PUB/MH I-1 (Revised)

Reference: Reason for Application Tab 2, Page 2, Tables 1

Please re-file table from page 2 of 5 reflecting two scenarios (including and excluding the 1% deferral) incorporating the following adjustments:

i. Include 2003/04 to 2011/12 actual results and add forecast 2012/13 to 2015/16

ii. Debt: Equity, Interest & Capital Coverage ratios (electric operations) for all years.

iii. Please refile both scenarios removing all IFRS accounting related adjustments made in advance of mandatory adoption. For the years 2009/10 through 2012/13.

ANSWER:

Please see the following tables.

Please see the following table which is consistent with Manitoba Hydro's Application to reinstate the 1% rate roll-back (scenario including the 1% deferral).

Net Income - Electricity Operations Scenario 1

						Actual				Forecast			
(in millions of $)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Revenue													
General Consumers Revenue													
- at approved rates	$ 918	$ 939	$ 984	$ 1,024	$ 1,075	$ 1,127	$ 1,145	$ 1,200	$ 1,214	$ 1,281	$ 1,308	$ 1,319	$ 1,326
- 1% rate deferral									(23)				
Extraprovincial Revenue	351	554	827	592	625	623	427	398	363	341	363	394	469
Other Revenue	7	4	5	5	8	16	6	6	6	16	16	16	17
Total Revenue	1,276	1,497	1,816	1,621	1,708	1,766	1,578	1,605	1,560	1,638	1,687	1,730	1,812
Expenses													
Operating, Maintenance and Administrative	283	299	311	323	323	364	378	397	403	447	532	542	548
Finance Expense	453	468	468	467	401	433	373	388	385	440	452	504	537
Depreciation and Amortization	274	289	301	311	324	340	358	365	353	401	354	358	375
Water Rentals and Assessments	71	112	131	112	124	123	121	120	119	106	112	113	113
Fuel and Power Purchased	569	135	125	226	135	176	104	106	146	182	158	187	193
Capital and Other Taxes	50	51	53	55	57	64	76	81	83	87	92	99	107
Corporate Allocation	4	6	6	7	8	8	8	9	9	9	8	8	8
Total Expenses	1,704	1,360	1,396	1,502	1,371	1,508	1,418	1,466	1,498	1,672	1,709	1,810	1,881
Non-controlling Interest							-	-	-	(1)	(1)	(1)	(2)
Net Income (loss) before proposed rate increases	$ (428)	$ 137	$ 420	$ 119	$ 337	$ 257	$ 160	$ 139	$ 62	$ (35)	$ (23)	$ (82)	$ (71)
Proposed rate increases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	-	20	80	130	182
Rate rollback reinstatement										35	12	13	13
Net Income after proposed rate increases & rate rollback reinstatement	$ (428)	$ 137	$ 420	$ 119	$ 337	$ 258	$ 160	$ 139	$ 62	$ 20	$ 68	$ 62	$ 124

Retained Earnings and Financial Ratios (after proposed rate increases & rate rollback reinstatement)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Retained Earnings (electric operations)	$ 707	$ 843	$ 1,262	$ 1,378	$ 1,784	$ 2,028	$ 2,190	$ 2,328	$ 2,390	2,411	2,203	2,265	2,389
Debt to Equity Ratio (electric operations)	87:13	85:15	81:19	80:20	73:27	77:23	72:28	72:28	74:26	76:24	81:19	83:17	85:15
Interest Coverage Ratio (electric operations)	0.12	1.27	1.83	1.23	1.72	1.50	1.33	1.26	1.11	1.03	1.11	1.09	1.15
Capital Coverage Ratio (electric operations)	-0.42	1.20	2.52	1.12	1.65	1.82	1.28	1.22	1.10	1.07	1.13	1.15	1.43

Please see the following table which assumes that the 1% rate roll-back is denied (scenario excluding the 1% deferral) and is consistent with the response to PUB/MH 1-24.

Net Income - Electricity Operations Scenario 2

	Actual									Forecast			
(in millions of $)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Revenue													
General Consumers Revenue													
- at approved rates	$ 918	$ 939	$ 984	$ 1,024	$ 1,075	$ 1,127	$ 1,145	$ 1,200	$ 1,214	$ 1,280	$ 1,307	$ 1,319	$ 1,326
- 1% rate deferral									(23)				
Extraprovincial Revenue	351	554	827	592	625	623	427	398	363	341	363	394	469
Other Revenue	7	4	5	5	8	16	6	6	6	16	16	16	17
Total Revenue	1,276	1,497	1,816	1,621	1,708	1,766	1,578	1,605	1,560	1,637	1,686	1,729	1,811
Expenses													
Operating, Maintenance and Administrative	283	299	311	323	323	364	378	397	403	447	532	542	548
Finance Expense	453	468	468	467	401	433	373	388	385	439	453	507	542
Depreciation and Amortization	274	289	301	311	324	340	358	365	353	401	354	358	375
Water Rentals and Assessments	71	112	131	112	124	123	121	120	119	106	112	113	113
Fuel and Power Purchased	569	135	125	226	135	176	104	106	146	182	158	187	193
Capital and Other Taxes	50	51	53	55	57	64	76	81	83	87	92	99	107
Corporate Allocation	4	6	6	7	8	8	8	9	9	9	8	8	8
Total Expenses	1,704	1,360	1,396	1,502	1,371	1,508	1,418	1,466	1,498	1,671	1,710	1,814	1,886
Non-controlling Interest							-	-	-	(1)	(1)	(1)	(2)
Net Income (loss) before proposed rate increases	$ (428)	$ 137	$ 420	$ 119	$ 337	$ 257	$ 160	$ 139	$ 62	$ (35)	$ (25)	$ (86)	$ (76)
Proposed rate increases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	-	20	80	129	180
Net Income after proposed rate increases & rate rollback reinstatement	$ (428)	$ 137	$ 420	$ 119	$ 337	$ 258	$ 160	$ 139	$ 62	$ (16)	$ 54	$ 44	$ 104

Retained Earnings and Financial Ratios (after proposed rate increases)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Retained Earnings (electric operations)	$ 707	$ 843	$ 1,262	$ 1,378	$ 1,784	$ 2,028	$ 2,190	$ 2,328	$ 2,390	2,376	2,152	2,196	2,299
Debt to Equity Ratio (electric operations)	87:13	85:15	81:19	80:20	73:27	77:23	72:28	72:28	74:26	76:24	82:18	84:16	85:15
Interest Coverage Ratio (electric operations)	0.12	1.27	1.83	1.23	1.72	1.50	1.33	1.26	1.11	0.97	1.09	1.06	1.13
Capital Coverage Ratio (electric operations)	-0.42	1.20	2.52	1.12	1.65	1.82	1.28	1.22	1.10	0.98	1.08	1.11	1.38

Please note that the proposed rate increases for 2014/15 and 2015/16 are indicative only and are subject to review and approval of the MHEB.

With respected to part iii of this IR, all of the accounting changes implemented by Manitoba Hydro in advance of the adoption of IFRS in 2013/14 are in accordance with Canadian accounting standards and are generally consistent with the overhead capitalization practices of other Canadian electric utilities. While these changes are generally consistent with the direction of IFRS, MH does not consider them as early adoption of IFRS.

PUB/MH I-2

Reference: Reason for Application Page 3 of 4

a) Please populate the following table consistent with PUB/MH I-2 last GRA for each of the years 2004/05 through 2015/16:

Year	% Rate Increase Requested	% Approved Final/ Interim	MB CPI	Annual Increase in Revenue	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Revenue From Rate Increases	% of Total Revenue from Domestic	Debt to Equity Ratio
2003/04									

ANSWER:

Please see the following table which is consistent with Manitoba Hydro's Application to reinstate the 1% rate roll-back (table includes the 1% deferral).

Year	% Rate Increase Requested	% Approved Final/Interim	MB CPI	Annual Increase in Revenue	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Revenue From Rate Increases	% of Total Revenue from Domestic (Actual)	Actual Consolidated Debt to Equity Ratio
2003/04	0.0%	-0.72% April 1/03	0.90%	$ (6.5)	-0.72%	0.90%	$ (6.5)	72%	87:13
2004/05	3% April 1/04	5% August 1/04	2.70%	32.3	4.24%	3.62%	25.8	63%	85:15
2005/06	2.5% April 1/05	2.25% April 1/05	2.40%	21.8	6.59%	6.11%	47.6	54%	81:19
2006/07	2.25% February 1/07	2.25% March 1/07	2.00%	23.1	8.99%	8.23%	70.7	63%	80:20
2007/08	0.0% April 1/07	0.0% April 1/07	1.90%	-	8.99%	10.29%	70.7	63%	73:27
2008/09	2.9% April 1/08	5% July 1/08	2.20%	52.4	14.44%	12.72%	123.1	64%	77:23
2009/10	3.9% April 1/09	2.84% April 1/09	0.60%	32.8	17.69%	13.39%	155.9	72%	73:27
2010/11	2.9% April 1/10	2.8% interim April 1/10	1.00%	32.9	20.98%	14.53%	188.8	74%	73:27
2011/12	2.9% April 1/11	2.0% April 1/11	2.80%	24.4	23.40%	17.73%	213.2	76%	74:26
2012/13	3.5% April 1/12	2% interim April 1/12	2.00%	25.8	25.87%	20.09%	239.0	79%	76:24
2012/13	2.5% Sept 1/12	2.4% interim Sept 1/12	2.00%	31.0	28.89%	22.49%	270.0	79%	76:24
2013/14*	3.5% April 1/13	n/a	2.00%	47.4	33.40%	24.94%	317.4	79%	82:18

* To calculate the annual increase in revenue and the cumulative % rate increase, approval of a 3.5% rate increase effective April 1, 2013 has been assumed.

Please note that the proposed rate increases for 2014/15 and 2015/16 are indicative only and are subject to review and approval of the MHEB.

PUB/MH I-2

Reference: Reason for Application Page 3 of 4

b) Please provide the cumulative totals from 2004/05 to 2011/12 and for 2012/13 and 2013/14.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-2(a).

PUB/MH I-2

Reference: Reason for Application Page 3 of 4

c) Please provide the scenario in (a) excluding from base rates the 1% interim rate from April 1, 2010.

ANSWER:

Please see the following table which assumes that the 1% rate roll-back is denied (table excluding the 1% deferral). Please note that the impact of excluding the 1% interim rate from April 1, 2010 is based on estimated values.

Year	% Rate Increase Requested	% Approved Final/Interim	MB CPI	Annual Increase in Revenue	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Revenue From Rate Increases	% of Total Revenue from Domestic (Actual)	Actual Consolidated Debt to Equity Ratio
2003/04	0.0%	-0.72% April 1/03	0.90%	$ (6.5)	-0.72%	0.90%	$ (6.5)	72%	87:13
2004/05	3% April 1/04	5% August 1/04	2.70%	32.3	4.24%	3.62%	25.8	63%	85:15
2005/06	2.5% April 1/05	2.25% April 1/05	2.40%	21.8	6.59%	6.11%	47.6	54%	81:19
2006/07	2.25% February 1/07	2.25% March 1/07	2.00%	23.1	8.99%	8.23%	70.7	63%	80:20
2007/08	0.0% April 1/07	0.0% April 1/07	1.90%	-	8.99%	10.29%	70.7	63%	73:27
2008/09	2.9% April 1/08	5% July 1/08	2.20%	52.4	14.44%	12.72%	123.1	64%	77:23
2009/10	3.9% April 1/09	2.84% April 1/09	0.60%	32.8	17.69%	13.39%	155.9	72%	73:27
2010/11	2.9% April 1/10	1.8% April 1/10	1.00%	22.0	19.81%	14.53%	177.9	74%	73:27
2011/12	2.9% April 1/11	2.0% April 1/11	2.80%	24.0	22.20%	17.73%	201.9	76%	74:26
2012/13	3.5% April 1/12	2% interim April 1/12	2.00%	25.1	24.65%	20.09%	227.0	78%	76:24
2012/13	2.5% Sept 1/12	2.4% interim Sept 1/12	2.00%	30.7	27.64%	22.49%	257.7	78%	76:24
2013/14	3.5% April 1/13	n/a	2.00%	26.8	32.10%	24.94%	284.5	79%	82:18

* To calculate the annual increase in revenue and the cumulative % rate increase, approval of a 3.5% rate increase effective April 1, 2013 has been assumed.

PUB/MH I-3

Reference: Financial History

a) Please provide a table, which details the debt to equity ratio, capital coverage ratio and interest coverage ratio, net assets, net income, total debt and retained earnings and DBRS bond ratings in each year since the inception of the MHEB.

ANSWER:

Please see the following table that was developed based on information that is available in the Manitoba Hydro's annual reports for the period from 1992 through 2012. Given the difficulty in restating historical information and ensuring the reliability/comparability of the information, this information is based on the accounting policies and financial ratio target definitions that were utilized at the time.

Financial History

	Debt/Equity Ratio	Capital Coverage Ratio	Interest Coverage Ratio	Total Assets	Net Income	Total Debt	Retained Earnings	DBSR Bond Rating
2012	74:26	1.13	1.10	13,791	61	9,382	2,450	A (high)
2011	73:27	1.25	1.27	12,882	150	8,647	2,389	A (high)
2010	73:27	1.30	1.32	12,437	163	8,538	2,239	A (high)
2009	77:23	1.77	1.48	11,547	266	8,187	2,076	A (high)
2008	73:27	1.62	1.69	11,766	346	7,571	1,822	A (high)
2007	80:20	1.10	1.23	10,922	122	7,227	1,407	A (high)
2006	81:19	2.28	1.77	10,482	415	7,169	1,285	A (high)
2005	85:15	1.20	1.25	9,952	136	7,204	870	A (high)
2004	87:13	(0.32)	0.17	9,903	(436)	7,390	734	A (high)
2003	80:20	1.10	1.14	10,234	71	7,268	1,170	A (high)
2002	77:23	1.67	1.42	10,405	214	7,661	1,302	A
2001	80:20	1.18	1.62	9,966	270	7,464	1,088	A
2000	83:17	1.28	1.35	8,692	152	6,770	818	A
1999	84:16	1.22	1.23	7,866	100	5,883	666	A
1998	86:14	1.13	1.25	7,617	111	5,548	566	A
1997	88:12	1.12	1.23	7,133	101	5,175	455	A
1996	91:09	1.00	1.16	6,737	70	5,284	354	A
1995	92:08	1.00	1.13	6,449	56	5,034	284	A
1994	93:07	n/a	1.16	6,543	70	5,406	228	A
1993*	95:05	n/a	0.95	6,025	(24)	4,971	159	A
1992	94:06	n/a	1.04	6,505	18	5,441	183	A

* The first unit of the Limestone Generation Station went into service in September of 1990 and all ten units were operational by September 1992.

PUB/MH I-3

Reference: Financial History

b) Please ensure all ratios incorporate current methodology for calculation for comparative purposes.

ANSWER:

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

It should be recognized that there are a number of limitations in comparing history to Manitoba Hydro's current financial situation. In particular, the credit rating environment in the post-Enron and post-2008 financial crisis is very different than it was prior these events. Further, because Manitoba Hydro's current and projected debt represents a greater proportion of Provincial debt than in the past, the potential impacts on Provincial credit ratings is a much greater risk.

PUB/MH I-3

Reference: Financial History

c) Please include notes indicating when major G&T came in service.

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH I-3(a) and (b).

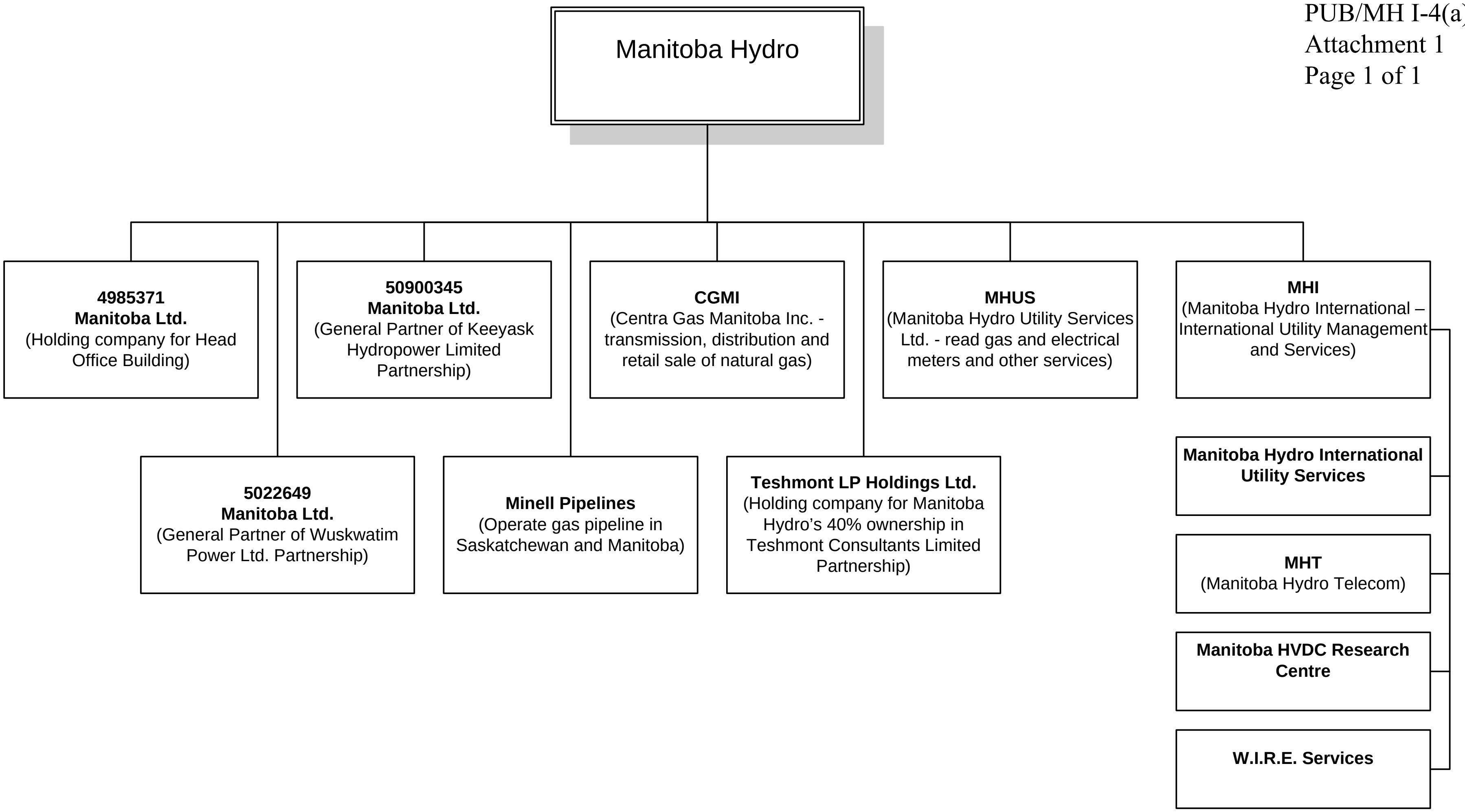
PUB/MH I-4

Reference: Tab 3, Organizational Chart

a) Please provide a Corporate Organization chart indicating all affiliated Companies, subsidiaries, joint ventures and other ownership interests.

ANSWER:

Please see the attached organizational chart.


Manitoba Hydro
4985371 Manitoba Ltd. (Holding company for Head Office Building)
50900345 Manitoba Ltd. (General Partner of Keeyask Hydropower Limited Partnership)
CGMI (Centra Gas Manitoba Inc. - transmission, distribution and retail sale of natural gas)
MHUS (Manitoba Hydro Utility Services Ltd. - read gas and electrical meters and other services)
MHI (Manitoba Hydro International – International Utility Management and Services)
5022649 Manitoba Ltd. (General Partner of Wuskwatim Power Ltd. Partnership)
Minell Pipelines (Operate gas pipeline in Saskatchewan and Manitoba)
Teshmont LP Holdings Ltd. (Holding company for Manitoba Hydro's 40% ownership in Teshmont Consultants Limited Partnership)
Manitoba Hydro International Utility Services
MHT (Manitoba Hydro Telecom)
Manitoba HVDC Research Centre
W.I.R.E. Services

PUB/MH I-4

Reference: Tab 3, Organizational Chart

b) Please provide a summary of all related party transactions between MH and Centra and Wuskwatim (WPLP) for the years 2009/10, 2010/11, 2011/12 and 2012/13 (year to date).

ANSWER:

Summaries of all related party transactions between Manitoba Hydro and Centra and Wuskwatim (WPLP) are provided below.

Centra Gas Manitoba Inc.

Centra's operating and administrative costs represent a transfer of direct and allocated costs from Manitoba Hydro for ongoing operating and administrative costs. Centra's short-term funding is financed by Manitoba Hydro with interest calculated monthly at floating rates with no fixed repayment terms. Manitoba Hydro has also provided long-term advances to Centra with various interest rates and repayment terms. The corporate allocation represents Centra's portion of annual interest costs and provincial guarantee fee on the acquisition debt. Depreciation on common assets represents Centra's portion of depreciation expense on assets acquired by either Centra or Manitoba Hydro in support of the operations of both utilities. As such, the depreciation expense for the common assets which are owned by Centra are first charged to Manitoba Hydro and then allocated back to Centra along with the depreciation on the common assets which are owned by Manitoba Hydro.

The following amounts are provided in millions of dollars.

Centra Gas Manitoba Inc.

	2009/10	2010/11	2011/12
Operating & Admin charged by MH	61	61	62
Interest charged by MH	19	18	19
Corporate allocation	12	12	12
Common asset depreciation to Centra	5	5	5
Common asset depreciation from Centra	1	1	1
Due to Parent	24	19	14
Long term debt	297	297	298

Wuskwatim Power Limited Partnership (WPLP)

The Wuskwatim Power Limited Partnership was formed on December 9, 2004 to carry on the business of developing, owning and operating the Wuskwatim hydroelectric generating station and related works excluding the transmission facilities but including all dams, dikes, channels, excavations and roads to be located at Taskinigahp Falls near Wuskwatim Lake.

WPLP has entered into various agreements with Manitoba Hydro to provide services to the partnership. The following agreements are currently in effect:

a) the Construction Agreement, whereby Manitoba Hydro will construct the Wuskwatim Generating Station and related works;

b) the Interconnection and Operating Agreement, whereby Manitoba Hydro will connect the Wuskwatim generating station to Manitoba Hydro's integrated power system;

c) the Management Agreement, whereby Manitoba Hydro will provide administrative and management functions to WPLP; and

d) the Project Financing Agreement, whereby Manitoba Hydro will provide debt financing to WPLP.

The following amounts are in millions of dollars:

	2009/10	2010/11	2011/12
Amounts paid to MH - Construction Agreement	280	299	156
Amounts paid to MH - Interconnection	52	31	27
Amounts paid to MH - Management Agreement	3	4	3
Long term debt (due to MH)	804	1,058	1,201
Interest payable on long term debt	8	12	17
Equity contributions received from MH and the GP	47	50	26

PUB/MH I-4

Reference: Tab 3, Organizational Chart

c) Please file the latest annual audited financial statements of each of the affiliated companies.

ANSWER:

The financial statements for the following affiliate companies are provided in Appendix 14.

Centra Gas Manitoba Inc. – audited
Manitoba Hydro International Limited – audited
Minell Pipelines Ltd. – audited
Wuskwatim Power Limited Partnership – audited
Keeyask Hydropower Limited Partnership – audited
Manitoba Hydro Utility Services Limited – unaudited
4985371 Manitoba Ltd. – unaudited
Teshmont Holdings LP Ltd. – unaudited
5022649 Manitoba Ltd. (Wuskwatim Power General Partner) – unaudited
5900345 Manitoba Ltd. (Keeyask Power General Partner) – unaudited

PUB/MH I-5

Reference: Corporate Strategic Plan – Energy Markets and Interconnections

a) Please file MH's export business plan and explain how it is reflected in the Corporate Strategic Plan.

ANSWER:

MH's export business plan is contained in the Corporate Strategic Plan (See Appendix 3.1) under the export goal.

"Extend and protect access to North American energy markets and profitable export sales".

Strategic activities associated with this goal are as follows:

- Pursue a balanced portfolio of export sales.
- Protect transmission rights and expand transmission capacity to support access for exports and imports.
- Participate in national and international forums to facilitate exports.
- Promote new hydro and transmission as part of the solution to climate change.
- Participate in the development of regulatory and industry frameworks for electricity, including renewable energy standards.
- Advance in-service dates of new hydro facilities, where economic, to take advantage of export opportunities.
- Ensure that plans are robust enough to withstand a range of alternative scenarios.

Further information on Manitoba Hydro's export plans are contained in the Power Resource Plan (See Attachment 3).

PUB/MH I-6

Reference: Appendix 3.1 Corporate Strategic Plan

a) Please file the 2012/13 CSP.

ANSWER:

The 2012-2013 Corporate Strategic Plan is provided in Appendix 15.

PUB/MH I-6

Reference: Appendix 3.1 Corporate Strategic Plan

b) For each of the measures and related targets for the 2011/12 or 2012/13 CSP, please provide a schedule that indicates the Corporation's performance against each target similar in format to CAC/MSOS/MH I-9 (d) Attachment 1 from the last GRA.

ANSWER:

Please see the attachment to this response.

Targets in 2011/12 CSP & Results for 2011/12

Goal	Measure	Target	Performance Reported as of March 31, 2012
Improve safety in the workplace	Accident severity rate	< 16 days per 200 000 hours worked	10.18
	Accident frequency rate	< 0.80 accidents per 200 000 hours worked	0.91
	High risk incidents	0	2
Provide exceptional customer value	System average interruption duration	≤ 90 minutes	143.4 minutes
	System average interruption frequency	≤ 1.3 per year	1.67
	Canadian Electricity Association (CEA) Customer Service Index	Best in Canada	Best in Canada
	Retail electricity rates	Lowest in North America	Lowest in North America *
	Retail natural gas distribution rates	Among the lowest in North America	3rd lowest amongst local distribution companies in major Canadian cities
Strengthen working relationships with Aboriginal peoples	Percentage of impacted Aboriginal communities with a workable management framework	100%	Measure under review
	Percentage Aboriginal employment - Corporate Overall - Northern - Management - Professional	 16% 45% 6% 8%	 15.7% 41.3% 4.6% 6.7%
Maintain financial strength	Interest coverage	> 1.2	1.1
	Debt/equity ratio	Maximum 75% debt ratio	74:26
	Capital financing ratio	> 1.2 excluding major generation & transmission	1.13
	Operation, maintenance and administration (OM&A) cost per customer - electric	$739 per customer (March 2012)	$743
	OM&A cost per customer - gas	$238 per customer (March 2012)	$232
Attract, develop and retain a highly skilled and motivated workforce that reflects the demographics of Manitoba	Percentage of non-entry positions filled by external applicants	Range 8%-12%	7.06%
	Percentage of designated group members in Manitoba Hydro workforce - Women - Women in management - Women professionals - Persons with a disability - Visible minorities - Aboriginal	 26% 20% 35% 6% 6% 16%	 24.7% 20.3% 33.9% 4.7% 6.1% 15.7%
Protect the environment in everything that we do	Percent of electricity generated in Manitoba that is renewable	> 99%	99.90%
	Environmental component of CEA Customer Service Index	≥ 8.5	7.5
	Corporate Citizenship Index - environmental component	≥ 8.4	7.47
	Greenhouse gas emissions	< 520 kilotonnes/yr (6% below 1990 levels)	157 kilotonnes (Calendar 2011)

Targets in 2011/12 CSP & Results for 2011/12

Goal	Measure	Target	Performance Reported as of March 31, 2012
	Maintain EMS ISO 14001 registration	Registration maintained	Registration maintained
Promote cost effective energy conservation and innovation	Demand side management (DSM) - electric energy saved	1 939 gigawatt-hours (GWh) per year by March 2012 3 408 GWh per year by 2024/25	1 966 GWh
	DSM - electric capacity saved (at winter peak)	575 megawatts (MW) by March 2012 918 MW by 2024/25	583 MW
	DSM - natural gas energy saved	61 million cubic metres per year by March 2012 149 million cubic metres per year by 2024/25	70 million cubic metres
Be recognized as an outstanding corporate citizen and a supporter of economic development in Manitoba	CEA Public Attitude Index	≥ 8.5	7.7
	Manitoba Hydro Corporate Citizenship Index	≥ 8.2	7.65
	Public Contacts - natural gas & electric	20% injury reduction (reduction of average of previous 5 years = 15 injuries)	15
	Economic Development Agency satisfaction	100% satisfied	89%

* Retail electricity rates: as of March 31, 2012 based on the 2011 reports available at the time, Manitoba Hydro had the lowest rates in North America. Subsequently the 2012 surveys were released and Manitoba Hydro is amongst the lowest in North America.

PUB/MH I-7

Reference: Appendix 4.1 Wuskwatim Development- Federal Government

a) Please provide the Corporation understands of the Federal Government's involvement in the training initiative and its recent claims that monies were inappropriately spent.

ANSWER:

Manitoba Hydro, the Province of Manitoba and the Federal Government provided $60.26 million to the Hydro Northern Employment and Training Initiative (HNTEI). The Federal Government's contribution to this initiative was $30.26 million.

The Federal Government's claim that monies were inappropriately spent is with respect to a separate contribution agreement between the Federal Government and Nisichawayasihk Cree Nation (NCN) to develop and build the Atoskiwin Training and Employment Centre. Manitoba Hydro is not a party to this agreement. Manitoba Hydro understands this matter is currently before the courts. Manitoba Hydro is not a party to the litigation and is not in a position to comment on same.

PUB/MH I-7

Reference: Appendix 4.1 Wuskwatim Development- Federal Government

b) Please discuss the controls in place to ensure monies advanced by MH were spent in accordance with the agreement.

ANSWER:

The Wuskwatim and Keeyask Training Consortium Inc. (WKTC) was a non-profit corporation, with a Board of Directors consisting of five First Nations, the MMF, MKO, Manitoba Hydro and the Province, developed to undertake the administration and coordination of the Hydro Northern Training and Employment Initiative (HNTEI). This involved entering into contribution sub-agreements with the Aboriginal partners and ensuring they maintained accountabilities to project funders. WKTC provided regular reports to funders, reconciled activities, expenditures and results.

The accountability framework process established for HNTEI included the following:

- Multi-year training plans were provided from each Aboriginal partner and approved by the funders;
- Annual training plans from each Aboriginal partner were submitted that identified annual objectives, projected outcomes and a detailed budget for each training program in the plan. Annual plans were approved by the funders and funded through the WKTC. Any amendments to the annual plans required the funders' pre-approval;
- Funding was disbursed quarterly, based on cash flows developed as part of the annual planning process;
- Each Aboriginal partner had to maintain separate financial records related to the financial management activities of the initiative in accordance with generally accepted accounting principles and practices, provide quarterly and annual financial reports detailing expenditures and explanations for any variations in projected cash flows, make accounts, records and supporting documentation available to funders for accountability and review;
- Each Aboriginal partner completed a financial audit annually, prepared by professional accountants, which was then combined to provide a year-end WKTC financial audit to the funders;
- Manitoba Hydro, Manitoba and WKTC together, conducted financial monitors of the Aboriginal partners on an annual basis. This monitoring process was considered a key means of ensuring funds were spent in accordance with the contribution sub-agreements.

The monitors sought to validate that activities were conducted as set out in the agreements, financial records reflected what was claimed, supporting documentation was available to show that expenditures took place, expenditures were not charged to another funding sources, claimed amounts were eligible, and payments and advances were in keeping with expenditures.

PUB/MH I-7

Reference: Appendix 4.1 Wuskwatim Development- Federal Government

c) Please indicate the amount expended or planned to be expended by MH, the Province and Federal Government and the number of individuals trained or forecast be trained through the Northern Training Initiative for each of the years 2004/05 through 2014/15

ANSWER:

The Hydro Northern Training and Employment Initiative (HNTEI) ended March 31, 2010. The following table summarizes the funding disbursed to the initiative.

Funding to HNTEI

	Manitoba Hydro	Province of Manitoba	Western Economic Diversification Canada	Human Resources and Skills Development Canada	Indian and Northern Affairs Canada	TOTAL
2001-02**	$ 1,200,000	$ -	$ -	$ -	$ -	$ 1,200,000
2002-03**	$ 1,525,720	$ 634,954	$ -	$ -	$ -	$ 2,160,674
2003-04**	$ 1,650,093	$ 2,459,335	$ -	$ -	$ 3,260,000	$ 7,369,428
2004-05***	$ 2,414,560	$ 1,517,228	$ 500,000	$ 2,000,000	$ -	$ 6,431,788
2005-06	$ 2,330,114	$ 1,750,000	$ -	$ 8,966,165	$ -	$ 13,046,279
2006-07	$ 3,358,282	$ 700,000	$ 502,946	$ 5,612,675	$ -	$ 10,173,903
2007-08	$ 2,139,718	$ 1,000,000	$ -	$ 3,313,165	$ -	$ 6,452,883
2008-09	$ 2,267,679	$ 450,121	$ 2,083,045	$ 1,091,681	$ -	$ 5,892,526
2009-10	$ 2,513,834	$ 1,188,362	$ 1,914,009	$ 1,016,314	$ -	$ 6,632,519
2010-11	$ -	$ 300,000	$ -	$ -	$ -	$ 300,000
2011-Present****	$ 600,000					
TOTAL	**$ 20,000,000**	**$ 10,000,000**	**$ 5,000,000**	**$ 22,000,000**	**$ 3,260,000**	**$ 60,260,000**

**Funding paid directly to Aboriginal Partners

***Funding paid directly to Aboriginal Partners and through WKTC.

**** Funding provided directly to Aboriginal Partners with remaining HNTEI allocations.

The following table summarizes the number of forecasted and actual trainees per year from 2004/05 to 2009/10 (end of HNTEI). There are no forecasts for additional trainees beyond March 2010.

	Previous	2004-05	2005-06	2006-07	2007-08	2008/09	2009/10	Total
Target enrollment	123	300	303	301	88			1,115
Actual number of enrollments	445	250	600	289	589	242	255	2670

PUB/MH I-8

Reference: Contingent Liabilities

a) Please provide a list of contingent liabilities.

ANSWER:

In accordance with Section 3290 of the CICA Handbook - Contingencies, “A contingency is defined as an existing condition or situation involving uncertainty as to possible gain or loss to an enterprise that will ultimately be resolved when one or more future events occur or fail to occur. Resolution of the uncertainty may confirm the acquisition of an asset or the reduction of a liability or the loss or impairment of an asset or the incurrence of a liability.”

For accounting purposes, the amount of a contingent loss is accrued in the financial statements when it is likely that a future event will confirm that a liability has been incurred and the amount of the loss can be reasonably estimated. Contingent losses are disclosed in the notes to the financial statements when the incurrence of the confirming future event is likely but the amount of the loss cannot be reasonably estimated or the occurrence confirming of the future event is not determinable.

Manitoba Hydro has disclosed the following contingent liabilities in its March 31, 2012 financial statements in Notes 19 & 20. A copy of page 83 of the 2012 Annual Report, which was filed as Appendix 5.8, is attached which includes a copy of Notes 19 and 20.

- Future costs associated with the assessment and the remediation of contaminated lands and facilities and the phase-out and destruction of PCB contaminated equipment.
- Various litigation claims (please see the response to PUB/MH I-8(b) for a list of legal claims exceeding $1 million).
- Various outstanding mitigation issues associated with compensation and remedial measures necessary to ameliorate the adverse affects of hydroelectric developments.

NOTE 19 COMMITMENTS AND CONTINGENCIES

Manitoba Hydro has energy purchase commitments of $1 651 million (2011 - $1 562 million) that relate to future purchases of wind, natural gas (including transportation and storage contracts), coal and electricity. Commitments are primarily for wind, which expire in 2039, and natural gas purchases, which expire in 2013. In addition, other outstanding commitments principally for construction, are approximately $771 million (2011 - $673 million).

The Corporation will incur future costs associated with the assessment and remediation of contaminated lands and facilities and for the phase-out and destruction of PCB contaminated mineral oil from electrical equipment. Although these costs cannot be reasonably determined at this time (except for items already recognized as asset retirement obligations), a contingent liability exists.

Due to the size, complexity and nature of Manitoba Hydro's operations, various legal and operational matters are pending. It is not possible at this time to predict with any certainty the outcome of these matters. Management believes that any settlements related to these matters will not have a material effect on Manitoba Hydro's consolidated financial position or results of operations.

Manitoba Hydro provides guarantees to counterparties as part of its use of natural gas derivative commodity contracts. Guarantees issued at March 31, 2012 totaled $305 million (2011 - $305 million) and do not have specific maturity dates. Letters of credit in the amount of $10 million (2011 - $4 million) have been issued for energy related transactions with maturities until 2013.

NOTE 20 MITIGATION

Manitoba Hydro's mitigation program addresses past, present and ongoing adverse effects of hydroelectric development. The mitigation program, established in the late 1970s to address project impacts through alleviation of adverse effects, remedial works, offsetting programs and residual monetary compensation, grew out of the experience of planning and development of the Lake Winnipeg Regulation and Churchill River Diversion projects. The Northern Flood Agreement, signed December 16, 1977, created a process that addressed ongoing mitigation and compensation for adverse effects of hydroelectric development in five signatory First Nation communities (Nelson House, Split Lake, York Landing, Norway House and Cross Lake). The mitigation program continues to address impacts arising from past hydro-electric developments, particularly for Aboriginal people residing or engaged in resource harvesting in the project area, and it is essential for operating and future development purposes.

Expenditures recorded or settlements reached to mitigate the impacts of all projects amounted to $123 million during the year (2011 - $92 million). In recognition of future anticipated mitigation payments, the Corporation has recorded a liability of $251 million (2011 - $185 million). To March 31, 2012, $948 million (2011 - $825 million) has been recorded to mitigate and compensate for all project-related impacts. These expenditures are included in the costs of the related projects and amortized over the respective remaining lives. There are other mitigation issues, the outcomes of which are not determinable at this time.

Included in mitigation payments or liabilities are obligations assumed on behalf of the Province of Manitoba with respect to certain northern development projects. The Corporation has assumed obligations totaling $145 million for which water power rental charges were fixed until March 31, 2001. The obligations outstanding at March 31, 2012 amounted to $11 million (2011 - $12 million).

PUB/MH I-8

Reference: Contingent Liabilities

b) Please list the major litigation cases where the claims exceed $1 million which MH is involved including a summary of the claim and the amounts at issue.

ANSWER:

Manitoba Hydro is only aware of one court action currently active against the Corporation where a quantum of damage of one million dollars or greater was specified in the Statement of Claim. That is a claim by the Government of Canada for recovery of $20.3 million of alleged overpayments in contributions towards the costs of construction of the North-Central transmission project in the 1990's. Liability and the quantum of damage are both in dispute.

In a large number of cases a Statement of Claim has been filed but does not specify the quantum of damage, or the corporation has been made aware of the existence of a claim through arbitration, mediation or other means (e.g. a letter is received asserting a claim). In a number of these cases Manitoba Hydro has received advice from legal counsel suggesting that the potential liability is one million dollars or greater. Estimates of liability based on the advice of legal counsel are not released publicly so as to avoid prejudicing the corporation's position in defending legal claims (which would be to the detriment of ratepayers).

PUB/MH I-9

Reference: Tab 3 page 10, Appendix 3.1 Corporate Strategic Plan maintain corporate financial strength

a) Please provide a table indicating the targeted OM&A cost per customer in each of the last ten CSP, the actual number of customers and actual OM&A, actual OM&A per customer and explain the changes in the target.

ANSWER:

Please see the following table for the requested information.

	Actual				
	2008	**2009**	**2010**	**2011**	**2012**
OM&A expense 'electric only' (in millions of $)	323	364	378	397	403
# of Customers	521,599	527,472	532,359	537,299	542,681
OM&A (electric only) per customer (in dollars)	619	691	709	739	743
CSP Target	640	665	673	708	739

The CSP OM&A targets are based on the OM&A and customer forecasts included in the integrated Financial Forecast available at the time of the preparation of the CSP. Changes are due to variations in the actual number of customers and/or unforeseen operating events or conditions.

PUB/MH I-9

Reference: Tab 3 page 10, Appendix 3.1 Corporate Strategic Plan maintain corporate financial strength

b) Please provide the OM&A cost per GWh for other Canadian Electric Utilities [including BC, Sask, Ontario and Quebec.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-75.

PUB/MH I-9

Reference: Tab 3 page 10, Appendix 3.1 Corporate Strategic Plan maintain corporate financial strength

c) Please update the comparison of the OM&A cost per customer for the years 2009 through 2017 provided at the last GRA [PUB/MH I-8 (c)] to include actual and IFF11-2 with IFF10 and discuss the trend.

ANSWER:

The cost per customer has remained constant between the years 2009 through 2012 as compared to IFF10. The increase in OM&A cost per customer in 2013 and beyond reflects changes in accounting practices and policies including a reduction in capitalized overhead, accounting reclassifications and the elimination of Rate Regulated Assets & Liabilities (e.g. DSM programs, Site Remediation costs) beginning in 2013/14 under IFRS.

Please see the following table for the requested information.

	Actual				Forecast - IFF11-2				
	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only' (in millions of $)	364	378	397	403	447	532	542	548	554
# of Customers	527,472	532,359	537,299	542681	549,150	555,651	562,303	569,044	575,874
OM&A (electric only) per customer (in dollars)	691	709	739	743	814	957	963	963	962

	Actual		Forecast - IFF10-2						
(in millions of dollars)	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only' (in millions of $)	364	378	398	402	414	422	430	439	448
# of Customers	527,472	532,359	538,002	543,574	548,659	553,369	558,059	562,706	567,338
OM&A (electric only) per customer (in dollars)	691	709	739	739	754	762	771	780	789

	Change								
(in millions of dollars)	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A (electric only) per customer (in dollars)	-	-	-	4	60	195	192	183	172

PUB/MH I-9

Reference: Tab 3 page 10, Appendix 3.1 Corporate Strategic Plan maintain corporate financial strength

d) Provide an additional comparison between Actual/ IFF11-2 and IFF-9. Please discuss the trend since the 2008 GRA.

ANSWER:

The increase in OM&A cost per customer compared to IFF09 for the years 2010 and 2011 is primarily a result of reductions in overhead capitalized (not incorporated until IFF10) including the removal of interest on common assets and motor vehicles as well as general and administrative departmental costs. IFF09 had included an additional $15 million provision for accounting changes beginning in 2012.

The increase in OM&A cost per customer in 2013 and beyond reflects changes in accounting practices and policies including a reduction in capitalized overhead, accounting reclassifications and the elimination of Rate Regulated Assets & Liabilities (e.g. DSM programs, Site Remediation costs) beginning in 2013/14 under IFRS.

Please see the following table for the requested information.

	Actual					Forecast - IFF11-2				
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
OM&A expense 'electric only' (in millions of $)	323	364	378	397	403	447	532	542	548	554
# of Customers	521,599	527,472	532,359	537,299	542,681	549,150	555,651	562,303	569,044	575,874
OM&A (electric only) per customer (in dollars)	619	691	709	739	743	814	957	963	963	962

	Actual		Forecast - IFF09							
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
OM&A expense 'electric only' (in millions of $)	323	364	372	380	403	411	420	428	437	445
# of Customers	521,599	527,472	531,804	536,267	540,756	545,215	549,623	553,968	558,286	562,580
OM&A (electric only) per customer (in dollars)	619	691	699	708	746	755	764	773	782	792

	Change									
(in millions of dollars)	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
OM&A (electric only) per customer (in dollars)	-	-	11	31	(3)	59	194	190	180	170

PUB/MH I-9

Reference: Tab 3 page 10, Appendix 3.1 Corporate Strategic Plan maintain corporate financial strength

e) File a similar schedule as in (c) eliminating the impact of IFRS accounting changes.

ANSWER:

Please see the following table for the requested information.

	Actual				Forecast - IFF11-2																
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OM&A expense 'electric only' (in millions of $)	364	378	397	403	447	532	542	548	554	571	580	595	611	622	634	646	669	676	688	700	713
# of Customers	527,472	532,359	537,299	542,681	549,150	555,651	562,303	569,044	575,874	582,657	589,354	595,997	602,561	609,041	615,417	621,677	627,805	633,798	639,646	645,347	650,894
OM&A per customer (in dollars) net of Accounting Changes	691	709	739	743	814	957	963	963	962	980	984	999	1,014	1,021	1,031	1,039	1,065	1,067	1,075	1,085	1,096

	Actual				Forecast - IFF11-2																
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OM&A expense 'electric only' (in millions of $)	364	378	397	403	447	532	542	548	554	571	580	595	611	622	634	646	669	676	688	700	713
CGAAP Changes																					
Intangibles																					
DSM	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2
Planning Studies	3	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3
IT Application	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	5	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6
Overhead Capitalized																					
Stores	5	5	5	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7
Admin& General	-	4	24	24	51	52	53	54	55	56	58	59	60	61	62	64	65	66	67	69	70
Store & Admin General	5	9	29	29	56	58	59	60	61	62	64	65	66	68	69	70	72	73	75	76	78
Change in Discount Rate on Pension & Other Benefits	-	-	-	3	-	-	-	-	-	-	-	-	-	-							
Subtotal CGAAP Changes	10	13	33	37	61	62	63	65	66	67	68	70	71	73	74	76	77	79	80	82	83
IFRS Changes																					
DSM	-	-	-	-	-	32	29	29	26	22	21	19	19	19	19	19	20	15	14	14	15
Site Remediation	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	6	6	6	6	6	6
Regulatory Costs	-	-	-	-	-	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2
Pension	-	-	-	-	-	(1)	(3)	1	3	4	5	6	7	9	9	10	11	12	14	15	16
Employee Benefits (amortization of RHSA)	-	-	-	-	-	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	-	-	-	-
Admin & General	-	-	-	-	-	36	37	37	38	39	40	40	41	42	43	44	45	46	47	48	49
Subtotal IFRS Changes	-	-	-	-	-	72	67	72	71	69	72	72	74	76	78	80	83	81	82	85	87
Reclassifications																					
Wire & Telecom Services	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4
Funding Agreements	-	(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(7)	(7)
Operating Expense Recoveries					8	8	9	9	9	9	9	10	10	10	10	10	11	11	11	11	11
Subtotal Reclassifications	3	(2)	(2)	(2)	6	6	6	7	7	7	7	7	7	7	8	8	8	8	8	8	9
Total OM&A Accounting Changes	13	11	31	35	67	140	136	143	144	143	147	149	152	156	160	163	168	167	171	175	179
OM&A expense 'electric only' net of Accounting Changes	352	366	366	368	380	392	405	404	410	427	433	446	459	465	475	482	501	509	517	525	534
# of Customers	527,472	532,359	537,299	542,681	549,150	555,651	562,303	569,044	575,874	582,657	589,354	595,997	602,561	609,041	615,417	621,677	627,805	633,798	639,646	645,347	650,894
OM&A per customer (in dollars) net of Accounting Changes	667	688	681	679	692	705	721	711	712	734	735	749	762	764	771	776	797	803	808	814	820

	Actual		Forecast - IFF10-2																		
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OM&A expense 'electric only' (in millions of $)	364	378	398	402	414	422	430	439	448	469	478	495	511	521	531	552	563	575	587	598	609
# of Customers	527,472	532,359	538,002	543,574	548,659	553,369	558,059	562,706	567,338	571,939	576,511	581,051	585,562	590,039	594,483	598,891	603,268	607,611	611,918	616,190	620,431
OM&A per customer (in dollars) net of Accounting Changes	691	709	739	739	754	762	771	780	789	820	829	852	872	883	894	922	934	946	959	970	982

	Actual		Forecast - IFF10-2																		
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OM&A expense 'electric only' (in millions of $)	364	378	398	402	414	422	430	439	448	469	478	495	511	521	531	552	563	575	587	598	609
CGAAP Changes																					
Intangibles																					
DSM	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Planning Studies	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
IT Application	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	5	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Overhead Capitalized																					
Stores	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Admin& General		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Store & Admin General	5	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Waterways Management no longer capitalized				5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Subtotal CGAAP Changes	10	13	13	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
IFRS Changes																					
Provision	-	-	18	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Subtotal IFRS Changes	-	-	18	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Reclassifications																					
Wire & Telecom Services	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Funding Agreements	-	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Subtotal Reclassifications	3	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Total OM&A Accounting Changes	13	11	29	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
OM&A expense 'electric only' net of Accounting Changes	352	367	369	372	384	392	401	409	418	439	448	465	481	491	502	523	534	545	557	568	579
# of Customers	527,472	532,359	538,002	543,574	548,659	553,369	558,059	562,706	567,338	571,939	576,511	581,051	585,562	590,039	594,483	598,891	603,268	607,611	611,918	616,190	620,431
OM&A per customer (in dollars) net of Accounting Changes	667	689	686	685	700	708	718	727	737	768	777	800	821	832	844	873	885	897	910	921	934

											Change - IFF11-2 vs IFF10-2										
(in millions of dollars)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OM&A per customer (in dollars)	-	-	(0)	4	60	195	192	183	172	160	155	147	142	139	137	116	131	121	116	116	114
OM&A per customer (in dollars) net of Accounting Changes	-	(1)	(4)	(6)	(8)	(3)	3	(16)	(25)	(34)	(43)	(51)	(59)	(68)	(72)	(97)	(87)	(94)	(102)	(107)	(113)

	Actual	Forecast - IFF09																			
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OM&A expense 'electric only' (in millions of $)	364	372	380	403	411	420	428	437	445	467	478	497	509	519	536	547	558	569	580	592	603
# of Customers	527,472	531,804	536,267	540,756	545,215	549,623	553,968	558,286	562,580	566,841	571,081	575,158	579,338	583,485	587,600	591,681	595,737	599,764	603,763	607,735	611,680
OM&A per customer (in dollars) net of Accounting Changes	691	699	708	746	755	764	773	782	792	824	837	864	878	889	913	925	937	949	961	973	986

	Actual	Forecast - IFF09																			
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OM&A expense 'electric only' (in millions of $)	364	372	380	403	411	420	428	437	445	467	478	497	509	519	536	547	558	569	580	592	603
CGAAP Changes																					
Intangibles																					
DSM	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Planning Studies	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
IT Application	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	5	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Overhead Capitalized																					
Stores	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Admin& General	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Store & Admin General	5	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Waterways Management no longer capitalized	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Subtotal CGAAP Changes	10	11	11	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
IFRS Changes																					
Provision	-	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Subtotal IFRS Changes	-	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Reclassifications																					
Wire & Telecom Services	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Funding Agreements		(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Subtotal Reclassifications	3	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Total OM&A Accounting Changes	13	9	9	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
OM&A expense 'electric only' net of Accounting Changes	352	363	371	375	383	391	399	408	417	438	449	468	480	490	508	518	529	540	552	563	575
# of Customers	527,472	531,804	536,267	540,756	545,215	549,623	553,968	558,286	562,580	566,841	571,081	575,158	579,338	583,485	587,600	591,681	595,737	599,764	603,763	607,735	611,680
OM&A per customer (in dollars) net of Accounting Changes	667	682	692	693	702	711	721	731	741	773	787	814	828	840	864	876	888	901	914	926	939

											Change - IFF11-2 vs IFF09										
(in millions of dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
OM&A per customer (in dollars)	-	11	31	(3)	59	194	190	180	170	156	147	135	137	132	118	114	128	118	114	112	109
OM&A per customer (in dollars) net of Accounting Changes	-	6	(10)	(14)	(10)	(6)	(0)	(20)	(29)	(39)	(52)	(64)	(66)	(76)	(92)	(100)	(91)	(98)	(105)	(112)	(119)

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Reference: Tab 3 Consulting & Mitigation Costs

a) Please provide a table by major capital G&T project for the years 2003/04 to 2012/13 listing the annual amounts incurred/paid to:

i. External Consultants hired by MH,
ii. Internal MH Staff Costs,
iii. MH funded expenses for costs incurred by third parties,
iv. Amounts paid under joint generation development agreements, and
v. Annual mitigation costs paid to third parties.

ANSWER:

Please see the table below for Major New Generation & Transmission project annual amounts from 2003/04 to 2011/12. Please note fiscal years 2005/06 and 2006/07 have been updated to reflect additions related to deferred site study costs. Please also note fiscal year 2009/10 has been updated to reflect the full year's actual expenditures, along with updates to External Consultants hired by MH; Joint Generation Development Agreements, Process and Study Costs; and Mitigation for all years.

(in thousands of dollars)

Project	Fiscal Year								
	2004	2005	2006	2007	2008	2009	2010	2011	2012
Wuskwatim - Generation	**29 788**	**29 395**	**20 356**	**61 064**	**148 921**	**174 639**	**309 569**	**294 967**	**173 807**
External Consultants hired by MH	10 623	7 784	7 124	2 830	2 135	11 337	12 517	8 014	2 527
Internal MH Staff Costs	7 279	5 019	1 996	8 122	12 885	13 134	15 407	15 597	17 364
MH funded expenses for costs incurred by third parties	120	94	1 944	25 163	109 897	121 554	245 111	218 395	90 103
Joint Generation Development Agreements, Process and Study Costs	5 688	5 247	7 877	8 706	6 335	869	1 248	1 278	1 228
Mitigation				1 000	305	4 682	141	149	172
Materials & Other	701	3 451	400	7 096	5 686	4 347	6 799	6 755	3 771
Capitalized Interest	5 377	7 937	5 284	8 147	11 679	18 717	28 347	44 779	58 642
Transfers from Wuskwatim Generation to Transmission		(137)	(4 268)						
Wuskwatim - Transmission	**29**	**7 041**	**15 166**	**16 119**	**57 586**	**79 365**	**57 564**	**31 389**	**43 718**
External Consultants hired by MH		2 427	686	1 063	10 928	23 708	15 633	3 474	3 866
Internal MH Staff Costs	29	1 266	4 593	4 055	7 608	7 693	10 861	10 026	6 188
MH funded expenses for costs incurred by third parties		11	174	6 400	19 210	33 000	16 352	1 683	2 189
Mitigation					27	126	270	360	487
Materials & Other		3 200	3 162	1 693	16 480	7 533	2 713	2 228	15 720
Capitalized Interest	0	(0)	2 282	2 908	3 333	7 304	11 736	13 618	15 268
Transfers from Wuskwatim Generation to Transmission		137	4 268						
Herblet Lake-The Pas 230 kV Transmission				**241**	**4 388**	**6 931**	**35 055**	**21 090**	**8 251**
External Consultants hired by MH				7	1 176	3 757	2 156	651	786
Internal MH Staff Costs				42	437	2 487	6 505	6 762	2 738
MH funded expenses for costs incurred by third parties					262	1 916	13 765	8 231	240
Materials & Other				191	2 443	(1 528)	11 294	2 107	2 974
Capitalized Interest				2	70	298	1 336	3 339	1 513
Keeyask - Generation	**31 335**	**33 314**	**32 301**	**36 083**	**43 112**	**54 280**	**56 677**	**56 434**	**80 229**
External Consultants hired by MH	6 185	7 309	6 332	8 644	9 514	11 803	11 731	2 340	2 329
Internal MH Staff Costs	4 427	2 890	2 915	3 515	4 583	4 415	6 417	6 589	10 733
MH funded expenses for costs incurred by third parties	598	54	12	225	839	42	135	5 149	17 745
Joint Generation Development Agreements, Process and Study Costs	10 835	11 651	11 614	11 086	12 017	12 579	12 388	8 051	8 783
Mitigation						5 886	4 635	1 103	1 528
Materials & Other	1 855	1 538	1 045	(79)	775	723	751	7 598	9 404
Capitalized Interest	7 436	9 871	10 383	12 692	15 384	18 832	20 620	25 605	29 707

(in thousands of dollars)

Project	Fiscal Year								
	2004	2005	2006	2007	2008	2009	2010	2011	2012
Conawapa - Generation	**2 907**	**8 478**	**28 098**	**32 636**	**34 030**	**33 429**	**35 169**	**29 724**	**28 203**
External Consultants hired by MH	2 237	4 096	8 167	12 585	11 748	12 591	6 674	5 238	2 869
Internal MH Staff Costs	514	2 503	4 790	6 762	6 338	5 792	6 292	5 141	5 526
MH funded expenses for costs incurred by third parties	1	26	415	3 107	1 540	670	1 313	628	59
Joint Generation Development Agreements, Process and Study Costs		291	734	1 510	3 958	3 961	3 699	2 414	2 431
Mitigation							4 800		
Materials & Other	154	1 563	13 992	5 239	4 707	2 294	2 305	4 116	3 299
Capitalized Interest	1	(1)	0	3 434	5 740	8 120	10 087	12 187	14 019
Kelsey Improvements & Upgrades	**4 733**	**7 214**	**18 144**	**29 682**	**31 758**	**44 477**	**47 028**	**37 797**	**32 794**
External Consultants hired by MH	37	132	389	216	150	260	435	401	58
Internal MH Staff Costs	1 411	3 025	5 325	7 240	10 308	9 093	7 945	8 648	8 051
MH funded expenses for costs incurred by third parties	2 723	3 107	10 068	15 522	13 946	27 031	29 756	21 197	18 029
Materials & Other	313	477	1 480	4 399	4 263	5 479	6 105	4 378	3 607
Capitalized Interest	250	474	882	2 305	3 091	2 614	2 788	3 172	3 049
Kettle Improvements & Upgrades						**785**	**7 502**	**17 814**	**22 137**
External Consultants hired by MH						3	15	256	24
Internal MH Staff Costs						465	1 215	3 854	7 153
MH funded expenses for costs incurred by third parties						10	6 045	11 013	10 023
Materials & Other						285	64	1 793	2 850
Capitalized Interest						21	162	897	2 088
Pointe du Bois - Spillway Replacement				**4 420**	**9 314**	**13 345**	**10 639**	**15 253**	**24 880**
External Consultants hired by MH					4 706	7 438	4 049	6 885	8 767
Internal MH Staff Costs					2 275	3 893	4 240	4 616	6 832
MH funded expenses for costs incurred by third parties					0	189	(2)	505	3 673
Materials & Other				4 420	1 806	473	250	335	1 543
Capitalized Interest					527	1 351	2 101	2 912	4 064
Pointe du Bois - Transmission				**176**	**770**	**1 715**	**5 992**	**17 004**	**15 743**
External Consultants hired by MH				0	18	296	452	824	(617)
Internal MH Staff Costs				174	583	1 016	1 603	3 671	7 329
MH funded expenses for costs incurred by third parties					3	81	18	1 350	1 426
Materials & Other				1	133	225	3 693	10 159	5 646
Capitalized Interest				2	33	97	226	1 000	1 959
Gillam Redevelopment and Expansion Program								**14**	**(14)**
Internal MH Staff Costs								12	(12)
Materials & Other								1	(1)
Capitalized Interest								0	(0)
Bipole III - Transmission Line	**907**	**1 235**	**1 213**	**1 472**	**1 955**	**3 336**	**11 709**	**19 002**	**18 350**
External Consultants hired by MH	23	511	484	633	344	916	3 932	5 266	4 819
Internal MH Staff Costs	611	374	369	354	639	1 473	3 420	3 981	4 442
MH funded expenses for costs incurred by third parties		11			0	2	3	40	1
Joint Generation Development Agreements, Process and Study Costs							247	2 374	1 786
Materials & Other	73	89	2	24	36	203	2 200	5 205	3 905
Capitalized Interest	200	250	358	461	936	744	1 907	2 135	3 398
Bipole III - Converter Stations						**14 541**	**15 882**	**28 069**	**36 417**
External Consultants hired by MH						531	3 151	3 708	5 551
Internal MH Staff Costs						292	3 425	5 864	7 453
MH funded expenses for costs incurred by third parties							1 877	5 163	13 848
Materials & Other						13 706	6 987	11 688	5 858
Capitalized Interest						12	443	1 645	3 707
Bipole III - Collector Lines							**0**	**387**	**2 075**
External Consultants hired by MH								7	107
Internal MH Staff Costs							0	318	985
MH funded expenses for costs incurred by third parties								40	299
Materials & Other								20	620
Capitalized Interest								2	64
Riel 230/500 kV Station	**268**	**187**	**367**	**242**	**2 318**	**2 007**	**25 483**	**46 465**	**52 732**
External Consultants hired by MH	49	0		101	295	563	5 219	3 424	2 540
Internal MH Staff Costs	98	51	314	44	607	2 189	3 798	4 635	5 472
MH funded expenses for costs incurred by third parties	3					24	6 887	10 739	26 006
Materials & Other	2	-	0	24	1 676	663	8 683	24 383	12 471
Capitalized Interest	116	135	53	73	10	220	895	3 284	6 244
Costs Transferred to Bipole 3 - Transmission					(270)	(1 651)			
Dorsey - US Border New 500kV Transmission Line							**811**	**158**	**68**
External Consultants hired by MH							811	32	
Internal MH Staff Costs								64	2
MH funded expenses for costs incurred by third parties								2	
Materials & Other								5	1
Capitalized Interest								56	65

(in thousands of dollars)

Project	Fiscal Year								
	2004	2005	2006	2007	2008	2009	2010	2011	2012
St. Joseph Wind Transmission						**6**	**756**	**8 131**	**1 037**
External Consultants hired by MH							343	499	15
Internal MH Staff Costs						6	462	3 529	704
MH funded expenses for costs incurred by third parties							9	1 193	414
Materials & Other							(62)	2 777	(148)
Capitalized Interest						0	4	134	51
Firm Import Upgrades							**8**	**161**	**22**
External Consultants hired by MH								109	
Internal MH Staff Costs							8	49	10
Materials & Other									0
Capitalized Interest								3	12
Brandon Combustion Turbine Pipeline Upgrade							**3 660**	**20**	
MH funded expenses for costs incurred by third parties							3 660	20	
Northern AC Transmission System Requirements	**8 706**	**19 110**	**8 834**	**4 049**	**395**				
External Consultants hired by MH	129	737	277	190	31				
Internal MH Staff Costs	3 957	6 988	5 793	1 302	288				
MH funded expenses for costs incurred by third parties	268	112	37	5					
Materials & Other	4 096	10 337	1 545	2 229	76				
Capitalized Interest	258	935	1 183	324	0				
Manitoba - Ontario Clean Energy/Transfer Initiative			**54**	**42**					
Internal MH Staff Costs			54	38					
Capitalized Interest			0	4					
Brandon Combustion Turbine	**(3 024)**	**1 163**	**6**						
External Consultants hired by MH	174	262	4						
Internal MH Staff Costs	242	198	2						
MH funded expenses for costs incurred by third parties	(3 544)	448							
Materials & Other	103	204	(0)						
Capitalized Interest	1	50							

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Reference: Tab 3 Consulting & Mitigation Costs

b) For the analysis in (a) please provide a breakdown of payments by community.

ANSWER:

Please see the following schedules which provide a breakdown of payments by community. There are only two "joint generation development agreements," namely the Project Development Agreement for Wuskwatim and the Joint Keeyask Development Agreement for Keeyask. The schedules contain payments related to these two agreements as well as process, study and mitigation costs paid to communities related to Wuskwatim transmission, Keeyask transmission, Conawapa and Bipole III.

4) Joint Generation Development Agreements, Process and Study Costs						(in thousands of dollars)
Project	Community	2008	2009	2010	2011	2012
Bipole III	Fox Lake Cree Nation	-	-	-	243	830
	Manitoba Metis Federation	-	-	50	225	166
	Opaskwayak Cree Nation	-	-	125	125	-
	Long Plain First Nation	-	-	-	60	7
	Swampy Cree Tribal Council	-	-	-	-	15
	Swan Lake First Nation	-	-	-	60	43
	Wuskwi Sipihik First Nation	-	-	-	25	10
	Southern Chiefs Organization	-	-	32	-	-
	Sapotaweyak Cree Nation	-	-	-	-	30
	Cree Nation Partners (TCN/WLFN)	-	-	40	1,636	684
Bipole III Total		-	-	247	2,374	1,786
Keeyask - Generation	Fox Lake Cree Nation	2,367	2,401	2,317	1,472	1,712
	Manitoba Metis Federation	-	-	25	-	16
	Nisichawayasihk Cree Nation	-	-	-	-	4
	York Factory First Nation	2,014	2,239	2,377	2,006	2,010
	Cree Nation Partners (TCN/WLFN)	7,636	7,938	7,669	4,515	4,755
Keeyask - Generation Total		12,017	12,579	12,388	7,993	8,497
Keeyask - Transmission	Cree Nation Partners (TCN/WLFN)	-	-	-	58	286
Keeyask - Transmission Total		-	-	-	58	286
Wuskwatim - Generation	Nisichawayasihk Cree Nation	5,971	869	1,248	1,278	1,228
	Cree Nation Partners (TCN/WLFN)	364	-	-	-	-
Wuskwatim - Generation Total		6,335	869	1,248	1,278	1,228
Conawapa	Fox Lake Cree Nation	2,102	1,250	1,049	751	915
	Manitoba Metis Federation	-	-	25	-	16
	York Factory First Nation	929	1,150	908	575	616
	Shamattawa First Nation	100	134	327	355	329
	Cree Nation Partners (TCN/WLFN)	827	1,427	1,389	733	555
Conawapa Total		3,958	3,961	3,699	2,414	2,431
Grand Total		22,310	17,408	17,582	14,117	14,228

5) Mitigation						**(in thousands of dollars)**
Project	Community	2008	2009	2010	2011	2012
Keeyask - Generation	Fox Lake Cree Nation	-	100	2,112	30	-
	York Factory First Nation	-	-	100	300	207
	Cree Nation Partners (TCN/WLFN)	-	5,786	2,423	773	1,321
Keeyask - Generation Total		-	5,886	4,635	1,103	1,528
Wuskwatim - Generation	Nisichawayasihk Cree Nation	305	4,682	141	149	172
Wuskwatim - Generation Total		305	4,682	141	149	172
Wuskwatim - Transmission	Opaskwayak Cree Nation	4	19	41	54	73
	Nisichawayasihk Cree Nation	12	55	119	158	214
	Nelson House Community Council	1	3	5	7	10
	Cormorant	4	19	41	54	73
	Snow Lake	5	25	54	72	97
	Thicket Portage	1	3	5	7	10
	Herb Lake Landing	1	3	5	7	10
Wuskwatim - Transmission Total		27	126	270	360	487
Conawapa	Fox Lake Cree Nation	-	-	4,800	-	-
Conawapa Total		-	-	4,800	-	-
Grand Total		332	10,695	9,847	1,612	2,187

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Reference: 2012 GRA Tab 9 P. 16-19

a) Please refile the information in 2012 GRA Tab 9 (P.18) and provide unit price calculations for the entire period since 2000/01.

ANSWER:

Please see tables below.

TOTAL SALES									
	DEPENDABLE SALES			**OPPORTUNITY SALES**			**SYSTEM MERCHANT SALES**		
	GWh	**CAD $M**	**AvgPrice**	**GWh**	**CAD $M**	**AvgPrice**	**GWh**	**CAD $M**	**AvgPrice**
2000/01	6,352	258	40.64	5,801	217	37.39	0	0	0
2001/02	6,277	322	51.65	6,022	281	46.63	0	0	0
2002/03	6,544	339	53.37	3,191	137	42.97	0	0	0
2003/04	6,231	295	48.46	735	52	48.46	11	0.5	44.43
2004/05	5,633	290	51.44	4,798	239	51.44	315	11	33.32
2005/06	4,044	240	59.25	10,303	510	47.73	919	63	60.07
2006/07	3,654	218	59.67	6,250	295	46.53	1,206	60	43.38
2007/08	3,921	209	53.22	7,099	328	44.42	1,262	72	49.17
2008/09	4,087	233	57.12	6,039	287	43.64	1,598	86	48.08
2009/10	3,263	186	56.99	7,597	184	22.98	775	26	28.29
2010/11	3,377	172	51.09	6,967	181	24.77	712	28	36.93
2011/12	3,742	175	46.79	6,502	152	22.18	436	17	31.10

TOTAL U.S. SALES									
	U.S. DEPENDABLE SALES			U.S. OPPORTUNITY SALES			U.S. SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2000/01	4,895	199	40.69	4,511	167	36.95	0	0	0
2001/02	4,767	263	55.15	5,083	247	48.66	0	0	0
2002/03	4,947	277	56.09	2,713	115	42.30	0	0	0
2003/04	5,245	259	49.45	507	35	69.42	0	0	0
2004/05	5,633	290	51.44	3,218	171	54.48	109	1	10.64
2005/06	4,044	240	59.25	8,879	401	45.12	0	0	0
2006/07	3,654	218	59.67	5,877	270	46.24	0	0	0
2007/08	3,921	209	53.22	6,618	289	44.19	0	0	0
2008/09	4,087	233	57.12	5,622	237	43.24	0	0	0
2009/10	3,263	186	56.99	7,224	160	22.28	33	2	0
2010/11	3,377	172	51.09	6,062	146	24.44	5	0.3	37.82
2011/12	3,742	175	46.79	5,616	117	21.13	80	3	35.21

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Reference: 2012 GRA Tab 9 P. 16-19

b) Please refile and update opportunity sales and prices – peak/off-peak in Tab 9 (P.16) to include revenues achieved in each case.

ANSWER:

Please see table below.

OPPORTUNITY EXPORTS						
	On Peak GWh	**Off Peak GWh**	**On Peak Avg Price (CAD$)**	**Off Peak Avg Price (CAD$)**	**On Peak Revenues (CAD $M)**	**Off Peak Revenues (CAD $M)**
2005/06	3,142	7,161	72.73	36.75	245	265
2006/07	1,972	4,278	66.26	37.44	135	160
2007/08	2,212	4,887	66.19	32.97	162	166
2008/09	1,802	4,237	71.78	29.37	153	134
2009/10	2,497	5,100	31.14	18.74	84	100
2010/11	2,268	4,699	31.90	21.23	76	105
2011/12	1,952	4,550	28.76	22.51	59	93

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Reference: 2012 GRA Tab 9 P. 16-19

c) Please file the tables in Tab 9 (P.19) showing unit prices for exports

ANSWER:

Please see table below.

	EXPORT REVENUES											
	2008/09			2009/10			2010/11			2011/12		
	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price
Opportunity												
Bilateral	1305	101	71.37	2628	60	24.08	1851	52	28.44	1923	50	26.02
Market												
Day Ahead	4040	122	30.33	3111	59	19.09	3233	69	21.39	2720	52	18.68
Real Time	690	60	50.88	1858	71	27.33	1883	60	26.83	1859	50	23.24
Merchant	1598	86	48.08	775	26	28.29	712	27	36.93	436	17	31.10

PUB/MH I-12

Reference: 2010 GRA MH Exhibit #51

a) Please file the 2010 GRA # Exhibit 51 (Table 1 Exports, Table 2 Imports)

ANSWER:

Table 1. Export Revenues		**2008/09**			**2009/10**	
	GWh	**$M (Cdn)**	**¢/kWh**	**GWh**	**$M (Cdn)**	**¢/kWh**
Dependable						
Physical	3,741	213	5.7	3,146	178	5.7
Financial	346	20		117	8	
Dependable Total	4,087	233	5.7	3,263	186	5.7
Opportunity						
Bilateral						
Physical	1,099	83	7.6	2,122	44	2.1
Financial	206	18		506	16	
Opportunity Bilateral Total	1,305	101		2,628	60	
Market						
Day Ahead						
Physical	4,288	147	3.4	3,154	69	2.2
Financial	-248	-25		-43	-10	
Day Ahead Total	4,040	122	3.0	3,111	59	1.9
Real Time						
AESO	40	3		144	5	
IESO						
Energy	264	13		219	6	
Congestion Mgmnt. Settlement Credits		23			17	
Inter-tie Offer Guarantee		2			1	
MISO						
Real Time Physical	271	14		167	5	
Real Time Financial	0	0		1	0	
ASM Energy	115	4		1326	34	
ASM Other (Reg, Spin, Supp, True-Ups)		1			2	
RT Total (only physical and energy related)	690	34	4.9	1,856	50	2.7
RT Total		60			70	
Total (only physical and energy related)	9,818	477	4.9	10,278	341	3.3
Total		516			375	

note: excludes System Merchant

Table 2. Purchases		**2008/09**			**2009/10**	
	GWh	**$M (Cdn)**	**¢/kWh**	**GWh**	**$M (Cdn)**	**¢/kWh**

Dependable						
Physical	395	21	5.3	454	21	4.6
Financial	0	0		59	1	
Dependable Total	395	21	5.3	513	22	4.3
Opportunity						
Bilateral						
Physical	1	0.04	4.0	3	0.05	1.7
Financial	8	6.86		3	0.00	
Opportunity Bilateral Total	9	7		6	0	
Market						
Day Ahead						
Physical	73	2	2.8	74	1.9	2.6
Financial	-1	0		1	0.1	
Day Ahead Total	72	2	2.8	75	2	2.7
Real Time						
IESO						
IESO Energy	140	6		107	3	
CMSC		-1			-2	
MISO						
Physical	63	5		41	2	
Financial	302	12		578	11	
RT Total (only physical and energy related)	203	11	5.4	148	5	3.4
RT Total		22			14	
Total (only physical and energy related)	672	34	5.1	679	28	4.1
Total	981	52		1,320	38	

note: excludes System Merchant

PUB/MH I-12

Reference: 2010 GRA MH Exhibit #51

b) Please file the same information for 2010/11 and 2011/12

ANSWER:

Table 1. Export Revenues		**2010/11**			**2011/12**	
	GWh	**$M (Cdn)**	**¢/kWh**	**GWh**	**$M (Cdn)**	**¢/kWh**
Dependable						
Physical	3,138	161	5.1	3,490	163	4.7
Financial	239	12		253	12	
Dependable Total	3,377	172	5.1	3,743	175	4.7
Opportunity						
Bilateral						
Physical	1,608	45	2.8	1,535	40	2.6
Financial	243	7		388	10	
Opportunity Bilateral Total	1,851	52		1,923	50	
Market						
Day Ahead						
Physical	3,240	73	2.3	3,009	62	2.1
Financial	-8	-4		-290	-10	
Day Ahead Total	3,232	69	2.1	2,719	52	1.9
Real Time						
AESO	24	1		25	1	
IESO						
Energy	671	18		538	13	
Congestion Mgmnt. Settlement Credits		9			4	
Inter-tie Offer Guarantee		1			3	
MISO						
Real Time Physical	215	6		290	7	
Real Time Financial	4	0		10	0	
ASM Energy	970	24		997	20	
ASM Other (Reg, Spin, Supp, True-Ups)		2			1	
RT Total (only physical and energy related)	1,880	49	2.6	1,850	41	2.2
RT Total		60			50	
Total (only physical and energy related)	9,866	328	3.3	9,884	306	3.1
Total		353			327	

note: excludes System Merchant

Table 2. Purchases **2010/11** **2011/12**

	GWh	$M (Cdn)	¢/kWh	GWh	$M (Cdn)	¢/kWh
Dependable						
Physical	433	22	5.1	936	62	6.7
Financial	16	0		33	0	
Dependable Total	449	22	5.0	969	63	6.5
Opportunity						
Bilateral						
Physical	1	0.06	6.4	1	0.03	4.3
Financial	7	-0.02		0	0.05	
Opportunity Bilateral Total	8	0		1	0.08	
Market						
Day Ahead						
Physical	128	2.5	2.0	215	3.0	1.4
Financial	19	0.1		10	0.2	
Day Ahead Total	147	2.6	1.8	225	3	1.4
Real Time						
IESO						
IESO Energy	15	0.3		20	0	
CMSC		-0.1			0	
MISO						
Physical	60	2.6		72	3	
Financial	475	12.0		348	7	
RT Total (only physical and energy related)	75	3	3.9	92	3	3.2
RT Total		15			10	
Total (only physical and energy related)	637	28	4.3	1,244	68	5.5
Total	1,154	40		1,635	76	

note: excludes System Merchant

PUB/MH I-13

Reference: 2010 GRA Exhibit #MH-16

a) CCCT Generation Costs: Please confirm and graphically illustrate that the variable cost of CCCT (natural gas) generation can typically be reflected by natural gas supply costs as follows:

Natural Gas Supply Cost US$/mmBtu	Marginal Cost of CCCT Electricity ¢/kWh
3.00	3.7
7.00	6.7
12.50	10.8

ANSWER:

The 2010 GRA Exhibit #MH-16 document does use the term "marginal cost", but uses the term variable production costs for gas and coal generation. The variable production costs for a less efficient CCCT generator as identified in this illustrative example are reproduced below. The marginal generator in a large market such as MISO can change as frequently as every five minutes. Each generator which is operating in the day ahead or real time market in a particular hour will be paid the market clearing price for that hour, which is based on and is not less than the variable (or marginal) cost of the most expensive unit operating during each interval of that hour. Any capacity revenue would be in addition to the revenue received from the day ahead or real time market.

Natural Gas Supply Cost US$/mmBtu	Variable Production Cost For less efficient CCCT US ¢/kWh
3.00	3.7
7.00	7.7
12.50	13.2

PUB/MH I-13

Reference: 2011 GRA Exhibit #MH-16

b) Please confirm that the MISO Day-Ahead Market price is typically at or below the variable cost of CCCT generation (if not explain).

ANSWER:

It is not confirmed that MISO Day-Ahead market price is typically at or below the variable cost of CCCT generation.

As explained in the response to PUB/MH I-18 b), there are a wide variety of generation types in the MISO market footprint, including wind, hydro, biomass, nuclear, coal, combined cycle natural gas and combustion turbine natural gas. Pricing factors such as current thermal fuel prices (coal and natural gas), forced generation outages, weather/ forecast loads and regional wind speeds all contribute to establishing day-ahead and real time MISO market prices.

The CCCT generation within the MISO market footprint utilizes a variety of gas turbine models and steam turbine/generator arrangements of varying ages and technologies- hence there is no single heat rate (fuel efficiency) number that represents the variable cost of all CCCT generation.

Manitoba Hydro can confirm that CCCT generation is the marginal generator in the MISO market a portion of the time and does set the market price during those hours. As far as Manitoba Hydro is aware, MISO does not publish any data as to the portion of time that CCCT generation is the marginal type of generation in the MISO market.

PUB/MH I-14

Reference: **2012 GRA – Tab 9 (Pg. 16 and 18)/Attachment 5 (July 20/12)**

Average Export Revenue Prices

Average Export Revenue Prices (Ref.: Attachment 5)
Out to 2015/16 Calculation

Export Sales	2012/13 (GWh)	2013/14 (GWh)	2014/15 (GWh)	2015/16 (GWh)
CDN Market Price	915	589	577	603
U.S.L.T Fixed Price	2000	2000	2000	2000
U.S Market Price	4337	4537	4378	4257

Export Prices	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
CDN Market Sales	3.7	4.4	5.3	6.2
U.S.L.T Contract[1]	5.5	5.6	5.7	5.8
U.S Market Sales[2]	2.6	2.7	4.7	6.4

[1] Projection of NEB Data based on inflation

[2] Back-calculated from U.S sales revenues

Preamble: **Average Export Revenue Prices**

a) Canadian Exports

Please confirm the Forecast Revenue for CDN export sales reflects primarily non-firm energy sales with prices as follows:

2012/13 - 3.7¢/kWh (equivalent to $3.00 natural gas)
2013/14 - 4.4¢/kWh
2014/15 - 5.3¢/kWh
2015/16 - 6.2¢/kWh (equivalent to $6.50 natural gas)

ANSWER:

It is confirmed that the above Forecast Revenue for CDN average export revenue figures are correct.

As noted in the response to PUB/MH I-19(a), average export revenue is not the same as an export price forecast.

As noted in the response to PUB/MH I-18(b) that there are a wide variety of generation types and pricing factors that contribute to the determination of prices in a power market and hence it is not appropriate to imply a specific natural gas price can translate into a specific market price.

PUB/MH I-14

Reference: 2012 GRA – Tab 9 (Pg. 16 and 18)/Attachment 5 (July 20/12)

Average Export Revenue Prices

Average Export Revenue Prices (Ref.: Attachment 5)
Out to 2015/16 Calculation

Export Sales	2012/13 (GWh)	2013/14 (GWh)	2014/15 (GWh)	2015/16 (GWh)
CDN Market Price	915	589	577	603
U.S.L.T Fixed Price	2000	2000	2000	2000
U.S Market Price	4337	4537	4378	4257

Export Prices	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
CDN Market Sales	3.7	4.4	5.3	6.2
U.S.L.T Contract[1]	5.5	5.6	5.7	5.8
U.S Market Sales[2]	2.6	2.7	4.7	6.4

[1] **Projection of NEB Data based on inflation**

[2] **Back-calculated from U.S sales revenues**

Preamble: Average Export Revenue Prices

b) Long-term U.S. Contracts:

Please confirm that the forecast revenue for U.S. export sales includes about 2000 GWh of L.T. firm contract sales out to 2015 with defined prices in the 5.0 to 6.0¢/kWh range.

ANSWER:

Not confirmed.

Manitoba Hydro can confirm that the indicated total energy volumes to the US market are correct.

Manitoba Hydro cannot confirm the allocation of this export energy into fixed and opportunity components as it allows the determination of commercially-sensitive contract specific unit revenues on a go-forward basis.

PUB/MH I-14

Reference: **2012 GRA – Tab 9 (Pg. 16 and 18)/Attachment 5 (July 20/12)**

Average Export Revenue Prices

Average Export Revenue Prices (Ref.: Attachment 5)
Out to 2015/16 Calculation

Export Sales	2012/13 (GWh)	2013/14 (GWh)	2014/15 (GWh)	2015/16 (GWh)
CDN Market Price	915	589	577	603
U.S.L.T Fixed Price	2000	2000	2000	2000
U.S Market Price	4337	4537	4378	4257
Export Prices				
	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
CDN Market Sales	3.7	4.4	5.3	6.2
U.S.L.T Contract[1]	5.5	5.6	5.7	5.8
U.S Market Sales[2]	2.6	2.7	4.7	6.4

[1] Projection of NEB Data based on inflation

[2] Back-calculated from U.S sales revenues

Preamble: **Average Export Revenue Prices**

c) Exports into U.S. MISO Market:

Please confirm that the forecast revenue for U.S. export sales includes opportunity market sales at approximate average unit prices that can be back-calculated as follows:

2012/13 - 4300 GWh @ 2.6¢/kWh (equivalent to $2.00 natural gas)
2013/14 - 4500 GWh @ 2.7¢/kWh
2014/15 - 4400 GWh @ 4.7¢/kWh
2015/16 - 4300 GWh @ 6.4¢/kWh (equivalent to $7.00 natural gas)

ANSWER:

Manitoba Hydro cannot confirm the opportunity market average unit prices as it requires the allocation of this export energy into fixed and opportunity components which allows the determination of commercially-sensitive contract specific unit revenues on a go-forward basis.

