.00	1.54	53,727.31	31.47	0.5159	1,799,691
1977	5,270,392.40	65.00	1.54	93,338.65	32.37	0.5020	3,042,598
1978	2,634,319.79	65.00	1.54	46,653.80	33.28	0.4880	1,478,380
1979	606,840.63	65.00	1.54	10,747.15	34.20	0.4739	330,684
1980	6,807,630.10	65.00	1.54	120,563.13	35.12	0.4597	3,598,809
1981	436,619.15	65.00	1.54	7,732.53	36.05	0.4454	223,631
1982	57,853,123.93	65.00	1.54	1,024,578.82	36.99	0.4309	28,669,578
1983	84,846.80	65.00	1.54	1,502.64	37.93	0.4165	40,636
1984	362,239.79	65.00	1.54	6,415.27	38.88	0.4019	167,401

MANITOBA HYDRO

ACCOUNT 2000L - OVERHEAD CONDUCTOR AND DEVICES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	--ACCRUED DEPREC.-- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 65-R4							
NET SALVAGE PERCENT.. -15							
1985	22,264,507.75	65.00	1.54	394,304.43	39.83	0.3872	9,914,708
1986	19,805.94	65.00	1.54	350.76	40.79	0.3725	8,483
1987	13,031.21	65.00	1.54	230.78	41.75	0.3577	5,360
1988	421,948.99	65.00	1.54	7,472.72	42.72	0.3428	166,326
1989	6,555,982.36	65.00	1.54	116,106.45	43.69	0.3279	2,471,786
1990	9,394,025.98	65.00	1.54	166,368.20	44.66	0.3129	3,380,515
1991	2,617,663.25	65.00	1.54	46,358.82	45.64	0.2979	896,622
1992	3,793,724.33	65.00	1.54	67,186.86	46.62	0.2828	1,233,664
1993	2,462,562.70	65.00	1.54	43,611.99	47.60	0.2677	758,084
1994	1,868,678.63	65.00	1.54	33,094.30	48.58	0.2526	542,875
1995	4,369,494.93	65.00	1.54	77,383.76	49.57	0.2374	1,192,815
1996	445,858.55	65.00	1.54	7,896.15	50.56	0.2222	113,905
1997	18,664,969.99	65.00	1.54	330,556.62	51.55	0.2069	4,441,479
1998	14,863,385.61	65.00	1.54	263,230.56	52.54	0.1917	3,276,537
1999	16,583,325.93	65.00	1.54	293,690.70	53.53	0.1765	3,365,238
2000	3,795,733.12	65.00	1.54	67,222.43	54.53	0.1611	703,129
2001	11,356,603.50	65.00	1.54	201,125.45	55.52	0.1459	1,904,815
2002	13,860,228.87	65.00	1.54	245,464.65	56.52	0.1305	2,079,436
2003	13,387,009.11	65.00	1.54	237,083.93	57.51	0.1152	1,773,973
2004	6,813,310.01	65.00	1.54	120,663.72	58.51	0.0999	782,355
2005	6,212,543.46	65.00	1.54	110,024.14	59.51	0.0845	603,418
2006	2,272,917.45	65.00	1.54	40,253.37	60.51	0.0691	180,565
2007	16,445,139.06	65.00	1.54	291,243.41	61.50	0.0539	1,018,406
2008	4,416,009.70	65.00	1.54	78,207.53	62.50	0.0385	195,316
2009	2,021,804.32	65.00	1.54	35,806.15	63.50	0.0231	53,663
2010	2,322,979.57	65.00	1.54	41,139.97	64.50	0.0077	20,543
	304,577,151.60			5,390,076.60			110,285,411

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 1.77

MANITOBA HYDRO

ACCOUNT 1175D - SPILLWAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 75-R2						
PROBABLE RETIREMENT YEAR.. 12-2131						
NET SALVAGE PERCENT.. -10						
1991	80,430,469.28	20,041,906	20,505,114	67,968,402	58.01	1,171,667
1992	80,430,469.28	19,051,002	19,491,308	68,982,208	58.85	1,172,170
1993	40,215,234.64	9,030,049	9,238,750	34,998,008	59.69	586,330
2007	68,329.54	3,159	3,232	71,930	71.79	1,002
2008	94,022.89	3,106	3,178	100,247	72.67	1,379
2010	2,246.89	15	16	2,456	74.43	33
	201,240,772.52	48,129,237	49,241,598	172,123,252		2,932,581

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 58.7 1.46

MANITOBA HYDRO

ACCOUNT 2000L - OVERHEAD CONDUCTOR AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -15						
1911	225,000.00	258,750	258,750			
1923	51,028.75	56,417	58,683			
1926	62,927.80	68,738	72,367			
1927	314,857.21	342,479	362,086			
1928	39,363.53	42,636	45,268			
1930	522,063.55	560,658	600,373			
1931	1,500,000.00	1,603,715	1,725,000			
1939	446.20	458	513			
1946	1,053.27	1,030	1,211			
1948	596.21	572	682	4	10.75	
1949	439,651.86	417,701	498,093	7,507	11.30	664
1950	516,410.37	485,514	578,958	14,914	11.86	1,258
1951	411,102.89	382,214	455,776	16,992	12.45	1,365
1952	623,823.40	573,258	683,589	33,808	13.06	2,589
1953	184,704.93	167,673	199,944	12,467	13.69	911
1955	214,227.77	189,509	225,983	20,379	15.00	1,359
1956	1,017,699.36	888,205	1,059,152	111,202	15.67	7,096
1957	244,145.73	210,101	250,538	30,230	16.36	1,848
1958	11,557.33	9,805	11,692	1,599	17.05	94
1959	45,931.38	38,389	45,777	7,044	17.76	397
1960	9,105.00	7,494	8,936	1,535	18.48	83
1961	1,271,931.21	1,030,662	1,229,027	233,694	19.20	12,172
1962	2,239,550.14	1,785,402	2,129,027	446,456	19.94	22,390
1963	110,859.67	86,908	103,635	23,854	20.69	1,153
1964	76,762.00	59,132	70,513	17,763	21.46	828
1965	1,325,873.24	1,003,288	1,196,385	328,369	22.23	14,771
1966	577,503.19	428,928	511,481	152,648	23.02	6,631
1967	10,483,558.18	7,639,825	9,110,214	2,945,878	23.81	123,724
1968	749,644.48	535,557	638,632	223,459	24.62	9,076
1969	1,855,561.71	1,298,732	1,548,691	585,205	25.44	23,003
1970	1,197,235.01	820,378	978,271	398,549	26.27	15,171
1971	1,766,128.46	1,183,634	1,411,441	619,607	27.12	22,847
1972	3,539,695.96	2,319,009	2,765,334	1,305,316	27.97	46,668
1973	1,861,910.17	1,191,490	1,420,809	720,388	28.83	24,987
1974	3,198,096.34	1,997,345	2,381,761	1,296,050	29.70	43,638
1975	3,554,160.95	2,164,381	2,580,946	1,506,339	30.58	49,259
1976	3,033,727.44	1,799,691	2,146,066	1,342,721	31.47	42,667
1977	5,270,392.40	3,042,598	3,628,188	2,432,763	32.37	75,155
1978	2,634,319.79	1,478,380	1,762,914	1,266,554	33.28	38,058
1979	606,840.63	330,684	394,329	303,538	34.20	8,875
1980	6,807,630.10	3,598,809	4,291,449	3,537,326	35.12	100,721
1981	436,619.15	223,631	266,672	235,440	36.05	6,531
1982	57,853,123.93	28,669,578	34,187,431	32,343,662	36.99	874,389
1983	84,846.80	40,636	48,457	49,117	37.93	1,295
1984	362,239.79	167,401	199,620	216,956	38.88	5,580

MANITOBA HYDRO

ACCOUNT 2000L - OVERHEAD CONDUCTOR AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -15						
1985	22,264,507.75	9,914,708	11,822,929	13,781,255	39.83	346,002
1986	19,805.94	8,483	10,116	12,661	40.79	310
1987	13,031.21	5,360	6,392	8,594	41.75	206
1988	421,948.99	166,326	198,338	286,903	42.72	6,716
1989	6,555,982.36	2,471,786	2,947,515	4,591,865	43.69	105,101
1990	9,394,025.98	3,380,515	4,031,141	6,771,989	44.66	151,634
1991	2,617,663.25	896,622	1,069,189	1,941,124	45.64	42,531
1992	3,793,724.33	1,233,664	1,471,100	2,891,683	46.62	62,027
1993	2,462,562.70	758,084	903,988	1,927,959	47.60	40,503
1994	1,868,678.63	542,875	647,359	1,501,621	48.58	30,910
1995	4,369,494.93	1,192,815	1,422,389	3,602,530	49.57	72,676
1996	445,858.55	113,905	135,828	376,909	50.56	7,455
1997	18,664,969.99	4,441,479	5,296,302	16,168,413	51.55	313,645
1998	14,863,385.61	3,276,537	3,907,151	13,185,742	52.54	250,966
1999	16,583,325.93	3,365,238	4,012,924	15,057,901	53.53	281,298
2000	3,795,733.12	703,129	838,456	3,526,637	54.53	64,673
2001	11,356,603.50	1,904,815	2,271,423	10,788,671	55.52	194,320
2002	13,860,228.87	2,079,436	2,479,652	13,459,611	56.52	238,139
2003	13,387,009.11	1,773,973	2,115,398	13,279,662	57.51	230,910
2004	6,813,310.01	782,355	932,930	6,902,377	58.51	117,969
2005	6,212,543.46	603,418	719,554	6,424,871	59.51	107,963
2006	2,272,917.45	180,565	215,317	2,398,538	60.51	39,639
2007	16,445,139.06	1,018,406	1,214,412	17,697,498	61.50	287,764
2008	4,416,009.70	195,316	232,907	4,845,504	62.50	77,528
2009	2,021,804.32	53,663	63,991	2,261,084	63.50	35,608
2010	2,322,979.57	20,543	24,497	2,646,930	64.50	41,038
	304,577,151.60	110,285,411	131,135,862	219,127,863		4,734,784

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.3 1.55

MIPUG/MH I-16

Subject: Appendix 5.7 Depreciation Study re: Wuskwatim

a) Please provide the first full year (2013/14) depreciation expenses for each of Wuskwatim Generation and Wuskwatim Transmission under (i) the rates applicable April 1, 2007, (ii) the rates applicable April 1, 2011, (iii) the rates set out in Gannett Fleming's January 13, 2012 report, (iv) the rates set out in Gannett Fleming's November 2, 2011 report, and (v) the rates proposed to be adopted by Hydro as of April 1, 2013.

ANSWER:

There were no approved rates effective April 1, 2007 (part i) available for Wuskwatim. The rates applicable April 1, 2011 (part ii) and the rates set out in Gannett Fleming's January 13, 2012 report (part iii) are the same and would result in 2013/14 projected depreciation expense of $27.0 million. The rates set out in Gannett Fleming's November 2, 2011 report (part iv) and the rates proposed to be adopted by Hydro as of April 1, 2013 (part v) are the same and result in 2013/14 projected depreciation expense of $24.8 million as shown in the projected financial statements in response to PUB/MH I-134.

MIPUG/MH I-16

Subject: Appendix 5.7 Depreciation Study re: Wuskwatim

b) Please indicate if the rates proposed by Hydro in Appendix 5.7 apply to the financial accounts of WPLP.

ANSWER:

In accordance with the Wuskwatim Limited Partnership Agreement, the Wuskwatim Power Limited Partnership (WPLP) will calculate net income and net loss according to the application of Hydro's accounting policies and practices, in effect from time to time, in accordance with Generally Accepted Accounting Principles. As such, the rates effective April 1, 2013 proposed in Appendix 5.7 would apply to the financial accounts of WPLP when the Generating Station asset is placed in-service.

MIPUG/MH I-16

Subject: Appendix 5.7 Depreciation Study re: Wuskwatim

c) If the answer to (b) is yes, please provide a copy of the WPLP financial statements (based on IFF11-2 forecasts – including operating statement, balance sheet and cash flow) under each of the depreciation methods set out in (a).

ANSWER:

Please see the response to PUB/MH I-134 for IFF11-2 WPLP projected financial statements reflecting depreciation rates effective April 1, 2013. As indicated in the response to MIPUG/MH I-16(a), the depreciation expense using the rates set out in Gannett Fleming's January 2012 report is $27 million annually commencing in 2013/14.

MIPUG/MH I-16

Subject: Appendix 5.7 Depreciation Study re: Wuskwatim

d) Please indicate if the values in IFF11-2 pages 31 and 32 for "non-controlling interest" would be affected by adoption of alternative depreciation rates as per part (a) above. If so, please provide the values for each approach.

ANSWER:

"Non-controlling interest" in IFF11-2 represents dividends paid under an assumed NCN preferred equity investment. A change to depreciation rates does not impact non-controlling interest under this assumption.

MIPUG/MH I-17

Subject: Appendix 5.7 Depreciation Study re: Brandon Unit #5

a) Please confirm that the Gannett Fleming November 2, 2011 study proposes that Brandon Unit #5 be amortized over a period to 2020, such that by 2020 all surviving original costs have been fully amortized.

ANSWER:

Confirmed.

MIPUG/MH I-17

Subject: Appendix 5.7 Depreciation Study re: Brandon Unit #5

b) Please confirm that as of March 31, 2010, the $141 million in surviving original cost for Brandon Unit #5 has only $82 million of accrued depreciation (58% of original surviving cost)

ANSWER:

Confirmed.

MIPUG/MH I-17

Subject: Appendix 5.7 Depreciation Study re: Brandon Unit #5

c) Please provide all calculations in support of the $87.5 million calculated accrued depreciation for Brandon #5.

ANSWER:

The following response was prepared by Gannett Fleming.

Please see the attached tables which provide the calculation supporting the calculated accrued depreciation for each of the asset accounts for Brandon #5.

MANITOBA HYDRO

ACCOUNT 1205B - POWERHOUSE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 65-R4					
PROBABLE RETIREMENT YEAR.. 12-2020					
NET SALVAGE PERCENT.. 0					
1958	4,004,277.44	1.63	65,269.72	0.8558	3,426,861
1959	2,743.57	1.66	45.54	0.8549	2,345
1970	3,667,541.62	2.00	73,350.83	0.8100	2,970,709
1971	2,218.19	2.04	45.25	0.8058	1,787
1974	6,019.59	2.17	130.63	0.7920	4,768
1977	117,844.68	2.31	2,722.21	0.7738	91,188
1983	125,400.07	2.68	3,360.72	0.7370	92,420
1985	233,701.84	2.83	6,613.76	0.7216	168,639
1989	131,504.71	3.18	4,181.85	0.6837	89,910
1991	37,619.40	3.40	1,279.06	0.6630	24,942
2004	79,792.30	6.06	4,835.41	0.3939	31,430
2005	111,093.07	6.45	7,165.50	0.3548	39,416
2006	422,430.43	6.90	29,147.70	0.3105	131,165
2007	1,362,020.01	7.41	100,925.68	0.2594	353,308
2008	518,254.82	8.00	41,460.39	0.2000	103,651
2009	684,262.03	8.70	59,530.80	0.1305	89,296
2010	222,794.16	9.53	21,232.28	0.0476	10,605
	11,729,517.93		421,297.33		7,632,440

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.59

MANITOBA HYDRO

ACCOUNT 1205F - ROADS AND SITE IMPROVEMENTS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 50-R3					
PROBABLE RETIREMENT YEAR.. 12-2020					
NET SALVAGE PERCENT.. 0					
1958	132,388.76	1.69	2,237.37	0.8872	117,455
1961	13,558.33	1.77	239.98	0.8762	11,880
1962	4,026.93	1.79	72.08	0.8682	3,496
1970	68,735.09	2.04	1,402.20	0.8262	56,789
1990	348,139.98	3.32	11,558.25	0.6806	236,944
1993	38,011.38	3.67	1,395.02	0.6422	24,411
1994	3,755.62	3.81	143.09	0.6286	2,361
1995	1,212,682.70	3.96	48,022.23	0.6138	744,345
1996	781,979.28	4.12	32,217.55	0.5974	467,154
1997	537,528.95	4.29	23,059.99	0.5792	311,337
1998	233,636.34	4.48	10,466.91	0.5600	130,836
2000	281,761.75	4.91	13,834.50	0.5156	145,276
2005	109,583.42	6.49	7,111.96	0.3570	39,121
2006	784.97	6.94	54.48	0.3123	245
2008	81,826.46	8.06	6,595.21	0.2015	16,488
2009	150,517.98	8.76	13,185.38	0.1314	19,778
2010	13,412.92	9.63	1,291.66	0.0482	647
	4,012,330.86		172,887.86		2,328,563

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.31

MANITOBA HYDRO

ACCOUNT 1205G - THERMAL TURBINES AND GENERATORS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 50-S3					
PROBABLE RETIREMENT YEAR.. 12-2020					
NET SALVAGE PERCENT.. 0					
1970	3,833,513.77	2.06	78,970.38	0.8343	3,198,301
1978	255,528.34	2.41	6,158.23	0.7832	200,130
1984	890,072.87	2.78	24,744.03	0.7367	655,717
1993	100,386.00	3.65	3,664.09	0.6388	64,127
1994	134,172.20	3.79	5,085.13	0.6254	83,911
1995	76,556.76	3.93	3,008.68	0.6092	46,638
1996	3,977,145.32	4.09	162,665.24	0.5930	2,358,447
1997	355,629.14	4.26	15,149.80	0.5751	204,522
1998	134,449.24	4.45	5,982.99	0.5562	74,781
1999	135,185.62	4.66	6,299.65	0.5359	72,446
2000	603,623.24	4.88	29,456.81	0.5124	309,297
2004	1,984,782.56	6.06	120,277.82	0.3939	781,806
2005	5,490,710.36	6.45	354,150.82	0.3548	1,948,104
2007	1,129,705.55	7.41	83,711.18	0.2594	293,046
2009	509,706.58	8.70	44,344.47	0.1305	66,517
	19,611,167.55		943,669.32		10,357,790

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.81

MANITOBA HYDRO

ACCOUNT 1205H - GOVERNORS AND EXCITATION SYSTEM

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 50-R4					
PROBABLE RETIREMENT YEAR.. 12-2020					
NET SALVAGE PERCENT.. 0					
2000	2,343,861.07	4.89	114,614.81	0.5134	1,203,338
	2,343,861.07		114,614.81		1,203,338

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.89

MANITOBA HYDRO

ACCOUNT 1205J - STEAM GENERATOR AND AUXILIARIES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 65-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2020					
NET SALVAGE PERCENT.. 0					
1958	449,370.05	1.63	7,324.73	0.8558	384,571
1959	733.40	1.65	12.10	0.8498	623
1962	16,431.92	1.74	285.92	0.8439	13,867
1963	16,107.90	1.76	283.50	0.8360	13,466
1967	6,180.62	1.89	116.81	0.8222	5,082
1970	6,846,243.17	2.00	136,924.86	0.8100	5,545,457
1974	5,110.27	2.17	110.89	0.7920	4,047
1976	3,032.49	2.27	68.84	0.7832	2,375
1978	83,103.71	2.38	1,977.87	0.7735	64,281
1979	213,848.80	2.43	5,196.53	0.7654	163,680
1980	197,083.36	2.49	4,907.38	0.7594	149,665
1982	6,818.19	2.62	178.64	0.7467	5,091
1983	302,810.28	2.69	8,145.60	0.7398	224,019
1989	36,343.80	3.20	1,163.00	0.6880	25,005
1992	178,748.68	3.53	6,309.83	0.6530	116,723
1993	237,281.67	3.66	8,684.51	0.6405	151,979
1994	551,211.31	3.80	20,946.03	0.6270	345,609
1995	363,550.75	3.95	14,360.25	0.6122	222,566
1996	2,731,155.65	4.11	112,250.50	0.5960	1,627,769
1997	15,202.87	4.29	652.20	0.5792	8,806
1998	70,869.15	4.48	3,174.94	0.5600	39,687
1999	1,013.90	4.68	47.45	0.5382	546
2000	161,537.81	4.91	7,931.51	0.5156	83,289
2003	6,353.51	5.76	365.96	0.4320	2,745
2004	1,325.90	6.11	81.01	0.3972	527
2005	942,222.59	6.51	61,338.69	0.3580	337,316
2006	108.48	6.96	7.55	0.3132	34
2010	1,383,382.41	9.75	134,879.78	0.0488	67,509
	14,827,182.64		537,726.88		9,606,334

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.63

MANITOBA HYDRO

ACCOUNT 1205P - A/C ELECTRICAL POWER SYSTEMS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 50-R3					
PROBABLE RETIREMENT YEAR.. 12-2020					
NET SALVAGE PERCENT.. 0					
1958	996,490.01	1.69	16,840.68	0.8872	884,086
1959	15,360.51	1.72	264.20	0.8858	13,606
1970	1,068,764.12	2.04	21,802.79	0.8262	883,013
1986	12,442.46	2.94	365.81	0.7203	8,962
1993	484,151.59	3.67	17,768.36	0.6422	310,922
1995	188,243.47	3.96	7,454.44	0.6138	115,544
1996	2,660,168.97	4.12	109,598.96	0.5974	1,589,185
1997	1,689,713.37	4.29	72,488.70	0.5792	978,682
1998	313,998.62	4.48	14,067.14	0.5600	175,839
1999	166,322.80	4.69	7,800.54	0.5394	89,715
2000	23,165.06	4.91	1,137.40	0.5156	11,944
2002	191.69	5.44	10.43	0.4624	89
2006	14,116.89	6.94	979.71	0.3123	4,409
2007	369,783.98	7.46	27,585.88	0.2611	96,551
2008	5,727.89	8.06	461.67	0.2015	1,154
2009	1,061.58	8.76	92.99	0.1314	139
	8,009,703.01		298,719.70		5,163,840

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.73

MANITOBA HYDRO

ACCOUNT 1205Q - INSTRUMENTATION, CONTROL AND D/C SYSTEMS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

INTERIM SURVIVOR CURVE.. IOWA 23-L2
PROBABLE RETIREMENT YEAR.. 12-2020
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
1958	970,651.69	1.83	17,762.93	0.9608	932,602
1959	54,433.22	1.86	1,012.46	0.9579	52,142
1961	2,160.84	1.91	41.27	0.9454	2,043
1962	5,469.20	1.95	106.65	0.9458	5,173
1966	70.01	2.08	1.46	0.9256	65
1970	2,257,981.75	2.24	50,578.79	0.9072	2,048,441
1978	1,738.71	2.65	46.08	0.8612	1,497
1979	18,881.70	2.71	511.69	0.8536	16,117
1980	28,480.80	2.78	791.77	0.8479	24,149
1985	99,861.39	3.18	3,175.59	0.8109	80,978
1986	45,307.08	3.28	1,486.07	0.8036	36,409
1987	4,676.73	3.39	158.54	0.7966	3,725
1991	220,847.34	3.88	8,568.88	0.7566	167,093
1993	253,685.57	4.18	10,604.06	0.7315	185,571
1994	617,174.16	4.34	26,785.36	0.7161	441,958
1995	1,977,242.89	4.52	89,371.38	0.7006	1,385,256
1996	12,286,642.29	4.70	577,472.19	0.6815	8,373,347
1997	3,923,378.58	4.89	191,853.21	0.6602	2,590,215
1998	1,961,104.95	5.09	99,820.24	0.6362	1,247,655
1999	4,552.26	5.31	241.73	0.6106	2,780
2000	703,070.02	5.53	38,879.77	0.5806	408,202
2002	295,169.12	6.03	17,798.70	0.5126	151,304
2003	119,790.98	6.32	7,570.79	0.4740	56,781
2004	33,693.52	6.64	2,237.25	0.4316	14,542
2005	105,357.85	7.01	7,385.59	0.3856	40,626
2006	162,589.41	7.43	12,080.39	0.3344	54,370
2007	56,929.58	7.92	4,508.82	0.2772	15,781
2008	72,286.49	8.48	6,129.89	0.2120	15,325
2009	59,677.80	9.14	5,454.55	0.1371	8,182
2010	46,868.84	9.93	4,654.08	0.0496	2,325
	26,389,774.77		1,187,090.18		18,364,654

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.50

MANITOBA HYDRO

ACCOUNT 1205R - AUXILIARY STATION PROCESSES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2020
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	ANNUAL ACCRUAL RATE (3)	ANNUAL ACCRUAL AMOUNT (4)	ACCRUED DEPREC. FACTOR (5)	ACCRUED DEPREC. AMOUNT (6)
1958	4,527,055.63	1.75	79,223.47	0.9188	4,159,459
1959	37,213.50	1.78	662.40	0.9167	34,114
1961	2,794.55	1.83	51.14	0.9058	2,531
1968	45,589.79	2.05	934.59	0.8712	39,718
1969	4,854.76	2.08	100.98	0.8632	4,191
1970	802,938.91	2.12	17,022.30	0.8586	689,403
1971	1,137,098.15	2.16	24,561.32	0.8532	970,172
1972	73,474.76	2.19	1,609.10	0.8432	61,954
1973	4,540.68	2.23	101.26	0.8362	3,797
1974	36,017.98	2.28	821.21	0.8322	29,974
1975	4,136.03	2.32	95.96	0.8236	3,406
1977	15,596.42	2.42	377.43	0.8107	12,644
1978	1,836.45	2.47	45.36	0.8028	1,474
1979	225,297.19	2.52	5,677.49	0.7938	178,841
1980	11,925.44	2.58	307.68	0.7869	9,384
1981	5,900.53	2.64	155.77	0.7788	4,595
1982	14,449.05	2.70	390.12	0.7695	11,119
1983	426,211.94	2.77	11,806.07	0.7618	324,688
1984	56,096.80	2.84	1,593.15	0.7526	42,218
1986	31,161.34	2.99	931.72	0.7326	22,829
1987	24,560.75	3.08	756.47	0.7238	17,777
1988	1,007,008.98	3.17	31,922.18	0.7132	718,199
1989	9,337.13	3.26	304.39	0.7009	6,544
1990	22,430.10	3.37	755.89	0.6908	15,495
1991	162,753.16	3.48	5,663.81	0.6786	110,444
1992	202,191.35	3.60	7,278.89	0.6660	134,659
1993	1,805,352.05	3.72	67,159.10	0.6510	1,175,284
1994	1,181,821.30	3.86	45,618.30	0.6369	752,702
1995	1,090,511.78	4.01	43,729.52	0.6216	677,862
1996	22,090,567.76	4.17	921,176.68	0.6046	13,355,957
1997	2,220,483.97	4.34	96,369.00	0.5859	1,300,982
1998	808,168.66	4.53	36,610.04	0.5662	457,585
2000	842,069.00	4.97	41,850.83	0.5218	439,392
2002	1,662,801.18	5.51	91,620.35	0.4684	778,856
2003	761,856.88	5.82	44,340.07	0.4365	332,551
2004	776,584.75	6.18	47,992.94	0.4017	311,954
2005	67,950.82	6.58	4,471.16	0.3619	24,591
2006	256,011.83	7.03	17,997.63	0.3164	81,002
2007	3,791,575.26	7.56	286,643.09	0.2646	1,003,251
2008	644,635.85	8.19	52,795.68	0.2048	132,021
2009	362,171.88	8.94	32,378.17	0.1341	48,567
2010	51,383.10	9.92	5,097.20	0.0496	2,549
	47,306,417.44		2,028,999.91		28,484,735

MANITOBA HYDRO

ACCOUNT 1205R - AUXILIARY STATION PROCESSES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL--		--ACCRUED DEPREC.--	
		RATE	AMOUNT	FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.29

MANITOBA HYDRO

ACCOUNT 1205X - SUPPORT BUILDINGS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

INTERIM SURVIVOR CURVE.. IOWA 65-R3
PROBABLE RETIREMENT YEAR.. 12-2020
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
1958	394,807.45	1.63	6,435.36	0.8558	337,876
1959	9,806.92	1.65	161.81	0.8498	8,334
1971	6,227.03	2.04	127.03	0.8058	5,018
1972	85,371.48	2.08	1,775.73	0.8008	68,365
1976	20,689.49	2.27	469.65	0.7832	16,204
1978	2,559.00	2.37	60.65	0.7702	1,971
1980	7,135.80	2.49	177.68	0.7594	5,419
1981	119,608.61	2.55	3,050.02	0.7522	89,970
1982	2,520.00	2.62	66.02	0.7467	1,882
1994	151,611.96	3.79	5,746.09	0.6254	94,818
1995	18,753.77	3.94	738.90	0.6107	11,453
1996	5,570,744.74	4.10	228,400.53	0.5945	3,311,808
1997	459,371.25	4.27	19,615.15	0.5764	264,782
1998	165,840.78	4.46	7,396.50	0.5575	92,456
2000	49,964.98	4.90	2,448.28	0.5145	25,707
2002	536.72	5.43	29.14	0.4616	248
2006	79,468.45	6.92	5,499.22	0.3114	24,746
2007	48,140.15	7.44	3,581.63	0.2604	12,536
2008	60,740.80	8.04	4,883.56	0.2010	12,209
	7,253,899.38		290,662.95		4,385,802

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.01

MIPUG/MH I-17

Subject: Appendix 5.7 Depreciation Study re: Brandon Unit #5

d) Please reconcile the Gannett Fleming retirement data of 2020 with the 2011/12 Power Resource Plan which assumes a 2019 retirement date.

ANSWER:

The Depreciation Study and the Power Resource Plan reflect the assumptions in place at the time each document was prepared.

The expected retirement dates for generating station were reviewed for the purposes of the Depreciation Study in June, 2010. At that time, Brandon Unit #5 was expected to continue operating until 2020.

The 2011/12 Power Resource Plan was finalized in August, 2011. At that time, Brandon Unit #5 was expected to continue operating until 2019.

The plant accounts for Brandon Unit #5 will be monitored as the retirement date approaches, and depreciation rates will be adjusted, if necessary, to ensure that the costs are fully amortized when Unit #5 is retired.

MIPUG/MH I-17

Subject: Appendix 5.7 Depreciation Study re: Brandon Unit #5

e) Please explain the basis for creation of an account 1205L for Brandon Licence renewal, and the adoption of a 10% rate (10 year) when spending on this category is not proposed to be in-service until 2015/16 per CEF11-2.

ANSWER:

Generating station licence renewals were identified as a separate depreciable component and new accounts were created for all generating stations during the depreciation study.

The Brandon Unit #5 Licence Review item in CEF11-2 includes: past expenditures for review and renewal work to comply with the existing licence under *The Manitoba Environment Act*; past expenditures for work performed with respect to the ash lagoons; and planned future expenditures related to physical modifications to the water treatment plant, to the burners and additional modification to the ash lagoons, which were identified during the review process.

The licence review and renewal portion of the work was completed, placed into service and commenced depreciating during the 2011 fiscal year. The 10% depreciation rate reflects the assumption of a 2020 retirement date in the depreciation study, which allows for a 10 year amortization period.

The expected in-service date for the total project, as stated in CEF11-2 is November, 2014 (please refer to page 40 of Appendix 6.1 to the filing). This date reflects the expected final in-service date for the forecast item.

MIPUG/MH I-18

Subject: IFRS and Power Smart costs

a) In light of the evidence provided at transcript pages 4442 to 4450 of the 2010 GRA (March 21, 2011), please indicate the options Manitoba Hydro has assessed with respect to the treatment of Power Smart costs (one-time and ongoing) for the purposes of rate setting, and the specific identified pros and cons, and cost implications for each year of IFF11-2 for each option.

ANSWER:

The current accounting treatment of Electric Power Smart costs under CGAAP for both financial reporting and rate-setting purposes is to defer the costs as a rate-regulated asset and to amortize the balance of the deferred account over a 10 year period.

IFF11-2 assumes that the cumulative unamortized deferred balance related to Electric Power Smart expenditures is adjusted to retained earnings upon transition to IFRS in 2013/14 and that on-going expenditures will be expensed as incurred over the forecast period. The write-off of the unamortized Power Smart deferred balance upon transition to IFRS in 2013/14 will eliminate any future amortization expense over the forecast period.

Electric Power Smart costs are the largest component of Electric operations rate-regulated assets. The projected amortization of the deferred Electric Power Smart costs under the current accounting treatments is similar to the projected expense that would be charged to OM&A under the proposed accounting treatment. As a result, the impact of the accounting change on the net income, financial ratios and revenue requirements of Electric operations is relatively minimal, as can be demonstrated by comparing the response to PUB/MH I-22(a) which provides the Electric operations IFF with the proposed accounting treatment of rate-regulated assets to the response to PUB/MH I-78(a) which provides an Electric operations IFF scenario assuming the continuation of rate-regulated accounting (i.e., the current accounting treatment).