As noted in the response to PUB/MH I-18 b) there are a wide variety of generation types and pricing factors that contribute to the determination of prices in a power market and hence it is not appropriate to imply a specific natural gas price can translate into a specific market price.

PUB/MH I-15

Reference: 22012 GRA – Tab 9/ Attachment 5 (July 20/12)

Export Sales/Prices

Average Export Revenue Prices (Reference Attachment 5)
2016/19 to 2020/21 Calculation

Export Sales	2016/17 (GWh)	2017/18 (GWh)	2018/19 (GWh)	2019/20 (GWh)	2020/21 (GWh)
CDN Market Price	505	581	570	537	471
U.S.L.T Fixed Price	1400	1400	1400	1400	2800
U.S Market Price	4648	4453	4273	4445	4913
Export Prices					
	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
CDN Market Sales	7.0	7.7	8.4	9.1	9.9
U.S.L.T Contract[1]	8.7	8.8	8.9	9.0	9.2
U.S Market Sales[2]	6.3	7.1	7.8	9.0	9.5

[1] ICF (Feb 2011) with added inflation

[2] Back-calculated from U.S sales revenues

Preamble: Export Sales/Prices

a) Canadian Exports

Please confirm the forecast revenue for CDN export sales reflects primarily non-firm energy sales with prices as follows:

2016/17 7.0 ¢/kWh (equivalent to $7.50 GJ Natural Gas
2017/18 7.7 ¢/kWh
2018/19 8.4 ¢/kWh
2019/20 9.1 ¢/kWh
2020/21 9.9 ¢/kWh (equivalent to $9.0 GJ Natural Gas

ANSWER:

With respect to the Canadian export sales information, Manitoba Hydro can confirm that this information is consistent with the information for export sales to Canada provided in Tab 9/Attachment 5, with the exception of the total export energy to the Canadian market for 2016/17 which should be set equal to 595 GWh instead of 505 GWh. In addition, Manitoba Hydro would clarify that the information referenced in this question as export prices are more accurately referenced as average export unit revenues.

As noted in the response to PUB/MH I-18(b), there are a wide variety of generation types and pricing factors that contribute to the determination of prices in a power market and hence it is not appropriate to imply a specific natural gas price can translate into a specific market price.

PUB/MH I-15

Reference: 2012 GRA – Tab 9 (Pg. 16 and 18)/Attachment 5 (July 20/12)

Average Export Revenue Prices

Average Export Revenue Prices (Reference Attachment 5)
2016/19 to 2020/21 Calculation

Export Sales	2016/17 (GWh)	2017/18 (GWh)	2018/19 (GWh)	2019/20 (GWh)	2020/21 (GWh)
CDN Market Price	505	581	570	537	471
U.S.L.T Fixed Price	1400	1400	1400	1400	2800
U.S Market Price	4648	4453	4273	4445	4913
Export Prices					
	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
CDN Market Sales	7.0	7.7	8.4	9.1	9.9
U.S.L.T Contract[1]	8.7	8.8	8.9	9.0	9.2
U.S Market Sales[2]	6.3	7.1	7.8	9.0	9.5

[1] ICF (Feb 2011) with added inflation

[2] Back-calculated from U.S sales revenues

Preamble: Export Sales/Prices

b) Long-term U.S. Contracts

Please confirm the forecast revenue for U.S. Export sales includes about 1600 GWh of L.T. firm contract sales out to 2019/20 and about 3800 GWh of L.T. contracts in 2019/20 and beyond, with prices starting in the 8.0 to 9.0¢/kWh range.

ANSWER:

Not confirmed.

Manitoba Hydro can confirm that the indicated total energy volumes to the US market are correct.

Manitoba Hydro cannot confirm the allocation of this export energy into fixed and opportunity components as it allows the determination of commercially-sensitive contract specific unit revenues on a go-forward basis.

PUB/MH I-15

Reference: **2012 GRA – Tab 9 (Pg. 16 and 18)/Attachment 5 (July 20/12)**

Average Export Revenue Prices

Average Export Revenue Prices (Reference Attachment 5)
2016/19 to 2020/21 Calculation

Export Sales	2016/17 (GWh)	2017/18 (GWh)	2018/19 (GWh)	2019/20 (GWh)	2020/21 (GWh)
CDN Market Price	505	581	570	537	471
U.S.L.T Fixed Price	1400	1400	1400	1400	2800
U.S Market Price	4648	4453	4273	4445	4913
Export Prices					
	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
CDN Market Sales	7.0	7.7	8.4	9.1	9.9
U.S.L.T Contract[1]	8.7	8.8	8.9	9.0	9.2
U.S Market Sales[2]	6.3	7.1	7.8	9.0	9.5

[1] ICF (Feb 2011) with added inflation

[2] Back-calculated from U.S sales revenues

Preamble: **Export Sales/Prices**

c) Exports into the U.S. MISO Market

Please confirm that the forecast revenue for U.S. Export sales from 2016/17 to 2020/21 includes opportunity market sales at approximate average unit prices that can be back-calculated as follows:

2016/17	**4600 GWh @ 6.3¢/kWh (equivalent to $7.00 GJ natural gas)**
2017/18	**4400 GWh @ 7.1¢/kWh**
2018/19	**4300 GWh @ 7.8¢/kWh**
2019/20	**4400 GWh @ 9.0¢/kWh (equivalent to $9.00 GJ natural gas)**
2020/21	**4900 GWh @ 9.5¢/kWh**

ANSWER:

Not confirmed.

Manitoba Hydro can confirm that the indicated total energy volumes to the US market are correct.

Manitoba Hydro cannot confirm the allocation of this export energy into fixed and opportunity components as it allows the determination of commercially-sensitive contract specific unit revenues on a go-forward basis.

As noted in the response to PUB/MH I-18 b) that there are a wide variety of generation types and pricing factors that contribute to the determination of prices in a power market and hence it is not appropriate to imply a specific natural gas price can translate into a specific market price.

PUB/MH I-16

Reference: 2012/13 and 2013/14 GRA/Tab 4/ Attachment 5 (July 20/12)

a) Natural Gas Supply Prices Assumptions and ICF – 2011 Projections

Please provide the ICF comparison of their natural gas supply price forecasts provided during the 2010 GRA hearing and also provide the prices submitted by CENTRA (Augu.15/11) to PUB.

ANSWER:

Please see the attachments to this response.

Exhibit # MH-60
Transcript Page #2721

Manitoba Hydro Undertaking #56

Extend ICF's natural gas forecast approximately 10 - 15 years.

ICF Response:

ICF Forecast of Henry Hub Natural Gas Prices: 2011 -2035

Year	Nominal $/MMBtu	2010$/MMBtu
2011	4.2	4.1
2012	4.7	4.5
2013	5.0	4.6
2014	5.7	5.2
2015	5.3	4.6
2016	6.4	5.6
2017	7.0	5.9
2018	7.1	5.8
2019	7.7	6.2
2020	8.4	6.6
2021	8.8	6.7
2022	8.7	6.5
2023	8.8	6.4
2024	9.2	6.5
2025	9.4	6.5
2026	9.8	6.6
2027	10.0	6.6
2028	10.2	6.5
2029	10.4	6.5
2030	10.7	6.5
2031	11.3	6.7
2032	11.9	6.9
2033	11.8	6.7
2034	12.5	6.9
2035	12.9	6.9

Note: 2.5% annual inflation is assumed.

Centra Gas Manitoba Inc. PUB/Centra 21
Process for Review of Gas Supply, Storage and Transportation Arrangements Attachment
August 15, 2011

	ICF Base Case Price Forecast at Henry Hub (Real $/MMBtu)			ICF Base Case Price Forecast at AECO (Real $/MMBtu)		
1		**November 2008**	**April 2011**		**November 2008**	**April 2011**
2	2001	4.79		2001	4.23	
3	2002	3.92		2002	3.01	
4	2003	6.24		2003	5.35	
5	2004	6.53		2004	5.49	
6	2005	9.56		2005	7.78	
7	2006	7.17		2006	6.05	
8	2007	7.20		2007	6.19	
9	2008	9.02	9.02	2008	7.81	7.89
10	2009	5.40	3.98	2009	4.18	3.56
11	2010	7.31	4.38	2010	6.73	3.89
12	2011	6.84	4.59	2011	6.18	3.86
13	2012	7.30	4.71	2012	6.69	3.87
14	2013	7.04	4.60	2013	6.47	3.79
15	2014	7.73	5.51	2014	7.16	4.65
16	2015	7.61	5.40	2015	6.99	4.64
17	2016	7.46	5.23	2016	6.53	4.49
18	2017	7.66	5.36	2017	6.82	4.64
19	2018	7.85	5.35	2018	7.04	4.60
20	2019	7.93	5.48	2019	7.17	4.74
21	2020	8.22	5.80	2020	7.41	5.06
22	2021	7.34	5.99	2021	5.93	5.28
23	2022	8.16	6.20	2022	7.00	5.51
24	2023	8.14	6.11	2023	6.93	5.46
25	2024	7.98	6.34	2024	6.49	5.71
26	2025	8.20	6.14	2025	6.87	5.52
27	2026	8.66	6.22	2026	7.39	5.65
28	2027	8.68	6.14	2027	7.43	5.56
29	2028	9.12	6.52	2028	7.96	5.95
30	2029	9.00	6.27	2029	7.82	5.70
31	2030	9.49	6.61	2030	8.35	6.08

PUB/MH I-16

Reference: 2012/13 and 2013/14 GRA/Tab 4/ Attachment 5 (July 20/12)

Preamble: Export Sales/Prices

b) Carbon Pricing – ICF Presentation at 2010 GRA Hearing

Please indicate what level of CO2 pricing has been incorporated in MH's export price/import cost projections prior to 2015/16, 2020/21, 2025/26 and 2030/31

ANSWER:

Manitoba Hydro's electricity export price forecast is prepared using information from several external price forecast consultants. Manitoba Hydro has a consultant services agreement with each of the electricity export price forecast consultants and the services agreement has confidentiality requirements that prevent Manitoba Hydro from publically releasing the forecast reports and any associated input/ output data identified in the reports. The electricity export price forecast consultants vigorously protect their reports from becoming public as it would impair their ability to sell similar reports to other clients.

Further, the specific details of Manitoba Hydro's electricity price forecast, including details on specific pricing factors such as the assumptions regarding CO2 premiums, are commercially sensitive information and therefore, are confidential since public release could harm the Corporation in negotiation of contracts for export sales.

For some perspective on the outlook of the electricity export price forecast consultants regarding the value of carbon in the price forecast please see Manitoba Hydro's response to CAC/MH I-110(a).

PUB/MH I-17

Reference: GRA – Attachment 5 (July 20/12)

a) MH Thermal Generation – Cost Assumptions

Please explain the 8-9¢/kWh cost of thermal generation in the years from 2012/13 to 2018/19 and the increase to 12.0 to 13.0¢/kWh in 2019/20 to 2021/22 with reference to natural gas price increases (for MH's SCCT and other natural gas generation).

ANSWER:

Prior to 2019/20, thermal energy includes generation from the Brandon Unit 5 coal-fired plant (as constrained under the Climate Change and Emissions Reductions Act), the Brandon 6&7 gas-fired plant, and the Selkirk gas-fired plant. As a result, the average cost for thermal generation in Attachment 5 reflects the costs of coal and gas generation.

With the assumed cessation of operations at the Brandon Unit 5 plant in 2019/20, thermal generation after this date will be based exclusively on gas. As the variable cost for coal-fired generation is less than that for gas-fired generation, the average cost for thermal generation after 2019/20 will increase.

PUB/MH I-17

Reference: GRA – Attachment 5 (July 20/12)

b) Imported Energy – Cost Assumptions

Please explain the price discrepancy in MH"s ability to import about 1500 GWh/yr in the 5 years after 2014/15 at about 6.0¢/kWh from the market while achieving MISO Market export sales prices rising from 6.5¢/kWh to 10¢/kWh.

ANSWER:

Manitoba Hydro cannot confirm the average unit costs and revenues referenced in this question. The following response is based on the information provided in Attachment 5 of this GRA.

Through the use of the reservoir storage, Manitoba Hydro can transfer import energy, purchased primarily during off-peak hours, into export sales made primarily in the on-peak hours. Market prices for energy are significantly correlated to energy demand, amongst other factors. During the low-demand off-peak hours (overnight and weekends), the market energy prices are less than those observed during the on-peak weekday hours. Consequently, the average price for import energy is generally less than the average sale price for export energy.

PUB/MH I-18

Reference: 2010 GRA Exhibit #MH 83

a) MISO Regional Power Supplies

Please provide an updated view of the MISO Region power supply capacity/actual energy production for 2008/2009/2010/2011/2012 years:

Resource Type	Total Capacity (MW)	Annual Energy (GWh)	On-line %
Coal			
Nuclear			
CCCT Nat. Gas			
SCCT Nat. Gas			
Wind			
Other			
Totals			

ANSWER:

The information in the following tables was obtained from MISO Monthly Market Assessment Reports and MISO Summer Resource Assessment Reports. Estimated average annual capacity factor values were calculated by Manitoba Hydro using the value of the Nameplate Capacity provided in the MISO Annual Summer assessment, which represents the capacity at the date of the assessment. Values such as the Nameplate Capacity do vary throughout the year due to factors such as unit additions, unit upgrades, and unit retirements as well as changes in the MISO market membership.

Manitoba Hydro's generation resources are not included in these statistics.

Nameplate Capacity assumed in the MISO Annual Summer Assessment (GW)						
	Coal	Gas, Oil/Gas	Hydro	Nuclear	Oil	Wind
2012	63.1	38.3	3.7	8.1	3.0	10.8
2011	69.2	40.5	3.7	8.2	3.3	9.1
2010	74.3	41.4	3.6	10.4	3.7	7.6
2009	68.0	40.1	3.6	10.4	3.4	5.1
2008	67.9	37.8	4.1	10.3	3.5	2.9

Generation by fuel type as reported in MISO Monthly Reports (TWh)						
	Coal	Gas, Oil/Gas	Hydro	Nuclear	Oil	Wind
*Year to July 2012	182	33	3	37	3	19
2011	436	32	5	78	2	29
2010	490	25	4	93	2	24
2009	453	15	2	82	1	16
2008	463	22	2	69	0	4

Estimated Average Annual Capacity Factor						
	Coal	Gas, Oil/Gas	Hydro	Nuclear	Oil	Wind
*Year to July 2012	56%	17%	14%	91%	17%	35%
2011	72%	9%	15%	95%	7%	36%
2010	75%	7%	12%	95%	7%	35%
2009	76%	4%	7%	91%	2%	36%
2008	78%	7%	6%	77%	1%	14%

PUB/MH I-18

Reference: 2010 GRA Exhibit #MH 83

b) Energy Supply into Day-Ahead/Real-Time Market

Please discuss in detail the relative roles of MISO-CCCT natural gas generation and MH's exports in establishing day-ahead and real-time MISO Market prices.

ANSWER:

There are a wide variety of generation types in the MISO market footprint, including wind, hydro, biomass, nuclear, coal, combined cycle natural gas and combustion turbine natural gas. Pricing factors such as current thermal fuel prices (coal and natural gas), forced generation outages, transmission outages, weather/ forecast loads and regional wind speeds all contribute to establishing day-ahead and real time MISO market prices.

In a power market such as that operated by MISO, offers to generate for each unit are prepared by the generation owners based on their variable production costs and start-up costs, which can and does vary significantly between the various generation technologies and even within types of generation technologies. As noted in the response to PUB/MH I-13(a), the marginal generator in a large market such as MISO can change as frequently as every five minutes. Each generator which is operating in the day ahead or real time market in a particular hour will be paid the market clearing price for that hour, which is based on and is not less than the variable (or marginal) cost of the most expensive unit operating during each interval of that hour.

As the load constantly varies the marginal or price setting generator changes causing variations in price. Combined cycle gas generation is but one of several technologies which can set the market clearing price. As indicated in the response to PUB/MH I-18(a), for the current year to July 2012, natural gas fired generation (included natural gas / oil dual fueled generators), from both combined cycle generation and combustion turbines, provided about 17% of the total generation supplied within the MISO market footprint.

The forecasting of power market prices requires the consideration of the whole range of load over the course of each day/ month/ year, and the consideration of the cost of each type of existing resource and potential new resources, as well as, determination of when each resource will operate.

The MISO market footprint is many times larger than the potential supply from Manitoba Hydro. The annual peak MISO market load is on the order of 100,000 MW while the transmission interconnection capacity from Manitoba Hydro is less than 2,000 MW. Therefore the primary determinate of the MISO market prices are the MISO market footprint demand, and cost of available supply within the MISO market footprint. Exports from or imports to Manitoba Hydro are not a major factor in determining MISO market prices.

PUB/MH I-18

Reference: 2010 GRA Exhibit #MH 83

c) Please discuss in detail the role of state-mandated wind energy in defining MISO Market prices and establishing MH's market share and MH's sale prices.

ANSWER:

The state level renewable energy mandates within the MISO market region are generally not explicitly wind energy mandates, but rather require a specified portion of the overall energy supply come from specified types of renewable energy. However, due to economics and locally available renewable resources, these state level mandates have mostly been satisfied by using local wind resources.

To the extent that wind power is developed through state renewable portfolio mandates, wind power is, overall, expected to have a slight suppression effect on power market prices. The specific impact on power market prices in any individual hour does vary in accordance with the actual hourly wind generation. Wind generation displaces higher cost fossil fuel generation and, due to the low variable cost of wind, has a slight suppression effect on power prices. This price suppression effect is more pronounced during off-peak hours when loads are lower and wind output tends to be higher. As the wind is displacing fossil fuels, there is no significant impact on Manitoba Hydro's market share.

The impacts of increasing development of MISO wind resources due to regional energy policies are an important consideration taken into account by external consultants when preparing their electricity price forecasts.

PUB/MH I-18

Reference: 2010 GRA Exhibit #MH 83

d) Please discuss in detail MH's use of CDN and MISO imports in low, median and high flow years with particular emphasis on the specific fossil fuel generation source.

ANSWER:

In high flows years, Manitoba Hydro has minimal need for energy imports. As annual flows drop below high, the opportunity or requirement for imports increases. To the extent possible, imports are made during the lowest price period which is generally the off peak period. The overall mix of generation within the MISO market footprint in the off-peak period, is predominantly coal but also includes nuclear and wind generation.

From a price setting perspective, coal would be expected to be the marginal generation type in the off peak period, whether Manitoba Hydro is importing relatively low quantities of energy or larger quantities that may be required in a drought.

PUB/MH I-19

Reference: Forecasts of Export Prices

a) Average Export Price Forecasts
Please provide MH's own version of Example Figure 4.1 on following page illustrating:

- **i. CEC hearing export price forecasts (high and low) by MH**
- **ii. Actual average annual export prices 2004/05 to 2011/12**
- **iii. IFF09-1 average export price forecasts**
- **iv. IFF10-2 average export price forecasts**
- **v. IFF11-2 average export price forecasts**
- **vi. CCCT-driven electricity market prices (reflective of recent ICF natural gas price forecasts)**

ANSWER:

Manitoba Hydro does not normally prepare a graph similar to Example Figure 4.1 but has prepared the attached Average Export Unit Revenue graph and would like to note the following regarding this graph:

- The attached graph is for historical and forecast Average Export Unit Revenue, expressed in US$/ MWh. Manitoba Hydro's price forecast consultants provide their forecast in US dollars and therefore the revenue comparison is being made in US currency.
- The term Average Export Unit Revenue is calculated dividing the total revenue dollars by the export volume.
- A forecast of Average Export Unit Revenues is not the same as a forecast of market prices. Forecasts of Average Export Unit Revenues are related to actual/ forecast market prices, but also take into account Manitoba Hydro's system constraints including water supply, export transmission limitations and generation capacity limitations. Long term forecasts of Average Export Unit Revenues are based on the average revenues over all flow conditions in the hydraulic record. Actual Average Export Unit Revenues will reflect the actual water conditions. For periods where annual flows were high, such as 2005 thru 2008, the Average Export Unit Revenues will tend to be somewhat depressed in comparison with a forecast based on the average of all flow conditions due to the greater proportion of off peak exports made in above average water conditions.

The data for the following Average Export Unit Revenue graph was determined as follows:

i.) CEC Wuskwatim Hearing Unit Revenue

- Data source: Submission to the Manitoba CEC NFAAT - Wuskwatim Project (April 2003) Attachment 6 - Tables A.15 & A.16, expressed in US dollars

ii.) Historical Export Unit Revenue

- Data source: PUB/MH I – 11(a)

iii.) IFF 09-01 Unit Revenue

- Data source: Response to 2010/11 GRA - PUB/MH I -209

iv.) IFF 10-2 Unit Revenue

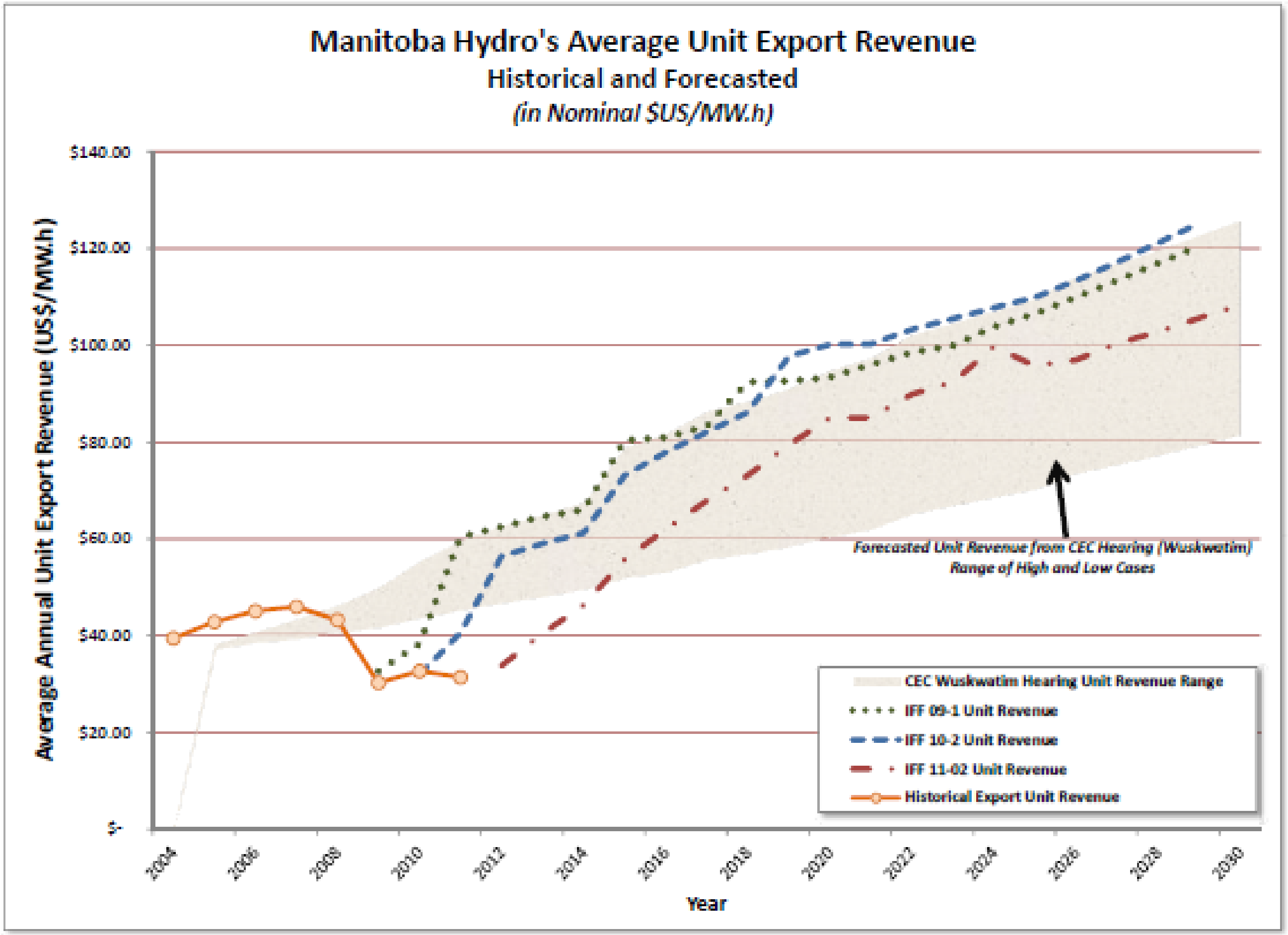
- Data source: GRA 2010/11 – MH Exhibit #155

v.) IFF 11-2 Unit Revenue

- Data source: 2012/13 GRA - Response for Additional Info - Attachment 5

vi) CCCT-driven electricity market prices

- Manitoba Hydro declines to provide the requested information as Manitoba Hydro does not have a price forecast/ production costing/ revenue analysis developed directly from the reference ICF natural gas price forecasts.



Manitoba Hydro's Average Unit Export Revenue
Historical and Forecasted
(in Nominal $US/MW.h)
Average Annual Unit Export Revenue (US$/MW.h)
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$-
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Year
Forecasted Unit Revenue from CEC Hearing (Wuskwatim)
Range of High and Low Cases
CEC Wuskwatim Hearing Unit Revenue Range
IFF 09-1 Unit Revenue
IFF 10-2 Unit Revenue
IFF 11-02 Unit Revenue
Historical Export Unit Revenue

PUB/MH I-19

Reference: Forecasts of Export Prices

b) Please define in the absence of any CO2 price adders, the natural gas prices that would result in CCCT generation costs at export price levels in Attachment 5.

ANSWER:

Manitoba Hydro does not have available to it the requested information and is therefore unable to provide the requested data.

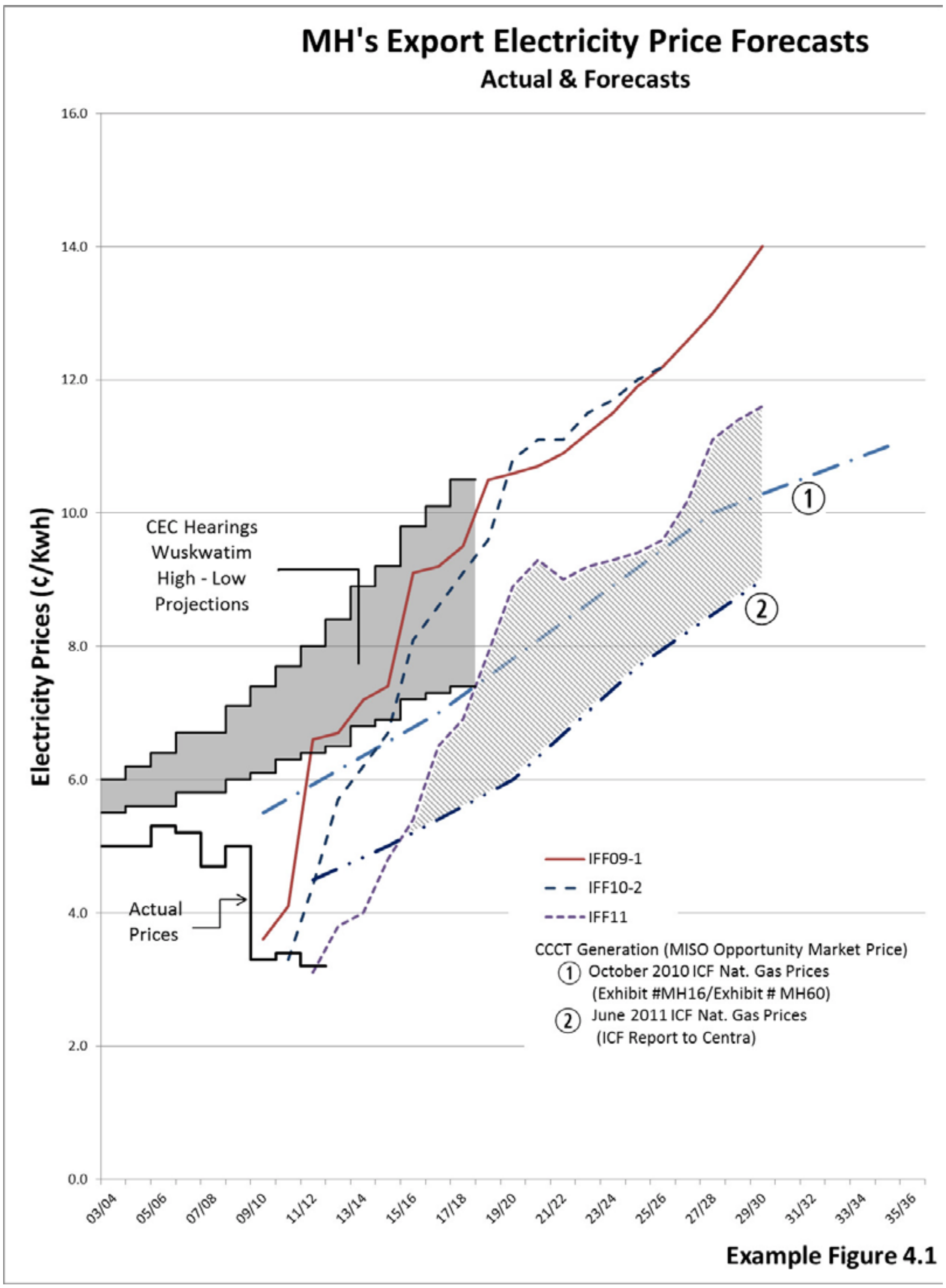
As noted in the response to PUB/MH I-18(b), the forecasting of power market prices requires the consideration of the whole range of load over the course of each day/ month/ year, and the consideration of the cost of each type of existing resource and potential new resources, as well as, determination of when each resource will operate. The load and in turn the market price can be different in each of the 8760 hours in a year, proper price forecasting requires consideration of all load hours in the year and all generation technologies, not just a single hour and single generation technology.

It is also noted in the response to PUB/MH I-18(b), there are a wide variety of generation types in the MISO market footprint, including wind, hydro, biomass, nuclear, coal, combined cycle natural gas and combustion turbine natural gas. Pricing factors such as current thermal fuel prices (coal and natural gas), forced generation outages, weather/ forecast loads and regional wind speeds all contribute to establishing day-ahead and real time MISO market prices.

PUB/MH I-19

Reference: Forecasts of Export Prices

c) Please define the specific U.S.MISO transmission upgrades required to achieve Attachment 5 export volumes and prices.



ANSWER:

Please see Manitoba Hydro's response to CAC/MH I-72(g).

PUB/MH I-20

Reference: Reference: Tab 9/2011/12 Power Resource Plan — Attachment 3 (July 20/12)

a) Contracted Export Transmission Access

Please confirm that MH's new export contracts will provide MH with assured MISO transmission access for exports as follows:

- **NSP or MISO Market (at least 450 MW/possibly 850MW of 5x16 energy in summer months)**
- **MP (at 250 MW of 7x16 energy —12 months)**
- **WPS (at 100 MW of 7x1 6 energy — 12 months)**

Also provide the status of each of the above and indicate whether transmission needs to be constructed to serve each of these contracts.

ANSWER:

MH's new export contracts with NSP, MP and WPS require those customers to hold MISO Network Transmission Service reservations of sufficient capacity to deliver the contracted capacity and energy. These reservations will be available continuously during the term of the contracts for the delivery of both contract and additional energy.

Only the MP 250 MW export contract requires the construction of a new transmission line as the NSP contracts and WPS 100 MW contract can be served from existing transmission facilities. Additional sales to WPS under the MH-WPS Term Sheet will require the construction of major new transmission.

Manitoba Hydro, Minnesota Power and Wisconsin Public Service are proceeding with plans to build a new 500 kV line between Canada and the US with an anticipated in-service date of 2020.

PUB/MH I-20

Reference: Tab 9/2011/12 Power Resource Plan – Attachment 3 (July 20/12)

b) Total Export Transmission Access

Please indicate the total transmission access (MW and GWh) that MH can realistically count on for exports into:

- **MISO (firm and non-firm)**
- **Canada (firm and non-firm)**

Over the course of the 2012 Power Resource Plan (PRP)

ANSWER:

The current export transfer limits on Manitoba Hydro's interconnections during system intact conditions are as follows:

Interconnection	System Operating Limit	Firm Export Schedule Limit	Potential maximum annual on-peak export based on Firm Schedule Limit
US	2175 MW	1950 MW	8,100 GWh/ yr
Ontario	288 MW	200 MW	830 GWh/ yr
Saskatchewan	225 MW	150 MW	620 Gwh/ yr

The MW limits apply to both the peak and off-peak periods. Note that transmission capability is affected by many factors and hence these values change from time to time. They change over the long term as the transmission system evolves and in the short term due to issues such as outages of individual transmission lines. A portion of the maximum capability is reserved for transmission reliability purposes, which includes the delivery of operating reserves. Also note that the limits are not additive in that even if supply were available, exports could not be maximized in all three directions at one time due to transmission reliability considerations. For planning studies that require the capability over the period of a month, Manitoba Hydro utilizes lower limits corresponding to 1850 MW for U.S. transfer capability and a total of 250 MW for Canadian transfer capability.

In terms of the additional capacity from a new interconnection, Manitoba Hydro notes that detailed design of the new 500 kV interconnection, including route location, voltage, and line capability has not yet begun. . For the 2011/12 power resource plan, it was assumed that the new interconnection would have an additional capacity of 400 MW (import & export) from 2019/20 to 2023/24 and then increase to 1000 MW export (south) and 750 MW import (north) over the long term for the balance of the planning horizon.

Transmission limits are one of three key limits or constraints on the Manitoba Hydro system. Two other key limits which also affect and limit exports are availability of supply (i.e. water conditions), and the availability of surplus generation capacity beyond the Manitoba load. In winter, when the Manitoba load is higher, Manitoba Hydro has reduced surplus capacity, and exports are significantly limited by this factor in comparison with the summer period. Thus from a practical perspective, annual on peak utilization rates of greater than 80% based on the Firm Schedule Limit are unlikely to be achieved.

PUB/MH I-20

Reference: Tab 9/2011/12 Power Resource Plan – Attachment 3 (July 20/12)

c) Total Import Transmission Access

Please indicate what actual level of transmission access (MW and GWh) MH can realistically count on for imports from:

- **MISO (firm and non-firm)**
- **Canada (firm and non-firm)**

ANSWER:

The current import transfer limits on Manitoba Hydro's interconnections during system intact conditions are as follows:

Interconnection	System Operating Limit	Firm Transfer Capability for the Planning Horizon	Potential maximum annual off-peak import based on Long Term Firm Import Reservation Limit/ Firm Schedule Limit
US	900 MW	700 MW	3,200 GWh/ yr
Ontario	268 MW	0 MW	0 GWh/ yr**
Saskatchewan	125-400 MW*	0 MW	0 Gwh/ yr **

The MW limits apply to both the peak and off-peak periods. Note that transmission capability is affected by many factors and hence these values change from time to time. They change over the long term as the transmission system evolves and in the short term due to issues such as outages of individual transmission lines. A portion of the maximum capability is reserved for transmission reliability purposes, which includes the delivery of operating reserves. The import capabilities from the interfaces are independent at the present time as no long term import capability has been assumed from Ontario and Saskatchewan.

Notes:

* System Operating Limits for imports from Saskatchewan depend on a number of electrical system conditions, including AC power flow from northern Manitoba and generation patterns within Saskatchewan.

** At the present time, there is a short term Firm Import Schedule Limit of 50 MW from both North-Western Ontario and Saskatchewan, but this capability is not assured for the planning horizon. In addition, there is no assurance of availability of supply from Saskatchewan or Ontario under certain conditions such as a regional drought, which can impact hydraulic generation in Saskatchewan and North-Western Ontario at the same time Manitoba is in a drought. Therefore, Manitoba Hydro does not rely on imports of dependable energy from Saskatchewan and North-Western Ontario on the planning horizon.

PUB/MH I-20

Reference: **Reference: Tab 9/2011/12 Power Resource Plan — Attachment 3 (July 20/12)**

d) Please provide a status update on the U.S. transmission projects that MH indicated in last GRA were necessary for 250 MW MP and 500 MW WPS export sales.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-20(a).

PUB/MH I-21

Reference: Tab 9.5/2010 GRA PUB/MH II-191(a)

a) NEB Data:

Please provide a summary tabulation of MH's 2010/11 and 2011/12 monthly export sales broken down by permit number (same format as PUB/MH II-191(a)).

ANSWER:

Please see below for NEB data.

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**
Apr-10	144	17,111	1,371,751	80.17						
	155	10,308	556,029	53.94						
	224	171,379	9,453,481	55.16						
	269				502,793	11,922,854	23.71			
	345	455	34,287	75.36						
								1,175	19,334	16.45
May-10	35	53,700	1,874,870	34.91						
	155	10,080	573,486	56.89						
	224	167,000	9,737,141	58.31						
	269				194,547	7,894,406	40.58			
	345	357	25,898	72.54						
								122,179	2,634,286	21.56
Jun-10	33	37,900	1,460,750	38.54						
	34	28,495	1,098,260	38.54						
	35	82,651	2,570,108	31.10						
	155	10,560	599,904	56.81						
	224	171,412	10,026,035	58.49						
	269				461,086	13,150,740	28.52			
	273	4	515	128.75						
	345	356	25,910	72.78						
								5,241	60,258	11.50

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**
Jul-10	33	56,900	2,127,711	37.39						
	34	42,672	1,595,671	37.39						
	35	106,253	3,410,437	32.10						
	155	10,511	580,139	55.19						
	224	175,324	9,869,728	56.29						
	269				738,392	19,473,860	26.37			
	345	424	28,688							
								3,755	218,864	58.29
Aug-10	33	55,590	2,149,228	38.66						
	34	41,765	1,614,724	38.66						
	35	110,249	3,928,184	35.63						
	155	10,403	595,507	57.24						
	224	173,783	10,146,551	58.39						
	269				748,854	22,321,983	29.81			
	345	374	25,689	68.69						
								1,660	56,302	33.92
Sep-10	33	25,000	935,573	37.42						
	34	18,600	696,067	37.42						
	35	97,125	2,254,630	23.21						
	155	21,600	801,336	37.10						
	224	175,000	9,865,613	56.37						
	269				656,585	13,486,571	20.54			
	345	395	28,650	72.53						
								1,654	56,879	34.39

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**
Oct-10	33	639	23,658	37.02						
	34	484	17,919	37.02						
	35	107,046	2,616,994	24.45						
	155	10,069	557,502	55.37						
	224	167,819	9,501,757	56.62						
	269				788,954	18,110,622	22.96			
	345	389	27,656	71.10						
								2,192	100,023	45.63
Nov-10	33									
	34									
	35									
	155	10,560	580,559	54.98						
	224	167,297	9,553,709	57.11						
	269									
	345	545	37,269	68.38						
	355				547,247	12,127,472	22.16			
								10,623	554,475	52.20
Dec-10	155	11,040	580,475	52.58						
	224	153,546	8,774,516	57.15						
	345	786	51,282	65.24						
	355				303,045	8,939,053	29.50			
								25,018	682,532	27.28

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**
Jan-11	155	10,080	548,832	54.45						
	224	112,447	7,386,342	65.69						
	345	1,191	71,423	59.97						
	352	8	915	114.38						
	355				245,554	7,812,197	31.81			
								24,152	721,794	29.89
Feb-11	155	9,596	515,658	53.74						
	224	121,398	7,485,752	61.66						
	345	936	60,466	64.60						
	355				330,931	7,867,230	23.77			
								7,413	203,037	27.39
Mar-11	155	11,032	566,877	51.38						
	224	167,830	9,063,793	54.01						
	345	858	57,603	67.14						
	355				502,988	11,600,765	23.06			
								1,046,183	17,949,845	17.16
Apr-11	155	15,572	606,291	38.93						
	224	164,230	8,726,760	53.14						
	345	579	39,945	68.99						
	355				618,224	14,188,453	22.95			
								3,256	109,433	33.61

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh
May-11	35	42,777	792,209	18.52						
	155	16,324	648,972	39.76						
	224	173,679	9,311,462	53.61						
	345	368	28,018	76.14						
	355				797,049	15,842,119	19.88			
								5,182	(1,351)	(0.26)
Jun-11	33	41,459	1,464,428	35.32						
	34	31,095	1,098,347	35.32						
	35	107,501	2,191,176	20.38						
	155	15,915	636,843	40.02						
	224	174,716	9,303,831	53.25						
	345	363	26,742	73.67						
	352	4	598	149.50						
	355				646,648	12,969,331	20.06			
								8,705	393,106	45.16
Jul-11	33	50,289	1,756,982	34.94						
	34	37,717	1,317,745	34.94						
	35	111,478	3,815,718	34.23						
	155	10,055	528,715	52.58						
	224	164,093	8,878,007	54.10						
	345	429	29,265	68.22						
	355				875,740	24,180,464	27.61			
								639	71,427	111.78

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**
Aug-11	33	51,800	1,856,449	35.84						
	34	38,850	1,392,337	35.84						
	35	110,100	3,291,117	29.89						
	155	11,040	576,490	52.22						
	224	180,211	9,631,375	53.44						
	345	362	25,789	71.24						
	355				793,003	19,359,907	24.41			
								1,264	132,285	104.66
Sep-11	33	30,775	1,171,140	38.05						
	34	23,090	878,688	38.05						
	35	98,726	2,285,351	23.15						
	155	15,629	675,726	43.24						
	224	164,376	9,640,954	58.65						
	345	383	27,659	72.22						
	355				486,600	10,262,974	21.09			
								9,098	199,844	21.97
Oct-11	35	108,181	2,373,741	21.94						
	155	13,777	603,480	43.80						
	224	166,825	9,306,310	55.78						
	345	347	28,276	81.49						
	355				510,915	9,244,684	18.09			
								3,209	77,832	24.25

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**
Nov-11	35	91,504	2,321,519	25.37						
	155	10,417	585,995	56.25						
	224	163,189	9,575,319	58.68						
	345	494	35,603	72.07						
	355				298,541	7,194,432	24.10			
								23,347	491,168	21.04
Dec-11	35	73,016	2,086,927	28.58						
	155	10,560	580,752	55.00						
	224	119,976	7,829,309	65.26						
	345	684	46,526	68.02						
	352	6	813	135.50						
	355				159,283	4,441,916	27.89			
								45,055	1,041,320	23.11
Jan-12	35	70,101	1,685,321	24.04						
	155	10,560	574,013	54.36						
	224	112,150	7,458,255	66.50						
	345	966	62,509	64.71						
	355				178,927	4,636,174	25.91			
								45,241	716,312	15.83
Feb-12	35	68,150	1,666,184	24.45						
	155	10,080	545,463	54.11						
	224	147,786	259,936	1.76						
	345	826	55,996	67.79						
	355				93,295	3,015,205	32.32			
								95,568	1,766,968	18.49

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**
Mar-12	35	68,747	206,998	3.01						
	155	10,514	31,154	2.96						
	224	172,839	9,572,792	55.39						
	345	651	45,895	70.50						
	355				230,778	5,366,606	23.25			
								75,530	1,022,020	13.53

PUB/MH I-21

Reference: Tab 9.5/2010 GRA PUB/MH II-191(a)

b) NEB – 2008/2009 and 2009/10:

Please re-file 2010 GRA PUB/MH II-191(a).

ANSWER:

Please see below for NEB data.

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh
Apr-08	144	17,554	1,331,013	75.82						
	155	21,063	1,081,235	51.33						
	224	175,438	9,140,552	52.10						
	259	523	33,718	64.47						
	269				674,057	38,710,758	57.43			
								498	56,930	114.32
May-08	35	81,724	3,401,427	41.62						
	144	17,600	1,282,846	72.89						
	155	21,120	1,087,816	51.51						
	224	175,500	9,220,917	52.54						
	259	396	28,906	72.99						
	269				699,599	31,370,396	44.84			
								500	47,713	95.43
Jun-08	33	19,490	697,220	35.77						
	34	14,617	522,897	35.77						
	35	73,902	3,379,308	45.73						
	144	16,407	1,233,972	75.21						
	155	19,866	1,068,185	53.77						
	224	162,001	8,977,792	55.42						
	259	475	31,630	66.59						
	269				494,860	24,520,507	49.55			
								4,897	744,598	152.05

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh
Jul-08	33	70,400	2,535,990	36.02						
	34	52,800	1,901,992	36.02						
	35	96,900	5,633,561	58.14						
	144	18,380	1,375,994	74.86						
	155	22,055	1,157,066	52.46						
	224	183,686	9,799,722	53.35						
	259	366	28,736	78.51						
	269				799,886	37,260,178	46.58			
								1,106	134,304	121.43
Aug-08	33	67,200	2,507,804	37.32						
	34	50,400	1,880,853	37.32						
	35	108,900	4,898,303	44.98						
	144	16,788	1,314,433	78.30						
	155	20,160	1,125,657	55.84						
	224	168,000	9,583,228	57.04						
	259	383	29,647	77.41						
	269				859,734	34,817,392	40.50			
								2,356	254,097	107.85

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh
Sep-08	33	19,210	705,067	36.70						
	34	14,407	536,282	37.22						
	35	106,950	3,584,400	33.51						
	144	17,428	1,354,954	77.75						
	155	21,120	1,159,702	54.91						
	224	173,640	9,762,961	56.23						
	259	357	28,666	80.30						
	269				795,097	23,433,570	29.47			
								492	52,767	107.25
Oct-08	35	111,600	4,153,724	0.04						
	144	18,400	1,633,552	0.09						
	155	22,080	1,373,405	0.06						
	224	184,000	11,635,701	0.06						
	259	384	29,688	0.08						
	269				694,487	24,144,820	34.77			
								1,199	82,222	68.58
Nov-08	144	15,994	1,465,977	91.66						
	155	19,200	1,265,540	65.91						
	224	160,000	10,819,982	67.62						
	259	642	39,378	61.34						
	269				614,926	24,241,549	39.42			
								300	8,925	29.75

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**
Dec-08	144	18,381	1,642,812	89.38						
	155	22,080	1,382,550	62.62						
	224	158,320	10,639,551	67.20						
	259	854	52,411	61.37						
	269				197,415	13,641,499	69.10			
								48,883	1,682,653	34.42
Jan-09	144	17,600	1,595,364	90.65						
	155	21,117	1,352,687	64.06						
	224	161,779	10,888,078	67.30						
	259	1,192	68,796	57.71						
	269				123,830	7,442,112	60.10			
								61,915	2,559,045	41.33
Feb-09	144	16,000	1,506,201	94.14						
	155	19,200	1,301,862	67.81						
	224	156,110	10,944,203	70.11						
	259	833	50,946	61.16						
	269				173,600	8,571,553	49.38			
								6,749	344,517	51.05

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**	**MWh**	**Revenue (CAN$)**	**¢/kWh**
Mar-09	144	17,568	1,623,272	92.40						
	155	21,120	1,378,863	65.29						
	224	172,308	11,550,659	67.03						
	259	833	50,946	61.16						
	269				194,748	8,194,807	42.08			
								19,095	719,180	37.66
Apr-09	144	17,541	1,536,031	87.57						
	155	21,049	1,303,354	61.92						
	224	175,418	11,070,661	63.11						
	259	639	40,227	62.95						
	269				466,954	11,164,381	23.91			
								500	61,317	122.63
May-09	33	47,217	629,505	13.33						
	34	35,430	469,493	13.25						
	35	52,174	1,046,940	20.07						
	144	16,588	1,445,711	87.15						
	155	9,928	587,038	59.13						
	224	287,476	11,604,608	40.37						
	259	481	35,977	74.80						
	269				448,634	10,411,481	23.21			
								813	33,550	41.27

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh
Jun-09	33	86,711	2,357,030	27.18						
	34	6,588	1,805,106	274.00						
	35	7,200	308,462	42.84						
	144	17,600	1,617,138	91.88						
	155	16,078	758,261	47.16						
	224	303,767	13,019,826	42.86						
	259	461	35,204	76.36						
	269				434,693	11,286,387	25.96			
								1,851	32,292	17.45
Jul-09	33	119,319	2,928,700	24.55						
	34	89,632	2,197,587	24.52						
	35	2,250	58,679	26.08						
	144	18,400	1,562,504	84.92						
	155	14,731	680,137	46.17						
	224	358,969	12,602,626	35.11						
	259	394	32,545	82.60						
	269				521,232	10,303,089	19.77			
								1,851	160,870	86.91

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh
Aug-09	33	132,126	3,214,448	24.33						
	34	9,063	2,410,700	265.99						
	35	1,650	43,737	26.51						
	144	16,800	1,463,074	87.09						
	155	13,800	653,061	47.32						
	224	362,391	12,705,102	35.06						
	259	425	33,766	79.45						
	269				512,427	11,298,361	22.05			
								495	34,035	68.76
Sep-09	33	28,367	961,127	33.88						
	34	21,352	724,358	33.92						
	144	16,888	1,437,114	85.10						
	155	15,644	682,116	43.60						
	224	176,859	9,980,692	56.43						
	259	320	29,621	92.57						
	269				721,192	13,904,731	19.28			
								437	41,672	95.36
Oct-09	35	77,706	2,358,613	30.35						
	144	17,358	1,480,174	85.27						
	155	10,416	596,508	57.27						
	224	173,876	10,162,359	58.45						
	269				866,924	20,512,094	23.66			
	345	527	37,820	71.76						
								0	0	0.00

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh
Nov-09	144	16,800	1,410,645	83.97						
	155	10,080	572,268	56.77						
	224	168,000	9,756,683	58.08						
	269				652,817	15,208,111	23.30			
	345	503	36,853	73.27						
								12,766	291,376	22.82
Dec-09	144	18,337	1,510,887	82.40						
	155	11,002	602,185	54.73						
	224	178,620	10,045,274	56.24						
	269				180,369	7,233,228	40.10			
	345	785	50,708	64.60						
								96,983	2,446,474	25.23
Jan-10	144	16,800	1,420,784	84.57						
	155	10,080	576,381	57.18						
	224	157,869	9,449,930	59.86						
	269				294,690	12,031,863	40.83			
	345	1,004	61,779	61.53						
								78,020	1,928,233	24.71
Feb-10	144	1,600	1,344,224	840.14						
	155	9,600	550,946	57.39						
	224	159,086	9,384,649	58.99						
	269				238,998	9,492,286	39.72			
	345	948	58,242	61.44						
								43,325	1,060,605	24.48

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh	MWh	Revenue (CAN$)	¢/kWh
Mar-10	144	18,389	1,469,898	79.93						
	155	11,033	585,515	53.07						
	224	183,900	9,935,043	54.02						
	269				496,047	14,153,374	28.53			
	345	684	46,670	68.23						
								1,107	15,147	13.68

PUB/MH I-21

Reference: Tab 9.5/2010 GRA PUB/MH II-191(a)

c) New MISO Sale:

Please provide specifics on permit EPE-35 Amendment Application (July 16/12) to National Energy Board (NEB).

ANSWER:

Manitoba Hydro has filed an Application for Review requesting approval from the NEB to amend Permit EPE-35. The Permit is associated with the Diversity Exchange Agreement between MH and Great River Energy (a successor to United Power Association). It permits exports during the summer season (May 1 - October 31) but does not provide for winter season deliveries.

Manitoba Hydro and GRE would like to use the transmission available under the Diversity Exchange Agreement for winter deliveries and thus requires the NEB to amend the permit to allow these transactions.

PUB/MH I-21

Reference: Tab 9.5/2010 GRA PUB/MH II-191(a)

d) NEB Licenses:

Please provide specifics on other actual or pending permit/licences amendments since Mar.31/2012.

ANSWER:

Manitoba Hydro has no other permit or /licence amendment requests before the NEB.

PUB/MH I-22

Reference: IFF11-2 – Electric Operations

a) Please refile the IFF11-2 electric operations for the 20 year outlook including financial targets for each year.

ANSWER:

Please note that while financial targets have been calculated based on electric operations only in the following attachment, as requested, Manitoba Hydro's financial targets apply to consolidated operations only.

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

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 186	1 290	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	45	106	156	208	265	325	387	455	527	603
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 693	1 778	1 873	2 007	2 114	2 224	2 320	2 466	2 769	2 957
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	452	504	537	570	640	763	803	1 147	1 109
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 672	1 709	1 810	1 881	1 952	2 100	2 300	2 393	2 823	2 833
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	68	62	124	159	121	18	70	(57)	113
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase	0.00%	4.50%	8.16%	11.94%	15.86%	19.92%	24.11%	28.46%	32.95%	37.61%	42.42%
Financial Ratios											
Equity	26%	24%	19%	17%	15%	15%	14%	13%	13%	12%	12%
Interest Coverage	1.12	1.03	1.11	1.09	1.15	1.17	1.12	1.02	1.06	0.96	1.08
Capital Coverage	1.04	1.07	1.13	1.15	1.43	1.54	1.48	1.29	1.46	1.43	1.86

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

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers										
at approved rates	1 441	1 460	1 479	1 498	1 521	1 541	1 562	1 582	1 602	1 622
additional*	683	767	822	880	941	1 004	1 069	1 136	1 205	1 277
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
Other	19	20	20	20	21	21	22	22	23	23
	3 074	3 193	3 445	3 806	4 008	4 110	4 191	4 284	4 394	4 497
EXPENSES										
Operating and Administrative	634	646	669	676	688	700	713	727	741	755
Finance Expense	1 091	1 079	1 173	1 398	1 545	1 512	1 473	1 424	1 438	1 338
Depreciation and Amortization	579	583	615	682	733	741	753	761	793	814
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	156	158	160	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2 850	2 891	3 032	3 345	3 582	3 591	3 591	3 580	3 655	3 604
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	213	291	402	450	415	507	588	691	726	878
* Additional General Consumers Revenue										
Percent Increase	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.41%	52.57%	55.62%	58.73%	61.91%	65.14%	68.45%	71.82%	75.25%	78.76%
Financial Ratios										
Equity	12%	13%	14%	15%	17%	19%	21%	23%	26%	29%
Interest Coverage	1.14	1.19	1.26	1.28	1.26	1.33	1.38	1.46	1.49	1.63
Capital Coverage	1.93	1.99	2.04	2.36	2.32	2.57	2.59	2.65	3.34	3.00

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

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

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

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	29 045	29 610	34 023	38 098	39 357	39 988	40 557	41 087	43 107	43 823
Accumulated Depreciation	(9 752)	(10 344)	(10 970)	(11 663)	(12 407)	(13 160)	(13 926)	(14 701)	(15 509)	(16 338)
Net Plant in Service	19 293	19 267	23 053	26 435	26 951	26 828	26 631	26 386	27 599	27 485
Construction in Progress	6 099	6 969	4 170	1 022	545	786	1 259	1 722	618	758
Current and Other Assets	2 158	2 426	2 660	2 640	3 029	3 431	3 695	3 929	4 486	5 143
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27 641	28 752	29 972	30 183	30 609	31 128	31 667	32 118	32 783	33 466
LIABILITIES AND EQUITY										
Long-Term Debt	23 437	24 240	24 593	24 795	24 796	24 738	24 489	24 391	24 180	23 152
Current and Other Liabilities	1 140	1 146	1 599	1 146	1 145	1 203	1 390	1 236	1 374	2 193
Contributions in Aid of Construction	429	440	451	463	475	487	499	512	525	538
Retained Earnings	3 026	3 317	3 719	4 170	4 584	5 092	5 679	6 370	7 096	7 974
Accumulated Other Comprehensive Income	(392)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)
	27 641	28 752	29 972	30 183	30 609	31 128	31 667	32 118	32 783	33 466
Equity Ratio	12%	13%	14%	15%	17%	19%	21%	23%	26%	29%

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

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

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

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 074	3 193	3 445	3 806	4 008	4 110	4 191	4 284	4 394	4 497
Cash Paid to Suppliers and Employees	(1 154)	(1 201)	(1 215)	(1 234)	(1 272)	(1 303)	(1 329)	(1 358)	(1 383)	(1 410)
Interest Paid	(1 108)	(1 092)	(1 196)	(1 433)	(1 582)	(1 561)	(1 534)	(1 490)	(1 484)	(1 423)
Interest Received	20	21	31	36	38	49	60	64	71	84
	832	921	1 066	1 175	1 192	1 295	1 388	1 501	1 598	1 748
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	980	790	790	190	(10)	-	(10)	(10)	(30)	(10)
Sinking Fund Withdrawals	159	-	-	401	-	-	60	250	-	13
Retirement of Long-Term Debt	(159)	-	-	(450)	-	-	(60)	(220)	(100)	(213)
Other	(7)	(6)	(6)	(8)	(8)	(7)	(7)	(6)	(4)	(19)
	973	784	784	133	(18)	(7)	(17)	14	(134)	(229)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 510)	(1 401)	(1 578)	(891)	(746)	(834)	(1 003)	(953)	(876)	(814)
Sinking Fund Payment	(234)	(246)	(263)	(282)	(274)	(285)	(297)	(306)	(305)	(317)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1 773)	(1 677)	(1 869)	(1 201)	(1 051)	(1 148)	(1 328)	(1 288)	(1 211)	(1 160)
Net Increase (Decrease) in Cash	32	28	(19)	108	124	140	43	227	253	359
Cash at Beginning of Year	340	372	400	381	489	613	752	796	1 023	1 276
Cash at End of Year	372	400	381	489	613	752	796	1 023	1 276	1 635

PUB/MH I-22

Reference: IFF11-2 – Electric Operations

b) Please provide a comparison of the IFF forecast for IFF11-2 – electric operation with IFF09 for each of the comparative years between the two forecasts and comment on the reasons for the changes.

ANSWER:

Please see attachment.

ELECTRIC OPERATIONS
COMPARISON OF MH11-2 To MH09-1
INCREASE / (DECREASE)
(In Millions of Dollars)

ACCOUNT	2012	2013	2014	CUMULATIVE 2012-2020	VARIANCE EXPLANATION
REVENUES					
General Consumers Revenue including Projected Rate Increases	(60)	31	35	129	Lower General Service revenues in the early portion due to the economic recession. The cumulative percent increase is much lower in MH11-2 compared to MH09-1 given the rate increases started in 2010/11 in MH09-1. Residential customer growth is higher due to increased immigration with spin-off effects on GS load growth. Offset by EIIR revenue removal from forecast for IFF11-2.
Extraprovincial	(191)	(241)	(252)	(2,373)	Lower throughout forecast due to lower prices, increased Manitoba demand, a reduction of contracted energy delivered, reduced capacity for the US interconnection and a stronger Canadian dollar. Also decrease the forecast due to Wuskatim GS deferral.
Other	(1)	8	8	67	Higher due to the reclassification of Operating Expense Recoveries to Other Income as a result of adoption of IFRS.
Total Revenue	**(252)**	**(203)**	**(209)**	**(2,178)**	
EXPENSES					
Operating and Administrative	(5)	36	112	780	Increased primarily due to IFRS adjustments and CGAAP accounting changes, slightly offset by cost reductions.
Finance Expense	(82)	(86)	(75)	(183)	Lower primarily due to favourable interest rates and stronger Canadian dollar.
Depreciation and Amortization	(54)	(35)	(92)	(709)	Lower due to elimination of negative salvage value and regulated asset amortization partially offset by change to equal life group methodology related to IFRS implementation. Also lower due to increase in estimated asset lives.
Water Rentals and Assessments	9	(7)	(2)	(19)	Increased in 2012 due to expected flows in IFF11-2 vs average flow forecast in IFF09. Decreased in 2013 and 2014 due to Wuskatim GS deferral and lower average flows.
Fuel and Power Purchased	(103)	(67)	(102)	(1,113)	Favourable water flows in 2012 reduce the requirement for thermal generation and imports. Decreased primarily due to lower market prices and stronger Canadian dollar.
Capital and Other Taxes	5	8	7	77	Higher capital tax due to increased financing requirements. Also increased payments to Gillam Townsite and Frontier School Division for grants in lieu of taxes.
Corporate Allocation	(0)	(0)	(1)	(4)	
Total Expenses	**(230)**	**(152)**	**(151)**	**(1,170)**	
Non-controlling Interest	(1)	(2)	1	50	
Change in Net Income	**(23)**	**(53)**	**(57)**	**(958)**	

PUB/MH I-22

Reference: IFF11-2 – Electric Operations

c) Please provide a schedule that indicates the amount of cash flow from electric operations, forecast electric base capital spending and net cash flow available to finance Major Generation & Transmission Projects in each of the forecast years and provide the (electric) capital coverage ratio.

[			Y1	Y2 to Y20
Cash Flow from Operations (IFF11-2 Cash Flow Statement)	1			
Base Capital Spending (CEF11)	2			
Net Cash Flow	3	3 = 2-1		
Capital Coverage Ratio	4	4 = 1/2		

The following analysis should agree with the figures presented in IFF11-2 and CEF 11. If not please reconcile.

ANSWER:

Please see the following table.

	For the year ended March 31	2008	*Actuals* 2009	2010	2011	2012	*Forecast* 2012	2013	2014	2015	2016	2017	2018	2019	2020
1	**Cash Flow from Operations**	599.0	653.0	528.0	550.0	518.0	434.2	438.6	444.2	446.9	518.9	574.2	563.7	499.2	580.4
2	**Base Capital Spending**	363.0	359.0	414.0	450.0	472.0	417.4	411.5	394.4	387.3	363.8	372.4	380.4	387.6	396.4
3	**Excess Cash Flow after Base Capital Spending (1-2)**	236.0	294.0	114.0	100.0	46.0	16.8	27.1	49.8	59.6	155.0	201.8	183.3	111.6	184.0
4	**Capital Coverage Ratio (1/2)**	1.65	1.82	1.28	1.22	1.10	1.04	1.07	1.13	1.15	1.43	1.54	1.48	1.29	1.46
5	**Major New Generation & Transmission**	477.4	543.5	679.0	657.5	567.8	656.1	762.6	1060.0	1223.4	1566.9	1610.5	1953.0	1177.1	1412.0
6	**Cash Flow required to Finance MNG&T**	241.4	249.5	565.0	557.5	521.8	639.4	735.5	1010.1	1163.8	1411.9	1408.7	1769.7	1065.5	1228.0

	For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	**Cash Flow from Operations**	514.1	716.6	832.0	920.9	1065.5	1175.2	1192.2	1294.5	1388.2	1501.2	1597.8	1748.2
2	**Base Capital Spending**	359.8	385.9	430.2	462.4	522.7	498.6	514.6	503.1	535.9	567.5	478.6	583.7
3	**Excess Cash Flow after Base Capital Spending (1-2)**	154.3	330.7	401.7	458.5	542.8	676.6	677.6	791.5	852.4	933.7	1119.2	1164.6
4	**Capital Coverage Ratio (1/2)**	1.43	1.86	1.93	1.99	2.04	2.36	2.32	2.57	2.59	2.65	3.34	3.00
5	**Major New Generation & Transmission**	1445.8	1306.0	1071.8	933.3	1050.2	385.6	224.1	323.8	460.0	374.9	390.2	225.5
6	**Cash Flow required to Finance MNG&T**	1291.5	975.3	670.1	474.7	507.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0

PUB/MH I-23

Reference: IFF11-2 – Capital Coverage Ratio

Please file an updated IFF11-2 scenario to meet a capital coverage ratio of 1.0 in each year throughout the 20 year forecast with financial ratios and annual impact on rate increase requests assuming all major capital costs are financed by debt. Any reduced revenue requirement should be reflected in the additional revenue line. Please provide all assumptions.

ANSWER:

Please see the following projected financial statements for the requested rate scenario.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
Rates Required From 2013/14 And On To Maintain 1.0 Capital Coverage Ratio
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 186	1 290	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	45	60	97	66	83	176	316	325	440	348
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 693	1 732	1 814	1 865	1 932	2 074	2 248	2 336	2 681	2 702
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	452	509	547	593	676	812	862	1 219	1 196
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 672	1 709	1 815	1 891	1 975	2 137	2 349	2 452	2 895	2 921
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	22	(2)	(29)	(45)	(65)	(103)	(119)	(216)	(229)
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	0.10%	2.69%	-2.23%	1.16%	6.40%	8.97%	0.29%	6.33%	-5.22%
Cumulative Percent Increase	0.00%	4.50%	4.60%	7.42%	5.02%	6.24%	13.03%	23.18%	23.53%	31.35%	24.50%
Financial Ratios											
Equity	26%	24%	18%	16%	14%	12%	11%	10%	8%	7%	6%
Interest Coverage	1.12	1.03	1.03	1.00	0.97	0.95	0.94	0.91	0.91	0.86	0.85
Capital Coverage	1.04	1.07	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
Rates Required From 2013/14 And On To Maintain 1.0 Capital Coverage Ratio
(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*	393	441	446	411	520	517	578	621	571	678
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
Other	19	20	20	20	21	21	22	22	23	23
	2 783	2 867	3 069	3 338	3 587	3 623	3 701	3 769	3 760	3 897
EXPENSES										
Operating and Administrative	634	646	669	676	688	700	713	727	741	755
Finance Expense	1 203	1 223	1 351	1 617	1 812	1 828	1 846	1 859	1 940	1 915
Depreciation and Amortization	579	583	615	682	733	741	753	761	793	814
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	155	158	159	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2 962	3 034	3 211	3 564	3 848	3 906	3 963	4 015	4 156	4 180
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	(190)	(178)	(152)	(237)	(273)	(295)	(275)	(259)	(409)	(297)
* Additional General Consumers Revenue										
Percent Increase	2.23%	2.32%	-0.02%	-2.10%	5.28%	-0.48%	2.59%	1.66%	-2.60%	4.52%
Cumulative Percent Increase	27.27%	30.22%	30.19%	27.46%	34.19%	33.55%	37.01%	39.28%	35.67%	41.80%
Financial Ratios										
Equity	5%	4%	3%	2%	1%	0%	-1%	-1%	0%	0%
Interest Coverage	0.88	0.89	0.91	0.87	0.85	0.84	0.86	0.87	0.79	0.85
Capital Coverage	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
Rates Required From 2013/14 And On To Maintain 1.0 Capital Coverage Ratio
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
ASSETS											
Plant in Service	13 795	15 212	15 723	16 485	17 410	17 993	21 415	21 904	25 521	28 275	28 636
Accumulated Depreciation	(4 917)	(5 266)	(5 581)	(5 911)	(6 272)	(6 638)	(7 065)	(7 539)	(8 028)	(8 583)	(9 165)
Net Plant in Service	8 878	9 947	10 142	10 574	11 138	11 355	14 351	14 365	17 492	19 692	19 472
Construction in Progress	2 443	2 196	3 149	3 997	5 014	6 410	5 346	6 447	4 558	3 595	4 964
Current and Other Assets	1 906	1 864	1 327	1 373	1 559	1 743	1 987	1 803	1 956	2 071	2 018
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	241	-	-	-	-	-	-	-	-	-
	13 648	14 426	14 780	16 093	17 847	19 634	21 800	22 725	24 109	25 456	26 547
LIABILITIES AND EQUITY											
Long-Term Debt	9 253	9 469	10 909	12 368	13 989	15 661	17 626	19 318	20 480	21 990	23 834
Current and Other Liabilities	1 351	1 917	1 454	1 431	1 638	1 807	2 090	1 432	1 779	1 838	1 325
Contributions in Aid of Construction	317	328	341	348	355	365	376	386	396	407	418
Retained Earnings	2 391	2 411	2 156	2 154	2 125	2 080	2 015	1 912	1 793	1 577	1 348
Accumulated Other Comprehensive Income	335	302	(79)	(208)	(261)	(279)	(306)	(322)	(338)	(356)	(379)
	13 648	14 426	14 780	16 093	17 847	19 634	21 800	22 725	24 109	25 456	26 547

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
Rates Required From 2013/14 And On To Maintain 1.0 Capital Coverage Ratio
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	29 045	29 610	34 023	38 098	39 357	39 988	40 557	41 087	43 107	43 823
Accumulated Depreciation	(9 752)	(10 344)	(10 970)	(11 663)	(12 407)	(13 160)	(13 926)	(14 701)	(15 509)	(16 338)
Net Plant in Service	19 293	19 267	23 053	26 435	26 951	26 828	26 631	26 386	27 599	27 485
Construction in Progress	6 099	6 969	4 170	1 022	545	786	1 259	1 722	618	758
Current and Other Assets	2 126	2 335	2 626	2 528	2 839	3 249	3 460	3 560	3 997	4 289
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27 609	28 660	29 937	30 072	30 420	30 946	31 432	31 749	32 294	32 612
LIABILITIES AND EQUITY										
Long-Term Debt	25 237	26 440	27 393	28 195	28 797	29 538	30 089	30 791	31 580	31 352
Current and Other Liabilities	1 176	1 192	1 656	1 214	1 222	1 290	1 488	1 349	1 502	2 331
Contributions in Aid of Construction	429	440	451	463	475	487	499	512	525	538
Retained Earnings	1 158	980	828	591	318	22	(253)	(512)	(921)	(1 218)
Accumulated Other Comprehensive Income	(392)	(392)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)
	27 609	28 660	29 937	30 072	30 420	30 946	31 432	31 749	32 294	32 612

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
Rates Required From 2013/14 And On To Maintain 1.0 Capital Coverage Ratio
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 556	1 693	1 732	1 814	1 865	1 932	2 074	2 248	2 336	2 681	2 702
Cash Paid to Suppliers and Employees	(742)	(816)	(886)	(931)	(951)	(976)	(1 018)	(1 048)	(1 084)	(1 103)	(1 125)
Interest Paid	(406)	(466)	(479)	(516)	(577)	(618)	(717)	(856)	(895)	(1 255)	(1 227)
Interest Received	26	28	27	20	27	34	41	43	40	36	35
	434	439	394	387	364	373	380	388	396	360	386
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	900	1 630	1 605	1 990	2 200	2 790	2 000	1 790	2 190	1 990
Sinking Fund Withdrawals	23	129	395	105	24	-	7	424	183	265	689
Retirement of Long-Term Debt	(25)	(119)	(808)	(179)	(312)	(408)	(530)	(837)	(309)	(640)	(692)
Other	(81)	(21)	(14)	(5)	(7)	(7)	(7)	(16)	(5)	26	(6)
	729	889	1 203	1 526	1 695	1 785	2 259	1 571	1 659	1 841	1 981
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1 163)	(1 226)	(1 481)	(1 616)	(1 934)	(1 986)	(2 336)	(1 567)	(1 820)	(1 856)	(1 697)
Sinking Fund Payment	(98)	(117)	(208)	(125)	(192)	(160)	(231)	(216)	(219)	(288)	(346)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1 280)	(1 363)	(1 709)	(1 761)	(2 146)	(2 191)	(2 603)	(1 813)	(2 069)	(2 179)	(2 083)
Net Increase (Decrease) in Cash	(116)	(36)	(112)	152	(86)	(33)	37	146	(13)	22	284
Cash at Beginning of Year	66	(50)	(86)	(198)	(45)	(132)	(165)	(128)	18	5	27
Cash at End of Year	(50)	(86)	(198)	(45)	(132)	(165)	(128)	18	5	27	310

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
Rates Required From 2013/14 And On To Maintain 1.0 Capital Coverage Ratio
(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	2 783	2 867	3 069	3 338	3 587	3 623	3 701	3 769	3 760	3 897
Cash Paid to Suppliers and Employees	(1 154)	(1 201)	(1 215)	(1 234)	(1 272)	(1 303)	(1 329)	(1 357)	(1 383)	(1 409)
Interest Paid	(1 220)	(1 226)	(1 365)	(1 644)	(1 841)	(1 870)	(1 902)	(1 918)	(1 981)	(2 003)
Interest Received	20	22	33	38	39	52	66	72	82	98
	430	462	522	498	514	503	535	567	478	583
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 380	1 190	1 390	790	590	800	790	790	970	790
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)
	1 373	1 184	1 384	782	582	793	783	814	866	571
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	(248)	(265)	(288)	(314)	(311)	(330)	(350)	(370)	(380)	(404)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1 788)	(1 696)	(1 894)	(1 232)	(1 087)	(1 192)	(1 382)	(1 352)	(1 285)	(1 248)
Net Increase (Decrease) in Cash	15	(50)	13	48	9	103	(63)	28	58	(93)
Cash at Beginning of Year	310	326	276	289	336	346	449	386	414	472
Cash at End of Year	326	276	289	336	346	449	386	414	472	379

PUB/MH I-24

Reference: Attachment 6

Please refile IFF11-2 for electric operations only with financial ratios assuming 1% rollback is denied recovery in rates.

ANSWER:

Please see the following IFF11-2 scenario for the requested information.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
ALTERNATIVE SCENARIO - REFUND OF 1% RATE ROLLBACK OVER TWO YEARS
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 186	1 256	1 282	1 293	1 300	1 316	1 336	1 348	1 368	1 389	1 407
additional*	0	44	105	154	206	262	322	384	451	522	597
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 656	1 765	1 858	1 992	2 098	2 207	2 303	2 448	2 750	2 937
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	439	453	507	542	577	648	774	815	1 161	1 126
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 671	1 710	1 814	1 886	1 958	2 108	2 311	2 405	2 838	2 850
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	(16)	54	44	104	137	96	(11)	40	(91)	76
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.55%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase	0.00%	4.50%	8.16%	11.94%	15.86%	19.92%	24.11%	28.46%	32.95%	37.61%	42.42%
Financial Ratios											
Equity	26%	24%	18%	16%	15%	14%	13%	13%	12%	11%	11%
Interest Coverage	1.12	0.97	1.09	1.06	1.13	1.15	1.09	0.99	1.03	0.94	1.05
Capital Coverage	1.04	0.98	1.08	1.11	1.38	1.48	1.42	1.23	1.38	1.34	1.77

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
ALTERNATIVE SCENARIO - REFUND OF 1% RATE ROLLBACK OVER TWO YEARS
(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	1 426	1 445	1 464	1 483	1 505	1 526	1 546	1 566	1 586	1 606
additional*	676	760	814	871	932	994	1 058	1 125	1 193	1 265
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
Other	19	20	20	20	21	21	22	22	23	23
	3 052	3 171	3 422	3 783	3 984	4 085	4 165	4 257	4 366	4 468
EXPENSES										
Operating and Administrative	634	646	669	676	688	700	713	727	741	755
Finance Expense	1 110	1 103	1 199	1 427	1 579	1 552	1 516	1 469	1 487	1 390
Depreciation and Amortization	579	583	615	682	733	741	753	761	793	814
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	156	158	160	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2 870	2 914	3 058	3 373	3 616	3 630	3 633	3 625	3 703	3 656
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	172	246	353	398	356	442	519	619	649	798
* Additional General Consumers Revenue										
Percent Increase	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.41%	52.57%	55.62%	58.73%	61.91%	65.14%	68.45%	71.82%	75.25%	78.76%
Financial Ratios										
Equity	11%	12%	12%	14%	15%	17%	19%	21%	23%	26%
Interest Coverage	1.12	1.16	1.22	1.24	1.22	1.28	1.33	1.40	1.42	1.56
Capital Coverage	1.84	1.92	1.95	2.25	2.21	2.44	2.46	2.52	3.18	2.86

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
ALTERNATIVE SCENARIO - REFUND OF 1% RATE ROLLBACK OVER TWO YEARS
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
ASSETS											
Plant in Service	13 795	15 212	15 723	16 485	17 410	17 993	21 415	21 904	25 521	28 275	28 636
Accumulated Depreciation	(4 917)	(5 266)	(5 581)	(5 911)	(6 272)	(6 638)	(7 065)	(7 539)	(8 028)	(8 583)	(9 165)
Net Plant in Service	8 878	9 947	10 142	10 574	11 138	11 355	14 351	14 365	17 492	19 692	19 472
Construction in Progress	2 443	2 196	3 149	3 997	5 014	6 410	5 346	6 447	4 558	3 595	4 964
Current and Other Assets	1 906	1 864	1 327	1 373	1 559	1 741	1 987	1 810	1 951	2 152	1 997
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	241	-	-	-	-	-	-	-	-	-
	13 648	14 426	14 780	16 093	17 847	19 632	21 800	22 732	24 105	25 537	26 525
LIABILITIES AND EQUITY											
Long-Term Debt	9 253	9 469	10 909	12 169	13 789	15 460	17 225	18 718	19 679	21 190	22 634
Current and Other Liabilities	1 351	1 952	1 457	1 588	1 663	1 648	1 971	1 427	1 804	1 824	1 303
Contributions in Aid of Construction	317	328	341	348	355	365	376	386	396	407	418
Retained Earnings	2 391	2 376	2 153	2 197	2 300	2 438	2 534	2 523	2 563	2 472	2 548
Accumulated Other Comprehensive Income	335	302	(79)	(209)	(261)	(279)	(306)	(322)	(338)	(356)	(378)
	13 648	14 426	14 780	16 093	17 847	19 632	21 800	22 732	24 105	25 537	26 525

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
ALTERNATIVE SCENARIO - REFUND OF 1% RATE ROLLBACK OVER TWO YEARS
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	29 045	29 610	34 023	38 098	39 357	39 988	40 557	41 087	43 107	43 823
Accumulated Depreciation	(9 752)	(10 344)	(10 970)	(11 663)	(12 407)	(13 160)	(13 926)	(14 701)	(15 509)	(16 338)
Net Plant in Service	19 293	19 267	23 053	26 435	26 951	26 828	26 631	26 386	27 599	27 485
Construction in Progress	6 099	6 969	4 170	1 022	545	786	1 259	1 722	618	758
Current and Other Assets	2 065	2 298	2 688	2 615	3 150	3 487	3 683	3 844	4 325	4 902
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27 547	28 623	29 999	30 158	30 731	31 184	31 655	32 034	32 622	33 225
LIABILITIES AND EQUITY										
Long-Term Debt	23 637	24 439	24 992	25 195	25 396	25 338	25 089	24 991	24 779	23 752
Current and Other Liabilities	1 152	1 168	1 627	1 174	1 177	1 235	1 422	1 268	1 406	2 225
Contributions in Aid of Construction	429	440	451	463	475	487	499	512	525	538
Retained Earnings	2 721	2 966	3 320	3 718	4 073	4 516	5 035	5 654	6 303	7 101
Accumulated Other Comprehensive Income	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)
	27 547	28 623	29 999	30 158	30 731	31 184	31 655	32 034	32 622	33 225

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
ALTERNATIVE SCENARIO - REFUND OF 1% RATE ROLLBACK OVER TWO YEARS
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 556	1 656	1 765	1 858	1 992	2 098	2 207	2 303	2 448	2 750	2 937
Cash Paid to Suppliers and Employees	(741)	(816)	(886)	(931)	(951)	(976)	(1 018)	(1 048)	(1 084)	(1 103)	(1 125)
Interest Paid	(406)	(466)	(479)	(517)	(564)	(606)	(689)	(822)	(854)	(1 202)	(1 164)
Interest Received	26	28	27	20	27	34	41	43	40	36	35
	434	403	428	431	503	550	541	476	549	482	683
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	900	1 630	1 405	1 990	2 200	2 590	1 800	1 590	2 190	1 590
Sinking Fund Withdrawals	23	129	395	105	24	-	5	424	178	265	689
Retirement of Long-Term Debt	(25)	(119)	(808)	(179)	(312)	(408)	(530)	(837)	(309)	(640)	(692)
Other	(81)	(21)	(14)	(5)	(7)	(7)	(7)	(16)	(5)	26	(6)
	729	889	1 203	1 326	1 695	1 785	2 058	1 371	1 454	1 841	1 581
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1 140)	(1 237)	(1 493)	(1 616)	(1 934)	(1 986)	(2 336)	(1 567)	(1 820)	(1 856)	(1 697)
Sinking Fund Payment	(98)	(117)	(208)	(125)	(192)	(158)	(231)	(211)	(219)	(288)	(346)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1 257)	(1 374)	(1 721)	(1 761)	(2 146)	(2 190)	(2 603)	(1 808)	(2 069)	(2 179)	(2 083)
Net Increase (Decrease) in Cash	(93)	(83)	(91)	(4)	53	146	(5)	40	(66)	144	181
Cash at Beginning of Year	66	(27)	(110)	(200)	(204)	(151)	(5)	(10)	30	(36)	108
Cash at End of Year	(27)	(110)	(200)	(204)	(151)	(5)	(10)	30	(36)	108	289

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
ALTERNATIVE SCENARIO - REFUND OF 1% RATE ROLLBACK OVER TWO YEARS
(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	3 052	3 171	3 422	3 783	3 984	4 085	4 165	4 257	4 366	4 468
Cash Paid to Suppliers and Employees	(1 154)	(1 201)	(1 215)	(1 234)	(1 272)	(1 303)	(1 329)	(1 357)	(1 383)	(1 410)
Interest Paid	(1 129)	(1 105)	(1 217)	(1 462)	(1 612)	(1 601)	(1 577)	(1 536)	(1 534)	(1 476)
Interest Received	20	22	32	36	38	49	61	65	73	86
	790	886	1 022	1 123	1 138	1 230	1 320	1 429	1 521	1 668
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	980	790	990	190	190	-	(10)	(10)	(30)	(10)
Sinking Fund Withdrawals	159	-	-	410	-	-	60	250	-	13
Retirement of Long-Term Debt	(159)	-	-	(450)	-	-	(60)	(220)	(100)	(213)
Other	(7)	(6)	(6)	(8)	(8)	(7)	(7)	(6)	(4)	(19)
	973	784	984	143	182	(7)	(17)	14	(134)	(229)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 510)	(1 401)	(1 578)	(891)	(746)	(834)	(1 003)	(953)	(876)	(814)
Sinking Fund Payment	(236)	(249)	(267)	(286)	(279)	(292)	(303)	(313)	(313)	(324)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1 776)	(1 680)	(1 873)	(1 205)	(1 055)	(1 154)	(1 335)	(1 295)	(1 218)	(1 168)
Net Increase (Decrease) in Cash	(13)	(10)	134	60	266	69	(32)	148	170	271
Cash at Beginning of Year	289	276	266	399	460	726	794	762	910	1 080
Cash at End of Year	276	266	399	460	726	794	762	910	1 080	1 351

PUB/MH I-25

Reference: IFF11-2, PUB/MH II-90 (b) 2011 GRA

a) Please file in a similar format of II-90 (b) on separate schedules the impacts on interest, depreciation, OM&A, Capital Tax , water rentals and net revenues in IFF11-2 by year for Wuskwatim, Bipole 3, Keeyask, and Conawapa.

For each year of the analyses, please provide two columns the first reflecting the amounts without the project costs & revenues and the other column containing only the assumed project costs & revenues.

ANSWER:

As noted in Manitoba Hydro's submission of July 20, 2012 (Interim Rates Effective September 1, 2012 and Response to Request for Additional Information), there are no Revenue Requirement Impacts for Keeyask, Conawapa or BiPole III in the test years under consideration, as none of these projects have been approved and any costs associated with maintaining the in-service dates are not incorporated into the Revenue Requirement for purposes of establishing rates.

The Clean Environment Commission has established a process to review the BiPole III project, and the Province of Manitoba has stated its intention to hold a Needs For and Alternatives To hearing prior to Manitoba Hydro formally committing to Keeyask or Conawapa. If these projects are approved and the costs associated with their construction are incorporated into the Revenue Requirement, Manitoba Hydro will be in a position to advise the PUB of the Revenue Requirement impacts at that time.

For information related to Wuskwatim, please see Manitoba Hydro's response to CAC/MH I-15(a).

PUB/MH I-25

Reference: IFF11-2, PUB/MH II-90 (b) 2011 GRA

b) Please file an IFF11-2 for the years 2012/13 through 2015/16 which removes the impacts of Wuskwatim (revenues and expenses) which are to be shown in a separate columns.

For each year of the analyses, please provide two columns the first reflecting the amounts without the project costs & revenues and the other column containing only the assumed project costs & revenues.

ANSWER:

It is not practical to remove the impacts of Wuskwatim from the IFF as Wuskwatim is required to meet firm load commitments. If Wuskwatim is removed, alternative generation sources (e.g. gas, coal) or increased imports must be added to meet load requirements.

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

PUB/MH I-25

Reference: IFF11-2, PUB/MH II-90 (b) 2011 GRA

c) Please file an IFF11-2 (4 separate scenarios) which reflects the elimination of the financial impact of;

- **Wuskwatim**
- **Keeyask**
- **Conawapa**
- **Bipole III**

For each year of the analyses, please provide two columns the first reflecting the amounts without the project costs & revenues and the other column containing only the assumed project costs & revenues.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-25(b) with respect to Wuskwatim. For Keeyask, Conawapa and Bipole III, please see Manitoba Hydro's response to PUB/MH I-25(a).

PUB/MH I-26

Reference: Tab 4 Page 5 of 9

a) With respect to the revenue reductions cited, please explain the reduction in net extra-provincial revenue in relation to the term sheets discussed at the last GRA.

ANSWER:

The reduction in net extra-provincial revenue in IFF11-2 versus IFF10-2 is in regard to the revised start dates for the MP and WPS sales.

PUB/MH I-26

Reference: Tab 4 Page 5 of 9

b) Please provide details of the calculation of the public announced gross revenue resulting from these new export contract/ term sheets. Please provide the press releases.

ANSWER:

Manitoba Hydro cannot provide details of the gross revenues resulting from the new export contract/term sheets as it contains commercially sensitive and confidential information that cannot be released to the public.

The press releases by the Province of Manitoba for the MP 250MW Sale and the WPS 100MW Sale and WPS Term Sheet are provided below:

May 25, 2011
$4 BILLION IN POWER SALES TO U.S. FOR MANITOBA HYDRO: SELINGER

Premier Greg Selinger announced today that Manitoba Hydro has signed agreements for a 250 megawatt (MW) sale of electricity to Minnesota Power and a 100-MW sale to Wisconsin Public Service. Combined with a previously completed 125 MW sale to Northern States Power, these sales total 475 MW with an estimated value of $4 billion, Selinger said.

The premier said these sales will require the construction of new hydroelectric generating capacity in Manitoba. They will trigger the development of the 695-MW Keeyask (Cree for gull) Generating Station located on the lower Nelson River 175 km northeast of Thompson in the Split Lake Resource Management Area. Keeyask is to be developed by a partnership consisting of Manitoba Hydro and the Keeyask Cree Nations-Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation, and York Factory First Nation. The $5.6-billion project will provide some 4,500 person-years of construction employment, said Selinger.

“I am very pleased that Manitoba Hydro is moving forward with these power sales which will significantly increase our exports and lead to further development of Manitoba’s renewable hydro power resources,” stated Selinger. “These sales will add

to Manitoba's reputation as a sustainable energy leader and help reduce global greenhouse-gas emissions by reducing the need for thermal generation in the United States. At the same time, the development of Keeyask will deliver jobs, training and business opportunities to the Keeyask Cree Nations, the north and all of Manitoba."
"Today's announcement demonstrates there is strong interest in Manitoba hydro power in U.S. markets, resulting in the need to advance construction of new generation and a new interconnection with the U.S. that will broaden and diversify our customer base, increase our revenues and contribute to reliable, cost-effective future electricity supply for Manitobans," said Bob Brennan, president and CEO, Manitoba Hydro.

The 250-MW power sale to Minnesota Power over a 15-year period from 2020 to 2035 requires an additional interconnection between Manitoba and the United States which will provide increased export capability and reliability benefits for Manitoba, said Selinger.

The 100-MW power sale agreement to Wisconsin Public Service covers the 2021-2027 period. Negotiations are continuing to expand the Wisconsin sale to 500 MW which would require construction of the Conawapa Generating Station, the premier said, adding with these sales, Manitoba Hydro and its partners are reviewing scheduling and other requirements for moving forward with Keeyask.

Manitoba Hydro's construction program also includes the Bipole III transmission line, being developed for a 2017 in-service date to provide reliability for Manitoba customers. Bipole III will also be utilized to transmit power from Keeyask and the 1,485-MW Conawapa Generating Station, supporting expanded electricity export sales outside of Manitoba's borders. The Conawapa site is located in the Fox Lake Cree Nation Resource Management Area.

Sale agreements with Minnesota Power and Wisconsin Public Service will require regulatory approval in Canada and the United States.

April 17, 2008

MANITOBA HYDRO REACHES ARRANGEMENT TO SELL POWER TO WISCONSIN PUBLIC SERVICE

– – –

500-megawatt Deal Worth over $2 Billion: Doer

Manitoba Hydro has signed a ‘term sheet’ with Wisconsin Public Service (WPS) to provide up to 500 megawatts of clean, renewable hydro power over 15 years starting in 2018, Premier Gary Doer announced today.

“We are pleased to have come to this agreement with Wisconsin Public Service that will significantly increase our exports, allow us to maintain our low energy rates for domestic users and reduce the production of greenhouse gases by reducing the need for thermal generation in the United States,” said Doer.

Electricity exports generated $592 million in revenues for Manitoba Hydro last year and are expected to produce $5.5 billion in revenues over the next 10 years. This deal is worth over $2 billion. Manitoba Hydro export sales, on average, account for more than 40 per cent of Manitoba Hydro’s electricity revenues.

“Our government is developing our province’s clean, renewable energy to its full potential for the benefit of all Manitobans,” said Finance Minister Greg Selinger, minister responsible for Manitoba Hydro. “We are moving forward with construction on the Wuskwatim dam, working on a co-operative agreement with First Nations on Keeyask and continuing development work on the Conawapa generating station.”

“This proposed major agreement with WPS will trigger additional generating and transmission facilities, adding to the capability and reliability of the regional power system,” noted Bob Brennan, Manitoba Hydro president and CEO. “At the same time, new northern hydroelectric developments will bring direct benefits to local Aboriginal communities.”

Manitoba Hydro recently signed a term sheet with Minnesota Power, an ALLETE company, to provide 250 megawatts (MW) of hydro power over 15 years starting in 2020 as well as well surplus energy starting this year. In early 2007, Manitoba Hydro and Wisconsin Public Service renewed a 100 MW export agreement.

The long-term sale will require the construction of the Bipole III transmission line as well as hydroelectric facilities in northern Manitoba and a major transmission line between Canada and the United States.

PUB/MH I-27

Reference: **Tab 4 Page 2 of 9 , Appendix 4.1 Economic Outlook, Attachment 4 2012 economic outlook**

a) Please provide a comparison table of major assumptions utilized in IFF11-2 based on EO11 with those now forecast in EO12.

ANSWER:

The following table provides a comparison of major assumptions utilized in IFF11-2 based on the EO11 October 2011 update to those now forecast in EO12.

	Manitoba Consumer Price Index		MH Cdn Short Term Interest Rate*		MH Cdn Long Term Interest Rate *		$US/$Cdn Exchange Rate	
	Oct-11	EO12	Oct-11	EO12	Oct-11	EO12	Oct-11	EO12
2011/12	2.0	2.8	0.90	0.90	3.75	2.80	0.98	0.99
2012/13	2.0	1.7	1.25	1.00	3.70	3.50	0.99	1.00
2013/14	2.0	1.8	2.20	1.45	4.05	3.70	0.99	0.99
2014/15	2.0	1.8	3.80	3.00	5.40	4.55	1.05	1.02
2015/16	2.0	1.8	4.05	3.60	5.90	5.05	1.06	1.03
2016/17	2.0	1.8	4.25	4.05	6.20	5.60	1.06	1.04
2017/18	2.1	1.9	4.30	4.30	6.40	5.90	1.06	1.04
2018/19	2.1	1.9	4.30	4.30	6.40	6.00	1.06	1.04
2019/20	2.1	1.9	4.30	4.30	6.40	6.00	1.06	1.04
2020/21	2.1	1.9	4.30	4.30	6.40	6.00	1.06	1.04

* The rates on debt do not include the 1.00% Provincial Guarantee Fee

PUB/MH I-27

Reference: **Tab 4 Page 2 of 9 , Appendix 4.1 Economic Outlook, Attachment 4 2012 economic outlook**

b) **Please indicate whether the Corporation has done any analysis on the impact of changed assumptions, if so please file.**

ANSWER:

The impact of the changed assumptions will be reflected in IFF12-1, which will be finalized in the fall of 2012.

PUB/MH I-27

Reference: Tab 4 Page 2 of 9 , Appendix 4.1 Economic Outlook, Attachment 4 2012 economic outlook

c) If not, please refile IFF11-2 updated based on the changed major assumptions in EO12.

ANSWER:

The assumptions in EO12 will be incorporated into IFF12.

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Reference: Tab 4 Appendix 4.1, Attachment 4 EO12, Tab 5 Section 5.6 Finance Expense

a) Please provide table(s) detailing the relied upon interest forecasts by forecaster for both short term and long term interest rates indicating, the date of the forecast, whether the forecast represented end of period data or average and describe what if any adjustments were made to end of period data forecasts to average the results.

ANSWER:

Manitoba Hydro's interest rate forecasting methodology was reviewed in detail as part of the 2010/11 & 2011/12 Electric GRA. The detailed methodology was described in the previous GRA in response to PUB/MH I-46(b), a copy of which is attached.

Consistent with the agreed upon methodology utilized at that time, the updated Economic Outlook adjusts interest rate forecasts with end of period rates to a comparable average period basis. In addition, a copy of each interest rate forecast utilized in EO11 is provided in the tables below.

Please note the following with respect to the tables for EO11 for 2011/12 and beyond that are shown below:

- Table 1 on the following page depicts the sources used to derive the forecast of Canadian 3 month T-Bill rates (with end of period rates adjusted to a comparable average period basis) for each quarter of the 2011/12 – 2013/14 period.
- Table 2 depicts the forecast sources used to derive the forecast of Canadian 3 month T-Bill rates for the 2014-2021 period.
- Table 3 depicts the sources used to derive the forecast of Canadian 10 year+ bond yield rates (with end of period rates adjusted to a comparable average period basis) for the 2011/12 – 2013/14 period.
- Table 4 depicts the forecast sources used to derive the forecast of Canadian 10 year+ bond yield rates for the 2014 - 2021 period.

Table 1 – Canadian 3 Month T-Bill Rate - %

			2011			2012				2013				2014			
	Fcst Date	**End Period or Average**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
BMO Nesbitt Burns	30-Sep-11	Average	0.96	0.90	0.83	0.83	0.83	0.83	0.83								
CIBC	3-Oct-11	End Period	0.96	0.90	0.87	0.98	1.10	1.28	1.38	1.53	1.65	1.65	1.65	1.95	2.25	2.25	2.25
National Bank	1-Oct-11	End Period	0.96	0.90	0.81	0.88	1.36	1.36	1.36								
Royal Bank	1-Sep-11	End Period	0.96	0.90	0.94	1.13	1.23	1.58	2.00								
Scotiabank	7-Oct-11	End Period	0.96	0.90	0.82	0.90	1.03	1.23	1.65								
TD Bank	13-Sep-11	End Period	0.96	0.90	0.84	0.90	0.90	0.93	0.98	1.15	1.55	1.95	2.35	2.93			
IHS Global Insight	14-Sep-11	Average	0.96	0.90	0.93	0.94	0.96	1.03	1.28	1.50	1.50	1.75	1.75	2.00	2.25	2.50	3.00
Conference Board	21-Sep-11	Average	0.96	0.90	0.93	0.92	0.90	1.19	1.67	2.16	2.64	3.13	3.63	3.83	3.83	3.83	3.84
			2011/12	**2012/13**	**2013/14**												
EO2011 - Fiscal			0.90	1.25	2.20												

NOTE: The extended forecast provided by BMO Nesbitt Burns for 2013+ is proprietary and cannot be disclosed.

Table 2 – Canadian 3 Month T-Bill Rate - %

	Fcst Date	**End Period or Average**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
IHS Global Insight	11-Mar-11	Average	4.62	4.75	4.75	4.50	4.50	4.50	4.50	4.50
Conference Board	15-Mar-11	Average	3.85	3.85	4.11	4.11	4.11	4.11	4.11	4.11
Informetrica	29-Jan-11	Average	3.42	4.22	4.24	4.24	4.24	4.24	4.24	4.24
Spatial Economics	1-Jan-11	Average	3.10	3.10	3.60	4.20	4.80	5.00	4.60	4.20
Average			3.75	3.98	4.18	4.26	4.41	4.46	4.36	4.26
EO2011 - Calendar			3.75	4.00	4.20	4.30	4.30	4.30	4.30	4.30
			2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	
EO2011 - Fiscal			3.80	4.05	4.25	4.30	4.30	4.30	4.30	

Table 3 – Canadian 10 Year+ Bond Yield Rate - %

	Fcst Date	End Period or Average	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4
BMO Nesbitt Burns	30-Sep-11	Average	3.41	2.86	2.42	2.35	2.35	2.41	2.51								
CIBC	3-Oct-11	End Period	3.41	2.86	2.56	2.64	2.75	2.89	3.00	3.23	3.40	3.40	3.40	3.46	3.53	3.53	3.53
National Bank	1-Oct-11	End Period	3.41	2.86	2.48	2.50	2.82	2.82	2.82								
Royal Bank	1-Sep-11	End Period	3.41	2.86	2.76	3.10	3.25	3.43	3.63								
Scotiabank	7-Oct-11	End Period	3.41	2.86	2.46	2.44	2.60	2.83	3.04								
TD Bank	13-Sep-11	End Period	3.41	2.86	2.42	2.44	2.76	3.14	3.41	3.60	3.70	3.79	3.93				
IHS Global Insight	14-Sep-11	Average	3.41	2.86	2.57	2.84	3.00	3.09	3.13	3.16	3.19	3.24	3.41	3.66	3.77	4.00	4.23
Conference Board	21-Sep-11	Average	3.41	2.86	2.80	2.69	2.59	2.64	2.79	2.97	3.18	3.43	3.70	3.86	3.95	4.04	4.12
			2011/12	**2012/13**		**2013/14**											
EO2011 - Fiscal			2.85	2.95		3.40											

NOTE: The extended forecast provided by BMO Nesbitt Burns for 2013+ is proprietary and cannot be disclosed.

Table 4 – Canadian 10 Year+ Bond Yield Rate - %

	Fcst Date	End Period or Average	2014	2015	2016	2017	2018	2019	2020	2021
IHS Global Insight	11-Mar-11	Average	5.12	5.95	6.00	6.00	6.00	6.00	6.00	6.00
Conference Board	15-Mar-11	Average	4.54	4.62	4.85	4.88	4.92	4.94	4.96	4.97
Informetrica	29-Jan-11	Average	4.80	5.40	5.80	6.00	6.10	6.10	6.10	6.10
Spatial Economics	1-Jan-11	Average	4.20	4.95	5.45	6.05	6.65	6.85	6.45	6.10
Average			4.66	5.23	5.53	5.73	5.92	5.97	5.88	5.79
EO2011 - Calendar			4.65	5.25	5.50	5.80	5.80	5.80	5.80	5.80
			2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	
EO2011 - Fiscal			4.80	5.30	5.60	5.80	5.80	5.80	5.80	

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Subject: Tab 5: Integrated Financial Forecast
Reference: Tab 5 Appendix 5.2 IFF09-1 Page 5 Interest Rates

b) Please provide table(s) detailing the relied upon interest forecasts by forecaster for both short term and long term interest rates indicating, the date of the forecast, whether the forecast represented end of period data or average and describe what if any adjustments were made to end of period data forecasts to average the results.

ANSWER:

Short and long term interest rates for 2009/10 - 2012/13 period were reviewed and revised in July 2009 based on currently available information. As noted in Tab 5.2, page 2, lines 1-16, the forecast of exchange rates and interest rates were again reviewed in October 2009 due to the continuing volatility of the Canadian dollar. This review resulted in a further revision to the long term Canadian debt rate for 2009/10 and 2010/11. The forecasts of interest rates for the 2013/14 - 2019/20 period are from the Spring 2009 Economic Outlook.

Table 1 on the following page depicts the sources used to derive the forecast of Canadian T-bill rates for the 2009/10 - 2012/13 period. Table 2 depicts the forecast sources used to derive the forecast of Canadian t-bill rates for the 2013/14 - 2019/20 period.

Table 3 depicts the sources used to derive the forecast of Canadian bond yield 10 yr+ rates for the 2009/10 - 2012/13 period. Table 4 depicts the forecast sources used to derive the forecast of Canadian bond yield 10 yr+ rates for the 2013/14 - 2019/20 period.

The information in Table 1 reflects actual 3 month T-bill rates from for Q1, Q2, and Q3 of 2009 (as indicated in shaded area). For the subsequent quarters, for forecasters that provided average period rates, the rates in Table 1 reflect the forecast provided from that forecaster. For forecasters that provided end of period rates, the rates in Table 1 reflect rates adjusted to a comparable average period basis. For example, Royal Bank's forecast provided end of period rates. Their forecast for 2009 Q4 end of period was 0.35%. In order to place the forecast on an equivalent average period basis for 2009 Q4, Royal Bank's 2009 Q4 end of period forecast of 0.35% was averaged with their 2009 Q3 end of period actual rate of 0.22% to approximate an average period 2009 Q4 forecast of 0.29%. This process was followed for all subsequent quarters and for all forecasters that provided end of period rates in Table 1. i.e., Q1 end of period forecast for 2010 was averaged with Q4 end of period forecast for 2009 to obtain an average period Q1 2010 forecast, etc.

The information in Table 3 reflects actual rates for Q1, Q2, and Q3 of 2009 for the long bond rates applicable to each forecast source (as indicated in shaded area). The long bond rate used for each forecaster was as follows:

Forecaster	**Long Bond Rate Used**
BMO Nesbitt Burns	Canada 10 Year
CIBC	Average of Canada 10 Yr and 30 Yr
National Bank	Average of Canada 10 Yr and 30 Yr
RBC	Average of Canada 10 Yr and 30 Yr
Scotiabank	Average of Canada 10 Yr and 30 Yr
TD Bank	Average of Canada 10 Yr and 30 Yr
Global Insight	Average of Canada 10 Yr and 30 Yr
Conference Board	Canada 10 Year+

With respect to Canadian long bond rate forecasts, BMO Nesbitt Burns only provides a Canadian 10 year forecast while the other five banks provide both 10 year and 30 year Canada long bond forecasts. Conference Board only provides a Canada 10 Year+ forecast. Global Insight provides a Canada 10 year, 30 year and 10 year+ forecast. For Global Insight, the average of the Canada 10 year and 30 year forecasts were used in the derivation of the forecasts in Table 3.

The actual rates in Table 3 for Q1, Q2, and Q3 2009 reflect the actual Canada 10 year bond rate for BMO Nesbitt Burns, the average of the actual Canada 10 year bond and 30 year bond rates for CIBC, National Bank, RBC, Scotiabank, TD Bank and Global Insight and the actual Canada 10 Year+ rate for Conference Board, consistent with the forecast rates used for each of those sources.

For the subsequent quarters, for forecasters that provided average period rates, the rates in Table 3 reflect the forecast provided from that forecaster. For forecasters that provided end of period rates, the rates in Table 3 reflect rates adjusted to a comparable average period basis. For example, Royal Bank’s forecast provided end of period rates. Their forecast for 2009 Q4 end of period was 3.15% for Canada 10 year and 4.00% for Canada 30 year (average of 3.58%). In order to place the forecast on an equivalent basis for a Q4 average period forecast, Royal Bank's Q4 end of period forecast of 3.58% was averaged with their Q3 end of period actual rate of 3.58% (average of 3.31% for Canada 10 year and 3.84% for Canada 30 year) to approximate an average period Q4 forecast of 3.58%. This process was followed for all subsequent quarters and for all forecasters that provided end of period rates in Table 3. i.e., Q1 end of period forecast for 2010 was averaged with Q4 end of period forecast for 2009 to obtain an average period Q1 2010 forecast, etc.

It should be noted that adjusting end of period forecasts to average forecasts may or may not result in a better consolidated forecast. The result is still a forecast which will be updated in subsequent periods and will ultimately be updated to actual borrowing rates. The adjustments which put all of the independent forecasts on an equivalent basis have the potential to qualify, to some extent, the independence of externally derived forecasts. Further, the use of end of period versus average is normally immaterial in the overall scheme of the financial forecast which has many moving parts. Nevertheless, such adjustments may have some value during extreme volatility in rates.

Table 1 - Canada 90 Day T-bill Rate - %

			2009				2010				2011				2012				2013			
	Fcst Date	End Period or Average	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
BMO Nesbitt Burns	09-Oct-09	Average	0.71	0.23	0.23	0.22	0.22	0.30	0.78	1.25												
CIBC	30-Sep-09	End Period	0.71	0.23	0.23	0.24	0.24	0.28	0.30	0.30												
National Bank	Oct-09	End Period	0.71	0.23	0.23	0.29	0.64	1.21	1.69	2.05												
Royal Bank	02-Oct-09	End Period	0.71	0.23	0.23	0.29	0.43	0.63	1.00	1.55												
Scotiabank	07-Oct-09	End Period	0.71	0.23	0.23	0.27	0.33	0.43	0.90	1.78												
TD Bank	15-Oct-09	End Period	0.71	0.23	0.23	0.27	0.30	0.38	0.53	0.75												
IHS Global Insight	09-Oct-09	Average	0.71	0.23	0.23	0.25	0.28	0.53	0.79	1.30	1.98	2.24	2.50	2.75	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.50
Conference Board	16-Sep-09	Average	0.71	0.23	0.23	0.20	0.18	0.25	0.69	1.47	2.46	3.44	4.14	4.54	4.58	4.58	4.59	4.59	4.60	4.60	4.60	4.60
Average			0.71	0.23	0.23	0.25	0.33	0.50	0.83	1.31	2.22	2.84	3.32	3.65	3.79	3.92	4.05	4.17	4.30	4.42	4.55	4.55
			2009/10	**2010/11**	**2011/12**	**2012/13**																
EO2009 - Fiscal			0.25	1.20	3.40	4.10																

Table 2 - Canada 90 Day T-Bill Rate - %

		End Period or Average	2013	2014	2015	2016	2017	2018	2019	2020
IHS Global Insight	Feb-09	Average	4.31	4.75	4.75	4.75	4.50	4.50	4.50	4.50
Conference Board	Dec-08	Average	4.60	4.60	4.60	4.61	4.61	4.61	4.61	4.61
Informetrica	Feb-09	Average	3.90	3.80	3.80	3.80	3.80	3.80	3.80	3.80
Spatial Economics	Nov-08	Average	5.10	4.30	3.70	3.50	3.60	4.20	4.60	4.70
Province of BC	Feb-09	Average *	4.80							
Federal Finance	Nov-08	Average *	4.20							
Average			4.48	4.36	4.21	4.17	4.13	4.28	4.38	4.40
EO2009 - Calendar			4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
			2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	
EO2009 - Fiscal			4.25	4.25	4.25	4.25	4.25	4.25	4.25	

* The source forecast tables do not indicate end period or average period. Manitoba Hydro has treated them as average period rates.

Table 3 - Canada Bond Yield 10 Year+ Rate - %

			2009				2010				2011				2012				2013			
		End Period or Average	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
BMO Nesbitt Burns	09-Oct-09	Average	2.96	3.37	3.41	3.30	3.43	3.54	3.65	3.76												
CIBC	30-Sep-09	End Period	3.34	3.67	3.67	3.60	3.70	3.89	4.03	4.11												
National Bank	Oct-09	End Period	3.34	3.67	3.67	3.82	4.08	4.24	4.32	4.41												
Royal Bank	02-Oct-09	End Period	3.34	3.67	3.67	3.58	3.63	3.78	3.98	4.19												
Scotiabank	07-Oct-09	End Period	3.34	3.67	3.67	3.66	3.85	4.19	4.54	4.73												
TD Bank	15-Oct-09	End Period	3.34	3.67	3.67	3.73	3.85	3.75	3.74	3.94												
IHS Global Insight	09-Oct-09	Average	3.34	3.67	3.67	4.03	4.07	4.08	4.09	4.12	4.16	4.21	4.23	4.41	4.66	4.87	4.93	4.93	4.93	4.95	5.13	5.60
Conference Board	16-Sep-09	Average	3.69	3.93	3.98	3.96	3.71	3.53	3.54	3.72	4.03	4.41	4.72	4.96	5.07	5.18	5.28	5.36	5.43	5.49	5.55	5.60
Average			**3.34**	**3.67**	**3.68**	**3.71**	**3.79**	**3.87**	**3.98**	**4.12**	**4.10**	**4.31**	**4.47**	**4.69**	**4.87**	**5.03**	**5.10**	**5.14**	**5.18**	**5.22**	**5.34**	**5.60**
			2009/10	**2010/11**	**2011/12**	**2012/13**																
EO2009 - Fiscal			3.70	4.00	4.60	5.10																

Table 4 - Canada Bond Yield 10 Year+ Rate - %

		End Period or Average	2013	2014	2015	2016	2017	2018	2019	2020
IHS Global Insight	Feb-09	Average	5.27	5.94	5.93	5.93	5.93	5.92	5.92	5.92
Conference Board	Dec-08	Average	5.64	5.75	5.82	5.86	5.88	5.90	5.91	5.91
Informetrica	Feb-09	Average	4.90	4.90	4.90	4.90	4.90	4.90	4.80	4.80
Spatial Economics	Nov-08	Average	7.20	6.40	5.70	5.40	4.90	5.50	5.90	6.00
Province of BC	Feb-09	Average *	5.80							
Federal Finance	Nov-08	Average *	5.00							
Consensus Economics	Oct-08	End Period	5.20	5.10	5.10	5.10	5.10	5.10		
Average			5.57	5.62	5.49	5.44	5.34	5.46	5.63	5.66
EO2009 - Calendar			5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50
			2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	
EO2009 - Fiscal			5.50	5.50	5.50	5.50	5.50	5.50	5.50	

* The source forecast tables do not indicate end period or average period. Manitoba Hydro has treated them

Canadian Economic Outlook

BMO Capital Markets Economics

September 30, 2011

	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2009	2010	2011	2012
PRODUCTION	**(quarter/quarter % change : a.r.)**															
Real GDP (chain-weighted)	5.6	2.3	2.5	3.1	3.6	-0.4	2.0	1.5	1.8	2.1	2.3	2.5	-2.8	3.2	2.2	1.8
Final Sales	4.2	1.1	1.4	7.7	1.2	-2.7	3.2	2.1	2.0	2.2	2.2	2.6	-2.0	2.6	1.9	1.9
Final Domestic Demand	5.3	3.9	4.3	4.8	1.8	3.0	1.7	1.8	2.0	2.1	2.2	2.5	-2.1	4.5	3.0	2.1
Consumer Spending	4.2	1.4	2.8	4.4	-0.1	1.6	1.6	1.5	1.6	1.9	2.1	2.4	0.4	3.3	1.8	1.8
durables	4.0	-7.4	1.6	11.0	-5.2	1.5	0.5	0.5	1.0	1.5	2.0	2.5	-1.9	4.4	0.7	1.2
nondurables	1.7	2.7	2.6	0.9	-1.3	-0.3	1.2	1.0	1.0	1.3	1.6	2.2	0.8	1.8	0.5	1.1
services	3.4	3.7	2.9	4.8	1.4	3.1	2.0	2.0	2.0	2.2	2.3	2.4	1.1	3.5	2.8	2.2
Government Spending	1.6	5.3	2.9	3.4	0.1	1.6	-2.3	-1.0	0.1	0.1	0.1	0.7	4.3	4.7	1.3	-0.3
Business Investment	11.9	17.9	23.5	13.5	12.9	15.5	8.5	7.2	6.5	6.7	6.3	5.5	-20.8	7.3	14.0	7.4
non-residential construction	17.5	7.2	16.6	22.8	10.7	2.0	10.0	6.5	6.0	5.5	5.5	5.0	-22.2	2.8	11.2	6.1
machinery and equipment	6.8	29.4	30.5	5.0	15.2	31.0	7.0	8.0	7.0	8.0	7.0	6.0	-19.5	11.8	17.0	8.6
Residential Construction	19.8	-0.4	-5.1	-0.9	7.5	0.7	7.0	5.0	4.0	3.0	3.0	5.0	-8.0	10.2	2.3	4.1
Exports	8.8	11.9	-1.2	8.8	7.7	-8.3	9.7	5.3	3.8	4.0	4.3	4.3	-13.8	6.4	3.9	4.1
Imports	12.3	21.8	8.4	-0.5	9.5	10.0	4.6	4.1	3.6	3.6	4.0	4.0	-13.4	13.1	7.2	4.3
	(billions of chained 2002 dollars : a.r.)															
Inventory Change	6.5	13.3	15.6	0.2	9.1	19.2	13.6	11.6	11.1	10.7	11.2	11.1	-0.5	8.9	13.4	11.0
Contribution to GDP Growth	0.6	1.7	0.6	-3.8	2.2	2.5	-1.2	-0.6	-0.2	-0.1	0.1	-0.1	-0.7	0.6	0.3	-0.1
Net Exports	-109.2	-124.2	-137.2	-127.0	-131.8	-156.2	-152.5	-152.7	-153.8	-154.7	-155.8	-157.1	-85.0	-124.4	-148.3	-155.3
Contribution to GDP Growth	-1.1	-2.8	-2.9	2.7	-0.6	-5.6	1.5	0.3	0.0	0.1	0.0	0.1	0.1	-1.9	-1.1	-0.1
	(billions of dollars : a.r.)															
Nominal GDP	1,601	1,610	1,625	1,662	1,695	1,701	1,716	1,726	1,743	1,761	1,779	1,799	1,529	1,625	1,709	1,771
(% chng : a.r.)	9.7	2.4	3.8	9.3	8.1	1.5	3.6	2.3	4.1	4.1	4.3	4.5	-4.6	6.3	5.2	3.6
INFLATION	**(quarter/quarter % change : a.r.)**															
GDP Price Index	3.7	0.3	1.3	6.0	4.3	1.9	1.6	0.8	2.2	2.0	1.9	2.0	-1.9	2.9	3.0	1.8
CPI All Items	2.2	-0.1	2.4	4.4	3.6	3.1	0.8	2.4	1.8	2.1	2.2	1.9	0.3	1.8	2.9	2.0
Excl. Food & Energy	1.6	1.1	1.8	1.9	1.7	1.3	0.6	1.9	1.3	2.3	2.4	2.0	1.1	1.3	1.5	1.7
Food Prices	2.4	0.4	3.1	1.1	5.5	5.8	4.7	3.3	2.0	1.2	1.2	1.2	4.9	1.4	3.9	2.5
Energy Prices	7.4	-10.6	6.7	35.8	15.4	11.9	-5.1	4.9	6.4	2.6	2.4	2.4	-13.5	6.6	11.8	3.5
Services	1.0	3.1	4.3	1.6	1.3	3.7	2.7	2.5	2.3	2.3	2.4	2.4	2.1	2.0	2.5	2.5
	(year/year % change)															
CPI All Items	1.6	1.4	1.8	2.3	2.6	3.4	3.0	2.5	2.0	1.9	2.2	2.0				
BoC Core	1.9	1.8	1.6	1.6	1.3	1.6	1.8	1.9	2.0	1.9	2.1	2.0	1.8	1.7	1.7	2.0
FINANCIAL	**(average for the quarter : %)**															
Overnight Rate	0.25	0.33	0.83	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.40	0.60	1.00	1.00
3-Month T-Bill	0.19	0.41	0.70	0.94	0.95	0.95	0.88	0.83	0.83	0.83	0.83	0.83	0.33	0.56	0.90	0.83
90-Day BAs	0.39	0.69	1.02	1.23	1.26	1.26	1.22	1.21	1.21	1.21	1.21	1.21	0.50	0.83	1.23	1.21
10 Year Bond Yield	3.47	3.47	3.01	3.00	3.31	3.16	2.53	2.13	2.05	2.05	2.12	2.22	3.23	3.24	2.78	2.11
Canada/US spread: (bps)																
90 day	8	26	54	80	82	90	86	81	81	81	81	81	18	42	85	81
10 year	-25	-2	22	13	-15	-5	10	23	28	30	28	26	-3	2	3	28
FOREIGN TRADE	**(billions of dollars : a.r.)**															
Current Account Balance	-34.7	-56.0	-71.5	-41.1	-40.3	-61.3	-61.7	-64.7	-61.8	-59.8	-59.6	-58.8	-45.2	-50.9	-57.0	-60.0
(% of GDP)	-2.2	-3.5	-4.4	-2.5	-2.4	-3.6	-3.6	-3.7	-3.5	-3.4	-3.4	-3.3	-3.0	-3.1	-3.3	-3.4
Merchandise Balance	1.1	-11.8	-26.9	1.5	7.2	-14.0	-14.6	-16.7	-15.2	-14.2	-13.5	-12.7	-4.7	-9.0	-9.5	-13.9
Non-Merchandise Balance	-35.9	-44.3	-44.7	-42.6	-47.5	-47.3	-47.1	-48.0	-46.6	-45.5	-46.1	-46.2	-40.5	-41.9	-47.5	-46.1
	(average for the quarter)															
Exchange Rate (US¢/C$)	96.0	97.3	96.3	98.7	101.4	103.4	102.2	96.3	93.0	93.0	95.2	98.8	88.0	97.1	100.8	95.0
Exchange Rate (C$/US$)	1.041	1.028	1.039	1.013	0.986	0.967	0.979	1.038	1.075	1.075	1.050	1.012	1.141	1.030	0.993	1.053
Exchange Rate (¥/C$)	87.1	89.7	82.6	81.5	83.4	84.3	79.3	73.5	70.7	70.7	73.7	78.4	82.3	85.2	80.1	73.4
Exchange Rate (C$/Euro)	1.44	1.31	1.34	1.38	1.35	1.39	1.38	1.38	1.40	1.40	1.40	1.40	1.58	1.37	1.37	1.40
INCOMES	**(billions of dollars : a.r.)**															
Corporate Profits Before Tax	179.5	172.7	177.1	193.6	202.6	198.2	196.5	195.9	198.4	200.8	201.5	204.1	149.1	180.7	198.3	201.2
Corporate Profits After Tax	107.9	114.4	129.1	145.3	155.2	150.9	149.2	148.6	151.1	153.4	154.1	156.7	89.2	124.2	151.0	153.9
	(year/year % change)															
Corporate Profits Before Tax	20.4	27.2	19.0	19.1	12.9	14.8	11.0	1.2	-2.0	1.3	2.5	4.1	-33.1	21.2	9.7	1.4
Personal Income	2.4	4.3	4.8	5.3	4.8	3.9	3.9	2.9	3.3	3.6	3.9	4.5	0.0	4.2	3.9	3.8
Real Disposable Income	1.6	5.5	3.0	4.2	3.1	-0.7	1.8	0.9	1.3	1.9	2.2	2.6	0.8	3.6	1.3	2.0
	(average for the quarter : %)															
Savings Rate	3.6	6.8	4.3	4.4	4.4	4.1	4.2	4.1	4.2	4.3	4.6	4.7	4.6	4.8	4.2	4.5
OTHER INDICATORS	**(quarter average)**															
Unemployment Rate (%)	8.2	8.0	8.0	7.7	7.7	7.5	7.3	7.4	7.5	7.4	7.4	7.3	8.3	8.0	7.5	7.4
Housing Starts (000s, a.r.)	198	198	192	179	178	193	193	185	184	181	181	182	149	192	187	182
Existing Home Sales (y/y % ch)	44.4	-4.2	-23.5	-15.9	-7.1	0.2	12.3	-0.8	-5.2	-1.6	-3.2	-2.6	7.7	-3.9	0.6	-3.2
Home Prices (y/y % ch, CREA)	18.8	8.8	0.3	1.1	7.1	8.0	9.1	5.4	-1.5	-2.4	-1.5	-1.3	4.5	6.8	7.4	-1.7
Motor Vehicle Sales (mlns, a.r.)	1.59	1.55	1.60	1.60	1.61	1.62	1.64	1.69	1.64	1.65	1.65	1.66	1.48	1.58	1.64	1.65
	(quarter/quarter % change : a.r.)															
Employment Growth	1.5	3.4	1.4	0.4	2.4	2.0	0.7	0.4	0.7	0.9	1.2	1.2	-1.6	1.4	1.5	0.8
Industrial Production	10.8	9.1	2.9	3.8	6.9	-4.2	3.3	2.1	1.9	3.0	2.2	2.2	-9.5	4.9	3.0	2.0
Federal Budget Balance (% of GDP)													-0.4	-3.6	-2.2	-1.9

Note: Outlined areas represent forecast periods

United States Economic Outlook

BMO Capital Markets Economics

September 30, 2011

	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2009	2010	2011	2012
PRODUCTION	(quarter/quarter % change : a.r.)															
Real GDP (chain-weighted)	3.9	3.8	2.5	2.3	0.4	1.3	1.9	1.5	1.7	2.1	2.6	2.9	-3.5	3.0	1.6	1.9
Final Sales	0.8	3.0	1.7	4.2	0.0	1.6	2.0	1.4	1.7	2.1	2.6	2.9	-2.6	1.4	1.8	1.9
Final Domestic Demand	1.7	4.9	2.3	2.7	0.4	1.3	1.7	1.3	1.5	1.9	2.4	2.7	-3.6	1.8	1.7	1.7
Consumer Spending	2.7	2.9	2.6	3.6	2.1	0.7	1.4	1.4	1.6	2.1	2.5	2.6	-1.9	2.0	2.1	1.7
durables	9.9	7.8	8.8	17.2	11.8	-5.3	3.0	1.0	1.8	2.0	2.5	2.7	-5.4	7.2	6.9	1.5
nondurables	4.8	1.9	3.0	4.3	1.6	0.2	-4.0	1.5	2.0	3.0	3.0	3.0	-1.8	2.9	1.3	1.4
services	1.0	2.5	1.6	1.3	0.8	1.9	2.2	1.4	1.5	1.8	2.3	2.4	-1.4	0.9	1.5	1.8
Government Spending	-1.2	3.7	1.0	-2.8	-5.9	-0.9	-1.6	-1.7	-0.5	-1.2	-0.7	0.8	1.7	0.7	-2.1	-1.0
Business Investment	6.0	18.6	11.3	8.7	2.1	10.3	8.8	5.6	3.2	4.9	5.8	5.8	-17.9	4.4	8.0	5.6
non-residential construction	-24.7	7.4	4.2	10.6	-14.4	22.6	-3.0	4.0	4.0	4.5	4.9	4.9	-21.2	-15.8	2.7	4.4
equipment & software	21.7	23.2	14.2	8.0	8.7	6.3	13.0	6.0	3.0	5.0	6.0	6.0	-16.0	14.6	9.9	5.9
Residential Construction	-15.3	22.8	-27.7	2.5	-2.5	4.2	2.0	4.0	6.0	6.0	7.0	7.0	-22.2	-4.3	-1.7	5.2
Exports	7.3	10.0	10.0	7.8	7.9	3.6	7.3	5.4	4.7	5.0	4.9	4.9	-9.4	11.3	7.2	5.2
Imports	12.6	21.6	12.3	-2.3	8.3	1.4	4.3	4.2	3.0	3.3	3.3	3.3	-13.6	12.5	5.4	3.4
	(billions of 2005 dollars : a.r.)															
Inventory Change	39.9	64.6	92.3	38.3	49.1	39.1	36.0	39.0	38.0	38.0	38.0	38.0	-145.3	59.4	42.3	38.0
Net Exports	-376.8	-437.4	-458.7	-414.2	-424.3	-416.4	-407.8	-406.6	-402.1	-397.6	-393.7	-389.7	-358.8	-421.8	-413.8	-395.8
Contribution to GDP Growth	-1.0	-1.9	-0.7	1.4	-0.3	0.2	0.3	0.0	0.1	0.1	0.1	0.1	1.0	-0.5	0.1	0.1
	(billions of dollars : a.r.)															
Nominal GDP	14,278	14,468	14,606	14,755	14,868	15,013	15,132	15,271	15,411	15,558	15,727	15,915	13,939	14,527	15,071	15,653
(% chng : a.r.)	5.5	5.4	3.9	4.2	3.1	4.0	3.2	3.7	3.7	3.9	4.4	4.9	-2.5	4.2	3.7	3.9
INFLATION	(quarter/quarter % change : a.r.)															
GDP Price Index	1.5	1.5	1.4	1.9	2.5	2.5	1.4	2.2	2.0	1.8	1.8	1.9	1.1	1.2	2.0	1.9
Core PCE Deflator	1.1	1.3	0.7	0.7	1.6	2.3	2.1	1.3	2.0	2.1	1.9	1.1	1.6	1.4	1.5	1.8
CPI All Items	1.3	-0.5	1.4	2.6	5.2	4.1	2.9	2.4	2.8	2.7	2.1	1.7	-0.3	1.6	3.2	2.6
Excl. Food & Energy	-0.0	0.8	1.1	0.6	1.7	2.5	2.8	1.5	2.1	2.2	2.0	1.2	1.7	1.0	1.7	2.1
Food Prices	1.8	1.4	0.7	2.1	5.2	5.9	4.7	4.5	4.4	3.9	2.3	2.6	1.8	0.8	3.8	4.1
Energy Prices	13.0	-14.0	5.4	22.7	38.3	14.5	1.3	6.0	6.4	4.5	2.4	4.1	-18.2	9.6	15.9	5.1
Services	-0.2	1.4	1.1	1.1	1.9	2.1	2.2	2.3	2.2	2.3	1.3	1.3	1.4	0.8	1.7	2.1
	(year/year % change)															
CPI All Items	2.4	1.8	1.2	1.2	2.2	3.3	3.7	3.6	3.0	2.7	2.5	2.3				
Excl. Food & Energy	1.3	1.0	0.9	0.6	1.1	1.5	1.9	2.1	2.2	2.2	2.0	1.9				
FINANCIAL	(average for the quarter)															
Fed Funds Rate	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
90 Day T-Bill	0.11	0.15	0.15	0.14	0.13	0.05	0.03	0.02	0.02	0.02	0.02	0.02	0.15	0.14	0.05	0.02
3-Month Libor	0.26	0.43	0.39	0.29	0.31	0.26	0.30	0.37	0.37	0.37	0.37	0.37	0.70	0.34	0.31	0.37
10 Year Bond Yield	3.72	3.49	2.79	2.86	3.46	3.21	2.43	1.90	1.77	1.75	1.83	1.96	3.26	3.21	2.75	1.83
FOREIGN TRADE	(billions of dollars : a.r.)															
Current Account Balance	-473	-481	-481	-449	-478	-509	-478	-474	-462	-457	-453	-449	-377	-471	-485	-455
(% of GDP)	-3.3	-3.3	-3.3	-3.0	-3.2	-3.4	-3.2	-3.1	-3.0	-2.9	-2.9	-2.8	-2.7	-3.2	-3.2	-2.9
Merchandise Balance	-611	-664	-671	-637	-729	-784	-746	-744	-742	-743	-746	-748	-506	-646	-751	-745
Non-Merchandise Balance	138	183	191	188	251	274	268	270	280	286	293	299	129	175	266	290
	(average for the quarter)															
Exchange Rate (¥/US$)	91	92	86	83	82	82	78	76	76	76	77	79	94	88	79	77
Exchange Rate (US$/€)	1.38	1.27	1.29	1.36	1.37	1.44	1.41	1.33	1.30	1.30	1.33	1.38	1.39	1.33	1.39	1.33
Exchange Rate (US$/£)	1.56	1.49	1.55	1.58	1.60	1.63	1.61	1.54	1.50	1.50	1.53	1.58	1.57	1.55	1.59	1.53
Broad TWD	102.12	103.60	102.42	99.25	97.8	95.3	95.8	99.7	100.8	100.4	98.8	96.7	105.7	101.9	97.2	99.2
COMMODITY PRICES	(average for the quarter)															
WTI spot (US$/bbl)	78.6	77.9	76.2	85.0	94.0	102.6	90.3	89.2	92.0	90.0	91.0	95.0	61.7	79.4	94.0	92.0
Henry Hub spot (US$/mmBtu)	5.1	4.3	4.3	3.8	4.2	4.4	4.2	4.5	4.9	4.5	4.3	4.7	4.0	4.4	4.3	4.6
	(year/year % change)															
Pre-tax Profits with IVA and CCA	46.7	41.5	27.4	18.2	8.8	8.5	6.6	6.4	6.7	4.4	4.7	4.9	9.1	32.2	7.6	5.2
Personal Income	1.4	3.2	4.9	5.4	5.8	5.4	4.8	4.8	3.6	3.6	4.3	4.5	-4.3	3.7	5.2	4.0
Real Disposable Income	-0.3	1.0	3.0	3.5	2.6	1.4	0.9	0.9	1.0	1.6	2.2	2.6	-2.3	1.8	1.4	1.8
	(average for the quarter)															
Savings Rate (%)	4.9	5.6	5.6	5.2	5.0	5.1	4.8	4.8	4.9	5.0	5.1	5.2	5.1	5.3	4.9	5.0
OTHER INDICATORS	(average for the quarter)															
Unemployment Rate (%)	9.7	9.6	9.6	9.6	8.9	9.1	9.1	9.2	9.2	9.1	9.0	8.9	9.3	9.6	9.1	9.1
Housing Starts (mlns, a.r.)	0.61	0.60	0.58	0.54	0.58	0.57	0.59	0.60	0.61	0.62	0.63	0.64	0.55	0.58	0.58	0.63
Existing Home Sales (mlns, a.r.)	5.18	5.57	4.17	4.75	5.14	4.88	4.87	4.85	4.98	5.10	5.23	5.47	5.15	4.92	4.93	5.20
Home Prices (y/y % ch, Case-Shiller)	0.8	4.3	1.6	-1.7	-3.5	-4.4	-4.4	-3.7	-3.1	-2.8	-1.6	-0.1	-13.3	1.3	-4.0	-1.9
Motor Vehicle Sales (mlns, a.r.)	11.0	11.4	11.6	12.3	13.0	12.2	12.3	12.7	13.1	13.5	14.1	14.7	10.4	11.6	12.5	13.9
	(quarter/quarter % change : a.r.)															
Civilian Employment Growth	1.2	1.6	-0.2	-0.4	1.5	0.0	-0.2	1.1	1.2	1.4	1.7	1.8	-3.8	-0.6	0.4	1.1
Industrial Production	8.1	7.1	6.7	3.1	4.8	0.5	5.0	2.4	2.5	2.9	3.2	3.4	-11.2	5.3	3.9	2.9
CBO Budget Deficit (% of GDP)													-9.9	-8.9	-8.5	-6.2

Note: Outlined areas represent forecast periods

Quarterly Medium Term Outlook

CIBC World Markets *

		2011		2012				2013				2014				2015				2016			
	Forecast Date	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Cdn 90 Day T-bill - %	3-Oct-11		0.95	1.00	1.20	1.35	1.40	1.65	1.65	1.65	1.65	2.25	2.25	2.25	2.25	2.95	2.95	2.95	2.95	3.40	3.40	3.40	3.40
Cdn 10 Yr Bond Yield - %	3-Oct-11		2.30	2.35	2.60	2.80	2.95	3.30	3.30	3.30	3.30	3.45	3.45	3.45	3.45	3.50	3.50	3.50	3.50	3.70	3.70	3.70	3.70
Cdn 30 Yr Bond Yield - %	3-Oct-11		2.90	3.00	3.05	3.10	3.15	3.50	3.50	3.50	3.50	3.60	3.60	3.60	3.60	3.70	3.70	3.70	3.70	3.85	3.85	3.85	3.85
US 90 day T-bill - %	3-Oct-11		0.05	0.10	0.10	0.10	0.20	0.25	0.25	0.25	0.25	0.55	0.55	0.55	0.55	1.50	1.50	1.50	1.50	2.50	2.50	2.50	2.50
US 10 Yr Bond Yield - %	3-Oct-11		2.05	2.10	2.25	2.45	2.60	3.10	3.10	3.10	3.10	3.20	3.20	3.20	3.20	3.45	3.45	3.45	3.45	3.65	3.65	3.65	3.65
US 30 Yr Bond Yield - %	3-Oct-11		3.10	3.20	3.25	3.35	3.40	4.00	4.00	4.00	4.00	4.20	4.20	4.20	4.20	4.40	4.40	4.40	4.40	4.50	4.50	4.50	4.50
Exchange Rate**	3-Oct-11		1.02	0.99	0.95	0.94	0.96	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01
Cdn CPI*** - % change	3-Oct-11	2.9	2.7	2.3	1.6	1.8	1.9	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1
Manitoba CPI*** - % change	3-Oct-11	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Cdn GDP Deflator - % change	3-Oct-11	-0.5	3.0	1.9	0.3	1.2	3.5	2.2	2.2	2.2	2.2	2.5	2.5	2.5	2.5	2.7	2.7	2.7	2.7	3.0	3.0	3.0	3.0
US CPI*** - % change	3-Oct-11	3.8	3.8	3.0	2.2	2.5	2.5	2.1	2.1	2.1	2.1	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.5	2.5	2.5	2.5
US GDP Deflator - % change	3-Oct-11	2.2	2.1	2.0	2.0	2.0	2.0	1.7	1.7	1.7	1.7	2.0	2.0	2.0	2.0	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9

* End of Period Data
** (C$/US$)
*** CPI All Items (year/year)
**** shaded area denotes forecast period

If data can only be provided in annual granularity, assume it is the same for each quarter.

<u>**NOTE:**</u>
Please note that rows 4-10 inclusive are end-of-period forecasts for 2011-2012. Thereafter the forecasts are provided in annual granularity, as annual averages.
CPI data are y/y; GDP deflator data are q/q annualized

NATIONAL BANK
FINANCIAL GROUP

Monthly ECONOMIC MONITOR

October 2011

Highlights

- *Euro-zone discord on a bailout for Greece suggests imminent default, since it is generally agreed that the country is insolvent. The mishandling of this crisis has got investors much more worried about other euro countries in difficulty, though their problems are much less acute than Greece's. As a result, the international financial system is under stress, an unfortunate development at a time when the global economy has been showing signs of cooling. However, the latest leading indicators do not yet point to a decline in global activity.*
- *Concerns abound as to whether the U.S. can avoid a double dip recession. Though early indications suggest that the economy remained above water in the third quarter, there are significant risks to growth. These include spillover from any euro-zone implosion and domestic frailties including a stagnant labour market and anemic consumption. Today's slow-growth environment warrants some stimulus. With the Fed almost out of bullets, fiscal policy seems better-positioned to do the job. Yet an impasse in Congress threatens to deprive the U.S. of the only major tool it has left to head off another downturn.*
- *Canada's GDP contraction in the second quarter was due entirely to a powerful drag from trade that offset a relatively healthy domestic demand. In Q3 the story seems to be the opposite: exports turning around and compensating for softer-looking domestic demand. That should be enough for some growth in Q3, but the prospect for subsequent quarters seems less upbeat. Risks outside our borders and the strength of the currency threaten to curtail the apparent recovery of exports, while softening of the labour market and of business investment may weigh on the domestic economy. In light of these uncertainties, we expect the BoC to keep monetary policy loose until at least the middle of next year.*

				Change from Previous Forecast	
	2010	2011	2012	2011	2012
United States					
GDP	2.9%	1.6%	2.2%	unch	unch
CPI inflation	1.7%	3.0%	1.4%	+0.1 pp	+0.2 pp
Overnight rate*	0.25%	0.03%	0.05%	-0.07 pp	-0.05 pp
Ten-year bond yield*	3.29%	1.88%	2.32%	-0.63 pp	-0.44 pp
Canada					
GDP	3.1%	2.2%	2.1%	-0.2 pp	unch
CPI inflation	1.8%	2.8%	1.7%	+0.1 pp	unch
Overnight rate*	1.00%	1.00%	1.75%	unch	unch
Ten-year bond yield*	3.12%	2.13%	2.74%	-0.63 pp	-0.29 pp
USD/CAD	0.97	1.00	0.99	unch	unch

* end of period

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Canada
Economic Forecast

(Annual % change)*	2008	2009	2010	2011	2012	Q4/Q4 2011	Q4/Q4 2012
Gross domestic product (2002 $)	0.7	(2.8)	3.2	2.2	2.1	1.8	2.3
Consumption	3.0	0.4	3.3	2.0	2.3	1.6	2.3
Residential construction	(3.2)	(8.0)	10.2	1.0	(0.8)	1.8	(0.8)
Business investment	3.7	(20.8)	7.3	12.8	7.1	8.5	8.0
Government expenditures	4.8	4.3	4.7	1.8	0.7	0.8	0.6
Exports	(4.7)	(13.8)	6.4	3.6	4.5	2.6	4.9
Imports	1.5	(13.4)	13.1	6.7	3.6	5.8	3.7
Change in inventories (millions $)	9,683	(539)	8,899	12,639	6,579	10,523	6,022
Domestic demand	3.0	(2.1)	4.5	3.0	2.2	2.2	2.3
Real disposable income	4.1	0.8	3.6	1.4	2.3	1.3	2.4
Employment	1.7	(1.6)	1.4	1.7	1.3	1.7	1.3
Unemployment rate	6.2	8.3	8.0	7.5	7.2	7.3	7.1
Inflation	2.4	0.3	1.8	2.8	1.7	2.4	2.0
Before-tax profits	8.0	(32.3)	20.9	13.5	4.5	5.4	5.2
Federal balance (Public Acc., bil. $)	(5.7)	(55.7)	(40.5)	(30.0)	(20.0)	....	....
Current account (bil. $)	5.3	(45.2)	(50.9)	(51.1)	(46.5)	(48.0)	(40.0)

** or as noted*

Financial Forecast*

	Current 9/16/11	Q3	Q4	Q1/12	Q2	2011	2012
Overnight rate	1.00	1.00	1.00	1.00	1.00	1.00	1.75
Prime rate	3.00	3.00	3.00	3.00	3.00	3.00	3.75
3 month T-Bills	0.87	0.87	0.83	0.92	1.23	0.83	1.79
Treasury yield curve							
2-Year	1.04	0.96	1.03	1.12	1.68	1.03	2.34
5-Year	1.55	1.49	1.58	1.68	2.02	1.58	2.53
10-Year	2.29	2.08	2.13	2.24	2.37	2.13	2.74
30-Year	2.93	2.75	2.78	2.86	2.93	2.78	3.14
Exchange rates*							
USD per CAD	1.02	0.98	0.95	0.98	1.00	1.00**	0.99**
Oil price (WTI), U.S.$	88	84	80	82	83	91**	82**

National Bank Financial
** end of period*
*** annual average*

United States
Economic Forecast

(Annual % change)*	2008	2009	2010	2011	2012	Q4/Q4 2011	Q4/Q4 2012
Gross domestic product (2005 $)	(0.3)	(3.5)	3.0	1.6	2.2	1.2	2.2
Consumption	(0.6)	(1.9)	2.0	2.1	2.0	1.5	2.1
Residential construction	(23.9)	(22.2)	(4.3)	(2.4)	4.1	0.2	7.7
Business investment	(0.8)	(17.9)	4.4	7.7	6.6	6.0	6.5
Government expenditures	2.6	1.7	0.7	(2.0)	(1.0)	(2.2)	(1.1)
Exports	6.1	(9.4)	11.3	7.4	6.9	6.5	6.6
Imports	(2.7)	(13.6)	12.5	5.3	3.9	4.3	4.3
Change in inventories (bil. $)	(36.3)	(145.0)	58.8	32.7	28.5	22.0	28.0
Domestic demand	(1.0)	(3.6)	1.8	1.7	1.9	1.1	2.0
Real disposable income	2.4	(2.3)	1.8	1.9	2.1	1.9	0.8
Household employment	(0.5)	(3.8)	(0.6)	0.4	1.0	0.7	1.2
Unemployment rate	5.8	9.3	9.6	9.1	8.8	9.1	8.7
Inflation	3.8	(0.3)	1.7	3.0	1.4	2.9	1.5
Before-tax profits	(17.4)	9.1	32.2	7.7	5.3	7.1	4.2
Federal balance (unified budget, bil. $)	(459.0)	(1,800.0)	(1,300.0)	(1,350.0)	(1,100.0)	...	
Current account (bil. $)	(690.0)	(410.0)	(500.0)	(480.0)	(490.0)	(510.0)	

** or as noted*

Financial Forecast

	Current 9/16/11	Q3	Q4	Q1/12	Q2	2011	2012
Fed Fund Target Rate	0.01	0.25	0.25	0.25	0.25	0.25	0.25
3 month Treasury bills	0.01	0.00	0.03	0.05	0.06	0.03	0.05
Treasury yield curve							
2-Year	0.17	0.21	0.23	0.29	0.38	0.23	0.62
5-Year	0.91	0.83	0.86	0.99	1.07	0.86	1.30
10-Year	2.05	1.84	1.88	2.01	2.10	1.88	2.32
30-Year	3.32	2.98	3.02	3.12	3.19	3.02	3.36
Exchange rates*							
U.S.$/Euro	1.38	1.36	1.30	1.32	1.34	1.39**	1.34**
YEN/U.S.$	77	77	75	77	79	79**	80**

National Bank Financial
** end of period*
*** annual average*

Financial market forecast detail

Interest rates

%, end of period

	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	2009	2010	2011	2012
							Forecast						Forecast	
Canada														
Overnight	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.75	2.00	0.25	1.00	1.00	2.00
Three-month	0.88	0.97	1.10	0.90	1.05	1.10	1.15	1.30	1.85	2.15	0.19	0.97	1.10	2.15
Two-year	1.40	1.71	1.85	1.42	1.00	1.20	1.40	1.70	2.10	2.25	1.47	1.71	1.20	2.25
Five-year	2.04	2.46	2.65	2.06	1.50	1.80	2.15	2.50	2.80	3.00	2.77	2.46	1.80	3.00
10-year	2.75	3.16	3.25	2.91	2.40	2.70	2.90	3.00	3.30	3.40	3.61	3.16	2.70	3.40
30-year	3.34	3.55	3.80	3.42	3.10	3.30	3.50	3.60	3.80	4.00	4.07	3.55	3.30	4.00
Yield curve (10s-2s)	135	145	140	149	140	150	150	130	120	115	214	145	150	115
United States														
Fed funds	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0.13	0.13	0.13	0.13	0.13	0.13	0 to 0.25	0 to 0.25	0.13	0.13
Three-month	0.16	0.12	0.15	0.03	0.10	0.05	0.10	0.10	0.10	0.10	0.06	0.12	0.05	0.10
Two-year	0.44	0.61	0.70	0.41	0.25	0.30	0.35	0.50	0.60	0.75	1.14	0.61	0.30	0.75
Five-year	1.27	2.01	2.10	1.45	1.00	1.10	1.35	1.45	1.75	2.10	2.69	2.01	1.10	2.10
10-year	2.48	3.30	3.45	2.92	2.10	2.40	2.70	2.75	3.10	3.50	3.85	3.30	2.40	3.50
30-year	3.67	4.34	4.50	4.27	3.50	3.90	4.20	4.20	4.55	4.90	4.63	4.34	3.90	4.90
Yield curve (10s-2s)	204	269	275	251	185	210	235	225	250	275	271	269	210	275
Yield spreads														
Three-month T-bills	0.72	0.85	0.95	0.87	0.95	1.05	1.05	1.20	1.75	2.05	0.13	0.85	1.05	2.05
Two-year	0.96	1.10	1.15	1.01	0.75	0.90	1.05	1.20	1.50	1.50	0.33	1.10	0.90	1.50
Five-year	0.77	0.45	0.55	0.61	0.50	0.70	0.80	1.05	1.05	0.90	0.08	0.45	0.70	0.90
10-year	0.27	-0.14	-0.20	-0.01	0.30	0.30	0.20	0.25	0.20	-0.10	-0.24	-0.14	0.30	-0.10
30-year	-0.33	-0.79	-0.70	-0.85	-0.40	-0.60	-0.70	-0.60	-0.75	-0.90	-0.56	-0.79	-0.60	-0.90

Exchange rates

%, end of period

	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	2009	2010	2011	2012
							Forecast						Forecast	
Australian dollar	0.97	1.02	1.03	1.07	1.07	1.05	1.04	1.03	1.02	1.01	0.69	1.02	1.05	1.01
Brazilian real	1.69	1.66	1.63	1.56	1.60	1.55	1.60	1.65	1.68	1.70	2.32	1.66	1.55	1.70
Canadian dollar	1.03	1.00	0.97	0.96	1.00	1.01	1.00	0.98	0.97	0.95	1.26	1.00	1.01	0.95
Renminbi	6.69	6.59	6.55	6.46	6.35	6.25	6.15	6.05	5.95	5.85	6.83	6.59	6.25	5.85
Euro	1.36	1.34	1.42	1.45	1.42	1.37	1.36	1.35	1.33	1.31	1.33	1.34	1.37	1.31
Yen	84	81	83	81	75	74	73	70	73	75	99	81	74	75
Mexican peso	12.59	12.36	11.91	11.71	11.75	11.50	12.00	12.50	12.25	12.00	14.17	12.36	11.50	12.00
New Zealand dollar	0.73	0.78	0.76	0.83	0.85	0.83	0.81	0.79	0.77	0.77	0.56	0.78	0.83	0.77
Swiss franc	0.98	0.93	0.92	0.84	0.85	0.88	0.90	0.91	0.93	0.95	1.14	0.93	0.88	0.95
U.K. pound sterling	1.57	1.56	1.60	1.61	1.63	1.61	1.62	1.63	1.62	1.64	1.43	1.56	1.61	1.64

Source: Reuters, RBC Economics Research forecasts

Economic forecast detail — Canada

Real growth in the economy

Quarter-over-quarter annualized % change unless otherwise indicated

	2010				2011				2012				year-over-year % change			
							Forecast								Forecast	
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2009	2010	2011	2012
Consumer spending	4.2	1.4	2.8	4.4	-0.1	1.6	3.0	2.6	2.4	2.2	2.1	2.1	0.4	3.3	2.1	2.4
Durables	4.0	-7.4	1.6	11.0	-5.2	1.5	3.5	6.0	4.7	4.7	5.2	5.1	-1.9	4.4	1.4	4.7
Semi-Durables	19.1	-4.5	5.6	2.9	0.1	-3.2	4.4	1.5	2.5	1.5	1.4	1.4	-2.3	5.0	1.0	1.8
Non-durables	1.7	2.7	2.6	0.9	-1.3	-0.3	3.5	2.0	2.3	1.8	1.7	1.7	0.8	1.8	0.8	2.0
Services	3.4	3.7	2.9	4.8	1.4	3.1	2.5	2.3	2.0	2.0	1.8	1.8	1.1	3.5	2.9	2.2
Government spending	-0.4	3.3	0.5	2.7	0.0	1.6	0.1	0.1	0.4	0.1	0.5	1.0	3.6	2.4	1.1	0.5
Residential investment	19.8	-0.4	-5.1	-0.9	7.5	0.7	7.7	2.1	-0.9	-0.2	0.7	0.5	-8.0	10.2	2.2	1.2
Business investment	11.9	17.9	23.5	13.5	12.9	15.5	8.3	4.8	6.1	7.1	6.8	6.7	-20.8	7.3	13.8	7.0
Non-residential structures	17.5	7.2	16.6	22.8	10.7	2.0	9.6	8.8	8.1	8.3	8.1	8.1	-22.2	2.8	11.3	8.1
Machinery & equipment	6.8	29.4	30.5	5.0	15.2	31.0	7.0	0.6	4.0	5.8	5.5	5.3	-19.5	11.8	16.4	5.8
Final domestic demand	5.3	3.9	4.3	4.8	1.8	3.0	2.9	1.4	1.7	2.1	2.2	2.3	-2.1	4.5	3.1	2.0
Exports	8.8	11.9	-1.2	8.8	7.7	-8.3	11.9	9.7	9.0	7.9	6.9	6.9	-13.8	6.4	4.4	7.7
Imports	12.3	21.8	8.4	-0.5	9.5	10.0	3.3	3.0	5.0	6.0	5.8	6.0	-13.4	13.1	7.0	5.1
Inventories (change in $b)	6.5	13.3	15.6	0.2	9.1	19.2	10.3	7.4	7.4	7.3	7.5	8.2	-0.5	8.9	11.5	7.6
Real gross domestic product	**5.6**	**2.3**	**2.5**	**3.1**	**3.6**	**-0.4**	**2.9**	**2.6**	**2.9**	**2.6**	**2.6**	**2.7**	**-2.8**	**3.2**	**2.4**	**2.5**

Other indicators

Year-over-year % change unless otherwise indicated

	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2009	2010	2011	2012
Business and labour																
Productivity	1.8	1.2	1.4	0.8	0.8	0.9	0.8	0.8	0.7	1.3	1.2	1.3	0.6	1.3	0.8	1.1
Pre-tax corporate profits	20.4	27.2	19.0	19.1	12.9	14.8	11.6	5.8	5.8	10.8	14.2	13.4	-33.1	21.2	11.1	11.0
Unemployment rate (%)*	8.2	8.0	8.0	7.7	7.8	7.5	7.3	7.4	7.4	7.3	7.2	7.2	8.3	8.0	7.5	7.3
Inflation																
Headline CPI	1.6	1.4	1.8	2.3	2.6	3.4	2.8	2.1	1.9	1.6	2.0	2.1	0.3	1.8	2.7	1.9
Core CPI	1.9	1.8	1.6	1.6	1.3	1.6	1.7	1.7	1.7	1.7	1.7	1.8	1.7	1.8	1.6	1.7
External trade																
Current account balance ($b)	-35	-56	-72	-41	-40	-61	-51	-42	-36	-34	-32	-31	-45	-51	-49	-33
% of GDP	-2.2	-3.5	-4.4	-2.5	-2.4	-3.6	-3.0	-2.4	-2.1	-1.9	-1.8	-1.7	-3.0	-3.1	-2.8	-1.9
Housing starts (000s)*	198	198	192	179	178	193	196	186	184	183	181	179	149	190	188	182
Motor vehicle sales (mill., saar)*	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.5	1.6	1.6	1.6

*Period average

Source: Statistics Canada, RBC Economics Research forecasts

Global Forecast Update

Financial Markets	10Q4	11Q1	11Q2	11Q3f	11Q4f	12Q1f	12Q2f	12Q3f	12Q4f
				(%, end of period)					
Canada									
BoC Overnight Target Rate	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.75
3-month T-bill	1.05	0.96	0.90	0.82	0.85	0.95	1.10	1.35	1.95
2-year Canada	1.68	1.83	1.59	0.89	1.00	1.10	1.30	1.80	2.15
5-year Canada	2.42	2.78	2.33	1.40	1.50	1.70	1.85	2.30	2.60
10-year Canada	3.12	3.35	3.11	2.16	2.10	2.20	2.45	2.65	2.90
30-year Canada	3.53	3.76	3.55	2.77	2.70	2.75	3.00	3.20	3.40
Real GDP (q/q, ann. % change)	3.1	3.6	-0.4	1.4	1.4	1.6	2.0	2.4	2.4
Real GDP (y/y, % change)	3.3	2.9	2.2	1.9	1.5	1.0	1.6	1.9	2.1
Consumer Prices (y/y, % change)	2.3	2.6	3.4	2.9	2.6	2.2	1.8	1.9	2.1
Core CPI (y/y % change)	1.6	1.3	1.6	1.8	1.8	1.8	1.8	1.8	1.8
United States									
Fed Funds Target Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
3-month T-bill	0.12	0.09	0.01	0.02	0.00	0.05	0.05	0.10	0.15
2-year Treasury	0.59	0.82	0.46	0.24	0.30	0.40	0.70	0.90	1.10
5-year Treasury	2.00	2.28	1.76	0.95	1.00	1.20	1.35	1.55	1.70
10-year Treasury	3.29	3.47	3.16	1.92	1.80	1.90	2.20	2.60	3.00
30-year Treasury	4.33	4.51	4.37	2.91	2.80	2.85	3.15	3.60	4.00
Real GDP (q/q, ann. % change)	2.3	0.4	1.3	2.5	1.5	1.2	1.4	1.7	2.0
Real GDP (y/y, % change)	3.1	2.2	1.6	1.6	1.4	1.6	1.6	1.4	1.6
Consumer Prices (y/y, % change)	1.3	2.3	3.5	3.2	2.8	2.0	1.6	2.0	2.1
Core CPI (y/y % change)	0.6	1.1	1.5	1.6	1.6	1.7	1.7	1.7	1.8
Spreads									
Target Rate	0.75	0.75	0.75	0.75	0.75	0.75	0.75	1.00	1.50
3-month T-bill	0.93	0.87	0.89	0.80	0.85	0.90	1.05	1.25	1.80
2-year	1.09	1.01	1.13	0.65	0.70	0.70	0.60	0.90	1.05
5-year	0.42	0.50	0.57	0.45	0.50	0.50	0.50	0.75	0.90
10-year	-0.17	-0.12	-0.05	0.24	0.30	0.30	0.25	0.05	-0.10
30-year	-0.80	-0.75	-0.82	-0.14	-0.10	-0.10	-0.15	-0.40	-0.60
Central Bank Rates									
European Central Bank	1.00	1.00	1.25	1.50	1.50	1.50	1.50	1.50	1.50
Bank of England	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Swiss National Bank	0.25	0.25	0.25	0.00	0.00	0.00	0.00	0.25	0.25
Bank of Japan	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Reserve Bank of Australia	4.75	4.75	4.75	4.75	4.75	4.75	5.00	5.00	5.00
Exchange Rates									
Canadian Dollar (USDCAD)	1.00	0.97	0.96	1.05	1.02	1.00	0.99	0.98	0.98
Canadian Dollar (CADUSD)	1.00	1.03	1.04	0.95	0.99	1.00	1.01	1.02	1.02
Euro (EURUSD)	1.34	1.42	1.45	1.34	1.40	1.42	1.42	1.40	1.40
Euro (EURGBP)	0.86	0.88	0.90	0.86	0.88	0.88	0.88	0.86	0.85
Sterling (GBPUSD)	1.56	1.60	1.61	1.56	1.60	1.61	1.62	1.63	1.64
Yen (USDJPY)	81	83	81	77	80	82	83	84	85
Australian Dollar (AUDUSD)	1.02	1.03	1.07	0.97	1.00	1.02	1.04	1.06	1.08
Chinese Yuan (USDCNY)	6.6	6.5	6.5	6.4	6.3	6.2	6.1	6.0	5.9
Mexican Peso (USDMXN)	12.3	11.9	11.7	13.9	12.9	12.9	12.7	12.7	12.7
Brazilian Real (USDBRL)	1.66	1.63	1.56	1.88	1.80	1.79	1.77	1.76	1.75

Scotia Economics

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Global Forecast Update

North America	2000-09	2010	2011f	2012f
	(annual % change)			
Canada				
Real GDP	2.1	3.2	2.1	1.7
Consumer Spending	3.2	3.3	1.9	1.8
Residential Investment	3.8	10.2	1.7	2.2
Business Investment	2.0	7.3	13.9	6.8
Government	3.5	4.7	1.8	-0.6
Exports	-0.7	6.4	4.3	5.9
Imports	2.1	13.1	7.3	4.9
Nominal GDP	4.5	6.3	4.9	2.9
GDP Deflator	2.4	2.9	2.8	1.2
Consumer Price Index	2.1	1.8	2.9	2.0
Core CPI	1.9	1.7	1.6	1.8
Pre-Tax Corporate Profits	3.0	21.2	8.5	4.0
Employment	1.6	1.4	1.6	0.9
thousands of jobs	241	231	269	155
thousands of jobs (Q4/Q4)	229	279	253	156
Unemployment Rate (%)	7.0	8.0	7.5	7.4
Current Account Balance (C$ bn.)	13.8	-50.9	-54.7	-50.4
per cent of GDP	1.2	-3.1	-3.2	-2.9
Merchandise Trade Balance (C$ bn.)	51.7	-9.0	-7.5	-4.0
Federal Budget Balance (C$ bn.)	2.0	-36	-30	-21
per cent of GDP	0.3	-2.2	-1.8	-1.2
Housing Starts (thousands)	201	190	186	180
Motor Vehicle Sales (thousands)	1,591	1,557	1,590	1,605
Motor Vehicle Production (thousands)	2,481	2,100	2,250	2,400
Industrial Production	-0.6	4.6	2.7	2.4
United States				
Real GDP	1.7	3.0	1.7	1.5
Consumer Spending	2.2	2.0	2.1	1.1
Residential Investment	-5.0	-4.3	-1.9	1.5
Business Investment	0.6	4.4	7.5	4.5
Government	2.1	0.7	-1.8	-0.5
Exports	3.2	11.3	7.1	5.8
Imports	2.5	12.5	5.2	2.8
Nominal GDP	4.1	4.2	3.8	3.2
GDP Deflator	2.4	1.1	2.0	1.7
Consumer Price Index	2.6	1.6	2.8	1.9
Core CPI	2.2	1.0	1.5	1.7
Pre-Tax Corporate Profits	4.8	32.2	8.1	5.5
Employment	0.1	-0.7	1.0	1.1
millions of jobs	0.18	-0.97	1.30	1.50
millions of jobs (Q4/Q4)	-0.09	0.70	1.52	1.64
Unemployment Rate (%)	5.5	9.6	9.0	8.9
Current Account Balance (US$ bn.)	-573	-471	-489	-495
per cent of GDP	-4.7	-3.2	-3.2	-3.2
Merchandise Trade Balance (US$ bn.)	-632	-646	-761	-785
Federal Budget Balance (US$ bn.)	-318	-1,294	-1,300	-1,240
per cent of GDP	-2.4	-8.9	-8.6	-8.0
Housing Starts (millions)	1.54	0.58	0.59	0.64
Motor Vehicle Sales (millions)	15.8	11.6	12.7	13.5
Motor Vehicle Production (millions)	10.9	7.7	8.5	9.1
Industrial Production	-0.3	5.3	3.8	2.8
Mexico				
Real GDP	1.7	5.4	3.7	2.9
Industrial Production	1.0	6.0	3.8	3.5
Consumer Price Index (year-end)	4.9	4.4	3.4	4.0
Current Account Balance (US$ bn.)	-10.4	-5.7	-15.0	-21.0
per cent of GDP	-1.3	-0.5	-1.3	-1.5

Forecast Changes

Canada & United States

- We have revised down our quarterly pattern for U.S. GDP growth, front-loading a weaker performance to the fourth quarter of this year and through the first half of 2012. These adjustments leave output growth at 1.7% for 2011, but lower the 2012 advance from 2.1% to 1.5%. Recent indicators confirm that a gradual recovery remains underway, but with downside risks to the outlook, including concerns over consumer, business and investor sentiment, global growth prospects and fiscal stabilization. Foreign demand, especially from emerging markets, will remain a key driver of growth, supporting exports and business investment.
- We have likewise lowered our expectations for the Canadian economy in 2011-12. GDP growth is now expected to average 2.1% this year and 1.7% in 2012, down 0.1 and 0.4 percentage points, respectively, from our prior forecast. The revision builds in a more cautious consumer and business outlook, as well as a weaker export profile.
- In the U.S., a compromise for some extended stimulus alongside more modest economic growth is expected to result in a federal deficit in fiscal 2012 wider than US$1.2 trillion. Ottawa, for the first four months of fiscal 2011-12, reports a relatively modest 3.2% advance in revenues with July receipts soft, but the cumulative budget shortfall is still narrower than a year earlier, aided by a constrained 1.4% program spending increase.

Mexico

- In line with the downward revision to U.S. GDP growth, we are adjusting our expectation for Mexican economic growth in 2012 from 3.5% to 2.9%, while the 2011 forecast remains unchanged at 3.7%. Additionally, due to recent Mexican peso (MXN) depreciation, the economic deceleration and lower oil prices, we are adjusting our MXN year-end forecasts from 12.3 to 12.9 for 2011 and from 12.5 to 12.7 for 2012.