While there is a projected write-off of $183 million of deferred Electric Power Smart costs associated with the transition to IFRS, this does not, in isolation, result in the requirement to increase projected rate increases during the 10-year IFF11-2 period. This demonstrates the effectiveness of Manitoba Hydro's approach to maintain a sufficient level of retained earnings to be able to withstand the one-time adverse impacts of financial consequences outside of its control and the flexibility of the cost of service rate-setting model which allows for a longer-term rate setting perspective.

Given that there is no significant negative impacts on revenue requirements and customer rates as a result of the proposed accounting treatment of Electric Power Smart costs under IFRS, Manitoba Hydro’s position is that the proposed accounting treatment should be adopted by the PUB for rate-setting purposes.

MIPUG/MH I-19

Subject: July 2012 Interim Rate Filing – Attachment 1 (2012 Load Forecast)

a) Please explain the reference at Page ii that "These events are deemed to be captured within the overall load variability analysis of the forecast"?

ANSWER:

The analysis assumes that historical load variability is representative of future load variability, and includes variability due to economic conditions and events such as those found on page ii of the 2012 Load Forecast. The confidence bands in the forecast include all such possible events.

MIPUG/MH I-19

Subject: July 2012 Interim Rate Filing – Attachment 1 (2012 Load Forecast)

b) Please confirm that the 2009/10 Load Forecast (Appendix 7.1 of the 2010 GRA) projected a possible load risk related to increased use of electric space heating, of 6000 GW.h and 2000 MW within 20 years. Please provide the rationale for now assuming the risk is only 746 GW.h and 243 MW.

ANSWER:

The 2009/10 Load Forecast presented the theoretical possibility of additional load of 6,000 GW.h and 2,000 MW within 20 years. This represents an extreme case where gas prices were assumed to be higher than electricity prices. It assumed that all new customers would install electric furnaces and all existing customers who were in the process of replacing existing gas furnaces would switch from gas to electricity.

The 2010/11 Electric Load Forecast presented a different case where the percentage of electric heat billed customers in 2031/32 would be 10% higher, or 50.6%, rather than 40.6% as forecast.

The scenarios are not directly comparable as they are different illustrations of electricity requirements under different assumptions for market penetration of electric space heat. The intention was to illustrate the potential impact of increased use of electric space heating on the electric load for sensitivity analysis purposes.

MIPUG/MH I-20

Subject: July 2012 Interim Rate Filing – Attachment 8 (Proof of Revenue)

a) Please provide the 2012/13 proof of revenue, showing all rates and billing determinants, for the April 1 2011 rates, April 1, 2012 rates, and proposed September 1, 2013 rates.

ANSWER:

The tables on the following pages provide billing determinants for the Residential and General Service rate classes based on fiscal 2012/13 forecast data at April 1, 2011 rates, April 1, 2012 rates and September 1, 2012 rates as approved in Order 117/12.

RESIDENTIAL:

Forecast Data	**Customer Months**	**>200 A Cust Months**	**1st block kWh**	**Balance of kWh**	**Total kWh**
Basic	5,467,368	38,756	-	7,215,717,688	7,215,717,688
Diesel	6,708	0	7,621,869	332,950	7,954,819
Seasonal	(avg mthly) 21,286	0	-	81,331,300	81,331,300
FRWH	49,146	0			20,726,194

April 2011 Rates	**Basic Charge**	**>200 A Charge**	**1st block kWh Charge**	**Balance of kWh Charge**
Basic	$6.85	$6.85		$0.0662
Diesel	$6.85		1st 900 kWh $0.0662	$0.3500
Seasonal	(annual) $82.20			$0.0662
FRWH	(average) $23.32			

Revenue at 2011 Rates	**BC & >200 A Revenue**	**1st Block kWh $**	**Balance of kWh $**	**Total Revenue**	**Adj. Factor**	**Adjusted Revenue**
Basic	$37,716,949	-	$477,680,511	$515,397,460	.9989	$514,850,181
Diesel	$45,950	$504,568	$116,532	$667,050	.9829	$655,648
Seasonal	$1,749,709		$5,384,132	$7,133,841	.9947	$7,096,251
FRWH				$1,145,914	1.000	$1,145,914

April 2012 Rates	**Basic Charge**	**>200 A Charge**	**kWh Charge**
Basic	$6.85	$6.85	$0.0677
Diesel	$6.85		$0.0677
Seasonal	(annual) $82.20		$0.0677
FRWH	(average) $23.78		

Revenue at 2012 Rates	**BC & >200 A Revenue**	**kWh Revenue**	**Total Revenue**	**Adj. Factor**	**Adjusted Revenue**
Basic	$37,716,949	$488,504,087	$526,221,037	.9989	$526,662,264
Diesel	$45,950	$538,541	$584,491	.9829	$574,500
Seasonal	$1,749,709	$5,506,129	$7,255,838	.9947	$7,217,605
FRWH		-	$1,168,692	1.000	$1,168,692

Sept 2012 Rates	Basic Charge	>200 A Charge	kWh Charge
Basic	$6.85	$6.85	$0.0694
Diesel	$6.85		$0.0694
Seasonal	(annual) $82.20		$0.0694
FRWH	(average) $24.37		

Revenue at 2012 Rates	BC & >200 A Revenue	kWh Revenue	Total Revenue	Adj. Factor	Adjusted Revenue
Basic	$37,719,949	$500,770,808	$538,487,757	.9989	$537,915,959
Diesel	$45,950	$552,064	$598,014	.9829	$587,792
Seasonal	$1,749,709	$5,644,392	$7,394,101	.9947	$7,355,140
FRWH		-	$1,197,496	1.000	$1,197,496

GENERAL SERVICE:

Forecast Data 2012/13	Cust Months	3 Phase Cust Months	1st 11000 kWh	Next 8500 kW.h & ND Runoff	Balance of kWh	Total kW.h	Billable Demand
Small ND	$620,904	137,256	1,485,980,163	139,668,178	0	1,625,648,341	0
Small Demand	146,838	94,478	809,323,566	449,434,508	745,961,336	2,004,719,409	2,276,921
Small LUBD	720	678	-	-	4,448,767	4,448,767	23,911
Seasonal	(avg mthly) 854	-	4,730,000	0	0	4,730,000	0
FRWH	4,778	-	-	-	-		0
Medium	23,012	-	251,053,667	190,137,117	2,697,037,933		7,089,302
Med. LUBD	244	-	-	-	4,155,190	4,155,190	40,954
Large <30	3,428	-	-	-	1,742,888,000	1,742,888,000	4,185,838
L<30 LUBD	45	-	-	-	1,471,000	1,471,000	16,073
Lrg30-100	484	-	-	-	1,066,502,992	1,066,502,992	2,146,316
Lrg >100	168	-	-	-	4,928,180,000	4,928,180,000	8,591,010
L>100 LUBD	24	-	-	-	1,152,000	1,152,000	26,874
DFC Fed Govt	546	-	-	-	1,773,500	1,773,500	0
DFC Prov Gov	246	-	-	-	381,500	381,500	0
DFC Non-Gov	1,348	-	(1st 2000 kW.h)	1,265,455	2,087,625		0
SEP Med	252	-	-	-	23,500,000	23,500,000	0
SEP Lrg <30	60	-	-	-	2,100,000	2,100,000	0

April 2011 Rates	**Basic Charge**	**3 Ph Charge**	**1st 11000 kWh Chg**	**Next 8500 kWh Chg & ND Bal.**	**Balance of kWh Charge**	**Demand Charge**
Small ND	$18.25	$7.30	$0.0696	$0.0484		
Small Demand	$18.25	$7.30	$0.0696	$0.0484	$0.0315	$8.34
Small LUBD	$18.25	$7.30			$0.0796	$2.09
Seasonal	(annual) $219.00	$87.60	$0.0696	$0.0484		
FRWH	(average) $104.38					
Medium	$27.60		$0.0696	$0.0484	$0.0315	$8.34
Med. LUBD	$27.60				$0.0796	$2.09
Large <30	$0.00				$0.0297	$7.08
L<30 LUBD	$0.00				$0.0705	$1.77
Large 30-100	$0.00				$0.0277	$6.06
Large >100	$0.00				$0.0269	$5.40
L>100 LUBD	$0.00				$0.0576	$1.41
DFC Fed Govt	$18.25				$2.1300	
DFC Prov Gov	$18.25				$2.1300	
DFC Non-Gov	$18.25		First 2000 kW.h @ $0.0696		$0.3500	
SEP Med	$50.00		$0.02800 average energy charge & $0.0062 dist. charge (per kW.h)			
SEP Lrg <30	$100.00		$0.02835 average energy charge & $0.0033 dist. charge (per kW.h)			

Revenue at 2011 Rates	**Basic Chg Revenue.**	**3 Ph Chg Revenue**	**1st Block Revenue**	**2nd Block Rev.& ND Runoff**	**Run-Off Revenue**	**Demand Charge Revenue**	**Adj Factor**	**Adjusted Revenue**
Small ND	$11,331,498	$1,001,969	$103,424,219	$6,759,940	$0	$0	1.016	$124,530,299
Small D.	$2,679,794	$689,689	$56,328,920	$21,752,630	$23,497,782	$18,989,524	0.986	$122,228,253
Small LUBD	$13,140	$4,949	-	-	$354,122	$49,973	0.958	$404,543
Seasonal	$187,026	$0	$329,208	$0	$0	-	1.007	$519,967
FRWH	-	-	-	-	-	-	1.000	$498,740
Medium	$635,131	-	$17,473,335	$9,202,685	$84,956,695	$59,124,780	0.998	$171,034,728
Med. LUBD	$6,734	-	-	-	$330,753	$85,594	0.989	$418,279
Lrg <30	$0	-	-	-	$51,763,774	$29,635,730	0.996	$81,088,077
L<30 LUBD	$0	-	-	-	$103,706	$28,450	1.000	$132,142
Lrg30-100	$0	-	-	-	$29,542,133	$13,006,676	0.993	$42,268,955
Lrg >100	$0	-	-	-	$132,568,042	$46,391,454	1.000	$178,959,470
L100 LUBD	$0	-	-	-	$66,355	$37,893	1.000	$104,248
DFC Fed G	$9,959	-	-	-	$3,777,555	-	1.004	$3,801,426
DFC Prov G	$4,491	-	-	-	$812,595	-	1.014	$828,682
DFC Non-G	$24,605	-	$88,076		$730,669	-	0.996	$839,833
SEP Med	$12,600	-	$145,700 (distribution); $658,105 (energy)			-	1.000	$816,405
SEP Lrg <30	$6,000	-	$6,930 (distribution); $59,526 (energy)			-	1.000	$72,456

April 2012 Rates	**Basic Charge**	**3 Ph Charge**	**1st 11000 kWh Chg**	**Next 8500 kW.h Chg & ND Bal.**	**Balance of kWh Charge**	**Demand Charge**
Small ND	$18.55	$7.60	$0.0710	$0.0494		
Small Demand	$18.55	$7.60	$0.0710	$0.0494	$0.0326	$8.34
Small LUBD	$18.55	$7.60			$0.0807	$2.09
Seasonal	(annual) $222.60	$91.20	$0.0710	$0.0494		
FRWH	(average) $106.47					
Medium	$27.60		$0.0710	$0.0494	$0.0326	$8.34
Med. LUBD	$27.60				$0.0807	$2.09
Large <30	$0.00				$0.0307	$7.08
L<30 LUBD	$0.00				$0.0715	$1.77
Large 30-100	$0.00				$0.0285	$6.06
Large >100	$0.00				$0.0276	$5.40
L>100 LUBD	$0.00				$0.0583	$1.41
DFC Fed Govt	$18.55				$2.1300	
DFC Prov Gov	$18.55				$2.1300	
DFC Non-Gov	$18.55		First 2000 kW.h @ $0.0710		$0.3500	
SEP Med	$50.00		$0.0280 average energy charge & $0.0062 dist. charge (per kW.h)			
SEP Lrg <30	$100.00		$0.0283 average energy charge & $0.0033 dist. charge (per kW.h)			

Revenue at Apr 2012 Rates	**Basic Chg Revenue.**	**3 Ph Chg Revenue**	**1st Block Revenue**	**2nd Block Rev.& ND Runoff**	**Run-Off Revenue**	**Demand Charge Revenue**	**Adj Factor**	**Adjusted Revenue**
Small ND	$11,517,769	$1,043,146	$105,504,592	$6,899,608	$0	$0	1.016	$127,017,994
Small D.	$2,723,845	$718,033	$57,461,973	$22,202,065	$24,318,340	$18,989,524	0.986	$124,669,536
Sm LUBD	$13,356	$5,153	-	-	$359,015	$49,973	0.958	$409,634
Seasonal	$190,100	$0	$335,830	$0	$0	-	1.007	$529,734
FRWH	-	-	-	-	-	-	1.000	$508,714
Medium	$635,131	-	$17,824,810	$9,393,823	$87,923,437	$59,124,780	0.998	$174,535,757
Med. LUBD	$6,734	-	-	-	$335,324	$85,594	0.989	$422,797
Lrg <30	$0	-	-	-	$53,506,662	$29,635,730	0.996	$82,824,337
L<30 LUBD	$0	-	-	-	$98,170	$26,555	1.000	$124,711
Lrg30-100	$0	-	-	-	$30,395,335	$13,006,676	0.993	$43,116,284
Lrg >100	$0	-	-	-	$136,017,768	$46,391,454	1.000	$182,409,195
L100 LUBD	$0	-	-	-	$67,162	$37,893	1.000	$105,055
DFC Fed G	$10,123	-	-	-	$3,777,555	-	1.004	$3,801,590
DFC Prov G	$4,565	-	-	-	$812,595	-	1.014	$828,757
DFC Non-G	$25,009	-	$89,847		$730,669	-	0.996	$842,000
SEP Med	$12,600	-	$145,700 (distribution); $658,105 (energy)			-	1.000	$816,405
SEP Lrg <30	$6,000	-	$6,930 (distribution); $59,526 (energy)			-	1.000	$72,456

Sept 2012 Rates	**Basic Charge**	**3 Ph Charge**	**1st 11000 kWh Chg**	**Next 8500 kW.h Chg & ND Bal.**	**Balance of kWh Charge**	**Demand Charge**
Small ND	$18.55	$7.60	$0.0729	$0.0506		
Small Demand	$18.55	$7.60	$0.0729	$0.0506	$0.0334	$8.55
Small LUBD	$18.55	$7.60			$0.0827	$2.14
Seasonal	(annual) $222.60	$91.20	$0.0729	$0.0506		
FRWH	(average) $109.18					
Medium	$27.60		$0.0729	$0.0506	$0.0334	$8.55
Med. LUBD	$27.60				$0.0827	$2.14
Large <30	$0.00				$0.0314	$7.26
L<30 LUBD	$0.00				$0.0732	$1.82
Large 30-100	$0.00				$0.0292	$6.21
Large >100	$0.00				$0.0283	$5.53
L>100 LUBD	$0.00				$0.0600	$1.41
DFC Fed Govt	$18.55				$2.2700	
DFC Prov Gov	$18.55				$2.2700	
DFC Non-Gov	$18.55		First 2000 kW.h @ $0.0729		$0.3730	
SEP Med	$50.00		$0.0280 average energy charge & $0.0062 dist. charge (per kW.h)			
SEP Lrg <30	$100.00		$0.0283 average energy charge & $0.0033 dist. charge (per kW.h)			

Revenue at Sept 2012 Rates	Basic Chg Revenue.	3 Ph Chg Revenue	1st Block Revenue	2nd Block Rev.& ND Runoff	Run-Off Revenue	Demand Charge Revenue	Adj Factor	Adjusted Revenue
Small ND	$11,517,769	$1,043,146	$108,327,954	$7,067,210	$0	$0	1.016	$130,058,092
Small D.	$2,723,845	$718,033	$58,999,688	$22,741,386	$24,915,109	$19,467,678	0.986	$127,778,005
Sm LUBD	$13,356	$5,153	-	-	$367,913	$51,169	0.958	$419,306
Seasonal	$190,100	$0	$344,817	$0	$0	-	1.007	$538,786
FRWH	-	-	-	-	-	-	1.000	$521,683
Medium	$635,131	-	$18,301,812	$9,620,989	$90,081,067	$60,613,533	0.998	$178,878,222
Med. LUBD	$6,734	-	-	-	$343,634	$87,642	0.989	$433,038
Lrg <30	$0	-	-	-	$54,726,683	$30,389,181	0.996	$84,790,257
L<30 LUBD	$0	-	-	-	$100,504	$27,305	1.000	$127,795
Lrg30-100	$0	-	-	-	$31,141,887	$13,328,623	0.993	$44,177,751
Lrg >100	$0	-	-	-	$139,467,494	$47,508,285	1.000	$186,975,752
L100 LUBD	$0	-	-	-	$69,120	$37,893	1.000	$107,013
DFC Fed G	$10,123	-	-	-	$4,025,845	-	1.004	$4,050,792
DFC Prov G	$4,565	-	-	-	$866,005	-	1.014	$882,925
DFC Non-G	$25,009	-	$92,252		$178,684	-	0.996	$892,210
SEP Med	$12,600	-	$145,700 (distribution); $658,105 (energy)			-	1.000	$816,405
SEP Lrg <30	$6,000	-	$6,930 (distribution); $59,526 (energy)			-	1.000	$72,456

MIPUG/MH I-20

Subject: July 2012 Interim Rate Filing – Attachment 8 (Proof of Revenue)

b) Please provide the 2013/14 proof of revenue, showing all rates and billing determinants, for the April 1, 2012 rates, the proposed September 1, 2012 rates, and the proposed April 1, 2013 rates (when filed).

ANSWER:

The tables on the following pages provide billing determinants for the Residential and General Service rate classes based on fiscal 2013/14 forecast data at April 1, 2012 rates, interim-approved September 1, 2012 rates (as per BO 117/12), and proposed April 1, 2013 rates.

RESIDENTIAL:

Forecast Data	Customer Months	>200 A Cust Months	Total kWh
Basic	5,536,236	39,244	7,325,560,344
Diesel	6,768	-	8,098,556
Seasonal	(avg mthly) 21,461	-	83,541,950
FRWH	46,692	-	19,689,625

April 2012 Rates	Basic Charge	>200 A Charge	kWh Charge
Basic	$6.85	$6.85	$0.0677
Diesel	$6.85		$0.0677
Seasonal	(annual) $82.20		$0.0677
FRWH	(average) $23.78		

Revenue at Apr 2012 Rates	BC & >200 A Revenue	1st Block kWh $	Total Revenue	Adj. Factor	Adjusted Revenue
Basic	$38,192,038	$495,940,435	$534,132,473	.9989	$533,565,300
Diesel	$46,361	$548,272	$595,633	.9829	$584,469
Seasonal	$1,764,094	$5,655,790	$7,419,884	.9947	$7,380,786
FRWH			$1,110,336	1.000	$1,110,336

Sept 2012 Rates	Basic Charge	>200 A Charge	kWh Charge
Basic	$6.85	$6.85	$0.0694
Diesel	$6.85		$0.0694
Seasonal	(annual) $82.20		$0.0694
FRWH	(average) $24.37		

Revenue at Sep 2012 Rates	BC & >200 A Revenue	kWh Revenue	Total Revenue	Adj. Factor	Adjusted Revenue
Basic	$38,192,038	$508,393,888	$546,585,926	.9989	$546,005,529
Diesel	$46,361	$562,040	$608,401	.9829	$598,001
Seasonal	$1,764,094	$5,797,811	$7,561,906	.9947	$7,522,059
FRWH			$1,137,702	1.000	$1,137,702

April 2013 Rates	Basic Charge	>200 A Charge	kWh Charge
Basic	$6.85	$6.85	$0.0720
Seasonal	$6.85		$0.0720
Diesel	(annual) $82.20		$0.0720
FRWH	(average) $25.22		

Revenue at 2013 Rates	BC & >200 A Revenue	kWh Revenue	Total Revenue	Adj. Factor	Adjusted Revenue
Basic	$38,192,038	$527,440,345	$565,632,383	.9989	$565,031,761
Diesel	$46,361	$583,096	$629,457	.9829	$618,697
Seasonal	$1,764,094	$6,015,020	$7,779,115	.9947	$7,738,124
FRWH			$1,177,411	1.000	$1,177,411

<u>GENERAL SERVICE:</u>

Forecast Data 2013/14	**Cust Months**	**3 Phase Cust Months**	**1st 11000 kWh**	**Next 8500 kWh & ND Runoff**	**Balance of kWh**	**Total kWh**	**Billable Demand**
Small ND	623,652	137,864	1,492,078,028	140,100,193	0	1,632,178,221	0
Small Demand	151,322	97,363	833,960,423	462,968,708	767,673,003	2,064,602,134	2,344,935
Small LUBD	742	699	-	-	4,584,701	4,584,701	24,641
Seasonal	(avg mthly) 859	-	4,750,000	0	0	4,750,000	0
FRWH	4,548	-	-	-	-	6,730,000	0
Medium	23,570	-	257,132,733	194,718,947	2,750,619,981	3,202,471,661	7,234,426
Med. LUBD	250	-	-	-	4,257,367	4,257,367	41,961
Large <30	3,606	-	-	-	1,831,480,000	1,831,480,000	4,398,965
L<30 LUBD	45	-	-	-	1,471,000	1,471,000	16,073
Lrg30-100	501	-	-	-	1,218,773,234	1,218,773,234	2,545,857
Lrg >100	156	-	-	-	5,084,180,000	5,084,180,000	8,890,008
L>100 LUBD	24	-	-	-	1,152,000	1,152,000	26,874
DFC Fed Govt	551	-	-	-	1,790,100	1,790,100	0
DFC Prov Gov	248	-	-	-	385,000	385,000	0
DFC Non-Gov	1,361	-	(1st 2000 kWh)	1,276,760	2,104,629	3,381,389	0
SEP Med	0	-	-	-	0	0	0
SEP Lrg <30	0	-	-	-	0	0	0

April 2012 Rates	Basic Charge	3 Ph Charge	1st 11000 kWh Chg	Next 8500 kWh Chg & ND Bal.	Balance of kWh Charge	Demand Charge
Small ND	$18.55	$7.60	$0.0710	$0.0494		
Small Demand	$18.55	$7.60	$0.0710	$0.0494	$0.0326	$8.34
Small LUBD	$18.55	$7.60			$0.0807	$2.09
Seasonal	(annual) $222.60	$91.20	$0.0710	$0.0494		
FRWH	(average) $106.47					
Medium	$27.60		$0.0710	$0.0494	$0.0326	$8.34
Med. LUBD	$27.60				$0.0807	$2.09
Large <30	$0.00				$0.0307	$7.08
L<30 LUBD	$0.00				$0.0715	$1.77
Large 30-100	$0.00				$0.0285	$6.06
Large >100	$0.00				$0.0276	$5.40
L>100 LUBD	$0.00				$0.0583	$1.41
DFC Fed Govt	$18.55				$2.1300	
DFC Prov Gov	$18.55				$2.1300	
DFC Non-Gov	$18.55		First 2000 kWh @ $0.0710		$0.3500	
SEP Med	$50.00		$0.0280 average energy charge & $0.0062 dist. charge (per kWh)			
SEP Lrg <30	$100.00		$0.0283 average energy charge & $0.0033 dist. charge (per kWh)			

Revenue at 2012 Rates	Basic Chg Revenue.	3 Ph Chg Revenue	1st Block Revenue	2nd Block Rev.& ND Runoff	Run-Off Revenue	Demand Charge Revenue	Adj Factor	Adjusted Revenue
Small ND	$11,568,745	$1,047,766	$105,937,540	$6,920,950	$0	$0	1.016	$127,536,256
Small D.	$2,807,023	$739,959	$59,211,190	$22,870,654	$25,026,140	$19,556,758	0.986	$128,415,077
Small LUBD	$13,764	$5,312	-	-	$369,985	$51,500	0.958	$422,153
Seasonal	$191,213	$0	$337,250	$0	$0	-	1.007	$532,285
FRWH	-	-	-	-	-	-	1.000	$484,226
Medium	$650,532	-	$18,256,424	$9,619,116	$89,670,211	$60,335,109	0.998	$178,531,587
Med. LUBD	$6,900	-	-	-	$343,569	$87,699	0.989	$433,194
Lrg <30	$0	-	-	-	$56,226,436	$31,144,674	0.996	$87,036,365
L<30 LUBD	$0	-	-	-	$105,177	$28,450	1.000	$133,613
Lrg30-100	$0	-	-	-	$34,735,037	$15,427,893	0.993	$49,893,771
Lrg >100	$0	-	-	-	$140,323,368	$48,006,042	1.000	$188,329,384
L100 LUBD	$0	-	-	-	$67,162	$37,893	1.000	$105,055
DFC Fed G	$10,217	-	-	-	$4,063,527	-	1.004	$4,088,708
DFC Prov G	$4,608	-	-	-	$873,950	-	1.014	$891,026
DFC Non-G	$25,243	-	$90,650		$785,027	-	0.996	$897,164
SEP Med	$0	-	-	-	$0	-	1.000	$0
SEP Lrg <30	$0	-	-	-	$0	-	1.000	$0

September 2012 Rates	Basic Charge	3 Ph Charge	1st 11000 kWh Chg	Next 8500 kWh Chg & ND Bal.	Balance of kWh Charge	Demand Charge
Small ND	$18.55	$7.60	$0.0729	$0.0506		
Small Demand	$18.55	$7.60	$0.0729	$0.0506	$0.0334	$8.55
Small LUBD	$18.55	$7.60			$0.0827	$2.14
Seasonal	(annual) $222.60	$91.20	$0.0729	$0.0506		
FRWH	(average) $109.18					
Medium	$27.60		$0.0729	$0.0506	$0.0334	$8.55
Med. LUBD	$27.60				$0.0827	$2.14
Large <30	$0.00				$0.0314	$7.26
L<30 LUBD	$0.00				$0.0732	$1.82
Large 30-100	$0.00				$0.0292	$6.21
Large >100	$0.00				$0.0283	$5.53
L>100 LUBD	$0.00				$0.0600	$1.41
DFC Fed Govt	$18.55				$2.2700	
DFC Prov Gov	$18.55				$2.2700	
DFC Non-Gov	$18.55		First 2000 kWh @ $0.0729		$0.3730	
SEP Med	$50.00		$0.0280 average energy charge & $0.0062 dist. charge (per kWh)			
SEP Lrg <30	$100.00		$0.0283 average energy charge & $0.0033 dist. charge (per kWh)			

Revenue at Sept 2012 Rates	**Basic Chg Revenue.**	**3 Ph Chg Revenue**	**1st Block Revenue**	**2nd Block Rev.& ND Runoff**	**Run-Off Revenue**	**Demand Charge Revenue**	**Adj. Factor**	**Adjusted Revenue**
Small ND	$11,568,745	$1,047,766	$108,772,488	$7,089,070	$0	$0	1.016	$130,588,658
Small D.	$2,807,023	$739,959	$60,795,715	$23,426,217	$25,640,278	$20,049,194	0.986	$131,616,942
Sm LUBD	$13,764	$5,312	-	-	$379,155	$52,732	0.958	$432,120
Seasonal	$191,213	$0	$346,275	$0	$0	-	1.007	$541,375
FRWH	-	-	-	-	-	-	1.000	$496,570
Medium	$650,532	-	$18,744,976	$9,852,779	$91,870,707	$61,854,338	0.998	$182,591,252
Med. LUBD	$6,900	-	-	-	$352,084	$89,797	0.989	$443,686
Lrg <30	$0	-	-	-	$57,508,472	$31,936,488	0.996	$89,102,266
L<30 LUBD	$0	-	-	-	$107,677	$29,254	1.000	$136,917
Lrg30-100	$0	-	-	-	$35,588,178	$15,809,771	0.993	$51,122,166
Lrg >100	$0	-	-	-	$143,882,294	$49,161,743	1.000	$193,044,010
L100 LUBD	$0	-	-	-	$69,120	$37,893	1.000	$107,013
DFC Fed G	$10,217	-	-	-	$4,063,527	-	1.004	$4,088,708
DFC Prov G	$4,608	-	-	-	$873,950	-	1.014	$891,026
DFC Non-G	$25,243	-	$93,076		$785,027	-	0.996	$899,579
SEP Med	$0	-	-	-	$0	-	1.000	$0
SEP Lrg <30	$0	-	-	-	$0	-	1.000	$0

April 2013 Rates	Basic Charge	3 Ph Charge	1st 11000 kWh Chg	Next 8500 kWh Chg & ND Bal.	Balance of kWh Charge	Demand Charge
Small ND	$19.20	$7.86	$0.0750	$0.0530		
Small Demand	$19.20	$7.86	$0.0750	$0.0530	$0.0354	$8.55
Small LUBD	$19.20	$7.86			$0.0847	$2.14
Seasonal	(annual) $230.40	$94.32	$0.0750	$0.0530		
FRWH	(average) $113.01					
Medium	$27.60		$0.0750	$0.0530	$0.0354	$8.55
Med. LUBD	$27.60				$0.0847	$2.14
Large <30	$0.00				$0.0336	$7.26
L<30 LUBD	$0.00				$0.0754	$1.82
Large 30-100	$0.00				$0.0309	$6.21
Large >100	$0.00				$0.0296	$5.53
L>100 LUBD	$0.00				$0.0613	$1.41
DFC Fed Govt	$19.20				$2.2700	
DFC Prov Gov	$19.20				$2.2700	
DFC Non-Gov	$19.20		First 2000 kW.h @ $0.0729		$0.3730	
SEP Med	$0					
SEP Lrg <30	$0					

Revenue at April 2013 Rates	Basic Chg Revenue.	3 Ph Chg Revenue	1st Block Revenue	2nd Block Rev.& ND Runoff	Run-Off Revenue	Demand Charge Revenue	Adj. Factor	Adjusted Revenue
Small ND	$11,974,118	$1,083,611	$111,905,852	$7,425,310	$0	$0	1.016	$134,563,726
Small D.	$2,905,382	$765,273	$62,547,032	$24,537,342	$27,175,624	$20,049,194	0.986	$136,076,017
Sm LUBD	$14,246	$5,494	-	-	$388,324	$52,732	0.958	$441,542
Seasonal	$197,914	$0	$356,250	$0	$0	-	1.007	$558,171
FRWH	-	-	-	-	-	-	1.000	$513,956
Medium	$650,532	-	$19,284,955	$10,320,104	$97,371,947	$61,854,338	0.998	$189,086,205
Med. LUBD	$6,900	-	-	-	$360,599	$89,797	0.989	$452,104
Lrg <30	$0	-	-	-	$61,537,728	$31,936,488	0.996	$93,116,176
L<30 LUBD	$0	-	-	-	$110,913	$29,254	1.000	$140,153
Lrg30-100	$0	-	-	-	$37,660,093	$15,809,771	0.993	$53,182,322
Lrg >100	$0	-	-	-	$150,491,728	$49,161,743	1.000	$199,653,443
L100 LUBD	$0	-	-	-	$70,618	$37,893	1.000	$108,511
DFC Fed G	$10,575	-	-	-	$4,063,527	-	1.004	$4,089,067
DFC Prov G	$4,769	-	-	-	$873,950	-	1.014	$891,026
DFC Non-G	$26,127	-	$95,727		$785,027	-	0.996	$903,130
SEP Med	$0	-	-	-	$0	-	1.000	$0
SEP Lrg <30	$0	-	-	-	$0	-	1.000	$0

MIPUG/MH I-20

Subject: July 2012 Interim Rate Filing – Attachment 8 (Proof of Revenue)

c) Please show the calculation of the values accrued in the 1% rollback since ordered by the Board, by class.

ANSWER:

Please see the following table for the requested information.