FINANCIAL INDICATOR OUTLOOK end-of-period level	Spot Rate	2011				2012				2013			
	12/09/2011	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADIAN FIXED INCOME													
Overnight Target Rate (%)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.75	2.00	2.50
3-mth T-Bill Rate (%)	0.92	0.96	0.90	0.90	0.90	0.90	0.90	0.95	1.00	1.30	1.80	2.10	2.60
2-yr Govt. Bond Yield (%)	0.89	1.83	1.59	0.80	0.80	0.85	0.90	1.00	1.40	1.90	2.30	2.70	3.10
5-yr Govt. Bond Yield (%)	1.41	2.77	2.33	1.30	1.40	1.50	1.75	2.05	2.20	2.40	2.70	3.10	3.40
10-yr Govt. Bond Yield (%)	2.21	3.35	3.11	2.15	2.05	2.30	2.65	3.05	3.30	3.50	3.60	3.70	3.90
30-yr Govt. Bond Yield (%)	2.89	3.76	3.55	2.65	2.60	2.80	3.30	3.55	3.75	3.83	3.85	4.00	4.10
10-yr-2-yr Govt. Spread (%)	1.33	1.52	1.52	1.35	1.25	1.45	1.75	2.05	1.90	1.60	1.30	1.00	0.80
GLOBAL CURRENCIES													
USD per CAD	1.00	1.03	1.04	0.99	0.96	1.00	1.03	1.05	1.05	1.04	1.04	1.03	1.03
USD per EUR	1.37	1.42	1.45	1.41	1.40	1.40	1.40	1.45	1.45	1.42	1.42	1.38	1.38
JPY per USD	77.1	83.1	80.5	76.0	76.0	78.0	78.0	83.0	85.0	88.0	88.0	90.0	90.0

F: Forecast by TD Economics as at September 2011
Source: Statistics Canada, Bank of Canada, Bloomberg

INTEREST RATE OUTLOOK

	Spot Rate 09/12/11	2011 Q1	2011 Q2	2011 Q3F	2011 Q4F	2012 Q1F	2012 Q2F	2012 Q3F	2012 Q4F	2013 Q1F	2013 Q2F	2013 Q3F	2013 Q4F
Fed Funds Target Rate (%)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.75	1.00
3-mth T-Bill Rate (%)	0.02	0.09	0.00	0.05	0.07	0.10	0.10	0.10	0.10	0.10	0.15	0.80	1.10
2-yr Govt. Bond Yield (%)	0.20	0.82	0.46	0.20	0.20	0.20	0.25	0.25	0.50	0.80	0.95	1.15	1.55
5-yr Govt. Bond Yield (%)	0.91	2.27	1.76	0.90	0.90	1.00	1.25	1.40	1.55	1.65	1.70	1.95	2.10
10-yr Govt. Bond Yield (%)	2.04	3.47	3.16	1.90	1.75	2.00	2.40	2.65	2.75	2.75	2.80	3.00	3.25
30-yr Govt. Bond Yield (%)	3.37	4.51	4.38	3.05	3.00	3.25	3.75	3.90	4.00	4.05	4.10	4.20	4.30
10-yr-2-yr Govt. Spread (%)	1.84	2.65	2.70	1.70	1.55	1.80	2.15	2.40	2.25	1.95	1.85	1.85	1.70

f: Forecast by TD Economics as at September 2011; All forecasts are for end of period; Source: Bloomberg, TD Economics

FOREIGN EXCHANGE OUTLOOK

Currency	Exchange Rate	Spot Price 09/12/11	2011 Q1	2011 Q2	2011 Q3F	2011 Q4F	2012 Q1F	2012 Q2F	2012 Q3F	2012 Q4F	2013 Q1F	2013 Q2F	2013 Q3F	2013 Q4F
Canadian dollar	CAD per USD	1.00	0.97	0.96	1.01	1.04	1.00	0.97	0.95	0.95	0.96	0.96	0.97	0.97
Japanese yen	JPY per USD	77.09	83.1	80.5	76.0	76.0	78.0	78.0	83.0	85.0	88.0	88.0	90.0	90.0
Euro	USD per EUR	1.37	1.42	1.45	1.41	1.40	1.40	1.40	1.45	1.45	1.42	1.42	1.38	1.38
U.K. pound	USD per GBP	1.59	1.60	1.61	1.60	1.56	1.59	1.59	1.67	1.71	1.71	1.71	1.73	1.73
Swiss franc	CHF per USD	0.88	0.92	0.84	0.85	0.86	0.86	0.86	0.84	0.84	0.88	0.88	0.91	0.91
Australian dollar	USD per AUD	1.03	1.03	1.07	1.05	1.04	1.04	1.03	1.03	1.02	1.00	1.00	0.98	0.96
NZ dollar	USD per NZD	0.82	0.76	0.83	0.84	0.83	0.83	0.82	0.82	0.81	0.81	0.81	0.80	0.79

f: Forecast by TD Economics as at September 2011; All forecasts are for end of period; Source: Federal Reserve, Bloomberg, TD Economics

CANADIAN ECONOMIC OUTLOOK

Period-Over-Period Annualized Per Cent Change Unless Otherwise Indicated

	2011				2012				2013				Annual Average			4th Qtr/4th Qtr		
	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	11F	12F	13F	11F	12F	13F
Real GDP	3.6	-0.4	2.1	1.3	2.0	2.2	2.7	2.8	2.7	2.6	2.5	2.3	2.2	1.9	2.6	1.6	2.4	2.5
Consumer Expenditure	-0.1	1.6	1.9	1.5	2.3	2.7	3.0	2.9	2.8	2.5	2.1	1.9	1.9	2.3	2.6	1.2	2.7	2.3
Durable Goods	-5.2	1.5	1.0	0.5	3.5	4.5	6.0	6.3	4.5	2.5	1.0	-0.5	0.8	3.2	3.9	-0.6	5.1	1.9
Business Investment	12.9	15.5	5.5	3.5	4.3	6.6	8.0	10.6	11.3	12.0	8.7	6.8	13.4	6.2	10.0	9.2	7.3	9.7
Non-Res. Structures	10.7	2.0	3.5	3.0	4.0	5.2	6.0	8.2	7.5	7.0	6.8	5.0	10.1	4.4	7.0	4.7	5.8	6.6
Machinery & Equipment	15.2	31.0	7.5	4.0	4.5	8.0	10.0	13.0	15.0	17.0	10.5	8.5	16.8	8.1	12.9	14.0	8.8	12.7
Residential Investment	7.5	0.7	8.2	-3.0	-1.0	2.0	3.5	4.0	-1.5	-4.0	-3.0	-1.5	1.9	1.3	-0.3	3.2	2.1	-2.5
Government Expenditures	5.5	1.6	0.0	0.1	0.1	0.1	0.0	0.1	-0.1	-0.1	-0.1	-0.1	1.6	0.2	-0.1	0.5	0.1	-0.1
Final Domestic Demand	1.8	3.0	2.2	1.1	1.7	2.4	2.9	3.1	2.8	2.6	2.0	1.8	3.0	2.1	2.6	2.0	2.5	2.3
Exports	7.7	-8.3	4.3	1.3	1.7	2.6	4.3	3.8	4.9	5.3	6.0	6.4	3.0	1.9	4.8	1.1	3.1	5.6
Imports	9.5	10.0	-1.5	-0.2	0.8	3.1	5.1	4.8	4.8	5.1	4.1	4.3	6.2	2.1	4.7	4.3	3.4	4.6
Change in Non-Farm Inventories ($2002 Bn)	6.1	15.7	8.0	7.5	7.0	6.5	7.0	8.0	7.5	7.8	7.8	7.5	9.3	7.1	7.7	---	---	---
Final Sales	0.6	-3.3	4.8	1.8	2.3	2.4	2.7	3.1	3.1	3.0	2.8	2.5	1.9	2.3	2.9	1.0	2.6	2.9
International Current Account Balance ($Bn)	-40.3	-61.3	-58.6	-61.1	-39.6	-40.0	-40.3	-41.6	-42.4	-43.1	-41.6	-39.7	-55.3	-40.4	-41.7	---	---	---
% of GDP	-2.4	-3.6	-3.4	-3.6	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.2	-2.1	-3.2	-2.3	-2.3	---	---	---
Pre-tax Corp. Profits	19.7	-8.4	4.6	3.5	5.0	6.5	7.5	8.0	7.5	7.6	7.7	7.6	11.1	4.6	7.6	4.4	6.7	7.6
% of GDP	12.0	11.7	11.7	11.7	11.8	11.9	11.9	12.0	12.1	12.2	12.3	12.4	11.8	11.9	12.3	---	---	---
GDP Deflator (Y/Y)	3.0	3.4	3.3	1.9	1.2	1.2	1.5	1.9	1.9	1.9	1.7	1.7	2.9	1.5	1.8	1.9	1.9	1.7
Nominal GDP	8.1	1.5	3.1	1.7	3.6	4.2	4.9	4.8	4.4	4.3	4.2	4.0	5.1	3.4	4.5	3.6	4.4	4.2
Labour Force	2.6	0.8	0.2	0.8	0.9	1.0	1.2	1.2	1.2	1.2	1.2	1.0	1.0	0.9	1.2	1.1	1.1	1.1
Employment	2.4	2.0	0.7	0.3	0.8	1.2	1.8	1.7	1.5	1.4	1.2	1.0	1.5	1.0	1.5	1.3	1.4	1.3
Employment ('000s)	101	87	30	13	35	52	78	74	66	61	53	44	263	178	257	231	238	224
Unemployment Rate (%)	7.8	7.5	7.3	7.5	7.5	7.4	7.3	7.2	7.1	7.1	7.1	7.1	7.5	7.4	7.1	---	---	---
Personal Disp. Income	3.1	2.0	2.0	2.7	3.5	3.2	3.9	4.0	3.3	4.0	3.8	3.8	3.1	3.1	3.7	2.4	3.6	3.7
Pers. Savings Rate (%)	4.4	4.1	4.0	4.1	3.9	3.6	3.4	3.3	3.0	3.0	3.0	3.0	4.1	3.6	3.0	---	---	---
Cons. Price Index (Y/Y)	2.6	3.4	2.7	2.0	1.6	1.6	1.8	1.9	1.8	1.8	1.9	2.0	2.7	1.7	1.9	2.0	1.9	2.0
Core CPI (Y/Y)	1.3	1.6	1.7	1.5	1.5	1.6	1.7	1.8	1.8	1.8	1.9	1.9	1.5	1.7	1.8	1.5	1.8	1.9
Housing Starts ('000s)	178	193	190	188	185	184	182	178	170	165	162	160	187	182	164	---	---	---
Productivity: Real GDP / worker (Y/Y)	1.0	0.6	0.7	0.3	0.3	1.1	1.0	1.0	1.0	1.1	1.2	1.2	0.6	0.9	1.1	0.3	1.0	1.2

F: Forecast by TD Economics as at September 2011

Source: Statistics Canada, Bank of Canada, Canada Mortgage and Housing Corporation, Haver Analytics

U.S. ECONOMIC OUTLOOK

Period-Over-Period Annualized Per Cent Change Unless Otherwise Indicated

	2011				2012				2013				Annual Average			4th Qtr/4th Qtr		
	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	11F	12F	13F	11F	12F	13F
Real GDP	0.4	1.0	1.9	0.9	1.6	2.0	2.8	2.6	2.5	2.6	2.9	2.8	1.6	1.7	2.6	1.0	2.2	2.7
Consumer Expenditure	2.1	0.4	2.0	1.4	1:6	2.0	2.5	2.3	2.4	2.5	2.8	2.7	2.1	1.8	2.5	1.5	2.1	2.6
Durable Goods	11.8	-5.1	3.6	4.4	5.5	6.8	5.9	6.3	4.7	5.1	7.5	6.2	7.2	4.7	5.8	3.5	6.1	5.9
Business Investment	2.1	9.9	5.3	3.5	-0.2	2.9	5.9	5.9	7.6	8.6	10.9	10.1	7.3	3.5	7.5	5.1	3.6	9.3
Non-Res. Structures	-14.4	15.8	-0.2	-1.6	-0.8	0.6	3.5	2.4	3.1	4.3	4.6	5.1	1.6	1.1	3.4	-0.7	1.4	4.3
Machinery & Equipment	8.7	7.8	7.4	5.3	0.0	3.7	6.7	7.2	9.3	10.1	13.2	11.8	9.5	4.3	9.0	7.3	4.3	11.1
Residential Construction	-2.5	3.4	-1.2	0.2	0.9	2.4	3.0	3.2	4.2	5.7	7.3	US	-2.5	1.3	4.7	-0.1	2.4	6.4
Govt. Consumption & Gross Investment	-5.9	-0.9	-1.8	-0.8	-0.7	-1.4	-1.1	-1.3	-1.4	-1.6	-1.8	-1.4	-2.1	-1.1	-1.4	-2.4	-1.1	-1.6
Final Domestic Demand	0.4	1.1	1.5	1.1	1.0	1.4	2.1	2.0	2.2	2.4	2.8	2.9	1.6	1.4	2.3	1.0	1.6	2.6
Exports	7.9	3.1	7.9	4.1	6.2	6.6	7.3	7.0	7.4	8.2	6.8	7.2	7.1	6.1	7.3	5.7	6.8	7.4
Imports	8.3	1.9	3.1	3.4	2.0	3.1	4.0	3.5	4.7	5.8	6.0	6.9	5.2	2.9	4.8	4.1	3.1	5.8
Change in Non-Farm Inventories	59.7	52.4	39.4	31.7	29.7	33.5	39.3	44.1	44.0	43.2	45.0	46.5	45.8	36.6	44.7	—	—	—
Final Sales	0.0	1.2	2.1	1.1	1.6	1.9	2.6	2.5	2.5	2.6	2.8	2.8	1.7	1.8	2.5	1.1	2.1	2.7
International Current Account Balance ($Bn)	-494	-505	-497	-514	-512	-521	-531	-541	-541	-544	-552	-564	-502	-526	-550	—	—	—
% of GDP	-3.3	-3.4	-3.3	-3.4	-3.3	-3.4	-3.4	-3.4	-3.4	-3.3	-3.4	-3.4	-3.3	-3.4	-3.4	—	—	—
Pre-tax Corporate Profits including IVA&CCA	4.2	12.8	-5.3	0.0	2.6	1.0	2.1	2.7	3.4	4.3	4.8	5.1	5.9	1.4	3.4	2.7	2.1	4.4
% of GDP	12.6	12.9	12.6	12.5	12.5	12.4	12.3	12.3	12.2	12.2	12.2	12.2	12.7	12.4	12.2	—	—	—
GDP Deflator (Y/Y)	1.8	2.1	2.4	2.3	2.1	1.9	1.7	1.8	2.0	2.1	2.1	2.1	2.1	1.9	2.1	2.3	1.8	2.1
Nominal GDP	3.1	3.5	4.5	2.5	3.2	3.9	4.7	4.5	5.1	4.6	4.9	4.7	3.7	3.6	4.7	3.4	4.1	4.8
Labor Force	-1.5	0.6	0.0	0.6	0.8	1.0	1.1	1.1	1.2	1.2	1.2	1.3	-0.2	0.7	1.2	-0.1	1.0	1.2
Employment	1.3	1.4	0.5	0.6	0.9	1.1	1.7	1.5	1.6	1.6	1.8	1.9	0.9	1.0	1.6	1.0	1.3	1.7
Change in Empl. ('000s)	422	467	163	196	295	361	558	495	530	517	584	627	1,208	1,314	2,107	1,248	1,709	2,257
Unemployment Rate (%)	8.9	9.1	9.1	9.1	9.1	9.1	8.9	8.9	8.8	8.7	8.6	8.6	9.1	9.0	8.7	—	—	—
Personal Disp. Income	5.2	4.2	4.1	1.7	3.2	4.0	4.8	4.5	3.2	4.4	5.1	4.8	4.1	3.5	4.2	3.8	4.1	4.3
Pers. Savings Rate (%)	5.0	5.2	4.8	4.5	4.4	4.3	4.2	4.2	3.9	3.8	3.9	3.9	4.9	4.3	3.9	—	—	—
Cons. Price Index (Y/Y)	2.2	3.3	3.4	3.3	2.4	2.0	2.0	2.0	2.0	2.0	2.1	2.1	3.1	2.1	2.1	3.3	2.0	2.1
Core CPI (Y/Y)	1.1	1.5	1.9	2.2	2.3	2.2	2.0	1.9	1.9	1.9	2.0	2.0	1.7	2.1	2.0	2.2	1.9	2.0
Housing Starts (mns)	0.58	0.57	0.60	0.58	0.59	0.59	0.60	0.60	0.61	0.63	0.65	0.68	0.58	0.59	0.64	—	—	—
Productivity: Real Output per hour (y/y)	1.2	0.7	1.1	0.6	0.9	1.4	0.9	1.1	1.3	1.3	1.3	1.3	0.9	1.1	1.3	0.6	1.1	1.3

F: Forecast by TD Economics as at September 2011

Source: U.S. Bureau of Labor Statistics, U.S. Bureau of Economic Analysis, TD Economics

Conference Board Quarterly Forecast - September 21 2011

	2010.3	2010.4	2011.1	2011.2	2011.3	2011.4	2012.1	2012.2	2012.3	2012.4	2013.1	2013.2	2013.3	2013.4	2014.1	2014.2	2014.3	2014.4	2015.1	2015.2	2015.3	2015.4
Cdn GDP Price Deflator	1.22	1.24	1.25	1.26	1.27	1.28	1.29	1.29	1.30	1.31	1.32	1.32	1.33	1.34	1.34	1.35	1.36	1.36	1.37	1.37	1.38	1.39
% chge	2.6	2.8	2.9	3.4	4.1	3.1	2.5	2.6	2.1	2.3	2.3	2.3	2.2	2.1	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Cdn CPI	1.17	1.17	1.18	1.20	1.20	1.20	1.21	1.22	1.22	1.23	1.24	1.24	1.25	1.26	1.27	1.27	1.28	1.29	1.29	1.30	1.31	1.31
% chge	1.8	2.3	2.6	3.4	2.9	2.5	2.2	1.4	1.9	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.1	2.0	2.0	2.0
Cdn Long Bond rate	3.52	3.56	3.74	3.59	3.18	3.10	2.97	2.85	2.87	2.99	3.14	3.32	3.54	3.79	3.93	4.01	4.10	4.18	4.24	4.30	4.35	4.40
Cdn T-Bill Rate	0.74	0.97	0.96	0.95	0.93	0.93	0.92	0.90	1.19	1.67	2.16	2.64	3.13	3.63	3.83	3.83	3.83	3.84	3.84	3.85	3.85	3.85
Cdn$/US$	1.04	1.01	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.98	0.98	0.98	0.98	0.98	0.99	0.99	0.99	0.99
US T-Bill Rate %	0.16	0.14	0.13	0.05	0.04	0.02	-0.01	-0.02	-0.04	-0.05	-0.07	0.07	0.46	0.87	1.29	1.72	2.16	2.61	3.07	3.38	3.45	3.50
US Long Bond Rate	3.85	4.16	4.56	4.34	4.27	4.12	3.99	3.86	3.73	3.61	3.50	3.45	3.48	3.55	3.63	3.74	3.86	4.01	4.17	4.30	4.36	4.41
US GDP Price Deflator	111.16	111.70	112.39	113.07	113.87	114.32	114.77	115.30	115.90	116.54	117.21	117.84	118.47	119.11	119.76	120.43	121.10	121.80	122.52	123.19	123.87	124.57
% chge	1.4	1.6	1.8	2.1	2.4	2.3	2.1	2.0	1.8	1.9	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3
Cdn 10 Yr Bond rate	2.93	3.08	3.31	3.15	2.62	2.49	2.41	2.32	2.40	2.59	2.80	3.04	3.32	3.62	3.79	3.88	3.98	4.06	4.13	4.19	4.25	4.29

Source: Statistics Canada; The Conference Board of Canada.					
US-90-Day Tresury Bill Rate					
2010Q1	0.107				
2010Q2	0.147				
2010Q3	0.157				
2010Q4	0.137				
2011Q1	0.127				
2011Q2	0.047				
2011Q3	0.040				
2011Q4	0.015				
2012Q1	0.050				
2012Q2	0.050				
2012Q3	0.050				
2012Q4	0.050				
2013Q1	0.050				
2013Q2	0.072				
2013Q3	0.464				
2013Q4	0.871				
2014Q1	1.291				
2014Q2	1.722				
2014Q3	2.162				
2014Q4	2.611				
2015Q1	3.066				
2015Q2	3.379				
2015Q3	3.445				
2015Q4	3.502				
2016Q1	3.550				
2016Q2	3.593				
2016Q3	3.629				
2016Q4	3.660				

Gloabal Insight Quarterly Forecast - September 14 2011

Table 24																						
Interest Rates																						
(Percent)																						
	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4
Government of Canada																						
Treasury Bills																						
3 Months	0.74	0.97	0.96	0.95	0.93	0.93	0.94	0.96	1.03	1.28	1.50	1.50	1.75	1.75	2.00	2.25	2.50	3.00	3.25	3.50	3.75	4.00
6 Months	0.95	1.09	1.12	1.08	1.04	1.04	1.05	1.07	1.14	1.39	1.61	1.61	1.86	1.86	2.11	2.36	2.61	3.11	3.36	3.61	3.86	4.11
Bonds																						
1-3 Years	1.39	1.60	1.68	1.62	1.60	1.50	1.61	1.69	1.77	1.94	2.09	2.10	2.27	2.34	2.59	2.78	3.03	3.42	3.68	3.96	4.24	4.42
3-5 Years	1.96	2.10	2.35	2.18	2.08	1.91	2.10	2.22	2.30	2.41	2.51	2.53	2.64	2.76	3.01	3.17	3.40	3.72	3.98	4.28	4.59	4.73
5 Years	2.18	2.33	2.63	2.45	2.12	1.95	2.14	2.27	2.35	2.46	2.55	2.57	2.67	2.80	3.05	3.20	3.44	3.75	4.01	4.32	4.63	4.76
5-10 Years	2.62	2.76	3.02	2.81	2.46	2.23	2.48	2.64	2.72	2.79	2.84	2.87	2.93	3.10	3.34	3.47	3.70	3.96	4.22	4.54	4.88	4.97
10 Years	2.93	3.08	3.31	3.15	2.60	2.36	2.63	2.79	2.88	2.93	2.97	3.00	3.04	3.22	3.47	3.59	3.81	4.05	4.31	4.64	4.98	5.06
10+ Years	3.45	3.50	3.69	3.52	2.95	2.70	2.96	3.12	3.21	3.25	3.28	3.31	3.35	3.53	3.77	3.89	4.11	4.34	4.61	4.94	5.27	5.35
30 Years	3.52	3.56	3.74	3.59	3.04	2.78	3.05	3.21	3.29	3.33	3.36	3.39	3.43	3.61	3.85	3.96	4.19	4.42	4.68	5.01	5.35	5.43

Global Insight Quarterly Forecast - September 14 2011

ːable 25
ːinancial Aggregates and U.S.tes

	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4
J.S. Interest Rates (Percent)																						
Federal Funds	0.19	0.19	0.16	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.12	0.47	0.97	1.47	2.01	2.55	3.07	3.52	3.95
3-Month T-Bills	0.16	0.14	0.13	0.05	0.04	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.18	0.57	1.04	1.54	2.07	2.58	3.05	3.45	3.74
3-Month Comm. Paper	0.25	0.23	0.23	0.17	0.14	0.19	0.22	0.22	0.22	0.22	0.21	0.20	0.20	0.27	0.68	1.16	1.66	2.18	2.72	3.23	3.65	4.01
‑Month Euro Deposit Rate	0.39	0.29	0.31	0.26	0.29	0.32	0.31	0.31	0.31	0.31	0.30	0.29	0.29	0.36	0.77	1.27	1.78	2.33	2.87	3.41	3.84	4.21
Bank Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.49	3.98	4.47	5.01	5.55	6.07	6.52	6.95
5-year Treasury Notes	1.55	1.49	2.12	1.86	1.15	1.00	1.19	1.35	1.45	1.49	1.54	1.57	1.63	1.83	2.12	2.41	2.84	3.27	3.72	4.09	4.42	4.50
10-Year Treasury Notes	2.79	2.86	3.46	3.21	2.45	2.21	2.48	2.64	2.73	2.78	2.82	2.85	2.89	3.07	3.32	3.44	3.66	3.90	4.16	4.49	4.83	4.91
30-year Treasury Bonds	3.86	4.17	4.56	4.34	3.76	3.46	3.72	3.87	3.94	3.97	4.00	4.03	4.07	4.17	4.33	4.38	4.53	4.65	4.80	5.01	5.25	5.31

Global Insight Quarterly Forecast - September 14 2011

Table 1
Selected Economic Indicators

	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4
Nominal GDP (Bil. $)	1625.4	1661.9	1694.6	1701.0	1728.8	1748.9	1771.1	1792.0	1813.3	1836.1	1858.3	1880.3	1903.4	1926.5	1949.3	1972.6	1996.3	2020.0	2043.6	2066.9	2090.8	2114.6
Annual % Ch.	3.8	9.3	8.1	1.5	6.7	4.7	5.2	4.8	4.9	5.1	4.9	4.8	5.0	4.9	4.8	4.9	4.9	4.8	4.7	4.6	4.7	4.6
Raw Mat. Price Index	149.1	159.0	171.5	183.8	179.8	177.0	174.5	173.5	172.5	171.2	170.2	169.6	169.4	169.6	169.7	170.3	170.6	171.0	171.7	172.8	173.7	174.5
% Ch. Year Ago	5.9	8.6	12.7	23.7	20.6	11.3	1.7	-5.6	-4.0	-3.3	-2.5	-2.2	-1.8	-0.9	-0.3	0.4	0.7	0.8	1.2	1.5	1.8	2.1
Industry Price Index	109.0	110.8	113.3	114.7	113.4	113.9	114.4	114.9	115.4	115.8	116.4	117.0	117.5	118.0	118.5	118.9	119.3	119.6	119.9	120.4	120.8	121.3
% Ch. Year Ago	1.0	2.6	4.1	5.0	4.1	2.8	0.9	0.2	1.7	1.7	1.8	1.8	1.8	1.9	1.8	1.6	1.5	1.4	1.2	1.3	1.3	1.4
GDP Deflator	122.4	124.2	125.5	126.1	127.6	128.6	129.5	130.3	131.1	131.8	132.6	133.3	134.0	134.7	135.4	136.0	136.7	137.4	138.1	138.7	139.4	140.1
Annual % Ch.	1.3	6.0	4.3	1.9	5.0	3.0	2.7	2.5	2.7	2.2	2.2	2.3	2.2	2.1	1.9	1.9	2.1	2.0	2.0	1.8	1.9	1.9
CPI	116.8	117.5	118.4	120.1	120.1	120.6	121.3	122.3	122.2	122.7	123.6	124.8	124.7	125.2	126.1	127.3	127.3	127.7	128.6	129.8	129.8	130.3
% Ch. Year Ago	1.8	2.3	2.6	3.4	2.8	2.6	2.5	1.9	1.8	1.8	1.9	2.0	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Employment (Thousands)	17104	17123	17224	17311	17348	17433	17531	17584	17681	17780	17832	17930	17983	18057	18155	18226	18297	18347	18395	18445	18496	18545
Annual % Ch.	1.4	0.4	2.4	2.0	0.9	2.0	2.3	1.2	2.2	2.2	1.2	2.2	1.2	1.6	2.2	1.6	1.6	1.1	1.1	1.1	1.1	1.1
Unemployment Rate (%)	8.0	7.7	7.8	7.5	7.3	7.3	7.2	7.2	7.1	7.0	7.0	6.9	6.9	6.8	6.7	6.6	6.5	6.5	6.5	6.5	6.5	6.5
Productivity (Annual % Ch.)	1.1	2.7	1.2	-2.4	0.8	-0.3	0.1	1.0	-0.1	0.6	1.5	0.2	1.6	1.1	0.7	1.3	1.2	1.6	1.7	1.7	1.6	1.6
Average Hourly Earnings	21.12	21.25	21.52	21.73	21.82	22.02	22.20	22.39	22.58	22.78	22.97	23.18	23.38	23.59	23.80	23.91	24.02	24.14	24.28	24.40	24.43	24.47
Annual % Ch.	6.5	2.5	5.3	4.0	1.6	3.7	3.3	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.5	1.9	1.9	2.1	2.2	2.0	0.6	0.6
3-Month T-Bill Rate (%)	0.74	0.97	0.96	0.95	0.93	0.93	0.94	0.96	1.03	1.28	1.50	1.50	1.75	1.75	2.00	2.25	2.50	3.00	3.25	3.50	3.75	4.00
US 3-Month T-Bill Rate (%)	0.16	0.14	0.13	0.05	0.04	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.18	0.57	1.04	1.54	2.07	2.58	3.05	3.45	3.74
Canada-U.S. Differential (% pts.)	0.59	0.83	0.83	0.90	0.89	0.88	0.87	0.89	0.97	1.22	1.44	1.44	1.68	1.57	1.43	1.21	0.96	0.93	0.67	0.45	0.30	0.26
Prime Rate (%)	2.83	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.08	3.33	3.50	3.50	3.75	3.75	4.00	4.25	4.50	5.00	5.25	5.50	5.75	6.00
Overnight Rate (%)	0.83	1.00	0.99	1.00	1.00	1.00	1.00	1.00	1.08	1.33	1.50	1.50	1.75	1.75	2.00	2.25	2.50	3.00	3.25	3.50	3.75	4.00
Bank Rate (%)	1.08	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.33	1.58	1.75	1.75	2.00	2.00	2.25	2.50	2.75	3.25	3.50	3.75	4.00	4.25
GOC Bond Rate (1-3 yrs.) (%)	1.39	1.60	1.68	1.62	1.60	1.50	1.61	1.69	1.77	1.94	2.09	2.10	2.27	2.34	2.59	2.78	3.03	3.42	3.68	3.96	4.24	4.42
GOC Bond Rate (3-5 yrs.) (%)	1.96	2.10	2.35	2.18	2.08	1.91	2.10	2.22	2.30	2.41	2.51	2.53	2.64	2.76	3.01	3.17	3.40	3.72	3.98	4.28	4.59	4.73
GOC Ten-Year Bond Rate (%)	2.93	3.08	3.31	3.15	2.60	2.36	2.63	2.79	2.88	2.93	2.97	3.00	3.04	3.22	3.47	3.59	3.81	4.05	4.31	4.64	4.98	5.06
U.S. Ten-Year T-Note Rate (%)	2.79	2.86	3.46	3.21	2.45	2.21	2.48	2.64	2.73	2.78	2.82	2.85	2.89	3.07	3.32	3.44	3.66	3.90	4.16	4.49	4.83	4.91
U.S. Real GDP (Bil. 2005 $)	13139.6	13216.1	13227.9	13260.5	13299.2	13347.1	13415.3	13485.7	13550.4	13624.8	13688.6	13781.0	13881.7	13992.1	14107.9	14231.5	14366.2	14506.5	14625.7	14740.3	14854.9	14959.1
Annual % Ch.	2.5	2.3	0.4	1.0	1.2	1.4	2.1	2.1	1.9	2.2	1.9	2.7	3.0	3.2	3.4	3.5	3.8	4.0	3.3	3.2	3.1	2.8
Household Credit (Billion $)	1470.4	1491.3	1518.3	1542.2	1567.1	1592.6	1618.6	1645.1	1672.2	1699.8	1727.7	1755.8	1783.8	1811.5	1838.8	1865.7	1892.2	1918.3	1943.9	1969.1	1993.8	2017.8
Annual % Ch.	5.7	5.8	7.4	6.5	6.6	6.7	6.7	6.7	6.7	6.8	6.7	6.7	6.5	6.4	6.2	6.0	5.8	5.6	5.5	5.3	5.1	4.9
ExCh. Rate (U.S.-Can.)	96.2	98.7	101.4	103.3	102.9	102.5	102.6	103.3	104.1	104.4	104.0	102.8	100.4	97.7	96.0	94.6	93.0	91.5	90.6	90.2	89.5	88.8

Global Insight Quarterly Forecast - September 14 2011

OBS	2010Q2	2010Q3	2010Q4	2011Q1	2011Q2	2011Q3	2011Q4	2012Q1	2012Q2	2012Q3	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4
USPCWGDP	110.77	111.162	111.699	112.39	113.066	113.6937	114.0562	114.3593	114.4613	114.8058	115.1863	115.643	116.0607	116.5063	116.9852	117.5332	118.0545	118.5692	119.1117	119.7138	120.2572	120.7903	121.3383
% Ch. Year Ago	1.46	1.42	1.95	2.50	2.43	2.24	1.28	1.07	0.36	1.21	1.33	1.60	1.45	1.54	1.65	1.89	1.79	1.76	1.84	2.04	1.83	1.79	1.83

PUB/MH I-28

Reference: Tab 4 Appendix 4.1, Attachment 4 EO12, Tab 5 Section 5.6 Finance Expense

b) Please provide copies of all forecasts utilized in (a).

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-28(a).

PUB/MH I-28

Reference: Tab 4 Appendix 4.1, Attachment 4 EO12, Tab 5 Section 5.6 Finance Expense

c) Please file the detailed calculations in support of the short and long term interest rates utilized for MH's fiscal years 2011/12, 2012/13 & 2013/14 with narrative of the steps taken to derive the forecast.

ANSWER:

Refer to Tables 1 and 3 included in response to PUB/MH I-28 (a) for detailed information on the Canadian 3 month T-Bill and Canadian 10 year+ bond yield rates, respectively, for the 2011/12, 2012/13 and 2013/14 periods. The calculations of the rates were as follows:

- The 2011/12 forecast included the average of all data points within Q2, Q3, Q4 of 2011 and Q1 of 2012. The 2012/13 forecast included the average of all data points within Q2, Q3, Q4 of 2012 and Q1 of 2013. The 2013/14 forecast included the average of all data points within Q2, Q3, Q4 of 2013 and Q1 of 2014. For example, the Canadian 3 month T-Bill rate for 2012/13 of 1.25% in Table 1 was calculated as the average of the following data points:

	2012 Q2	2012 Q3	2012 Q4	2013 Q1
BMO Nesbitt Burns	0.83%	0.83%	0.83%	*
CIBC	1.10%	1.28%	1.38%	1.53%
National Bank	1.36%	1.36%	1.36%	
Royal Bank	1.23%	1.58%	2.00%	
Scotiabank	1.03%	1.23%	1.65%	
TD Bank	0.90%	0.93%	0.98%	1.15%
IHS Global Insight	0.96%	1.03%	1.28%	1.50%
Conference Board	0.90%	1.19%	1.67%	2.16%

**Information provided by BMO is proprietary and cannot be disclosed.*

Commencing April 1, 2011, Manitoba Hydro's forecasted short term interest rate changed from the Canadian 3 month Banker's Acceptance rate to the Canadian 3 month T-Bill rate. The Manitoba Hydro Canadian short term interest rate was calculated by adding the provincial debt guarantee fee of 1.00% to the Canadian 3 month T-Bill rate as follows:

	Canadian 3 Month T-Bill	Guarantee Fee	MH Canadian Short Term Interest Rate
2011/12	0.90%	1.00%	1.90%
2012/13	1.25%	1.00%	2.25%
2013/14	2.20%	1.00%	3.20%

The Manitoba Hydro Canadian long term interest rate was calculated by adding the appropriate credit spread to the Canadian 10 year+ bond yield rate and a provincial debt guarantee fee as follows:

	Canadian 10 Year+ Bond Yield	10 Year+ Credit Spread	Guarantee Fee	MH Canadian 10 Year+ Long Term Interest Rate
2011/12	2.85%	0.90%	1.00%	4.75%
2012/13	2.95%	0.75%	1.00%	4.70%
2013/14	3.40%	0.65%	1.00%	5.05%

PUB/MH I-28

Reference: **Tab 4 Appendix 4.1, Attachment 4 EO12, Tab 5 Section 5.6 Finance Expense**

d) **Please provide an analysis which shows how the long term borrowing rates of 4.70% for 2012/13 and 5.05% for 2013/14 was derived. In that analysis please provide the projected Manitoba to Canada bond spread.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-28(c).

PUB/MH I-28

Reference: Tab 4 Appendix 4.1, Attachment 4 EO12, Tab 5 Section 5.6 Finance Expense

e) Please provide details of the most recent Canadian dollar denominated, fixed coupon debt financing for a term of at least 20 years undertaken by MH, providing the date of the issue, the size, coupon, the offered yield at issue, the then spread over the most comparable Canada rate, the current market yield, and the current spread over Canada bonds of a similar term.

ANSWER:

On July 31, 2012 Manitoba Hydro arranged for the issue of new long term debt series C129 for CAD $50 million with a 40 year term to maturity (maturing September 5, 2052). C129 was issued with a fixed rate coupon of 3.15%. At 96.7 basis points (bps) over Canada 4.0% June 1, 2041 (yielding 2.20%), plus 1.1 bps commission, the all-in yield rate for C129 (excluding 1% provincial guarantee fee) was 3.178%. As at August 31, 2012, the Bloomberg closing offer yield for C129 was 3.271%, or 93.5 bps over Canada 4.0% June 1, 2041 (yielding 2.336%).

PUB/MH I-28

Reference: Tab 4 Appendix 4.1, Attachment 4 EO12, Tab 5 Section 5.6 Finance Expense

f) Please provide a comparison of finance expense for 2012/13 and 2013/14 based on short and long term interest rates forecast from EO11 versus that now forecast in EO12

ANSWER:

A comparison of finance expense for the two test years forecast in EO11 versus EO12 will not be available until IFF12-1 is finalized.

PUB/MH I-28

Reference: **Tab 4 Appendix 4.1, Attachment 4 EO12, Tab 5 Section 5.6 Finance Expense**

g) **Please provide a comparison between actual/updated forecast of short and long term interest rates for 2011/12, 2012/13 and 2013/14 with that used in the application and provide the impact on finance expense.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-28(f).

PUB/MH I-29

Reference: Appendix 5.1 Debt Management

a) To what extent does MH's Long-term debt reflected in Note 12 of Annual Report provide for early redemption or retirement?

ANSWER:

Manitoba Hydro's long term debt, as reflected in Note 12 of Annual Report, does not provide for early redemption or retirement with the exception of the following:

- CAD $99.6 million HydroBond Series 11, 5 year floating series redeemable annually on June 15 until June 15, 2016.
- CAD $1.9 million Mitigation bond series 5B with semi-annual serial redemptions in the size of approximately $600,000 until June 30, 2013.

PUB/MH I-29

Reference: Appendix 5.1 Debt Management

b) Please discuss what strategies the Corporation has employed to take advantage of historically low interest rates in managing its debt portfolio in the two test years.

ANSWER:

Manitoba Hydro's fundamental debt management objective is to provide stable, low cost funding to meet the financial obligations and liquidity needs of the Corporation.

The low interest rate environment across the entire yield curve over the past few years has provided the opportunity for Manitoba Hydro to reduce the debt portfolio's weighted average interest rates. This opportunity to secure low cost financing is balanced with the debt management objective to provide stability. To further enhance the stability of the debt portfolio, Manitoba Hydro has also increased the weighted average term to maturity of its long term debt portfolio by over one year since 2008/09.

During the past number of years, Manitoba Hydro's actual long term financing has included issuance in various terms throughout the curve, including the issuance of floating rate notes. When selecting terms for its new borrowings, Manitoba Hydro gives careful consideration to the debt maturity schedule and the total level of annual financing requirements. Moving forward, interest rates are forecasted to rise for the entire yield curve. Therefore, a debt management strategy favouring fixed long term debt versus floating rate debt or shorter dated debt maturities will reduce the risk that the Corporation's future gross interest expense will be higher upon refinancing the debt stream.

In order to mitigate refinancing risk, to maintain financing flexibility during the upcoming decade, and in keeping with the concept of matching the Corporation's long-lived assets with long term debt, Manitoba Hydro will continue to favour long term financings with maturities of 10 years+, while maintaining floating rate debt within policy limits.

For further information regarding Manitoba Hydro's Debt Management Strategy, please see Appendix 17.

PUB/MH I-30

Reference: Tab 4 Pages 7-9 , Financial Target Comparison

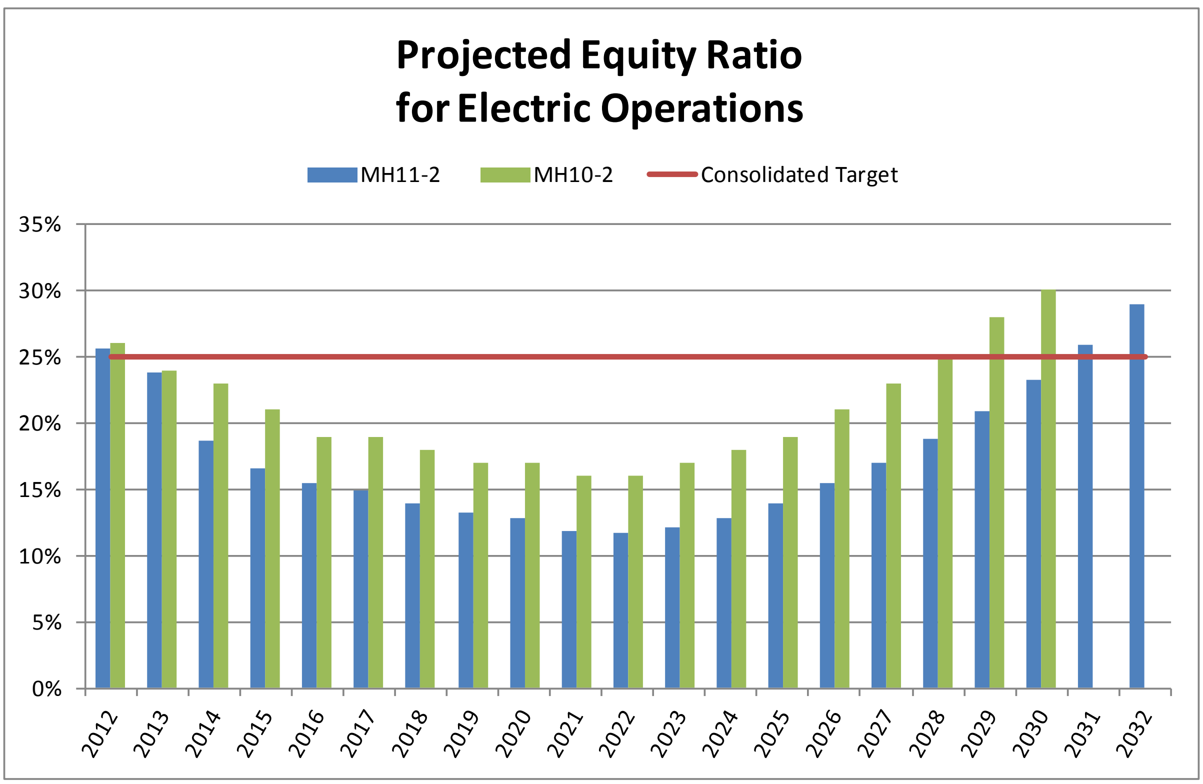
a) Please file the respective charts and data tables for the equity ratio, capital coverage ratio and interest coverage ratio for electric operations only.

ANSWER:

Equity Ratio

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
MH11-2	26%	24%	19%	17%	15%	15%	14%	13%	13%	12%	12%
MH10-2	26%	24%	23%	21%	19%	19%	18%	17%	17%	16%	16%
Consolidated Target	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%

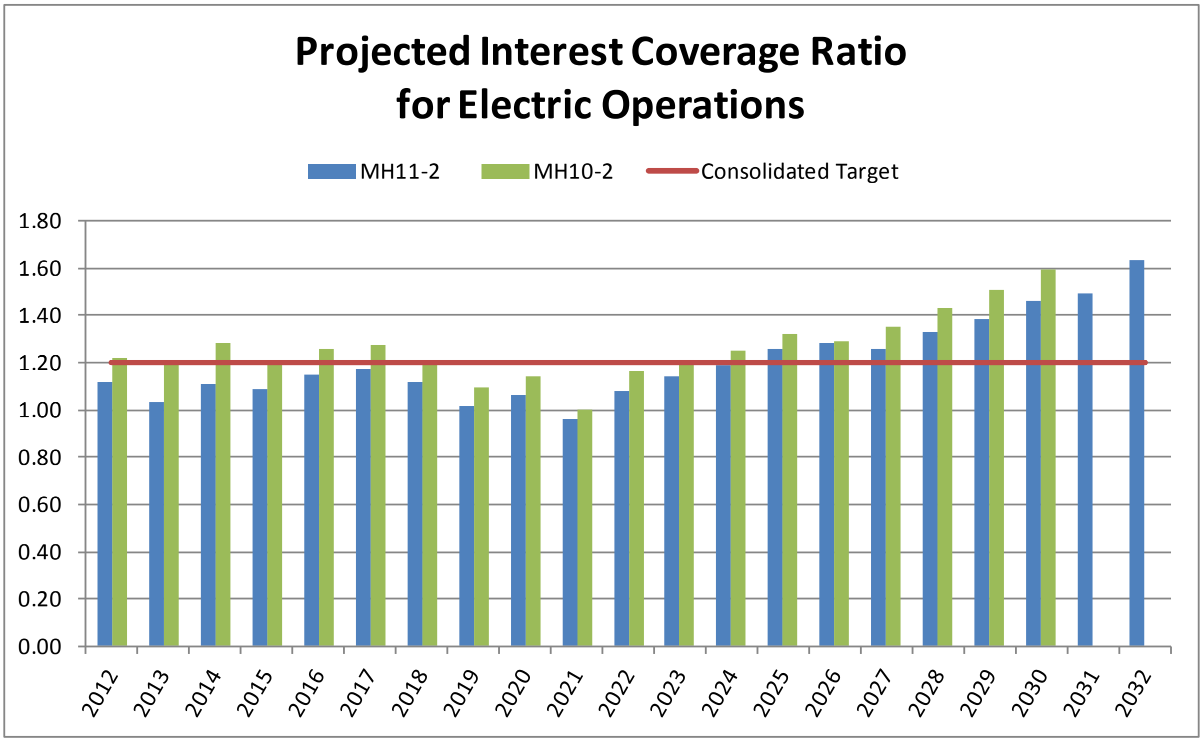
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MH11-2	12%	13%	14%	15%	17%	19%	21%	23%	26%	29%
MH10-2	17%	18%	19%	21%	23%	25%	28%	30%	0%	0%
Consolidated Target	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%



Interest Coverage Ratio

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
MH11-2	1.12	1.03	1.11	1.09	1.15	1.17	1.12	1.02	1.06	0.96	1.08
MH10-2	1.22	1.20	1.28	1.19	1.26	1.28	1.20	1.09	1.14	1.00	1.16
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20

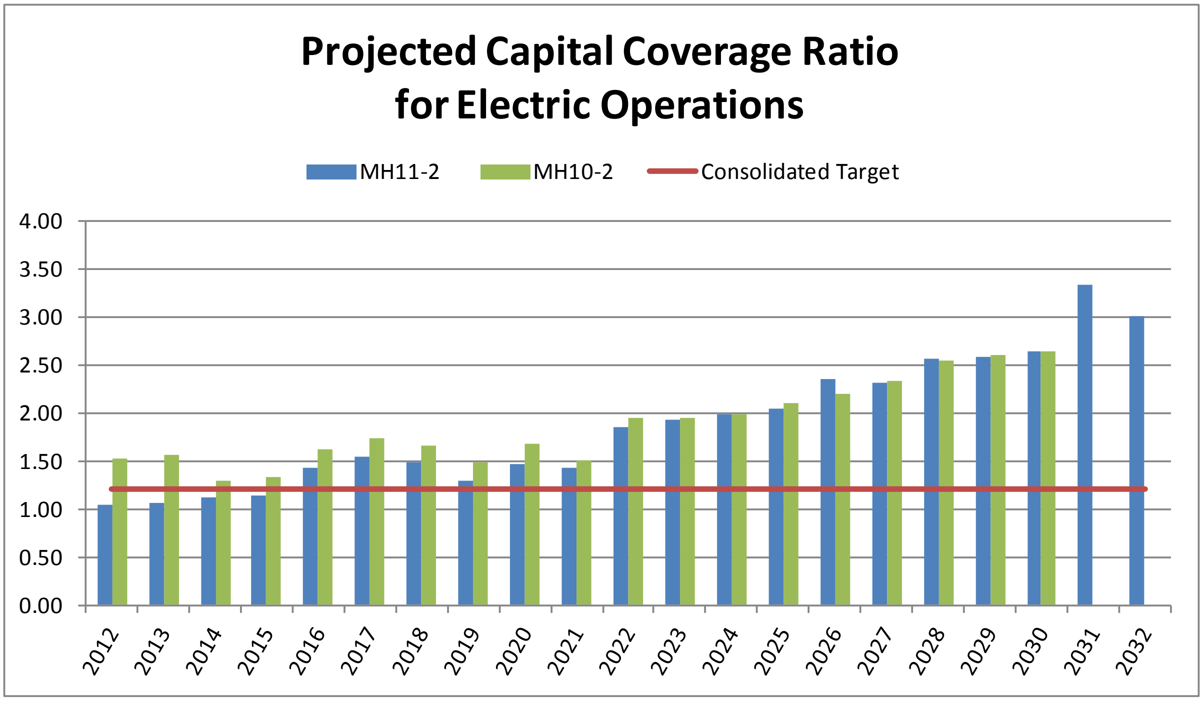
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MH11-2	1.14	1.19	1.26	1.28	1.26	1.33	1.38	1.46	1.49	1.63
MH10-2	1.22	1.25	1.32	1.29	1.35	1.43	1.51	1.59	-	-
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20



Capital Coverage Ratio

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
MH11-2	1.04	1.07	1.13	1.15	1.43	1.54	1.48	1.29	1.46	1.43	1.86
MH10-2	1.52	1.56	1.29	1.33	1.62	1.74	1.66	1.49	1.68	1.51	1.95
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MH11-2	1.93	1.99	2.04	2.36	2.32	2.57	2.59	2.65	3.34	3.00
MH10-2	1.95	1.99	2.10	2.20	2.34	2.56	2.60	2.65	-	-
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20



PUB/MH I-30

Reference: Tab 4 Pages 7-9 , Financial Target Comparison

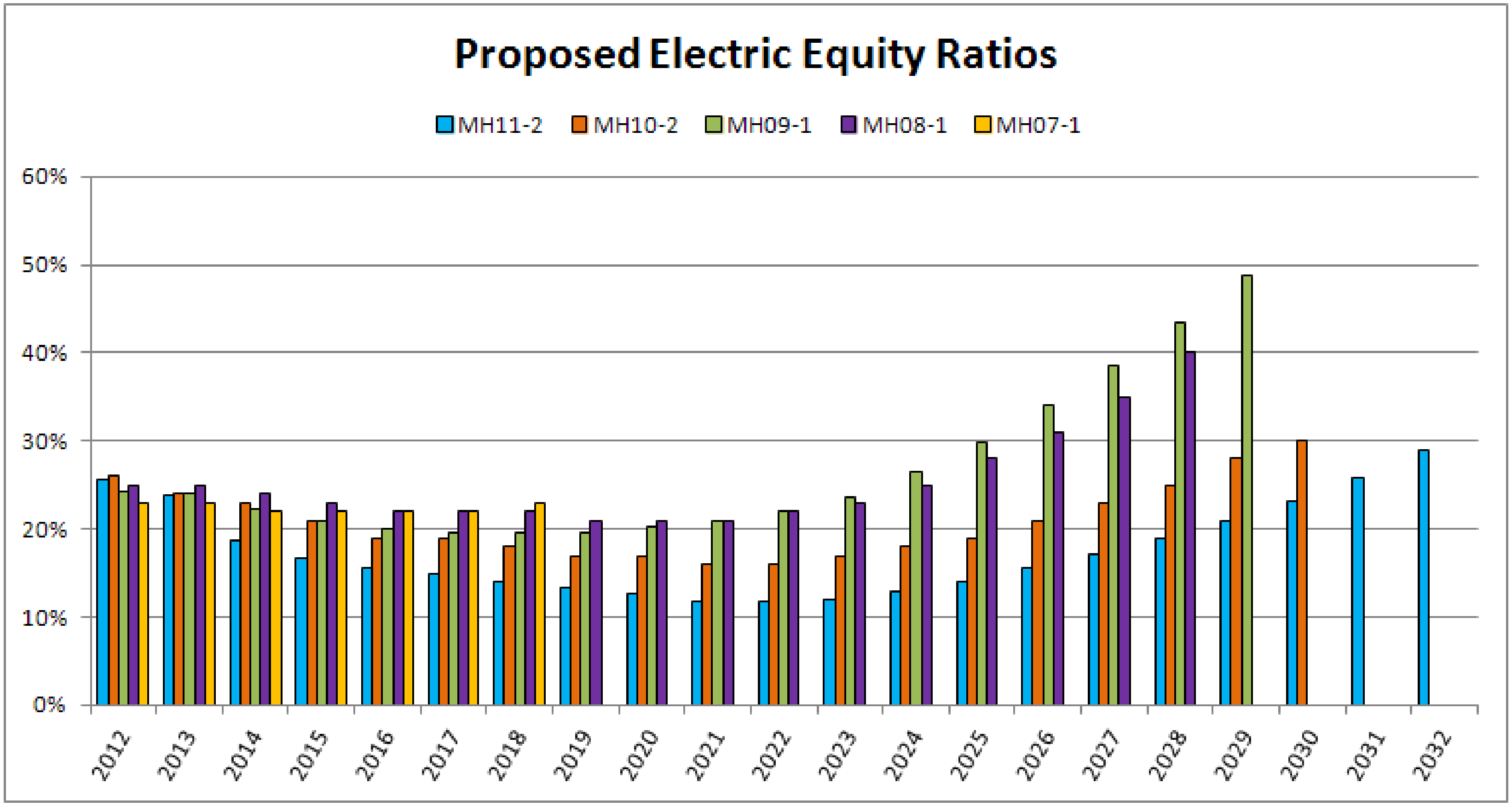
b) Please update PUB MH II-202 (a) from the last GRA to include IFF10-2 and IFF11-2.

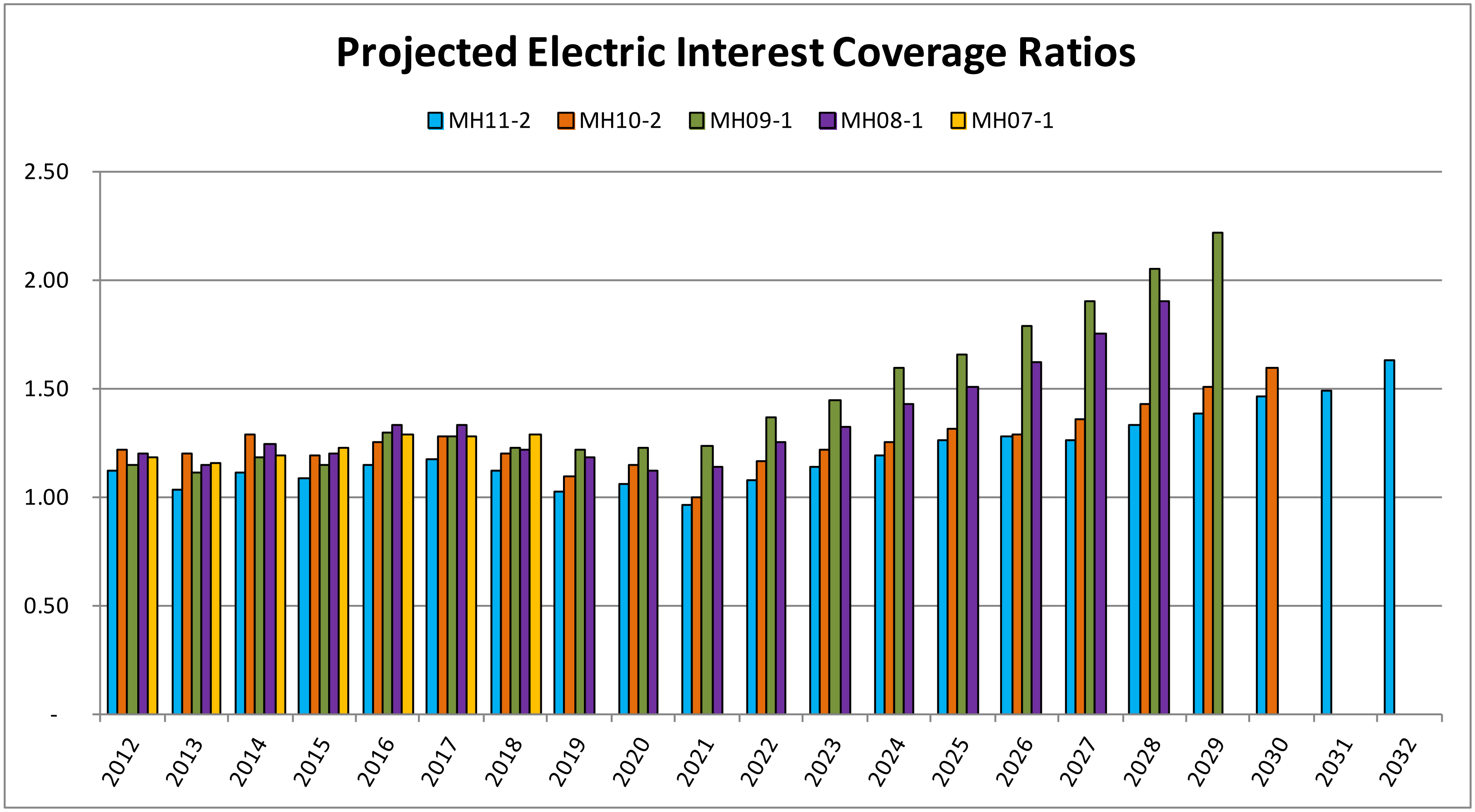
ANSWER:

Please see the attached graphs and tables. Please note a 20 year outlook was not prepared in conjunction with IFF07.

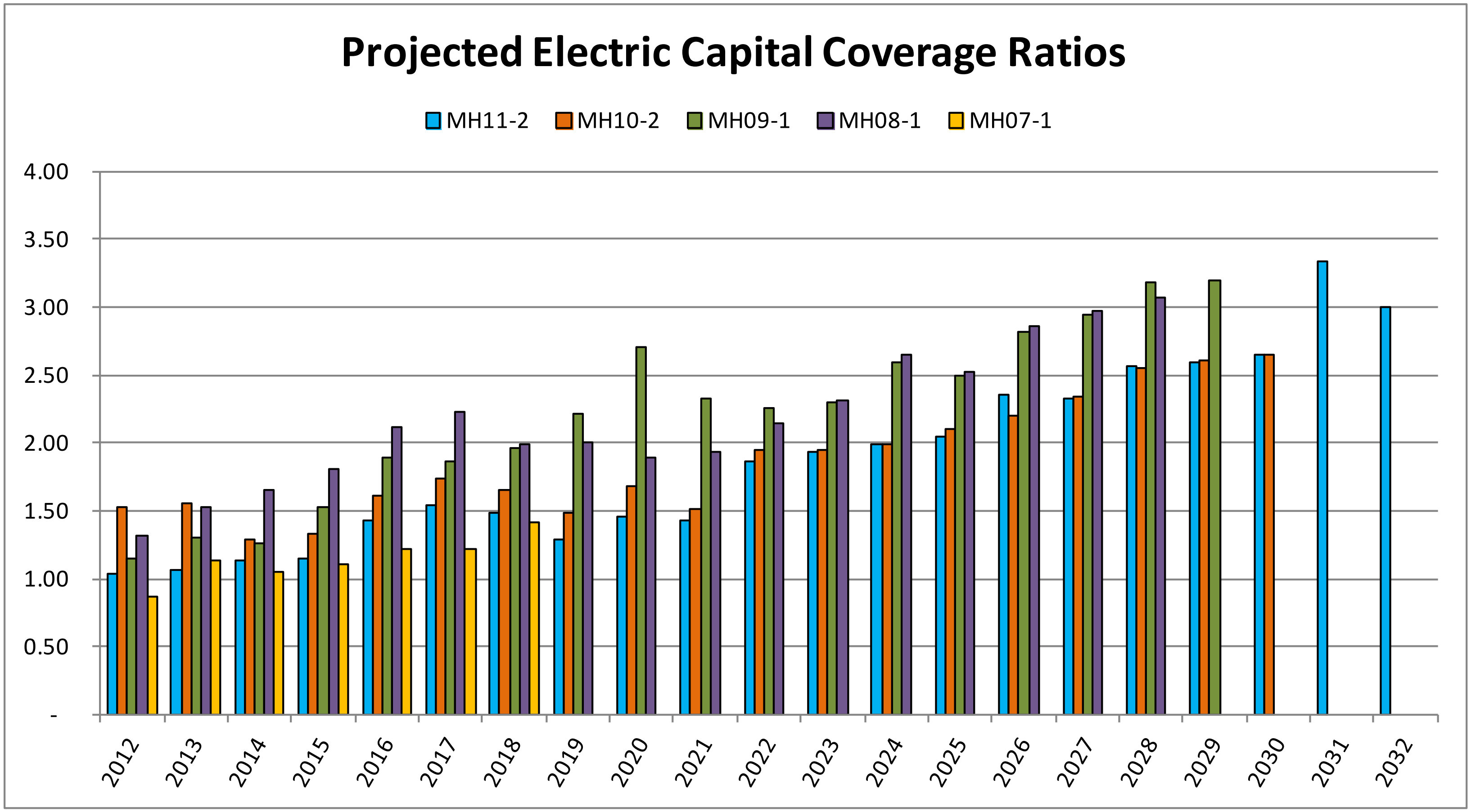
Projected Electric Financial Ratios

	MH11-2			MH10-2			MH09-1			MH08-1			MH07-1		
	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio
2012	26%	1.12	1.04	26%	1.22	1.52	24%	1.14	1.14	25%	1.20	1.31	23%	1.18	0.87
2013	24%	1.03	1.07	24%	1.20	1.56	24%	1.11	1.31	25%	1.15	1.52	23%	1.15	1.13
2014	19%	1.11	1.13	23%	1.28	1.29	22%	1.19	1.25	24%	1.24	1.66	22%	1.19	1.06
2015	17%	1.09	1.15	21%	1.19	1.33	21%	1.15	1.53	23%	1.20	1.80	22%	1.22	1.10
2016	15%	1.15	1.43	19%	1.26	1.62	20%	1.30	1.89	22%	1.33	2.12	22%	1.29	1.22
2017	15%	1.17	1.54	19%	1.28	1.74	20%	1.28	1.87	22%	1.33	2.23	22%	1.28	1.22
2018	14%	1.12	1.48	18%	1.20	1.66	20%	1.23	1.96	22%	1.22	1.99	23%	1.28	1.41
2019	13%	1.02	1.29	17%	1.09	1.49	20%	1.22	2.21	21%	1.18	2.01	NA	NA	NA
2020	13%	1.06	1.46	17%	1.14	1.68	20%	1.22	2.71	21%	1.12	1.89	NA	NA	NA
2021	12%	0.96	1.43	16%	1.00	1.51	21%	1.24	2.32	21%	1.14	1.93	NA	NA	NA
2022	12%	1.08	1.86	16%	1.16	1.95	22%	1.36	2.26	22%	1.26	2.14	NA	NA	NA
2023	12%	1.14	1.93	17%	1.22	1.95	24%	1.45	2.30	23%	1.32	2.32	NA	NA	NA
2024	13%	1.19	1.99	18%	1.25	1.99	26%	1.59	2.59	25%	1.43	2.65	NA	NA	NA
2025	14%	1.26	2.04	19%	1.32	2.10	30%	1.66	2.50	28%	1.51	2.53	NA	NA	NA
2026	15%	1.28	2.36	21%	1.29	2.20	34%	1.79	2.81	31%	1.62	2.86	NA	NA	NA
2027	17%	1.26	2.32	23%	1.35	2.34	38%	1.90	2.95	35%	1.75	2.97	NA	NA	NA
2028	19%	1.33	2.57	25%	1.43	2.56	43%	2.05	3.19	40%	1.90	3.07	NA	NA	NA
2029	21%	1.38	2.59	28%	1.51	2.60	49%	2.22	3.19	NA	NA	NA	NA	NA	NA
2030	23%	1.46	2.65	30%	1.59	2.65	NA	NA	NA	NA	NA	NA	NA	NA	NA
2031	26%	1.49	3.34	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2032	29%	1.63	3.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA


Proposed Electric Equity Ratios
MH11-2
MH10-2
MH09-1
MH08-1
MH07-1
60%
50%
40%
30%
20%
10%
0%
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032



Projected Electric Interest Coverage Ratios
MH11-2
MH10-2
MH09-1
MH08-1
MH07-1
2.50
2.00
1.50
1.00
0.50
-
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032


Projected Electric Capital Coverage Ratios
MH11-2
MH10-2
MH09-1
MH08-1
MH07-1
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
-
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032

PUB/MH I-30 (Revised)

Reference: Tab 4 Pages 7-9 , Financial Target Comparison

c) Please provide the supporting definition /formula/calculations for the determination of each of the ratios for electric operations for the years 2004/05 through 2013/14.

ANSWER:

Please see the following tables.

Debt Ratio
Manitoba Hydro (Electric only)
($ millions)

	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**(J-K+L-M) / (D+G+H+I+J-K+L-M)**
				(A-B-C)			**(E-F)**							
Fiscal Year Ended	Retained Earnings Consolidated	Retained Earnings Gas	Retained Earnings Subs	Retained Earnings	Unamortized Customer Contributions Consolidated	Unamortized Customer Contributions Gas	Unamortized Customer Contributions	Accumulated Other Comprehensive Income	Non-Contolling Interest	Long-Term Debt	Sinking Fund Investment	Short-Term Debt	Short-Term Investments	Debt Ratio
2005	870	25	2	843	296	32	264			6 998	562	59	9	0.85
2006	1 285	20	3	1 262	297	32	265			7 048	555	-	119	0.81
2007	1 407	21	8	1 378	298	31	267		15	7 136	630	148	1	0.80
2008	1 822	27	11	1 784	300	31	269	305	24	7 336	718	-	133	0.73
2009	2 076	36	12	2 028	296	30	266	(169)	39	7 953	666	100	159	0.77
2010	2 239	33	16	2 190	295	32	263	285	62	8 241	822	-	174	0.72
2011	2 389	40	21	2 328	295	33	262	367	87	8 350	282	-	70	0.72
2012	2 450	34	26	2 390	318	33	285	327	100	9 084	372	-	50	0.74
2013				2 411			328	302		9 942	327	86		0.76
2014				2 203			341	(79)		10 768	137	148		0.81

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

	a	b	c	d	e	f	g	
Fiscal Year Ended	MHEB Long-Term Debt	Gas Long-Term Debt	(a-b) Long-Term Debt	Write up/down to Sinking Fund	MHEB Current portion Long-Term Debt	Gas Current portion Long-Term Debt	(e-f) Current portion Long-Term Debt	(c+d+g) Long-Term Debt
2005	7 048	248	6 800	45	156	3	153	6 998
2006	7 051	190	6 861	127	118	58	60	7 048
2007	6 822	208	6 614	149	405	32	373	7 136
2008	7 218	233	6 985	-	353	2	351	7 336
2009	7 668	141	7 527	-	519	93	426	7 953
2010	8 228	297	7 931	-	310	-	310	8 241
2011	8 617	297	8 320	-	30	-	30	8 350
2012	9 101	235	8 866	-	281	63	218	9 084
2013	9 469	335	9 134		808	-	808	9 942
2014	10 909	325	10 584		214	30	184	10 768

Interest Coverage
Electric
($ millions)

	A	B	C	D	E	F	G	H	I	
				A-B-C				**E-F-G**		**(D+H+I)/(H+I)**
Fiscal Year Ended	Consolidated Net Income	Gas Net Income	Subs Net Income	**Electric Net Income**	Consolidated Finance Expense	Gas Finance Expense	Gas Corporate Allocation	**Electric Finance Expense**	**Electric Capitalized Interest**	**Electric Interest Coverage**
2005	136	(2)	1	**137**	502	17	12	**473**	**33**	**1.27**
2006	415	(5)	-	**420**	503	18	12	**473**	**34**	**1.83**
2007	122	1	2	**119**	506	22	12	**472**	**40**	**1.23**
2008	346	6	3	**337**	440	22	12	**406**	**59**	**1.72**
2009	266	9	1	**256**	471	20	12	**439**	**75**	**1.50**
2010	163	(1)	4	**160**	410	19	12	**379**	**102**	**1.33**
2011	150	7	5	**138**	425	18	12	**395**	**139**	**1.26**
2012	61	(6)	5	**62**	423	19	12	**392**	**171**	**1.11**
2013				**20**				**440**	**145**	**1.03**
2014				**68**				**452**	**178**	**1.11**

Capital Coverage Ratio
Excluding Major Generation
Electric
($ millions)

Fiscal Year Ended	A Consolidated Funds from Operations	B Gas Funds from Operations	**C A-B Electric Funds from Operations**	D Consolidated Capital Expenditures	E Gas Capital Expenditures	**F D-E Electric Capital Expenditures**	**C/F Electric Capital Coverage**
2005	433	27	**406**	360	23	**337**	**1.20**
2006	710	(2)	**712**	310	27	**283**	**2.52**
2007	443	22	**421**	405	29	**376**	**1.12**
2008	633	34	**599**	391	28	**363**	**1.65**
2009	688	35	**653**	388	30	**358**	**1.82**
2010	589	61	**528**	439	25	**414**	**1.28**
2011	595	45	**550**	477	27	**450**	**1.22**
2012	567	49	**518**	503	31	**472**	**1.10**
2013			**439**			**412**	**1.07**
2014			**444**			**394**	**1.13**

PUB/MH I-30

Reference: Tab 4 Pages 7-9 , Financial Target Comparison

d) Provide a comparison between the each of the financial targets, equity ratio, capital coverage ratio and interest coverage ratio with actual and forecast results for the years 2004/05 through 2013/14.

ANSWER:

Please see the following table.

Manitoba Hydro (Electric only)
Comparison of Actual to Forecast Ratios

		Debt Ratio	Capital Coverage Ratio	Interest Coverage Ratio
2008	Actual	0.73	1.65	1.72
	IFF07	0.77	1.77	1.56
2009	Actual	0.77	1.82	1.50
	IFF08	0.74	1.90	1.64
2010	Actual	0.72	1.28	1.33
	IFF09	0.74	1.39	1.24
2011	Actual	0.72	1.22	1.26
	IFF10-2	0.74	1.56	1.28
2012	Actual	0.74	1.10	1.11
	IFF11-2	0.74	1.04	1.12

PUB/MH I-30

Reference: Tab 4 Pages 7-9 , Financial Target Comparison

e) Please indicate the impact on the financial targets if rate regulated accounting were to be continued in 2013/14 for rate-setting purposes.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-78(b).

PUB/MH I-31

Reference: Tab 4 Page 6 of 9 Revenue reduction

MH has attributed the reduction in revenues to lower export revenue and other factors in IFF11-2 vs. IFF10-2. Please provide a detailed breakdown of the reduction in revenue in each of the years of the comparative forecasts attributed to each of the specific factor cited.

ANSWER:

The following table shows the change in net extraprovincial revenues between IFF11-2 and IFF10-2 due to price, volume, foreign exchange and other non-volume related variances. A further breakdown of the volume variance is not available as commercially sensitive information related to firm contract prices could be revealed and it is technically difficult to isolate the impacts of factors that are interdependent system assumptions.

Net Extraprovincial Revenue Price Volume Analysis
IFF11-2 to IFF10-2

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Price Variance	(113)	(108)	(97)	(74)	(85)	(66)	(51)	(39)	(73)	(91)	(65)
Volume Variance	75	(50)	(16)	(16)	(4)	4	(11)	(10)	(29)	15	(24)
Foreign Exchange Variance	(10)	(8)	(14)	(10)	(16)	(17)	(17)	(18)	(20)	(30)	(34)
Other Non-Volume Related Variance *	(12)	20	25	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Total Variance	(61)	(146)	(103)	(106)	(110)	(85)	(84)	(73)	(127)	(111)	(129)

	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	TOTAL
Price Variance	(41)	(21)	11	(73)	(110)	(120)	(135)	(143)	(191)	(201)	(1,886)
Volume Variance	(61)	(242)	(436)	(178)	(68)	(51)	(58)	(54)	(33)	(31)	(1,278)
Foreign Exchange Variance	(34)	(34)	(43)	(56)	(60)	(60)	(60)	(59)	(60)	(60)	(722)
Other Non-Volume Related Variance *	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(69)
Total Variance	(142)	(302)	(475)	(314)	(244)	(238)	(258)	(262)	(289)	(297)	(3,955)

* The Non-Volume Related Variances contain the differences due to transmission credits and charges, system merchant sales and purchases, forecast adjustments relating to short-term variability in export prices and volumes and various other costs and revenues not associated with volumes.

PUB/MH I-32

Reference: IFF11-1 Page 16 – Risk

a) Please restate the risk table on a consistent basis as that provide in IFF09

ANSWER:

Please see attached schedule.

Risk Analysis Comparison

	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)									Incremental Annual Electric Rate Increase/(Decrease) *		
	Year 3			Year 7			Year 11					
	IFF11-2	IFF10-2	IFF09-1	IFF11-2	IFF10-2	IFF09-1	IFF11-2	IFF10-2	IFF09-1	IFF11-2	IFF10-2	IFF09-1
+ 1% Interest Rates	3	5	26	(116)	(66)	(14)	(724)	(488)	(279)	0.91%	0.51%	0.23%
- 1% Interest Rates	(2)	(5)	(24)	113	63	13	671	458	254	-0.90%	-0.52%	-0.23%
US $ up $0.10	(7)	26	33	(12)	51	142	64	134	358	-0.08%	-0.15%	-0.34%
US $ down $0.10	8	(26)	(26)	10	(43)	(115)	(73)	(112)	(286)	0.10%	0.13%	0.27%
Low Export Prices	1	(42)	(54)	(184)	(268)	(363)	(684)	(624)	(920)	0.89%	0.67%	1.05%
High Export Prices	20	61	113	129	548	712	401	1,485	1,713	-0.53%	-1.72%	-2.10%
5 Year Drought (starting in Year 3)	N/A	N/A	N/A	(1,570)	(2,107)	(2,405)	N/A	N/A	N/A	2.53%	2.83%	3.37%
Capital Expenditures +$100M per year	(11)	(13)	N/A	(165)	(179)	N/A	(551)	(566)	N/A	0.65%	0.58%	N/A
High Domestic Load Growth	7	(3)	13	10	(43)	(3)	(119)	(281)	(9)	0.15%	0.30%	0.01%

* The rate increases represent the additional identical annual percentage (incremental to the base case annual rate increases) required to achieve the same level of retained earnings in year 11 as in the base MH11.

<u>Changes in impacts from forecast to forecast:</u>

Interest rate sensitivities	IFF10 & IFF11-2 sensitivites included impacts on fixed & floating rate debt. IFF09 included impacts on fixed rate debt only. Increases in borrowing requirements due to lower export revenues in IFF10 & IFF11 base case results in incremental interest rates being applied to greater volume of debt.
US exchange sensitivities	IFF09 forecast Canadian denominated debt issues only. IFF10 & IFF11-2 forecast both Canadian & US denominated debt more closely simulating practise under the Exposure Management Program and reducing the potential impact.
Export price sensitivities	The dispersion of the low & high electricity export price forecasts from the expected price forecast have also decreased as result of the forecast export prices decreasing from forecast to forecast.
5 Year Drought	Costs of power purchases and thermal generation required to meet firm demand are lower due to lower forecast electricity export and fossil fuel prices.
Capital Expenditures	Minimal change in impacts.
Medium High Electric Load Forecast	IFF10 & IFF11-2 sensitivites included costs related to incremental gas turbines required for the increased domestic load. IFF09 did not include incremental gas turbines. The impact decreased from IFF10 to IFF11 due to the decrease thermal fuel costs.

PUB/MH I-32

Reference: IFF11-1 Page 16 – Risk

b) Please provide a comparison between the risk exposure impacts identified in IFF09 with that now identified in IFF11 and explain the changes from the IFF09 forecast.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-32(a).

PUB/MH I-32

Reference: IFF11-1 Page 16 – Risk

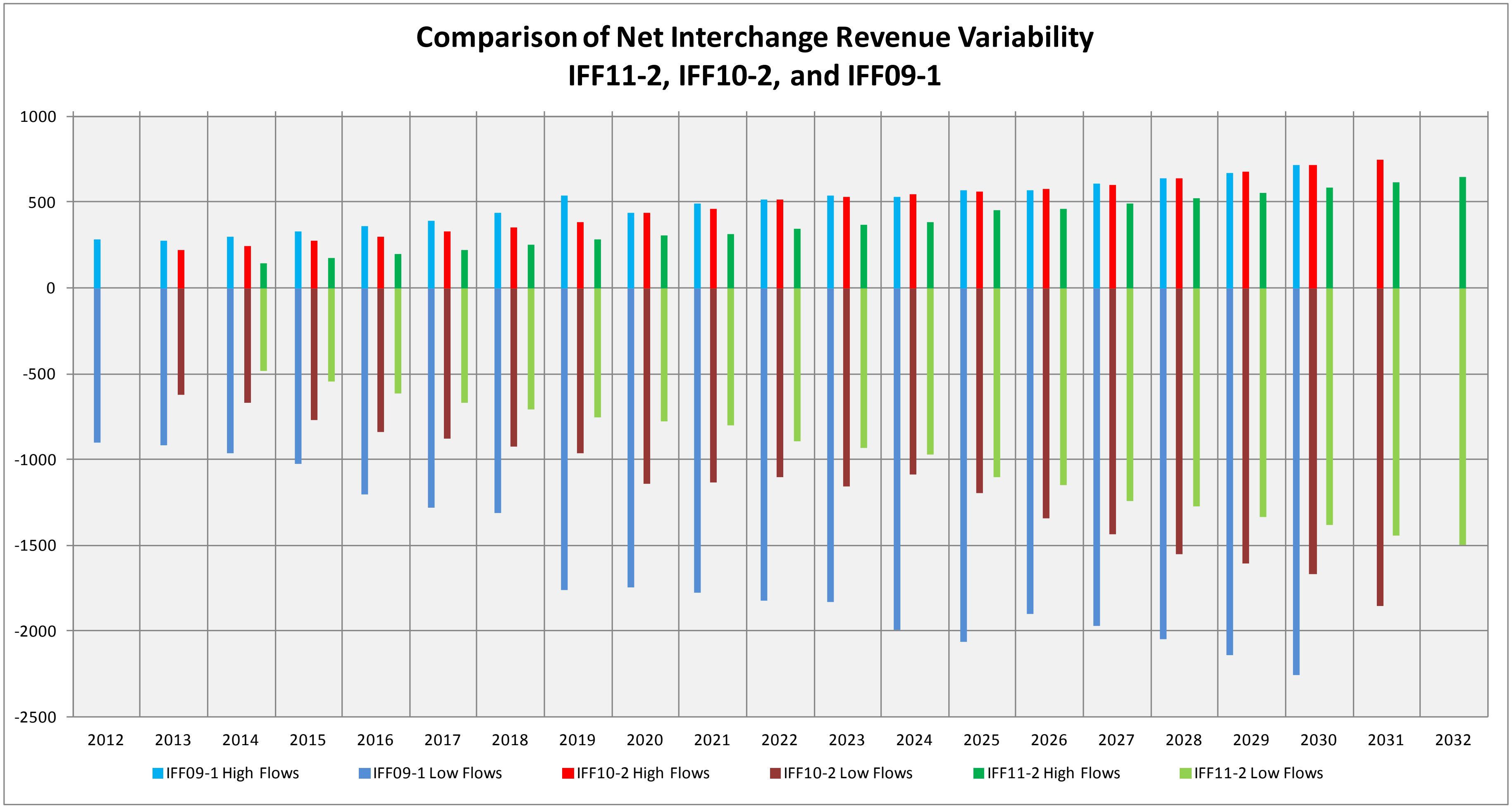
c) Please provide a comparative chart and table of data points of the variability of net interchange revenue reflected in IFF11-2 with that in IFF09

ANSWER:

Please see attached charts.

Comparison of Net Interchange Revenue Variability

	High Flows				Low Flows		
	IFF09-1	**IFF10-2**	**IFF11-2**		**IFF09-1**	**IFF10-2**	**IFF11-2**
2012	282			**2012**	(901)		
2013	279	220		**2013**	(915)	(623)	
2014	299	241	142	**2014**	(962)	(668)	(484)
2015	328	276	174	**2015**	(1,027)	(767)	(549)
2016	359	302	195	**2016**	(1,204)	(841)	(616)
2017	392	330	222	**2017**	(1,284)	(881)	(669)
2018	435	356	256	**2018**	(1,312)	(924)	(710)
2019	542	381	284	**2019**	(1,763)	(967)	(755)
2020	439	435	304	**2020**	(1,744)	(1,143)	(778)
2021	490	458	314	**2021**	(1,777)	(1,133)	(798)
2022	519	513	346	**2022**	(1,826)	(1,099)	(892)
2023	535	530	366	**2023**	(1,827)	(1,154)	(930)
2024	534	543	386	**2024**	(1,996)	(1,090)	(971)
2025	568	559	457	**2025**	(2,059)	(1,196)	(1,101)
2026	570	581	462	**2026**	(1,900)	(1,344)	(1,147)
2027	607	603	489	**2027**	(1,967)	(1,439)	(1,243)
2028	640	640	522	**2028**	(2,048)	(1,552)	(1,275)
2029	674	679	554	**2029**	(2,143)	(1,603)	(1,332)
2030	715	720	586	**2030**	(2,258)	(1,668)	(1,379)
2031		748	616	**2031**		(1,854)	(1,441)
2032			647	**2032**			(1,501)


Comparison of Net Interchange Revenue Variability
IFF11-2, IFF10-2, and IFF09-1
1000
500
0
-500
-1000
-1500
-2000
-2500
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
IFF09-1 High Flows
IFF09-1 Low Flows
IFF10-2 High Flows
IFF10-2 Low Flows
IFF11-2 High Flows
IFF11-2 Low Flows

PUB/MH I-32

Reference: IFF11-1 Page 16 – Risk

d) Provide a similar analysis in a, b, and c comparing IFF11-2 with IFF10.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-32(a) and (c).

PUB/MH I-33

Reference: IFF11-1 Page 16 – Risk- Adequate Retained Earnings

In IFF10 the Corporation stated that "from a financial perspective, Manitoba Hydro's best risk protection is achieved through adequate levels of equity [retained earnings]. Equity provides a buffer to absorb adverse events so that any compensating rate increases can be smoothed out over a period of time."

Please comment on the changed equity position from IFF 09 and indicate whether MH's current financial position provides adequate retained earnings to offset adverse risks.

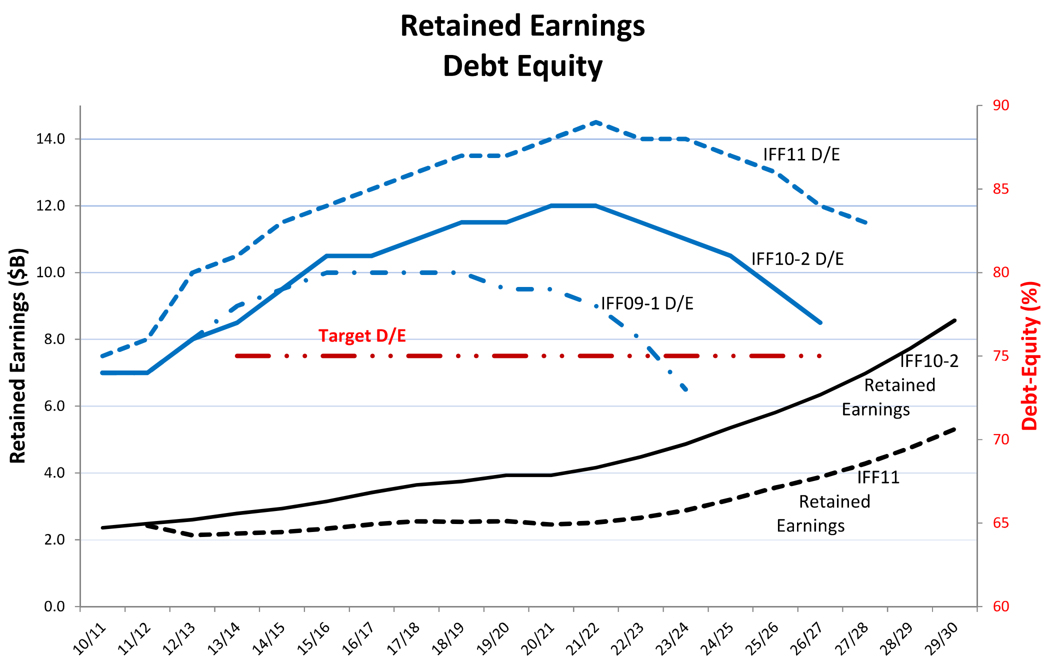
ANSWER:

Since March 31, 2009 actual consolidated retained earnings have increased by $374 million to 2011/12 which is approximately $50 million greater than what was projected in IFF09. Retained earnings were then projected to rise to $4.1 billion by 2019/20 in IFF09. In IFF11-2, retained earnings are now projected to rise to only $2.8 billion over the same period. The deterioration in projected retained earnings over this period can mainly be attributed to lower projected export prices.

Among the number of risks facing the Corporation, drought continues to be a major risk. The forecast of extraprovincial revenues incorporates average revenues from historical water flows over close to the past 100 years, therefore, drought risk is reflected in the base IFF11-2 financial projections. Of course, the specific timing of a drought is unknown, and should the Corporation experience a repeat of the worst drought on record, the impact on retained earnings could exceed $1.6 billion as shown in IFF11-2 drought risk sensitivity (Appendix 4.2, Page 16). Retained earnings under the base forecast are projected to be $1.2 billion greater than the estimated impact of the drought. Manitoba Hydro also requires retained earnings to cover numerous other risks that it is exposed to. As such, it is important that Manitoba Hydro continue to maintain an adequate level of retained earnings and that rates be raised gradually even during years of exceptional water flows in order to ensure that customers continue to have stable rates in the future.