Calculations of BO 5/12 on General Consumer Revenue by Class

(in thousands of $)	Residential	General Service Small	General Service Medium	General Service Large	Area & Roadway Lighting	**Total General Consumers Revenue**
2010/11 Revenue						
Interim Approved Revenue	$ 483,520	$ 235,310	$ 155,487	$ 297,168	$ 20,685	$ 1,192,170
BO 5/12 Revised Revenue	479,391	232,611	154,223	294,447	20,685	1,181,357
Difference	(4,129)	(2,699)	(1,264)	(2,721)	-	(10,813)
2011/12 Revenue						
Interim Approved Revenue	496,409	241,765	160,110	315,627	20,916	1,234,827
BO 5/12 Revised Revenue	491,603	239,040	158,786	312,816	20,916	1,223,162
Difference	(4,807)	(2,724)	(1,323)	(2,811)	-	(11,665)
2012/13 1st Quarter Revenue						
April - June Revenue	108,994	58,517	40,937	73,387	5,303	287,138
1% of the April - June Revenue	(1,090)	(585)	(409)	(734)		(2,818)

Balance of Deferral Account by Class

(in thousands of $)	Residential	General Service Small	General Service Medium	General Service Large	Area & Roadway Lighting	**Total General Consumers Revenue**
2010/11*	4,129	2,699	1,264	2,721	-	10,813
2011/12*	4,807	2,724	1,323	2,811	-	11,665
2012/13 1st Quarter**	1,090	585	409	734	-	2,818
Total Revenue	10,026	6,008	2,996	6,266	-	25,296
2010/11	37	24	11	24	-	96
2011/12	125	78	37	79	-	320
2012/13 1st Quarter	48	29	14	30		120
Total Accrued Interest	210	131	62	133	-	536
Total Deferral Account Balance	**$ 10,236**	**$ 6,139**	**$ 3,059**	**$ 6,399**	**$ -**	**$ 25,832**

* 2010/11 & 2011/12 deferral account revenue was calculated using forecast information based on IFF09
** 2012/13 1st quarter deferral account revenue was calculated using 1st quarter actual information.

MIPUG/MH I-21

Subject: Exhibit MH-55 from the 2010 GRA

a) Please update page 14 and 15 from Exhibit MH-55 (direct testimony of Judah Rose).

ANSWER:

Page 14 of Exhibit MH-55 from the 2010 GRA contains a table of U.S. Henry Hub Natural Gas Spot Prices (annual average) in 2010$/MMBtu from 1991 to 2010. The following table provides updates based on information available as of September 05, 2012.

Year	Henry Hub Spot Price in 2010$/MMBtu Annual Average
2010	4.4
2011	4.1
2012 Year-to-date as of September 5, 2012	2.6

Page 15 of Exhibit MH-55 from the 2010 GRA contains ICF forecasts dated February 2009 and October 2010 of the Henry Hub Natural Gas Price in 2010$/MMBtu. ICF International provided these natural gas forecasts as part of services to Manitoba Hydro for the 2010 GRA proceedings. At this time, ICF International is not under contract to provide similar services for the 2012 GRA proceedings. However, as part of the Centra Gas Manitoba Inc. Transportation & Storage Portfolio Application dated March 23, 2012, ICF International provided the following natural gas forecasts were presented on page 39 of Tab 4 - Attachment 1 of the Centra Gas application. These more current forecasts are dated April 2011.

Figure 17
Change in ICF Forecast of Henry Hub Price Since Previous Stakeholder Confer

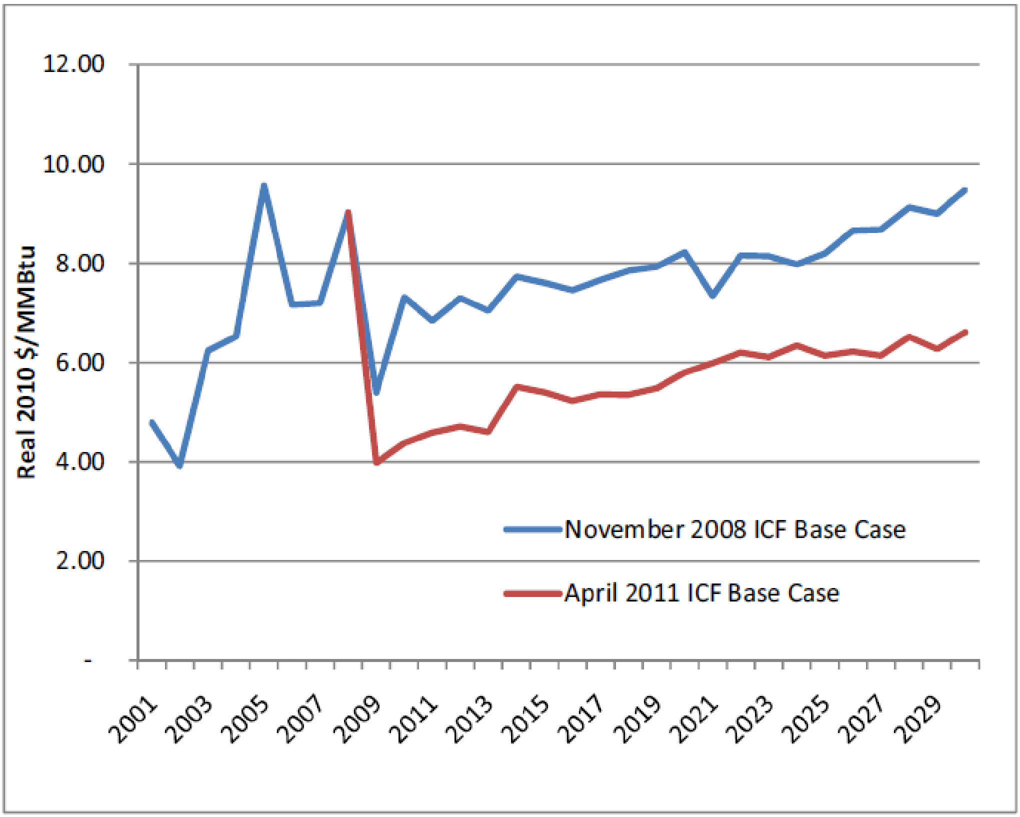
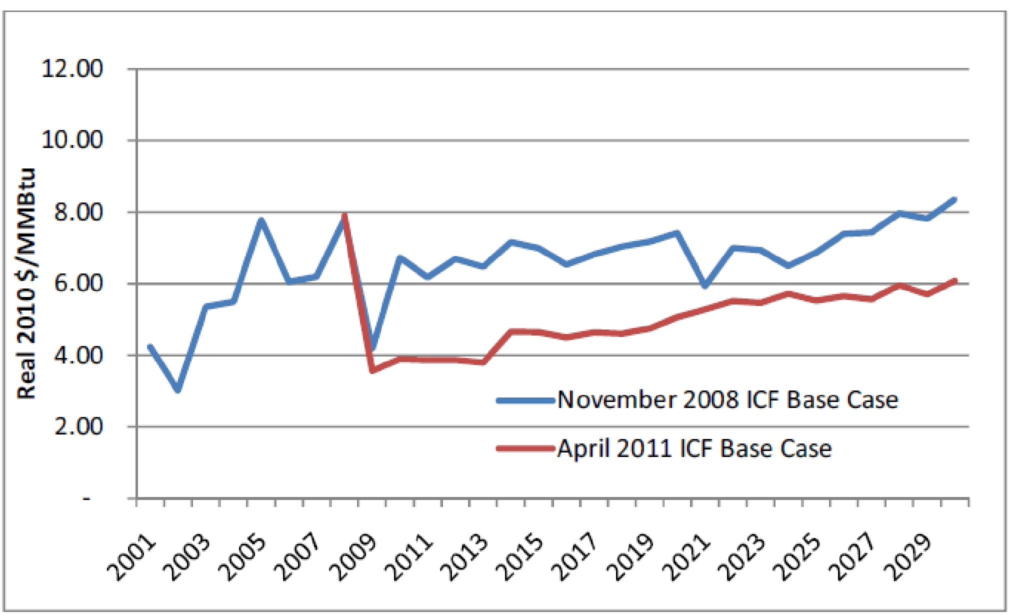


Figure 18
Change in ICF Forecast of AECO Price Since Previous Stakeholder Conference



MIPUG/MH I-22

Subject: Appendix 5.6: Operating, Maintenance and Administrative

a) Page 4 indicates "Power Smart program costs, Site Remediation costs and Regulatory costs will have to be expensed as incurred". For each category noted, as well as other categories similarly affected by IFRS, please provide the last 5 years of actual spending indicating the amounts that would have had to be expensed in the event the 2013/14 accounting rules had been in place at the time the expenses were incurred.

ANSWER:

Manitoba Hydro has not conducted a comprehensive analysis of IFRS changes on a retrospective basis back five years. Please see Manitoba Hydro's response to PUB/MH I-42, Schedule B, for details of the unamortized amounts for Power Smart Programs, Site Remediation and Regulatory costs that will be written off against retained earnings in 2013/14.

MIPUG/MH I-22

Subject: Appendix 5.6: Operating, Maintenance and Administrative

b) For the values shown in part (a) above, please specify which business unit is affected by the change in accounting.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-22(a).

MIPUG/MH I-23

Subject: Appendix 4.2: IFF11-2

a) On page 4 Manitoba Hydro states that over the 20-year forecast period, net extraprovincial revenues are projected to be $4.0 billion lower in IFF11-2 compared to IFF10. Please break down the amount attributable to each of the following, including their impact by fiscal year:

i. A decrease in the assumed dependable contract export prices
ii. A decrease in assumed opportunity export prices
iii. Deferral of Conawapa by one year to 2024/25
iv. Any other changes in the Power Resource Plan assumptions
v. Reduction in transfer capability for the new interconnection to the U.S.
vi. Reduction in the contracted energy delivered to Wisconsin Public Service
vii. Changes in forecast Manitoba load.
viii. Strengthened Canadian dollar relative to IFF10.
ix. Other factors (please specify)

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-31.

MIPUG/MH I-23

Subject: Appendix 4.2: IFF11-2

b) Please quantify the annual impact of IFRS on the administrative and other general overhead costs for each new major generation and transmission project in IFF11-2, by year.

ANSWER:

As noted in the response to CAC/MH I-51(c), IFRS adjustments for administrative and other general overhead costs were not assigned to specific projects in CEF11-2. The majority of Major New Generation and Transmission items do not include large amounts of Manitoba Hydro labour on which overhead rates are applied and would not reduce total spending requirements significantly.

MIPUG/MH I-24

Subject: Capital Expenditures

a) Please indicate all actions taken by Manitoba Hydro since 2010 to reduce or control capital costs for projects that are not major new generation and transmission, detailing associated cost reductions.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-65(c).

MIPUG/MH I-25

Subject: Exposure Management

a) Please provide an updated version of the information from MIPUG/MH I-13 (a) and (b) from the 2010 General Rate Application regarding US$ cash flows.

ANSWER:

Please see Manitoba Hydro’s response to CAC/MH I-103(a).

MIPUG/MH I-26

Subject: Tab 5: Financial Results and Forecast: General Consumer Revenues

a) **Please provide a copy of Schedule 5.2.0 with revenues broken out by General Service class and subclass (i.e. separately indicate revenues for GSS, GSM, GSL including all GSL sub-classes). Please show revenues at existing rates by class and subclass separately from additional general consumer revenues by class and subclass.**

ANSWER:

The tables below provide the data as shown in Schedule 5.2.0 followed by the breakdown of the General Service class into its subclasses.

The "Additional General Consumers Revenue" figures shown in Schedule 5.2.0 were based on the rate increases proposed in Manitoba Hydro's Application. The figures have since changed to reflect the revenues based on the revised September 1, 2012 rates which were approved on an interim basis in Order 117/12.

MANITOBA HYDRO **Schedule 5.2.0**
GENERAL CONSUMERS REVENUE **(000's)**

	2009/10 Actual	2010/11 Actual	2011/12 Projected	2012/13 Forecast	2013/14 Forecast
Residential	$ 475,986	$ 502,838	$ 484,147	$ 532,367	$ 543,464
General Service	668,905	697,543	724,969	748,255	763,878
1% rate rollback - 2010/11 & 2011/12			(22,894)	22,894	-
1% rate rollback - 2012/13 & 2013/14				12,144	12,096
Additional General Consumers Revenue*				19,912	79,651
Total Revenue	$ 1,144,891	$ 1,200,381	$ 1,186,222	$ 1,335,571	$ 1,399,088
Year over year $ change		$ 55,491	$ (14,159)	$ 149,349	$ 63,517
Year over year % change		4.8%	-1.2%	12.6%	4.8%

*Additional General Consumers Revenue - 2012/13 reflects an additional 2.5% interim rate increase effective September 1, 2012. 2013/14 reflects an additional 3.5% rate increase effective April 1, 2013.

	Breakdown of General Service Class into Sub-Classes (000's)				
	2009/10	**2010/11**	**2011/12**	**2012/13**	**2013/14**
GS Small	$224,981	$235,153	$239,218	$249,214	$254,331
GS Medium	156,598	163,652	166,986	173,904	177,475
GS Large <30	68,416	74,491	74,401	81,949	83,632
GS Lrg30-100	36,861	39,052	48,056	42,682	43,559
GS Large>100	158,443	156,320	159,653	181,137	184,856
GS DSM	-	-	-	(9,337)	(9,529)
Other GS	23,605	28,875	36,655	28,706	29,554
Total GS	**$668,905**	**$697,543**	**$724,969**	**$748,254**	**$763,878**

	Additional GCR (000's)	
	2012/13	**2013/14**
Residential	**$8,223**	**$31,625**
GS Small	3,820	15,518
GS Medium	2,593	10,910
GS Large <30	1,175	6,083
GS Lrg30-100	621	3,299
GS Large>100	2721	11,357
GS DSM	(143)	(832)
Other GS	425	1,292
Total GS	**11,211**	**47,628**
Total GCR	**$19,435**	**$79,253**

MIPUG/MH I-27

Subject: Tab 5: Financial Results and Forecast: Extra Provincial Revenues

a) Please provide a copy of Schedule 5.3.0 with revenues broken out by Dependable and Short-term Opportunity sales.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-27(b).

MIPUG/MH I-27

Subject: Tab 5: Financial Results and Forecast: Extra Provincial Revenues

b) Please expand Schedule 4.3.0 to show export volumes (kW.h) by dependable and short-term opportunity sales.

ANSWER:

Manitoba Hydro has interpreted this question to refer to Schedule 5.3.0 from Tab 5 of the 2012 GRA. Please see the table below.

MANITOBA HYDRO
EXTRAPROVINCIAL REVENUE

Schedule 5.3.0
(000's)

	2009/10		2010/11		2011/12		2012/13		2013/14	
	Actual k.W.h.	Actual $	Actual k.W.h.	Actual $	Forecasted k.W.h.	Forecast $	Forecasted k.W.h.	Forecast $	Forecasted k.W.h.	Forecast $
Dependable Sales	-	-	-	-	-	-	-	-	-	-
Opportunity Sales	373,000	27,987	904,760	27,178	887,000	26,694	915,000	33,720	589,000	25,704
Canadian Sales		27,987		27,178		26,694		33,720		25,704
System Merchant (IESO)		24,777		27,469		16,712		20,797		-
Other Sales		12,973		8,503		4,629		8,800		-
Canadian		65,737		63,150		48,035		63,317		25,704
Dependable Sales	3,262,976	185,967	3,377,506	172,361	3,742,000	174,872	2,691,000	148,076	2,553,455	157,037
Opportunity Sales	7,224,000	151,779	6,062,043	144,273	5,615,000	119,988	3,646,000	100,092	3,651,364	141,940
Fair Market Value Charge[1]		806		(637)		-		-		-
Forecast Adjustment[2]		-		-		-		10,000		20,000
US Sales		338,552		315,997		294,860		258,168		318,977
System Merchant (MISO)		1,369		82		-		-		-
Other Sales		2,197		1,559		558		987		1,237
Transmission Credits		17,710		16,402		17,559		16,374		17,002
Renewable Energy Certificates		1,076		1,116		2,032		2,321		-
US		360,904		335,156		315,009		277,850		337,216
Total Extraprovincial Revenue		$ 426,641		$ 398,306		$ 363,044		$ 341,167		$ 362,920

Notes:

1. Fair Market Value Charge – Fair market value gain or loss on any financial derivatives that are outstanding as of the end of the fiscal year, as required for IFRS reporting.
2. Forecast Adjustment – Adjustment following detailed forecasting.

MIPUG/MH I-27

Subject: Tab 5: Financial Results and Forecast: Extra Provincial Revenues

c) Please provide the US Sales data in both US$ and Canadian$ showing the effective exchange rate assumed, by year.

ANSWER:

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
US Sales in Canadian $	338,552	315,997	291,661	258,168	318,977
Average Yearly Exchange Rate	1.1231	1.0191	0.9895	0.9900	0.9900
US Sales in US $	301,445	310,075	294,756	260,776	322,199

MIPUG/MH I-27

Subject: Tab 5: Financial Results and Forecast: Extra Provincial Revenues

d) Please explain the lack of Merchant Sales (page 9) and Merchant Purchases (page 28) for 2012/13 for US Sales and 2013/14 for all Merchant Sales.

ANSWER:

MH did not include any US merchant sales revenues in 2012/13 because it did not expect there to be a favourable differential between the MISO market price and the Ontario market price.

Manitoba Hydro did not include merchant revenues and costs beyond the first two years of the IFF due to uncertainty as to whether Manitoba Hydro will continue to engage in these activities.

Please refer to 2010 GRA IRs listed below that address why MH does not forecast merchant activity beyond the second year of the IFF.

PUB/MH I-45(f)
PUB/MH II-46(b)
CAC/MSOS II-16(a)

MIPUG/MH I-27

Subject: Tab 5: Financial Results and Forecast: Extra Provincial Revenues

e) Please break out "power purchased" at page 5 between (i) Manitoba power purchased under contracted agreements (e.g., wind), (ii) power assumed to be purchased under existing extra provincial contracts, and (iii) power assumed to be purchased from un-contracted sources. For each category, indicate whether the purchases occur at a known or fixed price, or are subject to prevailing market conditions at the time of purchase.

ANSWER:

The page reference in this question appears incorrect. Manitoba Hydro assumes this question is referring to Schedule 5.9.0 of Tab 5.

Manitoba Hydro is unable to provide a detailed breakdown of Power Purchased due to confidentiality agreements associated with Manitoba Hydro's PPA's.

MIPUG/MH I-28

Subject: Major Projects

a) Please provide an update to MIPUG/MH I-14 a) from the 2010 GRA showing plant in service and accumulated depreciation in IFF11-2 for all major projects.

ANSWER:

Please see attached table below.

MIPUG-MH I-28a

IFF11-2 Major Projects Net Plant In Service ($ Millions)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Wuskwatim											
Plant In Service	756	1 674	1 674	1 674	1 674	1 674	1 674	1 674	1 674	1 674	1 674
Accumulated Depreciation	1	24	50	75	101	126	152	177	203	228	254
Net Plant In Service	755	1 649	1 624	1 598	1 573	1 547	1 522	1 496	1 471	1 445	1 420
Herblet Lake-The Pas 230 kV Transmission											
Plant In Service	74	75	75	75	75	75	75	75	75	75	75
Accumulated Depreciation	1	2	4	5	7	8	9	11	12	14	15
Net Plant In Service	73	73	71	70	68	67	65	64	63	61	60
Keeyask											
Plant In Service									3 296	5 636	5 636
Accumulated Depreciation									8	81	161
Net Plant In Service									3 288	5 555	5 475
Kelsey Improvements and Upgrades											
Plant In Service	40	81	136	136	136	136	136	136	136	136	136
Accumulated Depreciation	0	2	3	6	8	10	12	14	17	19	21
Net Plant In Service	40	79	132	130	128	126	123	121	119	117	115
Kettle Improvements & Upgrades											
Plant In Service	36	39	59	103	111	118	126	134	142	149	157
Accumulated Depreciation	0	1	1	2	3	5	6	7	9	10	12
Net Plant In Service	36	39	58	101	107	114	120	126	133	139	145
Pointe du Bois											
Plant In Service	0	10	11	377	392	431	431	431	431	431	431
Accumulated Depreciation	0	1	1	4	10	17	23	30	36	43	50
Net Plant In Service	0	9	10	373	382	414	407	401	394	388	381
Bipole III											
Plant In Service	1	13	17	23	144	163	3 203	3 262	3 262	3 262	3 262
Accumulated Depreciation	0	0	0	0	2	5	35	102	170	238	305
Net Plant In Service	1	13	17	23	143	158	3 168	3 160	3 092	3 024	2 956
Riel 230/500kV Station											
Plant In Service	0	0	0	4	268	268	268	268	268	268	268
Accumulated Depreciation	0	0	0	0	3	10	17	23	30	37	44
Net Plant In Service	0	0	0	4	265	258	251	244	237	231	224
Firm Import/Export Upgrades											
Plant In Service		20	20	20	20	20	20	30	122	225	225
Accumulated Depreciation		0	0	1	1	1	1	2	3	6	10
Net Plant In Service		20	20	19	19	19	18	28	119	218	214
Transmission for Wind											
Plant In Service	5	5	5	5	5	5	5	5	5	5	5
Accumulated Depreciation	0	0	0	0	0	0	0	1	1	1	1
Net Plant In Service	5	5	5	5	5	5	5	4	4	4	4
Hydraulic Improvements & Upgrades											
Plant In Service										45	77
Accumulated Depreciation											1
Net Plant In Service										45	77

MIPUG/MH I-28

Subject: Major Projects

b) Please provide a detailed description of the $99 million increase in capital costs for the Wuskwatim Generating Station shown on page 1 of CEF11. Please describe and quantify the increased costs related for general civil & mechanical system contracts and the first unit in-service deferral of six months from September 2011 referenced at page 14.

ANSWER:

The following provides a summary of the increases to the Wuskwatim Generating station capital costs in CEF11-2 (in millions).

General Civil Work Contracts	35.7
Supply and Install of Electrical and Mechanical Systems	12.0
Supply and Install of Intake Gates & Hoists	3.7
Supply and Install of Spillway Gates, Guides and Hoists	2.3
Supply and Install of Turbines & Generators	1.7
Catering Security and First Aid	11.0
Engineering Consultant	5.7
Construction Camp and Work Area Contracts	6.0
Environmental & Mitigation	4.0
Capitalized Interest	$17.9
	$100.0

MIPUG/MH I-28

Subject: Major Projects

c) Please provide an update to PUB/MH I-56 a) from the 2010 GRA showing the progression of project costs with the projected costs for each capital project updated with projections from the CEF-10 and CEF-11 capital expenditure forecasts.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-93(a).

MIPUG/MH I-28

Subject: Major Projects

d) Please provide CEF10-2.

ANSWER:

Please see attached CEF10-2.

Capital Expenditure Forecast (CEF10-2)

CEF10-2
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	11 Year Total
ELECTRIC													
Major New Generation & Transmission													
Wuskwatim - Generation	1 274.6	300.8	130.3	16.2	-	-	-	-	-	-	-	-	447.2
Wuskwatim - Transmission	291.2	35.7	21.2	-	-	-	-	-	-	-	-	-	56.9
Herblet Lake – The Pas 230 kV Transmission	74.9	22.2	6.0	0.0	-	-	-	-	-	-	-	-	28.3
Keeyask - Generation	5 636.9	71.2	152.5	179.2	312.3	379.5	683.0	749.1	1 080.5	816.6	640.1	164.4	5 228.4
Conawapa - Generation	7 770.8	42.4	104.4	105.2	83.3	166.4	288.6	333.4	325.1	623.4	1 038.0	1 091.4	4 201.5
Kelsey Improvements & Upgrades	301.7	42.7	34.7	28.5	12.5	-	-	-	-	-	-	-	118.6
Kettle Improvements & Upgrades	165.7	17.5	18.7	21.6	22.2	15.4	7.3	7.5	7.6	7.7	7.9	8.1	141.7
Pointe du Bois Spillway Replacement	398.2	18.6	24.4	92.7	103.6	89.2	31.5	0.5	0.0	0.0	0.0	-	360.5
Pointe du Bois - Transmission	86.0	20.5	15.6	25.0	13.1	3.1	-	-	-	-	-	-	77.3
Pointe du Bois Powerhouse Rebuild	NA	-	-	-	-	-	-	-	-	-	-	-	-
BIPOLE III - Transmission Line	1 259.9	16.1	24.8	59.9	162.0	298.9	318.5	234.6	120.1	0.4	-	-	1 235.3
BIPOLE III - Converter Stations	1 828.5	46.3	59.7	148.9	300.3	290.2	294.3	308.5	347.7	2.4	-	-	1 798.1
BIPOLE III - Collector Lines	191.4	2.1	19.9	52.7	30.1	30.9	34.3	13.5	7.8	-	-	-	191.4
Riel 230/ 500 kV Station	267.6	70.2	66.8	29.4	28.9	41.3	-	-	-	-	-	-	236.5
Firm Import Upgrades	4.8	-	0.6	2.2	1.9	-	-	-	-	-	-	-	4.8
Dorsey - US Border New 500kV Transmission Line	204.8	0.0	0.1	0.9	1.9	2.4	11.7	64.5	93.5	28.9	-	-	204.0
St. Joseph Wind Transmission	6.5	5.5	0.0	-	-	-	-	-	-	-	-	-	5.6
Demand Side Management	NA	36.9	38.0	39.1	38.6	36.2	29.5	25.0	23.0	21.9	20.4	19.7	328.3
Waterways Management Program	NA	5.5	-	-	-	-	-	-	-	-	-	-	5.5
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	-	-	-	-	-	45.0	45.0
Additional North South Trasmission	312.8	-	-	-	-	-	-	-	-	-	-	-	-
		754.3	717.7	801.5	1 110.9	1 353.7	1 698.7	1 736.5	2 005.2	1 501.3	1 706.4	1 328.6	14 714.7

CEF10-2
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	11 Year Total
Power Supply													
Converter Transformer Bushing Replacement	5.9	0.4	0.7	1.1	-	-	-	-	-	-	-	-	2.2
HVDC Auxiliary Power Supply Ugrades	5.3	0.9	0.2	-	-	-	-	-	-	-	-	-	1.2
Dorsey Synchronous Condenser Refurbishment	32.3	2.5	4.5	4.4	1.1	-	-	-	-	-	-	-	12.5
HVDC System Transformer & Reactor Fire Protection & Pr	10.4	1.0	0.6	0.2	-	-	-	-	-	-	-	-	1.8
HVDC AC Filter PCB Capacitor Replacement	29.8	1.2	-	-	-	-	-	-	-	-	-	-	1.2
HVDC Transformer Replacement Program	NA	0.3	1.1	4.9	8.1	-	-	-	-	-	-	0.5	15.0
Dorsey 230 kV Relay Building Upgrade	82.2	4.4	3.7	3.4	17.5	35.4	12.3	3.2	-	-	-	-	79.8
HVDC Stations Ground Grid Refurbishment	4.3	0.5	0.4	0.4	0.4	0.3	0.1	-	-	-	-	-	2.2
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	15.9	1.9	2.7	1.1	0.4	0.1	0.1	0.1	0.1	0.1	-	-	6.6
HVDC Bipole 1 Pole Differential Protection	3.3	-	-	1.1	2.2	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.5	2.5	3.9	11.0	2.1	-	-	-	-	-	-	19.9
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.9	2.4	5.7	-	-	-	-	-	-	11.0
HVDC Bipole 1 & 2 Smoothing Reactor Replacement	39.3	14.3	12.8	1.9	9.2	-	-	-	-	-	-	-	38.2
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Sep:	3.2	0.0	0.9	2.2	-	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	0.0	0.5	1.6	1.1	3.0	3.1	2.3	-	-	-	-	11.7
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Re	8.7	-	0.6	1.0	1.7	5.4	0.0	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	19.2	0.5	0.1	0.2	3.4	4.4	4.1	4.8	1.4	-	-	-	18.9
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.3	0.9	1.5	1.1	1.1	0.3	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	4.7	1.4	1.3	-	-	-	-	-	-	-	-	-	2.7
HVDC Bipole 1 Transformer Marshalling Kiosk Replacemei	6.8	0.6	1.8	2.0	1.2	0.7	-	-	-	-	-	-	6.3
HVDC Gapped Arrestor Replacement	16.3	0.1	3.8	3.4	4.0	3.5	1.3	0.2	-	-	-	-	16.3
HVDC Bipole 2 Upgrades & Replacements	444.2	-	-	-	-	-	-	-	-	-	-	12.3	12.3
Pine Falls Rehabilitation	56.2	2.5	5.8	15.8	1.2	4.6	6.8	9.0	-	-	-	-	45.8
Jenpeg Unit Overhauls	128.1	-	-	-	-	-	2.3	2.5	18.5	24.3	24.9	25.4	97.9
Power Supply Dam Safety Upgrades	34.0	4.3	-	-	-	-	-	-	-	-	-	-	4.3
Winnipeg River Riverbank Protection Program	19.7	1.2	1.2	1.3	1.3	1.3	1.3	1.4	-	-	-	-	9.1
Power Supply Hydraulic Controls	20.5	3.7	1.5	0.5	1.3	-	-	-	2.1	2.6	0.9	-	12.6
Slave Falls Rehabilitation	223.0	19.8	7.3	1.7	3.7	32.4	40.8	45.6	38.8	9.2	-	-	199.4
Great Falls Unit 4 Overhaul	19.7	4.5	9.5	-	-	-	-	-	-	-	-	-	14.0
Great Falls Unit 5 Discharge Ring Replacement and Major	24.8	-	-	-	-	2.3	17.5	5.0	-	-	-	-	24.8
Generation South Transformer Refurbish & Spares	29.8	0.4	4.8	11.3	12.1	0.5	0.3	0.3	-	-	-	-	29.7
Generation South Overhauls & Improvements	NA	-	-	-	-	-	-	-	-	-	-	4.7	4.7
Water Licenses & Renewals	40.8	5.3	6.0	6.2	6.8	6.6	0.7	-	-	-	-	-	31.5
Generation South PCB Regulation Compliance	4.7	0.6	0.5	0.4	0.4	0.2	2.4	-	-	-	-	-	4.5
Kettle Transformer Replacement Program	35.6	8.7	7.0	7.2	8.0	3.9	-	-	-	-	-	-	34.8
Generation South Breaker Replacement Program	11.1	2.5	3.0	1.4	3.4	-	-	-	-	-	-	-	10.3
Seven Sisters Upgrades	9.5	2.8	2.0	1.5	1.2	-	-	-	-	-	-	-	7.6
Generation South Excitation Program	32.3	0.1	0.3	2.1	2.4	0.6	1.5	2.9	1.7	6.8	-	4.4	22.7
Brandon Unit 5 License Review	18.7	0.2	0.1	1.6	2.7	9.2	-	-	-	-	-	-	13.8
Selkirk Enhancements	14.2	1.5	0.4	-	-	-	-	-	-	-	-	-	1.9
Laurie River/CRD Communications & Annunciation Upgrad	4.8	0.9	3.1	0.7	-	-	-	-	-	-	-	-	4.6
Notigi Marine Vessel Replacement & Infrastructure Improv	4.6	0.9	3.0	0.6	-	-	-	-	-	-	-	-	4.5
Pointe du Bois Safety Upgrades	50.0	0.5	1.6	5.5	11.2	16.0	11.7	3.5	-	-	-	-	50.0
Fire Protection Projects - HVDC	5.2	0.6	0.4	0.3	1.2	1.0	-	-	-	-	-	-	3.5
Halon Replacement Project	36.4	4.6	5.5	6.8	2.7	-	-	-	-	-	-	-	19.7
Oil Containment - Power Supply	19.1	0.5	0.6	0.5	0.7	0.4	0.5	0.5	-	-	-	-	3.8

CEF10-2
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	11 Year Total
Power Supply Continued													
Grand Rapids Townsite House Renovations	5.2	0.4	0.9	1.3	1.6	1.0	-	-	-	-	-	-	5.2
Grand Rapids Fish Hatchery	2.2	1.1	1.1	-	-	-	-	-	-	-	-	-	2.2
Generation Townsite Infrastructure	52.1	6.1	8.0	1.8	-	-	-	-	-	-	-	-	15.8
Site Remediation of Contaminated Corporate Facilities	34.7	1.0	1.7	1.0	1.6	-	-	-	-	-	-	-	5.3
High Voltage Test Facility	26.9	11.9	5.6	-	-	-	-	-	-	-	-	-	17.5
Security Installations / Upgrades	43.2	8.6	11.4	8.3	3.2	1.3	1.1	0.7	-	-	-	-	34.5
Sewer & Domestic Water System Install and Upgrade	26.9	7.1	4.9	3.2	(0.1)	-	-	-	-	-	-	-	15.0
Power Supply Domestic	NA	19.3	19.7	20.1	20.5	20.9	21.4	21.8	22.2	22.7	23.1	23.6	235.4
		152.1	155.6	137.6	152.2	163.9	130.5	104.1	84.8	65.6	48.9	70.8	1 266.1
Transmission													
Winnipeg - Brandon Transmission System Improvements	40.0	1.4	2.0	2.5	15.0	15.0	-	-	-	-	-	-	35.8
Transcona East 230 - 66 kV Station	33.1	10.4	17.7	3.6	0.0	-	-	-	-	-	-	-	31.7
Neepawa 230 - 66 kV Station	30.0	5.3	12.0	5.1	5.7	0.7	-	-	-	-	-	-	28.8
Pine Falls - Bloodvein 115 kV Transmission	33.1	0.3	0.9	4.4	20.7	6.8	-	-	-	-	-	-	33.1
Transmission Line Re-Rating	24.1	1.1	1.3	-	-	-	-	-	-	-	-	-	2.3
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	-	0.9	0.9	2.6	6.1	9.8	12.0	32.3
Rosser Station 230 - 115 kV Bank 3 Replacement	7.4	0.6	-	-	-	-	-	-	-	-	-	-	0.6
Rosser - Inkster 115 kV Transmission	5.1	2.6	-	-	-	-	-	-	-	-	-	-	2.6
Transcona Station 66 kV Breaker Replacement	6.0	0.0	0.4	2.9	1.5	1.1	0.0	-	-	-	-	-	6.0
Dorsey 500 kV R502 Breaker Replacement	2.6	0.3	-	-	-	-	-	-	-	-	-	-	0.3
13.2kV Shunt Reactor Replacements	33.0	0.0	4.0	4.1	4.2	4.3	4.4	4.5	4.6	2.9	-	-	33.0
Canexus Load Addition	0.2	(0.8)	2.0	0.0	-	-	-	-	-	-	-	-	1.3
Birtle South-Rossburn 66 kV Line	4.9	-	-	-	0.1	0.3	4.5	-	-	-	-	-	4.9
Stanley Station 230-66 kV Permanent Transformer Additic	21.1	-	-	1.7	8.1	7.5	3.8	-	-	-	-	-	21.1
Stanley Station 230-66 kV Hot Standby Installation	6.2	1.3	-	-	-	-	-	-	-	-	-	-	1.3
Enbridge Pipelines: Clipper Project Load Addition Phase 1	0.9	5.2	0.3	-	-	-	-	-	-	-	-	-	5.5
TCPL Keystone Project	8.0	2.3	1.9	1.6	-	-	-	-	-	-	-	-	5.8
Ashern Station Bank Addition	10.6	0.1	0.4	3.5	5.6	1.0	-	-	-	-	-	-	10.6
Ashern 230 kV Station Reactor Replacement	2.7	0.0	0.0	2.7	-	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Tank Farm Upgrade	1.1	5.1	(4.3)	-	-	-	-	-	-	-	-	-	0.7
Interlake Digital Microwave Replacement	19.7	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Pilot Wire Replacement	8.3	0.5	-	-	-	-	-	-	-	-	-	-	0.5
Transmission Line Protection & Teleprotection Replaceme	21.1	0.8	2.7	3.8	4.3	3.4	2.6	0.1	-	-	-	-	17.7
Winnipeg Central Protection Wireline Replacement	10.5	1.5	0.4	-	-	-	-	-	-	-	-	-	1.9
Mobile Radio System Modernization	30.7	0.4	2.5	6.1	2.9	11.7	7.1	-	-	-	-	-	30.6
Cyber Security Systems	10.1	1.3	-	-	-	-	-	-	-	-	-	-	1.3
Site Remediation of Diesel Generating Stations	13.3	3.8	1.9	0.3	-	-	-	-	-	-	-	-	6.0
Oil Containment - Transmission	7.4	0.8	0.2	-	-	-	-	-	-	-	-	-	1.1
Station Battery Bank Capacity & System Reliability Increas	46.5	5.0	5.7	4.8	5.8	4.5	4.4	-	-	-	-	-	30.2
Waverley Service Centre Oil Tank Farm Replacement	3.0	1.1	0.5	0.4	0.7	-	-	-	-	-	-	-	2.7
115 kV Transmission Lines	NA	-	-	-	-	-	-	-	-	-	-	10.3	10.3
230 kV Transmission Lines	NA	-	-	-	-	-	-	-	-	-	-	5.9	5.9
Sub-Transmission	NA	-	-	-	-	-	-	-	-	-	-	4.3	4.3
Communications	NA	-	-	-	-	-	-	-	-	-	-	14.7	14.7
Site Remediation	NA	-	-	-	-	-	-	-	-	-	-	1.2	1.2
Transmission Domestic	NA	30.0	30.6	31.2	31.8	32.4	33.1	33.7	34.4	35.1	35.8	36.5	364.6
		81.0	83.1	78.7	106.5	88.6	60.7	39.3	41.6	44.1	45.6	84.8	753.9

CEF10-2
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	11 Year Total
		81.0	83.1	78.7	106.5	88.6	60.7	39.3	41.6	44.1	45.6	84.8	753.9
Customer Service & Distribution													
Winnipeg Distribution Infrastructure Requirements	24.5	2.2	2.3	2.3	2.3	-	-	-	-	-	-	-	9.1
Defective RINJ Cable Replacements	8.7	1.0	2.1	-	-	-	-	-	-	-	-	-	3.1
Rover 4 kV Station Salvage & Feeder Conversion	12.7	0.1	3.1	4.3	-	-	-	-	-	-	-	-	7.5
Martin New 66-4 kV Station	28.2	1.0	5.1	6.9	9.0	1.8	-	-	-	-	-	-	23.7
Frobisher Station Upgrade	14.4	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Burrows New 66 -12 kV Station	28.6	4.2	12.2	6.4	-	-	-	-	-	-	-	-	22.8
Winnipeg Central Oil Switch Project	7.1	0.2	-	-	-	-	-	-	-	-	-	-	0.2
Teulon East 66-12 kV Station	4.6	4.5	0.1	-	-	-	-	-	-	-	-	-	4.6
William New 66 -12 kV Station	10.3	0.3	0.4	9.3	-	-	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply	6.5	3.0	-	-	-	-	-	-	-	-	-	-	3.0
St. James New Station & 24 kV Conversion	65.9	0.1	2.6	5.9	6.8	10.4	21.2	18.8	-	-	-	-	65.8
Shoal Lake New DSC & Town Conversion	3.6	0.2	-	-	-	-	-	-	-	-	-	-	0.2
York Station Bank & Switchgear Addition	4.0	2.7	-	-	-	-	-	-	-	-	-	-	2.7
Cromer North Station & Reston RE12-4 25 kV Conversion	4.3	0.3	1.3	-	-	-	-	-	-	-	-	-	1.6
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	0.0	0.0	6.2	-	-	-	-	-	-	-	-	6.2
Neepawa North Feeder NN12-2 & Line 57 Rebuild	1.9	1.9	-	-	-	-	-	-	-	-	-	-	1.9
Line 27 66 kV Extension and Arborg North DSC	6.0	0.4	5.4	-	-	-	-	-	-	-	-	-	5.7
Health Sciences Centre Service Consolidation & Distributio	15.8	3.6	3.6	3.1	2.2	3.2	0.1	-	-	-	-	-	15.8
AECL Switchgear Replacement	2.4	1.1	1.1	-	-	-	-	-	-	-	-	-	2.1
Waverley South DSC Installation	3.9	3.8	-	-	-	-	-	-	-	-	-	-	3.8
Niverville Station 66-12 kV Bank Replacements	2.6	0.6	-	-	-	-	-	-	-	-	-	-	0.6
Distribution	NA	-	-	-	-	-	-	-	-	-	-	30.5	30.5
Customer Service & Distribution Domestic	NA	117.5	119.9	122.3	124.7	127.2	129.8	132.4	135.0	137.7	140.5	143.3	1 430.2
		150.2	159.0	166.8	145.1	142.5	151.1	151.2	135.0	137.7	140.5	173.8	1 652.8
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	NA	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	31.2
		2.6	6.6	8.0	8.1	8.4	7.2	7.1	2.9	3.0	3.1	3.1	60.0
Finance & Administration													
Corporate Buildings Program	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
Workforce Management	11.3	0.8	-	-	-	-	-	-	-	-	-	-	0.8
Fleet Acqusitions	NA	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	16.5	164.5
Finance & Administration Domestic	NA	24.4	24.9	25.4	25.9	26.4	27.0	27.5	28.1	28.6	29.2	29.8	297.3
		46.7	46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	54.3	550.5
Capital Increase Provision		-	-	-	-	(0.0)	31.1	87.9	133.7	155.4	177.2	46.8	632.0
ELECTRIC CAPITAL SUBTOTAL		**1 187.0**	**1 168.7**	**1 240.0**	**1 571.1**	**1 806.2**	**2 129.0**	**2 176.7**	**2 454.7**	**1 959.6**	**2 174.9**	**1 762.2**	**19 630.2**

CEF10-2
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	11 Year Total
GAS													
Customer Service & Distribution													
Ile Des Chenes NG Transmission Network Upgrade	1.2	0.8	0.4	-	-	-	-	-	-	-	-	-	1.2
Centerport NPS 16 Natural Gas Transmission Main	1.7	1.7	-	-	-	-	-	-	-	-	-	-	1.7
Gas SCADA Replacement	4.6	1.8	2.6	-	-	-	-	-	-	-	-	-	4.4
Customer Service & Distribution Domestic	NA	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	25.9	258.4
		25.6	24.6	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	25.9	265.7
Customer Care & Marketing													
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.4	-	-	-	-	-	-	-	14.7
Demand Side Management	NA	11.2	12.0	12.4	10.4	10.4	10.0	9.4	7.2	5.6	5.1	5.1	98.8
Customer Care & Marketing Domestic	NA	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4	3.4	34.1
		14.0	15.9	20.7	21.8	13.4	13.1	12.5	10.5	8.9	8.5	8.5	147.7
Capital Increase Provision		-	-	-	-	-	-	-	2.3	4.9	5.0	5.1	17.2
GAS CAPITAL SUBTOTAL		**39.6**	**40.5**	**42.8**	**44.3**	**36.4**	**36.6**	**36.4**	**37.1**	**38.7**	**38.8**	**39.5**	**430.6**
CONSOLIDATED CAPITAL		**1 226.6**	**1 209.2**	**1 282.8**	**1 615.3**	**1 842.6**	**2 165.6**	**2 213.2**	**2 491.9**	**1 998.3**	**2 213.7**	**1 801.7**	**20 060.8**
TARGET ADJUSTMENT		(97.0)	(111.0)	(88.0)	-	-	-	-	-	-	-	-	(296.0)
CEF10-2 TOTAL		**1 129.6**	**1 098.2**	**1 194.8**	**1 615.3**	**1 842.6**	**2 165.6**	**2 213.2**	**2 491.9**	**1 998.3**	**2 213.7**	**1 801.7**	**19 764.8**

CEF10-2
(in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	21 Year Total
ELECTRIC											
Major New Generation & Transmission											
Wuskwatim - Generation	-	-	-	-	-	-	-	-	-	-	447.2
Wuskwatim - Transmission	-	-	-	-	-	-	-	-	-	-	56.9
Herblet Lake – The Pas 230 kV Transmission	-	-	-	-	-	-	-	-	-	-	28.3
Keeyask - Generation	43.2	-	-	-	-	-	-	-	-	-	5 271.6
Conawapa - Generation	1 134.1	1 058.0	815.9	342.0	47.3	-	-	-	-	-	7 598.8
Kelsey Improvements & Upgrades	-	-	-	-	-	-	-	-	-	-	118.6
Kettle Improvements & Upgrades	8.3	7.5	-	-	-	-	-	-	-	-	157.5
Pointe du Bois Spillway Replacement	-	-	-	-	-	-	-	-	-	-	360.5
Pointe du Bois - Transmission	-	-	-	-	-	-	-	-	-	-	77.3
Pointe du Bois Powerhouse Rebuild	0.5	2.2	16.0	37.8	90.7	157.8	245.0	403.9	312.7	216.2	1 482.8
BIPOLE III - Transmission Line	-	-	-	-	-	-	-	-	-	-	1 235.3
BIPOLE III - Converter Stations	-	-	-	-	-	-	-	-	-	-	1 798.1
BIPOLE III - Collector Lines	-	-	-	-	-	-	-	-	-	-	191.4
Riel 230/ 500 kV Station	-	-	-	-	-	-	-	-	-	-	236.5
Firm Import Upgrades	-	-	-	-	-	-	-	-	-	-	4.8
Dorsey - US Border New 500kV Transmission Line	-	-	-	-	-	-	-	-	-	-	204.0
St. Joseph Wind Transmission	-	-	-	-	-	-	-	-	-	-	5.6
Demand Side Management	19.5	19.4	19.2	15.2	15.5	15.8	16.1	16.5	16.8	17.2	499.4
Waterways Management Program	-	-	-	-	-	-	-	-	-	-	5.5
Generating Station Improvements & Upgrades	32.2	21.1	9.4	14.4	15.2	25.8	79.3	56.6	62.7	174.5	536.2
Additional North South Trasmission	-	-	-	312.8	-	-	-	-	-	-	312.8
	1 237.8	1 108.2	860.5	722.2	168.7	199.4	340.4	477.0	392.2	407.9	20 629.1

CEF10-2
(in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	21 Year Total
Power Supply											
Converter Transformer Bushing Replacement	-	-	-	-	-	-	-	-	-	-	2.2
HVDC Auxiliary Power Supply Ugrades	-	-	-	-	-	-	-	-	-	-	1.2
Dorsey Synchronous Condenser Refurbishment	-	-	-	-	-	-	-	-	-	-	12.5
HVDC System Transformer & Reactor Fire Protection & Pr	-	-	-	-	-	-	-	-	-	-	1.8
HVDC AC Filter PCB Capacitor Replacement	-	-	-	-	-	-	-	-	-	-	1.2
HVDC Transformer Replacement Program	4.6	6.4	32.9	6.7	7.0	50.3	22.5	77.8	88.1	39.3	350.6
Dorsey 230 kV Relay Building Upgrade	-	-	-	-	-	-	-	-	-	-	79.8
HVDC Stations Ground Grid Refurbishment	-	-	-	-	-	-	-	-	-	-	2.2
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	-	-	-	-	-	-	-	-	-	-	6.6
HVDC Bipole 1 Pole Differential Protection	-	-	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	-	-	-	-	-	-	-	-	-	-	19.9
HVDC Bipole 2 Refrigerant Condenser Replacement	-	-	-	-	-	-	-	-	-	-	11.0
HVDC Bipole 1 & 2 Smoothing Reactor Replacement	-	-	-	-	-	-	-	-	-	-	38.2
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Sep	-	-	-	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	-	-	-	-	-	-	-	-	-	-	11.7
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Re	-	-	-	-	-	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	-	-	-	-	-	-	-	-	-	-	18.9
HVDC Bipole 1 CQ Disconnect Replacement	-	-	-	-	-	-	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	-	-	-	-	-	-	-	-	-	-	2.7
HVDC Bipole 1 Transformer Marshalling Kiosk Replaceme	-	-	-	-	-	-	-	-	-	-	6.3
HVDC Gapped Arrestor Replacement	-	-	-	-	-	-	-	-	-	-	16.3
HVDC Bipole 2 Upgrades & Replacements	52.7	57.4	64.1	98.1	103.5	56.2	-	-	-	-	444.3
Pine Falls Rehabilitation	-	-	-	-	-	-	-	-	-	-	45.8
Jenpeg Unit Overhauls	18.1	-	-	-	-	-	-	-	-	-	116.0
Power Supply Dam Safety Upgrades	-	-	-	-	-	-	-	-	-	-	4.3
Winnipeg River Riverbank Protection Program	-	-	-	-	-	-	-	-	-	-	9.1
Power Supply Hydraulic Controls	-	-	-	-	-	-	-	-	-	-	12.6
Slave Falls Rehabilitation	-	-	-	-	-	-	-	-	-	-	199.4
Great Falls Unit 4 Overhaul	-	-	-	-	-	-	-	-	-	-	14.0
Great Falls Unit 5 Discharge Ring Replacement and Major	-	-	-	-	-	-	-	-	-	-	24.8
Generation South Transformer Refurbish & Spares	-	-	-	-	-	-	-	-	-	-	29.7
Generation South Overhauls & Improvements	10.2	40.3	29.4	48.6	28.5	33.3	82.8	53.3	53.7	-	384.8
Water Licenses & Renewals	-	-	-	-	-	-	-	-	-	-	31.5
Generation South PCB Regulation Compliance	-	-	-	-	-	-	-	-	-	-	4.5
Kettle Transformer Replacement Program	-	-	-	-	-	-	-	-	-	-	34.8
Generation South Breaker Replacement Program	-	-	-	-	-	-	-	-	-	-	10.3
Seven Sisters Upgrades	-	-	-	-	-	-	-	-	-	-	7.6
Generation South Excitation Program	5.0	3.4	1.2	-	-	-	-	-	-	-	32.3
Brandon Unit 5 License Review	-	-	-	-	-	-	-	-	-	-	13.8
Selkirk Enhancements	-	-	-	-	-	-	-	-	-	-	1.9
Laurie River/CRD Communications & Annunciation Upgrad	-	-	-	-	-	-	-	-	-	-	4.6
Notigi Marine Vessel Replacement & Infrastructure Improv	-	-	-	-	-	-	-	-	-	-	4.5
Pointe du Bois Safety Upgrades	-	-	-	-	-	-	-	-	-	-	50.0
Fire Protection Projects - HVDC	-	-	-	-	-	-	-	-	-	-	3.5
Halon Replacement Project	-	-	-	-	-	-	-	-	-	-	19.7
Oil Containment - Power Supply	-	-	-	-	-	-	-	-	-	-	3.8

CEF10-2
(in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	21 Year Total
Power Supply Continued											
Grand Rapids Townsite House Renovations	-	-	-	-	-	-	-	-	-	-	5.2
Grand Rapids Fish Hatchery	-	-	-	-	-	-	-	-	-	-	2.2
Generation Townsite Infrastructure	-	-	-	-	-	-	-	-	-	-	15.8
Site Remediation of Contaminated Corporate Facilities	-	-	-	-	-	-	-	-	-	-	5.3
High Voltage Test Facility	-	-	-	-	-	-	-	-	-	-	17.5
Security Installations / Upgrades	-	-	-	-	-	-	-	-	-	-	34.5
Sewer & Domestic Water System Install and Upgrade	-	-	-	-	-	-	-	-	-	-	15.0
Power Supply Domestic	24.1	24.5	25.0	25.5	26.0	26.6	27.1	27.6	28.2	28.7	498.7
	114.6	132.0	152.6	178.9	165.0	166.4	132.4	158.7	170.0	68.1	2 704.8
Transmission											
Winnipeg - Brandon Transmission System Improvements	-	-	-	-	-	-	-	-	-	-	35.8
Transcona East 230 - 66 kV Station	-	-	-	-	-	-	-	-	-	-	31.7
Neepawa 230 - 66 kV Station	-	-	-	-	-	-	-	-	-	-	28.8
Pine Falls - Bloodvein 115 kV Transmission	-	-	-	-	-	-	-	-	-	-	33.1
Transmission Line Re-Rating	-	-	-	-	-	-	-	-	-	-	2.3
St Vital-Steinbach 230 kV Transmission	-	-	-	-	-	-	-	-	-	-	32.3
Rosser Station 230 - 115 kV Bank 3 Replacement	-	-	-	-	-	-	-	-	-	-	0.6
Rosser - Inkster 115 kV Transmission	-	-	-	-	-	-	-	-	-	-	2.6
Transcona Station 66 kV Breaker Replacement	-	-	-	-	-	-	-	-	-	-	6.0
Dorsey 500 kV R502 Breaker Replacement	-	-	-	-	-	-	-	-	-	-	0.3
13.2kV Shunt Reactor Replacements	-	-	-	-	-	-	-	-	-	-	33.0
Canexus Load Addition	-	-	-	-	-	-	-	-	-	-	1.3
Birtle South-Rossburn 66 kV Line	-	-	-	-	-	-	-	-	-	-	4.9
Stanley Station 230-66 kV Permanent Transformer Additic	-	-	-	-	-	-	-	-	-	-	21.1
Stanley Station 230-66 kV Hot Standby Installation	-	-	-	-	-	-	-	-	-	-	1.3
Enbridge Pipelines: Clipper Project Load Addition Phase 1	-	-	-	-	-	-	-	-	-	-	5.5
TCPL Keystone Project	-	-	-	-	-	-	-	-	-	-	5.8
Ashern Station Bank Addition	-	-	-	-	-	-	-	-	-	-	10.6
Ashern 230 kV Station Reactor Replacement	-	-	-	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Tank Farm Upgrade	-	-	-	-	-	-	-	-	-	-	0.7
Interlake Digital Microwave Replacement	-	-	-	-	-	-	-	-	-	-	0.7
Pilot Wire Replacement	-	-	-	-	-	-	-	-	-	-	0.5
Transmission Line Protection & Teleprotection Replaceme	-	-	-	-	-	-	-	-	-	-	17.7
Winnipeg Central Protection Wireline Replacement	-	-	-	-	-	-	-	-	-	-	1.9
Mobile Radio System Modernization	-	-	-	-	-	-	-	-	-	-	30.6
Cyber Security Systems	-	-	-	-	-	-	-	-	-	-	1.3
Site Remediation of Diesel Generating Stations	-	-	-	-	-	-	-	-	-	-	6.0
Oil Containment - Transmission	-	-	-	-	-	-	-	-	-	-	1.1
Station Battery Bank Capacity & System Reliability Increas	-	-	-	-	-	-	-	-	-	-	30.2
Waverley Service Centre Oil Tank Farm Replacement	-	-	-	-	-	-	-	-	-	-	2.7
115 kV Transmission Lines	16.1	19.8	21.1	25.8	23.7	25.5	28.4	28.9	31.5	32.9	264.0
230 kV Transmission Lines	9.2	11.3	12.1	14.8	13.6	14.6	16.3	16.5	18.0	18.8	151.1
Sub-Transmission	6.7	8.3	8.8	10.8	9.9	10.6	11.9	12.1	13.1	13.7	110.2
Communications	23.0	28.2	30.0	36.8	33.8	36.3	40.5	41.2	44.8	46.9	376.2
Site Remediation	1.8	2.2	2.4	2.9	2.7	2.9	3.2	3.2	3.5	3.7	29.7
Transmission Domestic	37.3	38.0	38.8	39.5	40.3	41.1	42.0	42.8	43.7	44.5	772.7
	94.1	107.8	113.2	130.7	124.1	131.1	142.2	144.7	154.7	160.6	2 057.2

CEF10-2
(in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	21 Year Total
Customer Service & Distribution											
Winnipeg Distribution Infrastructure Requirements	-	-	-	-	-	-	-	-	-	-	9.1
Defective RINJ Cable Replacements	-	-	-	-	-	-	-	-	-	-	3.1
Rover 4 kV Station Salvage & Feeder Conversion	-	-	-	-	-	-	-	-	-	-	7.5
Martin New 66-4 kV Station	-	-	-	-	-	-	-	-	-	-	23.7
Frobisher Station Upgrade	-	-	-	-	-	-	-	-	-	-	1.6
Burrows New 66 -12 kV Station	-	-	-	-	-	-	-	-	-	-	22.8
Winnipeg Central Oil Switch Project	-	-	-	-	-	-	-	-	-	-	0.2
Teulon East 66-12 kV Station	-	-	-	-	-	-	-	-	-	-	4.6
William New 66 -12 kV Station	-	-	-	-	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply	-	-	-	-	-	-	-	-	-	-	3.0
St. James New Station & 24 kV Conversion	-	-	-	-	-	-	-	-	-	-	65.8
Shoal Lake New DSC & Town Conversion	-	-	-	-	-	-	-	-	-	-	0.2
York Station Bank & Switchgear Addition	-	-	-	-	-	-	-	-	-	-	2.7
Cromer North Station & Reston RE12-4 25 kV Conversion	-	-	-	-	-	-	-	-	-	-	1.6
Brandon Crocus Plains 115 - 25 kV Bank Addition	-	-	-	-	-	-	-	-	-	-	6.2
Neepawa North Feeder NN12-2 & Line 57 Rebuild	-	-	-	-	-	-	-	-	-	-	1.9
Line 27 66 kV Extension and Arborg North DSC	-	-	-	-	-	-	-	-	-	-	5.7
Health Sciences Centre Service Consolidation & Distributic	-	-	-	-	-	-	-	-	-	-	15.8
AECL Switchgear Replacement	-	-	-	-	-	-	-	-	-	-	2.1
Waverley South DSC Installation	-	-	-	-	-	-	-	-	-	-	3.8
Niverville Station 66-12 kV Bank Replacements	-	-	-	-	-	-	-	-	-	-	0.6
Distribution	47.9	58.8	62.6	76.7	70.5	75.7	84.4	85.8	93.5	97.8	784.2
Customer Service & Distribution Domestic	146.1	149.1	152.0	155.1	158.2	161.3	164.6	167.9	171.2	174.6	3 030.4
	194.0	207.8	214.7	231.8	228.7	237.0	249.0	253.6	264.7	272.4	4 006.5
Customer Care & Marketing											
Advanced Metering Infrastructure	-	-	-	-	-	-	-	-	-	-	28.8
Customer Care & Marketing Domestic	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	66.2
	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	95.0
Finance & Administration											
Corporate Buildings Program	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	168.0
Workforce Management	-	-	-	-	-	-	-	-	-	-	0.8
Fleet Acqusitions	16.8	17.1	17.5	17.8	18.2	18.6	18.9	19.3	19.7	20.1	348.5
Finance & Administration Domestic	30.4	31.0	31.6	32.2	32.9	33.5	34.2	34.9	35.6	36.3	629.9
	55.2	56.1	57.1	58.1	59.1	60.1	61.1	62.2	63.3	64.4	1 147.2
Capital Increase Provision	-	-	-	-	-	-	-	-	-	-	632.0
ELECTRIC CAPITAL SUBTOTAL	**1 698.9**	**1 615.2**	**1 401.4**	**1 325.1**	**749.1**	**797.5**	**928.7**	**1 099.9**	**1 048.6**	**977.2**	**31 271.8**

CEF10-2
(in millions of dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	21 Year Total
GAS											
Customer Service & Distribution											
Ile Des Chenes NG Transmission Network Upgrade	-	-	-	-	-	-	-	-	-	-	1.2
Centerport NPS 16 Natural Gas Transmission Main	-	-	-	-	-	-	-	-	-	-	1.7
Gas SCADA Replacement	-	-	-	-	-	-	-	-	-	-	4.4
Customer Service & Distribution Domestic	26.4	26.9	27.5	28.0	28.6	29.2	29.7	30.3	30.9	31.6	547.5
	26.4	26.9	27.5	28.0	28.6	29.2	29.7	30.3	30.9	31.6	554.8
Customer Care & Marketing											
Advanced Metering Infrastructure	-	-	-	-	-	-	-	-	-	-	14.7
Demand Side Management	5.1	5.1	5.1	5.1	5.1	5.0	4.9	4.9	4.8	4.8	148.7
Customer Care & Marketing Domestic	3.5	3.6	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	72.4
	8.6	8.6	8.7	8.8	8.8	8.8	8.9	8.9	8.9	9.0	235.6
Capital Increase Provision	5.2	5.3	5.4	5.5	5.6	5.8	5.9	6.0	6.1	6.3	74.3
GAS CAPITAL SUBTOTAL	**40.2**	**40.9**	**41.6**	**42.4**	**43.0**	**43.8**	**44.5**	**45.2**	**46.0**	**46.8**	**865.0**
CONSOLIDATED CAPITAL	**1 739.1**	**1 656.1**	**1 443.0**	**1 367.5**	**792.1**	**841.3**	**973.2**	**1 145.1**	**1 094.6**	**1 024.0**	**32 136.8**
TARGET ADJUSTMENT	-	-	-	-	-	-	-	-	-	-	(296.0)
CEF10-2 TOTAL	**1 739.1**	**1 656.1**	**1 443.0**	**1 367.5**	**792.1**	**841.3**	**973.2**	**1 145.1**	**1 094.6**	**1 024.0**	**31 840.8**

MIPUG/MH I-29

Subject: PUB/MH I-4 from 2010 GRA: Equivalent Full Time Employees

a) Please update PUB/MH I-4(a) from the 2010 GRA of actual equivalent full time employees for actual years up to 2011/12.

ANSWER:

Please see Manitoba Hydro's response to PUB MH I-37(a).

MIPUG/MH I-29

Subject: PUB/MH I-4 from 2010 GRA: Equivalent Full Time Employees

b) Please provide a definition of FTE as used in part (a) and indicate how the values were calculated, particularly with respect to the number of positions, vacancies, long term leave, and unbudgeted positions filled during the fiscal year.

ANSWER:

An equivalent full time employee (EFT) represents one employee working full-time hours of 73.7 hours biweekly or 1,916 hours per year.

Total EFTs are based on hours worked in relation to available hours in a specific period of time. Vacancies and unbudgeted positions are not included in the actual EFT calculation; however vacancies may be the driver of a variance when comparing different periods of time. Employees on long term leave are not specifically captured in this calculation since they are not available to work.

MIPUG/MH I-29

Subject: PUB/MH I-4 from 2010 GRA: Equivalent Full Time Employees

c) Please indicate the vacancy factor which has been utilized for 2012/13 through 2013/14.

ANSWER:

The vacancy factor for the 2012/13 forecast year is 6.2%.

MIPUG/MH I-29

Subject: PUB/MH I-4 from 2010 GRA: Equivalent Full Time Employees

d) Please provide supporting calculations for the vacancy factor used for 2012/13 through 2013/14 and supporting calculations on the impact of the vacancy factor on the forecast FTE.

ANSWER:

The vacancy rate is defined as the number of vacant positions as a percentage of the total positions.

	Total Positions	Budgeted Positions	Vacancy	Vacancy Rate
EFT	6,882	6,456	426	6.2%

MIPUG/MH I-29

Subject: PUB/MH I-4 from 2010 GRA: Equivalent Full Time Employees

e) Please indicate the impact on the vacancy factor of the "Ongoing Cost Constraint Measure" (Appendix 5.6 page 13) of the "External Hiring Freeze".

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-29(f).

MIPUG/MH I-29

Subject: PUB/MH I-4 from 2010 GRA: Equivalent Full Time Employees

f) Please provide a comparison of the vacancy rate assumed in IFF11-2 versus the vacancy rate that would be assumed absent the external hiring freeze.

ANSWER:

The vacancy rate assumed in IFF11-2 is 6.2%.

The vacancy rate is defined as the number of vacant positions as a percentage of the total positions. Vacant positions are attributable to a number of factors including the external hiring freeze as well as employee retirements and turnover of staff both internally and externally. As a result, these factors are not quantified individually in the vacancy rate calculation.

MIPUG/MH I-29

Subject: PUB/MH I-4 from 2010 GRA: Equivalent Full Time Employees

g) Please indicate the timeframe for the External Hiring Freeze as per Appendix 5.6. Is this to remain in place through both test years?

ANSWER:

Manitoba Hydro implemented an external hiring freeze (unless specifically approved by the President & CEO) effective August 10, 2010. Manitoba Hydro will continue to exercise cost constraint through the review and justification of all external hires in both test years.

MIPUG/MH I-29

Subject: PUB/MH I-4 from 2010 GRA: Equivalent Full Time Employees

h) Please provide Manitoba Hydro's actual vacancy rate for the five most recently available fiscal years.

ANSWER:

Vacancy Factor	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast
Actual	8.1%	7.2%	9.3%	7.4%	7.8%	
Forecast	5.2%	5.2%	6.6%	5.7%	6.3%	6.2%

MIPUG/MH I-30

Subject: PUB/MH I-24(a) from 2010 GRA: Payments to Governments

a) Please update the schedule provided in PUB/MH I-24(a) of the 2010 GRA with actuals to 2011/12 and forecast to 2031/32.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-49(a).

MIPUG/MH I-30

Subject: **PUB/MH I-24(a) from 2010 GRA: Payments to Governments**

b) Please also update PUB/MH-I-24(d) regarding any knowledge of pending or assumed changes to the charges to be applied.

ANSWER:

The Province has provided no indication regarding planned changes to government charges with respect to any future years.

MIPUG/MH I-31

Subject: PUB/MH I-25 from 2010 GRA: Sinking Fund

a) Please update PUB/MH I-25(a) from the 2010 GRA from fiscal years 2004/05 to 2031/32.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-50.

MIPUG/MH I-31

Subject: PUB/MH I-25 from 2010 GRA: Sinking Fund

b) Please update PUB/MH I-25(b) from the 2010 GRA and provide any updates to the status to eliminate the sinking fund requirements.