PUB/MH I-34

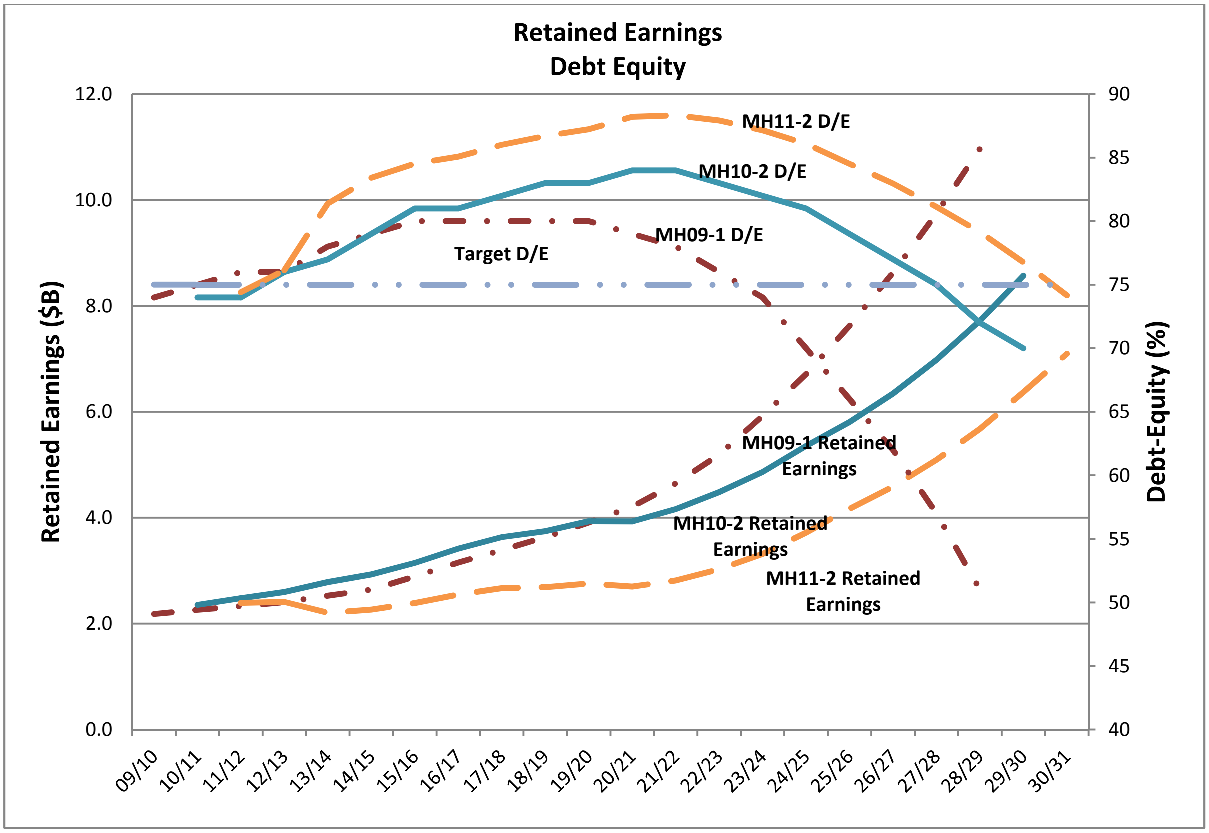
Reference: Debt to Equity Targets IFF09-1, IFF10-2 and IFF11-2



a) **Please provide a graphic illustration and comparative table (as per example graphic above) of MH's recent electric retained earnings and debt to equity forecast comparing IFF09-1, IFF10-2 and IFF11-2.**

ANSWER:

Please see the following table.


Retained Earnings
Debt Equity
Retained Earnings ($B)
Debt-Equity (%)
12.0
10.0
8.0
6.0
4.0
2.0
0.0
90
85
80
75
70
65
60
55
50
45
40
09/10
10/11
11/12
12/13
13/14
14/15
15/16
16/17
17/18
18/19
19/20
20/21
21/22
22/23
23/24
24/25
25/26
26/27
27/28
28/29
29/30
30/31
MH11-2 D/E
MH10-2 D/E
MH09-1 D/E
Target D/E
MH09-1 Retained Earnings
MH10-2 Retained Earnings
MH11-2 Retained Earnings

PUB/MH I-34

Reference: Debt to Equity Targets IFF09-1, IFF10-2 and IFF11-2

b) Please confirm MH's debt to equity electric objectives in IFF11-2 appear to be:

2011/12	**75:25**
2014/15	**85:15**
2020/21	**90/10**
2025/26	**88:12**
2030/31	**80:20**

ANSWER:

Manitoba Hydro's current debt to equity target is to maintain a minimum of 75:25, except during years of major investment in generation and transmission system. The amounts that are forecast for the debt to equity ratio in IFF11-2 are an outcome of the forecast for each respective year and indicates the deviation from long-term targets.

PUB/MH I-34

Reference: Debt to Equity Targets IFF09-1, IFF10-2 and IFF11-2

c) Please provide a revised IFF11 that includes higher annual equal rate increases (>3.5%) to achieve D/E ratios as follows:

2014/15	**80:20**
2020/21	**80/20**
2025/26	**80:20**
2030/31	**75:25**

ANSWER:

Please see the attached projected financial statements for the requested rate scenario.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
PUB/MH I-34 (C) - Achieve 80:20 DE in 2014/15, 2020/21, 2025/26, and 75:25 in 2030/31
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 186	1 290	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	45	258	493	496	503	512	517	526	535	523
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 693	1 931	2 210	2 295	2 353	2 410	2 450	2 537	2 776	2 876
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	448	488	499	511	561	668	693	1 026	982
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 672	1 705	1 794	1 843	1 893	2 022	2 205	2 283	2 702	2 706
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	225	415	450	457	386	243	251	71	160
Other Comprehensive Income	(18)	(33)	(15)	(142)	(53)	(18)	(27)	(15)	(16)	(18)	(22)
Comprehensive Income	46	(14)	210	272	397	438	359	227	235	53	137
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	14.80%	14.80%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	-0.99%
Cumulative Percent Increase	0.00%	4.50%	19.97%	37.73%	37.79%	37.86%	37.93%	37.99%	38.06%	38.13%	36.76%
Financial Ratios											
Equity	26%	24%	20%	20%	21%	21%	21%	21%	21%	20%	20%
Interest Coverage	1.12	1.03	1.36	1.58	1.58	1.52	1.40	1.23	1.22	1.05	1.13
Capital Coverage	1.04	1.07	1.51	2.06	2.30	2.33	2.17	1.87	1.93	1.78	2.00

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
PUB/MH I-34 (C) - Achieve 80:20 DE in 2014/15, 2020/21, 2025/26, and 75:25 in 2030/31
(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*	510	497	484	471	554	641	734	832	936	999
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
Other	19	20	20	20	21	21	22	22	23	23
	2 901	2 923	3 107	3 397	3 621	3 748	3 857	3 980	4 124	4 218
EXPENSES										
Operating and Administrative	634	646	669	676	688	700	713	727	741	755
Finance Expense	963	956	1 060	1 301	1 471	1 458	1 437	1 406	1 436	1 350
Depreciation and Amortization	579	583	615	682	733	741	753	761	793	814
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	156	158	160	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2 722	2 767	2 920	3 248	3 508	3 536	3 554	3 562	3 653	3 616
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	168	145	176	138	101	199	290	405	458	588
Other Comprehensive Income	(13)	0	0	0	-	-	-	-	-	-
Comprehensive Income	155	145	176	138	101	199	290	405	458	588
* Additional General Consumers Revenue										
Percent Increase	-0.99%	-0.99%	-0.99%	-0.99%	3.81%	3.81%	3.81%	3.81%	3.81%	2.00%
Cumulative Percent Increase	35.40%	34.06%	32.73%	31.42%	36.42%	41.62%	47.01%	52.61%	58.42%	61.59%
Financial Ratios										
Equity	20%	20%	20%	20%	20%	21%	22%	23%	25%	27%
Interest Coverage	1.13	1.10	1.12	1.09	1.07	1.13	1.19	1.27	1.31	1.42
Capital Coverage	1.81	1.69	1.63	1.73	1.72	1.97	2.04	2.15	2.79	2.50

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
PUB/MH I-34 (C) - Achieve 80:20 DE in 2014/15, 2020/21, 2025/26, and 75:25 in 2030/31
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS											
Plant in Service	13 795	15 212	15 723	16 485	17 410	17 993	21 415	21 904	25 521	28 275	28 636
Accumulated Depreciation	(4 917)	(5 266)	(5 581)	(5 911)	(6 272)	(6 638)	(7 065)	(7 539)	(8 028)	(8 583)	(9 165)
Net Plant in Service	8 878	9 947	10 142	10 574	11 138	11 355	14 351	14 365	17 492	19 692	19 472
Construction in Progress	2 443	2 196	3 149	3 997	5 014	6 410	5 346	6 447	4 558	3 595	4 964
Current and Other Assets	1 906	1 864	1 327	1 371	1 559	1 736	1 987	1 769	1 951	2 086	2 219
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	241	-	-	-	-	-	-	-	-	-
	13 648	14 426	14 780	16 091	17 847	19 627	21 800	22 691	24 105	25 470	26 747
LIABILITIES AND EQUITY											
Long-Term Debt	9 253	9 469	10 709	11 782	13 003	14 074	15 639	16 932	17 693	19 004	20 648
Current and Other Liabilities	1 351	1 917	1 451	1 409	1 539	1 799	2 038	1 399	1 806	1 797	1 282
Contributions in Aid of Construction	317	328	341	348	355	365	376	386	396	407	418
Retained Earnings	2 391	2 411	2 359	2 774	3 224	3 681	4 067	4 310	4 561	4 632	4 792
Accumulated Other Comprehensive Income	335	302	(79)	(222)	(275)	(293)	(320)	(336)	(352)	(370)	(392)
	13 648	14 426	14 780	16 091	17 847	19 627	21 800	22 691	24 105	25 470	26 747

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
PUB/MH I-34 (C) - Achieve 80:20 DE in 2014/15, 2020/21, 2025/26, and 75:25 in 2030/31
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
ASSETS										
Plant in Service	29 045	29 610	34 023	38 098	39 357	39 988	40 557	41 087	43 107	43 823
Accumulated Depreciation	(9 752)	(10 344)	(10 970)	(11 663)	(12 407)	(13 160)	(13 926)	(14 701)	(15 509)	(16 338)
Net Plant in Service	19 293	19 267	23 053	26 435	26 951	26 828	26 631	26 386	27 599	27 485
Construction in Progress	6 099	6 969	4 170	1 022	545	786	1 259	1 722	618	758
Current and Other Assets	2 074	2 204	2 622	2 489	2 770	3 069	3 240	3 393	3 887	4 254
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27 557	28 529	29 933	30 033	30 350	30 766	31 212	31 582	32 185	32 577
LIABILITIES AND EQUITY										
Long-Term Debt	21 451	22 253	23 006	23 409	23 610	23 752	23 703	23 805	23 794	22 766
Current and Other Liabilities	1 123	1 136	1 600	1 147	1 150	1 213	1 406	1 257	1 399	2 219
Contributions in Aid of Construction	429	440	451	463	475	487	499	512	525	538
Retained Earnings	4 960	5 105	5 281	5 419	5 520	5 719	6 009	6 414	6 872	7 459
Accumulated Other Comprehensive Income	(405)	(405)	(405)	(405)	(405)	(405)	(405)	(405)	(405)	(405)
	27 557	28 529	29 933	30 033	30 350	30 766	31 212	31 582	32 185	32 577

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
PUB/MH I-34 (C) - Achieve 80:20 DE in 2014/15, 2020/21, 2025/26, and 75:25 in 2030/31
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 556	1 693	1 931	2 210	2 295	2 353	2 410	2 450	2 537	2 776	2 876
Cash Paid to Suppliers and Employees	(742)	(816)	(886)	(931)	(951)	(976)	(1 018)	(1 048)	(1 084)	(1 103)	(1 125)
Interest Paid	(406)	(466)	(475)	(501)	(534)	(543)	(607)	(719)	(728)	(1 068)	(1 015)
Interest Received	26	28	27	20	27	34	41	43	39	36	35
	434	439	597	799	836	868	826	727	763	642	772
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	900	1 430	1 205	1 590	1 600	2 390	1 600	1 390	1 990	1 790
Sinking Fund Withdrawals	23	129	395	105	22	-	-	424	163	265	689
Retirement of Long-Term Debt	(25)	(119)	(808)	(179)	(312)	(408)	(530)	(837)	(309)	(640)	(692)
Other	(81)	(21)	(14)	(5)	(7)	(7)	(7)	(16)	(5)	26	(6)
	729	889	1 003	1 126	1 293	1 185	1 853	1 171	1 239	1 641	1 781
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1 163)	(1 226)	(1 481)	(1 616)	(1 934)	(1 986)	(2 336)	(1 567)	(1 820)	(1 856)	(1 697)
Sinking Fund Payment	(98)	(117)	(208)	(123)	(192)	(153)	(231)	(196)	(219)	(288)	(346)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1 280)	(1 363)	(1 709)	(1 759)	(2 146)	(2 184)	(2 603)	(1 793)	(2 069)	(2 179)	(2 083)
Net Increase (Decrease) in Cash	(116)	(36)	(109)	166	(16)	(131)	75	105	(67)	104	470
Cash at Beginning of Year	66	(50)	(86)	(195)	(29)	(45)	(176)	(101)	4	(63)	41
Cash at End of Year	(50)	(86)	(195)	(29)	(45)	(176)	(101)	4	(63)	41	511

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
PUB/MH I-34 (C) - Achieve 80:20 DE in 2014/15, 2020/21, 2025/26, and 75:25 in 2030/31
(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	2 901	2 923	3 107	3 397	3 621	3 748	3 857	3 980	4 124	4 218
Cash Paid to Suppliers and Employees	(1 154)	(1 201)	(1 215)	(1 234)	(1 272)	(1 303)	(1 329)	(1 357)	(1 383)	(1 410)
Interest Paid	(990)	(960)	(1 072)	(1 334)	(1 502)	(1 500)	(1 491)	(1 464)	(1 475)	(1 432)
Interest Received	20	21	30	34	37	47	58	62	69	81
	777	783	850	863	883	992	1 095	1 221	1 335	1 458
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	780	790	1 190	390	190	200	190	190	170	(10)
Sinking Fund Withdrawals	159	-	-	346	-	-	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)
	773	784	1 184	278	182	193	183	214	66	(229)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 510)	(1 401)	(1 578)	(891)	(746)	(834)	(1 003)	(953)	(876)	(814)
Sinking Fund Payment	(218)	(226)	(244)	(264)	(261)	(273)	(286)	(297)	(297)	(310)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1 757)	(1 657)	(1 850)	(1 183)	(1 037)	(1 135)	(1 318)	(1 279)	(1 202)	(1 154)
Net Increase (Decrease) in Cash	(207)	(90)	185	(42)	29	49	(39)	155	199	75
Cash at Beginning of Year	511	304	214	398	356	385	435	395	550	749
Cash at End of Year	304	214	398	356	385	435	395	550	749	824

PUB/MH I-34

Reference: Debt to Equity Targets IFF09-1, IFF10-2 and IFF11-2

d) Please provide the Corporation's new target time frame for meeting the 75:25 debts to equity ratio.

ANSWER:

The Corporation's debt/equity target has not changed since 2009, and as noted in PUB/MH I-34(b), is to maintain a minimum of 75:25, except during years of major investment in generation and transmission system. Although IFF11-2 indicates a deterioration from the target commencing in 2013/14 and projects that the target will not be obtained until 2030/31, the Corporation will do everything in its capability to maintain as close to the target as possible.

PUB/MH I-34

Reference: Debt to Equity Targets IFF09-1, IFF10-2 and IFF11-2

e) Please confirm that IFF11-2 export revenues out to 2020/21 are not achievable if natural gas prices remain in the $5/GJ ranges; in turn necessitating even higher rate increases.

ANSWER:

Manitoba Hydro's IFF11-2 is based on a significant number of projections and future expectations, including but not limited to water conditions, Manitoba load growth, economic growth, natural gas prices, coal prices, export electricity market prices, Canada-US exchanges rates, inflation rates and interest rates. To the extent any these projections and future expectations vary, there could be an impact on Manitoba Hydro's financial results which could, in turn, require rate increases higher or lower than that currently projected.

PUB/MH I-34

Reference: Debt to Equity Targets IFF09-1, IFF10-2 and IFF11-2

f) Please provide a revised IFF11 reflecting no further expenditures on Conawapa, Keeyask and Bipole 3 for five years and the reflective debt to equity ratios

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-25(c).

PUB/MH I-34

Reference: Debt to Equity Targets IFF09-1, IFF10-2 and IFF11-2

g) Please provide an updated IFF11-2 scenario assuming a further 20% capital cost escalation to construct Keeyask, Conawapa and Bipole III from current capital cost estimates.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-25(c).

PUB/MH I-34

Reference: Debt to Equity Targets IFF09-1, IFF10-2 and IFF11-2

h) Please file an IFF11-2 scenario similar to part (c) reflecting the higher capital costs requested in (g).

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-25(c).

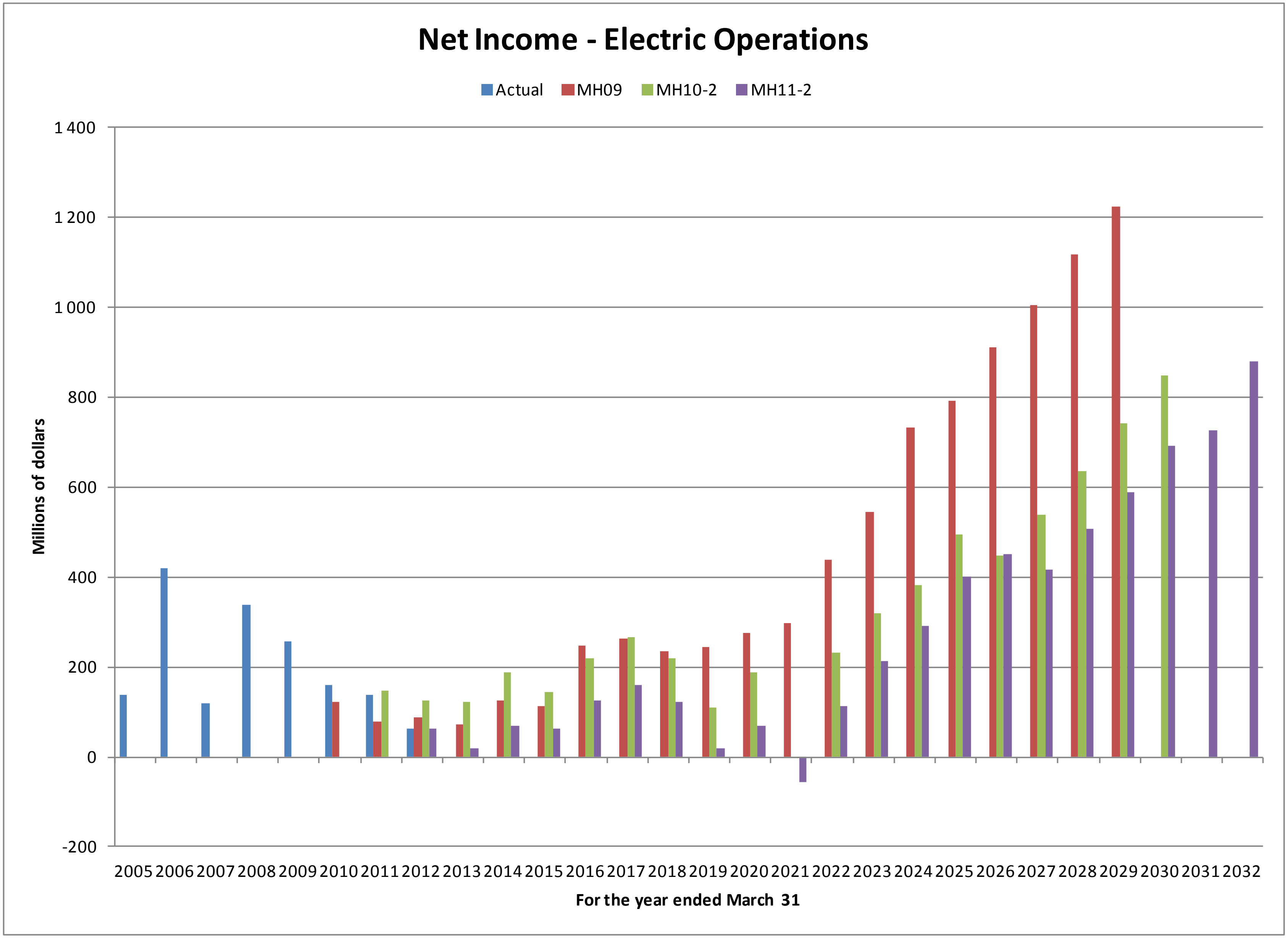
PUB/MH I-35 (Revised)

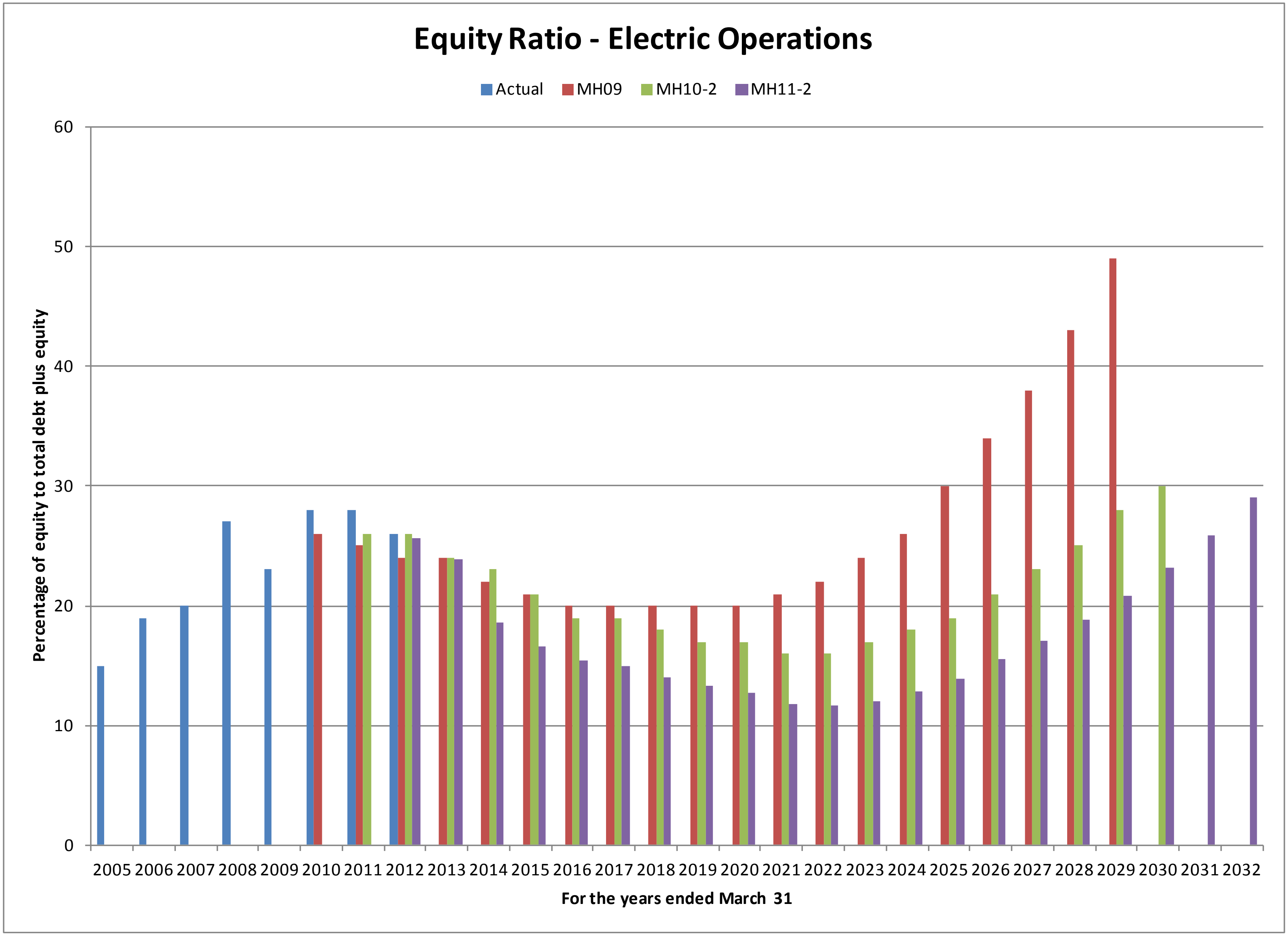
Reference: Appendix 4.2, 2012 Annual Report & 2011 Annual Report, Page 10

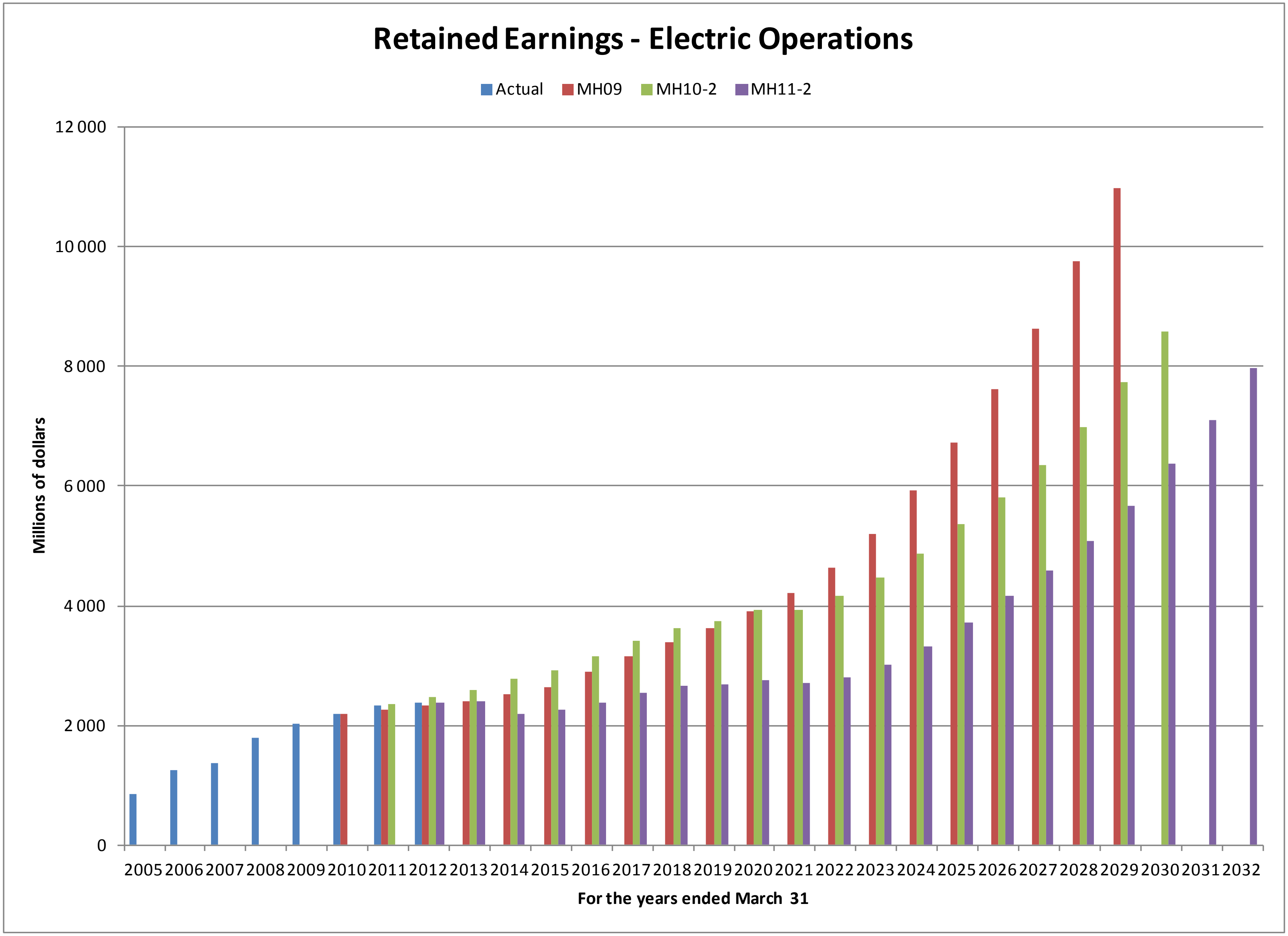
a) Please provide the charts on page 10 for the years 2004 to 2032 for actual/forecast net income, equity ratio and retained earnings (electric only) including forecasts based on IFF09, IFF10 and IFF11-2

ANSWER:

Please see the charts below.


Net Income - Electric Operations
Actual
MH09
MH10-2
MH11-2
1 400
1 200
1 000
800
600
400
200
0
-200
Millions of dollars
2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032
For the year ended March 31


Equity Ratio - Electric Operations
Actual
MH09
MH10-2
MH11-2
Percentage of equity to total debt plus equity
0
10
20
30
40
50
60
2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032
For the years ended March 31


Retained Earnings - Electric Operations
Actual
MH09
MH10-2
MH11-2
12 000
10 000
8 000
6 000
4 000
2 000
0
Millions of dollars
2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032
For the years ended March 31

PUB/MH I-35

Reference: Appendix 4.2, 2012 Annual Report & 2011 Annual Report, Page 10

b) Please provide a schedule detailing the supporting calculations for the data points determined.

ANSWER:

Please see the attached tables.

Net Income - Electric Operations
($Millions)

Fiscal Year Ending	Actual	MH09	MH10-2	MH11-2
2008	337			
2009	258			
2010	160	121		
2011	138	78	149	
2012	62	87	125	64
2013		72	121	20
2014		125	187	68
2015		113	145	62
2016		248	219	124
2017		263	267	159
2018		235	218	121
2019		244	111	18
2020		276	187	70
2021		299	(1)	(57)
2022		439	233	113
2023		544	319	213
2024		732	382	291
2025		791	493	402
2026		911	449	450
2027		1,005	538	415
2028		1,116	637	507
2029		1,224	741	588
2030			848	691
2031				726
2032				878

Equity Ratio - Electric Operations
(Percentage equity to total debt plus equity)

Fiscal Year Ending	Actual	MH09	MH10-2	MH11-2
2008	27			
2009	23			
2010	28	26		
2011	28	25	26	
2012	26	24	26	26
2013		24	24	24
2014		22	23	19
2015		21	21	17
2016		20	19	15
2017		20	19	15
2018		20	18	14
2019		20	17	13
2020		20	17	13
2021		21	16	12
2022		22	16	12
2023		24	17	12
2024		26	18	13
2025		30	19	14
2026		34	21	15
2027		38	23	17
2028		43	25	19
2029		49	28	21
2030			30	23
2031				26
2032				29

Retained Earnings - Electric Operations
($Millions)

Fiscal Year Ending	Actual	MH09	MH10-2	MH11-2
2008	1,784			
2009	2,028			
2010	2,190	2,183		
2011	2,328	2,261	2,355	
2012	2,390	2,331	2,480	2,391
2013		2,403	2,598	2,411
2014		2,528	2,784	2,203
2015		2,641	2,930	2,265
2016		2,889	3,148	2,389
2017		3,153	3,415	2,548
2018		3,388	3,634	2,669
2019		3,632	3,744	2,687
2020		3,908	3,931	2,757
2021		4,207	3,930	2,700
2022		4,645	4,163	2,814
2023		5,190	4,482	3,026
2024		5,922	4,864	3,317
2025		6,713	5,357	3,719
2026		7,623	5,806	4,170
2027		8,629	6,344	4,584
2028		9,745	6,981	5,092
2029		10,969	7,722	5,679
2030			8,570	6,370
2031				7,096
2032				7,974

PUB/MH I-36

Reference: Appendix 5.6 Page 2 Aging infrastructure

a) Please discuss the corporation's experience relative to target for system average interruption duration and frequency. Provide specific results for the last five years.

ANSWER:

The System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) statistics are provided below.

Year	**SAIFI**	**SAIDI**	**SAIDI (Minutes)**
*2012/13**	*0.96*	*1.56*	*93.74*
2011/12	1.70	2.41	144.44
2010/11	1.35	2.08	125.03
2009/10	1.42	1.88	112.81
2008/09	1.39	1.69	101.33
2007/08	1.24	1.87	112.07

* Reporting period for the 2012/13 year-to-date: April 1, 2012 - August 31, 2012.

Manitoba Hydro's target for SAIDI of 92 minutes and SAIFI of 1.3 were established in 1999 and did not change until the 2012/2013 fiscal year. For 2012/13 the targets for SAIDI and SAIFI have been revised to 113 minutes for SAIDI and 1.4 for SAIFI, representing the best performing utility in the Canadian Electric Association based on a 5 year average.

Equipment failures, adverse weather, and tree contact remain three of the leading causes of outages on the transmission and distribution systems. The two outages with the highest customer minutes for each year are detailed below.

<u>2012/2013</u>

August 9, 2012 – A fault occurred at the East Selkirk station damaging both banks and requiring a mobile substation to be installed. In total 2,045 customer interruptions and 1,881,400 customer minutes were associated with the outage.

August 15, 2012 – A 66 kV line was forced out of service due to broken x-arms on two structures in the Powerview District. In total 1,417 customer interruptions and 1,798,221 customer minutes were associated with the outage.

<u>2011/2012</u>

September 9, 2011 – A 69 kV current transformer associated with a line at Rover station failed resulting in outages to several stations in Winnipeg (Martin, Alfred, Charles, Boyd, and Rover). In total 20,786 customer interruptions and 1,974,670 customer minutes were associated with the outage.

July 17, 2011 – The Scotland station was de-energized for safety concerns due to loss of protection. In total 7,489 customer interruptions and 1,955,549 customer minutes were associated with the outage.

<u>2010/2011</u>

August 20, 2010 – A fallen tree on a 66 kV line damaged cross arms, insulators and conductor. In total 6,234 customers interruptions and 2,699,322 customer minutes were associated with the outage.

June 26, 2010 – A wind storm in the Steinbach area broke several poles and tripped the 66 kV line. In total 5,007 customer interruptions and 1,441,170 customer minutes were associated with the outage.

<u>2009/10</u>

May 13, 2009 – Lightning damaged a disconnect at Rosser Station resulting in outages at several stations in northwest Winnipeg. In total 47,401 customer interruptions and 3,096,359 customer minutes were associated with the outage.

June 27, 2009 – A major wind storm resulted in multiple outages on the Star Lake Feeder. In total 538 customer interruptions and 1,383,198 customer minutes were associated with the outage.

2008/09

August 31, 2008 – A cable failure occurred on Inkster feeder. In total 1,185 customer interruptions and 782,100 customer minutes were associated with the outage.

June 9, 2008 – A current transformer failure occurred at the Mystery Lake Station resulting in outages at several stations in northern Manitoba. In total 4,609 customer interruptions and 699,251 customer minutes were associated with the outage.

2007/08

May 18, 2007 – A lightning strike resulted in the tripping of two 66 kV lines resulting in outages at several stations in eastern Winnipeg. In total 25,336 customer interruptions and 2,278,493 customer minutes were associated with the outage.

April 22, 2007 – A scheduled outage was taken on a 66 kV line to complete the energization of a new circuit resulting in outages at several stations in the Interlake. In total 5,546 customer interruptions and 1,896,732 customer minutes were associated with the outage.

<u>PUB/MH I-36</u>

Reference: Appendix 5.6 Page 2 Aging infrastructure

b) Please advise on NERC reliability and security requirements for the Manitoba Hydro system including compliance with standards, and discuss regulatory and cost implications. Please include a list and description of all alleged non-compliance with standards including financial consequences.

<u>ANSWER</u>:

Manitoba Hydro has long been a supporter of mandatory reliability standards. Manitoba Hydro is a member of NERC, and member of the MRO (Midwest Reliability Organization, a NERC sub-region), and a strong participant in the North American electricity reliability arena. In particular, Manitoba Hydro is actively involved in the ongoing development of standards and criteria by NERC and the MRO, and involved in key committees of both organizations.

In 2004, Manitoba Order in Council 206/2004 authorized Manitoba Hydro to join the MRO and adopt NERC's reliability standards, except to the extent disallowed or suspended by the Lieutenant Governor in Council. In response to the North American industry initiative to make reliability standards subject to financial penalties, an Interim Agreement between Manitoba Hydro, NERC, and the MRO was established in 2008 for the monitoring and enforcement of Manitoba Hydro's compliance with electric reliability standards in Manitoba pending the enactment of legislation. Officials from the government of Manitoba and the Public Utilities Board (PUB) were consulted and supported this Interim Agreement. The interim process required the MRO and NERC to monitor Manitoba Hydro's compliance with NERC reliability standards and the PUB to decide whether a violation of a standard had taken place and the penalty, if any, which should apply for non-compliance. The PUB's jurisdiction with respect to standards violations under the Interim Agreement was authorized by Order in Council 68/2009.

On April 1, 2012, Manitoba Hydro and all other registered entities in Manitoba became legally obligated to comply with applicable NERC reliability standards with the enactment of *The Manitoba Hydro Amendment and Public Utilities Board Amendment Act* and the Manitoba Reliability Standards Regulation (M.R. 25/2012). The Regulation adopted 100 NERC reliability standards pertaining to system operations, maintenance, planning, and cyber security, and outlined the Compliance Monitoring and Enforcement Process (CMEP). Under this process, the MRO and NERC are authorized to monitor compliance with the reliability standards (compliance body). If the MRO alleges that a violation of a reliability standard occurs, it must apply to the PUB for a determination on whether a standard has been violated and the PUB will impose a penalty in respect of the violation. Manitoba Hydro has not received any Notices of Alleged Violation from the MRO that have not already been filed with the PUB.

Manitoba Hydro has a Reliability Compliance Department to orchestrate the corporation's compliance responsibilities and obligations. The annual department operating cost is approximately $600 thousand per year.

PUB/MH I-36 (Revised)

Subject: **Tab 3: Corporate Overview**

Reference: **Corporate Strategic Plan: provide customers with exceptional value**

c) **Please detail the number of electrical service outages by time, duration and by whether the outage was due to malfunctions in distribution, transmission or generation for the years 2002/03 through 2012/13 year-to-date.**

ANSWER:

The outages due to malfunction in distribution and transmission for the years 2002/03 - 2012/13 year-to-date are provided in the following table. Loss of generation did not cause electrical service outages.

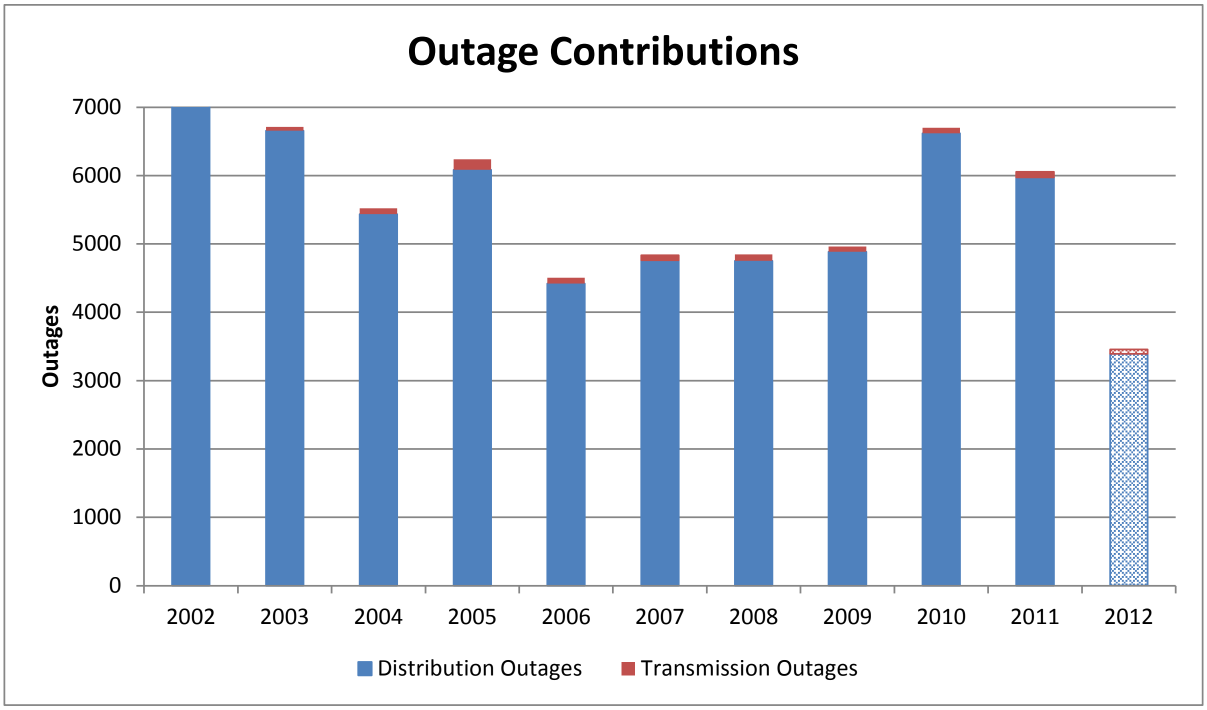
Manitoba Hydro has provided the results requested; however, the results for the periods prior to 2007 may not be comparable due to, the introduction of a new outage reporting system in 2005/06, changes in procedures to improve safety, and reorganized Customer Service and Operations functions.

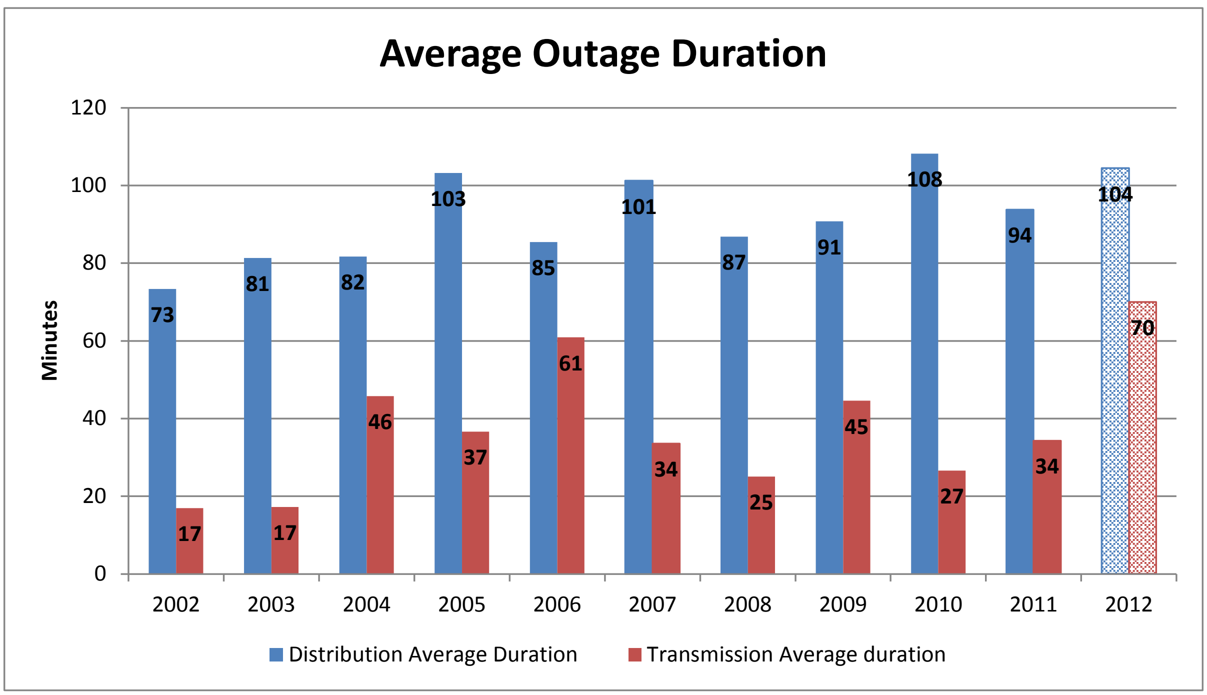
Year *	System	Number of Outages	Average Duration (Minutes) **
2012/13	Distribution & Subtransmission Outages	*3389*	*104*
	Transmission Outages	*64*	*70*
	Total Outages	*3453*	*98*
2011/12	Distribution & Subtransmission Outages	5975	94
	Transmission Outages	81	34
	Total Outages	6056	85
2010/11	Distribution & Subtransmission Outages	6618	108
	Transmission Outages	81	27
	Total Outages	6699	92
2009/10	Distribution & Subtransmission Outages	4886	91
	Transmission Outages	75	45
	Total Outages	4961	79

Year *	System	Number of Outages	Average Duration (Minutes) **
2008/09	Distribution & Subtransmission Outages	4752	87
	Transmission Outages	94	25
	Total Outages	4846	73
2007/08	Distribution & Subtransmission Outages	4763	101
	Transmission Outages	72	34
	Total Outages	4835	90
2006/07	Distribution & Subtransmission Outages	4,421	85
	Transmission Outages	85	61
	Total Outages	4,506	81
2005/06	Distribution & Subtransmission Outages	6,084	103
	Transmission Outages	154	37
	Total Outages	6,238	87
2004/05	Distribution & Subtransmission Outages	5,436	82
	Transmission Outages	85	46
	Total Outages	5,521	76
2003/04	Distribution & Subtransmission Outages	6,658	81
	Transmission Outages	54	17
	Total Outages	6,712	75
2002/03	Distribution & Subtransmission Outages	7,160	73
	Transmission Outages	75	17
	Total Outages	7,235	65

* Reporting period for the 2012/13 year-to-date: April 1, 2012 - August 31, 2012. Reporting period for remaining years are April 1 - March 31.

** Average of an individual outage (i.e. CAIDI = customer interruption minutes/customer interruptions).


Outage Contributions
7000
6000
5000
4000
3000
2000
1000
0
Outages
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Distribution Outages
Transmission Outages


Average Outage Duration
120
100
80
60
40
20
0
Minutes
73
17
81
17
82
46
103
37
85
61
101
34
87
25
91
45
108
27
94
34
104
70
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Distribution Average Duration
Transmission Average duration

PUB/MH I-36

Reference: Appendix 5.6 Page 2 Aging infrastructure

d) Please provide support for the estimated $50 million in annual funding required to maintain the distribution system.

ANSWER:

Manitoba Hydro's distribution system is complex and composed of a vast number of separate components. A significant portion of these assets were installed during initial urban and rural electrification efforts between the 1930s and 1960s and are approaching the end of their serviceable lives. Approximately 25% or 250,000 of the wood poles asset population was installed during that time.

Similarly, underground cables assets also have a finite lifespan. Over half of Manitoba Hydro's underground cable infrastructure (3,300 km) was installed in the 1970s and 1980s. Failure rates involving that type of cable have steadily increased on Manitoba Hydro's distribution system over the last several years. This is consistent with the experience of other utilities and is expected to continue to increase as the underground cable ages. The majority of these critical assets will require refurbishment or replacement over the next 20 years as it reaches the end of its serviceable life.

For Manitoba Hydro to maintain its top quartile reliability performance when compared to peer Canadian Utilities, existing asset replacement rates will need to increase.

PUB/MH I-36

Reference: Appendix 5.6 Page 2 Aging infrastructure

e) Please detail the nature and frequency of transmission restrictions on exports to the USA, Ontario and Saskatchewan, from 2002/03 through 2012/13 year-to-date including the Bipole I & II failures.

ANSWER:

Transfer capability on interfaces with the USA, Ontario, and Saskatchewan can be affected by transmission facility outages within the Manitoba Hydro system or in neighboring systems. Common causes of forced outages to transmission facilities are: equipment failure, adverse weather, and wildlife interference. Planned transmission outages may also be required for maintenance or facility upgrades, and can also limit export capability.

Generation patterns within Manitoba and in neighbouring systems can also require a reduction in transfer capability to neighbouring markets. Generation patterns are affected by factors such as water conditions at hydraulic generating stations, or unit outages.

Market conditions in Ontario, Saskatchewan and the US may also limit the amount of electricity exported. So even if there is physical transfer capability available on the transmission facilities, neighbouring markets may refuse to accept delivery or may price it at a negative price. At negative prices, Manitoba Hydro would have to pay to export.

Outages to the HVdc system do not restrict export capability to the USA, Ontario, or Saskatchewan; however, they can restrict the transmission of power from northern generating stations to the southern transmission system and as a result restrict Manitoba Hydro's ability to export energy.

Table 1 below shows the percentage of time on a seasonal basis that maximum export capability to the USA, Ontario, and Saskatchewan was not restricted by system conditions. Data prior to winter 2008/09 is not available.

Table 1. Export Availability by Interface.

Export Availability (% of maximum)			
	USA	Ontario	Saskatchewan
Winter 2011/12	91.95	81.76	92.03
Summer 2011	90.93	67.81	94.97
Winter 2010/11	96.26	98.79	77.26
Summer 2010	97.62	80.56	75.92
Winter 2009/10	94.61	83.33	64.34
Summer 2009	96.37	86.12	53.28
Winter 2008/09	97.60	85.22	50.23

Table 2 includes HVDC energy availability. This data is tracked on a calendar year basis, and is not available prior to 2005.

Table 2. HVDC Energy Availabiltiy.

HVDC Energy Availability (%)		
Year	Bipole I	Bipole II
2011	96.3	96.0
2010	95.2	94.7
2009	97.7	97.2
2008	96.7	96.9
2007	96.3	96.6
2006	95.1	97.6
2005	96.1	96.8

PUB/MH I-37 (Revised)

Reference: Appendix 5.6 page 11-12 , Appendix 4.4 Schedule 4.5.4, 2010/11& 2011/12 GRA

a) Please provide a schedule similar to schedule provided in response to PUB/MH I-4 (a) at the last GRA of actual equivalent full time employees (EFT's) for each of the years 1999/00 through 2013/14. Please identify the number of EFT's attributable to the acquisition of Centra and Winnipeg Hydro at the year of acquisition.

ANSWER:

The following schedule identifies actual EFTs for the fiscal years from 2005 to 2012, as well as EFTs forecast for years 2013 and 2014. Due to the numbers of employee transfers and restructuring of Business Units, providing EFTs in the requested format prior to 2005 would not be comparable or meaningful.

The acquisitions of Centra and Winnipeg Hydro pre-date the information provided in this response. Information regarding the acquisition of Centra and Winnipeg Hydro has been addressed in a previous GRA.

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

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
President & CEO										
General Counsel	24	25	26	27	26	29	31	32	33	33
Public Affairs	32	30	30	31	32	34	33	33	34	34
Research & Development	5	3	2	2	2	2	1	1	1	1
Administration	23	24	26	27	27	29	32	32	31	31
Coporate Planning and Strategic Review	19	19	20	19	20	22	27	29	27	27
	104	101	104	106	107	116	123	127	126	126
Corporate Relations										
Aboriginal Relations	44	54	59	61	67	68	65	66	72	72
Administration	5	8	8	7	8	5	4	3	3	3
	49	62	67	69	75	73	69	69	75	75
Finance & Administration										
Information Technology Services	350	364	336	313	313	313	314	312	310	310
Treasury	17	16	15	15	16	14	13	13	13	13
Corporate Risk Management	1	2	3	4	5	5	6	6	6	6
Gas Supply	20	20	19	19	20	20	21	20	19	19
Rates & Regulatory Affairs	22	19	19	19	19	20	22	21	21	21
Corporate Controller	116	113	106	108	107	113	110	104	105	105
Human Resources	146	141	139	135	138	129	127	126	131	131
Corporate Safety & Health	54	53	54	59	61	57	57	55	61	61
Corporate Services	298	294	298	304	311	321	325	313	323	323
Administration	14	14	18	17	18	18	16	13	14	14
	1,038	1,035	1,006	993	1,006	1,010	1,009	983	1,003	1,003

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

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Power Supply										
Power Planning	32	35	42	55	58	66	75	78	77	77
Power Projects Development	38	37	39	42	44	47	48	53	58	58
Portfolio Projects Management	-	0	3	4	5	4	6	9	13	13
HVDC	266	228	232	235	250	254	260	258	273	273
Generation North	234	213	211	215	219	224	235	249	268	268
Generation South	496	462	459	455	459	471	488	489	492	492
Engineering Services	79	84	82	84	84	82	86	88	89	89
Power Sales & Operations	163	162	176	175	183	214	233	239	248	248
New Generation Construction	13	14	25	55	83	108	124	137	181	181
Administration	23	131	137	150	191	208	243	255	273	273
	1,345	1,366	1,405	1,470	1,576	1,679	1,796	1,853	1,972	1,972
Transmission										
Transmission System Operations	341	346	363	362	362	364	365	356	358	358
Transmission Planning & Design	202	195	193	178	191	206	214	233	235	235
Transmission Construction & Line Maintenance	271	276	274	273	276	292	303	301	320	320
Apparatus Maintenance	357	362	365	397	420	431	434	428	429	429
Administration	37	42	38	46	49	50	48	36	44	44
	1,208	1,220	1,233	1,256	1,298	1,342	1,365	1,354	1,385	1,385

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

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Customer Services & Distribution										
Customer Service Operations - Winnipeg & North	535	537	515	520	530	528	532	508	528	528
Customer Service Operations - South	547	569	559	561	566	577	580	562	561	561
Distribution Engineering & Construction Rural	253	255	261	276	284	277	288	309	307	307
Distribution Engineering & Construction Winnipeg	271	287	282	283	291	288	298	296	308	308
Administration	-	-	-	-	1	7	6	27	27	27
	1,605	1,647	1,616	1,640	1,671	1,678	1,704	1,701	1,731	1,731
Customer Care & Marketing										
Industrial & Commercial Solutions	48	49	51	52	54	57	54	52	59	59
Consumer Marketing & Sales	204	221	228	218	216	207	210	199	206	206
Business Support Services	230	237	239	229	228	222	217	220	235	235
Administration	39	39	39	39	44	46	47	49	49	49
	521	547	556	538	543	532	528	521	549	549
Total	5,870	5,978	5,988	6,071	6,276	6,429	6,594	6,608	6,842	6,842

PUB/MH I-37

Reference: Appendix 5.6 page 11-12 , Appendix 4.4 Schedule 4.5.4, 2010/11& 2011/12 GRA

b) Please provide a comparison of the actual EFT for the years 2009/10, 2010/11 and 2011/12 with the schedule 4.5.4 provided at the last GRA.

ANSWER:

The following schedule compares actual EFT information to the forecast filed in schedule 4.5.4. at the last GRA for fiscal years 2010 to 2012.

	2009/10 Actual	2009/10 Forecast	Variance	2010/11 Actual	2010/11 Forecast	Variance	2011/12 Actual	2011/12 Forecast	Variance
President & CEO									
General Counsel	29	29	-	30	29	1	32	29	3
Public Affairs	34	34	(1)	33	34	(1)	33	34	(1)
Research & Development	2	2	-	1	2	(1)	1	2	(1)
Administration	29	32	(3)	32	34	(2)	32	34	(2)
Corporate Planning and Strategic Review	22	23	-	27	36	(8)	29	36	(7)
	116	120	(4)	123	135	(13)	127	135	(8)
Corporate Relations									
Aboriginal Relations	68	64	4	65	65	1	66	65	1
Administration	5	4	-	4	4	(1)	3	4	(1)
	73	69	4	69	69	-	69	69	-
Finance & Administration									
Information Technology Services	313	313	-	314	314	-	312	314	(2)
Treasury	14	15	(1)	13	15	(2)	13	15	(2)
Corporate Risk Management	5	6	(1)	6	6	(1)	6	6	-
Gas Supply	20	20	-	21	20	1	20	20	-
Rates & Regulatory Affairs	20	21	(2)	22	21	-	21	21	(1)
Corporate Controller	113	119	(6)	110	119	(9)	104	119	(15)
Human Resources	129	132	(3)	127	133	(6)	126	133	(6)
Corporate Safety & Health	57	60	(3)	57	60	(4)	55	60	(6)
Corporate Services	321	342	(21)	325	342	(18)	313	342	(29)
Administration	18	20	(2)	16	20	(4)	13	20	(7)
	1,010	1,050	(40)	1,009	1,051	(42)	983	1,051	(68)
Power Supply									
Power Planning	66	68	(2)	75	68	7	78	68	10
Power Projects Development	47	50	(4)	48	50	(3)	53	50	2
Portfolio Projects Management	4	7	(3)	6	7	(1)	9	7	1
HVDC	254	268	(14)	260	270	(10)	258	270	(12)
Generation North	224	227	(4)	235	229	6	249	229	21
Generation South	471	469	3	488	470	18	489	470	19
Engineering Services	82	88	(6)	86	89	(3)	88	89	(1)
Power Sales & Operations	214	213	1	233	213	19	239	213	26
New Generation Construction	108	142	(34)	124	143	(19)	137	143	(6)
Administration	208	224	(16)	243	246	(3)	255	246	9
	1,679	1,757	(79)	1,796	1,785	12	1,853	1,785	69

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
Transmission									
Transmission System Operations	364	370	(6)	365	370	(5)	356	370	(14)
Transmission Planning & Design	206	215	(10)	214	216	(1)	233	216	17
Transmission Construction & Line Maintenance	292	295	(3)	303	296	7	301	296	5
Apparatus Maintenance	431	432	(1)	434	433	2	428	433	(5)
Administration	50	44	6	48	44	4	36	44	(8)
	1 342	1 355	(13)	1 365	1 358	6	1 354	1 358	(5)
Customer Services & Distribution									
Customer Service Operations - Winnipeg & North	528	532	(4)	532	534	(2)	508	534	(26)
Customer Service Operations - South	577	578	(1)	580	579	1	562	579	(18)
Distribution Engineering & Construction Rural	277	290	(12)	288	290	(2)	309	290	18
Distribution Engineering & Construction Winnipeg	288	297	(9)	298	298	0	296	298	(1)
Administration	7	10	(3)	6	10	(4)	27	10	17
	1 678	1 708	(30)	1 704	1 711	(7)	1 701	1 711	(9)
Customer Care & Marketing									
Industrial & Commercial Solutions	57	60	(4)	54	60	(6)	52	60	(8)
Consumer Marketing & Sales	207	216	(9)	210	219	(9)	199	219	(20)
Business Support Services	222	229	(7)	217	227	(10)	220	227	(7)
Administration	46	48	(2)	47	51	(5)	49	51	(3)
	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)

PUB/MH I-37

Reference: Appendix 5.6 page 11-12 , Appendix 4.4 Schedule 4.5.4, 2010/11& 2011/12 GRA

c) Please provide a schedule of OM&A by business unit for the years 2003/04 through 2013/14 and provide the Compound Annual Growth for the years 2003/04 through 2011/12 and that for 2011/12 through 2013/14.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-62.

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

a) Please provide a table/ matrix of EFT per 1,000 of GWh, per $millions of domestic revenue, per domestic customers.

	1999/00			*2011/12*
EFT's				
EFT per 1,000 GWH of domestic Supply				
EFT per 1000 GWH of total supply				
EFT per number of domestic customers				
EFT's per $Millions of domestic revenue				
Average Salary & Benefits per EFT				
Annual Wage Rate Adjustment (Union)				
Average Wage Rate Adjustment – Non Union				

Please provide rows in the above table including all data used to calculate the ratios above.

ANSWER:

Please see the following tables.

Information Requested					
	2007/08	2008/09	2009/10	2010/11	2011/12
EFTs	6,071	6,276	6,429	6,594	6,608
EFT per 1000 GWh of domestic supply	253.12	258.43	275.98	277.26	281.20
EFT per 1000 GWh of total supply	171.72	181.77	189.31	193.36	198.83
EFT per number of domestic customers	0.01	0.01	0.01	0.01	0.01
EFT per $ millions of domestic revenue	5.65	5.57	5.62	5.49	5.55
Average Salary & Benefits per ST EFT	$ 76,961	$ 78,568	$ 82,283	$ 83,466	$ 88,741
Annual Wage Rate Adjustment*		2.1%	4.8%	1.5%	6.3%

* Annual Wage Rate Adjustment comes from CAC/MH I-39(b).

Data Table					
	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**
EFTs (ST & OT)	6,071	6,276	6,429	6,594	6,608
EFTs (ST)	5,747	5,935	6,080	6,246	6,250
GWh of domestic Supply	23,985	24,285	23,295	23,783	23,499
GWh of total Supply	35,354	34,528	33,961	34,102	33,235
Electric Customers	521,599	527,472	532,359	537,299	542,681
Domestic revenue (in millions)	1,075	1,127	1,145	1,200	1,191
Wages & Salaries (in thousands)	357,690	376,985	404,576	422,240	448,032
Benefits (in thousands)	84,631	89,348	95,681	99,099	106,571

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

b) Please provide a schedule which indicates the total increase in salary wage, benefits and overhead [both OM&A and Capitalized] related to changes in EFT's for each of the years 1999/00 to 20013/14.

ANSWER:

The total of salaries, wages, overtime and benefits related to EFTs is provided in the following table:

Fiscal Year	**Wages & Salaries**	**Overtime**	**Benefits**	**Total**	**EFTs**
2007/08	$ 359 249	$ 41 781	$ 76 807	$ 477 838	6 071
2008/09	$ 380 031	$ 45 890	$ 83 671	$ 509 592	6 276
2009/10	$ 407 988	$ 50 307	$ 83 013	$ 541 307	6 429
2010/11	$ 425 158	$ 50 704	$ 95 376	$ 571 238	6 594
2011/12	$ 451 925	$ 54 987	$ 104 444	$ 611 356	6 608
2012/13 Forecast	$ 476 887	$ 56 005	$ 109 649	$ 642 542	6 842
2013/14 Forecast	$ 486 425	$ 57 126	$ 111 842	$ 655 393	6 842

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

c) Please indicate the total increases in wages and benefits attributable to new labour agreements on IFF11-2.

ANSWER:

The recently concluded labour agreement with IBEW provided for the following increases in wages:

January 1, 2012	2.5%
April 1, 2012	2.0% market adjustment for trades classifications
January 1, 2013	0.0%
January 1, 2014	2.75%
January 1, 2015	2.75%

The impact of the IBEW wage settlement on the IFF is as follows:

2012/13	$6.2 million
2013/14	$1.2 million
2014/15	$4.8 million

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

d) Please provide a schedule which indicates the salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized,

ANSWER:

Please see the following tables for salary, wages and benefits information for 2007/08 through 2013/14.

Labour & Benefits includes salary, wages, overtime and benefits.
(in thousands of $)

Labour and Benefits as a Percentage of OM&A and Domestic Revenue	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Labour and Benefits	$477,838	$509,592	$541,307	$571,238	$611,356	$642,542	$655,393
Total OM&A Costs (before capitalization)	$638,594	$687,149	$722,951	$748,471	$787,156	$829,765	$848,951
Labour and Benefits as a % of OM&A	74.8%	74.2%	74.9%	76.3%	77.7%	77.4%	77.2%
Domestic Revenue (GCR)	$1,074,581	$1,126,812	$1,144,891	$1,200,381	$1,191,117	$1,335,571	$1,399,088
Labour and Benefits as a % of GCR	44.5%	45.2%	47.3%	47.6%	51.3%	48.1%	46.8%

Activity charges form the basis for cost allocation to capital projects and are built up from a number of cost components including salaries, wages and benefits, meals & accommodations, transportation costs etc. Overhead is also capitalized as a percentage of activity charges and includes a number of cost categories, some of which have a labour and benefit component. Direct quantification of the labour and benefit component of both activity charges and overhead is not available as the approach taken by Manitoba Hydro is one of cost allocation. The following provides an estimate of the amount of labour and benefits capitalized through activity charges and associated overhead. Please note that 2013/14 does not reflect the impact of IFRS changes.

(in thousands of $)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Capital Order Activities	($192,338)	($203,077)	($224,298)	($243,545)	($268,651)	($246,065)	($250,986)
Capitalized Overhead	($67,289)	($65,743)	($60,151)	($47,336)	($53,084)	($69,434)	($70,823)
Labour & Benefits Capitalized	($185,900)	($193,500)	($207,600)	($221,200)	($246,800)	($264,400)	($269,700)

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

e) Please provide the total Labour & Benefits Costs and the dollar and percentage of Labour & Benefits Capitalized for each of the years 1999/00 to 2013/14. Include the EFT equivalent in each year of Labour & Benefits capitalized.

ANSWER:

Please see schedule:

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Labour and Benefits	$477,838	$509,592	$541,307	$571,238	$611,356	$642,542	$655,393
Labour & Benefits Capitalized							
in dollars	$185,900	$193,500	$207,600	$221,200	$246,800	$264,400	$269,700
as a percentage of total Labour and Benefits	39%	38%	38%	39%	40%	41%	41%
EFTs (S/T & O/T) capitalized	2 369	2 397	2 479	2 566	2 678	2 825	2 825

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

f) Indicate to what extent any change in labour and benefits capitalized relates to IFRS- related or IFRS accounting changes.

ANSWER:

The accounting changes implemented since 2009/10 have impacted labour and benefits capitalized to the extent that the costs no longer eligible for capitalization (see page 5 of Appendix 5.6 for a summary of the "Reductions to Costs Capitalized) include a labour and /or benefit component.

PUB/MH I-39

Reference: Appendix 5.6 Page 11 Line 6, Interim Rates & Request for Additional Information Filing page 11

a) MH has indicated that OM&A costs in 2012/13 and 2013/14 are impacted by the in-service of Wuskwatim. Please provide an analysis that reflects the determination of all the revenue requirement impacts on fiscal 2012/13 and 2013/14.

ANSWER:

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

PUB/MH I-39

Reference: Appendix 5.6 Page 11 Line 6, Interim Rates & Request for Additional Information Filing page 11

b) Please provide a description of the accounting policy followed for the transfer of major projects from CWIP to in-service.

ANSWER:

For major projects such as generating stations, as major generating components become operational they are transferred from CWIP to plant in service. The transfer from CWIP to plant in service is done on a pro-rata basis typically based on the generating capacity of the generating unit relative to the entire generating station. Thus, if one turbine became operational and began generating energy for a plant that when complete, will contain three generating turbines of equal capacity, one-third of the CWIP balance will be transferred from CWIP to plant in service.

PUB/MH I-39

Reference: Appendix 5.6 Page 11 Line 6, Interim Rates & Request for Additional Information Filing page 11

c) Please indicate to what extent the facility is in service currently, (the GWh/month of electricity to be generated) and the GWh/month that will to be in service by the end of 2012/13.

ANSWER:

As at September 6, 2012, approximately 60% of the ultimate capacity at Wuskwatim G.S. was in commercial service:

- Unit #1 is partially commissioned (at a lower capacity)
- Unit #3 is fully commissioned
- Unit #2 is expected to be fully commissioned by October 12, 2012

The remaining capacity of Unit #1 will be commissioned after Unit #2 is in service.

As of September 6, Wuskwatim is generating approximately 90 GWh/month. Once fully commissioned, average generation is expected to be 127 GWh/month or 1,500 GWh/year.

PUB/MH I-39

Reference: Appendix 5.6 Page 11 Line 6, Interim Rates & Request for Additional Information Filing page 11

d) Please indicate how much revenue the facility is expected to provide in each of 2012/13 and 2013/14. Provide detailed calculations supporting the estimated revenue.

ANSWER:

Based on IFF11-2, the Wuskwatim Generating Station is expected to provide approximately $57 million in revenue in each of 2012/13 and 2013/14. Please also see Manitoba Hydro's response to PUB/MH I-134 for additional information related to the revenue calculation.

PUB/MH I-40

Reference: 2011 Annual Report Page 22 &23

a) As a document to this proceeding please file a link to an electronic copy of the Joint Keeyask Development Agreement.

ANSWER:

Review of matters related to the development of the Keeyask Generating Station 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. As such Manitoba Hydro declines to file the Joint Keeyask Development Agreement (JKDA) for review in the current rate proceeding.

Manitoba Hydro notes that the JKDA is a publicly available document. Parties interested in this topic can view the JKDA on the Corporation's website: http://www.hydro.mb.ca/projects/keeyask/pdf/JKDA_090529.pdf.

PUB/MH I-40

Reference: 2011 Annual Report Page 22 &23

b) Please file the comparison between the Wuskwatim and Keeyask Agreement filed in response to PUB/MH II-7 at the last GRA and indicate if there have been any changes to either agreement. If so, please summarize the changes and explain why the changes were made.

ANSWER:

Review of matters related to the development of the Keeyask Generating Station and alternatives thereto are expected to take place in the context of A Needs For and Alternatives To (NFAT) hearing, which process is expected to commence in 2013.

A summary of the Wuskwatim Project Development Agreement terms is provided below and updated from PUB/MH I-42(c) in the 2010/11 GRA:

The Nisichawayasihk Cree Nation has the option of being a Limited Partner in the Wuskwatim G.S. with an interest of up to 33%. Manitoba Hydro, through a holding company as General Partner, would have a 0.01% interest, with Manitoba Hydro as a Limited Partner holding the balance.

The assets of the Partnership would consist of the Wuskwatim G.S. and, to the degree required, a small amount of working capital. The capital cost would include planning studies, engineering and licensing from April 1, 2002 plus the unamortized balance of prior expenditures. Accounting policies would mirror those of Manitoba Hydro.

Revenues received by the Partnership from the sale of power to Manitoba Hydro would be based on the actual output of Wuskwatim G.S. and be priced in accordance with an agreed methodology which reflects Manitoba Hydro's actual selling prices for exports. The Partnership would pay Manitoba Hydro a percentage of gross revenues to contribute towards the marketing and transmission risks borne by the Corporation.

Manitoba Hydro will make a credit facility available to the Partnership for funding the costs that the Partnership is obligated to pay to Hydro for the construction and installation of the transmission interconnection facilities required to accommodate the Wuskwatim G.S. The advances under the credit facility will bear an interest rate intended to approximate Manitoba Hydro's actual cost of borrowing. The Partnership will repay the total outstanding under the interconnection credit facility by making semi-annual blended payments of interest and principal based on an amortization period of fifty years.

The Partnership structure is intended to maintain each partner's current income tax status. Any taxes which are nonetheless required to be paid by one partner would be borne exclusively by that partner and would not be an expenditure of the Partnership itself.

For the purposes of the projections, and consistent with Manitoba Hydro's Integrated Financial Forecast, water rental rates are assumed to continue at current levels. As in the economic analysis, annual operating cost estimates are based on a long run average which includes some provision for minor capital maintenance. Larger periodic scheduled capital expenditures are assumed to generally fall outside of the study period which extends to 2034/35. It is expected that the partnership will accumulate a reserve to fund these larger capital expenditures in the future. The administrative costs, which Manitoba Hydro performs on behalf of the Partnership, would be charged on an actual basis.

The capital structure of the partnership will be 75% debt /25% equity, except for the first ten years of the project when the debt ratio may be allowed to temporarily rise to as much as 85% in order to accommodate any front-end losses. Cash calls would be made on the Partners, if required, to ensure that the debt ratio does not exceed the prescribed limits.

The debt/equity ratio would be a primary parameter in determining the portion of profits that may be distributed as dividends. Although it is generally expected that dividends would not normally exceed net income, the projections presented here assume maximum dividend payouts, subject only to maintaining the 25% equity ratio. Dividends would be reduced somewhat if the partners establish reserves for future capital replacement, but the level of these reserves has not yet been established.

The debt advanced by Manitoba Hydro to the Partnership would be secured by the assets and bear an interest rate intended to approximate Manitoba Hydro's actual cost of borrowing. As the timing of Manitoba Hydro's borrowings for its total requirements both within and outside of the partnership may not correspond to that of the cash requirements of the Partnership in isolation, the Partnership would be charged interest rates based upon market benchmarks. These would be adjusted for the provincial spread and other fees that would generally apply to Manitoba Hydro's own borrowing.

Manitoba Hydro recognises that the Nisichawayasihk Cree Nation may not have the financial resources necessary to make a direct 33% cash investment in the project, and that third party lenders may charge rates which effectively levy a premium equivalent to an equity return on the Nisichawayasihk Cree Nation's shares – potentially extracting the Nisichawayasihk Cree Nation's entire potential returns. Accordingly, Manitoba Hydro is prepared to partially finance the Nisichawayasihk Cree Nation's equity contribution at a rate above Manitoba Hydro's cost of borrowing and subject to the following rules:

- The two Limited Partners would invest equity in the project by subscribing for units worth, in total, 25% of the total capital. The analysis in this submission assumes that the Nisichawayasihk Cree Nation will subscribe for a 33% share of these units. The Nisichawayasihk Cree Nation was required to make an initial cash down payment of not less than $1 million on initial close of the project (June 2006) and would finance the balance of its investment during construction through loans from Manitoba Hydro. Upon the in-service of Wuskwatim G.S., the Nisichawayasihk Cree Nation would be required to provide an additional cash equity payment (referred to, in conjunction with the $1 million down payment, as the *cash component* of its investment). The balance (the *financed component*) would be provided by Manitoba Hydro. The minimum *cash component* and maximum *financed component* are governed by an agreed upon formula. Based on the Wuskwatim G.S. cost assumptions in this submission, Manitoba Hydro is prepared to lend Nisichawayasihk Cree Nation $78.8 million for the *financed component* of its units in the Partnership at in-service.

Manitoba Hydro is also prepared to lend the Nisichawayasihk Cree Nation funds ("*cash call advances*") to cover its share of any cash calls which may be made on the owners – for example if profits are insufficient to maintain the required debt ratio. In order to have a degree of certainty in its cash-flow planning, the Nisichawayasihk Cree Nation would also have the option to draw on a loan from Manitoba Hydro for annual "dividend advances". These would permit the Nisichawayasihk Cree Nation to top up the annual dividends otherwise payable on the *cash component* of its equity to a specified allowed minimum return which would be less than Manitoba Hydro's cost of borrowing.

The interest rate to be applied to the financed component, cash call advances and dividend advances would be Hydro's long-term cost of borrowing plus a premium. These mark-ups are to compensate Manitoba Hydro for providing these credit facilities to the Nisichawayasihk Cree Nation and to create an appropriate risk/reward relationship.

A Supplemental Agreement to the Wuskwatim Project Development Agreement was developed to address the project's changing economic conditions.

Manitoba Hydro notes that both the Wuskwatim PDA and the JKDA are publicly available documents. Parties interested in this topic can view these documents on the Corporation's website: http://www.hydro.mb.ca/projects/wuskwatim/pda/Wuskwatim_PDA_ToC.pdf. and http://www.hydro.mb.ca/projects/keeyask/pdf/JKDA_090529.pdf.

PUB/MH I-40

Reference: 2011 Annual Report Page 22 &23

c) Please provide details of all monies disbursed or planned to be disbursed under the provisions of the agreement by year through 2018/19

ANSWER:

Manitoba Hydro assumes that the agreement referenced is the Joint Keeyask Development Agreement (JKDA). For the time period April 2012 through March 2019, monies disbursed or planned to be disbursed under the provisions of this agreement for Transition, Implementation and Operational Employment funding total $33.8 million. This does not include Adverse Effects payments as these are addressed under separate agreements or the value of Direct Negotiated Contracts with the partners.

Year	Amount
2013	$ 9.7
2014	9.7
2015	4.1
2016	2.5
2017	2.6
2018	2.6
2019	2.6
	$ 33.8
*in millions	

PUB/MH I-40

Reference: 2011 Annual Report Page 22 &23

d) Please provide a comparison for both Keeyask and Wuskwatim development agreements, the maximum First Nations (FN) contributions, FN debt financed by MH to fund equity ownership and / FN ownership percentage allowed under the agreements with actual financial contributions and ownership stake made by parties to date.

ANSWER:

Nisichawayasihk Cree Nation (NCN) has the right to acquire up to a 33% ownership interest in the Wuskwatim Power Limited Partnership under the Wuskwatim Project Development Agreement (PDA). NCN has contributed $13.6 million and total outstanding advances are $89.2 million (not including interest) to June 30, 2012. The final NCN contribution and total outstanding advances will be determined July, 2013 based upon the final cost of completion. The PDA does not limit the maximum NCN contribution except to the extent that NCN may acquire up to 33%. NCN may, if it so wishes, make qualifying cash contributions for the full amount of the equity investment required.

Please also see the response to PUB/MH I-40(b) for a summary of the terms of the agreement Manitoba Hydro has with NCN and Taskinigahp Power Corporation.

Review of matters related to the development of the Keeyask Generating Station and alternatives thereto are expected to take place in the context of A Needs For and Alternatives To (NFAT) hearing, which process is expected to commence in 2013.

PUB/MH I-40

Reference: 2011 Annual Report Page 22 &23

e) Please indicate whether any additional agreements have been reached with First Nations, if so please provide a summary of the terms of the agreements.

ANSWER:

No additional project development agreements have been reached with First Nations.

PUB/MH I-41

Reference: 2011 Annual Report/ 2012 Annual Report

Please file MH's 61st Annual Report and 1st and 2nd Quarter Report for 2012/13.

ANSWER:

On September 5, 2012 Manitoba Hydro filed the 61st Annual Report as Appendix 5.8 and the Quarterly Report for the three months ended June 30, 2012 as Appendix 5.9.

PUB/MH I-42

Reference: 2011 Annual Report Page 78, Accounting Changes/ 2012 Annual Report

Please re-file IFF11-2 Pages 31 and 33 including an additional line items quantifying the net impact of accounting changes reflected in the IFF. Please provide a further detailed schedule on the net amount, including narrative descriptions of each of the accounting changes and cite specific handbook sections.

ANSWER:

Please see the following schedules:

Schedule A presents the net impacts of accounting changes by operating statement line item under CGAAP and IFRS. Narratives referencing the changes are provided following the schedules.

Schedule B presents the net impacts of the accounting changes to Retained Earnings.

Schedules C & D reflect the impact of the accounting changes in the income statement and balance sheet of IFF11-2 respectively.

SCHEDULE A - ACCOUNTING CHANGES - IFF11-2

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast --> 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Ref
Electric only (in millions of $'s)															
OM&A															
CGAAP Changes															
Intangibles															
DSM	1	1	1	1	1	1	1	1	2	2	2	2	2	2	
Planning Studies	3	2	2	2	2	2	2	2	2	2	2	2	2	3	
IT Application	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total	5	4	4	4	4	4	5	5	5	5	5	5	5	5	**1**
Overhead Capitalized															
Stores	5	5	5	5	5	6	6	6	6	6	6	6	6	6	**2**
Admin& General		4	24	24	51	52	53	54	55	56	58	59	60	61	**3**
Store & Admin General	5	9	29	29	56	58	59	60	61	62	64	65	66	68	
Change in Discount Rate on Pension & Other Benefits				3											**4**
Subtotal CGAAP Changes	10	13	33	37	61	62	63	65	66	67	68	70	71	73	
IFRS Changes															
DSM						32	29	29	26	22	21	19	19	19	**5**
Site Remediation						5	5	5	5	5	5	5	5	5	**5**
Regulatory Costs						1	1	1	1	1	1	2	2	2	**5**
Pension						(1)	(3)	1	3	4	5	6	7	9	**6**
Employee Benefits (amortization of RHSA)						(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(0)	**6**
Admin & General						36	37	37	38	39	40	40	41	42	**7**
Subtotal IFRS Changes						72	67	72	71	69	72	72	74	76	
Reclassifications															
Wire & Telecom Services	3	3	3	3	3	3	3	3	4	4	4	4	4	4	**8**
Funding Agreements		(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	**9**
Operating Expense Recoveries					8	8	9	9	9	9	9	10	10	10	**10**
Subtotal Reclassifications	3	(2)	(2)	(2)	6	6	6	7	7	7	7	7	7	7	
Total OM&A Accounting Changes	13	11	31	35	67	140	136	143	144	143	147	149	152	156	

SCHEDULE A - ACCOUNTING CHANGES - IFF11-2 cont'd

Electric only (in millions of $'s)	Actual	Actual	Actual	Actual	Forecast -->										
DEPRECIATION & AMORTIZATION EXPENSE	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Ref
CGAAP Changes															
Administrative & General Overhead Capitalized				-	(0)	(1)	(2)	(2)	(3)	(4)	(4)	(5)	(6)	(7)	**3**
Average Service Life				(35)	(38)	(41)	(43)	(44)	(46)	(49)	(53)	(57)	(65)	(68)	**11**
Subtotal CGAAP Changes				(35)	(39)	(41)	(44)	(46)	(49)	(52)	(57)	(62)	(70)	(74)	
IFRS Changes															
Administrative & General Overhead Capitalized				-	-	(0)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	**7**
Reduction in Amortization of Rate Regulated Assets				-	-	(37)	(39)	(40)	(40)	(39)	(36)	(34)	(33)	(32)	**5**
Change to Equal Life Group Depreciation method				-	-	32	33	35	36	39	43	44	51	53	**12**
Removal of Net Salvage from depreciation rates						(55)	(58)	(61)	(64)	(72)	(82)	(85)	(96)	(99)	**13**
Subtotal IFRS Changes				-	-	(60)	(65)	(68)	(71)	(75)	(80)	(81)	(85)	(86)	
Total Depreciation Accounting Changes				(35)	(39)	(101)	(109)	(114)	(120)	(128)	(137)	(143)	(155)	(160)	
FINANCE EXPENSE															
CGAAP Changes				0	0	0	0	0	1	1	1	1	1	1	
IFRS Changes				-	-	2	2	2	2	1	1	0	0	0	
Total Finance Expense Accounting Changes				0	0	3	3	2	2	2	2	1	1	1	**14**
CAPITAL TAX EXPENSE															
CGAAP Changes				0	0	0	0	0	1	1	1	1	1	1	
IFRS Changes				-	-	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	
Total Capital Tax Expense Accounting Changes				0	0	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	0	**14**

SCHEDULE B - ACCOUNTING CHANGES IMPACT TO RETAINED EARNINGS - IFF11-2

Electric only (in millions of $'s)	Actual	Actual	Actual	Actual	Forecast -->										
IMPACT TO RETAINED EARNINGS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	**Total**
CGAAP Changes															
Retrospective adjustment for intangible Assets		(35)													**(35)**
Annual change to OM&A	(10)	(13)	(33)	(37)	(61)	(62)	(63)	(65)	(66)	(67)	(68)	(70)	(71)	(73)	**(759)**
Annual change to Depreciation & Amortization	-	-	-	35	39	41	44	46	49	52	57	62	70	74	**570**
Annual change to Finance & Capital Tax Changes	-	-	-	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	**(13)**
Total	**(10)**	**(48)**	**(33)**	**(2)**	**(23)**	**(21)**	**(20)**	**(20)**	**(18)**	**(16)**	**(13)**	**(10)**	**(3)**	**(1)**	**(236)**
IFRS Changes															
Annual change to OM&A	-	-	-	-	-	(72)	(67)	(72)	(71)	(69)	(72)	(72)	(74)	(76)	**(644)**
Annual change to Depreciation & Amortization	-	-	-	-	-	60	65	68	71	75	80	81	85	86	**672**
Annual change to Finance & Capital Tax Changes	-	-	-	-	-	(1)	(0)	0	(0)	0	0	1	1	1	**2**
Write Offs to:															-
Power Smart Programs						(183)									**(183)**
Site Remediation						(36)									**(36)**
Acquisition (Centra & Manitoba Hydro)						(20)									**(20)**
Regulatory Costs						(2)									**(2)**
Administrative Overhead						(36)									**(36)**
Removal of Net Salvage Depreciation						53									**53**
Change to Equal Life Group Depreciation						(31)									**(31)**
Employee Benefits						(22)									**(22)**
Total	**-**	**-**	**-**	**-**	**-**	**(288)**	**(2)**	**(4)**	**(0)**	**6**	**8**	**11**	**12**	**10**	**(247)**
Total Annual Impact to Retained Earnings	**(10)**	**(48)**	**(33)**	**(2)**	**(23)**	**(310)**	**(22)**	**(23)**	**(19)**	**(10)**	**(5)**	**1**	**9**	**9**	**(483)**

Reference	Description	Accounting Handbook Reference
1	The OM&A adjustments for intangible assets under CGAAP reflect a change (new section 3064 Goodwill and Intangible Assets) in the Canadian accounting standards for Goodwill and Intangible assets that was effective for MH April 1, 2009. The new standard was harmonized with IFRS and required research and promotional costs to be expensed as incurred with retrospective application. Approximately $35 million was adjusted to retained earnings in fiscal 2009/10 for research and promotional costs included in opening intangible asset balances. Effective April 1, 2009 and forward, research and promotional costs associated with intangible assets are expensed as incurred	**CGAAP – Section 3064 Goodwill and Intangible Assets** .37 No intangible asset arising from research (or from the research phase of an internal project) should be recognized. Expenditure on research (or on the research phase of an internal project) should be recognized as an expense when it is incurred. [OCT. 2008] .52 In some cases, expenditure is incurred to provide future economic benefits to an entity, but no intangible asset or other asset is acquired or created that can be recognized,…,Other examples of expenditure that is recognized as an expense when it is incurred include expenditure on: (a) start-up activities (i.e., start-up costs), (b) training activities. (c) advertising and promotional activities.
2	The OM&A adjustments for stores reflect a change in the accounting standards for costs eligible to be included in the cost of inventories. The CGAAP section 3031 Inventories is converged with IFRS and was effective for MH April 1, 2007. As per Section 3031, storage related overhead charges are no longer permitted in the cost of material in inventory.	**CGAAP –Section 3031 Inventories** .16 Examples of costs excluded from the cost of inventories and recognized as expenses in the period in which they are incurred are: (a) abnormal amounts of wasted materials, labour or other production costs; (b) storage costs, unless those costs are necessary in the production process before a further production stage; (c) administrative overheads that do not contribute to bringing inventories to their present location and condition; and
3	The reduction in administrative and general overhead capitalized reflects adjustments made under CGAAP to become more consistent with other Canadian utilities. The adjustments result in the following: • an annual increase in operating and administrative expense;	**CGAAP – Section 3061 Property, plant & equipment:** .20 The cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity.