ANSWER:

Manitoba Hydro is legislated under the Manitoba Hydro Act to make sinking fund payments to the Province of Manitoba of not less than 1% of the principal amount of the outstanding debt on the preceding March 31, and 4% of the balance in the sinking fund at such date. Sinking fund withdrawals are applied towards the repayment of advances made to, and moneys borrowed by, the Corporation. Sinking funds are a source of liquidity that is frequently cited by Standard & Poor's as a positive rating factor. For example, in the October 24, 2011 report on the Province of Manitoba, S&P stated that the province had "healthy liquidity levels, owing to a large pool of sinking funds."[1] The US sinking fund is also an integral part of the Corporation's foreign currency exposure management program.

Sinking funds are invested in government bonds and the bonds of highly rated corporations and financial institutions. As the sinking funds tend to have returns lower than the Corporation's financing rates, the sinking funds typically have a negative cost to carry.

At the previous GRA, in response to information request cited in this question, Manitoba Hydro estimated the sinking fund cost to carry to be approximately $8 million per year. In order to minimize this carrying cost, Manitoba Hydro has in recent years reduced the sinking fund balances from $718 million at March 31, 2008 to $372 million at March 31, 2012. Consequently, the estimated cost to carry has been reduced to approximately $5 million per year. With targeted sinking fund withdrawals in the next few years drawing the sinking fund balances down to under $175 million, it is anticipated that the cost to carry will further decline (for the sinking fund continuity schedule, please see PUB/MH I – 50).

Manitoba Hydro recognizes the value of having sinking funds and being able to manage them in a flexible manner. The Province of Manitoba is aware of Manitoba Hydro's objective to ultimately eliminate the mandatory sinking fund requirements.

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[1] Standard & Poor's, "Rating Report: Province of Manitoba" dated October 24, 2011; page 2 (see Appendix 20Attachment 26).

MIPUG/MH I-31

Subject: PUB/MH I-25 from 2010 GRA: Sinking Fund

c) Please provide the assumed effective earnings rate on the Sinking Funds for the period of IFF11-2, including the basis for the earnings estimates.

ANSWER:

The existing investments within the sinking fund portfolio are anticipated to be liquidated during 2013/14 as part of scheduled sinking fund withdrawals. The earnings on these existing investments are forecasted utilizing known investment returns. Incremental new sinking fund contributions are anticipated to have short term investment periods in order to maintain liquidity and to provide the flexibility to withdraw sinking fund amounts toward the repayment of approaching debt maturities. Therefore, the returns on these new sinking fund contributions are based on Manitoba Hydro's forecasted short term interest rates, exclusive of the Provincial Debt Guarantee Fee. On a portfolio basis, the effective earnings rate on the sinking funds is forecasted to be 4.12% in 2012/13 and 3.83% in 2013/14, with the earnings rate after this time being in line with Manitoba Hydro's forecasted short term interest rates, exclusive of the Provincial Debt Guarantee Fee.

MIPUG/MH I-32

Subject: PUB/MH I-27 and PUB/MH-I-28 (a) from 2010 GRA: Financial Results

a) Please update the actual MH Electric Operations financial statements similar to PUB/MH I-27 and PUB/MH-I-28(a) with actual information to 2011/12.

ANSWER:

For the update to PUB/MH I-27 from the 2010/11 & 2011/12 GRA, please see Manitoba Hydro's response to PUB/MH I-51. For the update to PUB/MH-I-28(a) from the 2010/11 & 2011/12 GRA, please see Manitoba Hydro's response to PUB/MH I-52(a).

MIPUG/MH I-33

Subject: PUB/MH I-32(d) from 2010 GRA

a) Please provide a schedule similar to that provided in PUB/MH I-32(d) from the 2010 GRA which compares for fiscal 2010/11 and 2011/12 actual results presented in this application with the forecast results provided at the 2010 GRA by cost element and business unit. Similar to the 2010 GRA PUB IR, please explain any differences over 5%.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-59(d).

MIPUG/MH I-34

Subject: **PUB/MH I-34(a) REVISED from 2010 GRA: Financial Results and Forecast**

a) Please re-file the schedule provided in PUB/MH I-34(a) REVISED from the 2010 GRA and provide a detailed comparison of the reasons for variation in the EFTs forecast versus actuals for 2009/10, 2010/11 and 2011/12.

ANSWER:

Please see the following table.

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY BUSINESS UNIT

	2009/10 Actual	2009/10 Forecast	Variance	2010/11 Actual	2010/11 Forecast	Variance	2011/12 Actual	2011/12 Forecast	Variance
President & CEO	116	120	(4)	123	135	(13)	127	135	(8)
Corporate Relations	73	69	4	69	69	0	69	69	(0)
Finance & Administration	1 010	1 050	(40)	1 009	1 051	(41)	983	1 051	(68)
Power Supply	1 679	1 757	(79)	1 796	1 785	12	1 853	1 785	69
Transmission	1 342	1 355	(13)	1 365	1 358	6	1 354	1 358	(5)
Customer Services & Distribution	1 678	1 708	(30)	1 704	1 711	(7)	1 701	1 711	(9)
Customer Care & Marketing	532	553	(22)	528	558	(30)	521	558	(37)
Total	6 429	6 612	(183)	6 594	6 667	(73)	6 608	6 667	(59)

Variance

Variances in actual EFTs as compared to the 2009/10, 2010/11 and 2011/12 Forecsts are mainly due to vacancies and hiring delays throughout business units due to cost saving measures. The IBEW labour dispute also contributed to the favourable variance in the 2009/10 fiscal year.

MIPUG/MH I-35

Subject: PUB/MH I-81(a) from 2010 GRA: Energy Supply

a) Please file an updated version of the schedule provided in PUB/MH I-81(a) from the 2010 GRA and explain fully the derivation of the "net revenue" column, what is included in the calculations, and how these values are incorporated into IFF forecasts.

ANSWER:

The attached table contains the net revenue for the load year 2013/14 for the entire 96 flow history (1912/13 to 2007/08, inclusive). This update is based on the 2011 Load Forecast and the 2011 forecast of export and import prices as well as all other updates for the 2011 IFF.

The net revenue represents the revenues minus costs. Revenues are inclusive of firm and opportunity export sales and transmission inter-connection revenues. Costs are inclusive of water rentals for Manitoba Hydro hydraulic energy generation, costs of Manitoba Hydro thermal generation, import and wind energy purchases, and transmission inter-connection costs.

The revenues and costs are reflected in Manitoba Hydro's Integrated Financial Forecast Statement of Income. Revenues are reflected in the Extra-provincial Revenue, while the costs are reflected in the Water Rentals & Assessments and the Fuel & Power Purchased.

Flow Year	Annual System Inflow	MH Hydraulic Energy	Net Revenue	Variation of Net Revenue from Average
	Kcfs	(GWh/yr)	(M $Cdn)	(M $Cdn)
1912	112	33311	163	85
1913	118	32586	145	67
1914	98	29436	78	0
1915	105	30489	104	26
1916	136	35587	199	121
1917	118	33818	172	94
1918	105	30401	99	21
1919	98	27720	28	-50
1920	103	29204	67	-11
1921	113	31050	117	39
1922	105	30392	98	20
1923	111	30721	108	30
1924	98	27261	12	-66
1925	119	31994	135	57
1926	111	31450	127	48
1927	154	37324	208	130
1928	114	33612	165	86
1929	87	25626	-46	-124
1930	89	24518	-100	-178
1931	87	24074	-121	-199
1932	95	26473	-12	-90
1933	101	27936	39	-39
1934	118	32074	138	60
1935	117	32275	141	63
1936	96	27498	18	-61
1937	98	27794	26	-52
1938	89	25634	-44	-122
1939	79	22487	-223	-301
1940	55	20042	-406	-484
1941	92	22218	-242	-320
1942	101	29103	63	-15
1943	108	30218	97	18
1944	106	30400	101	23
1945	119	32241	143	65
1946	113	32110	139	60
1947	125	34004	173	95
1948	113	32939	134	56
1949	116	31104	117	38
1950	144	35273	184	106
1951	132	36093	202	124
1952	106	31902	131	53
1953	124	33367	168	90
1954	142	37174	213	135
1955	132	34986	174	95
1956	118	32997	144	66
1957	113	31665	128	50
1958	95	27565	24	-54
1959	137	34268	179	101
1960	102	30318	81	3

Flow Year	Annual System Inflow	MH Hydraulic Energy	Net Revenue	Variation of Net Revenue from Average
	Kcfs	(GWh/yr)	(M $Cdn)	(M $Cdn)
1961	75	21612	-288	-366
1962	118	31334	121	43
1963	110	31345	123	45
1964	113	31738	133	55
1965	156	36961	212	134
1966	151	35673	184	106
1967	115	32846	136	58
1968	133	33801	172	94
1969	147	37347	208	130
1970	144	36113	198	120
1971	140	35744	192	114
1972	125	34240	158	79
1973	116	31592	129	51
1974	164	36449	195	117
1975	139	35487	186	108
1976	94	26961	-29	-107
1977	100	26793	-1	-79
1978	121	32405	146	68
1979	136	33443	140	61
1980	93	26105	-24	-102
1981	86	24082	-121	-199
1982	115	30779	110	32
1983	111	30740	100	22
1984	99	27876	30	-48
1985	137	33909	171	93
1986	131	34115	161	83
1987	83	23940	-127	-206
1988	72	20209	-395	-473
1989	90	25839	-39	-117
1990	86	25187	-70	-148
1991	91	26074	-31	-109
1992	115	30747	107	29
1993	106	29974	88	10
1994	102	28723	52	-26
1995	104	30239	96	18
1996	142	34890	177	99
1997	153	36080	196	117
1998	106	29969	49	-29
1999	112	30608	105	27
2000	126	33153	161	83
2001	129	32678	124	46
2002	107	29637	73	-5
2003	74	21460	-290	-368
2004	129	33671	173	95
2005	187	37846	221	142
2006	114	32052	96	18
2007	150	36202	201	123
Average	**114**	**30744**	**78.12**	**0**

MIPUG/MH I-36

Subject: PUB/MH I-150(a) from 2010 GRA: Drought Risk

a) Please update the schedules provided in PUB/MH I-150(a) from the 2010 GRA regarding the five year and seven year drought impacts.

ANSWER:

Manitoba Hydro's methodology for the calculation of the five-year and seven-year drought impact utilizes an onset date of the drought that is two-years subsequent to the start of the forecast. For the 2011/12 forecast of the drought impact, the start date of the drought would be in year 2013/14.

	2013/14	2014/15	2015/16	2016/17	2017/18	Total
Impact of 5-Year Drought on Revenues (millions of $ CDN)						
Revenue						
Extra-Provincial Sales	-144	-201	-142	-191	-169	-848
Expense						
Water Rental	-23	-35	-16	-19	-16	-109
Fuel & Power Purchase	76	375	44	63	58	616
Net Revenue (Excluding Finance Expense)	-206	-541	-170	-236	-211	-1363
Impact of 5-Year Drought on Energy (GWh/yr)						
Extra-Provincial Sales	-3904	-4081	-3149	-3520	-3130	-17785
Hydro Generation	-6804	-10442	-4866	-5548	-4925	-32585
Fuel & Power Purchase	2318	2229	1501	1707	1544	9299

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Impact of 7-Year Drought on Revenues (millions of $ CDN)								
Revenue								
Extra-Provincial Sales	-52	-63	-140	-243	-296	-285	-11	-1090
Expense								
Water Rental	-11	-10	-17	-28	-35	-31	-6	-137
Fuel & Power Purchase	17	10	51	229	449	359	10	1126
Net Revenue (Excluding Finance Expense)	-61	-63	-174	-445	-710	-613	-14	-2081
Impact of 7-Year Drought on Energy (GWh/yr)								
Extra-Provincial Sales	-2029	-1951	-3199	-4086	-4264	-4024	-973	-20526
Hydro Generation	-3246	-2912	-5078	-8233	-10616	-9178	-1801	-41063
Fuel & Power Purchase	1127	910	1650	2093	2142	1877	962	10762

MIPUG/MH I-36

Subject: PUB/MH I-150(a) from 2010 GRA: Drought Risk

b) Please provide an IFF 20 year Electric Operations scenario (Operating Statement, Balance Sheet and Cash Flow) for the 5 year drought Risk Analysis cited at page 16 of IFF11-2 ($1.570 billion reduction in Retained Earnings by 2017/18). Please include the annual financial targets for each year of the scenario.

ANSWER:

See attached schedules.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
5 YEAR DROUGHT RISK SCENARIO
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 243	1 268	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	44	92	142	194	250	309	371	438	509	584
Extraprovincial	370	359	219	193	327	311	362	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 620	1 686	1 620	1 658	1 850	1 907	2 038	2 304	2 448	2 751	2 938
EXPENSES											
Operating and Administrative	402	517	527	534	544	551	569	579	595	612	624
Finance Expense	399	451	463	535	597	648	742	885	936	1 291	1 266
Depreciation and Amortization	357	343	353	357	374	386	422	467	482	549	575
Water Rentals and Assessments	120	116	90	78	97	95	96	113	114	123	128
Fuel and Power Purchased	157	158	234	562	236	268	278	236	249	256	257
Capital and Other Taxes	83	85	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	8	8	8	8	8	8	8	8	8	8
	1 526	1 678	1 768	2 172	1 963	2 071	2 241	2 420	2 524	2 968	2 991
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	94	7	(149)	(516)	(115)	(166)	(206)	(119)	(79)	(220)	(64)
Other Comprehensive Income	(18)	(33)	(15)	(145)	(48)	(18)	(27)	(15)	(16)	(18)	(22)
Comprehensive Income	76	(26)	(164)	(660)	(163)	(184)	(233)	(134)	(95)	(238)	(86)
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase	0.00%	3.50%	7.12%	10.87%	14.75%	18.77%	22.93%	27.23%	31.68%	36.29%	41.06%
Financial Ratios											
Equity	26%	21%	18%	12%	10%	8%	6%	5%	4%	3%	3%
Interest Coverage	1.17	1.01	0.77	0.32	0.87	0.84	0.82	0.91	0.94	0.86	0.96
Capital Coverage	1.12	0.98	0.57	(0.33)	0.78	0.66	0.63	0.95	1.10	0.98	1.41

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
5 YEAR DROUGHT RISK SCENARIO
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
REVENUES										
General Consumers										
at approved rates	1 441	1 460	1 479	1 498	1 521	1 541	1 562	1 582	1 602	1 622
additional*	663	746	800	857	918	980	1 044	1 110	1 178	1 250
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
Other	19	20	20	20	21	21	22	22	22	23
	3 053	3 172	3 423	3 784	3 985	4 086	4 166	4 258	4 367	4 469
EXPENSES										
Operating and Administrative	636	649	672	681	693	707	720	735	750	765
Finance Expense	1 263	1 268	1 378	1 622	1 787	1 773	1 758	1 731	1 768	1 692
Depreciation and Amortization	579	582	614	681	732	740	752	760	793	813
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	156	158	160	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	3 023	3 081	3 241	3 572	3 828	3 857	3 882	3 894	3 992	3 967
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	20	80	171	200	145	216	272	350	361	488
Other Comprehensive Income	(13)	0	0	0	-	-	-	-	-	-
Comprehensive Income	7	80	172	200	145	216	272	350	361	488
* Additional General Consumers Revenue										
Percent Increase	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	46.00%	51.11%	54.13%	57.21%	60.36%	63.56%	66.83%	70.17%	73.57%	77.05%
Financial Ratios										
Equity	3%	3%	4%	4%	5%	6%	7%	8%	9%	11%
Interest Coverage	1.01	1.05	1.10	1.11	1.08	1.12	1.15	1.19	1.20	1.28
Capital Coverage	1.48	1.54	1.61	1.85	1.80	2.00	2.02	2.05	2.59	2.33

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
5 YEAR DROUGHT RISK SCENARIO
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
ASSETS											
Plant in Service	13 795	15 115	15 661	16 424	17 348	17 931	21 354	21 842	25 459	28 214	28 575
Accumulated Depreciation	(4 921)	(5 227)	(5 564)	(5 894)	(6 253)	(6 618)	(7 044)	(7 518)	(8 006)	(8 560)	(9 141)
Net Plant in Service	8 874	9 888	10 097	10 530	11 095	11 313	14 310	14 325	17 453	19 653	19 434
Construction in Progress	2 443	2 196	3 149	3 997	5 014	6 410	5 346	6 447	4 558	3 595	4 964
Current and Other Assets	1 905	1 641	1 471	1 518	1 693	1 884	2 120	1 939	2 125	2 233	2 138
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	-	-	-	-	-	-	-	-	-	-
	13 643	13 903	14 879	16 194	17 937	19 733	21 893	22 820	24 239	25 579	26 628
LIABILITIES AND EQUITY											
Long-Term Debt	9 253	9 469	11 109	12 984	14 800	16 671	18 636	20 329	21 491	23 001	24 645
Current and Other Liabilities	1 316	1 878	1 364	1 457	1 540	1 638	2 055	1 415	1 757	1 814	1 294
Contributions in Aid of Construction	317	327	340	347	355	365	376	385	396	406	418
Retained Earnings	2 421	2 134	1 986	1 470	1 355	1 189	983	865	786	566	502
Accumulated Other Comprehensive Income	335	95	80	(65)	(113)	(131)	(158)	(174)	(190)	(208)	(230)
	13 643	13 903	14 879	16 194	17 937	19 733	21 893	22 820	24 239	25 579	26 628
Equity Ratio	26%	21%	18%	12%	10%	8%	6%	5%	4%	3%	3%

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
5 YEAR DROUGHT RISK SCENARIO
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
ASSETS										
Plant in Service	28 984	29 549	33 961	38 036	39 296	39 927	40 496	41 025	43 046	43 762
Accumulated Depreciation	(9 728)	(10 318)	(10 943)	(11 635)	(12 379)	(13 131)	(13 896)	(14 670)	(15 477)	(16 306)
Net Plant in Service	19 256	19 231	23 018	26 401	26 917	26 795	26 600	26 355	27 569	27 456
Construction in Progress	6 099	6 969	4 170	1 022	545	786	1 259	1 722	618	758
Current and Other Assets	2 254	2 513	2 922	2 650	2 974	3 289	3 646	3 744	4 140	4 611
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27 700	28 802	30 198	30 159	30 521	30 954	31 587	31 902	32 408	32 906
LIABILITIES AND EQUITY										
Long-Term Debt	25 848	26 851	27 604	27 806	28 008	28 149	28 300	28 402	28 391	27 528
Current and Other Liabilities	1 146	1 154	1 614	1 161	1 164	1 227	1 425	1 276	1 418	2 278
Contributions in Aid of Construction	429	440	451	462	474	486	499	511	524	538
Retained Earnings	521	601	772	972	1 118	1 334	1 606	1 956	2 317	2 805
Accumulated Other Comprehensive Income	(244)	(243)	(243)	(243)	(243)	(243)	(243)	(243)	(243)	(243)
	27 700	28 802	30 198	30 159	30 521	30 954	31 587	31 902	32 408	32 906
Equity Ratio	3%	3%	4%	4%	5%	6%	7%	8%	9%	11%

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
5 YEAR DROUGHT RISK SCENARIO
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 620	1 686	1 620	1 658	1 850	1 907	2 038	2 304	2 448	2 751	2 938
Cash Paid to Suppliers and Employees	(758)	(880)	(947)	(1 276)	(988)	(1 033)	(1 074)	(1 064)	(1 102)	(1 123)	(1 147)
Interest Paid	(419)	(469)	(475)	(529)	(606)	(662)	(765)	(913)	(951)	(1 312)	(1 283)
Interest Received	26	28	27	20	27	34	41	43	40	37	35
	469	366	226	(127)	282	247	241	370	435	352	543
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	900	1 830	2 005	2 200	2 400	2 790	1 990	1 790	2 190	1 790
Sinking Fund Withdrawals	23	129	395	105	26	-	14	424	193	275	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	1 403	1 926	1 907	1 985	2 267	1 561	1 669	1 851	1 781
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1 163)	(1 154)	(1 481)	(1 616)	(1 934)	(1 986)	(2 336)	(1 567)	(1 820)	(1 856)	(1 697)
Sinking Fund Payment	(98)	(117)	(208)	(126)	(192)	(167)	(231)	(226)	(229)	(288)	(346)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1 280)	(1 291)	(1 709)	(1 763)	(2 146)	(2 199)	(2 603)	(1 823)	(2 078)	(2 179)	(2 083)
Net Increase (Decrease) in Cash	(82)	(36)	(81)	37	44	34	(95)	108	26	24	241
Cash at Beginning of Year	66	(16)	(52)	(133)	(96)	(52)	(19)	(113)	(5)	21	45
Cash at End of Year	(16)	(52)	(133)	(96)	(52)	(19)	(113)	(5)	21	45	286

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
5 YEAR DROUGHT RISK SCENARIO
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 053	3 172	3 423	3 784	3 985	4 086	4 166	4 258	4 367	4 469
Cash Paid to Suppliers and Employees	(1 178)	(1 228)	(1 245)	(1 266)	(1 306)	(1 341)	(1 369)	(1 400)	(1 429)	(1 459)
Interest Paid	(1 257)	(1 254)	(1 372)	(1 632)	(1 792)	(1 790)	(1 782)	(1 765)	(1 782)	(1 744)
Interest Received	20	22	33	39	40	53	66	72	81	96
	638	712	840	924	927	1 008	1 081	1 165	1 237	1 362
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 190	990	1 190	190	190	190	400	190	160	190
Sinking Fund Withdrawals	159	-	-	450	-	-	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)
	1 183	984	1 184	182	182	183	393	214	56	(29)
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	(257)	(272)	(292)	(315)	(308)	(323)	(338)	(352)	(355)	(370)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1 796)	(1 702)	(1 898)	(1 234)	(1 085)	(1 185)	(1 370)	(1 334)	(1 260)	(1 214)
Net Increase (Decrease) in Cash	25	(7)	127	(127)	24	6	105	45	33	120
Cash at Beginning of Year	286	311	305	431	304	328	334	439	484	517
Cash at End of Year	311	305	431	304	328	334	439	484	517	637

MIPUG/MH I-37

Subject: Exhibit MH-65 from 2010 GRA: Discount Rates

a) Please confirm whether or the discount rates described in Exhibit MH-65 from the 2010 GRA were used as a basis for the 2011/12 Power Resource Plan and the 2011 Power Smart Plan assessments.

ANSWER:

Manitoba Hydro does confirm that the discount rates described in Exhibit MH-65 from the 2010 GRA represent the Weighted Average Cost of Capital – WACC (real and nominal) were used in the 2011 Power Smart Plan.

Manitoba Hydro does not confirm that the discount rates described in Exhibit MH-65 from the 2010 GRA represent the Weighted Average Cost of Capital – WACC (real and nominal) used as a basis for the 2011/12 Power Resource Plan.

Manitoba Hydro continues to use a methodology consistent with that described in Exhibit MH-65 from the 2010 GRA. Assessments and plans prepared by Manitoba Hydro use the latest approved discount rates available at the time that analysis is undertaken.

MIPUG/MH I-37

Subject: Exhibit MH-65 from 2010 GRA: Discount Rates

b) If the answer to (a) is no, please indicate the values that were used for each plan, and provide the basis for how they were derived.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-37(a)

Manitoba Hydro respectfully declines to provide the discount used in the Power Resource Plan for 2011/12. Review of matters related to the discount rate used and the application of discount rates for Manitoba Hydro's Preferred Development Plan and its alternatives, including economics, is expected to take place in the context of a Needs For and Alternatives To (NFAT) hearing, which process is expected to commence in 2013.

MIPUG/MH I-37

Subject: Exhibit MH-65 from 2010 GRA: Discount Rates

c) If already available, please provide the discount rate to be used in the 2012/13 Power Resource Plan.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-37(b).

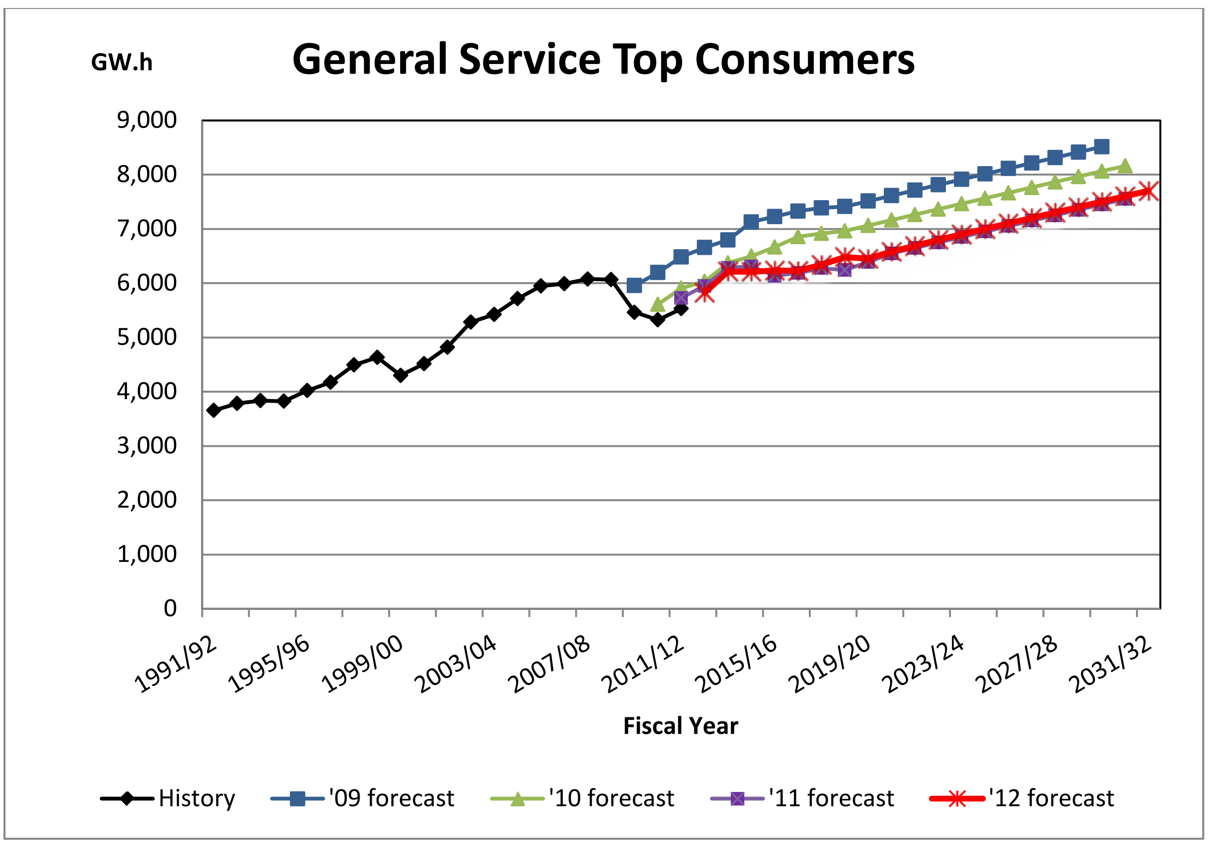
MIPUG/MH I-38

Subject: Exhibit MH-38 from 2010 GRA: Load Forecast

a) Please provide in graph and table format the General Service Top Consumers forecasts of the last three load forecasts (2009/10, 2010/11 and 2011/12) as well as the historical actual similar to Manitoba Hydro Exhibit MH-38 from the 2010 GRA.

ANSWER:

Please see the following graph and table.



TOP CONSUMERS

History and Base Forecasts

Fiscal Year	'09 Forecast			'10 Forecast			'11 Forecast			History and '12 Forecast		
	(Custs.)	(GW.h)	(Avg.)	(Custs.)	(GW.h)	(Avg.)	(Custs.)	(GW.h)	(Avg.)	(Custs.)	(GW.h)	(Avg.)
1991/92										20	3,655	182,751,101
1992/93										20	3,783	189,137,121
1993/94										21	3,836	182,644,052
1994/95										21	3,825	178,617,059
1995/96										26	4,021	155,147,829
1996/97										29	4,173	142,275,691
1997/98										33	4,493	135,794,672
1998/99										34	4,632	136,243,341
1999/00										35	4,299	124,313,600
2000/01										31	4,515	143,708,287
2001/02										25	4,818	190,202,962
2002/03										26	5,282	201,845,562
2003/04										27	5,423	202,105,234
2004/05										26	5,714	219,774,330
2005/06										26	5,948	228,753,323
2006/07										26	5,989	230,346,465
2007/08										26	6,075	233,643,398
2008/09										26	6,065	233,277,664
2009/10	25	5,956	238,256,000	.		.				26	5,461	210,031,369
2010/11	25	6,196	247,840,000	25	5,610	224,400,000				26	5,324	204,766,799
2011/12	25	6,482	259,280,000	25	5,909	236,360,000	31	5,730	184,851,613	32	5,531	175,134,063
2012/13	25	6,657	261,058,824	25	6,033	241,320,000	31	5,951	191,964,516	31	5,821	187,774,194
2013/14	26	6,795	261,346,154	25	6,375	250,000,000	31	6,283	202,693,548	31	6,214	200,451,613
2014/15	26	7,126	274,076,923	26	6,499	249,961,538	31	6,305	200,174,603	31	6,208	200,258,065
2015/16	26	7,226	277,923,077	26	6,666	256,384,615	32	6,135	191,734,375	31	6,228	197,714,286
2016/17	26	7,326	281,769,231	26	6,857	263,730,769	32	6,190	193,453,125	32	6,223	194,468,750
2017/18	26	7,386	284,076,923	26	6,917	266,038,462	32	6,275	196,109,375	32	6,338	198,062,500
2018/19	26	7,413	285,115,385	26	6,963	267,807,692	32	6,240	195,015,625	32	6,478	202,437,500
2019/20	26	7,513	288,961,538	26	7,063	271,653,846	32	6,390	199,703,125	32	6,448	201,500,000
2020/21	26	7,613	292,807,692	26	7,163	275,500,000	32	6,550	204,703,125	32	6,578	205,562,500
2021/22	26	7,713	296,653,846	26	7,263	279,346,154	32	6,650	207,828,125	32	6,688	209,000,000
2022/23	26	7,813	300,500,000	26	7,363	283,192,308	32	6,750	210,953,125	32	6,798	212,437,500
2023/24	26	7,913	304,346,154	26	7,463	287,038,462	32	6,850	214,078,125	32	6,898	215,562,500
2024/25	26	8,013	308,192,308	26	7,563	290,884,615	32	6,950	217,203,125	32	6,998	218,687,500
2025/26	26	8,113	312,038,462	26	7,663	294,730,769	32	7,050	220,328,125	32	7,098	221,812,500
2026/27	26	8,213	315,884,615	26	7,763	298,576,923	32	7,150	223,453,125	32	7,198	224,937,500
2027/28	26	8,313	319,730,769	26	7,863	302,423,077	32	7,250	226,578,125	32	7,298	228,062,500
2028/29	26	8,413	323,576,923	26	7,963	306,269,231	32	7,350	229,703,125	32	7,398	231,187,500
2029/30	26	8,513	327,423,077	26	8,063	310,115,385	32	7,450	232,828,125	32	7,498	234,312,500
2030/31	.	.	.	26	8,163	313,961,538	32	7,550	235,953,125	32	7,598	237,437,500
2031/32	.	.	.	.	.	.				32	7,698	240,562,500

MIPUG/MH I-39

Subject: CAC/MSOS/MH I-127 from 2010 GRA

a) Please update CAC/MSOS/MH I-127(a) through (c) for actual costs through the end of the 2011/12 year.

ANSWER:

Please refer to the attached schedules.

Electric Regulatory Costs by Proceeding

April 1, 2007 - August 31, 2012 (000s)

	Cost of Service Hearing 05/06	Electric GRA 2008/09	Energy Intensive Hearing	Electric GRA 2010/11 & 2011/12 & KPMG Report	Electric GRA 2012/13 & 2013/14	Other Regulatory	Diesel Applications	Total
Intervenor Costs	-	330	97	839	-	-	52	1,318
PUB Advisor Costs	129	1,369	473	3,996	397	83	170	6,617
PUB fees	1	-	-	-	-	1,735	-	1,736
External Costs	-	-	-	3,408	-	-	-	3,408
Internal Costs	6	1,715	242	3,492	252	522	607	6,835
Grand Total	$ 137	$ 3,414	$ 811	$ 11,734	$ 649	$ 2,340	$ 829	19,914

Internal Electric Regulatory Costs by Fiscal Year

April 1, 2007 - August 31, 2012 (000s)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Total
Cost of Service Hearing 05/06	5	1	-	-	-	-	$ 6
Electric GRA 08/09	1,228	442	45	0	-	-	$ 1,715
Energy Intensive Hearing	0	188	10	21	19	5	$ 242
Electric GRA 11/12 & KPMG Report	-	-	1,230	1,748	512	2	$ 3,492
Electric GRA 2012/13 & 2013/14	-	-	-	-	71	181	$ 252
Other Regulatory	11	28	107	87	33	255	$ 522
Diesel Applications	14	43	62	308	147	33	$ 607
	$ 1,259	$ 701	$ 1,455	$ 2,163	$ 782	$ 476	6,835

Summary of Electric Regulatory Costs by Fiscal Year

April 1, 2007 - August 31, 2012 (000s)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Total
Intervenor Costs	-	325	109	112	772	-	1,318
PUB Advisor Costs	645	923	884	2,325	1,436	405	6,617
PUB fees	314	328	320	322	323	130	1,736
External Costs	-	-	2,802	408	198	-	3,408
Internal Costs	1,259	701	1,455	2,163	782	476	6,835
	$ 2,218	$ 2,277	$ 5,569	$ 5,330	$ 3,510	$ 1,010	19,914

MIPUG/MH I-40

Subject: 2012 Load Forecast and MIPUG/MH I-11(a) and (b) from 2010 GRA

a) Please provide a schedule, similar to MIPUG/MH I-11(a) (i) and (ii) from the 2010 GRA proceeding, that compares for 2000 to 2012 load forecasts for each GSL <30kV, GSL 30-100kV, and GSL >100kV:

i. Manitoba Hydro's forecast (kW.h) to GSL customers for each of the next 20 years (i.e. the 2000 load forecast should show sales forecasts for 2001 through 2020, etc)

ii. Manitoba Hydro's actual sales to GSL customers for 2000 through 2012.

ANSWER:

The tables on the following pages provide forecast sales (GW.h) from the 2000 to 2011 System Load Forecasts for fiscal years 2000/01 to 2030/31 inclusive for each General Service Large sub-class. The last table provides actual data for the period 2000 to 2012. Limited Use of Billing Demand (LUBD) sales are not included in these figures.

LARGE 750-30 kV (Forecast GW.h)

FIS YR	YEAR OF SYSTEM LOAD FORECAST											
ENDING	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	1,175											
2002	1,224	1,159										
2003	1,273	1,178	1,158									
2004	1,323	1,201	1,204	1,194								
2005	1,366	1,230	1,226	1,233	1,471							
2006	1,406	1,260	1,248	1,271	1,494	1,509						
2007	1,442	1,287	1,266	1,288	1,512	1,521	1,565					
2008	1,475	1,317	1,282	1,305	1,527	1,586	1,636	1,546				
2009	1,505	1,349	1,297	1,322	1,543	1,629	1,657	1,573	1,530			
2010	1,523	1,382	1,310	1,338	1,559	1,643	1,681	1,585	1,558	1,558		
2011	1,541	1,417	1,331	1,354	1,576	1,661	1,692	1,602	1,575	1,574	1,606	
2012	1,560	1,451	1,354	1,370	1,599	1,683	1,706	1,623	1,593	1,591	1,624	1,688
2013	1,578	1,481	1,379	1,385	1,622	1,706	1,724	1,646	1,611	1,611	1,646	1,743
2014	1,596	1,509	1,402	1,401	1,646	1,729	1,744	1,661	1,637	1,633	1,658	1,831
2015	1,613	1,534	1,424	1,419	1,669	1,752	1,763	1,675	1,660	1,645	1,677	1,891
2016	1,630	1,557	1,445	1,439	1,692	1,772	1,782	1,690	1,681	1,665	1,689	1,951
2017	1,646	1,577	1,467	1,458	1,715	1,792	1,801	1,706	1,704	1,685	1,706	2,011
2018	1,661	1,595	1,489	1,477	1,737	1,813	1,820	1,722	1,724	1,706	1,725	2,066

2019	1,675	1,611	1,511	1,496	1,758	1,834	1,840	1,743	1,743	1,729	1,746	2,116
2020	1,688	1,626	1,533	1,516	1,780	1,857	1,860	1,765	1,763	1,750	1,764	2,166
2021	1,701	1,638	1,556	1,536	1,801	1,879	1,880	1,788	1,781	1,770	1,783	2,216
2022		1,649	1,579	1,555	1,822	1,902	1,900	1,811	1,800	1,790	1,802	2,265
2023			1,603	1,575	1,842	1,925	1,920	1,833	1,819	1,811	1,822	2,315
2024				1,596	1,861	1,948	1,940	1,856	1,837	1,831	1,841	2,365
2025					1,880	1,971	1,960	1,878	1,856	1,851	1,861	2,415
2026						1,994	1,980	1,902	1,874	1,873	1,881	2,460
2027							2,000	1,925	1,892	1,894	1,902	2,505
2028								1,950	1,911	1,916	1,923	2,550
2029									1,929	1,938	1,944	2,590
2030										1,961	1,966	2,630
2031											1,987	2,669

LARGE 30 - 100 kV (Forecast GW.h)

FIS YR	YEAR OF SYSTEM LOAD FORECAST											
ENDING	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	535											
2002	623	505										
2003	682	646	679									
2004	739	758	694	784								
2005	743	772	701	888	736							
2006	746	785	708	891	771	807						
2007	750	798	715	877	806	1,022	861					
2008	753	810	723	863	837	1,277	990	964				
2009	757	821	730	849	867	1,457	1,117	1,218	990			
2010	760	833	737	835	897	1,605	1,257	1,368	1,154	944		
2011	763	845	745	821	900	1,628	1,396	1,474	1,273	853	912	
2012	764	848	752	807	898	1,627	1,451	1,479	1,345	868	844	1,049
2013	766	851	755	809	896	1,624	1,453	1,483	1,353	855	845	1,067
2014	768	854	759	812	895	1,622	1,455	1,488	1,356	906	910	1,219
2015	770	857	761	814	895	1,620	1,457	1,492	1,358	1,091	914	1,243
2016	772	860	763	816	896	1,622	1,458	1,496	1,361	1,095	968	1,292
2017	774	863	766	819	897	1,624	1,460	1,499	1,362	1,099	1,045	1,366
2018	776	866	768	821	899	1,627	1,462	1,503	1,365	1,102	1,048	1,399

2019	777	869	770	824	901	1,629	1,463	1,505	1,369	1,103	1,050	1,366
2020	779	871	773	826	903	1,631	1,464	1,507	1,372	1,107	1,055	1,414
2021	781	874	775	829	905	1,632	1,465	1,509	1,375	1,111	1,059	1,470
2022		876	778	831	907	1,634	1,467	1,511	1,379	1,116	1,063	1,478
2023			780	834	911	1,636	1,468	1,513	1,382	1,120	1,067	1,485
2024				836	914	1,638	1,469	1,515	1,386	1,124	1,072	1,493
2025					917	1,640	1,470	1,517	1,389	1,128	1,076	1,501
2026						1,641	1,471	1,519	1,392	1,132	1,081	1,508
2027							1,472	1,522	1,396	1,136	1,085	1,516
2028								1,524	1,399	1,140	1,089	1,524
2029									1,403	1,144	1,094	1,531
2030										1,149	1,098	1,538
2031											1,103	1,545

LARGE >100 (Forecast GW.h)

FIS YR	YEAR OF SYSTEM LOAD FORECAST											
ENDING	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	3,991											
2002	4,319	4,173										
2003	4,385	4,445	4,474									
2004	4,426	4,607	4,480	4,687								
2005	4,526	4,739	4,577	4,880	4,833							
2006	4,626	4,871	4,673	4,950	5,132	5,089						
2007	4,726	5,003	4,789	5,061	5,436	5,122	5,135					
2008	4,826	5,085	4,905	5,163	5,580	5,205	5,213	5,158				
2009	4,926	5,168	5,021	5,244	5,714	5,309	5,285	5,378	5,390			
2010	5,026	5,250	5,137	5,325	5,828	5,442	5,545	5,823	5,633	5,018		
2011	5,121	5,332	5,254	5,406	5,928	5,536	5,805	6,011	5,952	5,354	4,700	
2012	5,176	5,402	5,370	5,498	5,828	5,469	5,995	6,195	6,246	5,635	5,079	4,718
2013	5,231	5,472	5,470	5,588	5,728	5,349	6,055	6,371	6,531	5,829	5,207	4,928
2014	5,286	5,542	5,570	5,668	5,648	5,229	6,115	6,547	6,591	5,920	5,496	5,084
2015	5,341	5,612	5,640	5,748	5,658	5,109	6,175	6,709	6,651	6,078	5,620	5,092
2016	5,396	5,682	5,710	5,828	5,668	5,184	6,235	6,871	6,711	6,178	5,738	4,882
2017	5,451	5,752	5,780	5,908	5,678	5,259	6,295	6,997	6,731	6,278	5,859	4,873
2018	5,506	5,822	5,850	5,988	5,738	5,334	6,355	7,123	6,831	6,338	5,919	4,934

2019	5,561	5,892	5,920	6,068	5,798	5,409	6,385	7,189	6,931	6,365	5,965	4,939
2020	5,616	5,962	5,990	6,148	5,858	5,459	6,415	7,255	7,031	6,465	6,065	5,049
2021	5,671	6,032	6,060	6,228	5,918	5,509	6,445	7,321	7,131	6,565	6,165	5,161
2022		6,102	6,130	6,308	5,978	5,559	6,475	7,387	7,231	6,665	6,265	5,261
2023			6,200	6,388	6,088	5,609	6,505	7,453	7,331	6,765	6,365	5,361
2024				6,468	6,198	5,659	6,535	7,519	7,431	6,865	6,465	5,461
2025					6,308	5,709	6,565	7,585	7,531	6,965	6,565	5,561
2026						5,759	6,595	7,651	7,631	7,065	6,665	5,661
2027							6,625	7,717	7,731	7,165	6,765	5,761
2028								7,783	7,831	7,265	6,865	5,861
2029									7,931	7,365	6,965	5,961
2030										7,465	7,065	6,061
2031											7,165	6,161

ACTUALS (GW.h)

FISC YR ENDING	LARGE 750-30	LARGE 30-100	LARGE >100
2000	1,101	492	3,473
2001	1,132	474	3,975
2002	1,130	457	4,282
2003	1,180	620	4,574
2004	1,463	735	4,615
2005	1,487	782	4,871
2006	1,531	776	5,115
2007	1,545	856	5,094
2008	1,546	905	5,154
2009	1,534	936	5,140
2010	1,545	941	4,523
2011	1,630	972	4,401
2012	1,599	1,164	4,412

MIPUG/MH I-40

Subject: 2012 Load Forecast and MIPUG/MH I-11(a) and (b) from 2010 GRA

b) Please provide a table similar to what was provided in MIPUG/MH I-11 of the 2010 GRA that separates the 2011 and 2012 Load Forecasts for each GS class and subclass for all forecast years in each Load Forecast.

ANSWER:

The following two tables provide the breakdown of the General Service forecast sector into its sub-classes based on the 2011 System Load Forecast. This level of detail, based on the 2012 Load Forecast is not yet available.

	Total GS	Small Non-Dem Demand	Small Demand	Small LUBD	Med Demand	Med LUBD	SEP Med	SEP Large <30
2012	14,181.7	1,619.9	1,950.7	4.3	3,102.3	4.1	23.5	2.1
2013	14,560.2	1,625.6	2,004.7	4.4	3,138.2	4.2	23.5	2.1
2014	15,062.2	1,632.2	2,064.6	4.6	3,202.5	4.3	-	-
2015	15,258.8	1,638.8	2,125.3	4.7	3,240.1	4.3	-	-
2016	15,265.0	1,645.6	2,185.9	4.9	3,279.3	4.4	-	-
2017	15,493.9	1,652.3	2,245.7	5.0	3,317.0	4.4	-	-
2018	15,747.5	1,658.9	2,304.7	5.1	3,356.3	4.5	-	-
2019	15,866.9	1,665.3	2,360.4	5.3	3,390.9	4.5	-	-
2020	16,168.9	1,671.6	2,413.8	5.4	3,425.4	4.6	-	-
2021	16,480.1	1,677.9	2,466.4	5.5	3,460.0	4.6	-	-
2022	16,729.1	1,684.4	2,518.2	5.6	3,492.9	4.7	-	-
2023	16,977.1	1,691.0	2,569.0	5.7	3,525.9	4.7	-	-
2024	17,222.6	1,697.8	2,618.5	5.8	3,557.4	4.8	-	-
2025	17,467.3	1,704.9	2,667.1	6.0	3,588.8	4.8	-	-
2026	17,708.8	1,712.9	2,715.3	6.1	3,621.4	4.9	-	-
2027	17,948.0	1,721.3	2,762.3	6.2	3,652.5	4.9	-	-
2028	18,185.8	1,730.4	2,808.3	6.3	3,682.3	4.9	-	-
2029	18,416.9	1,740.2	2,852.8	6.4	3,712.0	5.0	-	-
2030	18,645.9	1,750.8	2,896.1	6.5	3,740.3	5.0	-	-
2031	18,873.2	1,762.5	2,938.0	6.6	3,766.9	5.0	-	-

	Large <30 kV	Large LUBD <30kV	Large 30-100	Large >100	Large LUBD >100	Seas.	FRWH	Diesel Fed Gov	Diesel Prov Gov	Diesel Non - Gov
2012	1,687.5	1.3	1,049.1	4,718.2	1.2	4.7	7.4	1.8	0.4	3.3
2013	1,742.9	1.4	1,066.5	4,928.2	1.2	4.7	7.1	1.8	0.4	3.4
2014	1,831.5	1.5	1,218.8	5,084.2	1.2	4.8	6.7	1.8	0.4	3.4
2015	1,891.3	1.6	1,242.5	5,092.2	1.2	4.8	6.4	1.8	0.4	3.4
2016	1,951.2	1.7	1,292.3	4,882.2	1.2	4.8	6.1	1.8	0.4	3.4
2017	2,011.0	1.8	1,366.0	4,873.2	1.2	4.8	5.8	1.8	0.4	3.5
2018	2,065.8	1.9	1,398.9	4,934.2	1.2	4.9	5.5	1.8	0.4	3.5
2019	2,115.9	2.0	1,366.5	4,939.2	1.2	4.9	5.2	1.9	0.4	3.5
2020	2,165.6	2.1	1,414.5	5,049.2	1.2	4.9	5.0	1.9	0.4	3.6
2021	2,215.7	2.2	1,470.0	5,161.2	1.2	5.0	4.7	1.9	0.4	3.6
2022	2,265.3	2.3	1,478.0	5,261.2	1.2	5.0	4.5	1.9	0.4	3.6
2023	2,315.4	2.4	1,485.4	5,361.2	1.2	5.0	4.2	1.9	0.4	3.7
2024	2,365.1	2.5	1,493.3	5,461.2	1.2	5.0	4.0	1.9	0.4	3.7
2025	2,415.2	2.6	1,500.8	5,561.2	1.2	5.1	3.8	1.9	0.4	3.7
2026	2,460.2	2.6	1,508.3	5,661.2	1.2	5.1	3.6	2.0	0.4	3.7
2027	2,505.2	2.7	1,515.8	5,761.2	1.2	5.1	3.5	2.0	0.4	3.8
2028	2,549.8	2.8	1,524.0	5,861.2	1.2	5.1	3.3	2.0	0.4	3.8
2029	2,589.7	2.9	1,531.0	5,961.2	1.2	5.2	3.1	2.0	0.4	3.8
2030	2,629.6	3.0	1,537.9	6,061.2	1.2	5.2	3.0	2.0	0.4	3.9
2031	2,669.5	3.1	1,544.9	6,161.2	1.2	5.2	2.8	2.0	0.4	3.9

MIPUG/MH I-41

Subject: Manitoba Hydro Risk Presentations Exhibit MH-4 from 2010 GRA

a) Please indicate if there are any updates to the energy supply graph over all flow scenarios (as included at page 310 of the MIPUG Book of Documents, Exhibit MIPUG#12). If so, please provide an updated graph for 2013.

ANSWER:

Manitoba Hydro does not have available an update to the energy supply graph over all flow conditions.

MIPUG/MH I-41

Subject: Manitoba Hydro Risk Presentations Exhibit MH-4 from 2010 GRA

b) Please indicate if similar graphs are (or could be) produced for future years as per the respective Power Resource Plans.

ANSWER:

With reference to the energy supply graph from page 310 of the MIPUG Book of Documents, Exhibit MIPUG#12, 2010 GRA, similar graphs are only produced on a case by case basis and are not readily available for future years.

MIPUG/MH I-42

Subject: Attachment 4, Economic Outlook 2012-2033

a) Please file growth scenario data for EO2012, as per the growth scenarios presented in the Appendix of EO09-1.

ANSWER:

Growth scenario data for EO2012 can be found in Appendix C of the 2012 Economic Outlook.

MIPUG/MH I-43

Subject: Appendix 4.2-Consolidated Integrated Financial Forecast IFF11-2

a) Please provide a detailed explanation of the basis for forecasting water flows, by year, in IFF11-2.

ANSWER:

A forecast of flows for the first year (2011/12) wasn't required because IFF11-2 was completed after April 1st, 2012. Instead, 2011/12 was based on actual data.

The second year of IFF11-2 (2012/13) was based on expected inflows, where the spring runoff flows were were forecast based on antecedent precipitation conditions from September 2011 to April 2012.

For 2013/14 and for later years in IFF11-2, Manitoba Hydro assumes that flows from each year of the historic record are possible and calculates average flow related revenues and average flow related costs for each of the 18 years.

MIPUG/MH I-43

Subject: Appendix 4.2-Consolidated Integrated Financial Forecast IFF11-2

b) Please indicate if the approach set out in (a) above is different in any way than previous IFFs over the past 5 years.

ANSWER:

Yes, for the first two years of IFF11-2, the approach was different than IFFs over the past 5 years because of the timing of IFF preparation, and prior knowledge of water conditions.

Typically the IFF is prepared in mid-year, meaning the first year of the forecast is comprised of actual data and forecast flow related revenues and costs. The forecast period of the first year is based on 'expected' inflows. The expected inflow forecast is developed using knowledge of antecedent inflow and basin conditions leading up to the date the forecast is prepared.

Typically the second year of the IFF is based on median inflows. However, because of the timing when the forecast was prepared and knowledge of dry fall antecedent conditions and very low winter snow pack, Manitoba Hydro forecast below average flows for 2012/13.

The approach used for the third and subsequent years was unchanged from prior IFFs.

MIPUG/MH I-43

Subject: Appendix 4.2-Consolidated Integrated Financial Forecast IFF11-2

c) If the answer to (b) is yes (i.e., the approach is different), please provide a detailed explanation of the rationale for the change in method, the date of adoption of the change in method, and cite the specific IFFs to which the new method have been applied.

ANSWER:

The change in method for IFF11-2 was due to the date the forecast was prepared (April 2012) combined with the near record dry conditions leading up to the preparation of the IFF which strongly indicated that spring runoff would be well below normal. Please refer to parts (a) and (b) of this IR for rationale for the change in method. This is the first IFF in which the second year of the forecast had not assumed median inflows.

MIPUG/MH I-43

Subject: Appendix 4.2-Consolidated Integrated Financial Forecast IFF11-2

d) Please provide a detailed explanation of the approach to determining the "expected" conditions.

ANSWER:

The expected inflow conditions for the beginning of the second year of the IFF11-2 (2012/13) were based on a regression relationship between antecedent precipitation conditions (explanatory variable) versus future spring Hydraulic Energy from Inflows (HEFI) as the dependent variable. The observed precipitation (% of normal) from September 2011 to March 2012 (the antecedent condition) was applied to the regression relationship to determine the expected April to June 2012 HEFI. The remaining fiscal year volume from July 2012 to March 2013 was defined using a second regression relationship between June HEFI (as the explanatory variable) predicting July to March HEFI (as the dependent variable).

MIPUG/MH I-43

Subject: Appendix 4.2-Consolidated Integrated Financial Forecast IFF11-2

e) Please provide a detailed comparison of the water flows assumed in each year between the previous IFF approach and the current IFF approach, if different (by unit of inflow).

ANSWER:

The requested comparison in river flows is provided in the table below. The "previous" approach for 2012/13 water flows assumed median monthly inflows to reservoirs combined with expected storage carry over from 2011/12. IFF11-2 was based on storage conditions and expected inflows (based upon antecedent precipitation conditions) as of April 2012.

Table 1: Generating Station Outflows

	Slave Falls GS		Grand Rapids GS		Jenpeg GS		Kettle GS	
Inlow Case -->	Median Inflows	Expected Inflows per IFF11-2	Median Inflows	Expected Inflows per IFF11-2	Median Inflows	Expected Inflows per IFF11-2	Median Inflows	Expected Inflows per IFF11-2
Apr_2012	31.5	21.8	22.5	19.7	83.2	37.5	130.0	100.9
May_2012	32.7	16.9	16.5	17.4	80.8	35.7	144.0	95.8
Jun_2012	31.1	20.8	8.0	20.6	74.5	43.8	144.1	105.5
Jul_2012	29.5	27.5	9.5	18.9	70.1	56.6	141.4	116.2
Aug_2012	29.4	28.4	24.1	24.1	57.6	37.4	125.9	106.8
Sep_2012	25.4	17.0	7.0	7.0	35.5	43.2	101.9	94.7
Oct_2012	28.8	28.9	25.7	7.0	65.9	55.9	108.9	98.5
Nov_2012	29.5	26.8	24.2	7.0	71.8	71.8	116.1	108.1
Dec_2012	34.0	31.4	34.5	26.3	81.5	80.4	119.6	111.5
Jan_2013	33.6	31.8	34.0	31.3	73.0	72.1	118.6	125.2
Feb_2013	33.2	31.3	24.1	25.9	66.6	66.3	113.8	114.2
Mar_2013	30.8	30.5	13.1	7.0	34.9	34.9	94.1	102.6

MIPUG/MH I-43

Subject: Appendix 4.2-Consolidated Integrated Financial Forecast IFF11-2

f) Please provide a detailed comparison of the financial impacts, for each year of IFF11-2, of any change in approach to forecasting water flows.

ANSWER:

Financial Forecasts are consistently based on the most recent available water flow information at the time of preparation. There was no change in approach to forecasting water flows in IFF11-2.

MIPUG/MH I-43

Subject: Appendix 4.2-Consolidated Integrated Financial Forecast IFF11-2

g) If the answer to part (a) is no (the approach has not changed), please provide a detailed explanation of the meaning of the paragraph at the top of page 17 of PCOSS13, which indicates that the financial forecast in IFF11-2 "incorporates expected water flow conditions rather than the median flow water conditions normally used".

ANSWER:

Please see Manitoba Hydro's responses to MIPUG/MH I-43(a) and (b).

MIPUG/MH I-43

Subject: Appendix 4.2-Consolidated Integrated Financial Forecast IFF11-2

h) Please indicate if the quote "Expected flows in this case are lower than under median conditions, which can be expected to result in a reduction in opportunity export sales" from PCOSS13, page 17, will be true in every year, or whether in some years expected flows will be higher than median flows.

ANSWER:

Typically median water flows are used in the preparation of the IFF test period (and therefore in the preparation of the PCOSS). However, given that IFF11-2 was prepared in late fiscal 2011/12, expected water flows were used in its preparation (and therefore in the preparation of PCOSS13) to reflect the greater than normal likelihood that there would be below average winter snowmelt and spring runoff.

In other years, if the IFF is prepared at a time when antecedent conditions are indicative of water flows in the test year (and therefore used in the PCOSS), higher or lower than median flows may be indicated.

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

a) Please clarify that Manitoba Hydro is requesting the Board to approve the Curtailable Rate "Proposed Terms and Conditions" at Appendix 10.4 to become effective April 1, 2013.

ANSWER:

CRP rates are formula driven and change from time to time. The process for approving CRP rates contemplates that Manitoba Hydro will submit applications as necessary and the PUB will issue interim approval provided the rates are in accordance with the established formula and Terms and Conditions reviewed at the GRA.

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

b) Please explain what is meant by "Effective immediately upon confirmation that the PUB accepts the rate approval process given the modifications to the CRP Terms and Conditions…" set out in Tab 10, page 7. Is Manitoba Hydro asking the Board to approve the revised caps? Is this approval proposed to be effective April 1, 2013?

ANSWER:

Manitoba Hydro expects to implement the CRP changes in accordance with the PUB's recommendations effective April 1, 2013.

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

c) Please indicate the criteria Manitoba Hydro proposes to apply in determining whether to “exclude” a customer from the Curtailable Rate Program in the event that two or more failures to curtail occur in a twelve month period.

ANSWER:

A customer’s failure to curtail could jeopardize Manitoba Hydro’s ability to meet obligations with the MH-MISO Contingency Reserve Sharing Group. The criteria to exclude a customer from the Curtailable Rate Program is that the customer fails to curtail in two or more events in a twelve month period. Based on the program’s history this situation seems unlikely.

However, in the event of such a situation occuring, Manitoba Hydro would review the circumstances of the customers’ failure to curtail and, if finding no mitigating circumstances that were beyond the customer’s control, the customer could be excluded from the program.

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

d) Please provide the April 1, 2010 to March 31, 2011 Curtailable report, as well as the April 1, 2009 to March 31, 2010 report.

ANSWER:

Please see the attachments to this response.

Manitoba Hydro

REPORT TO THE PUBLIC UTILITIES BOARD

CURTAILABLE RATE PROGRAM

APRIL 1, 2010 – MARCH 31, 2011

OCTOBER 2011

TABLE OF CONTENTS

Page No.

REPORT TO PUBLIC UTILITIES BOARD
CURTAILABLE RATE PROGRAM
APRIL 1, 2010 – MARCH 31, 2011

SUMMARY

This annual report on the status of the Curtailable Rate Program (CRP) covers the period April 1, 2010 to March 31, 2011. Three customers participated in the program throughout the year, a decline of one Option A customer from the previous year. Production for this customer dropped in September 2009 below the minimum 5 MW of nominal curtailable load required for participation in the program, making available 52 MW of load under the current cap limitation.

There were 15 Option R curtailments and 2 Option A curtailments called during the 12 month reporting period, all of which were successfully initiated.

The Reference Discount of $3.08/kW/month for the 2010/11 reporting year was approved by the Public Utilities Board in Order 42/10 dated April 27, 2010. Customers received credit on their monthly electrical bill for their participation in the program, totaling $5,733,911 for the fiscal year.

BACKGROUND

The CRP Terms and Conditions applicable during the reporting period April 1, 2010 to March 31, 2011 took effect April 1, 2005 in accordance with Board Order No. 28/05 dated February 17, 2005. A slight modification to the Terms and Conditions was approved in Board Order 90/08 dated June 30, 2008 which required customers to provide Manitoba Hydro 48 hours notice period of any anticipated plant shut downs.

The Terms and Conditions allow Manitoba Hydro to reserve the right to limit the amount of total curtailable load used for maintaining operating and contingency reserves[1]. The current

[1] Per North American Electric Reliability Council (NERC) Glossary of Terms, Operating Reserves: The reserves needed to protect Manitoba Hydro and its obligations to the Midwest Independent System Operator power system against Contingencies or Disturbances. These events are typically a result of loss of supply caused by sudden generating or transmission outages. Operating Reserves consist of various types including Contingency Reserves. Contingency Reserves: a component of Operating Reserves which are sufficient in magnitude and response to meet NERC Disturbance Control Standards. Contingency Reserves are comprised of Operating Reserves-Spinning and Operating Reserves-Supplemental. Curtailable load (also referred to as Interruptible Load) can be a source of Operating Reserves-Supplemental.

limit is set at 230 MW under Options A and C and 100 MW under Option R. There is no limit for Option E load. The caps have been beneficial to both Manitoba Hydro and curtailable customers by ensuring the value of curtailable load does not depreciate. A decreased value would result in lower discounts paid to customers making the program less attractive to them.

Manitoba Hydro uses curtailable load, among other measures, to maintain operating and contingency reserves as a means of minimizing disruption to firm customers in the event of loss of generation or transmission.

Curtailable load provides value to Manitoba Hydro all year round, as curtailments for system emergencies can occur at any time of the year. However, it has the greatest value during peak times as it is during the peak periods that Manitoba Hydro's capacity surplus is the least. Additional Options A and C curtailable load in these hours increases the amount of capacity for sale in the firm export markets while additional Option R load can allow Manitoba Hydro to meet its contingency reserve obligations at a lower cost.

A significant risk mitigation benefit of curtailable load is not having the need to shed firm load should Manitoba Hydro be in a situation where it would otherwise be the cause of Manitoba Hydro or the Midwest Independent System Operator–Manitoba Hydro Contingency Reserve Sharing Group (MISO-MBHydro CRSG)[2] being non-compliant to North American Electric Reliability Council (NERC) Standard(s). Option R curtailable load allows Manitoba Hydro to meet our reserve obligation thereby freeing up hydro generation for market transactions in the short-term opportunity energy market[3]. In this circumstance the benefits of having Option R available are dependent on Manitoba Hydro's water supply conditions as follows:

- High Water Supply - the generating capacity freed up for commercial use allows for increased hydraulic generation for export as idle generating units can be run to capture additional on peak sales. Without Option R capacity in place on peak energy would be spilled. With Option R load, the additional energy generated can be sold at on peak prices.

[2] The MISO-MBHydro CRSG is a NERC registered Contingency Reserve Sharing Group that has operated since January 1, 2010. The CRSG was established under the terms of the Amended MISO-Manitoba Hydro Coordination Agreement and executed on October 9, 2009.

[3] Opportunity export sales are sales of capacity and/or energy that are not backed by dependable energy and are incremental exports that arise from time to time as a result of water conditions that are better than the lowest historic.

- Average Water Supply - allows for additional hydraulic generation during on-peak hours that would otherwise be produced during off-peak hours (due to limited on-peak generating capability). In this case Manitoba Hydro captures the benefit of the price differential between on and off-peak periods.

- Low Water Supply - does not provide any significant benefits because Manitoba Hydro has sufficient shut down generating units that could be run temporarily for operating reserves purposes without relying on Option R load reductions.

Manitoba Hydro will not utilize curtailable load in order to facilitate a high value opportunity spot market sale[4].

PERFORMANCE FOR 2010/11

Curtailment Options:

The Curtailable Rate Program consists of four base curtailment options and three combinations. Options vary dependent on: minimum notice to curtail, maximum duration per curtailment, maximum daily hours of curtailment, maximum number of curtailments per year, and maximum annual hours of curtailment.

The three customers that participated in the Curtailable Rate Program during the April 1, 2010 to March 31, 2011 period designated a total of 228 MW to Manitoba Hydro's reserves, allocated as 80 MW Option AE, 67 MW Option A, 31 MW Option C and 50 MW Option R. (Note Option R increased from 40 MW to 50 MW on May 1, 2010). The amount each customer designated as curtailable load in relation to their total load varies, and therefore impacts their curtailable credit, as shown on the following table:

Summary of Curtailment Credit Data April 1, 2010 to March 31, 2011					
Customer	**Option(s)**	**CRP Load as % of Total Load**	**Average On-Peak MW**	**Average On-Peak LF**	**Average Monthly Cr.**
1	A, R, E	87%*	192.2	94.2%	$417,410
2	A	94%	27.2	94.9%	$52,618
3	C	22%	42.1	69.3%	$7,798

*Customer 1: 87% of total load represents 41% Option AE, 26% Option R and 20% Option A for 2010/11.

[4] Spot market sales are sales that occur on a day ahead or real time basis. They are not considered to be a firm export sale.

Load designated under Option R must be nominated as a Guaranteed Curtailment, that is, the customer must agree to shed a specified number of MW in order to be compliant with the curtailment request. Under all the other curtailment options, customers can nominate curtailable load as Guaranteed Curtailment or Curtail to Protected Firm Load.

Dependent on the curtailment option selected, Manitoba Hydro will curtail customers to meet reliability obligations only. Options A, C and R curtailments assist in securing operating and contingency reserves whereas Option E curtailments are initiated to meet firm energy requirements in the event that Manitoba Hydro expects to be short of firm energy supplies.