	• reductions in plant asset values for amounts no longer capitalized; and • reductions in depreciation expense as a result of reduced asset values.	These changes were identified through discussions with other Canadian utilities.
4	The increase in the pension and employee benefits cost is a result of a reduction in the 2011/12 discount rate and the corresponding increase in current service cost for employee benefits.	**CGAAP – Section 3461 Employee Future Benefits:** .50 ¨ For a defined benefit plan, the discount rate used to determine the accrued benefit obligation should be an interest rate determined by reference to: (a) market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments; or (b) the interest rate inherent in the amount at which the accrued benefit obligation could be settled. [JAN. 2000] .054 The discount rate is re-evaluated at each measurement date. When long-term interest rates rise or decline, the discount rate changes in a similar manner.
5	IFF 11-2 assumes rate-regulated accounting is not permitted under IFRS and thus, rate-regulated accounting will be eliminated upon transition. The impacts of this assumption are as follows • upon transition to IFRS, a one-time adjustment to retained earnings will be made for unamortized rate-regulated account balances; • future expenditures on these items will be expensed as incurred resulting in an annual increase to operating and administrative expense; and • a reduction to depreciation and amortization for previously deferred regulatory accounts.	Unlike CGAAP and US GAAP, there is no specific IFRS standard that permits rate-regulated accounting. Generally, the application of the existing IFRS framework has not resulted in the recognition of regulatory assets and liabilities.

6	Overall, changes to the accounting for pension and benefits results in an increase in pension and benefit costs upon transition to IFRS. The primary pension accounting changes include: • upon transition, unamortized pension gains and losses will be adjusted to accumulated other comprehensive income; • the elimination of "corridor" determined amortization for unrealized pension experience gains and losses as IFRS requires annual gains and losses to be recognized in Other Comprehensive Income; and • the use of the pension discount rate for recording expected returns on plan assets as opposed to the expected market interest rate of return as per CGAAP.	**IFRS – IAS 19 Employee Benefits:** .120 An entity shall recognise the components of defined benefit cost, except to the extent that another IFRS requires or permits their inclusion in the cost of an asset, as follows: (a) service cost in profit or loss;…, (c) re-measurements of the net defined benefit liability (asset) in other comprehensive income. .125 Interest income on plan assets is a component of the return on plan assets, and is determined by multiplying the fair value of the plan assets by the discount rate specified in paragraph 83, both as determined at the start of the annual reporting period, taking account of any changes in the plan assets held during the period as a result of contributions and benefit payments. .103 An entity shall recognise past service cost as an expense at the earlier of the following dates: (a) when the plan amendment or curtailment occurs; and (b) when the entity recognises related restructuring costs or termination benefits (see paragraph 165).
	Employee benefits: The primary employee benefit related changes include: • upon transition, unamortized past service adjustments will be adjusted to retained earnings; and • future annual benefits expense will be higher for the recognition of benefits attributed to unvested employees for benefits such as sick leave and severance. Such unvested benefits were not recognized under CGAAP, but are required to be recognized under IFRS.	**Employee Benefits:** .15 Accumulating paid absences are those that are carried forward and can be used in future periods if the current period's entitlement is not used in full. ,…, An obligation arises as employees render service that increases their entitlement to future paid absences. The obligation exists, and is recognised, even if the paid absences are non-vesting, although the possibility that employees may leave before they use an accumulated non-vesting entitlement affects the measurement of that obligation.
7	The reduction in administrative and general overhead capitalized reflects adjustments to comply with IFRS upon transition. IFRS does not permit the capitalization	**IFRS - IAS 16 Property, plant & equipment:** .19 Examples of costs that are not costs of an item of property, plant

	of general administrative and overhead costs. The adjustments result in the following: • an annual increase in operating and administrative expense; • reductions in plant asset values for amounts no longer capitalized; and • reductions in depreciation expense as a result of reduced asset values.	and equipment are:,… (d) administration and other general overhead costs.
8	The increase to OM&A resulting from Wire and Telecom services reflects a change in MH's financial reporting where the operations pertaining to Wire and Telecom services are now reported under Manitoba Hydro International.	**No accounting standard reference applies**
9	The reduction to OM&A resulting from Funding payments (Town of Gillam & Frontier School Division) reflect the re-classification of these expenditures from OM&A to Capital & Other taxes as this more appropriately reflects the nature of these expenditures.	**CGAAP – Section 1000 Financial Statement Concepts** 21 For the information provided in financial statements to be useful, it must be reliable. Information is reliable when it is in agreement with the actual underlying transactions and events, … (a) …Thus, transactions and events are accounted for and presented in a manner that conveys their substance rather than necessarily their legal or other form.
10	The adjustments for operating expense recoveries are to comply with the financial reporting requirements of IFRS. Revenues that were once netted against operating costs for financial reporting will be reported as revenue in the future as IFRS generally does not permit netting of revenues and expenses.	**IFRS - IAS 1 Presentation of Financial Statements:** . 32 - An entity shall not offset assets and liabilities or income and expenses, unless required or permitted by an IFRS.
11	The net result of the depreciation study under CGAAP and the average service life approach is an overall reduction in annual depreciation expense for MH due to changes in the service lives for certain asset groups. This change is required to be implemented under Canadian	**CGAAP – 3061 Property, plant & equipment:** .28 Amortization should be recognized in a rational and systematic manner appropriate to the nature of an item of property, plant and equipment with a limited life and its use by the enterprise.

	GAAP.	.33 The amortization method and estimates of the life and useful life of an item of property, plant and equipment should be reviewed on a regular basis. [DEC. 1990 *****]
12	Upon adoption of IFRS, MH will be moving from the Average Service Life method of depreciation to the Equal Life Group method; increasing annual depreciation expense.	**IFRS - IAS 16 Property, plant & equipment:** The key IFRS reference supporting the move to the ELG method is: 68 The gain or loss arising from the de-recognition of an item of property, plant and equipment shall be included in profit or loss when the item is de-recognised. Gains shall not be classified as revenue.
13	Upon adoption of IFRS, MH will be removing the impact of net salvage from depreciation rates; decreasing annual depreciation expense.	-The Inclusion of net salvage in depreciation rates is a regulatory practice applied under CGAAP by Canadian utilities. Given that IFRS does not recognize rate regulated activities, the practice of including negative salvage in depreciation rates will be discontinued upon transition to IFRS. No IFRS standard reference is available for rate-regulated accounting.
14	The changes to finance expense and capital and other taxes reflect the cumulative impacts of changes 1 – 12 as identified in this chart.	**Please see descriptions as provided in 1- 12.**

SCHEDULE C - ACCOUNTING CHANGES - IMPACT ON IFF11-2

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
PUB-MH I-42 - Net Impact of Accounting Changes
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1,186	1,290	1,294	1,306	1,313	1,330	1,350	1,361	1,382	1,403	1,422
additional*	0	45	106	156	208	265	325	387	455	527	603
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	7	8	8	8	8	8	8	9	9	9
CGAAP Accounting Changes:	-	8	8	9	9	9	9	9	10	10	10
	1,556	1,693	1,778	1,873	2,007	2,114	2,224	2,320	2,466	2,769	2,957
EXPENSES											
Operating and Administrative	363	380	392	406	404	410	428	433	446	459	466
CGAAP Accounting Changes:	37	61	62	63	65	66	67	68	70	71	73
Reclassifications:	(2)	6	6	6	7	7	7	7	7	7	7
IFRS Accounting Changes:			72	67	72	71	69	72	72	74	76
Finance Expense	385	440	450	502	535	567	638	761	802	1,146	1,108
CGAAP Accounting Changes:	-	-	-	-	-	1	1	1	1	1	1
IFRS Accounting Changes:	-	-	2	2	2	2	1	1	-	-	-
Depreciation and Amortization	388	440	455	467	489	507	549	605	626	705	736
CGAAP Accounting Changes:	(35)	(39)	(41)	(44)	(46)	(49)	(52)	(57)	(62)	(70)	(74)
IFRS Accounting Changes:	-	-	(60)	(65)	(68)	(71)	(75)	(80)	(81)	(85)	(86)
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	77	81	89	94	103	112	120	126	135	122	128
CGAAP Accounting Changes:	-	-	-	-	-	1	1	1	1	1	1
Reclassifications:	5	5	5	6	6	6	6	6	6	6	6
IFRS Accounting Changes:	-	-	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1,492	1,671	1,709	1,810	1,881	1,953	2,101	2,300	2,393	2,823	2,833
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	68	62	124	159	121	18	70	(57)	113

SCHEDULE D - ACCOUNTING CHANGES - IMPACT ON IFF11-2

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
PUB-MH I-42 - Net Impact of Accounting Changes
(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	13,880	15,353	15,958	16,816	17,838	18,520	22,043	22,636	26,358	29,219	29,690
CGAAP Accounting Changes pre 2012:	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)
CGAAP Accounting changes	(29)	(85)	(143)	(202)	(262)	(323)	(385)	(449)	(514)	(580)	(648)
IFRS Accounting Changes			(36)	(73)	(110)	(148)	(187)	(227)	(267)	(308)	(350)
Accumulated Depreciation	(4,952)	(5,340)	(5,756)	(6,195)	(6,670)	(7,156)	(7,710)	(8,321)	(8,953)	(9,663)	(10,405)
CGAAP Accounting Changes:	35	74	115	159	205	254	306	363	425	495	569
IFRS Accounting Changes:	-	-	60	125	193	264	339	419	500	585	671
Net Plant in Service	8,878	9,946	10,142	10,574	11,138	11,355	14,350	14,365	17,493	19,692	19,471
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	1,909	1,868	1,697	1,742	1,929	2,110	2,357	2,149	2,321	2,540	2,418
CGAAP Accounting Changes pre 2012:	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
IFRS Accounting Changes:	-	-	(367)	(367)	(367)	(367)	(367)	(367)	(367)	(367)	(367)
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	241	241	233	225	214	200	188	175	163	154
IFRS Accounting Changes:	-	-	(241)	(233)	(225)	(214)	(200)	(188)	(175)	(163)	(154)
	13,648	14,426	14,780	16,092	17,846	19,631	21,800	22,701	24,105	25,555	26,576
LIABILITIES AND EQUITY											
Long-Term Debt	9,253	9,469	10,909	12,169	13,789	15,261	17,025	18,518	19,480	20,990	22,434
Current and Other Liabilities	1,351	1,916	1,386	1,502	1,560	1,727	2,031	1,430	1,812	1,807	1,285
IFRS Accounting Changes:	-	-	20	17	14	10	5	2	(1)	7	4
Contributions in Aid of Construction	317	328	341	348	355	365	376	386	396	407	418
Retained Earnings	2,485	2,527	2,628	2,712	2,860	3,037	3,168	3,191	3,261	3,194	3,297
CGAAP Accounting Changes pre 2012:	(91)	(91)	(91)	(91)	(91)	(91)	(91)	(91)	(91)	(91)	(91)
CGAAP Accounting Changes:	(2)	(25)	(46)	(66)	(86)	(104)	(120)	(133)	(143)	(146)	(147)
IFRS Accounting Changes:	-	-	(288)	(290)	(294)	(294)	(288)	(280)	(270)	(257)	(245)
Accumulated Other Comprehensive Income	335	302	288	158	106	88	61	45	29	11	(12)
IFRS Accounting Changes:	-	-	(367)	(367)	(367)	(367)	(367)	(367)	(367)	(367)	(367)
	13,648	14,426	14,780	16,092	17,846	19,631	21,800	22,701	24,105	25,555	26,576

PUB/MH I-43

Reference: 2012 & 2011 Annual Report, page 73 AOCI

Please provide an update of the current balance of the Accumulated Other Comprehensive Income. AOCI

ANSWER:

The balance of Accumulated Other Comprehensive Income (AOCI) was $327 million at March 31, 2012.

PUB/MH I-44

Reference: 2011 Annual Report Page 78 - Overhead Rate Estimate/ 2012 Annual Report

a) Please file the overhead rate studies used to prepare the 2011 Annual Report and that utilized for the 2012 Annual Report and IFF11-2.

ANSWER:

Please see the following schedule for a breakdown of the overhead rates, changes in the rates resulting from the elimination of various cost components from capitalized overhead under CGAAP and the annual impact of these changes. Please note that the overhead rates and the reductions to costs capitalized represent the consolidated operations.

It is noted that the increase in the overhead rates between 2011/12 and 2012/13 is primarily due to the removal of supports costs (deemed ineligible for capitalization under IFRS in 2013/14) from activity rates and allocated to programs/projects through the common overhead rate, partially offset by a $28 million reduction in costs eligible for capitalization. The reallocation of costs between activity and overhead rates will simplify the transition to IFRS in 2013/14 and assist with comparative year reporting in 2012/13.

Please see Manitoba Hydro's response to PUB/MH I-79(a) for more information on overhead changes that have been made under CGAAP and proposed under IFRS.

Overhead Rates
Fiscal Years Ended March 31

	2008	2009	2010	2011	2012	2013
Overhead Rates						
Common	29%	27%	24%	17%	17%	20%
Tool & Procurement [1]	-	-	-	-	-	5%
Stores Rates						
General Material Issues	21%	11%	11%	10%	10%	10%

Changes & Annual Impact - Reduction to Costs Capitalized *(in millions of dollars)*						
Stores Rate:						
Interest and Facilities Overhead on Stores		5				
Common/Tool & Procurement Rate:						
Executive Costs			2			
Property Taxes on Facilities			2			
Interest on Common Assets (Facilities & Equipment)				12		
General and Administrative Department Costs				5		
Interest on motor vehicles				4		
IT Infrastructure and Related Support						18
Building Depreciation and Operating Costs						10

[1] The tool & procurement rate includes costs associated with technical design and mapping software, personal computers as well as the Purchasing and Accounts Payable functions.

PUB/MH I-44

Reference: 2011 Annual Report Page 78 - Overhead Rate Estimate/ 2012 Annual Report

b) Please discuss changes/-planned changes to the overhead rate since 2003/04 through 2015/16.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-44(a).

PUB/MH I-44

Reference: 2011 Annual Report Page 78 - Overhead Rate Estimate/ 2012 Annual Report

c) Please indicate and detail the annual impact of changes to the overhead rate since fiscal 2003/04 through to forecast fiscal 2015/16 and identify the changes relate to IFRS standards.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-44(a).

PUB/MH I-45

Reference: 2012 Annual Report & 2011 Annual Report, Note 6, Page 80

With respect to the Construction in Progress balances outlined in note 6 to the financial statements, please provide the following:

a) Describe MH's policy for capitalizing Construction in Progress costs and how the policy has changed as a result of IFRS.

ANSWER:

Manitoba Hydro capitalizes all project costs related to asset additions, including direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Capital project costs are charged to Construction Work in Progress until the corresponding asset becomes available for use, at which time the transfer to in-service property plant and equipment is made, interest expense allocated to construction ceases, and depreciation and finance expense charged to operations commences.

Overall, MH's policy for capitalizing construction in progress costs is not expected to change as a result of IFRS. However some of the costs eligible for capitalization will change upon the adoption of IFRS. Please see Appendix 5.5 pages 30 – 32 for more information on MH costs not eligible for capitalization under IFRS.

PUB/MH I-45

Reference: 2012 Annual Report & 2011 Annual Report, Note 6, Page 80

b) Please provide a breakdown of the $2.7 billion balance for Generation & Transmission by component of capitalized costs (wages, overhead etc.) for each major Generation and Transmission project and identify the balance related to base capital.

ANSWER:

Breakdown of Major Generation and Transmission projects by capitalized cost components
As at March 31, 2011
(in millions of dollars)

	Activity Charges	Overhead	Interest	Material	Other	Total
Wuskwatim - Generation	68.8	15.3	133.6	12.6	892.1	1 122.4
Wuskwatim - Transmission	38.5	9.9	40.7	28.1	150.0	267.2
Keeyask	30.3	7.9	126.0	1.0	256.7	421.9
Conawapa	20.6	5.1	39.6	1.7	134.8	201.8
Pointe du Bois - Spillway Replacement	12.3	2.8	6.9	0.2	30.9	53.1
Pointe du Bois - Transmission	4.7	1.0	1.2	13.5	2.9	23.3
Kelse Re-runnering	12.2	3.1	7.6	5.5	26.4	54.8
Kelsey Transmission Upgrades	1.6	0.3	0.2	0.7	0.7	3.5
Kettle Improvements & Upgrades	4.5	0.9	1.1	0.9	17.7	25.1
Bipole III - Transmission Line	9.8	2.4	7.0	1.9	22.5	43.6
Bipole III-Converter Stations	7.8	1.5	2.1	13.2	15.9	40.5
Bipole III - Collector Lines	0.3	-	-	-	0.1	0.4
Riel 230/500kV Station	9.7	2.3	4.6	32.2	28.7	77.5
Herblet Lake-The Pas 230 kV Transmission	13.4	2.9	5.0	12.7	33.6	67.6
Ont to Man 100MW Firm Import U/G - Trans	-	-	-	-	0.1	0.1
Dorsey-US Border New 500kV Transm	0.1	-	0.1	-	0.8	1.0
St. Joseph Wind Transmission	1.0	0.2	-	0.7	0.8	2.7
Major Generation and Transmission	**235.6**	**55.6**	**375.7**	**124.9**	**1 614.7**	**2 406.5**
Base Capital						332.9
Annual Report - Note 6						**2 739.4**

PUB/MH I-45 (Revised)

Reference: 2012 Annual Report & 2011 Annual Report, Note 6, Page 80

c) Please indicate to which extent the current balance has been funded by internally generated funds

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-22(c) for a comparison of historical internally generated funds to capital expenditures.

The construction in progress (WIP) balance of $2.7 billion in Note 6 of the 2011 Annual Report is an accumulation of spending since the inception of each of those projects and is not an annual expenditure amount. The WIP balance will continue to grow based on expenditures each year until the project is placed in service. As internally generated funds is an annual calculation using cash from operations it is not possible to determine the quantum of those internally generated funds used for WIP.

PUB/MH I-22(c) looks at annual cash from operations and annual base capital expenditures and calculates the excess amount to be that which could finance major new generation and transmission. That excess amount could be used for projects that were placed in service in the current year or for projects that remain in WIP. There is no streaming of cash, either from operations or from financing, to specific projects.

PUB/MH I-45

Reference: 2012 Annual Report & 2011 Annual Report, Note 6, Page 80

d) Please update (b) with 2012 Annual Report and comment on changes.

ANSWER:

Breakdown of Major Generation and Transmission projects by capitalized cost components
As at March 31, 2012
(in millions of dollars)

	Activity Charges	Overhead	Interest	Material	Other	Total
Wuskwatim - Generation	83.9	17.5	192.3	14.2	988.3	1 296.2
Wuskwatim - Transmission	43.8	10.8	56.0	29.2	169.3	309.1
Keeyask	39.7	9.2	155.7	2.6	295.0	502.2
Conawapa	25.4	5.7	53.6	1.7	143.6	230.0
Pointe du Bois - Spillway Replacement	18.2	3.7	11.0	0.8	44.2	77.9
Pointe du Bois - Transmission	10.9	2.2	3.1	18.8	3.9	38.9
Kelsey Re-runnering	12.4	2.5	5.7	4.4	16.7	41.7
Kelsey Transmission Upgrades	0.5	0.1	0.1	0.1	(0.1)	0.7
Kettle GS Units 1-4 Stator Replacement	2.5	0.1	0.1	0.2	(1.3)	1.6
Bipole III - Transmission Line	13.4	3.0	10.4	2.6	32.5	61.9
Bipole III-Converter Stations	14.2	2.5	5.8	18.9	35.5	76.9
Bipole III - Collector Lines	1.1	0.2	0.1	-	1.1	2.5
Riel 230/500kV Station	14.1	3.0	10.8	44.1	57.8	129.8
Ont to Man 100MW Firm Import U/G - Trans	0.1	-	-	-	0.1	0.2
Dorsey-US Border New 500kV Transm	0.1	-	0.1	-	0.8	1.0
Major Generation and Transmission	**280.3**	**60.5**	**504.8**	**137.6**	**1 787.4**	**2 770.6**
Base Capital and Other						379.4
Annual Report - Note 6						**3 150.0**

Changes from the 2011 Annual Report balance and 2012 balance are due to increased spending offset by items going into service.

PUB/MH I-46

Reference: 2012 Annual Report & 2011 Annual Report, page 92 Pension Assets and Obligation, Appendix 5.6 Page 2/ 2

a) Please provide an update of the current deficit position of MH's and Centra's pension plans.

ANSWER:

Please see the following table for the requested information.

	MH Pension Fund	Enhanced Hydro Benefit Plan	Centra Gas curtailed pension plans	Total
	2012	**2012**	**2012**	**2012**
		millions of dollars		
Plan Assets at Fair Value				
Balance at beginning of year	**763**	**-**	**84**	**847**
Actual return on plan assets	**14**	**-**	**2**	**16**
Employer contributions	**23**	**11**	**2**	**36**
Benefit payments and refunds	**(42)**	**-**	**(4)**	**(46)**
	758	**11**	**84**	**853**
Accrued Benefit Obligation				
Balance at beginning of year	**837**	**-**	**86**	**923**
Transfer in - other benefits	**-**	**9**	**-**	**9**
Interest on obligation	**54**	**-**	**6**	**60**
Current service cost	**27**	**2**	**-**	**29**
Benefit payments and refunds	**(43)**	**-**	**(4)**	**(47)**
Actuarial losses	**137**	**-**	**10**	**147**
	1 012	**11**	**98**	**1 121**
Deficit at end of year	**(254)**	**-**	**(14)**	**(268)**

PUB/MH I-46

Reference: 2012 Annual Report & 2011 Annual Report, page 92 Pension Assets and Obligation, Appendix 5.6 Page 2/ 2

b) Please quantify the losses/ gains incurred on the pension fund assets since 2009/10.

ANSWER:

The actual returns on the Manitoba Hydro Pension Fund assets are as follows (in millions of dollars):

	Returns
2009/10	117
2010/11	81
2011/12	14

PUB/MH I-46

Reference: 2012 Annual Report & 2011 Annual Report, page 92 Pension Assets and Obligation, Appendix 5.6 Page 2/ 2

c) Please provide a schedule detailing the fair value of MH's Pension fund since 2003/04.

ANSWER:

The fair value of Manitoba Hydro's Pension Fund assets was as follows (in millions of dollars):

	Asset
2007/08	781
2008/09	623
2009/10	694
2010/11	763
2011/12	758

PUB/MH I-46

Reference: 2012 Annual Report & 2011 Annual Report, page 92 Pension Assets and Obligation, Appendix 5.6 Page 2/ 2

d) Please detail the annual gains and losses on the pension fund since 2003/04 and explain how the pension benefit cost was impacted in each of the years.

ANSWER:

Below are the annual gains/losses for the Manitoba Hydro Pension Fund (in millions of dollars).

	Asset Experience Gain (Loss)	**Obligation Actuarial Gain (Loss)**
2007/08	(55)	(19)
2008/09	(173)	20
2009/10	58	(9)
2010/11	27	(24)
2011/12	(43)	(137)

The annual gains and losses on the Pension Fund impacts the unamortized net gain/loss balance. The corridor approach is used for amortizing the net unrecognized gain/loss balance. Under this approach, the unrecognized net gain/loss balance is amortized when it exceeds 10% of the larger of the beginning balance of the projected benefit obligation or the market-related value of the plan assets. This amount is then recognized in pension expense.

The corridor amortization impacted pension expense for each of the fiscal years above as follows (in millions of dollars):

	Impact on Pension Expense
2007/08	3
2008/09	2
2009/10	-
2010/11	1
2011/12	3

PUB/MH I-46

Reference: 2012 Annual Report & 2011 Annual Report, page 92 Pension Assets and Obligation, Appendix 5.6 Page 2/ 2

e) Please provide a schedule detailing and comparing the 2012, 2011 and 2010 actuarial assumptions.

ANSWER:

The following table provides the actuarial assumptions for the Manitoba Hydro Pension Plan.

	2010	2011	2012
Discount rate - pensions	6.5%	6.5%	5.25%
Expected long-term rate of return on plan assets	7.0%	7.0%	7.0%
Rate of compensation increase, including merit and promotions	1.5 - 2.0%	1.5 - 2.0%	1.5 - 2.0%
Expected average remaining service life of employees - MH Pensions	14 years	14 years	14 years
Long-term inflation rate	2.5%	2.5%	2.0%

PUB/MH I-47

Reference: Appendix 4.2, 2011 Annual Report, Page 96, Note 21, Appendix 7.1 Page 44, 2011 Power Smart Plan

a) Please provide an update on the Affordable Energy Fund (AEF) including the projected use of the funds, by program and a detailed description of the programs.

ANSWER:

Projects supported through the Affordable Energy Fund include:

- **Low-Income/Community-Based Initiative: $15.1 Million**
  This initiative targets low-income Manitobans, including Aboriginals and seniors. These funds would be incremental to incentives that are available through Manitoba Hydro's Power Smart programs.

- **Geothermal Support Program: $1.6 Million**
  This initiative supports the application of geothermal technology.

- **Community Energy Development: $15.8 Million**

  - ***Energy & Resource Fund - $750 000***
    This fund, managed by the First Peoples Economic Growth Fund, is a joint initiative between the Government of Manitoba and the Assembly of Manitoba Chiefs. The fund was created to maximize First Nations participation in Major Energy and Resource Projects.

  - ***ecoENERGY Program Funding - $4.5 Million***
    This initiative provides funding to support the cost of offering ecoENERGY audits in Manitoba at a reduced cost for customers.

  - ***Power Smart Residential Loan (Additional) - $350 000***
    This initiative provides funding to reduce the interest rate for the Power Smart Residential Loan from a cost-recovery rate to a rate of 3.9%.

- ***Electric Bus - $1.2 Million***

  This joint initiative among the Province of Manitoba, Manitoba Hydro, Red River Community College, New Flyer Industries and Mitsubishi Heavy Industries, provides funding to assist in developing a commercially viable all-electric bus design with near-zero emissions for use in urban transit systems.

- ***Fort Whyte EcoVillage - $120 000***

  This initiative provides funding to support the research and design of a world-class EcoVillage located at Fort Whyte Alive.

- ***Diesel Community Green Pilot Demonstration - $400 000***

  This initiative provides funding to support a pilot demonstration focusing on green technologies in one of four diesel communities.

- ***Swan Lake First Nation Wind Farm - $8 Million***

  This initiative provides funding towards a joint project with the Manitoba Government, Manitoba Hydro and Swan Lake First Nation of a proposed community wind initiative.

- ***Metis Generation Fund for Resource & Development - $500 000***

  This funding is to be managed by the Métis Economic Development Organization for the purposes outlined in Bill 11.

- **Community Support and Outreach: $750 000**

  This initiative provides support for the participation of First Nation communities in the Lower Income Energy Efficiency Program through dedicated internal resources.

- **Oil and Propane-Heated Residential Homes: $250 000**

  This initiative extends the eligibility of Power Smart programs to include homes currently heated by a source other than electricity and natural gas.

- **Special Projects: $4.0 Million (including accrued fund interest as of August 31, 2012)**

  - ***Residential Energy Assessment Service - $545 000***

    This initiative funds the incremental costs associated with delivering Manitoba Hydro's In-home Energy Assessment service under the Federal ecoENERGY Retrofit program to rural and northern Manitobans.

- ***Oil and Propane Furnace Replacement - $150 000***

  This initiative targets the replacement of oil and propane furnaces with either an electric or high efficient natural gas furnace. The program provides a rebate of $245 to participating customers. Low Income customers will be eligible to convert at a cost of $19 per month for five years.

- ***Residential Solar Water Heating Program - $305 000***

  This initiative supports the application of solar domestic hot water pre-heating systems and the development of the local solar industry.

- ***Power Smart Residential Loan - Up to $2.45 Million***

  This initiative provides funding to reduce the interest rate for the Power Smart Residential Loan from the cost recovery rate to a rate of 3.9%.

- ***Oil and Propane-Heated Residential Homes (Additional) - $300 000***

  This initiative provides further funding to extend the eligibility of Power Smart programs to include homes currently heated by a source other than electricity or natural gas.

PUB/MH I-47

Reference: Appendix 4.2, 2011 Annual Report, Page 96, Note 21, Appendix 7.1 Page 44, 2011 Power Smart Plan

b) Please provide an updated continuity schedule for the actual and forecast use of the fund including a detail on the actual and anticipated expenditures by program for the years 2011/12,2012/13 and 2013/14. .[there is a large balance unallocated]

ANSWER:

Please see the following table.

Affordable Energy Fund ($millions)

	Actual Expenditures (millions)						Forecasted Expenditures (millions)				
Initiative	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16 - 2020/21	Total
Lower Income Program	0.3	0.2	0.9	1.7	2.7	3.1	3.8	2.5	-	-	15.1
Geothermal Support	0.6	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.2	1.6
Community Energy Development	-	-	-	-	-	-	-	-	-	-	-
ecoENERGYProgram Funding	-	-	-	-	-	2.8	1.7	-	-	-	4.5
Residential Loan - Additional Funding	-	-	-	-	-	-	0.4	-	-	-	0.4
Energy & Resource Fund	-	-	-	0.8	-	-	-	-	-	-	0.8
Manitoba Electric Bus	-	-	-	-	-	0.7	0.2	0.2	0.1	0.1	1.2
FortWhyte EcoVillage	-	-	-	-	-	0.1	-	-	-	-	0.1
Diesel Community Green Pilot Demonstration	-	-	-	-	-	0.0	0.2	0.2	-	-	0.4
Swan Lake First Nation Wind Farm	-	-	-	-	-	-	-	8.0	-	-	8.0
Métis Generation Fund	-	-	-	-	-	-	0.5	-	-	-	0.5
Community Support and Outreach	-	-	0.0	0.1	0.1	0.1	0.2	0.2	-	-	0.8
Oil and Propane Heated Homes	-	0.1	0.1	0.0	0.0	0.0	0.0	-	-	-	0.3
Special Projects											
Residential ecoEnergy Audits	-	0.1	0.2	0.1	0.1	0.0	-	-	-	-	0.5
Oil and Propane Furnace Replacement	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.2
Solar Water Heaters	-	-	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.3
Residential Loan	-	-	-	0.1	0.3	0.4	0.5	0.4	0.4	0.3	2.5
Oil and Propane-Heated Residential Homes - Additional Funding	-	-	-	-	-	0.0	0.1	0.1	0.1	0.1	0.3
ANNUAL EXPENDITURES	0.9	0.6	1.4	3.1	3.5	7.5	7.5	11.6	0.6	0.7	37.4

Note: Zeros indicate a small amount that rounds to zero.

PUB/MH I-47

Reference: Appendix 4.2, 2011 Annual Report, Page 96, Note 21, Appendix 7.1 Page 44, 2011 Power Smart Plan

c) Please provide MH's understanding and role in the recently announced Energy Savings Act and the detailed plans, costs, and implications of this Act on rate-payers.

ANSWER:

The Act contains provisions regarding the following three elements:

1. Affordable Energy Fund
   Under the Act, provisions exist to continue the fund at the discretion of the Corporation, in consultation with the Minister responsible for Manitoba Hydro ("Minister").

2. Energy Efficiency Plan
   In consultation with the Minister, Manitoba Hydro is required to prepare an energy efficiency plan by March 31, 2013 and provide updates each subsequent fiscal year. The plan is to set out energy efficiency targets, strategies and programs. In addition, Manitoba Hydro is required to submit to the Minister a report on the achievements of its energy efficiency efforts which will be subsequently tabled in the Assembly.

3. On-Meter Energy Efficiency Improvements Program
   Manitoba Hydro may establish an on-meter efficiency improvements program. Under this program, Manitoba Hydro would finance the cost of improving the efficiency of a customer's building and recover the amount through a monthly charge.

Manitoba Hydro is exploring opportunities which may be available through working with community groups to capture more energy efficient opportunities and is also assessing the merits of an On-Meter Energy Efficiency Improvement Program.

The overall implications, including the cost to Manitoba Hydro ratepayers to develop and implement programming measures as may be required under this Act, are not known at this time.

PUB/MH I-48

Reference: 2011 Annual Report Pages 98, 99 Financial & Operating Statistics

Please update PUB/MH I-22 from the last GRA providing revenue and expense results for fiscal years 2004 through 2012 in tabular form including annual data on.

i. Hydraulic Generation (GWh)
ii. Thermal Generation (GWh)
iii. Energy Purchases (GWh)
iv. Export Sales U.S. (GWh)
v. Export Sales Canada (GWh)
vi. Transmission Losses (GWh)

ANSWER:

Please see the following table for the requested information.

Electric Operating Statistics

(in millions of $)	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual
Revenue					
Residential	437	462	476	503	477
General Service	638	665	669	698	714
Extraprovincial	625	623	427	398	363
Other	8	16	6	6	6
Total Revenue	$ 1,707	1,765	1,578	$ 1,605	$ 1,560
Expenses					
Operating, Maintenance and Administrative	323	364	378	397	403
Finance Expense	401	433	373	388	385
Depreciation and Amortization	324	340	358	365	353
Water Rentals and Assessments	124	123	121	120	119
Fuel and Power Purchased	135	176	104	106	146
Capital and Other Taxes	57	64	76	81	83
Corporate Allocation	8	8	8	9	9
Total Expenses	1,370	1,508	1,418	1,466	1,498
Net Income	$ 337	$ 257	$ 160	$ 139	$ 62
i Hydraulic Generation (GWh)	34,897	34,193	33,818	34,036	33,158
ii Thermal Generation (GWh)	457	335	143	66	77
iii Energy Purchases (GWh)	816	981	1,325	1,132	1,637
iv Export Sales to U.S. (GWh)	10,539	9,709	10,487	9,439	9,358
v Export Sales to Canada (GWh)	482	417	373	905	886
vi Export Losses (GWh)	986	893	928	909	883

PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

a) Please provide a schedule that details all payments to municipalities and the Province by year for the fiscal years 2004 through 2032

ANSWER:

Please see the following schedule for all payments to municipalities and the Province for 2008 through 2032.

Payments to the Province and Municipalities (Millions)

Fiscal Year Ended	Water Rentals	Provincial Guarantee Fee	Sinking Fund Admin. Fee	Capital Taxes	Payroll Taxes	Provincial Mitigation or Settlement Obligations (1)	Municipal GILT and Business Taxes	Gross Electricity Operations Revenue	Gross Export Revenue	Total Provincial Payments (GILT & Business Tax Not Included)	Provincial Payments as a Percentage of Gross Revenue
2008	$ 117	$ 70	$ 1	$ 39	$ 8	$ 2	$ 11	$ 1,712	$ 625	$ 236	14%
2009	115	70	1	44	9	0	11	1,771	623	$ 240	14%
2010	114	72	1	46	9	0	20	1,583	427	$ 242	15%
2011	114	77	-	48	10	0	20	1,616	398	$ 249	15%
2012	111	82	-	52	10	1	21	1,573	363	$ 256	16%
2013	98	91	-	54	10	9	22	1,677	341	$ 262	16%
2014	103	100	-	58	11	0	23	1,762	363	$ 271	15%
2015	103	109	-	64	11	0	25	1,857	394	$ 286	15%
2016	103	122	-	71	11	0	25	1,990	469	$ 306	15%
2017	103	138	-	79	11	0	26	2,097	502	$ 331	16%
2018	102	154	-	88	12	0	26	2,206	531	$ 356	16%
2019	101	175	-	93	12	0	27	2,302	554	$ 381	17%
2020	103	184	-	100	12	0	27	2,448	611	$ 399	16%
2021	111	197	-	106	12	0	28	2,751	821	$ 426	16%
2022	116	211	-	112	13	0	28	2,938	913	$ 451	15%
2023	116	219	-	117	13	0	29	3,054	931	$ 465	15%
2024	116	228	-	121	13	0	30	3,173	946	$ 478	15%
2025	122	235	-	126	13	0	30	3,425	1,124	$ 496	14%
2026	135	244	-	127	14	0	31	3,786	1,408	$ 520	14%
2027	139	240	-	127	14	0	31	3,988	1,526	$ 521	13%
2028	139	240	-	128	14	0	32	4,089	1,544	$ 522	13%
2029	139	240	1	129	15	0	33	4,170	1,539	$ 524	13%
2030	139	240	1	130	15	0	34	4,261	1,544	$ 524	12%
2031	140	237	1	130	15	0	34	4,371	1,565	$ 523	12%
2032	140	230	1	130	15	0	35	4,474	1,574	$ 516	12%

(1) Hydro entered into an agreement with the Province whereby the Corporation assumed obligations of the Province with respect to certain northern development projects. Obligations totaling $143 million were assumed, with respect to which water rental charges had been fixed until March 31, 2001. Of these obligations, $9 million remain to be paid in fiscal 2013 and future years.

PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

b) Please provide a schedule that details the calculation of the debt guarantee fee for the fiscal years 2004 through 2012 and forecast for 2013 and 2014.

ANSWER:

Please see the following table:

)

Provincial Debt Guarantee Fee (PGF) Calculations
($ millions CAD)

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014
Long Term Debt Balance for PGF	7,160	7,486	8,132	8,538	8,528	9,434	10,274
Short Term Debt Balance for PGF	148	-	100	-	-	48	55
Trust Investment from Pre-Financing		(122)	(166)	(554)	-	-	-
Debt Balance for PGF Purposes	7,308	7,364	8,066	7,984	8,528	9,482	10,330
PGF Rate	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Amount PGF Paid to Province	73	74	76	80	85	95	103
PGF Portion Allocated to Centra	(3)	(3)	(3)	(3)	(3)	(4)	(4)
Net Hydro PGF	70	70	72	77	82	91	100

Notes: (1) The fee calculation is based on ending debt balances at March 31 of the prior fiscal year. Manitoba Hydro is not assessed the provincial debt guarantee fee on bonds issued for mitigation purposes. The fiscal year debt balances presented in PUB/MH I-49(b) represent that amount of debt upon which the PGF was paid or is payable for that fiscal year.

(2) The PGF on US debt is paid in US dollars using the stated PGF rate. For presentation purposes, US debt balances are translated to a Canadian equivalent using the year end exchange rate. The presentation of the US long term debt balance at March 31, 2009 was translated at the year end exchange rate of 1.2602 although the US dollar PGF payment was made at a 1.05036 exchange rate utilizing FX forward contracts. Therefore, the Canadian equivalent of the amount paid to the Province for 2010 was less than 1%. The forecasted year end exchange rates for 2012, 2013 and 2014 were 0.98, 0.99 and 0.99 respectively.

PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

c) Please provide a schedule that details the calculation of water rental payments for the fiscal years 2004 through 2012 and forecast for 2013, and 2014.

ANSWER:

Please see the following schedule for the water rental payment calculation for the years 2008 through 2014.

Water Rental Calculation

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014	
Megawatt-Hours Generated (billion kWh)	34.9	34.2	33.8	34.0	33.2	29.3	30.7	
Converted to Horsepower-years (million HP-YR)	5.7	5.6	5.6	5.6	5.5	4.8	5.1	(1)
Rental Rate per Horsepower-year	$ 20.32	$ 20.32	$ 20.32	$ 20.32	$ 20.32	$ 20.32	$ 20.32	(2)
Calculated Water Annual Rental ($ million)	$ 116.7	$ 114.3	$ 113.0	$ 113.8	$ 110.8	$ 97.8	$ 102.7	
Minimum Rental Adjustment		0.2	1.0	0.3				(3)
Other Adjustment	0.3							(4)
Total Water Rentals	$ 117.0	$ 114.5	$ 114.0	$ 114.1	$ 110.8	$ 97.8	$ 102.7	

(1) The Water Power Act defines "Horsepower-year" as kW.h/6535 X 1.075.

(2) The water rental fee was calculated at a rate of 9.90 per Horsepower-year generated up to March 31, 2001. Effective April 1, 2001 the rate was increased to its current level of $20.32 per Horsepower-year.

(3) The Water Power Act of Manitoba provides that the water rentals charged for each generation site be the greater of (a) a fixed rate multiplied by the installed capacity of that site and (b) a fixed rate multiplied by the electrical output for the year of that site. Generally , the calculation under (b) based on actual output results in the greatest amount for each generation site. In some years, such as 2009 it is necessary to adjust the amounts calculated under the (b) calculation for some specific sites to bring the total up to the amount calculated under the (a) installed capacity calculation method.

(4) Due to a rounding difference.

PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

d) Please provide a schedule that details all forecast payments to all Government by year from 2013 to 2032.

ANSWER:

Please see the response to PUB/MH I-49(a) for the forecast payments to municipalities and the Province for the years 2013 to 2032.

The only significant payments to the federal government are in the form of the employer premiums for Canada Pension Plan (CPP) and Employment Insurance (EI). For forecasting purposes these payments are included in the general employee benefit amount applied to salaries and are not forecasted as separate amounts.

The actual payments made for fiscal 2012 were $14.2 million for CPP premiums and $6.5 million for EI premiums.

PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

e) Please provide an update to the table in PUB/MH II-14 (a) adding the years 2025 and 2032.

ANSWER:

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

PUB/MH I-50

Reference: Tab 4 , IFF11-2, Sinking Fund

Please provide a continuity schedule of the sinking fund from fiscal years 2010 to 2032 including contributions, income earned, and withdrawals from the fund.

ANSWER:

Please see the attached schedule.

PUB/MH 1 - 50

MANITOBA HYDRO
SINKING FUND CONTINUITY

Actuals to March 31, 2012
(In $Millions Canadian Dollars)

	Actual 2007/08	Actual 2008/09	Actual 2009/10	Actual 2010/11	Actual 2011/12	Forecast 2012/13****	Forecast 2013/14	Forecast 2014/15	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20
CAD Sinking Fund													
Opening	(0)	(0)	(0)	17	55	129	68	18	53	42	59	68	99
Contributions *	-	-	17	55	98	68	10	35	12	17	13	31	14
Withdrawals	-	-	-	-	(23)	(129)	(60)	-	(24)	-	(4)	-	(18)
Premiums/Discounts	-	-	-	(17)	-	-	-	-	-	-	-	-	-
Transfer USD SF Balance to CAD	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	(0)	(0)	17	55	129	68	18	53	42	59	68	99	96
USD Sinking Fund in CAD													
Opening	630	718	666	366	227	211	259	119	107	284	434	650	403
Contributions *	96	124	82	66	-	49	198	89	180	140	217	178	205
Withdrawals	-	(261)	(263)	(191)	-	-	(335)	(105)	-	-	-	(424)	(159)
Premiums/Discounts/Other **	64	(32)	8	(2)	11	(3)	(3)	(2)	(4)	10	(1)	(2)	(2)
FX Adjustments ***	(72)	116	(126)	(12)	5	2	-	6	1	-	-	-	-
Transfer USD SF Balance to CAD	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	718	666	366	227	243	259	119	107	284	434	650	403	446
Total Sinking Funds in CAD	718	666	383	282	372	327	137	160	325	493	718	502	542

* The sinking fund contributions shown in this schedule total the amounts required by legislation and do not include any temporary investment amounts that may be deposited into the sinking fund.
** Premiums/Disounts/Other includes premiums and discounts on investments; as well as the difference between the fair market value and carrying value of the USD sinking fund portfolio.
*** As the continuity schedule is presented in Canadian dollars, the FX adjustment line shows the year-end retranslation of the USD sinking fund balances into their Canadian equivalencies.
**** A reconciling adjustment was made to the 2012/13 opening USD Sinking Fund balance in order to bring the actual 2011/12 closing balance in line with the forecasted 2012/13 opening balance.

PUB/MH 1 - 50

MANITOBA HYDRO
SINKING FUND CONTINUITY

Actuals to March 31, 2012
(In $Millions Canadian Dollars)

	Forecast 2020/21	Forecast 2021/22	Forecast 2022/23	Forecast 2023/24	Forecast 2024/25	Forecast 2025/26	Forecast 2026/27	Forecast 2027/28	Forecast 2028/29	Forecast 2029/30	Forecast 2030/31	Forecast 2031/32
CAD Sinking Fund												
Opening	96	147	203	278	524	787	668	976	1,261	1,498	1,554	1,859
Contributions *	51	56	75	246	263	282	274	285	297	306	305	317
Withdrawals	-	-	-	-	-	(401)	-	-	(60)	(250)	-	(13)
Premiums/Discounts	-	-	-	-	-	-	-	-		-	-	-
Transfer USD SF Balance to CAD	-	-	-	-	-	-	34	-	-	-	-	-
Total	147	203	278	524	787	668	976	1,261	1,498	1,554	1,859	2,163
USD Sinking Fund in CAD												
Opening	446	421	30	30	32	32	31	0	0	0	0	0
Contributions *	237	289	159	-	-	-	(0)	-	-	-	-	-
Withdrawals	(265)	(689)	(159)	-	-	-	-	-	-	-	-	-
Premiums/Discounts/Other **	3	8	(0)	2	(0)	(0)	2	-	-	-	-	-
FX Adjustments ***	-	-	-	-	-	-	-	-	-	-	-	-
Transfer USD SF Balance to CAD							(34)					
Total	421	30	30	32	32	31	0	0	0	0	0	0
Total Sinking Funds in CAD	568	233	307	556	819	699	976	1,261	1,498	1,554	1,859	2,163

* The sinking fund contributions shown in this schedule total the amounts required by legislation and do not include any temporary investment amounts that may be deposited into the sinking fund.
** Premiums/Disounts/Other includes premiums and discounts on investments; as well as the difference between the fair market value and carrying value of the USD sinking fund portfolio.
*** As the continuity schedule is presented in Canadian dollars, the FX adjustment line shows the year-end retranslation of the USD sinking fund balances into their Canadian equivalencies.

PUB/MH I-51

Reference: Financial Results

Please provide in same format as PUB/MH I-27 last GRA, the actual MH Electric Operations financial statements (i.e. Operating Statement, Balance Sheet and Cash Flow Statement) for 2005 through 2012 in the same format as the IFF, including the actual financial ratios.

ANSWER:

The financial statements and ratios are attached.

Electric Operations
Statement of Income

(millions of dollars)

For the year ended March 31:	2008	2009	2010	2011	2012
Revenues					
General consumers revenue	1,075	1,127	1,145	1,200	1,191
Extraprovincial	625	623	427	398	363
Other	8	16	6	6	6
	1,708	1,766	1,578	1,604	1,560
Expenses					
Operating and administrative	323	364	378	397	403
Finance expense	401	433	373	388	385
Depreciation and amortization	324	340	358	365	353
Water rentals and assessments	124	123	121	120	119
Fuel and power purchased	135	176	104	106	146
Capital and other taxes	57	64	76	81	83
Corporate allocation	7	8	8	9	9
	1,371	1,508	1,418	1,466	1,498
Net Income (Loss)	337	258	160	138	62
Financial Ratios					
Debt Ratio	0.73	0.77	0.72	0.72	0.74
Interest Coverage	1.72	1.50	1.33	1.26	1.11
Capital Coverage	1.65	1.82	1.28	1.22	1.10

Electric Operations
Balance Sheet

(millions of dollars)

As at March 31:	**2008**	**2009**	**2010**	**2011**	**2012**
Assets					
Plant in service	11 308	11 701	12 088	12 350	12 994
Accumulated depreciation	3 987	4 144	4 402	4 534	4 760
Net plant in service	7 321	7 557	7 686	7 816	8 234
Construction in progress	1 235	1 435	2 051	2 738	3 148
Current and other assets	2 503	1 837	2 011	1 627	1 713
Goodwill	108	108	108	108	108
	11 167	10 937	11 856	12 289	13 203
Liabilities and Retained Earnings					
Long-term debt	6 985	7 527	7 931	8 320	8 866
Current and other liabilities	1 789	1 234	1 109	904	1 209
Contributions in aid of construction	269	266	263	262	285
Non-controlling interest	24	39	62	87	100
Share capital	0	0	0	0	0
Retained earnings	1 795	2 040	2 206	2 349	2 416
Accumulated other comprehensive income (loss)	305	(169)	285	367	327
	11 167	10 937	11 856	12 289	13 203

Electric Operations
Statement of Cash Flows

(millions of dollars)

For the year ended March 31:	**2008**	**2009**	**2010**	**2011**	**2012**
Operating Activies					
Cash receipts from customers	1 699	1 829	1 604	1 626	1 610
Cash paid to suppliers and employees	(597)	(708)	(655)	(705)	(729)
Interest paid	(536)	(502)	(455)	(402)	(398)
Interest received	33	35	34	31	35
	599	654	528	550	518
Financing Activities					
Proceeds from long-term debt	981	423	1 425	915	698
Sinking fund withdrawals	0	261	263	646	23
Retirement of long-term debt	(311)	(366)	(452)	(723)	(25)
Other	(189)	98	(89)	(158)	35
	481	416	1 147	680	731
Investing Activities					
Property, plant & equipment, net of contributions	(802)	(885)	(1 043)	(1 139)	(1 093)
Sinking fund payment	(96)	(124)	(537)	(119)	(98)
Other	(50)	(35)	(80)	(76)	(78)
	(948)	(1 044)	(1 660)	(1 334)	(1 269)
Net increase (decrease) in cash	132	26	15	(104)	(20)
Cash at beginning of year	1	133	159	174	70
Cash at end of year	133	159	174	70	50

PUB/MH I-52

Reference: Tab 5 Page 2 of 36, Schedule 5.1.0 Statement of Income

a) Please re-file the schedule incorporating the years 2003/04 through 2013/14.

ANSWER:

Please see the following table for the requested information.

MANITOBA HYDRO **Schedule 5.1.0**
STATEMENT OF INCOME **(000's)**

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Revenue							
General Consumers*	1,074,581	1,126,812	1,144,891	1,200,381	1,191,117	1,335,571	1,399,088
Extraprovincial	624,971	622,646	426,641	398,306	363,044	341,167	362,920
Other	7,580	15,870	6,226	6,438	5,618	15,706	16,078
Total Revenue	$ 1,707,132	$ 1,765,328	$ 1,577,758	$ 1,605,126	$ 1,559,779	$ 1,692,445	$ 1,778,086
Expenses							
Operating, Maintenance and Administrative	322,697	364,287	377,551	396,946	403,304	446,966	531,825
Finance Expense	400,796	433,065	373,267	388,043	385,044	439,641	451,643
Depreciation and Amortization	323,573	340,314	358,179	364,727	353,376	400,846	354,307
Water Rentals and Assessments	123,767	123,000	121,033	120,163	119,300	105,900	112,470
Fuel and Power Purchased	134,887	176,383	103,973	106,169	145,632	182,478	158,040
Capital and Other Taxes	57,152	63,808	75,819	81,322	82,888	87,197	92,056
Corporate Allocation	7,576	7,554	8,035	8,892	8,880	8,835	8,336
Total Expenses	1,370,449	1,508,410	1,417,857	1,466,262	1,498,423	1,671,863	1,708,677
Non-controlling Interest**	-	-	-	-	-	(979)	(949)
Net Income	$ 336,683	$ 256,918	$ 159,901	$ 138,863	$ 61,356	$ 19,603	$ 68,460

*General Consumers Revenue- 2012/13 reflects the 2.5% interim rate increase effective September 1, 2012 that is embedded in IFF11-2 as well as the reinstatement of the 1% rate reduction in Order 5/12. 2013/14 reflects an additional 3.5% rate increase effective April 1, 2013.

**Non-controlling interest represents the projected distributions paid from WPLP to NCN.

PUB/MH I-52

Reference: Tab 5 Page 2 of 36, Schedule 5.1.0 Statement of Income

b) Please provide a schedule in part (a) which incorporates a column for the Compound Annual Growth (CAG) for the years 2004/05 through 2011/12 and a column for the CAG for the years 2009/10 through 2013/14.

ANSWER:

Please see the following table for the requested information.

MANITOBA HYDRO
STATEMENT OF INCOME

Schedule 5.1.0
(000's)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	Compounded Annual Growth (2007/08 to 2011/12
Revenue						
General Consumers*	1,074,581	1,126,812	1,144,891	1,200,381	1,191,117	2.6
Extraprovincial	624,971	622,646	426,641	398,306	363,044	-12.7
Other	7,580	15,870	6,226	6,438	5,618	-7.2
Total Revenue	$ 1,707,132	$ 1,765,328	$ 1,577,758	$ 1,605,126	$ 1,559,779	-2.2
Expenses						
Operating, Maintenance and Administrative	322,697	364,287	377,551	396,946	403,304	5.7
Finance Expense	400,796	433,065	373,267	388,043	385,044	-1.0
Depreciation and Amortization	323,573	340,314	358,179	364,727	353,376	2.2
Water Rentals and Assessments	123,767	123,000	121,033	120,163	119,300	-0.9
Fuel and Power Purchased	134,887	176,383	103,973	106,169	145,632	1.9
Capital and Other Taxes	57,152	63,808	75,819	81,322	82,888	9.7
Corporate Allocation	7,576	7,554	8,035	8,892	8,880	4.0
Total Expenses	1,370,449	1,508,410	1,417,857	1,466,262	1,498,423	2.3
Non-controlling Interest**	-	-	-	-	-	
Net Income	$ 336,683	$ 256,918	$ 159,901	$ 138,863	$ 61,356	-34.7

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Compounded Annual Growth (2009/10 to 2013/14
Revenue						
General Consumers*	1,144,891	1,200,381	1,191,117	1,335,571	1,399,088	5.1
Extraprovincial	426,641	398,306	363,044	341,167	362,920	-4.0
Other	6,226	6,438	5,618	15,706	16,078	26.8
Total Revenue	$ 1,577,758	$ 1,605,126	$ 1,559,779	$ 1,692,445	$ 1,778,086	3.0
Expenses						
Operating, Maintenance and Administrative	377,551	396,946	403,304	446,966	531,825	8.9
Finance Expense	373,267	388,043	385,044	439,641	451,643	4.9
Depreciation and Amortization	358,179	364,727	353,376	400,846	354,307	-0.3
Water Rentals and Assessments	121,033	120,163	119,300	105,900	112,470	-1.8
Fuel and Power Purchased	103,973	106,169	145,632	182,478	158,040	11.0
Capital and Other Taxes	75,819	81,322	82,888	87,197	92,056	5.0
Corporate Allocation	8,035	8,892	8,880	8,835	8,336	0.9
Total Expenses	1,417,857	1,466,262	1,498,423	1,671,863	1,708,677	4.8
Non-controlling Interest**	-	-	-	(979)	(949)	
Net Income	$ 159,901	$ 138,863	$ 61,356	$ 19,603	$ 68,460	-19.1

*General Consumers Revenue- 2012/13 reflects the 2.5% interim rate increase effective September 1, 2012 that is embedded in IFF11-2 as well as the reinstatement of the 1% rate reduction in Order 5/12. 2013/14 reflects an additional 3.5% rate increase effective April 1, 2013.

**Non-controlling interest represents the projected distributions paid from WPLP to NCN.

PUB/MH I-53

Reference: Tab 5 Page 5 of 36, Schedule 5.2.0 General Consumer Revenue, Additional Information – Item 7

Please re-file the schedule incorporating the years 2004/05 through 2013/14, detailing rate increases granted and requested.

ANSWER:

Please see the following table for the requested information.

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

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Residential - Base Rates	$ 436,634	$ 445,585	$ 440,545	$ 452,281	$ 428,616	$ 464,766	$ 474,450
General Service - Base Rates	637,947	640,499	619,098	627,409	641,922	653,234	666,877
Base Rates	1,074,581	1,086,084	1,059,643	1,079,690	1,070,539	1,118,000	1,141,327
2008/09 Approved Rate Increase (5.0% July 1, 2008)	-	40,728	52,982	53,985	53,527	55,900	57,066
2009/10 Approved Rate Increase (2.9% April 1, 2009)	-	-	32,266	32,877	32,598	34,043	34,753
2010/11 Interim Rate Increase (2.9% April 1, 2010)	-	-	-	33,830	33,543	-	-
2010/11 Approved Rate Increase (1.9% April 1, 2010)	-	-	-	-	-	22,951	23,430
2011/12 Approved Rate Increase (2.0% April 1, 2011)	-	-	-	-	23,804	24,618	25,132
2012/13 Interim Rate Increase (2.0% April 1, 2012)	-	-	-	-	-	25,110	25,634
Interim & Approved Rate Increases	-	40,728	85,248	120,691	143,472	162,622	166,015
Deferred Revenue - 2010/11 & 2011/12 (1% rate rollback)	-	-	-	-	(22,894)	22,894	-
Deferred Revenue - 2012/13 & 2013/14 (1% rate rollback)	-	-	-	-	-	12,144	12,096
Deferred Revenue from 1% rate rollback	-	-	-	-	(22,894)	35,038	12,096
Additional General Consumers Revenue (2.5% September 1, 2012)	-	-	-	-	-	19,912	32,669
Additional General Consumers Revenue (3.5% April 1, 2013)	-	-	-	-	-	-	46,982
Additional General Consumers Revenue	-	-	-	-	-	19,912	79,651
Total Revenue	$ 1,074,581	$ 1,126,812	$ 1,144,891	$ 1,200,381	$ 1,191,117	$ 1,335,571	$ 1,399,088
Rate increase requested	n/a	2.9%	3.9%	2.9%	2.9%	3.5%	3.5%
Rate increase granted*	n/a	5.0%	2.9%	1.9%	2.0%	2.0%/2.4%	n/a

* Please note that in Order 117/12 the PUB approved an interim rate increase of 2.4%.

PUB/MH I-54

Reference: Schedule 5.3.0 Extra-provincial Revenue PUB/MH I-31 2011 GRA

Please re-file PUB/MH I-31 (2011 & 2012 GRA) as updated to include:

- **2009/10 to 2011/12 actuals**
- **2012/13 to 2015/16 forecast.**

ANSWER:

Please see the attached table for actual data up to 2011/12. The average prices for prior years have been recalculated based upon the current reporting standard.

Please refer to the average price information found on page 1 of Attachment 5 of the General Rate Application for forecast numbers.

	1999/00 Actual	2000/01 Actual	2001/02 Actual	2002/03 Actual	2003/04 Actual	2004/05 Actual	2005/06 Actual
Canadian	90,233	109,275	92,615	84,143	53,601	78,255	172,938
U.S.	286,337	370,397	495,278	379,287	297,394	475,243	654,083
	376,570	479,673	587,893	463,430	350,994	553,499	827,021
Average Exchange Rate	1.17	1.1723	1.5665	1.5445	1.3491	1.2732	1.1893
Average Price/MWh	34.26	39.09	49.02	48.93	49.91	50.51	50.98
U.S. Revenue in US$	242,343	312,074	325,724	254,560	217,368	362,164	537,903

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual
Canadian	85,440	110,062	131,363	65,737	63,150	48,289
U.S.	506,985	514,909	491,283	360,904	335,157	341,755
	592,426	624,971	622,646	426,641	398,307	390,044
Average Exchange Rate	1.1352	1.0256	1.1345	1.0846	1.0191	0.9895
Average Price/MWh	51.38	47.36	48.85	32.99	33.31	31.10
U.S. Revenue in US$	432,814	482,512	427,771	320,494	310,647	299,581

PUB/MH I-55

Reference: IFRS – Jurisdictional Comparison

Please summarize how IFRS has been addressed for Rate Regulated Entities in other Canadian jurisdictions; filing an update to Pre-Ask -17 from the 2011 & 2012 GRA. Please file any regulatory pronouncements from other Canadian jurisdictions on the issue.

ANSWER:

Manitoba Hydro has provided its most recent update on the status of IFRS in Appendix 5.5. That document provides the most current overview of the implications of IFRS on Manitoba Hydro's financial accounting and reporting.

The following tables provide an update to the response provided in Pre-Ask -17 from the 2011 & 2012 GRA. Information provided on the Ontario Energy Board (OEB) was derived from the following:

- OEB report "EB-2008-0408, Report of the Board, Transition to International Financial Reporting Standards" (July 28, 2009) which was updated for the February 24, 2010 letter issued by the OEB re: Accounting for Overhead Costs Associated with Capital Work (This letter confirmed that the OEB will require utilities to adhere to IFRS overhead capitalization requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS);
- July 8, 2010 Asset Depreciation Study for the Ontario Energy Board (Kinectrics Report);
- April 20, 2012 OEB letter Impact on the Decision to defer the Mandatory Date for the Implementation of International Financial reporting Standards to January 1, 2013 by the Canadian Accounting Standards Board; and,
- July 9, 2012 OEB presentation re: 2013 Cost of Service Orientation Session Setting Rates on MIFRS – Review of Requirements for 2013 Filers.

Information provided on the Alberta Utilities Commission (AUC) was derived from AUC Rule 026 Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards (May 19, 2009) which was updated on December 20, 2011 for changes with respect to the transition dates to IFRS.

Please note that both the OEB and AUC pronouncements referred to above relate to the situation where a utility is transitioning to IFRS. Since the time that these pronouncements were issued, there have been a significant number of Canadian utilities that have decided to move to US GAAP for financial reporting purposes. While Manitoba Hydro is not in possession of all regulatory pronouncements on this issue, its general understanding is that those utilities that moved to US GAAP, also requested and obtained approval from their regulators to use US GAAP for rate setting purposes.

	Regulatory Assets and Liabilities
IFRS	No specific standard exists under IFRS regarding the accounting for rate regulated assets and liabilities. While IFRS does not preclude the recognition of regulatory assets and liabilities, it requires that an asset or liability must meet the existing framework for recognition. The application of IFRS framework in other countries has not typically resulted in the recognition of regulatory assets and liabilities. In the IASB's May 2012 update referencing the agenda consultation project, the IASB supported giving priority to developing a standard-level proposal for rate-regulated activities. The IASB is currently deliberating the future of the Rate-regulated activities project and the IASB staff has recently completed a paper outlining its preliminary views on how to proceed forward. The IASB has not made a formal decision as of the date of this response.
MH Current	MH recognizes the impact of rate-regulation by applying various accounting policies that allow for the deferral of certain costs or credits which will be recovered or refunded in future rates.
MH Proposed	Presently, MH's assessment is that its regulatory assets do not meet the recognition criteria for intangible or financial assets under the current IFRS standards. Under this assessment, these accounts will be adjusted to Retained Earnings and future charges will be expensed as incurred. MH will continue to monitor the developments on the IASB rate-regulated activities project and assess its options upon transition to IFRS.
OEB	The OEB will continue to use deferral and variance accounts for rate making in appropriate circumstances, whether or not these accounts are recognized under IFRS.
AUC	Utilities shall maintain the existing practice of applying to the Commission for approval of any deferral accounts that may be required for the purpose of establishing Regulatory Assets and Liabilities and proposing the mechanism for their disposition.

	Property Plant & Equipment - Borrowing Costs
IFRS	As per IAS 23, para. 1 "Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset. Other borrowing costs are recognized as an expense."
MH Current	MH's interest capitalization rate consists of the weighted average debt rate for all debt outstanding for the period, including anticipated borrowings in the upcoming fiscal year. Where debt is designated to finance a particular capital project, MH will capitalize interest to the asset based on the interest rate from that designated debt issue.
MH Proposed	No future changes are proposed upon transition to IFRS
OEB	The OEB will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the OEB's published rates. Otherwise, the applicant should use the OEB's published rates.
AUC	Subject to subsection (ii), utilities shall maintain the Existing Accounting Practice of including the debt and equity components of AFUDC when accounting for construction work in progress and plant in service. (ii) Utilities may submit an application to the AUC requesting approval to make their regulatory accounting practice the same as the practice under IFRS.

	Property Plant & Equipment - Customer Contributions
IFRS	Under IFRS, customer contributions are to be recognized as revenue; either immediately or over some future period of time. The customer contribution is recognized as revenue based upon the performance obligations of the underlying arrangement.
MH Current	Currently, non-refundable contributions in aid of construction are separately recorded on the balance sheet and amortized to income on a straight-line basis as a reduction to depreciation over the life of the related item of PP&E.
MH Proposed	MH is proposing that customer contributions be recognized as deferred revenue upon transition to IFRS where the revenue will be recognized over the life of the related plant asset. This will result in little or no impact to net income. However, classification on the income statement will change as the amortization of the contribution that was previously recognized as an offset in depreciation expense will now be recognized as revenue.
OEB	For regulatory reporting and rate making purposes, customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facilities to which they relate. Distributors should confirm in the introduction to their first rates application after the IFRS transition that the amortization period is being adjusted on an ongoing basis.
AUC	Utilities shall maintain the Existing Accounting Practice of recognizing customer contributions in their property, plant & equipment accounts and including the amortization as an offset to depreciation.

	Property Plant & Equipment - Asset Reclassifications from PPE to Intangible Assets
IFRS	As per IAS 38, para. 8 "An intangible asset is an identifiable non-monetary asset without physical substance." As per IAS 38, para. 4. "Some intangible assets may be contained in or on a physical substance such as a compact disc (in the case of computer software), legal documentation (in the case of a licence or patent) or film. In determining whether an asset that incorporates both intangible and tangible elements should be treated under IAS16 Property, Plant and Equipment or as an intangible asset under this Standard, an entity uses judgment to assess which element is more significant."
MH Current	Upon adoption of CICA section 3064 for its March 2010 year end, MH reclassified (April 1, 2008 balances, net of accumulated amortization) $103 million of Computer Software development and $37 million of Easements from Property, Plant & Equipment to a separate category titled Goodwill and Intangible Assets.
MH Proposed	No future changes are proposed upon transition to IFRS.
OEB	Where IFRS requires certain assets to be recorded as intangible assets that were previously included in PP&E (e.g. computer software and land rights), utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining revenue requirement.
AUC	Utilities shall maintain the Existing Accounting Practice of recognizing intangible assets as part of their property, plant & equipment accounts.

	Property Plant & Equipment - Asset Retirement Obligations
IFRS	As per IAS 16, para. 16 “The cost of an item of property, plant and equipment comprises:,… (c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.” As per IAS37 para. 10, “A constructive obligation is an obligation that derives from an entity's actions where: (a) by an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated to other parties that it will accept certain responsibilities; and (b) as a result, the entity has created a valid expectation on the part of those other parties that it will discharge those responsibilities.”
MH Current	Under GAAP, MH has recognized AROs for the decommissioning of a thermal generating station and the partial decommissioning of a hydraulic generating station.
MH Proposed	MH has reviewed its circumstances under IFRS and has preliminarily concluded that no new provisions exist pertaining to constructive obligations. MH will recognize such obligations when a commitment is made to decommission an asset and significant removal and/or remediation costs are expected to be incurred
OEB	Utilities shall identify separately in their rate applications the depreciation expense associated with amortizing asset retirement costs and the accretion expense associated with the amortization of the asset retirement obligations. The OEB will assess these costs independently of other amortization costs to determine the portion, if any, of these costs that should be recovered in revenue requirement.
AUC	Subject to subsection (ii), Utilities shall maintain the Existing Accounting Practice regarding the treatment of asset retirement obligations and future removal and site restoration costs. (ii) Utilities may, by way of application to the AUC, request approval to account for asset retirement obligations and future removal and site restoration costs in accordance with IFRS.

	Property Plant & Equipment - Gains and Losses on Disposition of Assets
IFRS	As per IAS 16, para. 68 "The gain or loss arising from the derecognition of an item of property, plant and equipment shall be included in profit or loss when the item is derecognized,…. Gains shall not be classified as revenue."
MH Current	MH currently recognizes gains and losses on the retirement of plant assets in accumulated depreciation.
MH Proposed	Upon transition to IFRS, MH is planning to recognize gains and losses on asset retirements to net income as they occur. Such gains and losses are expected to be minimized upon transitioning to the Equal Life Group method of depreciation upon transition to IFRS.
OEB	Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the OEB.
AUC	Utilities shall maintain the existing accounting practice of recording gains and losses upon retirement or disposal of assets. Utilities shall identify and record any difference in accounting between the IFRS reporting requirements and these regulatory reporting requirements in a separate subsidiary accumulated depreciation account.

	Property Plant & Equipment - Treatment of Asset Impairment
IFRS	As per IAS 36, para 9. "An entity shall assess at the end of each reporting period whether there is any indication that an asset may be impaired. If any such indication exists, the entity shall estimate the recoverable amount of the asset. para. 60, "An impairment loss shall be recognised immediately in profit or loss, unless the asset is carried at revalued amount in accordance with another Standard."
MH Current	Under CGAAP, long-lived assets should be tested whenever events or changes in circumstances indicate their carrying amount may not be recoverable. MH performs an annual impairment test on its goodwill balances which have not indicated any impairment to date.
MH Proposed	MH does not anticipate any substantial changes to its annual impairment testing requirements.
OEB	Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates.
AUC	Utilities shall maintain the existing accounting practice of having no impairment (or impairment reversal) charges included when providing or reporting financial information to the AUC.

	Depreciation
IFRS	As per IAS 16, para. 43 "Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately." para. 60, "The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity."
MH Current	MH currently depreciates its PP&E component groupings on a straight-line remaining-life basis.
MH Proposed	MH has established new depreciation component groupings as necessary to comply with IFRS requirements. New depreciation rates utilizing the Equal Life Group method of depreciation have been established for implementation upon transition to IFRS. In conjunction with this, Manitoba Hydro proposes to eliminate the inclusion of the cost of removing retired assets from its depreciation rates as this concept is not allowed under IFRS.
OEB	Utilities should continue to use the straight line method of depreciation for regulatory accounting purposes. The OEB engaged Kinectrics Inc. to perform a depreciation study for electricity distributors to assist them in making the transition from GAAP to IFRS and to assist them with the determination of suitable asset total service lives for assets commonly used in the distribution of electricity in Ontario. Distributors are required to assess whether the service lives as set out in the Kinectrics report are applicable to their own utility. Where applicable, utilities may make changes to their depreciation rates consistent with the recommendations of the Kinectrics report.
AUC	(i) Depreciation Rates A. Subject to subsection (B), utilities shall continue to use the depreciation rates utilized under the existing accounting practice. B. If the adoption of the IFRS requirements for external financial reporting results in depreciation rates that differ from existing accounting practice or results in a difference in the timing of commencement of depreciation, or both, then a utility may, by way of application to the AUC, request approval to account for regulatory depreciation in accordance with IFRS. (iii) Componentization A. Subject to subsection (B), with respect to componentization, utilities shall record assets at the level of detail being reported under the Existing Accounting Practice. B. If the adoption of IFRS requirements for external financial reporting results in a different level of componentization, then a utility may, by way of application to the AUC, request approval to account for regulatory componentization in accordance with IFRS.

	Inventory Valuation
IFRS	As per IAS 2, para. 9 "Inventories shall be measured at the lower of cost and net realisable value." para. 10 "The cost of inventories shall comprise all costs of purchase, costs of conversion and other costs incurred in bringing the inventories to their present location and condition." para 34 "When inventories are sold, the carrying amount of those inventories shall be recognized as an expense in the period in which the related revenue is recognized."
MH Current	MH records inventory at its average cost.
MH Proposed	No future changes are proposed upon transition to IFRS.
OEB	The OEB does not include a reference to inventory valuation outside of a reference to Purchased Gas Variance Accounts for gas utilities.
AUC	AUC Rule 026 does not include a reference to inventory valuation outside of capital inventories.

	Financial Reporting
IFRS	As per IAS 1, para. 15, “Financial statements shall present fairly the financial position, financial performance and cash flows of an entity. Fair presentation requires the faithful representation of the effects of transactions, other events and conditions in accordance with the definitions and recognition criteria for assets, liabilities, income and expenses set out in the Framework. The application of IFRSs, with additional disclosure when necessary, is presumed to result in financial statements that achieve a fair presentation.” para. 16 “An entity whose financial statements comply with IFRSs shall make an explicit and unreserved statement of such compliance in the notes. An entity shall not describe financial statements as complying with IFRSs unless they comply with all the requirements of IFRSs.”
MH Current	Given the recent AcSB announcement to permit rate-regulated entities an additional one year deferral to transition to IFRS, MH’s audited financial statements will be presented in accordance CGAAP for fiscal years 2012/13 – 2013/14.
MH Proposed	MH’s audited financial statements will be presented in accordance with IFRS commencing in its fiscal 2014/15 fiscal year and forward.
OEB	The OEB does not have the authority to determine a utilities form of financial reporting (i.e. IFRS or US GAAP) for external financial reporting purposes.
AUC	The AUC does not have the authority to determine a utilities form of financial reporting (i.e. IFRS or US GAAP) for external financial reporting purposes.

	Application Reporting
IFRS	IFRS does not include a standard that applies to the rate application reporting of rate-regulated utilities.
MH Current	MH's 2012/13 and 2013/14 GRA was prepared on the basis that MH would transition to IFRS in its 2013/14 fiscal year. As such the 2012/13 filing requirements were based on CGAAP and the 2013/14 filing requirements were based on IFRS. As a result of the recent announcement of the AcSB, MH will incorporate the impacts of the further deferral of IFRS to 2014/15 as part of IFF12.
MH Proposed	MH is proposing that upon transition to IFRS that financial and regulatory reporting will be aligned.
OEB	Effectively, all 2013 cost of service applications must be filed on the basis of modified IFRS for rate regulated utilities that have adopted IFRS or are required to adopt IFRS by January 1, 2013. An exception exists for those seeking the OEB's approval to adopt an alternate accounting standard such as US GAAP or Accounting Standards for Private Enterprises (ASPE). Please see Appendix 1 for application reporting requirements of Electric utilities.
AUC	Please see Appendix 2 to this response for the application reporting requirements of the AUC per AUC Rule 026. It is MH's understanding, that utilities that use a form of financial reporting that is different than CGAAP, must file rate applications in accordance with Rule 026 and where applicable, seek approval for regulatory deferral accounts for differences between financial reporting and regulatory reporting.

Appendix 1

The following chart was presented by the OEB on July 9, 2012 with respect to the filing requirements for rate setting purposes for 2013 filers:

The Year Applicant Adopts IFRS for Financial Reporting	Historical Year (2011)	Bridge year (2012)	Test Year (2013)
2012	CGAAP MIFRS	MIFRS	MIFRS
2013	CGAAP	CGAAP MIFRS	MIFRS

MIFRS refers to IFRS modified by the OEB for regulatory purposes consistent with the report of the Board on transition to IFRS.

Excerpt from AUC Rule 026 **Appendix 2**

Accounting/Reporting standards to use for Alberta utilities

Utilities that indicate to the Commission under subsection (2) that they will be adopting IFRS shall adhere to the following schedule

Fiscal Year	Year Filed	Actual / Forecast	Accounting/Reporting Standard to Use
2011	2012	Actual	For utilities that have adopted IFRS effective January 1, 2011 – this rule is to be followed for regulatory filings with the AUC, complete with 2010 comparatives prepared using this Rule; IFRS is to be used for financial statements, including 2010 comparatives prepared under IFRS. For utilities adopting IFRS effective January 1, 2012 – existing accounting practice is to be followed for regulatory filings with the AUC; existing Canadian GAAP is to be used for financial statements.
2012 & beyond	2013 & beyond	Actual	This Rule is to be followed for regulatory filings with the AUC; complete with prior year comparatives prepared using this rule; IFRS is to be followed for financial statements, including prior year comparatives prepared under IFRS.
2012 (first year in test period) & beyond	2011 & beyond	Forecast	This rule is to be used for forecasts filed with the AUC

Utilities shall disclose each IFRS adoption adjustment separately if the adjustment has an impact on a regulatory account. These adjustments shall be included in a utility’s first IFRS-compliant GRA/GTA, along with the utility’s proposal for the method for settling each adjustment.

PUB/MH I-56

Reference: Appendix 5.5 Page 19, IFRS – Goodwill Impairment Review

a) MH has made reference to a degradation in its distribution system and the generating stations on the Winnipeg River. To what extent were these assets former Winnipeg Hydro assets?

ANSWER:

Many of the former Winnipeg Hydro assets have reached an age where the overall condition is placing risk on reliable electric service. Examples include the Pointe Du Bois and the Slave Falls generating stations, as well as distribution assets within the City of Winnipeg.

PUB/MH I-56

Reference: Appendix 5.5 Page 19, IFRS – Goodwill Impairment Review

b) To what extent has the reassessment noted in this application of the condition of these assets impacted the Goodwill Impairment Review?

ANSWER:

As shown in Manitoba Hydro's response to PUB/MH I-56(c), there has been no impairment to electric operations goodwill.

There is no change in the assessment of the Winnipeg River assets. The cost of maintaining and replacing these assets has been factored into the goodwill impairment test.

PUB/MH I-56

Reference: Appendix 5.5 Page 19, IFRS – Goodwill Impairment Review

c) Please file a copy of the most recent Goodwill Impairment Valuation Review.

ANSWER:

Please see the most recent goodwill impairment test with respect to electric operations.

Electric Operations Goodwill Impairment Test
Based on MH11-2

Fiscal Year Ending	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Operating Activities											
Cash Receipts from Customers	1,556	1,693	1,778	1,873	2,007	2,114	2,224	2,320	2,466	2,769	2,957
Cash Paid to Suppliers and Employees	(742)	(816)	(886)	(931)	(951)	(976)	(1,018)	(1,048)	(1,084)	(1,103)	(1,125)
	815	876	892	942	1,056	1,138	1,206	1,273	1,382	1,666	1,832
Investing Activities											
Property, Plant & Equipment, Net of Contributions	(1,009)	(1,081)	(1,303)	(1,395)	(1,654)	(1,621)	(1,934)	(1,181)	(1,373)	(1,571)	(1,406)
Remove: Goodwill & Synergies in Electric	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1,036)	(1,109)	(1,330)	(1,423)	(1,680)	(1,674)	(1,977)	(1,218)	(1,410)	(1,613)	(1,453)
Free Cash Flow	**(221)**	**(232)**	**(438)**	**(480)**	**(624)**	**(536)**	**(771)**	**55**	**(28)**	**53**	**379**
MH Year End Discount Rate	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Growth Rate											
Capitalization Rate for Terminal Value											
Terminal Value Multiple											
Terminal Value											
Mid-Year	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5
Discount Factor	0.97	0.92	0.86	0.82	0.77	0.73	0.68	0.65	0.61	0.57	0.54
Discounted Value (Mid-Year)	**(215)**	**(213)**	**(378)**	**(392)**	**(480)**	**(389)**	**(528)**	**36**	**(17)**	**31**	**206**

Fiscal Year Ending	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Terminal Value
Operating Activities												
Cash Receipts from Customers	3,074	3,193	3,445	3,806	4,008	4,110	4,191	4,284	4,394	4,497	4,540	
Cash Paid to Suppliers and Employees	(1,154)	(1,201)	(1,215)	(1,234)	(1,272)	(1,303)	(1,329)	(1,358)	(1,383)	(1,410)	(1,437)	
	1,920	1,992	2,230	2,572	2,736	2,807	2,862	2,926	3,011	3,087	3,103	
Investing Activities												
Property, Plant & Equipment, Net of Contributions	(1,133)	(949)	(1,175)	(688)	(715)	(789)	(935)	(859)	(831)	(768)	(816)	
Remove: Goodwill & Synergies in Electric	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)	(30)	
	(1,169)	(986)	(1,209)	(723)	(752)	(824)	(971)	(895)	(867)	(804)	(853)	
Free Cash Flow	**751**	**1,006**	**1,021**	**1,849**	**1,984**	**1,983**	**1,891**	**2,032**	**2,144**	**2,282**	**2,251**	**2,251**
MH Year End Discount Rate	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Growth Rate												2.00%
Capitalization Rate for Terminal Value												3.77%
Terminal Value Multiple												27
Terminal Value												59,644
Mid-Year	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	19.5	20.5	21.5	
Discount Factor	0.51	0.48	0.46	0.43	0.41	0.38	0.36	0.34	0.32	0.30	0.29	0.29
Discounted Value (Mid-Year)	**384**	**486**	**465**	**794**	**804**	**758**	**682**	**691**	**688**	**691**	**643**	**17,041**

Fair Value of Goodwill:	
PV of Discretionary Cash Flow	4,747
Terminal Value	17,041
Enterprise Value	21,788
Carrying Amount of Goodwill:	
Value of Assets as at March 31	12,288
Unamortized CG Goodwill	(62)
Unamortized CG Capital Asset FMV Adjustment	(33)
Adjusted Value of Assets as at March 31	12,194
Excess Value	**9,595**

PUB/MH I-57

Reference: Appendix 5.5 Page 28 Capitalized Interest

a) Please describe how the corporation determines how much interest is allocated to construction and to specific construction projects.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-45(a).