Customers may nominate different quantities of curtailable or firm load for each month provided that a minimum of 5 MW of curtailable load is available in each month. Customers must specify the 12 months Guaranteed Load or 12 months Protected Firm Load prior to participation in the program and must provide 12 months' written notice to Manitoba Hydro should they wish to increase or decrease their load in any month. This may be subject to capacity limitations and will be at the discretion of Manitoba Hydro. To date no customers have elected to differentiate their monthly load.

Implementation and Size of Curtailments:

There were 17 curtailments during the April 1, 2010 to March 31, 2011 period: two Option A and 15 Option R curtailments. The two Option A curtailments were initiated to protect firm export schedules following a CRSG event. The 15 Option R were initiated in response to emergency energy requirements as part of Manitoba Hydro's supplemental reserves requirement. There were no Option C curtailments. The following table summarizes the duration and load in MW of each curtailment.

April 2010 to March 2011	Customer 1 Option 'A'		Customer 1 Option 'R'		Customer 2 Option 'A'		Customer 3 Option 'C'	
	Hrs	MW	Hrs	MW	Hrs	MW	Hrs	MW
April 13, 2010			0.67	40				
April 20, 2010			0.82	40				
May 14, 2010			1.07	50				
July 25, 2010			0.75	50				
July 25, 2010			0.73	50				
July 26, 2010			1.17	50				
October 27, 2010			0.97	50				
November 2, 2010			0.80	50				

April 2010 to March 2011	Customer 1 Option 'A'		Customer 1 Option 'R'		Customer 2 Option 'A'		Customer 3 Option 'C'	
	Hrs	MW	Hrs	MW	Hrs	MW	Hrs	MW
November 19, 2010	0.58	124	0.88	50	0.58	25		
November 24, 2010			0.28	50				
November 26, 2010			0.12	50				
December 1, 2010			0.27	50				
December 20, 2010			1.05	50				
January 9, 2011			0.97	50				
March 18, 2011			0.47	50				
Total	**0.58**	**124**	**11.02**	**730**	**0.58**	**25**	**0**	**0.00**
Average	**0.58**	**124**	**0.73**	**49**	**0.58**	**25**	**0**	**0.00**

All curtailments occurred during peak hours. Customer(s) did not use an alternative power source to supply their load during the curtailments.

Manitoba Hydro continues to use telephone to communicate curtailment requirements to the three customers on the program. This procedure is manageable and provides the additional security the curtailment(s) will be initiated by confirmation from an agent of the customer. Manitoba Hydro experienced no difficulties in communicating the 17 curtailments during this reporting period to the customer.

Reference and Reserve Discounts:

The maximum discount available to a participating customer is called the “Reference Discount.” The Reference Discount is related to the marginal value of capacity, expressed in Canadian Dollars, and was set at $2.75 per kW/month as of April 1, 2005. This amount is adjusted on April 1 of each year by the inflation factor (the change in Manitoba Consumer Price Index as recorded for the most recent 12 months). Each year Manitoba Hydro submits an application for the adjusted Reference Discount to the PUB for *ex parte* approval.

The Reference Discount in effect for the reporting period April 1, 2010 to March 31, 2011 was $3.08/kW/month, approved on April 27, 2010 via Board Order 42/10. Customers under Option AE receive 100% of the discount, while customers under Option A and Option R receive 70% of the discount or $2.16 per kW/month. Option C customers receive 40% of the discount or $1.23 per kW/month.

For curtailable load nominated as ‘Protect to Firm Load’ the Reference Discount is calculated and credited to customers’ bill each month as (A - B) x C x D where:

A = On-Peak Period Demand (kW)
B = Protected Firm Load (kW)
C = On-Peak Period Load Factor
D = Discount Amount

For curtailable load designated as a 'Guaranteed Curtailment' the Reference Discount is calculated and credited to customers' bill each month as GC x D where,

GC = the customer's guaranteed curtailable load
D = Discount Amount

Customers selecting Curtailment Option R receive, in addition to the Reference Discount, a Reserve Discount for each curtailment initiated and successfully completed. The Reserve Discount represents the value of carrying contingency reserves and is calculated and credited to customers' bill for each successful curtailment as LR x Du x FD where,

LR = amount of load reduction (in kW) requested by Manitoba Hydro's System Control to the customer at the time of an Option R curtailment
Du = duration of the curtailment (in hours)
FD = fixed discount amount, currently set at $0.04[5] per kWh

The monthly Reference Discount Credit, each customer received from April 1, 2010 to March 31, 2011 as well as their monthly On-Peak Demand and On-Peak Load Factor have been itemized in the following table.

Monthly Reference Discount Credit for 2010/2011

2010 to 2011	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option C		
	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Apr	197.2	89.9%	$381,671	26.0	98.2%	$52,022	37.7	58.2%	$3,359
May	191.1	89.7%	$402,614	26.9	96.0%	$52,663	32.4	69.9%	$0
June	186.9	97.0%	$426,461	26.9	96.0%	$52,628	32.2	72.6%	$0
Jul	186.4	96.3%	$424,261	27.1	89.9%	$49,778	33.1	75.5%	$52
Aug	186.2	96.0%	$423,374	27.5	97.1%	$54,438	33.6	70.4%	$513
Sep	186.3	94.5%	$418,545	27.1	98.3%	$54,403	32.4	78.2%	$0
Oct	186.2	96.6%	$425,279	27.2	97.6%	$54,227	32.9	74.1%	$0

[5] The Fixed Discount amount is based on the value of carrying contingency reserves on Manitoba Hydro units.

Monthly Reference Discount Credit for 2010/2011									
2010 to 2011	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option C		
	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Nov	197.2	96.3%	$424,195	27.2	97.6%	$54,450	33.1	58.5%	$72
Dec	197.2	95.1%	$420,286	27.5	97.0%	$54,504	59.5	68.2%	$22,272
Jan	197.2	93.3%	$414,570	27.4	97.7%	$54,631	60.5	71.9%	$24,281
Feb	197.1	93.3%	$414,439	28.0	96.1%	$54,908	60.8	68.6%	$23,480
Mar	197.1	92.5%	$411,778	27.2	77.0%	$42,769	57.1	66.0%	$19,547
Total	**2,306.1**	**94.2%**	**$4,987,472**	**326.1**	**94.9%**	**$631,419**	**505.3**	**69.3%**	**$93,576**

The discounts shown for Customer 1 do not include the $21,444 credited in respect of the Option R Reserve Discount.

Adequacy of Terms and Conditions:

The Terms and Conditions which have been in place since April 1, 2005 (with minor modification in 2008) continue to protect Manitoba Hydro's contingency reserves and provide operating reserves which satisfy the requirements of NERC and the MISO-MBHydro CRSG.

In order to protect the value of curtailable load, cap limitations have been put in place. Options A and C combined are capped at 230 MW and Option R is capped at 100 MW. Currently only 52 MW of Option A and 50 MW of Option R are available for subscription. However going forward it may be necessary to increase the cap limitation, primarily for Option A load, as a result of:

- Manitoba Hydro's summer load continues to grow, diminishing the amount of surplus capacity that Manitoba Hydro can sell, which is necessary in rolling over network transmission service in the United States.

- Manitoba Hydro may have Module E delivery obligations to MISO associated with Manitoba Hydro export contracts beyond the contract provisions. This obligation could put Manitoba load at risk. Additional load will assist in managing the risk to firm load.

Manitoba Hydro continues to review the terms and conditions of the program and the interest by customers for additional curtailable load.

CONCLUSION

The Curtailable Rate Program facilitates in fulfilling Manitoba Hydro's commitment of carrying, deploying and re-establishing contingency reserves to meet its obligations with the MISO-MBHydro CRSG and to maintain compliance to NERC Standards. The program also assists in minimizing disruption to Manitoba Hydro's firm customers.

The amount of curtailable load Manitoba Hydro has made available (230 MW for operating reserves and 100 MW for contingency reserves) has to date proven sufficient to meet Manitoba Hydro's requirements with respect to reserve obligations. Manitoba Hydro is however in the process of reviewing the cap limitation as changes are occurring within the MISO jurisdiction. In order to meet capacity obligations resulting from a Maximum Generation Event[6], Manitoba Hydro may need to have approximately 400 MW of Option A load available for curtailment. In addition, there is an opportunity for additional Option R curtailable load to be used to meet Manitoba Hydro's Supplemental Contingency Reserves obligation to the MISO-MBHydro Contingency Reserve Sharing Group. Manitoba Hydro continues to review the terms and conditions of the Curtailable Rate Program, and will advise the Public Utilities Board of any proposed changes and will seek confirmation of such.

[6] An event triggered by an emergency in the MISO jurisdiction.

ATTACHMENT 1

ESTIMATE OF THE VALUE OF CURTAILABLE LOAD AT MANITOBA HYDRO

The value of curtailable load to Manitoba Hydro is related to the Corporation's estimate of the marginal cost of firm, long term capacity which incorporates both winter deferral and summer marketing benefits. Over the long term, a relatively stable value for capacity can be provided by separating out the capacity component from bundled long term firm export sales. This is done by estimating the annual carrying cost (assumes finance and depreciation costs but not operating/fuel costs) of the lowest cost resource required to provide capacity benefits in Manitoba, that being, a simple cycle combustion turbine (SCCT). This is estimated at $78 per kW per year, or $6.50 per kW per month, evaluated at load. This approach has the advantage of providing a clear transparent value, which is also stable over time and can be applied to evaluate the benefits of DSM resources which have a capacity component.

Curtailable load is however less valuable than a generation resource such as a SCCT. The SCCT can provide more flexibility in dispatch and also has the capability to deliver for longer time periods during extended emergency situations. Once in place a SCCT can be relied upon as a permanent long term resource. Curtailable load normally has more value in the summer months, when it can assist in supporting seasonal capacity exports, and in the peak winter months, when it may add reliability to Manitoba Hydro's generation resource. Curtailable load will provide more winter reliability benefits in years in which there is little capacity surplus on the system. When there is a significant capacity surplus on the Manitoba Hydro system, curtailable load provides less winter value than it would, for example, in the year 2021, when the requirement to add generation to serve domestic customers is expected[7]. The value of reliability benefits in a single year is not easily determined, which is why longer-term levelized values are used to infer the benefits of curtailable load.

In the year 2000, evaluation of the benefits of curtailable load was based on separate estimates of generation deferral benefits and summer seasonal sale benefits. This analysis yielded an estimate of annual aggregate benefits at $33 per kW, or levelized over the year, $2.75 per kW/month. This is equal to 42% of the carrying cost of a SCCT, which appears reasonable, based on relative dispatchability, sustainability, and long term reliability. This value would apply to the curtailable service option that provides the most value to Manitoba Hydro, that being Options AE and RE, for which the discount is set to return 100% of the estimated value of curtailable load, that is, $3.08 per kW per month (applied throughout the reporting period), to the customer. Other options provide less flexibility and are accordingly

[7] 2010/11Power Resource Plan

worth less to Manitoba Hydro. These have been priced to reflect their lesser value to Manitoba Hydro but still to return the full estimated value of that option to the customer.

Manitoba Hydro normally markets its summer surplus capacity in the preceding February and will market curtailable load or other surpluses up to the point that there is still a low probability of breaching reserve obligations even in very warm weather conditions. Hence the summer weather does not impact on the value received for such sales. However, as noted earlier, year to year changes in conditions in the MISO market can lead to considerable volatility in the value of capacity in that market.

In general terms Manitoba Hydro's objective for marketing curtailable capacity and energy is to utilize any excess in a manner that provides the greatest profits. This may involve the sale of additional short term 5 x 16 contracts (e.g. 48% capacity factor) if there is sufficient surplus energy, or the sale of peaking capacity which requires the supply of less energy during the on-peak period (e.g. 20% capacity factor).

REPORT TO
THE PUBLIC UTILITIES BOARD

CURTAILABLE RATE PROGRAM

APRIL 1, 2009 – MARCH 31, 2010

JANUARY 2011

TABLE OF CONTENTS

REPORT TO PUBLIC UTILITIES BOARD
CURTAILABLE RATE PROGRAM
APRIL 1, 2009 – MARCH 31, 2010

SUMMARY

This annual report on the status of the Curtailable Rate Program (CRP) covers the period April 1, 2009 to March 31, 2010. During this time four customers participated in the program, one of which was only operational from April to September. This customer is currently operating below their protected firm load resulting in no available curtailable load.

Three curtailments were called throughout the 12 month reporting period. All curtailments were successfully initiated although one of the curtailments called for a reduction of Option R load whereas the customer inadvertently curtailed their Option A load. Fortunately this did not create any adversity for Manitoba Hydro and the customer's account was credited accordingly.

The Reference Discount of $3.03/kW/month for the 2009/10 reporting year was approved by the Public Utilities Board in Order 42/10 dated April 27, 2010. Customers received credit on their monthly electrical bill for their participation in the program, totaling $5,760,888 for the fiscal year.

BACKGROUND

The CRP Terms and Conditions applicable during the reporting period April 1, 2009 to March 31, 2010 took effect April 1, 2005 in accordance with Board Order No. 28/05 dated February 17, 2005. A slight modification to the Terms and Conditions was approved in Board Order 90/08 dated June 30, 2008 which required customers to provide Manitoba Hydro 48 hours notice period of any anticipated plant shut downs.

The Terms and Conditions allow Manitoba Hydro to reserve the right to limit the amount of total curtailable load used for maintaining operating and contingency reserves[1]. The current limit is set at 230 MW under Options A and C and 100 MW under Option R. There is no limit for Option E load. The caps have been beneficial to both Manitoba Hydro and curtailable customers by ensuring the value of curtailable load does not depreciate. A decreased value would result in lower discounts paid to customers making the program less attractive to them.

Manitoba Hydro uses curtailable load, among other measures, to maintain operating and contingency reserves as a means of minimizing disruption to firm customers in the event of loss of generation or transmission.

Curtailable load provides value to Manitoba Hydro all year round, as curtailments for system emergencies can occur at any time of the year. However, it has the greatest value during peak times as it is during the peak periods that Manitoba Hydro's capacity surplus is the least. Additional Options A and C curtailable load in these hours increases the amount of capacity for sale in the firm export markets while additional Option R load can allow Manitoba Hydro to meet its contingency reserve obligations at a lower cost.

A significant risk mitigation benefit of curtailable load is the avoidance of the need to shed firm load should Manitoba Hydro be in a situation where it would otherwise be the cause of Manitoba Hydro or the Midwest Independent System Operator (MISO) – Manitoba Hydro Contingency Reserve Sharing Group (MISO-MBHydro CRSG)[2] being non-compliant to North American Electric Reliability Council (NERC) Standard(s). Option R curtailable load allows Manitoba Hydro to obtain increased value in the short-term opportunity energy

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[1] Per North American Electric Reliability Council (NERC) Glossary of Terms, Operating Reserves: The reserves needed to protect Manitoba Hydro and its obligations to the Midwest Independent System Operator power system against Contingencies or Disturbances. These events are typically a result of loss of supply caused by sudden generating or transmission outages. Operating Reserves consist of various types including Contingency Reserves. Contingency Reserves: a component of Operating Reserves which are sufficient in magnitude and response to meet NERC Disturbance Control Standards. Contingency Reserves are comprised of Operating Reserves-Spinning and Operating Reserves-Supplemental. Curtailable load (also referred to as Interruptible Load) can be a source of Operating Reserves-Supplemental.

[2] The MISO-MBHydro CRSG is a NERC registered Contingency Reserve Sharing Group that has operated since January 1, 2010. The CRSG was established under the terms of the Amended MISO-Manitoba Hydro Coordination Agreement and executed on October 9, 2009. Prior to the MISO-MBHydro CRSG, Manitoba Hydro was a member of the Midwest CRSG.

market[3]. In this circumstance the benefits of having Option R available are dependent on Manitoba Hydro's water supply conditions as follows:

- High Water Supply - the generating capacity freed up for commercial use allows for increased hydraulic generation for export as idle generating units can be run to capture additional on peak sales. Without Option R capacity in place on peak energy would be spilled. With Option R load, the additional energy generated can be sold at on peak prices.

- Average Water Supply - allows for additional hydraulic generation during on-peak hours that would otherwise be produced during off-peak hours (due to limited on-peak generating capability). In this case Manitoba Hydro captures the benefit of the price differential between on and off-peak periods.

- Low Water Supply - does not provide any significant benefits because Manitoba Hydro has sufficient shut down generating units that could be run temporarily for operating reserves purposes without relying on Option R load reductions.

Manitoba Hydro will not utilize curtailable load in order to facilitate a high value opportunity spot market sale[4].

PERFORMANCE FOR 2009/10

Curtailment Options:

The Curtailable Rate Program consists of four base curtailment options and three combinations. Options vary dependent on: minimum notice to curtail, maximum duration per curtailment, maximum daily hours of curtailment, maximum number of curtailments per year, and maximum annual hours of curtailment.

[3] Opportunity export sales are sales of capacity and/or energy that are not backed by dependable energy and are incremental exports that arise from time to time as a result of water conditions that are better than the lowest historic.

[4] Spot market sales are sales that occur on a day ahead or real time basis. They are not considered to be a firm export sale.

Four customers participated in the Curtailable Rate Program during the April 1, 2009 to March 31, 2010 period. During this time these customers had designated a total of 270 MW to Manitoba Hydro's reserves, allocated as 80 MW Option AE, 119 MW Option A, 31 MW Option C and 40 MW Option R. (Note however that the Option R load increased from 40 MW to 50 MW on May 1, 2010). The amount each customer designated as curtailable load in relation to their total load varies, and therefore impacts their curtailable credit, as shown on the following table.

Summary of Curtailment Credit Data April 1, 2009 to March 31, 2010					
Customer	**Option(s)**	**Curt Load as % of Total Load**	**Average On-Peak MW**	**Average On-Peak LF**	**Average Monthly Cr.**
1	A, R, E	85%	185.2	93.0%	$382,626
2	A	26%	32.6	72.8%	$24,512
3	A	94%	26.5	94.6%	$50,142
4	C	44%	59.4	71.2%	$22,794

*Customer 1: 85% total load represents 43% Option AE, 22% Option R and 20% Option A for the 2009/10 period (prior to Option R load increasing).

Load designated under Option R must be nominated as a Guaranteed Curtailment, that is, the customer must agree to shed a specified number of MW in order to be compliant with the curtailment request. Under all the other curtailment options, customers can nominate curtailable load as Guaranteed Curtailment or Curtail to Protected Firm Load.

Dependent on the curtailment option selected, Manitoba Hydro will curtail customers to meet reliability obligations only. Options A, C and R curtailments assist in securing operating and contingency reserves whereas Option E curtailments are initiated to meet firm energy requirements in the event that Manitoba Hydro expects to be short of firm energy supplies.

Customers may nominate different quantities of curtailable or firm load for each month provided that a minimum of 5 MW of curtailable load is available in each month. Customers must specify the 12 months Guaranteed Load or 12 months Protected Firm Load prior to participation in the program and must provide 12 months' written notice to Manitoba Hydro should they wish to increase or decrease their load in any month. This may be subject to capacity limitations and will be at the discretion of Manitoba Hydro. To date no customers have elected to differentiate their monthly load.

Implementation and Size of Curtailments:

There were three curtailments during the April 1, 2009 to March 31, 2010 period: one Option A and two Option R curtailments. The first curtailment occurred on May 21, 2009 whereby Manitoba Hydro initiated an Option R curtailment due to the loss of Dorsey Valve Group 42. The customer however inadvertently reduced their Option A curtailable load. The Option A curtailment lasted 1 hour and resulted in a 42 MW load reduction. On January 19, 2010, an Option R curtailment was initiated due to the loss of Valve Group 32. The Option R curtailment lasted 0.55 hour and resulted in a 40 MW reduction. The last Option R curtailment was initiated on February 20, 2010 due to the loss of Pole 2 Valve and lasted for 3 minutes with a 40 MW load reduction. All curtailments occurred during peak hours. Customer(s) did not use an alternative power source to supply their load during the curtailments.

Manitoba Hydro continues to use manual telephone to communicate curtailment requirements to the four customers on the program. This procedure is manageable and provides the additional security the curtailment(s) will be initiated by confirmation from an agent of the customer. Manitoba Hydro experienced no difficulties in communicating the three curtailments during this reporting period to the customer, however on one of the curtailment calls the customer curtailed their Option A load instead of their Option R load as requested by Manitoba Hydro. This action did not create any adversity for Manitoba Hydro and the customer customer's account was credited accordingly.

Reference and Reserve Discounts:

The maximum discount available to a participating customer is called the "Reference Discount." The Reference Discount is related to the marginal value of capacity, expressed in Canadian Dollars, and was set at $2.75 per kW/month as of April 1, 2005. This amount is adjusted on April 1 of each year by the inflation factor (the change in Manitoba Consumer Price Index as recorded for the most recent 12 months). Each year Manitoba Hydro submits an application for the adjusted Reference Discount to the PUB for *ex parte* approval.

The Reference Discount in effect for the reporting period April 1, 2009 to March 31, 2010 was $3.03/kW/month, approved on April 24, 2009 via Board Order 46/09. The customer under Option AE received 100% of the discount, while customers under Option A and Option R received 70% of the discount or $2.12 per kW/month. The Option C customer received 40% of the discount or $1.21 per kW/month.

For curtailable load nominated as ‘Protect to Firm Load’ the Reference Discount is calculated and credited to customers’ bill each month as (A - B) x C x D where:

A = On-Peak Period Demand (kW)
B = Protected Firm Load (kW)
C = On-Peak Period Load Factor
D = Discount Amount

For curtailable load designated as a ‘Guaranteed Curtailment’ the Reference Discount is calculated and credited to customers’ bill each month as GC x D where,

GC = the customer’s guaranteed curtailable load
D = Discount Amount

Customers selecting Curtailment Option R receive, in addition to the Reference Discount, a Reserve Discount for each curtailment initiated and successfully completed. The Reserve Discount is set at $0.04/kW.h and represents the value of carrying contingency reserves. The actual amount of the Reserve Discount that customers receive depends on the amount of load reduction (in kW) requested by Manitoba Hydro’s System Control and the duration of the curtailment.

The monthly Reference Discount Credit each customer received from April 1, 2009 to March 31, 2010 has been itemized in the following table as well as their maximum monthly On-Peak Demand and On-Peak Load Factor.

The discounts shown in the table do not include the $960 paid to Customer 1 for the Option R Reserve Discount which is calculated and credited to customers’ bill for each successful curtailment as LR x Du x FD where,

LR = amount of load reduction (in kW) requested by Manitoba Hydro’s System Control to the customer at the time of an Option R curtailment
Du = duration of the curtailment (in hours)
FD = fixed discount amount, currently set at $0.04[5] per kW.h

[5] The Fixed Discount amount is based on the value of carrying contingency reserves on Manitoba Hydro units.

Monthly Reference Discount Credit for 2009/10												
	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option A			Customer 4 Option C		
2009 to 2010	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Apr	160.1	92.9	$375,126	72.8	85.5	$88,531	26.4	98.4	$51,960	60.6	78.8	$26,306
May	159.8	79.5	$332,964	73.6	88.3	$92,925	26.5	98.5	$52,272	58.0	62.2	$18,840
June	174.1	98.9	$404,111	74.2	48.2	$51,278	26.7	98.6	$52,682	59.8	84.9	$27,510
Jul	191.1	91.5	$380,405	70.7	12.2	$12,069	27.2	96.5	$52,645	60.6	78.5	$26,236
Aug	192.0	92.9	$384,959	73.4	47.1	$49,337	26.9	99.3	$53,529	58.8	58.3	$18,223
Sep	191.2	93.9	$388,156	3.7	83.0	$0	27.6	68.2	$37,710	57.9	61.8	$18,613
Oct	191.3	94.3	$389,319	3.9	77.7	$0	26.1	98.7	$51,389	59.0	61.0	$19,215
Nov	197.1	87.4	$366,970	3.9	75.8	$0	26.0	96.0	$49,837	59.7	58.8	$18,952
Dec	197.2	93.6	$386,961	4.3	87.4	$0	26.2	98.8	$51,639	59.3	69.8	$22,216
Jan	197.2	99.5	$393,033	3.7	88.4	$0	26.1	99.3	$51,848	59.9	84.6	$27,505
Feb	197.2	96.6	$396,844	3.7	87.5	$0	26.3	98.9	$52,030	59.7	76.9	$24,856
Mar	174.1	95.0	$391,709	3.3	92.5	$0	26.3	84.1	$44,163	59.2	79.1	$25,056
Total	**2,222.3**	**93.0**	**$4,590,558**	**391.1**	**72.8**	**$294,140**	**318.3**	**94.6**	**$601,704**	**712.5**	**71.2**	**$273,526**

Adequacy of Terms and Conditions:

The Terms and Conditions which have been in place since April 1, 2005 (with minor modification in 2008) continue to protect Manitoba Hydro's contingency reserves and provide operating reserves which satisfy the requirements of NERC and the MISO-MBHydro CRSG.

The cap limitation of 230 MW for Options A and C combined and 100 MW for Option R protects the value of curtailable load. However, going forward it may be necessary to increase the cap limitation, primarily of Option A load, for the following reasons.

- Manitoba Hydro's summer load continues to grow, diminishing the amount of surplus capacity that Manitoba Hydro can sell, which is necessary in rolling over network transmission service in the United States.

- Manitoba Hydro may have Module E delivery obligations to MISO associated with Manitoba Hydro export contracts beyond the contract provisions. This

Manitoba Hydro is currently reviewing the terms and conditions of the program and the interest by customers for additional curtailable load. One customer has shown interest in the program however the current economic situation has resulted in the customer having to reduce their operating requirements thereby making them ineligible for the program due to their significantly reduced on-peak load factor.

CONCLUSION

The Curtailable Rate Program facilitates in fulfilling Manitoba Hydro's commitment of supplying operating and contingency reserves as part of its reliability obligations with MAPP GRSP. The program also assists in minimizing disruption to Manitoba Hydro's firm customers.

The amount of curtailable load Manitoba Hydro has made available (230 MW for operating reserves and 100 MW for contingency reserves) has to date proven sufficient to meet Manitoba Hydro's requirements with respect to reserve obligations. Manitoba Hydro is however in the process of reviewing the cap limitation as changes are occurring within the MISO jurisdiction. In order to meet capacity obligations resulting from a Maximum Generation Event[6], Manitoba Hydro may need to have approximately 400 MW of Option A load available for curtailment. In addition, there is an opportunity for additional Option R curtailable load to be used to meet Manitoba Hydro's Supplemental Contingency Reserves obligation to the Midwest Independent System Operator – Manitoba Hydro Contingency Reserve Sharing Group. Manitoba Hydro continues to review the terms and conditions of the Curtailable Rate Program, and will advise the Public Utilities Board of any proposed changes and will seek confirmation of such.

[6] An event triggered by an emergency in the MISO jurisdiction.

ATTACHMENT 1

ESTIMATE OF THE VALUE OF CURTAILABLE LOAD AT MANITOBA HYDRO

The value of curtailable load to Manitoba Hydro is related to the Corporation's estimate of the marginal cost of firm, long term capacity which incorporates both winter deferral and summer marketing benefits. Over the long term, a relatively stable value for capacity can be provided by separating out the capacity component from bundled long term firm export sales. This is done by estimating the annual carrying cost (assumes finance and depreciation costs but not operating/fuel costs) of the lowest cost resource required to provide capacity benefits in Manitoba, that being, a simple cycle combustion turbine (SCCT). This is estimated at $78 per kW per year, or $6.50 per kW per month, evaluated at load. This approach has the advantage of providing a clear transparent value, which is also stable over time and can be applied to evaluate the benefits of DSM resources which have a capacity component.

Curtailable load is however less valuable than a generation resource such as a SCCT. The SCCT can provide more flexibility in dispatch and also has the capability to deliver for longer time periods during extended emergency situations. Once in place a SCCT can be relied upon as a permanent long term resource. Curtailable load normally has more value in the summer months, when it can assist in supporting seasonal capacity exports, and in the peak winter months, when it may add reliability to Manitoba Hydro's generation resource. Curtailable load will provide more winter reliability benefits in years in which there is little capacity surplus on the system. When there is a significant capacity surplus on the Manitoba Hydro system, curtailable load provides less winter value than it would, for example, in the year 2015, when the requirement to add generation to serve domestic customers is forecast to be will be more pressing. The value of reliability benefits in a single year is not easily determined, which is why longer-term levelized values are used to infer the benefits of curtailable load.

In the year 2000, evaluation of the benefits of curtailable load was based on separate estimates of generation deferral benefits and summer seasonal sale benefits. This analysis yielded an estimate of annual aggregate benefits at $33 per kW, or levelized over the year, $2.75 per kW/month. This is equal to 42% of the carrying cost of a SCCT, which appears reasonable, based on relative dispatchability, sustainability, and long term reliability. This value would apply to the curtailable service option that provides the most value to Manitoba Hydro, that being Options AE and RE, for which the discount is set to return 100% of the estimated value of curtailable load, that is, $3.03 per kW per month (applied throughout the reporting period), to the customer. Other options provide less flexibility and are accordingly worth less to Manitoba Hydro. These have been priced to reflect their lesser value to Manitoba Hydro but still to return the full estimated value of that option to the customer.

Manitoba Hydro normally markets its summer surplus capacity in the preceding February and will market curtailable load or other surpluses up to the point that there is still a low probability of breaching reserve obligations even in very warm weather conditions. Hence the summer weather does not impact on the value received for such sales. However, as noted earlier, year to year changes in conditions in the MISO market can lead to considerable volatility in the value of capacity traded in that market.

In general terms Manitoba Hydro's objective for marketing curtailable capacity and energy is to utilize any excess in a manner that provides the greatest profits. This may involve the sale of additional short term 5 x 16 contracts (e.g. 48% capacity factor) if there is sufficient surplus energy, or the sale of peaking capacity which requires the supply of less energy during the on-peak period (e.g. 20% capacity factor).

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

e) Please provide a blacklined copy of the current approved Curtailable Rate Terms and Conditions, showing all proposed changes.

ANSWER:

Please see attached blacklined copy of the current approved Curtailable Rate Terms and Conditions showing all proposed changes.

CURTAILABLE RATE PROGRAM

FOR INDIVIDUAL CUSTOMER LOADS

~~APPROVED~~PROPOSED
TERMS AND CONDITIONS
~~IN ACCORDANCE WITH~~
~~BOARD ORDER 90/08~~

Manitoba Hydro

~~JULY 1, 2008~~July 6, 2012

TABLE OF CONTENTS

CURTAILABLE RATE PROGRAM
TERMS AND CONDITIONS

1. DEFINITIONS

The following expressions when used in these Terms and Conditions shall have the following meanings:

a) **"Billing Month"**: the period of time, generally 30 days, in which Energy and/or Demand is consumed and thereafter billed to the Customer.

~~a)~~b) **"Contingency"**: the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

~~b)~~c) **"Contingency Reserves"**: a component of Operating Reserves which are sufficient in magnitude and response and meet the North American Electric Reliability Corporation~~ouncil~~'s (NERC) disturbance control standards. Contingency reserves are comprised of spinning and ~~non-spinning~~supplemental reserves.

~~c)~~d) **"Curtailment"**: a reduction in the use of Energy by the customer, as initiated by Manitoba Hydro.

~~d)~~e) **"Curtailment Period"**: for Option 'A' and 'R' customers, defined as the time from which Manitoba Hydro gives the customer the "notice to curtail" to the time the "notice to restore" is given; for Option 'C' customers, defined as the time from which Manitoba Hydro gives the customer the "notice to curtail" plus one full hour to the time the "notice to restore" is given; for Option 'E' customers, from the start and stop times specified on the customer fax to curtail and restore load.

~~e)~~f) **"Curtailment Year"**: the 12-month period commencing upon implementation of the Terms and Conditions of the Curtailable Rate Program by Manitoba Hydro once approved by the Public Utilities Board.

g) **"Demand"**: the maximum use of power within a specified period.

~~f)~~ **h) "Disturbance":** An unplanned event that produces an abnormal system condition; a perturbation to the electric system; or an unexpected change in the supply-demand balance that is caused by the sudden failure of generation or interruption of load.

~~g) **"Guaranteed Make-Up":** that quantity of energy consumed during the Off-Peak period (without incurring additional Demand Charges) which exactly compensates the customer for the energy use curtailed during the period of curtailment.~~

i) "Energy": power integrated over time and measured or expressed in kilowatt-hours (kW.h).

~~h)~~j) **"Firm Load"**: load that is not considered interruptible (curtailable).

~~j)~~k) **"Interruption"**: ~~a~~ discontinuance in the supply of Energy.