Manitoba Hydro capitalizes interest on all domestic, major and new generation projects except certain short-term customer service projects with construction durations averaging approximately three months or less.

Interest during construction is calculated by applying the interest capitalization rate to the actual or forecasted month-end work in progress balance of each project, until such project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Interest capitalized calculated by project is then aggregated to form to total interest allocated to construction.

PUB/MH I-57

Reference: Appendix 5.5 Page 28 Capitalized Interest

b) Please provide a table of the Interest capitalization rate for fiscal years 2009/10 through 2014/15.

ANSWER:

Please see the table below.

Interest Capitalization Rate

Fiscal Year	Actual/Forecast	Effective Annual Rate
2009/10	Actual	6.6%
2010/11	Actual	6.8%
2011/12	Actual	6.7%
2012/13	Forecast	7.0%
2013/14	Forecast	7.1%
2014/15	Forecast	7.1%

PUB/MH I-57

Reference: Appendix 5.5 Page 28 Capitalized Interest

c) Please summarize how the interest capitalization rate was determined in 2012/13 & 2013/14.

ANSWER:

The projected interest capitalization rate is determined by dividing projected interest costs including the provincial guarantee fee and before interest capitalized is deducted by the average projected outstanding long-term debt and short-term debt for that year.

Please see the schedule below for the calculation.

IFF11-2 CALCULATION OF PROJECTED INTEREST CAPITALIZATION RATE

BASED ON PROJECTED CONSOLIDATED OPERATIONS IFF10-2

Updated using the proposed G911-1 interest rates (May 2011)

For year ending March 31:	2012	2013	2014
Interest on Debt		547	606
Provincial Guarantee		93	99
Amortization of premiums and discounts		2	2
Interest on Winnipeg Hydro Obligation		16	16
Total Interest Expense		657	723
Long Term Debt	9,055	9,061	10,480
Current Portion of Long Term Debt	182	822	100
Short Term Debt	45	60	187
Total Debt	9,282	9,943	10,767
Average Debt		9,612	10,355
Average semi-annual rate		**6.8%**	**7.0%**
Effective annual rate		**7.0%**	**7.1%**

PUB/MH I-57

Reference: Appendix 5.5 Page 28 Capitalized Interest

d) Please indicate to which extent the Corporation has identified specific debt issues designated to finance a particular capital project. Please provide particulars.

ANSWER:

The Corporation has not identified specific debt issues to be designated to finance a particular capital project.

PUB/MH I-57

Reference: Appendix 5.5 Page 28 Capitalized Interest

e) Please provide a schedule similar to the response to PUB/MH II-35 last GRA providing a breakdown of the interest allocated to construction by major project for each of the fiscal years 2009/10 through 2014/15.

ANSWER:

Please see the following table for the requested information.

(In Millions)

INTEREST ALLOCATED TO CONSTRUCTION	Actual 2009/10	Actual 2010/11	Actual 2011/12	Forecast 2012/13	Forecast 2013/14	Forecast 2014/15
Wuskwatim	40.08	58.40	73.91	5.68	0.00	0.00
Herblet Lake-The Pas 230 kV Transmission	1.34	3.34	1.51	0.00	0.00	0.00
Keeyask	20.62	25.60	29.71	41.02	54.41	53.70
Conawapa	10.09	12.19	14.02	23.82	30.44	34.66
Kelsey Improvements and Upgrades	2.79	3.17	3.05	1.79	0.58	0.00
Kettle Improvements & Upgrades	0.16	0.90	2.09	0.97	1.58	0.71
Pointe du Bois	2.33	3.91	6.02	12.04	20.33	18.62
Bipole III	2.35	3.78	7.17	16.65	42.66	82.85
Riel 230/500kV Station	0.90	3.28	6.24	12.64	16.75	18.14
Firm Import/Export Upgrades	0.00	0.06	0.08	0.57	0.14	0.22
Transmission for Wind	0.00	0.13	0.05	0.00	0.00	0.00
	80.65	**114.77**	**143.85**	**115.19**	**166.90**	**208.90**

PUB/MH I-57

Reference: Appendix 5.5 Page 28 Capitalized Interest

f) For illustrative purposes please show supporting calculations for the amount of interest allocated for the construction of the Conawapa G.S. based on IFF11-2

ANSWER:

Please see attached tables.

Illustration:

Conawapa

IFF11-2 - Monthly Projection

(In Millions of Dollars)

Date	CWIP Opening Balance	Construction Expenditures	Escalation	Capitalized Interest *	In-service Amount	CWIP Closing Balance
Apr-2012	306.12	5.56	0.12	1.70	0.00	313.49
May-2012	313.49	6.84	0.15	1.80	0.00	322.28
Jun-2012	322.28	6.51	0.16	1.79	0.00	330.74
Jul-2012	330.74	6.19	0.16	1.90	0.00	338.99
Aug-2012	338.99	6.93	0.19	1.94	0.00	348.05
Sep-2012	348.05	6.30	0.19	1.93	0.00	356.47
Oct-2012	356.47	6.99	0.22	2.04	0.00	365.73
Nov-2012	365.73	7.34	0.24	2.03	0.00	375.34
Dec-2012	375.34	5.95	0.21	2.15	0.00	383.65
Jan-2013	383.65	6.99	0.26	2.20	0.00	393.10
Feb-2013	393.10	6.62	0.26	2.04	0.00	402.02
Mar-2013	402.02	6.72	0.27	2.30	0.00	411.32
Total		78.95	2.43	23.82	0.00	

Date	CWIP Opening Balance	Construction Expenditures	Escalation	Capitalized Interest *	In-service Amount	CWIP Closing Balance
Apr-2013	197.29	4.05	0.17	2.33	0.00	203.84
May-2013	203.84	2.89	0.12	2.45	0.00	209.30
Jun-2013	209.30	2.62	0.11	2.40	0.00	214.43
Jul-2013	214.43	2.75	0.13	2.51	0.00	219.81
Aug-2013	219.81	2.75	0.13	2.54	0.00	225.23
Sep-2013	225.23	2.48	0.12	2.49	0.00	230.33
Oct-2013	230.33	2.89	0.15	2.60	0.00	235.96
Nov-2013	235.96	2.62	0.14	2.55	0.00	241.26
Dec-2013	241.26	2.49	0.13	2.66	0.00	246.55
Jan-2014	246.55	2.89	0.16	2.70	0.00	252.29
Feb-2014	252.29	2.48	0.14	2.46	0.00	257.39
Mar-2014	257.39	3.10	0.19	2.76	0.00	263.44
Total		34.01	1.69	30.44	0.00	

Date	CWIP Opening Balance	Construction Expenditures	Escalation	Capitalized Interest *	In-service Amount	CWIP Closing Balance
Apr-2014	263.44	2.42	0.15	2.68	0.00	268.68
May-2014	268.68	2.54	0.16	2.80	0.00	274.19
Jun-2014	274.19	2.54	0.17	2.74	0.00	279.63
Jul-2014	279.63	2.54	0.17	2.86	0.00	285.21
Aug-2014	285.21	2.42	0.17	2.90	0.00	290.69
Sep-2014	290.69	2.42	0.17	2.83	0.00	296.11
Oct-2014	296.11	2.66	0.19	2.96	0.00	301.93
Nov-2014	301.93	2.29	0.17	2.90	0.00	307.28
Dec-2014	307.28	2.42	0.18	3.02	0.00	312.91
Jan-2015	312.91	2.54	0.20	3.06	0.00	318.71
Feb-2015	318.71	2.29	0.18	2.79	0.00	323.97
Mar-2015	323.97	3.24	0.27	3.12	0.00	330.60
Total		30.32	2.18	34.66	0.00	

* The Effective Interest Capitalization Rate 2013 is 7.0%, 2014 is 7.1% and 2015 is 7.1%

<u>PUB/MH I-57</u>

Reference: Appendix 5.5 Page 28 Capitalized Interest

g) Please indicate how MH determined the interest allocated to the Wuskwatim G.S. in 2011 and 2012

<u>ANSWER</u>:

The Wuskwatim Power Limited Partnership (WPLP) capitalizes interest at the same rate of interest on all project debt financing (75% of total Wuskwatim capital costs) in accordance with the Project Financing Agreement between Manitoba Hydro and WPLP. Manitoba Hydro further capitalizes interest on its 67% share of the 25% equity portion of total Wuskwatim capital costs at Manitoba Hydro's average interest capitalization rate which applies to all of Manitoba Hydro's capital projects.

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Reference: Appendix 5.6 Page 6 Cost Element Overview

Please provide a table providing the detailed cost element groupings represented in the pie chart for each of the years 2003/04 through 2013/14 and provide the compound annual growth rate for the years 2003/04 through 2011/12 and that for the period 2011/12 through 2013/14.

ANSWER:

Please see the attached schedule, which includes the detailed cost element groupings from 2007/08 through 2013/14.

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		$ 476,887	$ 486,425	
Overtime	41,781	45,890	50,307	50,704	54,987		56,005	57,126	
Employee Benefits	76,807	83,671	82,674	95,376	104,444		109,649	111,842	
Salaries, Overtime & Benefits	**477,838**	**509,592**	**540,968**	**571,238**	**611,356**	6.4	**642,542**	**655,393**	3.5
Travel	28,331	31,812	32,435	32,594	31,266		32,405	33,053	
Motor Vehicle	22,423	24,126	24,281	24,436	28,676		24,784	25,280	
Travel & Motor Vehicles	**50,754**	**55,938**	**56,716**	**57,029**	**59,942**	4.2	**57,189**	**58,333**	-1.4
Materials & Tools	27,824	29,345	26,897	28,105	26,663		27,173	27,716	
Equipment Maintenance & Rentals	11,719	13,029	14,379	14,165	13,388		14,476	14,766	
Materials & Equip Maintenance	**39,543**	**42,374**	**41,276**	**42,269**	**40,051**	0.3	**41,649**	**42,482**	3.0
Consulting & Professional Fees	7,503	9,704	14,814	11,157	10,250		11,639	11,872	
Construction & Maintenance Services	15,938	18,378	20,109	22,657	21,228		18,706	19,080	
External Services	**23,441**	**28,082**	**34,923**	**33,814**	**31,478**	7.6	**30,345**	**30,952**	-0.8
Building & Property Services	25,740	28,947	22,931	21,944	21,386		22,396	22,843	
Office & Administration	14,427	14,652	15,320	14,316	14,277		15,263	15,569	
Office & Building Services	**40,167**	**43,599**	**38,250**	**36,260**	**35,663**	-2.9	**37,659**	**38,412**	3.8
Employee Safety & Training	3,646	4,145	4,623	3,863	3,909		4,914	5,013	
Consumer Services	4,651	5,284	5,798	5,086	5,365		5,284	5,389	
Collection Costs	5,256	5,019	4,599	4,497	4,034		4,347	4,434	
Customer & Public Relations	6,665	6,901	8,155	7,905	8,093		6,949	7,088	
Sponsored Memberships	1,192	1,465	1,325	1,917	1,608		1,081	1,103	
Computer Services	1,131	858	983	1,003	861		909	927	
Communication Systems	1,353	1,449	1,772	1,678	1,683		1,683	1,717	
Research & Development Costs	2,979	3,059	3,952	3,651	2,796		3,509	3,579	
Miscellaneous Expense	3,292	903	1,190	1,264	2,032		1,213	1,237	
Contingency Planning		-	-	-	-		278	2,875	
Operating Expense Recovery	(23,314)	(21,519)	(21,580)	(23,004)	(21,716)		(9,787)	(9,983)	
Other	**6,851**	**7,564**	**10,817**	**7,860**	**8,665**	6.0	**20,381**	**23,379**	64.3
Total Costs	**$ 638,594**	**$ 687,149**	**$ 722,951**	**$ 748,471**	**$ 787,155**	5.4	**$ 829,765**	**$ 848,951**	3.9

PUB/MH I-59 (Revised)

Reference: Tab 5 Page 14 of 36, Schedule 5.5.0, Appendix 5.6 Page 7

a) Please provide a schedule detailing the operating and administration charged to Centra for each of the fiscal years 2004/05 – 2013/ 14 (actual/forecast) by:

i. Cost Element
ii. Business Unit

ANSWER:

Please see the following schedules.

MANITOBA HYDRO
CENTRA GAS PROGRAM COSTS BY BUSINESS UNIT

($000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
President & CEO	$ 1,271	$ 946	$ 1,078	$ 1,073	$ 1,374	$ 1,103	$ 976	$ 998	$ 895	$ 913
Finance & Administration	7,260	6,333	7,085	6,833	6,830	7,005	6,978	6,669	6,350	6,477
Power Supply	170	29	36	46	47	220	477	317	404	412
Transmission	209	217	200	236	224	255	250	101	194	197
Customer Service & Distribution	31,508	31,299	31,067	34,701	35,549	38,204	35,624	36,966	36,031	36,751
Customer Care & Marketing	21,984	21,752	19,882	20,363	20,993	20,492	19,877	20,501	19,758	20,153
Business Unit Subtotal	**62,402**	**60,576**	**59,349**	**63,252**	**65,017**	**67,279**	**64,183**	**65,552**	**63,631**	**64,904**
Corporate Allocations & Adjustments	804	221	2,035	1,455	2,027	1,578	1,656	1,840	6,671	6,786
Depreciation, Interest and Taxes	(7,974)	(7,712)	(7,879)	(8,437)	(8,003)	(7,906)	(5,194)	(5,275)	(3,003)	(3,063)
IFRS Changes										15,300
Operating and Administrative	**55,232**	**53,085**	**53,505**	**56,270**	**59,041**	**60,951**	**60,644**	**62,117**	**67,300**	**83,927**

Note:
Accounting Changes reflected in Business Unit Programs prior to 2013/14

MANITOBA HYDRO
CENTRA GAS PROGRAM COSTS BY COST ELEMENT

($000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Activity Charges	$ 39,680	$ 37,924	$ 38,381	$ 41,181	$ 42,310	$ 44,410	$ 45,918	$ 46,574	$ 41,336	$ 42,163
Primary Costs:										
External Course, Awards	54	44	41	55	26	24	26	21	9	$ 9
Material	1,460	1,256	1,107	1,326	1,472	1,294	1,184	1,170	1,337	1,364
Travel	131	125	96	102	122	87	102	79	135	137
Donations, Grants & Sponsorships	514	389	309	333	334	333	393	476	358	365
Memberships	113	95	138	98	140	51	176	60	180	184
Bad Debt & Collection Expense	2,771	4,128	2,427	2,148	2,135	2,086	1,613	1,435	1,559	1,590
Office Administration & Other	1,601	1,565	1,566	1,581	1,582	1,562	1,557	1,608	1,596	1,628
Computer Equipment & Maintenance	381	450	265	310	546	563	522	452	547	557
Meter Reading Charges (primarily MHUS)	1,698	1,738	1,677	1,765	2,190	2,425	1,949	2,130	2,126	2,169
Banking/Cash Management Services	299	90	207	205	192	222	220	255	284	290
Construction & Maintenance Services	1,204	1,214	1,116	1,288	977	1,240	947	1,823	1,138	1,160
Purchased Services	721	753	835	898	1,237	1,988	1,772	1,506	2,123	2,166
Promotional Items/Customer Incentives	19	38	54	20	39	25	57	71	27	28
Gas-PUB & Advisory Services	652	637	706	681	722	766	491	496	473	482
Operating Expense Recoveries	(1,109)	(1,013)	(823)	(821)	(561)	(537)	(620)	(598)	-	-
Other	522	25		2	5	5	6	5	1	1
Total Primary Costs	**11,031**	**11,534**	**9,721**	**9,989**	**11,159**	**12,134**	**10,394**	**10,988**	**11,893**	**12,131**
Corporate Allocations & Adjustments	804	221	2,035	1,455	2,027	1,578	1,656	1,840	6,671	6,805
Overhead	11,691	11,118	11,248	12,082	11,549	10,735	7,870	7,990	10,403	10,611
IFRS Changes										15,300
Total Program Costs	**63,206**	**60,797**	**61,384**	**64,707**	**67,044**	**68,856**	**65,838**	**67,392**	**70,303**	**87,009**
Depreciation, Interest and Taxes	(7,974)	(7,712)	(7,879)	(8,437)	(8,003)	(7,906)	(5,194)	(5,275)	(3,003)	(3,063)
Operating and Administrative	**55,232**	**53,085**	**53,505**	**56,270**	**59,041**	**60,951**	**60,644**	**62,117**	**67,300**	**83,946**

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Reference: Tab 5 Page 14 of 36, Schedule 5.5.0, Appendix 5.6 Page 7

b) Please provide a detailed breakdown of operating and administrative costs by division for the years 2003/04 through 2014/15 in the same level of detail provided at the last GRA.

ANSWER:

Please see the following Operating, Maintenance and Administrative Costs by Division from 2004/05 to 2013/14.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
(000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
President & CEO										
General Counsel	$ 4,383	$ 5,175	$ 4,887	$ 4,629	$ 5,669	$ 5,933	$ 5,665	$ 5,799	$ 6,406	$ 6,534
Public Affairs	2,804	2,856	3,288	2,939	3,189	3,582	3,938	3,682	3,688	3,762
Research & Development	3,491	3,462	3,491	3,548	3,396	4,148	3,773	2,856	3,650	3,723
Corp Planning & Strat Analysis			-	-	-	593	356	132		
Corporate Planning & Strategic Review	1,696	1,652	1,867	1,986	2,075	2,854	3,366	3,722	4,070	4,152
Administration	8,575	8,977	9,674	9,861	9,901	14,469	11,739	12,138	10,878	11,068
*Adjustment for IFRS										
	$ 20,949	**$ 22,123**	**$ 23,207**	**$ 22,963**	**$ 24,230**	**$ 31,578**	**$ 28,835**	**$ 28,328**	**$ 28,692**	**$ 29,239**
Corporate Relations										
Aboriginal Relations	$ 2,968	$ 4,653	$ 4,324	$ 4,331	$ 4,473	$ 3,929	$ 4,101	$ 2,475	$ 3,926	$ 4,004
Administration	535	844	896	914	1,047	769	638	550	566	581
*Adjustment for IFRS										
	$ 3,503	**$ 5,496**	**$ 5,220**	**$ 5,245**	**$ 5,520**	**$ 4,697**	**$ 4,739**	**$ 3,025**	**$ 4,491**	**$ 4,585**
Finance & Administration										
Information Technology Services	$ 29,273	$ 29,884	$ 34,413	$ 32,709	$ 33,959	$ 35,349	$ 34,181	$ 35,539	$ 38,037	$ 38,798
Treasury	2,267	2,146	1,887	2,001	2,067	1,957	1,909	1,915	1,981	2,021
Corporate Risk Mgmt Department	150	153	442	460	566	593	811	938	977	997
Gas Supply	1,789	2,027	1,981	2,058	2,248	2,356	2,428	2,488	2,590	2,642
Rates & Regulatory Affairs	3,105	2,913	3,037	2,999	2,918	3,388	3,139	3,152	3,273	3,339
Corporate Controller	9,085	9,161	8,800	9,475	10,053	11,327	10,873	10,694	11,173	11,397
Human Resources	11,505	11,486	11,749	11,664	11,972	11,232	10,655	11,352	12,032	12,273
Corporate Safety & Health	1,690	1,982	1,852	2,839	2,324	2,293	2,847	2,838	3,331	3,397
Corporate Services	30,258	31,608	32,527	33,108	35,313	37,274	37,003	35,947	38,263	39,028
Administration	1,500	1,656	2,337	2,207	2,303	3,144	2,682	2,582	2,685	2,764
*Adjustment for IFRS										2,160
	$ 90,622	**$ 93,016**	**$ 99,027**	**$ 99,521**	**$ 103,722**	**$ 108,914**	**$ 106,528**	**$ 107,445**	**$ 114,343**	**$ 118,816**
Power Supply										
Power Planning	$ 2,431	$ 1,836	$ 2,299	$ 2,955	$ 4,015	$ 5,657	$ 6,583	$ 6,741	$ 7,205	$ 7,349
Power Projects Development	865	581	696	354	764	156	647	225	2,304	2,350
Portfolio Projects Management	-	42	58	57	(34)	219	364	344	662	675
HVDC	17,653	17,282	19,177	19,128	21,659	23,170	22,927	24,698	27,380	27,927
Generation North	28,942	29,516	29,399	30,929	33,671	29,594	31,217	31,347	35,779	38,008
Generation South	44,755	43,734	45,105	46,747	50,020	54,332	54,602	56,495	58,670	59,843
Engineering Services	5,784	4,488	4,449	4,909	4,534	4,693	3,476	2,146	8,474	8,644
Power Sales & Operations	8,870	10,120	11,346	11,625	12,578	12,969	12,770	13,364	14,384	14,671
New Generation Construction	(134)	(306)	(447)	(228)	24	(212)	(744)	(303)	1,121	1,143
Administration	4,269	9,901	11,277	11,134	14,952	16,495	18,277	20,028	21,903	22,341
*Adjustment for IFRS										4,080
	$ 113,433	**$ 117,196**	**$ 123,359**	**$ 127,610**	**$ 142,183**	**$ 147,073**	**$ 150,119**	**$ 155,085**	**$ 177,882**	**$ 187,031**

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
(000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Transmission										
Transmission System Operations	$ 27,102	$ 27,639	$ 29,779	$ 28,453	$ 31,408	$ 33,185	$ 32,415	$ 29,857	$ 33,237	$ 33,902
Transmission Planning & Design	4,836	4,855	5,212	3,402	5,219	4,162	3,419	4,936	8,243	8,408
Transmission Construction & Line Mtce	14,349	14,395	14,861	15,952	15,964	17,219	16,239	15,998	19,707	20,101
Apparatus Maintenance	28,913	29,082	31,327	33,834	36,281	35,742	36,272	37,024	40,625	41,438
Administration	2,779	1,840	2,323	1,529	2,216	1,995	2,148	1,446	2,849	2,906
*Adjustment for IFRS										510
	$ 77,979	**$ 77,810**	**$ 83,503**	**$ 83,171**	**$ 91,088**	**$ 92,302**	**$ 90,493**	**$ 89,261**	**$ 104,662**	**$ 107,265**
Customer Services & Distribution										
Customer Service Operations - Wpg&North	$ 43,697	$ 44,249	$ 42,043	$ 44,838	$ 48,048	$ 49,635	$ 47,815	$ 49,287	$ 53,094	$ 54,156
Customer Service Operations - South	39,549	44,088	42,812	44,006	46,316	50,368	49,325	49,861	56,318	57,395
Distribution E&C Rural	5,025	6,056	5,378	7,048	7,685	8,238	6,802	6,249	11,077	11,299
Distribution E&C Winnipeg	3,836	2,011	1,580	1,937	1,483	1,359	1,505	774	6,291	6,417
Administration	-	560	277	544	230	1,468	1,259	3,873	3,578	3,649
	$ 92,107	**$ 96,964**	**$ 92,091**	**$ 98,373**	**$ 103,762**	**$ 111,068**	**$ 106,706**	**$ 110,044**	**$ 130,358**	**$ 132,916**
Customer Care & Marketing										
Industrial & Commercial Solutions	$ 2,780	$ 1,946	$ 2,449	$ 2,669	$ 2,077	$ 2,636	$ 2,077	$ 2,468	$ 5,150	$ 5,253
Consumer Marketing & Sales	9,874	9,741	9,913	8,905	9,545	10,642	11,518	11,630	13,574	13,846
Business Support Services	25,448	26,929	26,661	22,937	23,128	23,347	22,985	24,606	27,854	28,411
Administration	4,257	3,678	3,869	3,961	4,192	5,770	4,867	4,998	5,671	5,785
*Adjustment for IFRS										42,628
	$ 42,359	**$ 42,293**	**$ 42,891**	**$ 38,472**	**$ 38,942**	**$ 42,395**	**$ 41,447**	**$ 43,702**	**$ 52,249**	**$ 95,923**
Motor Vehicle Chargeout	$ (20,221)	$ (22,090)	$ (22,118)	$ (22,010)	$ (24,266)	$ (24,352)	$ (17,933)	$ (16,843)	$ (14,374)	$ (14,661)
Payroll Tax	(7,602)	(8,136)	(8,344)	(8,774)	(9,679)	(10,070)	(10,458)	(11,137)	(11,299)	(11,525)
Corporate Allocations & Adjustments	(1,110)	1,099	21	1,686	9,787	(4,952)	4,450	9,595	(3,304)	(3,370)
Operating & Administration Charged to Centra	(55,232)	(53,085)	(53,505)	(56,270)	(59,803)	(60,951)	(60,644)	(62,117)	(67,300)	(68,646)
Capitalized Overhead	(58,174)	(62,028)	(61,887)	(67,289)	(61,198)	(60,151)	(47,336)	(53,084)	(69,434)	(70,823)
Provision for IFRS										25,075
Operating & Administrative Costs Attributable to Electric Operations	**$ 298,613**	**$ 310,658**	**$ 323,465**	**$ 322,696**	**$ 364,288**	**$ 377,551**	**$ 396,946**	**$ 403,304**	**$ 446,966**	**$ 531,825**

* Adjustments for IFRS will be allocated to the Divisions in IFF12
**Other CICA Accounting Changes totalling $4 million (beginning in 2009/10) are embedded within the Business Units

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Reference: Tab 5 Page 14 of 36, Schedule 5.5.0, Appendix 5.6 Page 7

c) Please provide a schedule in part (b) which incorporates a column for the compounded annual growth for the years 2003/04 through 2011/12 and a column for the CAG for the years 2011/12 through 2014/15

ANSWER:

Please see the following Operating, Maintenance and Administrative Costs by Division from 2004/05 to 2013/14, with compounded annual growth from 2004/05 to 2011/12 and from 2011/12 through 2013/14.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
(000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	Fiscal 2004/05-2011/12 Compounded Annual Growth	2012/13 Forecast	2013/14 Forecast	Fiscal 2011/12-2013/14 Compounded Annual Growth
President & CEO												
General Counsel	$ 4,383	$ 5,175	$ 4,887	$ 4,629	$ 5,669	$ 5,933	$ 5,665	$ 5,799	4.1	$ 6,406	$ 6,534	6.1
Public Affairs	2,804	2,856	3,288	2,939	3,189	3,582	3,938	3,682	4.0	3,688	3,762	1.1
Research & Development	3,491	3,462	3,491	3,548	3,396	4,148	3,773	2,856	(2.8)	3,650	3,723	14.2
Corp Planning & Strat Analysis			-	-	-	593	356	132	0.0			(100.0)
Corporate Planning & Strategic Review	1,696	1,652	1,867	1,986	2,075	2,854	3,366	3,722	11.9	4,070	4,152	5.6
Administration	8,575	8,977	9,674	9,861	9,901	14,469	11,739	12,138	5.1	10,878	11,068	(4.5)
*Adjustment for IFRS									0.0			0.0
	$ 20,949	**$ 22,123**	**$ 23,207**	**$ 22,963**	**$ 24,230**	**$ 31,578**	**$ 28,835**	**$ 28,328**	**4.4**	**$ 28,692**	**$ 29,239**	**1.6**
Corporate Relations												
Aboriginal Relations	$ 2,968	$ 4,653	$ 4,324	$ 4,331	$ 4,473	$ 3,929	$ 4,101	$ 2,475	(2.6)	$ 3,926	$ 4,004	27.2
Administration	535	844	896	914	1,047	769	638	550	0.4	566	581	2.8
*Adjustment for IFRS									0.0			0.0
	$ 3,503	**$ 5,496**	**$ 5,220**	**$ 5,245**	**$ 5,520**	**$ 4,697**	**$ 4,739**	**$ 3,025**	**(2.1)**	**$ 4,491**	**$ 4,585**	**23.1**
Finance & Administration												
Information Technology Services	$ 29,273	$ 29,884	$ 34,413	$ 32,709	$ 33,959	$ 35,349	$ 34,181	$ 35,539	2.8	$ 38,037	$ 38,798	4.5
Treasury	2,267	2,146	1,887	2,001	2,067	1,957	1,909	1,915	(2.4)	1,981	2,021	2.7
Corporate Risk Mgmt Department	150	153	442	460	566	593	811	938	29.9	977	997	3.1
Gas Supply	1,789	2,027	1,981	2,058	2,248	2,356	2,428	2,488	4.8	2,590	2,642	3.0
Rates & Regulatory Affairs	3,105	2,913	3,037	2,999	2,918	3,388	3,139	3,152	0.2	3,273	3,339	2.9
Corporate Controller	9,085	9,161	8,800	9,475	10,053	11,327	10,873	10,694	2.4	11,173	11,397	3.2
Human Resources	11,505	11,486	11,749	11,664	11,972	11,232	10,655	11,352	(0.2)	12,032	12,273	4.0
Corporate Safety & Health	1,690	1,982	1,852	2,839	2,324	2,293	2,847	2,838	7.7	3,331	3,397	9.4
Corporate Services	30,258	31,608	32,527	33,108	35,313	37,274	37,003	35,947	2.5	38,263	39,028	4.2
Administration	1,500	1,656	2,337	2,207	2,303	3,144	2,682	2,582	8.1	2,685	2,764	3.5
*Adjustment for IFRS									0.0		2,160	0.0
	$ 90,622	**$ 93,016**	**$ 99,027**	**$ 99,521**	**$ 103,722**	**$ 108,914**	**$ 106,528**	**$ 107,445**	**2.5**	**$ 114,343**	**$ 118,816**	**5.2**
Power Supply												
Power Planning	$ 2,431	$ 1,836	$ 2,299	$ 2,955	$ 4,015	$ 5,657	$ 6,583	$ 6,741	15.7	$ 7,205	$ 7,349	4.4
Power Projects Development	865	581	696	354	764	156	647	225	(17.5)	2,304	2,350	223.2
Portfolio Projects Management	-	42	58	57	(34)	219	364	344	0.0	662	675	40.1
HVDC	17,653	17,282	19,177	19,128	21,659	23,170	22,927	24,698	4.9	27,380	27,927	6.3
Generation North	28,942	29,516	29,399	30,929	33,671	29,594	31,217	31,347	1.1	35,779	38,008	10.1
Generation South	44,755	43,734	45,105	46,747	50,020	54,332	54,602	56,495	3.4	58,670	59,843	2.9
Engineering Services	5,784	4,488	4,449	4,909	4,534	4,693	3,476	2,146	(13.2)	8,474	8,644	100.7
Power Sales & Operations	8,870	10,120	11,346	11,625	12,578	12,969	12,770	13,364	6.0	14,384	14,671	4.8
New Generation Construction	(134)	(306)	(447)	(228)	24	(212)	(744)	(303)	12.4	1,121	1,143	0.0
Administration	4,269	9,901	11,277	11,134	14,952	16,495	18,277	20,028	24.7	21,903	22,341	5.6
*Adjustment for IFRS									0.0		4,080	0.0
	$ 113,433	**$ 117,196**	**$ 123,359**	**$ 127,610**	**$ 142,183**	**$ 147,073**	**$ 150,119**	**$ 155,085**	**4.6**	**$ 177,882**	**$ 187,031**	**9.8**

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
(000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	Fiscal 2004/05-2011/12 Compounded Annual Growth	2012/13 Forecast	2013/14 Forecast	Fiscal 2011/12-2013/14 Compounded Annual Growth
Transmission												
Transmission System Operations	$ 27,102	$ 27,639	$ 29,779	$ 28,453	$ 31,408	$ 33,185	$ 32,415	$ 29,857	1.4	$ 33,237	$ 33,902	6.6
Transmission Planning & Design	4,836	4,855	5,212	3,402	5,219	4,162	3,419	4,936	0.3	8,243	8,408	30.5
Transmission Construction & Line Mtce	14,349	14,395	14,861	15,952	15,964	17,219	16,239	15,998	1.6	19,707	20,101	12.1
Apparatus Maintenance	28,913	29,082	31,327	33,834	36,281	35,742	36,272	37,024	3.6	40,625	41,438	5.8
Administration	2,779	1,840	2,323	1,529	2,216	1,995	2,148	1,446	(8.9)	2,849	2,906	41.8
*Adjustment for IFRS									0.0		510	0.0
	$ 77,979	**$ 77,810**	**$ 83,503**	**$ 83,171**	**$ 91,088**	**$ 92,302**	**$ 90,493**	**$ 89,261**	**1.9**	**$ 104,662**	**$ 107,265**	**9.6**
Customer Services & Distribution												
Customer Service Operations - Wpg&North	$ 43,697	$ 44,249	$ 42,043	$ 44,838	$ 48,048	$ 49,635	$ 47,815	$ 49,287	1.7	$ 53,094	$ 54,156	4.8
Customer Service Operations - South	39,549	44,088	42,812	44,006	46,316	50,368	49,325	49,861	3.4	56,318	57,395	7.3
Distribution E&C Rural	5,025	6,056	5,378	7,048	7,685	8,238	6,802	6,249	3.2	11,077	11,299	34.5
Distribution E&C Winnipeg	3,836	2,011	1,580	1,937	1,483	1,359	1,505	774	(20.4)	6,291	6,417	187.9
Administration	-	560	277	544	230	1,468	1,259	3,873	0.0	3,578	3,649	(2.9)
	$ 92,107	**$ 96,964**	**$ 92,091**	**$ 98,373**	**$ 103,762**	**$ 111,068**	**$ 106,706**	**$ 110,044**	**2.6**	**$ 130,358**	**$ 132,916**	**9.9**
Customer Care & Marketing												
Industrial & Commercial Solutions	$ 2,780	$ 1,946	$ 2,449	$ 2,669	$ 2,077	$ 2,636	$ 2,077	$ 2,468	(1.7)	$ 5,150	$ 5,253	45.9
Consumer Marketing & Sales	9,874	9,741	9,913	8,905	9,545	10,642	11,518	11,630	2.4	13,574	13,846	9.1
Business Support Services	25,448	26,929	26,661	22,937	23,128	23,347	22,985	24,606	(0.5)	27,854	28,411	7.5
Administration	4,257	3,678	3,869	3,961	4,192	5,770	4,867	4,998	2.3	5,671	5,785	7.6
*Adjustment for IFRS									0.0		42,628	0.0
	$ 42,359	**$ 42,293**	**$ 42,891**	**$ 38,472**	**$ 38,942**	**$ 42,395**	**$ 41,447**	**$ 43,702**	**0.4**	**$ 52,249**	**$ 95,923**	**48.2**
Motor Vehicle Chargeout	$ (20,221)	$ (22,090)	$ (22,118)	$ (22,010)	$ (24,266)	$ (24,352)	$ (17,933)	$ (16,843)	(2.6)	$ (14,374)	$ (14,661)	(6.7)
Payroll Tax	(7,602)	(8,136)	(8,344)	(8,774)	(9,679)	(10,070)	(10,458)	(11,137)	5.6	(11,299)	(11,525)	1.7
Corporate Allocations & Adjustments	(1,110)	1,099	21	1,686	9,787	(4,952)	4,450	9,595	(236.1)	(3,304)	(3,370)	0.0
Operating & Administration Charged to Centra	(55,232)	(53,085)	(53,505)	(56,270)	(59,803)	(60,951)	(60,644)	(62,117)	1.7	(67,300)	(68,646)	5.1
Capitalized Overhead	(58,174)	(62,028)	(61,887)	(67,289)	(61,198)	(60,151)	(47,336)	(53,084)	(1.3)	(69,434)	(70,823)	15.5
Provision for IFRS									0.0		25,075	0.0
Operating & Administrative Costs Attributable to Electric Operations	**$ 298,613**	**$ 310,658**	**$ 323,465**	**$ 322,696**	**$ 364,288**	**$ 377,551**	**$ 396,946**	**$ 403,304**	**4.4**	**$ 446,966**	**$ 531,825**	**14.8**

* Adjustments for IFRS will be allocated to the Divisions in IFF12
**Other CICA Accounting Changes totalling $4 million (beginning in 2009/10) are embedded within the Business Units

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Reference: Tab 5 Page 14 of 36, Schedule 5.5.0, Appendix 5.6 Page 7

d) Please provide a schedule which compares for fiscal 2009/10,2010/11 and 2011/12 actual/forecast results presented in this application with the forecast results and in the level of detail provided at the 2010/11 & 2011/12 GRA in both dollar change and % change by:

i. Cost element
ii. Business unit

And explain any differences over 5%

ANSWER:

Please see the following schedules for the requested information. Please note that the 2009/10 forecast data comes from IFF09 and the 2010/11 and 2011/12 data comes from IFF10-2.

Differences over 5% and $500,000 have been explained.

i)

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

	2009/10 Actual	2009/10 Forecast	2009/10 Variance	%	Ref
Wages, Salaries	$ 407,988	$ 411,832	$ 3,844	1%	
Overtime	50,307	47,248	(3,059)	-6%	1
Employee Benefits	83,013	85,971	2,958	3%	
Employee Safety & Training	4,284	4,257	(27)	-1%	
Travel	32,435	31,960	(475)	-1%	
Motor Vehicle	24,281	22,967	(1,314)	-6%	2
Materials & Tools	26,897	25,762	(1,135)	-4%	
Consulting & Professional Fees	14,814	10,594	(4,220)	-40%	3
Construction & Maintenance Services	20,109	21,489	1,380	6%	4
Building & Property Services	22,931	20,506	(2,425)	-12%	5
Equipment Maintenance & Rentals	14,379	13,794	(585)	-4%	
Consumer Services	5,798	5,572	(226)	-4%	
Computer Services	983	682	(301)	-44%	
Collection Costs	4,599	4,430	(169)	-4%	
Customer & Public Relations	8,155	5,870	(2,285)	-39%	6
Sponsored Memberships	1,325	1,242	(83)	-7%	
Office & Administration	15,320	15,526	206	1%	
Communication Systems	1,772	1,572	(200)	-13%	
Research & Development Costs	3,952	4,029	77	2%	
Miscellaneous Expense	1,190	1,066	(124)	-12%	
Contingency Planning	-	3,994	3,994	100%	7
Operating Expense Recovery	(21,580)	(16,662)	4,918	-30%	8
Total Costs	722,952	723,701	749	0%	
Capital Order Activities	(224,298)	(231,073)	(6,775)	-3%	
CICA Accounting Changes*			-	-	
Provision for IFRS			-	-	
Capitalized Overhead	(60,151)	(60,964)	(813)	-1%	
Operating and Administration Charged to Centra	(60,951)	(60,160)	791	1%	
OM&A Attributable to Electric Operations	**$ 377,552**	**$ 371,504**	**$ (6,048)**	**-2%**	

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT
2009/10 VARIANCE EXPLANATIONS

Ref	Cost Element	Fav (Unfav)	Explanation
1	Overtime	(3,059)	Increased requirements driven by capital projects, outage schedules, storm restorations, system emergencies, flood preparations and the strike.
2	Motor Vehicle	(1,314)	Increased repair and maintenance costs and higher insurance premiums.
3	Consulting & Professional Fees	(4,220)	Primarily due to Risk Management review, CICA accounting standard changes resulting in expensing select costs for DSM programs, and a higher number of employee relocations and associated costs.
4	Construction & Maintenance Services	1,380	Primarily due to reduced requirements for external contractors and equipment, and cancelled winter road maintenance due to mild weather conditions.
5	Building & Property Services	(2,425)	Higher costs resulting from delayed moves to 360 Portage, increased usage of staffhouses, additional security services during the strike and a higher value of insurance claims.
6	Customer & Public Relations	(2,285)	Primarily due to CICA accounting standard changes resulting in expensing select costs for DSM programs and higher corporate donations and sponsorships.
7	Contingency Planning	3,994	Unallocated general contingency.
8	Operating Expense Recovery	4,918	Higher revenue due to subsidiary recoveries, and higher business initiative revenue mainly related to Stony Mountain Penitentiary, MDS Aero Glacier and St Joseph Wind farm projects. In addition, increased staffhouse income related to higher utilization.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

	2010/11 Actual	2010/11 Forecast	2010/11 Variance	%	Ref
Wages, Salaries	$ 425,158	$ 415,215	$ (9,943)	-2%	
Overtime	50,704	48,061	(2,643)	-5%	9
Employee Benefits	95,376	93,035	(2,341)	-3%	
Employee Safety & Training	3,863	4,747	884	19%	10
Travel	32,594	32,963	369	1%	
Motor Vehicle	24,436	23,114	(1,322)	-6%	11
Materials & Tools	28,105	26,178	(1,927)	-7%	12
Consulting & Professional Fees	11,157	10,904	(253)	-2%	
Construction & Maintenance Services	22,657	21,785	(872)	-4%	
Building & Property Services	21,944	20,671	(1,273)	-6%	13
Equipment Maintenance & Rentals	14,165	13,858	(307)	-2%	
Consumer Services	5,086	5,683	597	11%	14
Computer Services	1,003	696	(307)	-44%	
Collection Costs	4,497	4,542	45	1%	
Customer & Public Relations	7,905	6,014	(1,891)	-31%	15
Sponsored Memberships	1,917	1,267	(650)	-51%	16
Office & Administration	14,316	15,703	1,387	9%	17
Communication Systems	1,678	1,603	(75)	-5%	
Research & Development Costs	3,651	4,110	459	11%	
Miscellaneous Expense	1,264	1,087	(177)	-16%	
Contingency Planning	-	5,417	5,417	100%	18
Operating Expense Recovery	(23,004)	(16,497)	6,507	-39%	19
Total Costs	748,472	740,156	(8,316)	-1%	
Capital Order Activities	(243,545)	(235,040)	8,505	4%	
CICA Accounting Changes*		9,000	9,000	100%	20
Provision for IFRS		18,000	18,000	100%	21
Capitalized Overhead	(47,336)	(71,021)	(23,685)	-33%	22
Operating and Administration Charged to Centra	(60,644)	(63,400)	(2,756)	-4%	
OM&A Attributable to Electric Operations	**$ 396,947**	**$ 397,695**	**$ 748**	**0%**	

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT
2010/11 VARIANCE EXPLANATIONS

Ref	Cost Element	Fav (Unfav)	Explanation
9	Overtime	(2,643)	Mainly related to wage settlements, increased maintenance and outage requirements, and increased activity related to major projects as such as Slave Falls Tramway and Wuskwatim.
10	Employee Safety & Training	884	Primarily due to reduced training costs associated with a lower number of trainees compared to forecast.
11	Motor Vehicle	(1,322)	Primarily due to rising fuel costs and increased vehicle requirements.
12	Materials & Tools	(1,927)	Primarily due to a business initiative purchases, with an offset residing in operating expense recovery.
13	Building & Property Services	(1,273)	Primarily due to higher than planned building service costs associated with delays in winding down the occupancy at various leased properties, and increased staffhouse costs associated with projects such as Kelsey Re-runnering with an offset residing in operating expense recovery.
14	Consumer Services	597	Primarily due to the repatriation of line locates previously performed by MHUS.
15	Customer & Public Relations	(1,891)	Primarily due to CICA accounting standard changes resulting in expensing select costs for DSM programs, and higher corporate donations and sponsorships.
16	Sponsored Memberships	(650)	Higher than planned membership fees for Canadian Electric Association.
17	Office & Administration	1,387	Mostly due to cost constraint measures.
18	Contingency Planning	5,417	Unallocated general contingency.
19	Operating Expense Recovery	6,507	Mainly related to higher profits and cost recoveries for business initiatives and increased staffhouse income related to higher utilization. Offsets are reflected in materials & tools, construction & maintenance services, and building & property services.
20	CICA Accounting Changes*	9,000	All accounting changes are reflected in the source cost elements.
21	Provision for IFRS	18,000	Adoption of IFRS deferred to 2013/14.
22	Capitalized Overhead	(23,685)	Lower mainly due to reduced capitalization of overhead resulting from the removal of interest, property taxes and certain general & administrative expenses in fiscal 2011.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

	2011/12 Actual	2011/12 Forecast	2011/12 Variance	%	Ref
Wages, Salaries	$ 451,925	$ 424,765	$ (27,160)	-6%	23
Overtime	54,987	49,166	(5,821)	-12%	24
Employee Benefits	104,444	95,175	(9,269)	-10%	25
Employee Safety & Training	3,909	4,856	947	20%	26
Travel	31,266	33,721	2,455	7%	27
Motor Vehicle	28,676	23,646	(5,030)	-21%	28
Materials & Tools	26,663	26,780	117	0%	
Consulting & Professional Fees	10,250	11,155	905	8%	29
Construction & Maintenance Services	21,228	22,286	1,058	5%	30
Building & Property Services	21,387	21,146	(241)	-1%	
Equipment Maintenance & Rentals	13,388	14,177	789	6%	31
Consumer Services	5,365	5,814	449	8%	
Computer Services	861	712	(149)	-21%	
Collection Costs	4,035	4,646	611	13%	32
Customer & Public Relations	8,093	6,152	(1,941)	-32%	33
Sponsored Memberships	1,608	1,296	(312)	-24%	
Office & Administration	14,277	15,857	1,580	10%	34
Communication Systems	1,683	1,640	(43)	-3%	
Research & Development Costs	2,797	4,205	1,408	33%	35
Miscellaneous Expense	2,032	1,112	(920)	-83%	36
Contingency Planning	-	3,921	3,921	100%	37
Operating Expense Recovery	(21,716)	(16,670)	5,046	-30%	38
Total Costs	787,158	755,558	(31,600)	-4%	
Capital Order Activities	(268,651)	(239,741)	28,910	12%	39
CICA Accounting Changes*		9,000	9,000	100%	40
Provision for IFRS		13,500	13,500	100%	41
Capitalized Overhead	(53,084)	(72,447)	(19,363)	-27%	42
Operating and Administration Charged to Centra	(62,117)	(64,000)	(1,883)	-3%	
OM&A Attributable to Electric Operations	**$ 403,306**	**$ 401,870**	**$ (1,436)**	**0%**	

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT
2011/12 VARIANCE EXPLANATIONS

Ref	Business Unit	Fav (Unfav)	Explanation
23	Wages, Salaries	(27,160)	Primarily due to wage settlements, partially offset by a reduction in EFT's.
24	Overtime	(5,821)	Mainly related to wage settlements, storm/flood activities, and higher requirements for various capital projects.
25	Employee Benefits	(9,269)	Mainly due to higher vacation expense resulting from an increase in accrued vacation days, and higher pension costs as a result of higher salaries than forecast and greater employee contributions. Other factors include a reduction in the discount rate for the valuation of Manitoba Hydro's pension and benefit obligations.
26	Employee Safety & Training	947	Primarily due to reduced training costs associated with a lower number of trainees compared to forecast.
27	Travel	2,455	Primarily due to cost constraint measures.
28	Motor Vehicle	(5,030)	Primarily due to higher fuel costs as a result of higher market prices and greater repair costs than anticipated.
29	Consulting & Professional Fees	905	Mainly due to the deferral of consulting work related to IFRS, Data Quality and Identity Management, Dam Safety reviews and Gas Environmental studies.
30	Construction & Maintenance Services	1,058	Primarily due to capitalization of the shoreline cleanup costs.
31	Equipment Maintenance & Rentals	789	Mainly due to lower IT infrastructure and operating costs partially as a result of lower negotiated software contracts.
32	Collection Costs	611	Mainly due to lower than expected uncollectible accounts.
33	Customer & Public Relations	(1,941)	Primarily due to CICA accounting standard changes resulting in expensing select costs for DSM programs, higher corporate donations and sponsorships, and discretionary billing adjustments.
34	Office & Administration	1,580	Primarily due to cost constraint measures and a lower demand for postage services.
35	Research & Development Costs	1,408	Lower spending on R&D projects.
36	Miscellaneous Expense	(920)	Primarily due to expensing costs no longer eligible for capitalization.
37	Contingency Planning	3,921	Unallocated general contingency.
38	Operating Expense Recovery	5,046	Mainly due to higher recoveries for business initiatives, Emergency Measures Organization refund for flood assistance, and increased staffhouse income related to higher utilization.
39	Capital Order Activities	28,910	Increased capital activities on various capital projects such as Pointe Du Bois, BiPoleIII, Wuskwatim, Stafford Rebuild and Rebuild 66kv Line 8 - Laurie River.
40	CICA Accounting Changes*	9,000	All accounting changes are reflected in the source cost elements.
41	Provision for IFRS	13,500	Adoption of IFRS deferred to 2013/14.
42	Capitalized Overhead	(19,363)	Primarily due to reduced capitalization of overhead resulting from the removal of interest, property taxes and certain general & administrative expenses in fiscal 2011, partially offset by increased activities in 2012.

ii)

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

	2009/10 Actual	2009/10 Forecast	2009/10 Variance	%	Ref
President & CEO	$ 31,578	$ 28,175	$ (3,403)	-12%	1
Corporate Relations	4,697	5,100	403	8%	
Finance and Administration	108,914	109,320	406	0%	
Power Supply	147,073	145,000	(2,073)	-1%	
Transmission	92,302	91,100	(1,202)	-1%	
Customer Service and Distribution	111,068	107,300	(3,768)	-4%	
Customer Care and Marketing	42,395	41,435	(960)	-2%	
Business Unit Subtotal	**538,027**	**527,430**	**(10,597)**	**-2%**	
Motor Vehicle Chargeout	(24,352)	(23,634)	718	3%	
Payroll Tax	(10,070)	(9,873)	197	2%	
Corporate Allocations & Adjustments	(4,952)	(1,294)	3,658	283%	2
CICA Accounting Changes*					
Provision for IFRS					
Operating & Administration Charged to Centra	(60,951)	(60,160)	791	1%	
Capitalized Overhead	(60,151)	(60,964)	(813)	-1%	
OM&A Costs Attributable to Electric Operations *	**$ 377,551**	**$ 371,505**	**$ (6,046)**	**-2%**	

* Note - OM&A figures do not include subsidiary amounts.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
2009/10 VARIANCE EXPLANATIONS

Ref	Business Unit	Fav (Unfav)	Explanation
1	President & CEO	(3,403)	Higher consulting and professional fees primarily associated with Risk Management review, greater than expected donations, partially offset by general contingency.
2	Corporate Allocations & Adjustments	3,658	Primarily due to lower current service benefit costs being less than expected (Sick Leave Vesting, Vacation and Health Benefits).

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

	2010/11 Actual	2010/11 Forecast	2010/11 Variance	%	Ref
President & CEO	$ 28,835	$ 31,729	$ 2,894	9%	3
Corporate Relations	4,739	5,200	461	9%	
Finance and Administration	106,528	109,967	3,439	3%	
Power Supply	150,120	148,100	(2,020)	-1%	
Transmission	90,493	92,400	1,907	2%	
Customer Service and Distribution	106,707	109,000	2,293	2%	
Customer Care and Marketing	41,446	43,000	1,554	4%	
Business Unit Subtotal	**528,868**	**539,396**	**10,528**	**2%**	
Motor Vehicle Chargeout	(17,933)	(16,601)	1,332	8%	4
Payroll Tax	(10,458)	(10,070)	388	4%	
Corporate Allocations & Adjustments	4,450	(7,609)	(12,059)	-158%	5
CICA Accounting Changes*		9,000	9,000	100%	6
Provision for IFRS		18,000	18,000	100%	7
Operating & Administration Charged to Centra	(60,644)	(63,400)	(2,756)	-4%	
Capitalized Overhead	(47,336)	(71,021)	(23,685)	-33%	8
OM&A Costs Attributable to Electric Operations *	**$ 396,947**	**$ 397,695**	**$ 748**	**0%**	

* Note - OM&A figures do not include subsidiary amounts.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
2010/11 VARIANCE EXPLANATIONS

Ref	Business Unit	Fav (Unfav)	Explanation
3	President & CEO	2,894	Primarily due to delays in hiring positions in Corporate Planning & Strategic Review, lower consulting services for programs such as Environmental Management System, and general contingency.
4	Motor Vehicle Chargeout	1,332	Mainly due to increased usage by the Business Units.
5	Corporate Allocations & Adjustments	(12,059)	Mainly due to a lower recovery of benefit costs charged to the Business Units, and higher vacation expense resulting from an increase in accrued vacation days.
6	CICA Accounting Changes*	9,000	All accounting changes are reflected in the Business Units.
7	Provision for IFRS	18,000	Adoption of IFRS deferred to 2013/14.
8	Capitalized Overhead	(23,685)	Lower mainly due to reduced capitalization of overhead resulting from the removal of interest, property taxes and certain general & administrative expenses in fiscal 2011.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

	2011/12 Actual	2011/12 Forecast	2011/12 Variance	%	Ref
President & CEO	$ 28,328	$ 32,459	$ 4,131	13%	9
Corporate Relations	3,025	5,320	2,295	43%	10
Finance and Administration	107,443	112,496	5,053	4%	
Power Supply	155,084	151,506	(3,578)	-2%	
Transmission	89,261	94,525	5,264	6%	11
Customer Service and Distribution	110,045	111,507	1,462	1%	
Customer Care and Marketing	43,703	43,989	286	1%	
Business Unit Subtotal	**536,889**	**551,802**	**14,913**	**3%**	
Motor Vehicle Chargeout	(16,843)	(16,983)	(140)	-1%	
Payroll Tax	(11,137)	(10,272)	865	8%	12
Corporate Allocations & Adjustments	9,595	(8,730)	(18,325)	-210%	13
CICA Accounting Changes*		9,000	9,000	100%	14
Provision for IFRS		13,500	13,500	100%	15
Operating & Administration Charged to Centra	(62,117)	(64,000)	(1,883)	-3%	
Capitalized Overhead	(53,084)	(72,447)	(19,363)	-27%	16
OM&A Costs Attributable to Electric Operations *	**$ 403,303**	**$ 401,870**	**$ (1,433)**	**0%**	

* Note - OM&A figures do not include subsidiary amounts.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
2011/12 VARIANCE EXPLANATIONS

Ref	Business Unit	Fav (Unfav)	Explanation
9	President & CEO	4,131	Primarily due to high vacancies, reduced spending on R&D projects, lower consulting costs, and general contingency.
10	Corporate Relations	2,295	Primarily related to capitalization of the shoreline cleanup program.
11	Transmission	5,264	Primarily related to higher capital activities, recoveries for flood assistance and winter road hauling, and increased material salvage credits.
12	Payroll Tax	865	Primarily due to higher wages and salaries in fiscal 2012 related to wage settlements.
13	Corporate Allocations & Adjustments	(18,325)	Mainly due to a lower recovery of benefit costs charged to the Business Units, higher vacation expense resulting from an increase in accrued vacation days, and higher pension costs as a result of higher salaries than forecast and greater employee contributions. Other factors include a reduction in the discount rate for the valuation of Manitoba Hydro's pension and benefit obligations.
14	CICA Accounting Changes*	9,000	All accounting changes are reflected in the Business Units.
15	Provision for IFRS	13,500	Adoption of IFRS deferred to 2013/14.
16	Capitalized Overhead	(19,363)	Lower mainly due to reduced capitalization of overhead resulting from the removal of interest, property taxes and certain general & administrative expenses in fiscal 2011, partially offset by increased activity in 2012.

PUB/MH I-60

Reference: Tab 5 Appendix 5.5, - Impact on Retained Earnings

Please provide a continuity schedule similar to PUB/MH II- 150 (b) from 2011 & 2012 GRA of retained earnings based on actual and IFF11-2 separately indicating each adjustment to retained earnings made related to compliance with GAAP and IFRS since 2010 and specifically identify the transitional adjusting entries made related to rate –regulated assets and liabilities.

ANSWER:

Please see Manitoba Hydro’s response to PUB/MH I-42, Schedule B.

PUB/MH I-61

Reference: Tab 5 Appendix 5.5, Appendix 5.6 Pages 3&5 of 13 – Accounting Changes

a) Please explain why MH has chosen to adopt IFRS related to the capitalization of Overhead costs in 2011/12 and 2012/13 rather than 2013/14 when IFRS is to be adopted and comment to what extent the current need for additional rate increases are impacted by this decision?

ANSWER:

Manitoba Hydro implemented changes to the capitalization of overhead costs starting in 2009/10 to recognize utility industry trends to move away from full cost accounting and ensure that its capitalization practices are consistent with the capitalization practices of other Canadian electrical utilities. While these changes are generally consistent with the direction of IFRS, Manitoba Hydro does not consider them as early adoption of IFRS. Manitoba Hydro's capitalization policies are fully compliant with Canadian GAAP and are endorsed by Manitoba Hydro's external auditors.

The current need for additional rate increases is largely unaffected by Manitoba Hydro's overhead capitalization policies. As stated in Manitoba Hydro's application, rate increases are required for the following reasons:

a) to avoid incurring losses on operations;

b) to limit the extent to which financial ratios are projected to deteriorate;

c) to maintain the financial and credit rating integrity of Manitoba Hydro;

d) to compensate for reduced prices for non-firm electricity sales on the export market;

e) to recognize that Manitoba Hydro's infrastructure is aging and that increased costs are necessary to maintain that infrastructure in a safe and reliable manner;

f) to provide customers with rate stability and predictability and to avoid the need for much higher rates in the future; and

g) to preserve Manitoba Hydro's status as the jurisdiction with the lowest electricity rates in North America.

PUB/MH I-61

Reference: Tab 5 Appendix 5.5, Appendix 5.6 Pages 3&5 of 13 – Accounting Changes

b) What would be the implications to operating results for 2012/13 if changes in overhead costs were implemented only when IFRS was required to be implemented for rate setting purposes?

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-61(a).

PUB/MH I-61

Reference: Tab 5 Appendix 5.5, Appendix 5.6 Pages 3&5 of 13 – Accounting Changes

c) MH has consulted with its external auditor on IFRS accounting issues including the capitalization of overhead. Please explain how MH and its external Auditor differentiated between the amounts of OM&A capitalized in 2012/13 versus 2013/14 to ensure the financial statements are not materially misstated in 2012/13. Said another way what support is there for not writing off the additional amounts in 2013/14 in 2012/13.

ANSWER:

Please see Manitoba Hydro’s response to PUB/MH I-79(a).

PUB/MH I-62 (Revised)

Reference: Appendix 5.6 Page 10

Please provide the table found on page 10 extending it to include the years 2003/04 through 2014/15 and provide the compounded annual growth from 2003/04 through 2011/12 and the growth from 2011/12 through 2014/15. Please comment on the reasons for the changes.

ANSWER:

Please see the following Operating, Maintenance and Administrative Costs by Business Unit schedule from 2004/05 to 2013/14, with compounded annual growth from 2004/05 to 2011/12 and from 2011/12 through 2013/14.

Explanations for changes greater than 3% have been provided below the table.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

(In thousands of $)	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	Fiscal 2004/05-2011/12 Compounded Annual Growth	Notes	2012/13 Actual	2013/14 Forecast	Fiscal 2011/12-2013/14 Compounded Annual Growth**	Notes
President & CEO	$ 20,949	$ 22,123	$ 23,207	$ 22,963	$ 24,230	$ 31,578	$ 28,835	$ 28,328	4.4	1	$ 28,692	$ 29,239	1.6	
Corporate Relations	3,503	5,496	5,220	5,245	5,520	4,697	4,739	3,025	(2.1)		4,491	$ 4,585	23.1	3
Finance & Administration	90,622	93,016	99,027	99,521	103,722	108,914	106,528	107,443	2.5		114,343	$ 118,816	5.2	4
Power Supply	113,433	117,196	123,359	127,610	142,183	147,073	150,120	155,084	4.6	2	177,882	$ 187,031	9.8	5
Transmission	77,979	77,810	83,503	83,171	91,088	92,302	90,493	89,261	1.9		104,662	$ 107,265	9.6	6
Customer Services & Distribution	92,107	96,964	92,091	98,373	103,762	111,068	106,707	110,045	2.6		130,355	$ 132,916	9.9	7
Customer Care & Marketing	42,359	42,293	42,891	38,472	38,942	42,395	41,446	43,703	0.4		52,249	$ 95,922	48.2	8
Business Unit Total*	**440,953**	**454,898**	**469,297**	**475,354**	**509,446**	**538,027**	**528,867**	**536,889**	**2.9**		**612,673**	**675,774**	**12.2**	

*Note: Does not include allocations to capital and Centra Gas.

** Compounded annual growth rates 2011/12-2013/14 are not meaningful due to accounting and other changes.

Fiscal 2004/05 to 2011/12 Cost Change Explanations:

1) The President & CEO area increased by 4.4% primarily as a result of increases in EFTs to support various initiatives undertaken by the Corporate Planning and Strategic Review Division as well as increased consulting services and professional fees related to Risk Management Review and Crown Corporation Council levy.

2) The Power Supply Business Unit increased by 4.6% primarily increases in EFTs necessary for increased maintenance of hydraulic and thermal stations, converter stations and control structures in order to supply secure energy and capacity to meet system needs. EFT increases are also due to higher trainee levels to address existing staff shortages and future anticipated attrition levels and to support the growing environmental management and emerging energy issues. The increase in costs also reflects impacts of union contract settlements.

Fiscal 2011/12 to 2013/14 Cost Change Explanations:

3) The Corporate Relations Business Unit is projected to increase by 23.1% primarily due to accounting changes reflecting departmental administrative and support costs no longer eligible for capitalization.

4) The Finance & Administration Business Unit is projected to increase by 5.2% primarily due to accounting changes reflecting costs no longer eligible for capitalization including Rate Regulated and departmental administrative and support costs as well as the reclassification of Operating Expense Recoveries to Other Revenue.

5) The Power Supply Business Unit is projected to increase by 9.8% primarily due to accounting changes reflecting costs no longer eligible for capitalization including Rate Regulated and departmental administrative and support costs as well as the reclassification of Operating Expense Recoveries to Other Revenue. The increase in costs also reflects the in-service of the Wuskwatim GS for a partial year in 2012/13 and a full year in 2013/14.

6) The Transmission Business Unit is projected to increase by 9.6% primarily as a result of accounting changes reflecting costs no longer eligible for capitalization including Rate Regulated and departmental administrative and support costs as well as the reclassification of Operating Expense Recoveries to Other Revenue.

7) The Customer Services & Distribution Business Unit is projected to increase by 9.9% primarily as a result of accounting changes reflecting costs no longer eligible for capitalization including departmental and administrative support costs and the reclassification of Operating Expense Recoveries to Other Revenue.

8) The Customer Care & Marketing Business Unit increased by 48.2% primarily due to accounting changes including Rate Regulated (DSM programs), departmental and administrative support costs no longer eligible for capitalization, and the reclassification of Operating expense Recoveries to Other Revenue.

Note:

All Business Units reflect an increase in past service pension costs as a result of the amortization of investment losses experienced since 2008 as well as higher current service pension costs due to higher pensionable earnings resulting from higher wages and salaries. In addition, the accounting changes allocated to the Business Units are approximately $95 million over the forecast period.

PUB/MH I-63

Reference: Tab 5 Appendix 5.6 Page 8 of 13 - cost escalation and wage settlement

a) Please provide a summary of the contracted wage settlements and indicate to which extent the settlements have impacted wages and benefits in 2011/12, 2012/13 and 2013/14 from that forecast at the last GRA.

ANSWER:

The following provides a summary of the contracted wage settlements since 2009. Manitoba Hydro also negotiated a 0.75% benefit improvement effective January 1, 2010.

Union	Effective Date	Contracted Wage Settlement
All	January 1, 2009	2.9%
All	December 31, 2010	1.0%
All	January 1, 2011	2.5%
All	January 1, 2012	2.5%
IBEW [1]	April 1, 2012	2.0%
IBEW	January 1, 2013	0.0%
IBEW	January 1, 2014	2.75%

The impact of contracted wage settlements since the last GRA is approximately $23 million in 2011/12, $9 million in 2012/13 and $1 million in 2013/14. The $23 million in 2012 represents the cumulative impact of the wage settlements since 2009.

[1] 2.0% market adjustment for identified trade classifications in IBEW.

PUB/MH I-63

Reference: Tab 5 Appendix 5.6 Page 8 of 13 - cost escalation and wage settlement

b) For each of the 2007/08 through 2013/14 please provide the average salary per EFT in the same level of detail as schedules similar to the response to PUB/MH I-33 at the 2011 & 2012 GRA

ANSWER:

Please see the following tables for the average salary per EFT from 2007/08 through 2013/14.

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY BUSINESS UNIT (000's)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
President & CEO	$ 83.218	$ 85.688	$ 92.174	$ 92.436	$ 95.891	$ 97.134	$ 99.077
Corporate Relations	63.417	62.454	63.131	63.983	68.324	68.939	70.318
Finance & Administration	65.868	67.298	70.879	71.751	76.281	76.672	78.206
Power Supply	64.877	66.014	68.747	69.616	73.790	75.603	77.115
Transmission	64.717	66.084	68.703	70.226	74.346	76.805	78.341
Customer Services & Distribution	56.094	57.220	60.088	61.135	64.733	67.261	68.606
Customer Care & Marketing	57.106	58.490	61.444	61.893	66.095	67.064	68.406
Business Unit Total	**$ 62.236**	**$ 63.515**	**$ 66.545**	**$ 67.600**	**$ 71.689**	**$ 73.498**	**$ 74.968**

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY DIVISION (000's)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
President & CEO							
General Counsel	$ 78.551	$ 85.035	$ 88.444	$ 90.328	$ 93.731	$ 92.521	$ 94.371
Public Affairs	59.978	60.337	63.809	65.682	72.068	72.026	73.467
Research & Development	77.842	83.868	90.518	56.003	55.238	55.761	56.876
Corporate Planning & Strategic Review	83.763	82.711	91.139	89.433	90.875	95.403	97.311
Corporate Planning Administration	-	-	115.735	108.493	112.319	-	-
Administration	114.786	118.753	127.271	124.135	127.592	131.531	134.161
	$ 83.218	**$ 85.688**	**$ 92.174**	**$ 92.436**	**$ 95.891**	**$ 97.134**	**$ 99.077**
Corporate Relations							
Aboriginal Relations	$ 57.607	$ 56.628	$ 60.147	$ 61.469	$ 65.749	$ 66.309	$ 67.635
Administration	110.320	110.598	104.715	108.406	123.827	135.412	138.120
	$ 63.417	**$ 62.454**	**$ 63.131**	**$ 63.983**	**$ 68.324**	**$ 68.939**	**$ 70.318**
Finance & Administration							
Information Technology Services	$ 70.187	$ 72.140	$ 75.848	$ 76.622	$ 81.129	$ 82.671	$ 84.325
Treasury	66.653	69.826	72.647	73.944	76.284	73.184	74.648
Corporate Risk Mgmt Department	95.747	97.363	84.998	93.196	100.976	102.068	104.109
Gas Supply	75.492	76.106	79.781	83.478	89.980	92.749	94.604
Rates & Regulatory Affairs	75.235	74.565	77.711	78.675	84.017	84.975	86.675
Corporate Controller	71.090	73.897	77.628	76.768	80.772	81.868	83.506
Human Resources	68.068	68.024	72.487	72.858	78.396	77.234	78.779
Corporate Safety & Health	72.795	74.611	78.448	79.469	83.685	81.119	82.742
Corporate Services	53.644	54.775	58.386	59.822	63.481	63.784	65.060
Administration	95.090	95.888	99.936	106.539	125.325	127.836	130.393
	$ 65.868	**$ 67.298**	**$ 70.879**	**$ 71.751**	**$ 76.281**	**$ 76.672**	**$ 78.206**
Power Supply							
Power Planning	$ 76.909	$ 79.466	$ 83.089	$ 83.629	$ 87.892	$ 90.856	$ 92.673
Power Projects Development	76.685	79.910	82.465	81.646	85.056	86.314	88.041
Portfolio Projects Management	69.485	66.139	67.566	70.363	70.635	81.011	82.631
HVDC	64.093	66.145	68.505	69.546	73.957	76.274	77.799
Generation North	63.428	64.789	67.885	68.549	72.627	73.797	75.273
Generation South	62.236	64.079	67.235	68.570	72.657	74.510	76.000
Power Sales & Operations	78.069	80.735	83.150	83.921	88.928	91.655	93.488
Engineering Services	71.429	72.525	74.711	75.305	79.690	82.392	84.040
New Generation Construction	69.967	69.180	72.064	74.845	79.731	80.757	82.372
Administration	49.656	49.326	51.295	51.943	55.666	56.317	57.443
	$ 64.877	**$ 66.014**	**$ 68.747**	**$ 69.616**	**$ 73.790**	**$ 75.603**	**$ 77.115**
Transmission							
Transmission System Operations	$ 70.473	$ 73.140	$ 76.549	$ 77.900	$ 81.442	$ 84.036	$ 85.717
Transmission Planning & Design	71.606	73.838	77.428	79.259	82.563	87.010	88.750
Transmission Construction & Line Mtce	60.948	62.665	65.015	65.714	70.356	72.197	73.641
Apparatus Maintenance	58.809	59.074	61.392	63.370	67.505	69.817	71.214
Administration	64.445	61.098	58.692	60.561	64.333	63.237	64.502
	$ 64.717	**$ 66.084**	**$ 68.703**	**$ 70.226**	**$ 74.346**	**$ 76.805**	**$ 78.341**
Customer Services & Distribution							
Customer Service Operations - Wpg&North	$ 58.109	$ 59.137	$ 60.840	$ 61.821	$ 65.207	$ 66.834	$ 68.170
Customer Service Operations - South	54.930	56.263	59.144	60.557	63.728	66.999	68.339
Distribution E&C Rural	56.464	57.105	61.055	61.198	64.806	67.221	68.566
Distribution E&C Winnipeg	54.431	55.703	58.419	59.656	63.309	66.003	67.323
Administration	-	76.235	107.873	124.256	91.462	94.393	96.281
	$ 56.094	**$ 57.220**	**$ 60.088**	**$ 61.135**	**$ 64.733**	**$ 67.261**	**$ 68.606**
Customer Care & Marketing							
Industrial & Commercial Solutions	$ 78.806	$ 82.082	$ 85.611	$ 86.140	$ 90.377	$ 92.037	$ 93.878
Consumer Marketing & Sales	53.540	53.777	56.488	57.369	62.008	63.498	64.768
Business Support Services	53.528	54.814	57.530	58.336	61.946	62.019	63.259
Administration	69.181	71.629	72.630	70.379	75.261	75.902	77.420
	$ 57.106	**$ 58.490**	**$ 61.444**	**$ 61.893**	**$ 66.095**	**$ 67.064**	**$ 68.406**
Total	**$ 62.236**	**$ 63.515**	**$ 66.545**	**$ 67.600**	**$ 71.689**	**$ 73.498**	**$ 74.968**

PUB/MH I-63

Reference: Tab 5 Appendix 5.6 Page 8 of 13 - cost escalation and wage settlement

c) Please indicate whether the Corporation participated in any salary benchmarking studies, if so please provide a description of the study and a summary of the comparison results.

ANSWER:

Manitoba Hydro has not conducted, nor commissioned, a wage benchmarking study at this time.

Manitoba does periodically participate in select salary surveys. In November 2011, Manitoba Hydro participated in a compensation benchmarking study conducted by Mercer on Hydro One's behalf. The study provided a Total Remuneration Comparison for 25 Manitoba Hydro positions. The following is a summary of the results relating to the 25 positions:

- 13 positions placed below the 25th percentile of surveyed participants
- 10 positions placed between the 25th and 50th percentile of surveyed participants
- 2 position placed between the 50th and 75th percentile of surveyed participants

The results of this comparison shows that Manitoba Hydro's Total Remuneration is below the market average for 23 out of 25 positions.

Manitoba Hydro has also participated in smaller scale salary surveys designed for specific jobs or group of jobs.

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

a) Please file expanded tables found on pages 10 and 12 to include the years 2003/04 to 2008/09.

ANSWER:

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

(In thousands of $)	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual % Inc/(Dec)
President & CEO	$ 22,963	$ 24,230	$ 31,578	$ 28,835	$ 28,328	$ 28,692	$ 29,239	4.8%
Corporate Relations	5,245	5,520	4,697	4,739	3,025	4,491	4,585	0.9%
Finance & Administration	99,521	103,722	108,914	106,528	107,443	114,343	118,816	3.0%
Power Supply	127,610	142,183	147,073	150,120	155,084	177,882	187,031	6.7%
Transmission	83,171	91,088	92,302	90,493	89,261	104,662	107,265	4.5%
Customer Services & Distribution	98,373	103,762	111,068	106,707	110,045	130,355	132,916	5.4%
Customer Care & Marketing	38,472	38,942	42,395	41,446	43,703	52,249	95,922	19.4%
Business Unit Total*	**475,354**	**509,446**	**538,027**	**528,867**	**536,889**	**612,673**	**675,774**	**6.2%**

*Note: Does not include allocations to capital and Centra Gas.

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES BY BUSINESS UNIT

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual % Inc/(Dec)
President & CEO	106	107	116	123	127	126	126	3.0%
Corporate Relations	69	75	73	69	69	75	75	1.7%
Finance & Administration	993	1,006	1,010	1,009	983	1,003	1,003	0.2%
Power Supply	1,470	1,576	1,679	1,796	1,853	1,972	1,972	5.0%
Transmission	1,256	1,298	1,342	1,365	1,354	1,385	1,385	1.7%
Customer Services & Distribution	1,640	1,671	1,678	1,704	1,701	1,731	1,731	0.9%
Customer Care & Marketing	538	543	532	528	521	549	549	0.4%
Total	6,071	6,276	6,429	6,594	6,608	6,842	6,842	2.0%

<u>PUB/MH I-64</u>

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

b) At the 2011 GRA MH indicated that it had 6,041 EFT in January 2010[PUB/MH I-34 (c)]. In the current GRA MH indicates actual EFT's for 2010/11 totalling 6,594? Please explain the difference.

<u>ANSWER</u>:

The January 2010 (2009/10 fiscal year) EFT figure, as reported in PUB MH I-34c is not comparable to the current GRA filing for fiscal year 2010/11.

The 6,041 EFTs reported in last GRA represent the number of EFTs at a fixed point in time (January 2010) and does not include overtime EFTs. The EFT figure in the current filing represents the average year to date EFT's for the 2010/11 fiscal year and includes overtime.

The comparable figure would be 6,429 EFTs which represents the previous average year to date EFT figure including overtime for the 2009/10 fiscal year. Please see Manitoba Hydro's response to PUB/MH I-64(e) explaining the difference.

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

c) Please explain why the President and CEO unit has expanded from 107 EFT EFT in 2008/09 to 116 EFT in 2010/11 and is forecast to expand further to 127 EFT in 2011/12, an increase of 20 EFTs in three years.

ANSWER:

The increase of 20 EFTs in the President and CEO business unit is explained as follows:

- 13 new positions:
  - 10 positions to support corporate strategic review, corporate planning, economic development and corporate environmental management.
  - 2 positions for corporate security function.
  - 1 Vice-President due to creation of new business unit whereby Customer Service & Marketing and Transmission & Distribution reorganized into three business units (Customer Care & Marketing, Customer Service & Distribution, and Transmission)

- 6 transfers into President & CEO:
  - 4 from Corporate Relations business unit for economic analysis & development and corporate analysis.
  - 2 from Finance & Administration business unit for Respectful Workplace.

- 1 filled vacancy
  - Legal counsel position

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

d) Please indicate to what extent costs from each business unit are capitalized in 2003/04 to 2015/16.

ANSWER:

Business Unit OM&A costs presented in Appendix 5.6 are net of costs capitalized through capital order activity charges. Please see the following schedule for a breakdown of costs capitalized for each business unit.

MANITOBA HYDRO
COSTS CAPITALIZED BY BUSINESS UNIT **(000's)**

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast [1]
President & CEO	$ 841	$ 948	$ 496	$ 331	$ 555	$ 675	$ 689
Corporate Relations	3,449	4,364	4,872	4,934	5,301	4,630	4,723
Finance & Administration	10,559	10,494	10,794	12,482	12,438	12,297	12,543
Power Supply	41,181	45,191	54,629	63,199	74,028	72,093	73,535
Transmission	50,131	53,067	61,254	67,377	72,554	67,637	68,989
Customer Services & Distribution	76,102	80,943	82,373	84,995	92,995	79,432	81,021
Customer Care & Marketing	10,069	10,164	9,879	10,226	10,780	9,299	9,485
	$ 192,331	**$ 205,169**	**$ 224,297**	**$ 243,545**	**$ 268,651**	**$ 246,065**	**$ 250,986**

[1] The forecasted capitalized costs for 2013/14 do not include the impact of IFRS changes on capital order activity charges. Detailed budgets by business unit/division for the 2013/14 fiscal year incorporating the changes under IFRS will be prepared following approval of IFF12.

PUB/MH I-64 (Revised)

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

e) For each of the divisions set out in part (a) please provide a continuity schedule of changes in EFT's by Division in a similar level of detail to that provided in response to PUB/MH I 34 from the 2011 GRA for the years 1999/00 through 2014/15 and indicate the number of EFT's that are attributable to:

i. Normal Growth
ii. Export Sales
iii. Generation development, and
iv. Other

ANSWER:

The attached schedules show the EFT changes from 2004/05 to 2012/13 by business unit. Please note that figures have been updated to reflect the current organizational structure.

Please also note the totals may not add due to rounding.