~~i)~~l) **"Load Factor"**: the ratio of a customer's average Demand over a designated period of time to the Customer's maximum Demand occurring in that period. Monthly Load Factor is found by calculating the ratio of Energy use (kW.h) to highest Demand (kW) multiplied by time (usually measured at 730 hours):

$$LF = \frac{\text{Energy (kW.h per month)}}{\text{Peak Demand (kW) x hours per month}}$$

~~j)~~m) **"MISO-MBHydro Contingency Reserve Sharing Group" or "MISO-MBHydro CRSG":** The Midwest Independent Transmission System Operator Inc. (MISO) and Manitoba Hydro balancing authorities collectively maintain, allocate, and supply operating reserves required for each entities' use in recovering from Contingencies or Disturbances on the transmission systems operated by either party. The group is established under the coordination agreement between MISO and Manitoba Hydro. ~~**"MAPP GRSP"**: the Mid-Continent Area Power Pool Generation Reserve Sharing Pool is a contractual membership of utilities in seven states and one province that share contingency reserves on a formula basis, to the benefit of all participating utilities.~~

~~k) "Non-Spinning Reserves": That generating reserve not connected to the system but capable of serving demand within a specified time or interruptible load that can be removed from the system in a specified time.contingency reserves that are not connected to the Manitoba Hydro system, but are capable of serving demand within a specified time; or interruptible load that can be removed from the Manitoba Hydro system in a specified time.~~

n) "Point of Delivery": the point at which the Corporation delivers electricity and beyond which electric service facilities (excluding meters and metering transformers) are supplied by and are the responsibility of the customer.

~~l)~~o) **"Power Factor":** ~~is~~ the ratio of real power in watts of an alternating current circuit to the apparent power in volt-amperes, expressed as kW/kV.A~~–~~.

~~kV.A~~

~~m)~~p) **"Protected Firm Load (PFL)"**: the amount of load (expressed in kW) that the customer wishes to protect from being curtailed.

~~n)~~q) **"Peak"**: defined as all hours from ~~7~~6:01 hours through ~~23~~22:00 hours Monday through Friday~~Sunday~~ inclusive excluding Statutory holidays~~.~~

~~o)~~r) **"Off-Peak"**: all nighttime hours from ~~23~~22:01 hours through ~~07~~06:00 hours Monday through Sunday inclusive, and all hours from 0:01 hours to 24:00 hours on Statutory holidays .

s) **"Operating Reserves"**: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of Spinning Reserves and Supplemental Reserves.~~The reserves needed to protect Manitoba Hydro and its obligations to the MAPP Generation Reserve Sharing Pool's power systems against loss of supply caused by major generating or transmission outages. Operating reserves consist of various types of reserves including contingency reserves.~~

t) **"Operating Reserve - Spinning"**: The portion of Operating Reserve consisting of: generation synchronized to the system and fully available to serve load within the NERC defined disturbance recovery period following the Contingency or Disturbance event; or Load fully removable from the system within the disturbance recovery period following the Contingency or Disturbance event.

u) **"Operating Reserve - Supplemental"**: The portion of ~~o~~Operating ~~r~~Reserves consisting of: generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the NERC defined disturbance recovery period following a Contingency or Disturbance event; or load fully removable from the system within the disturbance recovery period following a Contingency or Disturbance event.

~~p)~~

~~q)~~v) **"Planning Reserves"**: The reserves needed to ensure that future load obligations at times of peak demand do not exceed supply resources.

~~r)~~w) **"Reference Discount":** An amount credited to the customer each month for having ~~planning~~ Planning and/or ~~contingency~~ Contingency ~~reserve~~ Reserve load available.

~~s)~~x) **"Reserve Discount"**: an amount credited to the customer for energy curtailed each time Supplemental ~~non-spinning curtailable~~ R~~r~~eserve load is deployed under Option R.

~~t) **"Spinning Reserves":** contingency reserves that are comprised of uploaded generation that is synchronized and capable of serving additional demand instantaneously.~~

2. CURTAILABLE LOAD OPTIONS

The following ~~Available~~ curtailable load options are available, however are subject to capacity limitations and durations as noted in Section 6:

Option 'A': Curtail within five minutes of notice for a maximum of four hours and 15 minutes per curtailment period.

Option 'C': Curtail within one hour of notice for a maximum of four hours per curtailment period.

Option 'R': Curtail within five minutes of notice for a maximum of four hours and 15 minutes per curtailment period.

Option 'E': Curtail within 48 hours of notice for a maximum of 10 days per curtailment period.

Additional description of limits on curtailments (e.g. maximum curtailments per year) is provided on Page 13.

Options 'A', 'C' or 'R' cannot be combined with each other but may be combined with Option 'E' to increase the discount. The terms and conditions of combined Options 'AE', 'CE' and 'RE' are combinations of the individual options (e.g. notice to curtail for 'AE' would be five minutes for Option 'A' curtailments and 48 hours for Option 'E' curtailments).

Customers may elect to designate part of their load as Option 'A' and another part of their load as Option 'R' provided the loads designated under each option are distinct from each other. Although the customer designates a specific portion of their load as Option 'R', Manitoba Hydro's ~~System Control Department~~System Operator may request a curtailment of less than the amount designated by the customer. The minimum load ~~System Control~~the Manitoba Hydro System Operator can request under Option 'R' is 5,000 kW. Manitoba Hydro will make best efforts to request a curtailment equal to the customer's contracted amount.

3. NOMINATION OF CURTAILABLE LOAD

A customer must have a minimum, nominal curtailable load of 5 MW. Customers have two options of nominating eligible curtailable load however customers designating curtailable load under Option 'R' must nominate the "Guaranteed Curtailment" option.

Guaranteed Curtailment

A customer selecting this option must guarantee availability 95%[1] of the time during each curtailment year. Manitoba Hydro reserves the right to exclude customers from future participation in the program should they fail to meet this guaranteed requirement. The customer is required to nominate curtailable load equal to the amount of which is guaranteed to be reduced at the time requested. For example, a customer with a total load of 100 MW may nominate 10 MW as curtailable load and guarantee that when requested that 10 MW of load (or lesser amount if requested by Manitoba Hydro System ~~Control~~Operator) will be shed. In order to honour this guarantee, the customer will be required to ensure that its load prior to curtailment would be such that it never falls below 10 MW plus whatever ~~firm load~~Firm Load the customer wishes to protect.

In the event the Customer is unable to have the full amount of guaranteed curtailable load available for dispatch, the Customer must provide Manitoba Hydro 48 hours verbal notice of an anticipated plant shutdown and must also notify Manitoba Hydro immediately of any unanticipated unavailability of curtailable load. The customer shall immediately notify Manitoba Hydro when the curtailable load is again available.~~shutdowns.~~ Failure to do so will result in the same penalties as failure to curtail as outlined in Section 10.

For this customer, the Reference Discount is determined in accordance with the following formula:

Monthly Credit = GC x $/kW Credit for selected option where,

GC = the customer's guaranteed curtailable load

NOTE: The monthly credit will not be applied if a customer fails to provide guaranteed curtailable load for a period greater than 10% of the hours in the applicable calendar month. For example, a customer would have to have their guaranteed load available for a minimum of 648 hours in a 30-day month and 670 hours in a 31-day month. This will ensure that customers are not being paid a credit when they are shutdown for extended periods of time. The customer is still required

[1] The 95% availability means the customer must guarantee their designated curtailable load will be available for curtailment a minimum of 8,322 hours (8,760 hours x 95%) each curtailment year.

however to maintain the 95% per year availability criteria as specified above.

(i) Curtail to Protected Firm Load

The customer nominates a ~~firm load~~Protected Firm Load below which curtailment will not occur. The curtailable portion of the customer load will be the load available above the ~~protected~~ Protected ~~firm load~~Firm Load at the time of curtailment request. With this type of nomination, there is a risk to Manitoba Hydro that there will be little or no load to curtail when a request is made: i.e. that the customer is operating at or below protected firm level when curtailment request is made.

For this customer, the Reference Discount is determined in accordance with the following formula:

Monthly Credit = (PD-PFL) x LF x $/kW Credit for Selected Option where,

PD = the customer's highest demand (kW) in the ~~peak~~ Peak billing period in the billing month.

PFL = ~~protected~~ Protected ~~firm load~~Firm Load of the customer in kW.

LF = is the customer's overall load factor during the ~~peak~~ Peak billing period in the billing month and excluding any ~~periods~~days during which the customer complied with a curtailment request.

At Manitoba Hydro's discretion customers with load factors less than 50% during ~~peak~~ Peak periods on the curtailable portion of the load may be required to guarantee curtailable load, i.e. to take up Option 3(i).

4. CURTAILABLE RATE DISCOUNT

A Curtailable customer's bill is reduced by the curtailable load discount, calculated in accordance with the "Reference" discount appropriate to the curtailment option selected by the customer and the formula for determining curtailable load.

Customers selecting Curtailment Option 'R' will, in addition to the Reference discount, receive a "Reserve Discount" amount for each curtailment initiated and successfully completed. The Reserve Discount credit will be calculated based on the following formula:

Reserve Discount = LR x Du x FD, where

LR = amount of load reduction (in kW) requested by Manitoba Hydro's System ~~Control~~ Operator to the customer at the time of an Option 'R' curtailment

Du = duration of the curtailment (in hours)

FD = fixed discount amount, currently set at $0.04 [2] per kW.h

If, for example, a customer contracts for 15,000 kW of Option 'R' load, but the Manitoba Hydro System ~~Control~~ Operator only requires 10,000 kW of curtailable load, the Reserve Discount will be calculated based only on the 10,~~-~~000 kW regardless of whether or not the customer load drops by an amount greater than 10,000 kW. The Reference Discount however will be calculated in accordance with the formula provided in Section 3 (i).

5. USE OF CURTAILABLE LOAD

~~Manitoba Hydro~~ Reserves in the form of Curtailable Load can serve two general purposes. The ~~F~~first purpose is, ~~maintains generation reserves for two reasons. The first reason is t~~to minimize disruption to ~~firm~~ Firm ~~customers~~ Load in the event of a Contingency or Disturbance.~~loss of generation or transmission, or to respond to an unexpected increase in firm load.~~ Manitoba Hydro has a Contingency Reserve obligation to the MISO-MBHydro CRSG, or successor organization, to carry a pre-defined amount of Contingency Reserves, both Spinning and Supplemental, to respond to Contingencies and Disturbances in the MISO or Manitoba Hydro balancing areas.

The second ~~reason~~ purpose of Curtailable Load is to ~~fulfil Manitoba Hydro's commitment to~~ maintain a sufficient level of Planning Reserves and ~~a specific level of planning reserves and of operating~~ Operating ~~reserves~~ Reserves to maintain reliable operation of the bulk electric system and compliance to NERC reliability standards.

~~1. In the planning horizon, to ensure sufficient capacity and energy exists to reliably supply Firm Load and firm exports considering uncertainties such as forced outages and load growth. as part of its reliability obligations with the Mid Continent Area~~

2 The Fixed Discount amount is based on the value of carrying contingency reserves on Manitoba Hydro units.

~~Power Pool – Generation Reserve Sharing Pool (MAPP GRSP) or successor organization.~~

Dependent on the Curtailment Option selected, Manitoba Hydro will curtail customers in response to system emergencies and to maintain Planning and~~planning and~~ O~~o~~perating R~~r~~eserves for the following reasons.

(i) Option 'A' and 'C' Curtailable Load

Manitoba Hydro will use curtailable load designated under Options 'A' and 'C', to meet reliability obligations only. These include:

- to re-establish ~~Manitoba Hydro's MAPP GRSP~~the MISO-MBHydro CRSG's or successor organization's ~~contingency~~ Contingency ~~reserves~~Reserves. Once Manitoba Hydro's contingency reserves are ~~committed~~ deployed in response to a MISO-MBHydro CRSG's~~MAPP GRSP or successor organization's contingency~~Contingency or Disturbance, Manitoba Hydro is required to re-establish ~~its contingency~~ Contingency ~~reserves~~ Reserves within ~~45~~ 105 minutes of the event that triggered the commitment to supply the ~~contingency~~ Contingency ~~reserve~~Reserve. A curtailment may be called to reestablish those reserves;

- ~~to maintain Manitoba Hydro's MAPP GRSP or successor organization's planning reserve obligations. If domestic peak load increased to such a point that Manitoba Hydro were in immediate danger of failing to meet its MAPP GRSP or successor organization's planning reserve obligations, a curtailment would be called to protect that reserve;~~

- to protect ~~firm~~ Manitoba Firm L~~l~~oad or firm exports, when ~~operating~~ Operating ~~reserves~~ Reserves are insufficient to avoid curtailing ~~firm load~~Firm Load. ~~(~~This curtailment would be called prior to Manitoba Hydro curtailing ~~firm load~~Firm Load or firm exports~~)~~; and~~.~~

- as Planning Reserves to meet Manitoba Hydro or its firm export customers' resource adequacy requirements.

(ii) Option 'R' Curtailable Load

The ~~MAPP GRSP~~MISO-MBHydro (or successor organization) requires participants to maintain contingency reserves comprised of ~~spinning~~ Spinning ~~reserve~~ Reserves and ~~non-spinning~~ Supplemental ~~reserves~~Reserves. Manitoba Hydro will use curtailable load designated under Option 'R' to ~~meet~~ deploy Manitoba Hydro's ~~"Non-Spinning~~Supplemental —Reserves~~"~~ to the extent necessary, having first dispatched its own generation resources.

(iii) Option 'E' Curtailable Load

Curtailments under Option 'E' will be initiated to meet ~~firm~~ firm energy~~energy~~ requirements in the event that Manitoba Hydro expects to be short of firm energy supplies. Option 'E' customers will be curtailed prior to ~~firm~~ Manitoba Firm ~~load~~ Load and firm export sales.

6. MAXIMUM LEVEL OF CURTAILABLE LOAD

Manitoba Hydro, at its discretion, can limit the amount of curtailable load needed to maintain Planning and~~Planning and~~ Operating Reserve levels. Load under Option 'C' will no longer be available as of one year from the date of approval of the Terms and Conditions by the Public Utilities Board (the "sunset" date). Load currently served under Option 'C' will either revert to Firm Load or, at the customer(s) discretion, revert to Option 'A' Load prior to the sunset date.

(i) Option 'A' ~~and 'C'~~ Curtailable Load

The maximum amount of curtailable load needed under Option~~s~~ 'A' ~~and 'C'~~ has been set at 180~~230~~ MW ~~(NTD: to be reduced)~~ assuming Option 'C' load converts to Option 'A' Load. If however Option 'C' load converts to Firm Load, the cap for Option 'A' Load will be set at 150 MW. Manitoba Hydro may, from time-to-time, submit an Application to the Public Utilities Board for changes to this amount.

(ii) Option 'R' Curtailable Load

The maximum amount of curtailable load needed under Option 'R' has been set at 50~~100~~ MW, with a maximum number of participating customers at any time limited to three. Manitoba Hydro may, from time-to-time, submit an Application to the Public Utilities Board for changes to this amount.

(iii) Option 'E' Curtailable Load

There is currently no limit proposed.

7. CONTRACTS AND TERMINATION NOTICE

(i) Discounts or credits offered by the program, as well as all other terms and conditions, are fixed from the date of approval by the Public Utilities Board ~~for a minimum two year period,~~ unless superseded by a further order of the Public Utilities Board or unless the program is withdrawn by Manitoba Hydro.

(ii) Customers selecting the Curtailable Rate Program will be required to contract for the service. In the event that the Public Utilities Board mandates changes to the program, which in Manitoba Hydro's opinion are material, Manitoba Hydro and the customer will agree to amend the contract to incorporate the changes, failing which the contract shall terminate immediately.

(iii) Customers accepting Curtailable service for the first time may switch curtailment options (subject to capacity limitations) or switch to Firm service entirely within the first six months, unless they have entered into the Curtailable ~~Service~~ Rate Program from another interruptible rate program.

(iv) Customers who have participated in the program for a period in excess of six months may:

a) re-contract for another Curtailable Rate Option for the following changes by providing two months' written notice to Manitoba Hydro.

- switch from Option 'C' to Option 'A' prior to the sunset date ;
- add Option 'E' to any other Option

b) switch from Option 'R' to Option 'A' or from Option 'A' to Option 'R' by providing one year's written notice to Manitoba Hydro. Switching can only occur if provision allows (i.e. the maximum level of load in a particular Option will not be exceeded as per Section 6).

c) switch from Curtailable to Firm service by providing one year's written notice to Manitoba Hydro in which case Manitoba Hydro may convert the load from Curtailable to Firm service at any time during the one year notice period. The one-year notice will not apply when the customer's decision to withdraw from the program is a result of material changes mandated by the Public Utilities Board as outlined in Section 7 (ii). Customers who have switched from Curtailable to Firm service may not be permitted to switch back to Curtailable service for one year, provided Curtailable load is available as defined in Section 6.

(v) Customers may re-designate their ~~monthly~~ Protected Firm Loads or ~~monthly~~ Guaranteed Curtailable Load by providing 12 months' written notice to Manitoba Hydro. Decreases to Protected Firm Load and/or increases to Guaranteed Curtailable Load may be subject to capacity limitations and will be at the discretion of Manitoba Hydro. The time period may be shortened if customers are decreasing their Protected Firm Load as a result of notification by Manitoba Hydro that additional Option 'R' curtailable load is available, as described in section 6 (ii). Customers increasing their Protected Firm Load and/or decreasing their Guaranteed Curtailable Load must maintain a minimum curtailable load of 5 MW per month.

8. MANNER OF NOTICE TO CURTAIL

(i) Option 'A' ,' C' and 'R' Customers

For Option 'A' and 'R' customers, the Notice to Curtail of five minutes means that the customer must reduce the load by the contracted curtailable amount or to the contracted firm amount within five minutes of the initiation from Manitoba Hydro. For Option 'C', the Notice to Curtail of one hour means that the customer must reduce the load within one hour from the time the "Notice to Curtail" is given.

Initiation will be by telephone or by an electronic signal sent to the customer by the Manitoba Hydro System ~~Control Centr~~Operator~~e~~. Both the initiation signal and the load response will be recorded by Manitoba Hydro.

(ii) Option 'E' Customers

Manitoba Hydro will give Option 'E' customers notice in writing that their load may be curtailed when Manitoba Hydro expects to be short of firm energy supplies. Manitoba Hydro will provide not less than 30 days notice. Notice will be deemed received three days from the date of mailing; or if faxed or sent by electronic mail, on the date that it was sent.

After the notice period has been met, Option 'E' customers will be on standby and curtailable on 48 hours notice by fax or electronic mail. Manitoba Hydro will give Option 'E' customers notice in writing whenever their standby status is withdrawn.

9. DEMAND PRO-RATION FOR OPTION 'E' CUSTOMERS

Customers curtailed under Option 'E' will have their Demand Charge prorated on the curtailable portion of load to exclude the period during which an Option 'E' curtailment was in effect. For example, if the load were curtailed for ten days in December, the Demand Charge would be reduced by 10/31 or 32% and, as well, the curtailable credit would be applied. This additional discount would apply only during months of curtailment and only to that portion of load which is curtailable. This provision will not reduce the maximum demand established for the purposes of computing the demand~~winter~~ ratchet~~ (NTD: is 'ratchet' a common term?)~~.

10. ADDITIONAL CHARGES FOR FAILURE TO CURTAIL

(i) Option 'A' ,'C' and 'R' Customers

The first failure to curtail load on request in any contract period will not attract additional charges, but the customer will forego the discount for that month.

After the first failure~~ in a contract period~~, the following additional charges will apply. First subsequent failure in any 12-month period: loss of monthly discount plus additional charge equal to discount. Second and subsequent failure in any 12-month period: loss of discount and additional charge equal to 3 × ~~X~~ discount~~.~~, at which time ~~If a customer reaches a point at which cumulative additional charges during any contract period equal or exceed cumulative discounts~~, Manitoba Hydro will have the right to exclude the customer from further participation in the program.

(ii) Option 'E' Customers

If the customer has elected to participate in Option 'E', in the event of a single failure to curtail load, Manitoba Hydro may in its own discretion exercise one of the following remedies:

a) the normal additional charges, as described in 10 (i); or

b) twenty-four hours after the time curtailment was to have started, Manitoba Hydro may cause electricity service to the Point of Delivery ~~(NTD: this is a capitalized term but not defined herein – this definition could likely be found in the Load Interconnection Agreements)~~ to be restricted to achieve the maximum load that should have been achieved by curtailment; or

c) if load limitation as described in 10 (ii) b) is, in Manitoba Hydro's opinion, not practical or reasonable, 24 hours after the time curtailment was to have started, Manitoba Hydro may cause electricity service to the Point of Delivery to be disconnected for the remainder of the period. Disconnection shall only take place after explicit written communication with the customer and only if, otherwise, ~~firm load~~Firm Load customers would be impacted.

~~11. MONTHLY VARIATION~~

~~Customers may nominate different quantities of curtailable or firm load~~~~Firm Load~~ ~~for each month provided that a minimum of 5 MW of curtailable load is available in each month. Customers must specify the 12 months Protected Firm Load or 12 months Guaranteed Load prior to participation in the program and must provide 12 months' written notice to Manitoba Hydro should they wish to increase or decrease their load in~~

~~any month. This may be subject to capacity limitations and will be at the discretion of Manitoba Hydro (as discussed in Section 7: Contracts and Termination Notice).~~

~~12.~~11. DURATION OF CURTAILMENTS

Notwithstanding the maximum single curtailment duration provisions of each of the options, Manitoba Hydro will attempt to minimize the duration.

~~13.~~12. UNPLANNED INTERRUPTIONS

In addition to program curtailments for which notice is provided, customers will continue to be subject to unplanned interruptions such as those due to under frequency relay operation during power system emergencies. Manitoba Hydro cannot guarantee continuous service to any class of service in Manitoba or extra provincially.

CURTAILABLE RATE PROGRAM OPTIONS
FOR APPLICATION AS OF ~~NOVEMBER 1, 2004~~APRIL 1, 2012
UNLESS SUPERCEDED BY FURTHER ORDER OF THE PUB

Discount to Demand Charge Expressed as Percentage of Reference Discount per kW/month.

OPTIONS	TERMS AND CONDITIONS					
	Minimum Notice to Curtail	Maximum Duration Per Curtailment	Maximum Daily Hours of Curtailment	Maximum Number Curtailments Per Year	Maximum Annual Hours of Curtailment	Discount as Percentage of Reference Discount
A	5 minutes	4-1/4 Hours	6 Hours (Oct 1 - Apr 30) 10 Hours (May 1 - Sep 30)	15 Curtailments	63.75 Hours	70%
C*	1 Hour	4 Hours	8 Hours	15 Curtailments	60.00 Hours	40%
E	48 Hours	10 Days	24 Hours	3 Curtailments	720.00 Hours	35%
R	5 minutes	4-1/4 Hours	10 Hours (Apr 1 – Mar 31)	25 Curtailments	106.25 Hours	70% + Reserve Discount
A & E	Combination	Combination	Combination	18 Curtailments	783.75 Hours	100%
C & E*	Combination	Combination	Combination	18 Curtailments	780.00 Hours	70%
R & E	Combination	Combination	Combination	28 Curtailments	826.25 Hours	100% + Reserve Discount

* Options ‘C’ and ‘CE’ will no longer be available as of the sunset date.

The Monthly Reference Discount shall equal A, and shall be adjusted on April 1st of each fiscal year by the annual inflation factor, where:

A = the amount of the Reference Discount which is related to the marginal value of capacity, expressed in Canadian Dollars. The Reference Discount of $3.17 per kW/month as of April 1, 2011 shall be adjusted each year by the Inflation Factor as defined below.

Inflation Factor = at the end of each fiscal year of Manitoba Hydro, the percentage change in the Consumer Price Index for Manitoba as recorded for the most recent set of 12 month periods for which data are available.

Reserve Discount: The fixed price to be paid for energy during curtailment under Option 'R' has been set at $0.04 per kW.h. ~~The Monthly Reference Discount shall equal A, adjusted by the annual inflation factor as of April 1st of each fiscal year, where:~~

~~A = the amount of the Reference Discount which is related to the marginal value of capacity, expressed in Canadian Dollars; after April 1, 201205, this amount shall be adjusted at the start of each fiscal year of Manitoba Hydro by the Inflation Factor;~~

~~Inflation Factor = at the end of each fiscal year of Manitoba Hydro, the percentage change since 201105 in the Consumer Price Index for Manitoba as recorded for the most recent set of 12 month periods for which data are available.~~

~~Prior to the yearly adjustment for inflation, the Reference Discount shall be $2.763.17 per kW/month as of April 1, 2012 adjusted by the Inflation Factor. (NTD: Insert reference date).~~

~~Reserve Discount: The fixed energy amount per curtailment under Option 'R' has been set at $0.04 per kW.h.~~

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

f) Please indicate the proposed calculation of "load factor" in relation to peak demand. Is the peak demand the highest metered demand in that month, or the highest on-peak metered demand? Is it proposed that this calculation will change in the event Manitoba Hydro introduces time-of-use rates for large industrial customers?

ANSWER:

The On-Peak Load Factor is calculated using the period defined in the Curtailable Rate Terms & Conditions as On-Peak and is applied to the customer's total on-peak load (both firm and curtailable), the formula being as follows:

$$\frac{\text{On-Peak kWh}}{\text{(Highest On-Peak kW demand * On-Peak hours)}}$$

There would be no change to the calculation of On-Peak Load Factor in the event Manitoba Hydro introduces time-of-use rates. Only the hours defined as on-peak are proposed to change such that the Curtailable Rate Program and potential time-of-use offering use the same definition of on-peak hours.

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

g) Please provide the detailed rationale used by Hydro to conclude that the Curtailable Rate program availability should be reduced. Please provide specific reference to any changes in underlying system conditions, market conditions, market participation agreements, or infrastructure which support reducing the availability of the Curtailable Rate program.

ANSWER:

Please see Manitoba Hydro's response to CAC/MH I-84.

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

h) Please provide copies of any documents referenced in part (g) as justification for the proposed lower program caps.

ANSWER:

The agreement governing the MISO-MB Hydro CRSG was filed by MISO with the Federal Energy Regulatory Commission on October 19, 2009. The link to the FERC filing is as follows:

http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12178436

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

i) Is Hydro aware of existing or new industrial customers who have expressed an interest in participating in the Curtailable Rate program, but which cannot be accommodated under the proposed new lower program caps.

ANSWER:

Manitoba Hydro is aware of one industrial customer that has indicated an interest in participating in the Curtailable Rate Program. One other customer has expressed interest in expanding their participation, however, that increase will not be able to be accommodated under the proposed program caps.

MIPUG/MH I-44

Subject: Tab 10, Appendix 10.4 and Appendix 10.5: Curtailable Rates

j) Please indicate if the lower caps will result, immediately or over time, to changes to the reference discount for Curtailable Rates.

ANSWER:

No. Manitoba Hydro has no immediate plans to change the method of determining that discount. As noted in Manitoba Hydro's response to CAC/MH I-84(c), in order to avoid alienating existing customers by reducing the credit and potentially losing them as subscribers, Manitoba Hydro chose instead to reduce the amount of curtailable load required.

As for future changes to the reference discount, Manitoba Hydro will continue to monitor the value of curtailable load as it has always done since the program was introduced.

MIPUG/MH I-45

Subject: Appendix 8.1: 2011 Load Forecast

a) Please explain and show how the 100 GW.h in compounding PLIL used to forecast GS Top Consumers was arrived at as an appropriate contingency for unexpected major expansions or loss of customers in the future given the average since 1987 was only 69 GW.h per year (as referenced on page i of the 2011 Load Forecast).

ANSWER:

As referenced on page i of the 2011 Load Forecast, since 1987 the net effect of major increases and decreases in load to the GS Top Consumers category has been an additional 69 GW.h of energy per year. Normal company growth has added another 23 GW.h per year. The combined effect of major changes in load and normal company growth has been increases of 92 GW.h or 2.3% per year in the GS Top Consumers category.

The forecast of 100 GW.h per year for PLIL growth is slightly higher than the historical growth of 92 GW.h per year, but its percentage growth of 1.9% per year is lower than the historical growth rate of 2.3% per year.

MIPUG/MH I-45

Subject: Appendix 8.1: 2011 Load Forecast

b) Please provide the rationale for why load increases in residential consumers means load growth for GS Mass Market customers – especially since residential customer forecast load growth is lower than GS Mass Market (1.5% per year average).

ANSWER:

An increase in the number of residential customers has been found to be correlated with an increase in the number of GS Mass Market customers. The econometric model that captures the relationship is shown on pages 70-72 of the 2011 Electric Load Forecast found in Appendix 8.1 of this Application. The rationale for this relationship is that new residential housing developments generally require additional services, which manifests as an increase in GS Mass Market customers.

Electric load growth for the Residential sector and electric load growth for the GS Mass Market may increase at different rates even though growth in the number of customers in the sectors is correlated. This is because GS Mass Market customer growth is affected by Manitoba GDP. As well, the average use of a GS Mass Market customer is growing faster than the average use of a Residential customer.

MIPUG/MH I-45

Subject: Appendix 8.1: 2011 Load Forecast

c) Please provide the reports and data used to determine the additional growth in residential basic customers by 2030/31 due to an expectation of increased population from more immigration to the province. Please provide the reports and data used to determine the extent to which the increased immigration into the province by 2030/31 will have an effect on GS Mass Market customers.

ANSWER:

Manitoba Hydro's survey of forecasters projected that the population of Manitoba would grow at a rate of approximately 1.0% per year on an annualized basis as shown on page 8 of the EO2011 found in Appendix 4.1 of this Application. Manitoba Hydro's projection of Manitoba Residential Customers, also shown on page B-1, is based on this same escalation rate of approximately 1.0%.

GS Mass Market customers are forecast using an econometric model that uses the number of Residential Basic customers as one input. Please see pages 70-72 of the 2011 Electric Load Forecast for a further explanation.

MIPUG/MH I-46

Subject: PUB/MH I-71 from 2010 GRA: Load Forecast

a) **Please categorize the GS Top Consumers and their annual energy demands (in GW.h) by sector for 2008/09 to 2011/12 inclusive similar to PUB/MH I-71(b) of the 2010 GRA for each of the 2011 and 2012 Load Forecasts:**

- **i. Chemical**
- **ii. Petroleum Primary**
- **iii. Metals**
- **iv. Pulp/Paper**
- **v. Mining**
- **vi. Food/Beverage**
- **vii. Colleges and Universities**
- **viii. Other**

ANSWER:

2011 LOAD FORECAST

GW.h	2008/09	2009/10	2010/11	2011/12 forecast
Chemicals	1,929	1,912	1,977	2,005
Petroleum	944	903	728	790
Primary Metals	2,237	2,033	2,153	2,372
Pulp/Paper	674	332	185	279
Mining	4	3	3	0
Food/Beverage	202	204	201	207
College	75	74	76	77
Other	0	0	0	0
Total GW.h	6,065	5,461	5,324	5,730

2012 LOAD FORECAST

GW.h	2008/09	2009/10	2010/11	2011/12
Chemicals	1,929	1,912	1,977	2,018
Petroleum	944	903	728	856
Primary Metals	2,237	2,033	2,153	2,200
Pulp/Paper	674	332	185	171
Mining	4	3	3	3
Food/Beverage	202	204	201	203
College	75	74	76	80
Other	0	0	0	0
Total GW.h	6,065	5,461	5,324	5,531

MIPUG/MH I-46

Subject: PUB/MH I-71 from 2010 GRA: Load Forecast

b) What are the sector and by sector industry growth forecasts for Fiscal 2013, 2014 and 2015.

ANSWER:

The growth in the forecast from the previous year is shown below.

2011 FORECAST – SECTOR GROWTH

GW.h	**2012/13**	**2013/14**	**2014/15**
Chemicals	60	50	0
Petroleum	110	205	15
Primary Metals	58	70	-95
Pulp/Paper	-11	0	2
Mining	0	0	0
Food/Beverage	2	6	0
College	2	2	0
Other	0	0	0
PLIL	0	0	100
Total GW.h	221	333	22

2012 FORECAST –SECTOR GROWTH

GW.h	**2012/13**	**2013/14**	**2014/15**
Chemicals	57	50	50
Petroleum	89	235	-35
Primary Metals	151	80	-30
Pulp/Paper	-1	5	5
Mining	-3	0	0
Food/Beverage	9	5	0
College	3	3	4
Other	0	0	0
PLIL	0	0	0
Total GW.h	305	378	-6