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2004/05 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2005/06 Actual	Comments Regarding New Positions
President & CEO							
General Counsel	24				0	25	
Public Affairs	32				(2)	30	
Research & Development	5				(2)	3	
Administration	23				1	24	
Corporate Planning and Strategic Review	19	1				19	Administrative Officer Position to support growing Division.
	104	1	0	0	(3)	101	
Corporate Relations							
Aboriginal Relations	44	9			1	54	Positions for policy development and seasonal utility workers
Administration	5	3				8	Positions for newly formed business unit.
	49	12	0	0	1	62	
Finance & Administration							
Information Technology Services	350	4		7	3	364	Positions to support the Human Resource Management (HRMS) module of SAP following implementation.
Treasury	17			(1)		16	
Corporate Risk Management	1	1		(1)	1	2	Position for new division.
Gas Supply	20				(0)	20	
Rates & Regulatory Affairs	22				(4)	19	
Corporate Controller	116			(8)	4	113	
Human Resources	146			2	(7)	141	
Corporate Safety & Health	54				(0)	53	
Corporate Services	298				(4)	294	
Administration	14			1	(1)	14	
	1,038	5	0	0	(8)	1,035	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2004/05 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2005/06 Actual	Comments Regarding New Positions
31	**Power Supply**							
32	Power Planning	32				3	35	
33	Power Projects Development	38	3		(1)	(3)	37	Positions for new generation licensing and planning activities.
35	HVDC	266			(29)	(9)	228	
36	Generation North	234			(30)	10	213	
37	Generation South	496			(23)	(12)	462	
38	Power Sales & Operations	79	8		(3)	(0)	84	Positions for power marketing, regulatory standards, and licensing activities.
39	Engineering Services	163				(1)	162	
40	New Generation Construction	13	1			(0)	14	Position for new generation construction projects.
41	Administration	23	9		86	14	131	Positions for Operating Technician Trainee Program from operating Divisions
42		1,345	21	0	0	0	1,366	
43								
44	**Transmission**							
45	Transmission System Operations	341	3			2	346	Positions for Telecontrol Trainee Program
46	Transmission Planning & Design	202			(4)	(3)	195	
47	Transmission Construction & Line Maintenance	271			4	1	276	
48	Apparatus Maintenance	357				5	362	
49	Administration	37	5				42	Positions for Engineer-in-Training program and establishment of HVDC Research Centre.
50		1,208	8	0	0	5	1,220	
51								

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2004/05 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2005/06 Actual	Comments Regarding New Positions
52	**Customer Services & Distribution**							
53	Customer Service Operations - Winnipeg & North	535				2	537	
54	Customer Service Operations - South	547	2			20	569	Positions for Aboriginal Line Trades Pre-Placement Trainee program.
55	Distribution Engineering & Construction Rural	253				2	255	
56	Distribution Engineering & Construction Winnipeg	271				16	287	
58		1,605	2	0	0	40	1,647	
59								
60	**Customer Care & Marketing**							
61	Industrial & Commercial Solutions	48				1	49	
62	Consumer Marketing & Sales	204	16			1	221	Positions for support of Power Smart programs.
63	Business Support Services	230	8			(1)	237	Positions to support the Banner system in Customer Accounting.
64	Administration	39					39	
65		521	24	0	0	1	547	
66								
67	**Total**	5,870	73	0	0	37	5,978	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2005/06 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2006/07 Actual	Comments Regarding New Positions
President & CEO							
General Counsel	25	1				26	Position for security function.
Public Affairs	30					30	
Research & Development	3				(1)	2	
Administration	24				2	26	
Corporate Planning and Strategic Review	19			1		20	
	101	1	0	1	1	104	
Corporate Relations							
Aboriginal Relations	54	5				59	Position for settlement issues, policy development and community relations.
Administration	8					8	
	62	5	0	0	0	67	
Finance & Administration							
Information Technology Services	364			(10)	(18)	336	
Treasury	16				(1)	15	
Corporate Risk Management	2				2	3	
Gas Supply	20				(1)	19	
Rates & Regulatory Affairs	19				0	19	
Corporate Controller	113			(7)	0	106	
Human Resources	141			(4)	2	139	
Corporate Safety & Health	53			(1)	2	54	
Corporate Services	294			4		298	
Administration	14	2		1	0	18	Positions to support Corporate Safety & Health initiatives and the Worksmart and Business solutions projects (part year).
	1,035	2	0	(17)	(14)	1,006	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2005/06 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2006/07 Actual	Comments Regarding New Positions
31	**Power Supply**							
32	Power Planning	35			7	(0)	42	
33	Power Projects Development	37	2		(3)	2	39	Positions for new generation licensing and planning activitie
34	Portfolio Projects Management	0			3	(0)	3	
35	HVDC	228				4	232	
36	Generation North	213				(2)	211	
37	Generation South	462				(3)	459	
38	Power Sales & Operations	84	6		(7)	(0)	82	Positions for power marketing, regulatory standards, and licensing activities.
39	Engineering Services	162	3			11	176	Positions for Kelsey rerunnering project.
40	New Generation Construction	14	10			1	25	Positions for new generation construction.
41	Administration	131	6			(0)	137	Positions for Operating Technician Trainee Program
42		1,366	27	0	0	11	1,405	
43								
44	**Transmission**							
45	Transmission System Operations	346	13			4	363	Positions for Telecontrol Trainee Program
46	Transmission Planning & Design	195				(2)	193	
47	Transmission Construction & Line Maintenance	276				(2)	274	
48	Apparatus Maintenance	362				3	365	
49	Administration	42			1	(5)	38	
50		1,220	13	0	1	(2)	1,233	
51								

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2005/06 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2006/07 Actual	Comments Regarding New Positions
52	**Customer Services & Distribution**							
53	Customer Service Operations - Winnipeg & North	537				(22)	515	
54	Customer Service Operations - South	569				(10)	559	
55	Distribution Engineering & Construction Rural	255			4	2	261	
56	Distribution Engineering & Construction Winnipeg	287	1		(4)	(2)	282	Position for Underground Construction administration.
58		1,647	1	0	0	(32)	1,616	
59								
60	**Customer Care & Marketing**							
61	Industrial & Commercial Solutions	49				2	51	
62	Consumer Marketing & Sales	221	7			1	228	Positions for support of new Power Smart programs.
63	Business Support Services	237			14	(12)	239	
64	Administration	39					39	
65		547	7	0	14	(9)	556	
66								
67	**Total**	5,978	56	0	(1)	(44)	5,988	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2006/07 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2007/08 Actual	Comments Regarding New Positions
President & CEO							
General Counsel	26				1	27	
Public Affairs	30				1	31	
Research & Development	2					2	
Administration	26				1	27	
Corporate Planning and Strategic Review	20		(1)		(0)	19	
	104	0	(1)	0	3	106	
Corporate Relations							
Aboriginal Relations	59				2	61	
Administration	8				(1)	7	
	67	0	0	0	2	69	
Finance & Administration							
Information Technology Services	336			(14)	(9)	313	
Treasury	15				1	15	
Corporate Risk Management	3	1			(0)	4	Position to provide administrative support.
Gas Supply	19				(0)	19	
Rates & Regulatory Affairs	19				(0)	19	
Corporate Controller	106			10	(8)	108	
Human Resources	139			(2)	(2)	135	
Corporate Safety & Health	54	1		2	2	59	Position to provide administrative support.
Corporate Services	298			2	4	304	
Administration	18				(0)	17	
	1,006	2	0	(2)	(14)	993	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2006/07 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2007/08 Actual	Comments Regarding New Positions
31	**Power Supply**							
32	Power Planning	42	6		4	3	55	Positions to support Keeyask, Conawapa, and Pointe du Bois.
33	Power Projects Development	39	7		(2)	(1)	42	Positions to support Keeyask, Conawapa, and Pointe du Bois.
34	Portfolio Projects Management	3				1	4	
35	HVDC	232				4	235	
36	Generation North	211				4	215	
37	Generation South	459				(4)	455	
38	Power Sales & Operations	82	1			1	84	Position to support export power marketing/trading function.
39	Engineering Services	176				(1)	175	
40	New Generation Construction	25	25			5	55	Positions to support Wuskwatim, Keeyask and Conawapa. Licensing, BiPoleIII and Pointe Du Bois.
41	Administration	137	15		(2)		150	Positions for Operating Technician Trainee Program.
42		1,405	54	0	0	11	1,470	
43								
44	**Transmission**							
45	Transmission System Operations	363				(1)	362	
46	Transmission Planning & Design	193	4		(19)		178	Positions to support Wuskwatim Transmission.
47	Transmission Construction & Line Maintenance	274				(1)	273	
48	Apparatus Maintenance	365	13		19		397	Positions for Power Electrician Trainee program.
49	Administration	38	2		2	3	46	Positions for new International Education Engineer Qualification Program (IEEQ).
50		1,233	19	0	2	1	1,256	
51								

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2006/07 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2007/08 Actual	Comments Regarding New Positions
52	**Customer Services & Distribution**							
53	Customer Service Operations - Winnipeg & North	515	6			(0)	520	Positions for Gas Trades Trainee Program.
54	Customer Service Operations - South	559	7			(5)	561	Positions for Power Line Technician Trainee program and Aboriginal Line Trades Pre-Placement Trainee program.
55	Distribution Engineering & Construction Rural	261	7			8	276	Positions to support engineering & design functions.
56	Distribution Engineering & Construction Winnipeg	282	3			(2)	283	Positions for Power Line Technician Trainee program.
58		1,616	23	0	0	1	1,640	
59								
60	**Customer Care & Marketing**							
61	Industrial & Commercial Solutions	51				1	52	
62	Consumer Marketing & Sales	228				(9)	218	
63	Business Support Services	239				(10)	229	
64	Administration	39					39	
65		556	0	0	0	(18)	538	
66								
67	**Total**	5,988	98	(1)	0	(14)	6,071	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2007/08 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2008/09 Actual	Comments Regarding New Positions
President & CEO							
General Counsel	27				(1)	26	
Public Affairs	31				1	32	
Research & Development	2					2	
Administration	27					27	
Corporate Planning and Strategic Review	19				1	20	
	106	-	-	-	1	107	
Corporate Relations							
Aboriginal Relations	61	5			1	67	Positions for Utility workers in Cross Lake to take on work previously done by external contractors.
Administration	7					8	
	69	5	-	-	1	75	
Finance & Administration							
Information Technology Services	313					313	
Treasury	15					16	
Corporate Risk Management	4	1				5	Position to support middle office function.
Gas Supply	19	1				20	Position for power trading function.
Rates & Regulatory Affairs	19					19	
Corporate Controller	108				(1)	107	
Human Resources	135	2			1	138	Positions to fill analysis function.
Corporate Safety & Health	59				2	61	
Corporate Services	304	5			2	311	Positions for building operations at various Winnipeg facilities, for building maintenance in rural areas and for administrative support.
Administration	17				1	18	
	993	9	-	-	5	1 006	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2007/08 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2008/09 Actual	Comments Regarding New Positions
31	**Power Supply**							
32	Power Planning	54.9	2.0			0.8	57.7	Positions to support ongoing requirements for Emerging Energy Systems and Energy Policy & Emissions Trading.
33	Power Projects Development	42.3	3.0			(1.4)	43.9	Positions to support Keeyask, Conawapa, Pointe du Bois, and Planning Studies.
34	Portfolio Projects Management	4.1				0.8	4.9	
35	HVDC	235.2				14.5	249.7	
36	Generation North	214.9				4.5	219.4	
37	Generation South	454.6				4.0	458.6	
38	Power Sales & Operations	84.4				(0.3)	84.1	
39	Engineering Services	174.5	7.0			1.9	183.4	Positions for major capital projects such as Halon Replacement and Physical Security Upgrades, as well as Keeyask and Conawapa.
40	New Generation Construction	55.5	24.0			3.9	83.4	Positions to support Wuskwatim, Keeyask, Conawapa and Pointe du Bois.
41	Administration	149.7	39.0			2.1	190.8	Positions for Operating Technician Trainee Program
42		1,470.1	75.0	-	-	30.8	1,575.9	
43								
44	**Transmission**							
45	Transmission System Operations	361.8					362.3	
46	Transmission Planning & Design	178.1	7			6	191.1	Positions to support Riel Station.
47	Transmission Construction & Line Maintenance	273.4				2	275.5	
48	Apparatus Maintenance	396.6	24				420.5	Positions for Power Electrician Trainee program.
49	Administration	45.6	10		(7)	1	48.7	Positions for Engineer-in-Training program.
50		1,255.5	41	-	(7)	9	1,298.1	
51								

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2007/08 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2008/09 Actual	Comments Regarding New Positions
52	**Customer Services & Distribution**							
53	Customer Service Operations - Winnipeg & North	520.4	16			(6)	530.0	Positions for Gas Trades Trainee Program & two additional staff for Special Northern Collections Initiative.
54	Customer Service Operations - South	560.9	6	(2)		1	565.9	Positions for Power Line Technician Trainee program. .
55	Distribution Engineering & Construction Rural	276.2			4	1	283.8	
56	Distribution Engineering & Construction Winnipeg	282.5	6		(4)	9	291.0	Positions for Power Line Technician Trainee program.
57	Administration	-					0.7	
58		1,640.0	28	(2)	-	5	1,671.3	
59								
60	**Customer Care & Marketing**							
61	Industrial & Commercial Solutions	51.5				2	54.2	
62	Consumer Marketing & Sales	218.0			(4)	2	216.3	
63	Business Support Services	229.3				(1)	228.5	
64	Administration	39.5			4	1	43.6	
65		538.3	-	-	-	4	542.7	
66								
67	**Total**	6,071.0	158	(2)	(7)	56	6,276.0	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2008/09 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2009/10 Actual	Comments Regarding New Positions
President & CEO							
General Counsel	26				3	29	
Public Affairs	32				2	34	
Research & Development	2					2	
Administration	27	2		1		29	One vice-president & one division manager.
Corporate Planning and Strategic Review	20	1		3	(2)	22	Position for administrative support.
	107	3	-	4	3	116	
Corporate Relations							
Aboriginal Relations	67				1	68	
Administration	8			(4)	1	5	
	75	-	-	(4)	2	73	
Finance & Administration							
Information Technology Services	313					313	
Treasury	16				(1)	14	
Corporate Risk Management	5					5	
Gas Supply	20					20	
Rates & Regulatory Affairs	19				1	20	
Corporate Controller	107	2		4		113	Positions for IFRS project.
Human Resources	138		(1)	(5)	(2)	129	
Corporate Safety & Health	61				(4)	57	
Corporate Services	311			7	2	321	
Administration	18					18	
	1 006	2	(1)	6	(4)	1 010	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2008/09 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2009/10 Actual	Comments Regarding New Positions
31	**Power Supply**							
32	Power Planning	58	7			1	66	Positions mainly for Water Resource, Energy Policy & Emissions Trading.
33	Power Projects Development	44				3	47	
34	Portfolio Projects Management	5					4	
35	HVDC	250				4	254	
36	Generation North	219				5	224	
37	Generation South	459	3			9	471	Positions for Ice Safety Management.
38	Power Sales & Operations	84				(2)	82	
39	Engineering Services	183	14			17	214	Positions mainly for major capital projects (Keeyask & Conawapa)
40	New Generation Construction	83	25				108	Positions mainly for major capital projects (Keeyask, Conawapa, Pointe du Bois, Bipole 3)
41	Administration	191	17				208	Positions for the Operating Technician Trainee Program
42		1,576	66	0	0	37	1,679	
43								
44	**Transmission**							
45	Transmission System Operations	362			1	1	364	
46	Transmission Planning & Design	191	7		(1)	9	206	Positions to support Wuskwatim and Riel Station projects.
47	Transmission Construction & Line Maintenance	276	4			12	292	Positions to support Wuskwatim and Riel Station projects.
48	Apparatus Maintenance	420				10	431	
49	Administration	49	6		(3)	(2)	50	Positions for Engineer-in-Training program.
50		1,298	17	0	(3)	30	1,342	
51								

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2008/09 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2009/10 Actual	Comments Regarding New Positions
52	**Customer Services & Distribution**							
53	Customer Service Operations - Winnipeg & North	530	3		(7)	1	528	Positions related to Special Northern Collections Initiative.
54	Customer Service Operations - South	566	1		8	2	577	Position for administrative support.
55	Distribution Engineering & Construction Rural	284			(1)	2	277	
56	Distribution Engineering & Construction Winnipeg	291			(1)	(6)	288	
57	Administration	1	2		3		7	Positions for administrative support.
58		1,671	6	0	2	(1)	1,678	
59								
60	**Customer Care & Marketing**							
61	Industrial & Commercial Solutions	54				3	57	
62	Consumer Marketing & Sales	216			(7)	(2)	207	
63	Business Support Services	228	2		(1)	(7)	222	Positions for quality assessment and collections function.
64	Administration	44			3	(1)	46	
65		543	2	0	(5)	(7)	532	
66								
67	**Total**	6,276	96	(1)	(0)	60	6,429	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2009/10 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2010/11 Actual	Comments Regarding New Positions
President & CEO						
General Counsel	29	2			31	Positions for Corporate Security function.
Public Affairs	34			(1)	33	
Research & Development	2		(1)	(0)	1	
Administration	29		2	1	32	
Corporate Planning and Strategic Review	22	6	1	(2)	27	Positions to support corporate strategic review, corporate planning, economic development and corporate environmental management.
	116	8	2	(2)	123	
Corporate Relations						
Aboriginal Relations	68			(3)	65	
Administration	5		(1)	-	4	
	73	-	(1)	(3)	69	
Finance & Administration						
Information Technology Services	313			1	314	
Treasury	14			(1)	13	
Corporate Risk Management	5	1		(1)	6	Position for business analysis function.
Gas Supply	20			1	21	
Rates & Regulatory Affairs	20			2	22	
Corporate Controller	113		2	(4)	110	
Human Resources	129		(1)	(1)	127	
Corporate Safety & Health	57			(0)	57	
Corporate Services	321			4	325	
Administration	18			(2)	16	
	1 010	1	0	(2)	1 009	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2009/10 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2010/11 Actual	Comments Regarding New Positions
31	**Power Supply**							
32	Power Planning	66	4		1	4	75	Positions to support the growing environmental management and emerging energy issues within Power Supply.
33	Power Projects Development	47	2		(1)		48	Positions to support hydro power planning and assessments and licensing functions.
34	Portfolio Projects Management	4	1			1	6	Position to support Hydro's sustainable generation options.
35	HVDC	254				6	260	
36	Generation North	224				11	235	
37	Generation South	471	5			12	488	Positions for Ice Safety Management for the Winnipeg River.
38	Power Sales & Operations	82				3	86	
39	Engineering Services	214	16			3	233	Positions for Field Inspection work and to provide support in major projects such as Great Falls Unit #4 Overhaul and Physical Security Upgrades, as well as new generation projects such as Kettle Unit 1-4 Stator Replacement.
40	New Generation Construction	108	13			3	124	Positions to support new generation projects such as Wuskwatim, Conawapa, Keeyask, and Bipole III.
41	Administration	208	28			6	243	Positions for the Operating Technician Trainee Program
42		1679	69	0	(0)	49	1796	
43								
44	**Transmission**							
45	Transmission System Operations	364				1	365	
46	Transmission Planning & Design	206	4		(2)	6	214	Positions to support the environmental function for BPIII and to support the commissioning function for various northern projects.
47	Transmission Construction & Line Maintenance	292	6			5	303	Positions to support Riel Station and BPIII.
48	Apparatus Maintenance	431				3	434	
49	Administration	50				(2)	48	
50		1342	10	0	(2)	13	1365	
51								

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2009/10 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2010/11 Actual	Comments Regarding New Positions
52	**Customer Services & Distribution**							
53	Customer Service Operations - Winnipeg & No	528	8		1	(6)	532	Positions to support repatriation of Line Locate function from MHUS
54	Customer Service Operations - South	577				3	580	
55	Distribution Engineering & Construction Rural	277				11	288	
56	Distribution Engineering & Construction Winnip	288	2		2	6	298	Positions to support fleet, environmental and engineering functions.
57	Administration	7				(1)	6	
58		1678	10	0	3	14	1704	
59								
60	**Customer Care & Marketing**							
61	Industrial & Commercial Solutions	57				(3)	54	
62	Consumer Marketing & Sales	207			0	3	210	
63	Business Support Services	222			(2)	(4)	217	
64	Administration	46				1	47	
65		532	0	0	(2)	(2)	528	
66								
67	**Total**	6429	99	0	0	67	6594	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2010/11 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2011/12 Actual	Comments Regarding New Positions
President & CEO						
General Counsel	31			2	32	
Public Affairs	33				33	
Research & Development	1				1	
Administration	32		1		32	
Corporate Planning & Strategic Review	27	2	(1)	-	29	Positions to support administrative function.
	123	2	-	2	127	
Corporate Relations						
Aboriginal Relations	65			1	66	
Administration	4			(1)	3	
	69	-	-	(0)	69	
Finance & Administration						
Information Technology Services	314			(2)	312	
Treasury	13			(0)	13	
Corporate Risk Management	6			1	6	
Gas Supply	21			(1)	20	
Rates & Regulatory Affairs	22			(1)	21	
Corporate Controller	110			(6)	104	
Human Resources	127			(0)	126	
Corporate Safety & Health	57			(2)	55	
Corporate Services	325			(12)	313	
Administration	16			(3)	13	
	1 009	-	-	(27)	983	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2010/11 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2011/12 Actual	Comments Regarding New Positions
32	**Power Supply**							
33	Power Planning	75				3	78	
34	Power Projects Development	48	5			1	53	Positions mainly to support major capital projects such as Keeyask, Conawapa and Pointe du Bois capital projects.
35	Portfolio Projects Management	6	3		1	(1)	9	Positions to support regulatory reviews of Hydro's major projects and associated environmental processes.
36	HVDC	260	1			(3)	258	Positions hired later in year to support BipoleIII (translates to 1 EFT).
37	Generation North	235	3		4	8	249	Positions to support the upcoming in-service for Wuskwatim and the operations of the Kettle generating station.
38	Generation South	488				1	489	
39	Power Sales & Operations	86				2	88	
40	Engineering Services	233	6		(6)	6	239	Positions to support engineering field investigations and engineering design functions.
41	New Generation Construction	124	15		2	(4)	137	Positions to support various capital projects such as Pointe Du Bois, BPIII and, Keeyask.
42	Administration	243	12			0	255	Positions for the Operating Technician Trainee Program.
43		1,796	45	-	0	12	1,853	
44								
45	**Transmission**							
46	Transmission System Operations	365				(9)	356	
47	Transmission Planning & Design	214	1			18	233	Position for Station Standards Project.
48	Transmission Construction & Line Maintenance	303	2			(5)	301	Positions to support Bipole III project.
49	Apparatus Maintenance	434				(6)	428	
50	Administration	48				(12)	36	
51		1,365	4	-	-	(15)	1,354	
52								

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2010/11 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2011/12 Actual	Comments Regarding New Positions
53	**Customer Services & Distribution**							
54	Customer Service Operations - Winnipeg & No	532			(13)	(11)	508	
55	Customer Service Operations - South	580				(19)	562	
56	Distribution Engineering & Construction Rural	288	4			17	309	Positions to support MTS Fibre to Home program.
57	Distribution Engineering & Construction Winnip	298			(7)	5	296	
58	Administration	6			20	1	27	
59		1,704	4	-	-	(7)	1,701	
60								
61	**Customer Care & Marketing**							
62	Industrial & Commercial Solutions	54			1	(2)	52	
63	Consumer Marketing & Sales	210			(1)	(10)	199	
64	Business Support Services	217	1			2	220	Position for Meter Compliance project.
65	Administration	47				2	49	
66		528	1	-	-	(8)	521	
67								
68	**Total**	6,594	55	-	0	(42)	6,608	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2011/12 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2012/13 Forecast	Comments Regarding New Positions
President & CEO						
General Counsel	32			1	33	
Public Affairs	33			1	34	
Research & Development	1				1	
Administration	32		-	(1)	31	
Coporate Planning and Strategic Review	29	1	(1)	(2)	27	Position for economic development coordination.
	127	1	(1)	(1)	126	
Corporate Relations						
Aboriginal Relations	66	4		2	72	Positions for strategic initiatives and community relations.
Administration	3				3	
	69	4	-	2	75	
Finance & Administration						
Information Technology Services	312			(2)	310	
Treasury	13	1		(1)	13	Position for administrative support.
Corporate Risk Management	6				6	
Gas Supply	20			(1)	19	
Rates & Regulatory Affairs	21				21	
Corporate Controller	104		(1)	2	105	
Human Resources	126	3	1	2	131	Positions for the Aquired Brain Injury Program.
Corporate Safety & Health	55	2	5	(1)	61	Positions for research function.
Corporate Services	313	6	(5)	8	323	Positions for facility management.
Administration	13		1		14	
	983	12	1	7	1 003	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2011/12 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2012/13 Forecast	Comments Regarding New Positions
31	**Power Supply**						
32	Power Planning	78		(3)	2	77	
33	Power Projects Development	53	2		3	58	Positions for estimating, scheduling and post-project evalulation.
34	Portfolio Projects Management	9	2		2	13	Positions to support regulatory reviews of Hydro's major projects and associated environmental processes as well as portfolio regulation.
35	HVDC	258	7	-	8	273	Positions to support Bipole III, Radison/Henday operations, Dorsey operations and plant maintenance and training coordination.
36	Generation North	249	15	1	3	268	Positions for Wuskwatim operational requirements.
37	Generation South	489	13	-	(10)	492	Positions for phase 2 of the EAM project and for the Grand Rapids Fish Hatchery that was acquired from the Province of Manitoba in September 2012.
38	Power Sales & Operations	88	1			89	Position for Hydro-Electric Reservoir Management Evaluation System project.
39	Engineering Services	239	5	-	4	248	Positions for engineering field investigations and insulation testing.
40	New Generation Construction	137	55	(1)	(10)	181	Positions for increased capital requirements in projects such as BipoleIII Converter Stations, Keeyask and Pointe du Bois as well as accounting/administrative support for the division.
41	Administration	255	16		3	273	Positions for the Operating Technician Trainee Program, Northern Aboriginal Trainee Program and to support regulatory reviews of Hydro's major projects and associated environmental processes.
42		1,853	116	(3)	6	1,972	
43							
44	**Transmission**						
45	Transmission System Operations	356			2	358	
46	Transmission Planning & Design	233		1	1	235	
47	Transmission Construction & Line Maintenanc	301	8		11	320	Positions for Bipole III.
48	Apparatus Maintenance	428			1	429	
49	Administration	36			8	44	
50		1,354	8	1	23	1,385	
51							

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

		2011/12 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2012/13 Forecast	Comments Regarding New Positions
52	**Customer Services & Distribution**						
53	Customer Service Operations - Winnipeg & N	508	9	(3)	15	528	Positions for Meter Compliance Standards initiative.
54	Customer Service Operations - South	562	3	(1)	(3)	561	Positions for Meter Compliance Standards initiative.
55	Distribution Engineering & Construction Rural	309	4	(2)	(4)	307	Term positions for distribution construction.
56	Distribution Engineering & Construction Winn	296	4	3	5	308	Positions for planning and field/pipeline inspection functions.
57	Administration	27				27	
58		1,701	20	(3)	13	1,731	
59							
60	**Customer Care & Marketing**						
61	Industrial & Commercial Solutions	52		3	4	59	
62	Consumer Marketing & Sales	199		2	4	206	
63	Business Support Services	220		0	14	235	
64	Administration	49				49	
65		521	-	5	22	549	
66							
67	**Total**	6,608	161	0	72	6,842	

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

f) Please indicate the current number of unfilled EFT's

ANSWER:

The budgeted EFT complement for August 2012 was 6708 as compared to the actual EFT level of 6494, resulting in 214 unfilled EFTs.

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

g) Please provide a comparison of the EFT's forecast at the last GRA for 2009/10, 2010/11 and 2011/12 [PUB/MH I-34 (R)] and for each difference please indicate the attributed payroll difference between what was forecast in IFF09 versus actual.

ANSWER:

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

The attributed payroll difference between what was forecast in IFF09 versus actual would be a decrease in wages & salaries and overtime of approximately $12.2 million in 2009/10, $4.9 million in 2010/11 and $4.2 million in 2011/12.

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

h) Please refile the schedule on page 7 to agree with the OM&A reflected in IFF11-2.

ANSWER:

Please see the Operating, Maintenance and Administrative Costs by Cost Element schedule adjusted to reconcile with the OM&A reflected in IFF11-2.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2009/10 Actual	2010/11 Actual	2011/12 Forecast	2012/13 Forecast	2013/14 Forecast	Average Annual % Inc/(Dec)
Wages, Salaries	$ 407,988	$ 425,158	$ 448,371	$ 476,887	$ 486,425	4.5%
Overtime	50,307	50,704	50,680	56,005	57,126	3.3%
Employee Benefits	83,013	95,376	102,354	109,649	111,842	7.8%
Employee Safety & Training	4,284	3,863	4,165	4,914	5,013	4.5%
Travel	32,435	32,594	32,131	32,405	33,053	0.5%
Motor Vehicle	24,281	24,436	25,201	24,784	25,280	1.0%
Materials & Tools	26,897	28,105	26,900	27,173	27,716	0.8%
Consulting & Professional Fees	14,814	11,157	11,402	11,639	11,872	-4.6%
Construction & Maintenance Services	20,109	22,657	18,838	18,706	19,080	-0.7%
Building & Property Services	22,931	21,944	20,624	22,396	22,843	0.1%
Equipment Maintenance & Rentals	14,379	14,165	14,150	14,476	14,766	0.7%
Consumer Services	5,798	5,086	4,982	5,284	5,389	-1.6%
Collection Costs	4,599	4,497	4,521	4,347	4,434	-0.9%
Customer & Public Relations	8,155	7,905	6,797	6,949	7,088	-3.2%
Sponsored Memberships	1,325	1,917	996	1,081	1,103	1.8%
Office & Administration	15,320	14,316	14,826	15,263	15,569	0.5%
Computer Services	983	1,003	1,007	909	927	-1.3%
Communication Systems	1,772	1,678	1,796	1,683	1,717	-0.6%
Research & Development Costs	3,952	3,651	4,136	3,509	3,579	-1.9%
Miscellaneous Expense	1,190	1,264	1,278	1,213	1,237	1.1%
Contingency Planning	-	-	1,577	278	2,875	
Operating Expense Recovery	(21,580)	(23,004)	(16,256)	(9,787)	(9,983)	-15.1%
Total Costs	722,951	748,471	780,476	829,765	848,951	4.1%
Capital Order Activities	(224,298)	(243,545)	(265,803)	(246,065)	(250,986)	3.1%
Capitalized Overhead	(60,151)	(47,336)	(52,742)	(69,434)	(70,823)	5.9%
Operating and Administration Charged to Centra	(60,951)	(60,644)	(64,000)	(67,300)	(68,646)	3.0%
IFRS Changes					71,574	
Wuskatim GS for Full Year In-Service	-	-	-	-	1,754	
OM&A Attributable to Electric Operations	**$ 377,551**	**$ 396,946**	**$ 397,931**	**$ 446,966**	**$ 531,825**	
Less:						
Accounting Changes	11,240	30,910	34,973	67,059	139,974	
Wuskwatim				7,881	9,635	
OM&A Attributable to Electric Operations after adjusting for subsidiaries, accounting changes and Wuskwatim	**$ 366,311**	**$ 366,036**	**$ 362,958**	**$ 372,026**	**$ 382,216**	

Please note the 'OM&A Attributable to Electric Operations' does not include subsidiaries.

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

i) Please provide a comparison of the OM&A by cost element for the years 2009/10, 2010/11 and 2011/2 from PUB/MH II – 23 (from the 2011 & 2012 GRA) with the amount presented in Appendix 5.6 page 7 for those years. Please indicate the dollar and percentage difference for each line item and explain the reason for the variances; in particular the increases in labour costs for 2010/11 & 2011/12 given the reduction in actual EFT's from that forecast at the last GRA.

ANSWER:

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

The increase in labour costs for 2010/11 and 2011/12 are primarily due to wage settlements, net of the reduction in actual EFT's as compared to the forecast at the last GRA.

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

j) Please provide the compound annual growth rate for 2009/10 through 2011/12 by each line item last year and provide the same information for this year.

ANSWER:

The attached table provides 2009/10 through 2011/12 actual results as filed in Appendix 5.6 and the forecast for the same fiscal years as filed in the prior hearing.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2009/10 Actual	2010/11 Actual	2011/12 Actual	Fiscal 2009/10-2011/12 Compounded Annual Growth %	As per 2010/11, 2011/12 GRA 2009/10 Actual	2010/11 Forecast	2011/12 Forecast	Fiscal 2009/10-2011/12 Compounded Annual Growth %
Wages, Salaries	$ 407,988	$ 425,158	$ 451,925	5.2	$ 407,988	$ 415,215	$ 424,765	2.0
Overtime	50,307	50,704	54,987	4.5	50,307	48,061	49,166	-1.1
Employee Benefits	82,674	95,376	104,444	12.4	82,674	93,035	95,175	7.3
Employee Safety & Training	4,623	3,863	3,909	-8.0	4,623	4,747	4,856	2.5
Travel	32,435	32,594	31,266	-1.8	32,435	32,963	33,721	2.0
Motor Vehicle	24,281	24,436	28,676	8.7	24,281	23,114	23,646	-1.3
Materials & Tools	26,897	28,105	26,663	-0.4	26,897	26,178	26,780	-0.2
Consulting & Professional Fees	14,814	11,157	10,250	-16.8	14,814	10,904	11,155	-13.2
Construction & Maintenance Services	20,109	22,657	21,228	2.7	20,109	21,785	22,286	5.3
Building & Property Services	22,931	21,944	21,386	-3.4	22,931	20,671	21,146	-4.0
Equipment Maintenance & Rentals	14,379	14,165	13,388	-3.5	14,379	13,858	14,177	-0.7
Consumer Services	5,798	5,086	5,365	-3.8	5,798	5,683	5,814	0.1
Computer Services	983	1,003	861	-6.4	983	696	712	-14.9
Collection Costs	4,599	4,497	4,034	-6.3	4,599	4,542	4,646	0.5
Customer & Public Relations	8,155	7,905	8,093	-0.4	8,155	6,014	6,152	-13.1
Sponsored Memberships	1,325	1,917	1,608	10.1	1,325	1,267	1,296	-1.1
Office & Administration	15,320	14,316	14,277	-3.5	15,320	15,703	15,857	1.7
Communication Systems	1,772	1,678	1,683	-2.5	1,772	1,603	1,640	-3.8
Research & Development Costs	3,952	3,651	2,796	-15.9	3,952	4,110	4,205	3.2
Miscellaneous Expense	1,190	1,264	2,032	30.7	1,190	1,087	1,112	-3.3
Contingency Planning	-	-	-	0.0	-	5,417	3,921	0.0
Operating Expense Recovery	(21,580)	(23,004)	(21,716)	0.3	(21,580)	(16,497)	(16,670)	-12.1
Total Costs	722,951	748,471	787,155	4.3	722,951	740,156	755,557	2.2
Capital Order Activities	$ (224,298)	$ (243,545)	$ (268,651)	9.4	$ (224,298)	$ (235,040)	$ (239,741)	3.4
CICA Accounting Changes*	-				9,000	9,000	9,000	0.0
Provision for IFRS					-	18,000	13,500	
Capitalized Overhead	(60,151)	(47,336)	(53,084)	-6.1	(69,151)	(71,021)	(72,447)	2.4
Operating and Administration Charged to Centra	(60,951)	(60,644)	(62,117)	1.0	(60,951)	(63,400)	(64,000)	2.5
OM&A Attributable to Electric Operations	**$ 377,551**	**$ 396,946**	**$ 403,303**	3.4	**$ 377,551**	**$ 397,695**	**$ 401,870**	3.2

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

PUB/MH I-65

Reference: Appendix 5.6, Page 13 Cost Constraint Measures

a) Please file copies of all internal memos and directives by MH executive and Board directing cost constraint measures.

ANSWER:

Executive direction regarding cost constraint measures were filed in the 2010/11 & 2011/12 GRA – Exhibit #'s MH-112 and MH-124.

OM&A targets consider the projected impacts of the cost constraint measures as outlined in Appendix 5.6. In addition, Manitoba Hydro provides for a productivity factor in the order of 0.5% to 1.0% annually in the setting of targets. Implicit in the detailed budgets and actual operating performance is the achievement of cost reductions, process improvements and other steps necessary to meet target.

PUB/MH I-65

Reference: Appendix 5.6, Page 13 Cost Constraint Measures

b) Please provide an estimate of the savings realized with supporting calculations from each of the cost containment measures for 2010/11, 2011/12 and forecast for 2012/13 and 2013/14.

ANSWER:

Quantification of the individual measures is not available as the achievement of cost savings is in the attainment of necessary business requirements within target budget levels. The impact of these measures is in Manitoba Hydro's ability to hold the average annual increase below 2% over the 2009/10 to 2013/14 forecast period, as referenced on page one of Appendix 5.6, despite higher wage and benefit settlements, higher commodity prices and increased work requirements due to aging infrastructure.

PUB/MH I-65

Reference: Appendix 5.6, Page 13 Cost Constraint Measures

c) Please define and quantify the reductions in capital expenditures undertaken under the cost containment measures.

ANSWER:

Manitoba Hydro controls and manages its capital expenditure forecast through reviews of its capital expenditures and individual projects on an ongoing basis. Individual projects are reviewed for their requirement and adjusted or deferred as appropriate. A Capital Project Justification ("CPJ") framework is used to assist staff in summarizing technical, economic and financial information for a project that is being proposed or revised for inclusion in the capital program. Individual project forecasts consider a number of variables including resource requirements, material and equipment costs, required in-service dates etc. Estimates incorporate where appropriate, measures necessary to minimize the overall project costs including travel and overtime restrictions. Proposed CPJ's are reviewed and approved by the Executive Committee prior to their inclusion in the Capital Expenditure Forecast. All projects that are sustained are considered justified on the basis of safety, system reliability, customer load growth, environmental sustainability and efficiency of operations. Actual expenditures against the approved forecast are reviewed by Executive Committee on a regular basis. The impact of measures to control capital costs is reflected in the attainment of necessary business requirements within approved project forecasts.

PUB/MH I-66 (Revised)

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

a) Please re-file schedule 5.6.0 including the years 2003/04 through 2008/09.

ANSWER:

Please see the schedule below.

MANITOBA HYDRO
FINANCE EXPENSE

Schedule 5.6.0
(000's)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Interest on Short & Long-Term Debt											
Gross Interest	$ 489,978	$ 485,696	$ 492,656	$ 496,204	$ 448,106	$ 490,046	$ 447,346	$ 476,448	$ 492,561	$ 513,478	$ 550,766
Provincial Guarantee Fee	66,844	67,801	65,905	67,997	69,865	70,360	72,274	76,697	82,182	90,966	99,723
Amortization of (Premiums), Discounts, and Transaction Costs	(14,375)	(9,326)	(8,802)	(8,658)	(11,054)	(12,322)	(11,262)	2,872	255	396	430
Intercompany Interest Receivable	(15,259)	(15,392)	(16,470)	(16,827)	(19,774)	(18,182)	(15,737)	(16,224)	(17,318)	(15,072)	(15,404)
Total Interest on Short & Long-Term Debt	527,188	528,778	533,289	538,716	487,143	529,903	492,621	539,794	557,680	589,768	635,515
Interest Earned on Sinking Fund	(43,028)	(27,656)	(30,640)	(28,535)	(30,180)	(24,920)	(23,702)	(17,068)	(9,828)	(10,553)	(9,711)
Interest Allocated to Construction	(31,564)	(32,683)	(34,496)	(47,071)	(60,015)	(74,493)	(98,121)	(135,517)	(167,398)	(144,805)	(178,085)
Corporate Allocation	(16,830)	(16,763)	(16,809)	(17,141)	(17,483)	(17,543)	(17,896)	(19,112)	(19,174)	(19,128)	(19,128)
Other Amortization	17,035	16,166	17,015	21,170	21,331	20,116	20,365	19,946	23,765	24,359	23,053
Total Finance Expense	$ 452,801	$ 467,843	$ 468,359	$ 467,139	$ 400,796	$ 433,063	$ 373,267	$ 388,043	$ 385,044	$ 439,641	$ 451,643

PUB/MH I-66

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

b) Please provide a schedule which compares finance expense forecasts for 2009/10, 2010/11 and 2011/12 presented at the 2011 & 2012 GRA with the current years filing and explain any major variances.

ANSWER:

The IFF10-2 finance expense forecasts from the previous GRA finance expense were filed in PUB/MH/Pre-Ask-11 (a). The actuals from the current filing for 2009/10, 2010/11 and 2011/12 are as shown in response to PUB/MH I-66(a). Note that each of these responses show 2009/10 actuals. Please see the attached schedule which compares the IFF10-2 finance expense forecasts to actuals for 2010/11 and 2011/12.

The major forecast to actual variances occurred in 2011/12 as the actual total electric finance expense was nearly $26 million lower than forecast in IFF10-2. This variance was primarily due to:

i. lower actual gross interest expense (arising from lower actual interest rates and a stronger than forecast Canadian dollar), and
ii. higher actual than forecast credits for interest allocated to construction.

PUB/MH I - 66 (b)
MANITOBA HYDRO
FINANCE EXPENSE
($000's)

	2010/11 Actual PUB/MH I - 66(a) (A)	2010/11 Forecast (IFF10-2) PUB/MH/ Pre-Ask - 11(a) (B)	2010/11 Variance (A - B)	2011/12 Actual PUB/MH I - 66(a) (C)	2011/12 Forecast (IFF10-2) PUB/MH/ Pre-Ask - 11(a) (D)	2011/12 Variance (C - D)
Interest on Short & Long-Term Debt						
Gross Interest	$ 476,448	$ 473,180	$ 3,268	$ 492,561	$ 506,607	$ (14,046)
Provincial Guarantee Fee	76,697	76,694	3	82,182	83,816	(1,634)
Amortization of (Premiums), Discounts, and Transaction Costs	2,872	1,864	1,008	255	1,675	(1,420)
Intercompany Interest Receivable	(16,224)	(17,406)	1,182	(17,318)	(21,198)	3,880
Total Interest on Short & Long-Term Debt	539,794	534,332	5,461	557,680	570,900	(13,220)
Interest Earned on Sinking Fund	(17,068)	(15,329)	(1,739)	(9,828)	(10,981)	1,153
Interest Allocated to Construction	(135,517)	(132,015)	(3,502)	(167,398)	(151,346)	(16,052)
Corporate Allocation	(19,112)	(19,052)	(60)	(19,174)	(19,128)	(46)
Other Amortization	19,946	25,104	(5,158)	23,765	21,374	2,391
Total Finance Expense	**$ 388,043**	**$ 393,040**	**$ (4,998)**	**$ 385,044**	**$ 410,819**	**$ (25,775)**

PUB/MH I-67

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

a) Please provide in a similar level of detail provided in PUB/MH I-35 of the 2011 & 2012 GRA a summary of total interest and finance costs incurred/ forecasted by major category [debt charges, foreign currency gains/losses etc.] both capitalized and expended for the fiscal years 2004 to 2011/12(actual) and forecast for 2012/13 through 202014/15.

ANSWER:

As noted by Manitoba Hydro in the response to PUB/MH I-35(a) from the 2010/11 & 2011/12 General Rate Application, there were differences in presentation between the total finance expense in the requested schedule and the electric finance expense as outlined in main application.

For the presentation and categorization of electric finance expense, please see Manitoba Hydro's response to PUB/MH I-66(a).

PUB/MH I-67

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

b) Please refile the schedule in (a) utilizing updated interest rate assumptions from EO12.

ANSWER:

Schedule 5.6.0, Finance Expense, reflecting interest rate assumptions from EO12 will not be available until IFF12-1 is finalized.

PUB/MH I-67 (Revised)

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

c) Please provide a continuity schedule of the short and long-term debt for the fiscal years 2004 to 2032 detailing the retirement of existing debt and the issue of new debt. Please indicate the proportion of short-term debt to total debt for each of the years.

ANSWER:

Please see the schedule below.

Short term debt is defined as debt issued with maturities of less than one year. Manitoba Hydro's short term borrowing program is a credit facility to safeguard Manitoba Hydro from liquidity risk and to provide sufficient liquidity for the Corporation's temporary cash requirements. Short term borrowings are not intended as a financing vehicle to reduce Manitoba Hydro's overall debt servicing costs.

PUB 1-67 (c) Revised

MANITOBA HYDRO
CONTINUNITY SCHEDULE
SHORT AND LONG TERM DEBT

Actuals to March 31, 2012
(In $Millions Canadian Dollars)

	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Long Term Debt															
Opening Balance	7,268	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	10,311	11,158	12,514	14,229	15,823
LTD Issued	1,013	300	180	173	981	423	1,425	915	698	1,125	1,650	1,450	2,000	2,000	2,600
LTD Retired	(473)	(241)	(111)	(80)	(311)	(366)	(452)	(723)	(25)	(181)	(808)	(214)	(312)	(408)	(530)
Foreign Exchange and Adjustments*	(418)	(245)	(104)	(35)	(327)	559	(622)	(83)	62	(15)	5	120	28	1	1
Closing Balance	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	10,311	11,158	12,514	14,229	15,823	17,894

* Foreign Exchange and Adjustments includes: (a) changes in foreign exchange rates on US dollar denominated debt; and (b) effective 2007/08, 2008/09 and 2009/10, presentation changes related to financial instruments reporting standards to the portfolio carrying value for transaction costs, premiums/discounts, and dual currency bonds respectively.

Short Term Debt	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Opening Balance	128	93	59	-	148	-	100	-	-	-	55	126	131	50	99
Increase(Decrease)	(35)	(34)	(59)	148	(148)	100	(100)	-	-	55	71	5	(80)	49	(3)
Closing Balance	93	59	-	148	-	100	-	-	-	55	126	131	50	99	96

	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Long Term Debt	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	10,311	11,158	12,514	14,229	15,823	17,894
Short Term Debt	93	59		148	-	100	-	-	-	55	126	131	50	99	96
Total Debt	7,483	7,263	7,169	7,375	7,571	8,287	8,538	8,647	9,382	10,366	11,284	12,644	14,280	15,922	17,990
Proportion Short Term Debt	1%	1%	0%	2%	0%	1%	0%	0%	0%	1%	1%	1%	0%	1%	1%

PUB 1-67 (c) Revised

MANITOBA HYDRO
CONTINUNITY SCHEDULE
SHORT AND LONG TERM DEBT

Actuals to March 31, 2012
(In $Millions Canadian Dollars)

	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032
Long Term Debt														
Opening Balance	17,894	18,859	20,151	21,714	22,624	23,467	24,270	25,073	24,825	24,826	24,827	24,768	24,519	24,421
LTD Issued	1,800	1,600	2,200	1,600	1,000	800	800	200	-	-	-	-	-	-
LTD Retired	(837)	(309)	(640)	(692)	(159)	-	-	(450)	-	-	(60)	(250)	(100)	(13)
Foreign Exchange and Adjustments*	1	1	3	3	2	2	3	2	1	1	1	1	1	2
Closing Balance	18,859	20,151	21,714	22,624	23,467	24,270	25,073	24,825	24,826	24,827	24,768	24,519	24,421	24,409

* Foreign Exchange and Adjustments includes: (a) changes in foreign exchange rates on US dollar denominated debt; and (b) effective 2007/08, 2008/09 and 2009/10, presentation changes related to financial instruments reporting standards to the portfolio carrying value for transaction costs, premiums/discounts, and dual currency bonds respectively.

Short Term Debt	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032
Opening Balance	96	47	84	57	-	60	9	61	-	-	-	-	-	-
Increase(Decrease)	(49)	37	(27)	(57)	60	(51)	52	(61)	-	-	-	-	-	-
Closing Balance	47	84	57	-	60	9	61	-	-	-	-	-	-	-

	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032
Long Term Debt	18,859	20,151	21,714	22,624	23,467	24,270	25,073	24,825	24,826	24,827	24,768	24,519	24,421	24,409
Short Term Debt	47	84	57	-	60	9	61	-	-	-	-	-	-	-
Total Debt	18,906	20,235	21,771	22,624	23,528	24,279	25,134	24,825	24,826	24,827	24,768	24,519	24,421	24,409
Proportion Short Term Debt	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

PUB/MH I-67

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

d) Please provide a schedule of new debt issues of long-term borrowings for the years 2010/11, 2011/12 and 2012/13, 2013/14 and 2014/15 years and the forecast and Interest per year at forecast rate interest rates used for each loan.

ANSWER:

Please see the attached schedule.

PUB 1-67 (d) - Actuals as at Sept 19, 2012 (Forecast per IFF11-2)
New Long Term Debt Issues
All dollar amounts in CAD millions, and all interest rates and costs provided exclude the 1.00% Provincial Debt Guarantee Fee

(Notes 1, 2, 3, 4) (Notes 3, 5) (Note 6)

Fiscal Year	Debt Series	Principal (CAD)	Currency	Issue Date (IFF11-2 Forecast)	Issue Date (Actual)	Maturity Date (Actual or Forecasted 20 Year Debt Streams)	Debt Term (Forecasted Debt Streams)	Debt Term (Actual)	Coupon Rate (IFF11-2 10 Year+ Interest Rate Forecast)	All-in Yield (Forecast Fixed Yield or Forecast Equivalent Fixed Yield)	Coupon Rate (Actual: Rounded to Two Decimal Places)	All-in Yield (Actual Fixed Yield or Equivalent Fixed Swap Yield)	Forecasted All-in Yield Interest Costs (IFF11-2) 2010/11	2011/12	2012/13	2013/14	2014/15
2010/11	C115	50.0	CAD		4-May-2010	4-May-2015		5			3BA + 0.23%	3.56%					
	C116	100.0	CAD		4-Jun-2010	5-Mar-2031		21			6.30%	4.65%					
	C119-2	150.0	CAD		4-Aug-2010	5-Sep-2025		15			3BA + 0.43%	4.47%					
	FP-3	250.0	CAD		27-Oct-2010	3-Jun-2020		10			4.15%	3.47%					
	FR-2	250.0	CAD		28-Jan-2011	5-Mar-2041		30			4.10%	4.60%					
	C121-3	100.0	CAD		31-Mar-2011	19-Apr-2016		5			3BA + 0.20%	3.01%					
	Total New Debt	900.0						17				4.04%	-	-	-	-	-
2011/12	FS-1	95.5	USD		27-Apr-2011	28-Apr-2014		3			3 LIBOR + 0.10%	1.45%					
	FT	400.0	CAD		17-May-2011	5-Mar-2042		31			4.49%	4.49%					
	HB11-3 yr fixed	8.6	CAD		15-Jun-2011	15-Jun-2014		3			2.30%	2.60%					
	HB11-5 yr fixed	7.4	CAD		15-Jun-2011	15-Jun-2016		5			2.75%	2.98%					
	HB11-5 yr floating	99.6	CAD		15-Jun-2011	15-Jun-2016		5			1.75% Annual Reset	3.47%					
	FN-2	75.0	CAD	31-Mar-2012	28-Mar-2012	5-Mar-2050	20	38	3.75%	3.75%	4.70%	3.63%		0.0	2.8	2.8	2.8
	GA Part 1	85.0	CAD	31-Mar-2012	5-Jun-2012	5-Mar-2043	20	31	3.75%	3.75%	3.35%	3.41%		0.0	3.2	3.2	3.2
	GA Part 2	40.0	CAD	31-Mar-2012	5-Jun-2012	5-Mar-2043	20	31	3BA + 0.35%	4.53%	3.35%	3.41%		0.0	0.8	1.0	1.6
	Total New Debt	811.1					20	24		3.91%		3.73%		0.0	6.8	7.0	7.6
2012/13	GA Part 3	160.0	CAD	31-May-2012	5-Jun-2012	5-Mar-2043	20	31	3.70%	3.70%	3.35%	3.41%			4.9	5.9	5.9
	GA Part 4	15.0	CAD	31-May-2012	5-Jun-2012	5-Mar-2043	20	31	3BA + 0.35%	4.58%	3.35%	3.41%			0.2	0.4	0.6
	FN-3 Part 1	25.0	CAD	31-May-2012	12-Jul-2012	5-Mar-2050	20	38	3BA + 0.35%	4.58%	4.70%	3.28%			0.4	0.7	1.1
	FN-3 Part 2	25.0	CAD	30-Sep-2012	12-Jul-2012	5-Mar-2050	20	38	3.70%	3.70%	4.70%	3.28%			0.5	0.9	0.9
	C129	50.0	CAD	30-Sep-2012	31-Jul-2012	5-Sep-2052	20	40	3.70%	3.70%	3.15%	3.18%			0.9	1.9	1.9
	GC Part 1	85.0	CAD	30-Sep-2012	6-Sep-2012	6-Sep-2022	20	10	3.70%	3.70%	3BA + 0.4985%	2.13%			1.6	3.1	3.1
	GC Part 2	40.0	CAD	30-Sep-2012	6-Sep-2012	6-Sep-2022	20	10	3BA + 0.35%	4.64%	3BA + 0.4985%	2.13%			0.4	1.0	1.6
	GC Part 3	160.0	CAD	31-Oct-2012	6-Sep-2012	6-Sep-2022	20	10	3.70%	3.70%	3BA + 0.4985%	2.13%			2.5	5.9	5.9
	GC Part 4	11.4	CAD	31-Oct-2012	6-Sep-2012	6-Sep-2022	20	10	3BA + 0.35%	4.69%	3BA + 0.4985%	2.13%			0.1	0.3	0.5
	Forecast	28.6	CAD	31-Oct-2012		31-Oct-2032	20		3BA + 0.35%	4.69%					0.2	0.8	1.2
	Forecast	200.0	CAD	31-Dec-2012		31-Dec-2032	20			3.90%					1.7	7.0	7.6
	Forecast	200.0	CAD	31-Mar-2013		31-Mar-2033	20			3.91%					0.0	7.0	7.6
	Total New Debt	1,000.0					20	31		3.89%		2.72%		-	13.4	34.9	37.9
2013/14	Forecast	200.0	CAD, USD	30-Apr-2013		30-Apr-2033	20			4.18%						6.9	8.2
	Forecast	200.0	CAD, USD	30-Jun-2013		30-Jun-2033	20			4.18%						5.6	8.0
	Forecast	400.0	CAD, USD	30-Sep-2013		30-Sep-2033	20			4.19%						7.5	16.1
	Forecast	200.0	CAD, USD	31-Oct-2013		31-Oct-2033	20			4.20%						3.1	8.2
	Forecast	50.0	CAD, USD	30-Nov-2013		30-Nov-2033	20			4.20%						0.6	2.0
	Forecast	400.0	CAD, USD	31-Dec-2013		31-Dec-2033	20			4.20%						3.7	16.1
	Forecast	200.0	CAD, USD	31-Mar-2014		31-Mar-2034	20			4.20%						0.0	8.0
	Total New Debt	1,650.0					20			4.19%						27.4	66.5
2014/15	Forecast	200.0	CAD, USD	30-Apr-2014		30-Apr-2034	20			5.57%							10.0
	Forecast	200.0	CAD, USD	30-Jun-2014		30-Jun-2034	20			5.57%							8.5
	Forecast	400.0	CAD, USD	30-Sep-2014		30-Sep-2034	20			5.57%							11.6
	Forecast	200.0	CAD, USD	31-Dec-2014		31-Dec-2034	20			5.57%							2.8
	Forecast	200.0	CAD, USD	28-Feb-2015		28-Feb-2035	20			5.57%							1.0
	Forecast	250.0	CAD, USD	31-Mar-2015		31-Mar-2035	20			5.57%							0.0
	Total New Debt	1,450.0					20			5.57%							33.8

NOTE 1 Long term debt issues exclude refinancings of underlying requirements on existing interest rate swap obligations.

NOTE 2 Actual long term debt issues have been listed in chronological order of issue date. In order to notionally associate actual debt issuance with the forecasted tranches, for illustrative purposes of this information request, some debt series have been apportioned into parts to align actual principal amounts with forecasted tranches.

NOTE 3 In accordance with the IFF11-2 modeling algorithm, each new forecasted tranche is 80% fixed and 20% floating rate debt. In addition, these tranches are further subdivided into CAD or USD issues for 2013/14 and 2014/15. The forecasted all-in yield for the forecast debt issues is a blended rate.

NOTE 4 Actual financings will vary from the IFF11-2 forecast. Actual financings will consider the timing, dollar value, denomination, and fixed versus floating nature of the issue depending on a number of factors including: the cash and liquidity requirements in existence at the time of financing; refinancing requirements maturing debt and interest rate swaps; the term dependent on the current maturity schedule and forecasted borrowing requirements, interest rate expectations and the mitigation of interest rate risk; the management of foreign exchange risk; and the market

NOTE 5 The forecasted equivalent fixed yield for each forecasted CAD and USD floating rate debt issue is calculated as the yield to maturity based on all of the projected floating rate coupon payments utilizing the forecasted interest reset rates for the term of the debt series.

NOTE 6 The all-in yield interest costs do not represent the final impact to total finance expense and the overall revenue requirement, as the interest costs shown in this undertaking do not consider all of the finance expense components such as the counterbalancing impact of interest allocated to construction.

PUB/MH I-67

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

e) Please file a copy of term sheets related to long-term debt issued in 2010/11 and 2011/12.

ANSWER:

Please see the attached term sheets.

TERM SHEET

Series C115
Advance from Province of Manitoba

Issue Date	May 4, 2010
Maturity Date	May 4, 2015
Term to Maturity	5 Years
Coupon Rate	3 Month BAs + 0.23%
Yield Rate	3 Month BAs + 0.25%
Interest Payable	February 4, May 4, August 4 & November 4

	CAD Book Value
Principal	$ 50,000,000.00
Premium or (Discount)	-
Commissions and Fees	(45,500.00)
Proceeds	**$ 49,954,500.00**
Accrued Interest Received	-
Swap Premium or (Discount)	-
Net Proceeds	**$ 49,954,500.00**

AUTHORITY ABATED

Refunding Authority:

Loan Act Authority:

Loan Act 2009 Schedule A	$ 49,954,500.00
Total Loan Authority	**$ 49,954,500.00**

TERM SHEET

Series C116
Advance from Province of Manitoba

Issue Date	June 4, 2010
Maturity Date	March 5, 2031
Term to Maturity	21 Years
Coupon Rate	6.300%
Yield Rate	4.650%
Interest Payable	March 5 & September 5

	CAD Book Value
Principal	$ 100,000,000.00
Premium or (Discount)	22,052,000.00
Commissions and Fees	(250,000.00)
Proceeds	**$ 121,802,000.00**
Accrued Interest Received	1,570,684.93
Swap Premium or (Discount)	-
Net Proceeds	**$ 123,372,684.93**

AUTHORITY ABATED

Refunding Authority:

Loan Act Authority:

Loan Act 2009 Schedule A	$ 121,802,000.00
Total Loan Authority	**$ 121,802,000.00**

TERM SHEET

Series C117
Advance from Province of Manitoba

Issue Date	July 23, 2010
Maturity Date	October 14, 2011
Term to Maturity	1.2 Years
Coupon Rate	3 month BAs
Yield Rate	3 month BAs + 2 bps
Interest Payable	Oct, Jan, Apr, and Jul 15

	CAD Book Value
Principal	$ 100,000,000.00
Premium or (Discount)	-
Commissions and Fees	(24,240.00)
Proceeds	**$ 99,975,760.00**
Accrued Interest Received	-
Swap Premium or (Discount)	-
Net Proceeds	**$ 99,975,760.00**

AUTHORITY ABATED

Refunding Authority:

C102	$ 99,975,760.00

Loan Act Authority:

Total Loan Authority	**$ 99,975,760.00**

TERM SHEET

Series C117
Amended Advance from Province of Manitoba
Interest Rate Swaps

	Original Issue	C117 Swap
Par Value	CAD 100,000,000	CAD 100,000,000
Settlement Date	July 23, 2010	July 23, 2010
Maturity Date	October 14, 2011	March 1, 2039
Term to Maturity	1.2 Years	30 Years
Initial Interest Rate	3 Month BAs flat	4.688475%
Interest Payable	Oct, Jan, Apr, and Jul 15	Mar. 1 & Sept. 1
Amended Interest Rate		**4.588475%**

MANITOBA HYDRO COUNTERPARTY

The Province of Manitoba is the counterparty to Manitoba Hydro for the series C117 swap transactions. Debt series C102 previously had a forward interest rate swap associated with it which locked the fixed rate at a blended rate of 4.688475% on CAD $100,000,000 for a period of 30 years until March 1, 2039. The debt series C117 of CAD $100,000,000 was issued by the Province of Manitoba and advanced to Manitoba Hydro. The floating rate note issue will accommodate the cash flow structure of the forward interest rate swaps from maturing debt series C102. An interest rate adjustment will be paid semi-annually on the difference between the swap contract floating rate (3 Month BAs + 0.100000%) and the rate at which the financing occurred (3 Month BAs + 0.000000%). For example, this adjustment will revise the fixed rate on the C117 from 4.688475% to 4.588475% (4.688475% - 0.100000% + 0.00000% = 4.588475%).

PROVINCE OF MANITOBA COUNTERPARTY

Bank of Montreal is the counterparty to the Province of Manitoba on the interest rate swap transactions. The credit rating for this institution at the trade date is as follows:

	BMO
S&P	A+
Moody's	Aa1

TERM SHEET

Series C119
Advance from Province of Manitoba

Issue Date	August 4, 2010
Maturity Date	September 5, 2025
Term to Maturity	15 Years
Coupon Rate	4.400%
Yield Rate	4.468%
Interest Payable	March 5 & September 5

	CAD Book Value
Principal	$ 250,000,000.00
Premium or (Discount)	(1,217,500.00)
Commissions and Fees	(625,000.00)
Proceeds	**$ 248,157,500.00**
Accrued Interest Received	-
Swap Premium or (Discount)	1,842,500.00
Net Proceeds	**$ 250,000,000.00**

AUTHORITY ABATED

Refunding Authority:	
C108	$ 99,263,000.00
Loan Act Authority:	
Loan Act 2010 Schedule B	$ 148,894,500.00
Total Loan Authority	**$ 248,157,500.00**

TERM SHEET

Series C119

Amended Advance from Province of Manitoba
Interest Rate Swaps

	Original Issue	**C119-1 Swap**
Par Value	CAD 250,000,000	CAD 100,000,000
Settlement Date	August 4, 2010	September 1, 2010
Maturity Date	September 5, 2025	September 1, 2029
Term to Maturity	15 Years	19 Years
Initial Interest Rate	4.400%	6.250%
Interest Payable	March and September 5	March and September 1
Amended Interest Rate		**6.575%**

	C119-2 Swap
Par Value	CAD 150,000,000
Settlement Date	August 4, 2010
Maturity Date	September 5, 2025
Term to Maturity	15 Years
Initial Interest Rate	3 month BA + 42.5 bps
Interest Payable	March and September 5
Amended Interest Rate	

MANITOBA HYDRO COUNTERPARTY

The Province of Manitoba is the counterparty to Manitoba Hydro for the series C119 swap transactions. The debt series of C119 was immediately swapped to floating rate debt at a rate of 3 month BA + 0.425%. Debt series C108 previously had a forward interest rate swap associated with it which locked the fixed rate at 6.250% on CAD $100,000,000 for a period of 20 years until September 1, 2029. The debt series C119-1 of CAD $100,000,000 will accommodate the cash flow structure of the forward interest rate swaps from maturing debt series C108. An interest rate adjustment will be paid semi-annually on the difference between the swap contract floating rate (3 Month BAs + 0.100000%) and the rate at which the financing occurred (3 Month BAs + 0.425000%). For example, this adjustment will revise the fixed rate on the C119-1 from 6.250% to 6.575% (6.250% - 0.100000% + 0.425000% = 6.575%).

PROVINCE OF MANITOBA COUNTERPARTY

Bank of Montreal is the counterparty to the Province of Manitoba on the interest rate swap transactions. The credit rating for this institution at the trade date is as follows:

	BMO	CIBC
S&P	A+	A+
Moody's	Aa2	Aa2

TERM SHEET

Series FP-3
Advance from Province of Manitoba

Issue Date	October 27, 2010
Maturity Date	June 3, 2020
Term to Maturity	10 Years
Coupon Rate	4.150%
Yield Rate	3.468807%
Interest Payable	June 3 & December 3

	CAD Book Value
Principal	$ 250,000,000.00
Premium or (Discount)	15,305,000.00
Commissions and Fees	(1,500,000.00)
Proceeds	**$ 263,805,000.00**
Accrued Interest Received	4,150,000.00
Swap Premium or (Discount)	
Net Proceeds	**$ 267,955,000.00**

AUTHORITY ABATED

Refunding Authority:

Loan Act Authority:

Loan Act 2010 Schedule B	$ 36,690,250.00
Loan Act 2010 Schedule A	227,114,750.00
Total Loan Authority	**$ 263,805,000.00**

NOTE: Series FP-3 is a re-opening of series FP ($300 M) that was issued on Feb 19, 2010.

TERM SHEET

Series C119-3
Advance from Province of Manitoba

Issue Date	December 10, 2010
Maturity Date	September 5, 2025
Term to Maturity	15 Years
Coupon Rate	4.400%
Yield Rate	4.226%
Interest Payable	March 5 & September 5

	CAD Book Value
Principal	$ 115,000,000.00
Premium or (Discount)	2,171,200.00
Commissions and Fees	(287,500.00)
Proceeds	**$ 116,883,700.00**
Accrued Interest Received	1,330,849.32
Accrued Interest on Swap	(1,330,849.32)
Swap Premium or (Discount)	(1,883,700.00)
Net Proceeds	**$ 115,000,000.00**

AUTHORITY ABATED

Refunding Authority:

C099-1	$ 50,000,000.00
C099-2	25,000,000.00
C099-3A	25,000,000.00
C099-3B	15,000,000.00
Subtotal	$ 115,000,000.00

Total Loan Authority	**$ 115,000,000.00**

Note: This issue was immediately swapped to floating rate debt to accommodate the cash flow structures of the forward interest rate swaps from maturing debt series C099-1, C099-2, C099-3A and C099-3B.

TERM SHEET

Series C119-3
Amended Advance from Province of Manitoba
Interest Rate Swaps

	Original Issue	**C119-3A Swap**
Par Value	CAD 115,000,000	CAD 50,000,000
Settlement Date	December 10, 2010	December 10, 2010
Maturity Date	September 5, 2025	December 1, 2038
Term to Maturity	15 Years	28 Years
Initial Interest Rate	4.400%	4.8605%
Interest Payable	March and September 5	June and December 1
Amended Interest Rate		**5.2450%**

	C119-3B Swap	**C119-3C Swap**
Par Value	CAD 50,000,000	CAD 15,000,000
Settlement Date	December 10, 2010	December 10, 2010
Maturity Date	December 1, 2038	December 1, 2038
Term to Maturity	28 Years	28 Years
Initial Interest Rate	4.8475%	4.8600%
Interest Payable	June and December 1	June and December 1
Amended Interest Rate	**5.2320%**	**5.2445%**

MANITOBA HYDRO COUNTERPARTY

The Province of Manitoba is the counterparty to Manitoba Hydro for the series C119-3 swap transaction. The debt series of C119-3 was immediately swapped to floating rate debt at 3 month BA + 0.4845%. Debt series C099-1 ($50 M), C099-2 ($25 M), C099-3A ($25 M), and C099-3B ($15 M) previously had forward interest rate swaps associated with them which locked the fixed rate at 4.8605%, 4.8475%, 4.7875%, and 4.8600% respectively, for a period of 28 years until December 1, 2038. Debt series C119-3A ($50 M), C119-3B ($50 M), and C119-3C ($15M) will accommodate the cash flow structures of the forward interest rate swaps from maturing debt series C099-1, C099-2, C099-3A, and C099-3B respectively. An interest rate adjustment will be paid semi-annually on the differences between the swap contract floating rate (3 Month BAs + 0.1000%) and the rate at which the financing occurred (3 Month BAs + 0.4845%). For example, this adjustment will revise the fixed rate on C119-3A from 4.8605% to 5.2450% (4.8605% - 0.1000% + 0.4845% = 5.2450%).

PROVINCE OF MANITOBA COUNTERPARTY

Bank of Montreal is the counterparty to the Province of Manitoba on the interest rate swap transactions. The credit rating for this institution at the trade date is as follows:

	CIBC	BMO	Scotia
S&P	A+	A+	AA-
Moody's	Aa2	Aa2	Aa1

TERM SHEET

Series FR-2
Advance from Province of Manitoba

Issue Date	January 28, 2011
Maturity Date	March 5, 2041
Term to Maturity	30 Years
Coupon Rate	4.10%
Yield Rate	4.599%
Interest Payable	March 5 & September 5

	CAD Book Value
Principal	$ 250,000,000.00
Premium or (Discount)	(18,467,500.00)
Commissions and Fees	(1,750,000.00)
Proceeds	**$ 229,782,500.00**
Accrued Interest Received	4,071,917.81
Swap Premium or (Discount)	
Net Proceeds	**$ 233,854,417.81**

AUTHORITY ABATED

Refunding Authority:

Refunding HB Series 10	$ 73,294,802.20
Refunding HB Series 9	2,122,700.00

Loan Act Authority:

Loan Act 2010 Schedule A	$ 154,364,997.80
Total Loan Authority	**$ 229,782,500.00**

TERM SHEET

Series C121-3
Advance from Province of Manitoba

Issue Date	March 31, 2011
Maturity Date	April 19, 2016
Term to Maturity	5 Years
Coupon Rate	3 Month BAs + 0.20%
Yield Rate	3 Month BAs + 0.19057%
Interest Payable	April 19, July 19, October 19 & January 19

	CAD Book Value
Principal	$ 100,000,000.00
Premium or (Discount)	155,000.00
Commissions and Fees	(100,000.00)
Proceeds	**$ 100,055,000.00**
Accrued Interest Received	291,224.49
Swap Premium or (Discount)	-
Net Proceeds	**$ 100,346,224.49**

AUTHORITY ABATED

Refunding Authority:

Loan Act Authority:

Loan Act 2010 Schedule A	$ 100,055,000.00
Total Loan Authority	**$ 100,055,000.00**

TERM SHEET

Series FS-1
Advance from Province of Manitoba

Issue Date	April 27, 2011
Maturity Date	April 28, 2014
Term to Maturity	3 Years
Coupon Rate	3 mth LIBOR + 0.0976%
Yield Rate	1.445%
Interest Payable	April 28 & October 28

	USD Book Value
Principal	$ 100,000,000.00
Premium or (Discount)	(79,000.00)
Commissions and Fees	(125,000.00)
Proceeds	**$ 99,796,000.00**
Accrued Interest Received	-
Swap Premium or (Discount)	204,000.00
Net Proceeds	**$ 100,000,000.00**

AUTHORITY ABATED

Refunding Authority:

Loan Act Authority:

Loan Act 2010 Schedule A (USD $100M x 0.9549)	$ 95,490,000.00 (CAD)
Total Loan Authority	**$ 95,490,000.00 (CAD)**

NOTE: On April 27, 2011, the Province of Manitoba issued $100 million USD LTD at fixed 1.375% coupon rate, with an all-in-yield of 1.445%. This issue was immediately swapped to floating rate USD debt at 3 month LIBOR + 0.0976%, and was advanced to Manitoba Hydro. The noon foreign exchange rate (0.9549) on the issue date was utilized for the calculation of the Loan Act Authority abatement.

TERM SHEET

Series FS-2
Advance from Province of Manitoba

Issue Date	April 27, 2011
Maturity Date	April 28, 2014
Term to Maturity	3 Years
Coupon Rate	1.375%
Yield Rate	1.445%
Interest Payable	April 28 & October 28

	USD Book Value
Principal	$ 400,000,000.00
Premium or (Discount)	(316,000.00)
Commissions and Fees	(500,000.00)
Proceeds	**$ 399,184,000.00**
Accrued Interest Received	-
Swap Premium or (Discount)	816,000.00
Net Proceeds	**$ 400,000,000.00**

AUTHORITY ABATED

Refunding Authority:

C097-1 (US $104,986,876.64@ 0.9525)	$ 100,000,000.00	(CAD)
C097-2 (US $104,986,876.64@ 0.9525)	100,000,000.00	(CAD)
C117 (US $104,986,876.64@ 0.9525)	100,000,000.00	(CAD)
C100-2 (US $85,039,370.08@ 0.9525)	81,000,000.00	(CAD)

Loan Act Authority:

Total Loan Authority	**$ 381,000,000.00**	**(CAD)**

NOTE: On April 27, 2011, the Province of Manitoba issued $400 million USD LTD at fixed 1.375% coupon rate, with an all-in-yield of 1.445%. This issue was immediately swapped to $381 million floating rate CAD debt at 3 month BA + 0.1721%, and was advanced to Manitoba Hydro.

Term Sheet: Series FS-2
Amended Advance from Province of Manitoba
Interest Rate Swaps

	Original Issue	FS-2 Vanilla Swap	FS-2 Basis Swap
Par Value	USD 400,000,000	USD 400,000,000	CAD 381,000,000
Settlement Date	April 27, 2011	April 27, 2011	April 27, 2011
Maturity Date	April 28, 2014	April 28, 2014	April 28, 2014
Term to Maturity	3 Years	3 Years	3 Years
Initial Interest Rate	1.375%	3 mth LIBOR + 0.12835%	3 mth BA + 0.1721%
Interest Payable	April 28 & October 28	April 28 & October 28	April 28 & October 28

	FS-2A Swap	FS-2B Swap	FS-2C Swap
Par Value	CAD 100,000,000	CAD 100,000,000	CAD 100,000,000
Settlement Date	June 2, 2011	June 2, 2011	October 14, 2011
Maturity Date	June 2, 2018	June 2, 2018	March 1, 2039
Term to Maturity	7 Years	7 Years	27.5 Years
Initial Interest Rate	7.2229%	7.3325%	4.688475%
Interest Payable	December 2 & June 2	December 2 & June 2	September 1 & March 1
Amended Rate	**7.2950%**	**7.4046%**	**4.760575%**

	FS-2D Swap
Par Value	CAD 81,000,000
Settlement Date	November 1, 2011
Maturity Date	November 1, 2038
Term to Maturity	27 Years
Initial Interest Rate	4.787%
Interest Payable	May 1 & November 1
Amended Rate	**4.8591%**

MANITOBA HYDRO COUNTERPARTY

The Province of Manitoba is the counterparty to Manitoba Hydro for the debt series FS-2 swap transactions. On April 27, 2011, the Province of Manitoba issued $400 million USD debt at a fixed rate of 1.375%. This fixed issue was immediately swapped to $400 million USD floating rate debt at a blended rate of 3 month LIBOR + 0.12835%. The $400 million USD floating issue was then swapped to $381 million CAD floating rate debt issue at 3 month BA + 0.1721%. Of the $381 million CAD floating rate issue, $100 million is to refinance the upcoming maturing debt series C097-1, which has a forward interest rate swap associated with it locking the fixed rate at 7.2229% until June 2, 2018; $100 million is to refinance the upcoming maturing debt series C097-2, which has a forward interest rate swap associated with it locking the fixed rate at 7.3325% until June 2, 2018; $100 million is to refinance the upcoming maturing debt series C117, which has a forward interest rate swap associated with it locking the fixed rate at 4.688475% until March 1, 2039; the remaining $81 million is to refinance a part of the upcoming maturing debt series C100-2, which has a forward interest rate swap associated with it locking the fixed rate at 4.787% until November 1, 2038. An interest rate adjustment will be paid semi-annually on the difference between the swap contract floating rate (BAs + 0.100%) and the rate at which the refinancing occurred (BAs + 0.1721%). For example, this adjustment will revise the fixed rate on the C100-2 swap from 4.787% to 4.8591% (4.787% - 0.100% + 0.1721% = 4.8591%).

CIBC and BMO is the counterparty to the Province of Manitoba on the interest rate swap transactions. The credit rating for this institution at the trade date is as follows:

	CIBC	BMO
S&P	A+	A+
Moody's	Aa2	Aa1

TERM SHEET

Series FT
Advance from Province of Manitoba

Issue Date	May 17, 2011
Maturity Date	March 5, 2042
Term to Maturity	31 Years
Coupon Rate	4.40%
Yield Rate	4.458%
Interest Payable	September & March 5

	CAD Book Value
Principal	$ 400,000,000.00
Premium or (Discount)	(1,048,000.00)
Commissions and Fees	(2,800,000.00)
Proceeds	**$ 396,152,000.00**
Accrued Interest Received	-
Swap Premium or (Discount)	-
Net Proceeds	**$ 396,152,000.00**

AUTHORITY ABATED

Refunding Authority:

EM-1	$ 66,500,000.00
EM-3	50,000,000.00
EM-4	25,000,000.00
3T	16,677,247.80

Loan Act Authority:

Loan Act 2010	$ 237,974,752.20
Total Loan Authority	**$ 396,152,000.00**

NOTE: Debt series FT was issued at 4.4% coupon with an all-in rate of 4.458%. This debt was immediately swapped to a 30 year floating rate debt at 3 month BA + 37.6 bps.

Term Sheet

Series FT
Amended Advance from Province of Manitoba
Interest Rate Swaps

	Original Issue	FT Vanilla Swap	Forward Starting Swap
Par Value	CAD 400,000,000	CAD 400,000,000	CAD 400,000,000
Settlement Date	May 17, 2011	May 17, 2011	December 5, 2011
Maturity Date	March 5, 2042	March 5, 2042	March 5, 2042
Term to Maturity	31 Years	31 Years	31Years
Initial Interest Rate	4.40%	3 mth BA + 0.376%	4.492%
Interest Payable	September & March 5	September & March 5	September & March 5

MANITOBA HYDRO COUNTERPARTY

The Province of Manitoba is the counterparty to Manitoba Hydro for the debt series FT swap transactions. On May 17, 2011, the Province of Manitoba issued $400 million CAD debt at a fixed rate of 4.40% for 31 years. This fixed issue was immediately swapped to $400 million CAD floating rate debt at a rate of 3month BA + 0.376%. The Province of Manitoba also entered a forward starting interest rate swap which locked in a fixed rate of 4.492% for 30.5 years effective December 5, 2011.

RBC is the counterparty to the Province of Manitoba on the interest rate swap transactions. The credit rating for this institution at the trade date is as follows:

	RBC
S&P	AA-
Moody's	Aa1

TERM SHEET

Manitoba HydroBonds - Series 11

	5 Year Floating Rate	3 Year Fixed Rate	5 Year Fixed Rate	Total
Issue Date	June 15, 2011	June 15, 2011	June 15, 2011	
Maturity Date	June 15, 2016	June 15, 2014	June 15, 2016	
Term to Maturity	5 Years	3 Years	5 Years	
Price	100.00%	100.00%	100.00%	
Interest Rate	Initial 1.75%	2.30%	2.75%	
Interest Payable	Annual	Annual	Annual or Compound	
Special Features	Redeemable at the option of the holder annually			
Principal	$99,584,900.00	$8,636,100.00	$7,422,500.00	$115,643,500.00
Fees and Commisions	(602,210.64)	(74,700.62)	(79,048.21)	($755,959.48)
Net Proceeds	**$98,982,689.36**	**$8,561,399.38**	**$7,343,451.79**	**$114,887,540.52**

TERM SHEET

Series C125
Advance from Province of Manitoba

Issue Date	October 14, 2011
Maturity Date	February 1, 2013
Term to Maturity	3 Years
Coupon Rate	3 Month BAs + 0.01%
Yield Rate	3 Month BAs + 0.03%
Interest Payable	February 1, May 1, August 1 & November 1 commencing November 1, 2011

	CAD Book Value
Principal	$ 104,000,000.00
Premium or (Discount)	-
Commissions and Fees	(26,936.00)
Proceeds	**$ 103,973,064.00**
Accrued Interest Received	-
Swap Premium or (Discount)	-
Net Proceeds	**$ 103,973,064.00**

AUTHORITY ABATED

Refunding Authority:	C100 - $88,973,064.00
Loan Act Authority:	
Loan Act 2010 Schedule B	$ 15,000,000.00
Total Loan Authority	**$ 103,973,064.00**

NOTE: The debt series C125 floating rate note will accommodate the cash flow of forward interest rate swaps previously transacted on C100 to fix the interest rate for the new cash requirements.

TERM SHEET

Series C125
Amended Advance from Province of Manitoba
Interest Rate Swaps

	Original Issue
Par Value	CAD 104,000,000
Settlement Date	October 14, 2011
Maturity Date	February 1, 2013
Term to Maturity	1.3 Years
Initial Interest Rate	3 Month BAs + 0.01%
Interest Payable	February 1, May 1, August 1 & November 1

	C125-1 Swap	C125-2 Swap
Par Value	CAD 85,000,000	CAD 19,000,000
Settlement Date	November 1, 2011	November 1, 2011
Maturity Date	November 1, 2038	November 1, 2038
Term to Maturity	30 Years	30 Years
Initial Interest Rate	4.857%	4.787%
Interest Payable	May 1 & November 1	May 1 & November 1
Amended Interest Rate	**4.767%**	**4.697%**

MANITOBA HYDRO COUNTERPARTY

The Province of Manitoba is the counterparty to Manitoba Hydro for the debt series C125-1 and C125-2 swap transactions. Debt series C100-1 ($85 M), and C100-2 ($19 M) previously had forward interest rate swaps associated with them which locked the fixed rate at 4.857% and 4.787% respectively until November 1, 2038. Debt series C125-1 ($85 M) and C125-2 ($19 M) will accommodate the cash flow structures of the forward interest rate swaps from maturing debt series C100-1 and C100-2. An interest rate adjustment will be paid semi-annually on the differences between the swap contract floating rate (3 Month BAs + 0.1000%) and the rate at which the financing occurred (3 Month BAs + 0.01%). For example, this adjustment will revise the fixed rate on C125-1 from 4.857% to 4.767% (4.8570% - 0.1000% + 0.0100% = 4.7670%).

PROVINCE OF MANITOBA COUNTERPARTY

CIBC and BMO are the counterparties to the Province of Manitoba on the interest rate swap transactions. The credit ratings for these institutions at the trade date are as follows:

	CIBC	BMO
S&P	A+	A+
Moody's	Aa2	Aa1

TERM SHEET

Series FN-2 (Re-Opening)
Advance from Province of Manitoba

Issue Date	March 28, 2012
Maturity Date	March 5, 2050
Term to Maturity	38 Years
Coupon Rate	4.700%
Yield Rate	3.6285%
Interest Payable	March 5 & September 5

	CAD Book Value
Principal	$ 75,000,000.00
Premium or (Discount)	16,672,500.00
Commissions and Fees	(187,500.00)
Proceeds	**$ 91,485,000.00**
Accrued Interest Received	222,123.29
Swap Premium or (Discount)	-
Net Proceeds	**$ 91,707,123.29**

AUTHORITY ABATED

Refunding Authority:

HB9-Floating	$ 5,411,763.00
HB9-3 Year Fixed	11,413,700.17
3T	8,428,479.20
EL	45,068.00
C101	120,000.00
FD	1,345,750.00
C102	24,240.00
C100	26,936.00

Loan Act Authority:

Loan Act 2011 Schedule B	$ 64,669,063.63

Total Loan Authority	**$ 91,485,000.00**

Note: Reopening of 4.7% debentures series FN ($200M CAD) issued October 27, 2009, and due March 5, 2050.

PUB/MH I-67

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

f) Please provide a schedule detailing the maturities of MH's current long-term debt issues.

ANSWER:

Please see the debt maturity schedule as at June 30, 2012.

Note that the maturity dates listed in the schedule provide the most outward obligation dates on any debt series (the latter of physical debt or forward interest rate swap maturity dates). Therefore in cases where the maturity of a forward interest rate swap for a debt series is beyond the maturity date of the associated physical debt, a refinancing of the underlying physical debt will be required in advance of the maturity date listed in the schedule. Consequently, this schedule should not be utilized to determine the commitment dates for the refinancing of the existing physical debt.

Also, the interest rates shown in this schedule indicate the coupon rates on the debt and not the all-in yield cost to Manitoba Hydro.

MANITOBA HYDRO
LONG TERM DEBT MATURITY SCHEDULE
AT June 30, 2012
(IN MILLIONS $)

SERIES	CURRENCY	MATURITY	COUPON RATE	CAD $	US $	TOTAL CAD (US @ 1.0191)
C107	CAD	9/4/2012	3BA + 0.40%	100.0		100.0
ER2	CAD	12/3/2012	3BA + 0.192%	50.0		50.0
4I	CAD	2/11/2013	9.375%	10.0		10.0
5A	CAD	6/30/2013	5.750%	40.0		40.0
5B	CAD	6/30/2013	5.750%	1.3		1.3
DE	USD	7/22/2013	8.120%		188.4	192.0
C112-1	CAD	9/16/2013	5.485%	100.0		100.0
C112-2	CAD	9/16/2013	5.531%	100.0		100.0
EZ4	CAD	12/3/2013	3BA + 0.0925%	9.5		9.5
EZ3	CAD	12/3/2013	1.257%	208.3		208.3
4J	CAD	1/20/2014	8.000%	15.0		15.0
EZ-1	USD	1/21/2014	5.989%		50.0	51.0
EZ	USD	1/21/2014	5.929%		100.0	101.9
FS-1	USD	4/28/2014	3LIBOR + 0.0976%		100.0	101.9
HB11-5FL	CAD	6/15/2014	2.300%	38.7		38.7
FM-4	CAD	9/1/2014	3BA + 0.484%	100.0		100.0
C115	CAD	5/4/2015	3BA + 0.23%	50.0		50.0
4K	CAD	5/12/2015	9.125%	12.0		12.0
EY2	CAD	12/3/2015	3BA + 0.0455%	50.0		50.0
EY	CAD	12/3/2015	5.490%	200.0		200.0
C121-3	CAD	4/19/2016	3BA + 0.20%	100.0		100.0
HB11-5FX	CAD	6/15/2016	2.750%	7.4		7.4
HB11-3FX	CAD	6/15/2016	1.750%	8.6		8.6
AZ	CAD	7/17/2016	3BA + 1.08%	200.6		200.6
ER	CAD	9/3/2017	7.467%	200.0		200.0
C-011	CAD	9/22/2017	7.525%	55.5		55.5
4L	CAD	11/17/2017	6.250%	20.0		20.0
BM	CAD	1/15/2018	3BA + 3.29%	255.0		255.0
FC-3	CAD	6/2/2018	7.169%	200.0		200.0
FS-2A	CAD	6/2/2018	7.295%	100.0		100.0
FS-2B	CAD	6/2/2018	7.405%	100.0		100.0
EE	USD	9/15/2018	9.500%		200.0	203.8
BU	USD	12/1/2018	9.625%		200.0	203.8
3V	CAD	12/30/2018	10.000%	3.5		3.5
3W	CAD	12/30/2018	10.000%	2.0		2.0
3X	CAD	12/30/2018	10.000%	5.0		5.0
3Y	CAD	12/30/2018	10.000%	2.0		2.0
CO77-3	CAD	2/11/2020	3BA - 0.175%	50.0		50.0
CO77-2	CAD	2/11/2020	4.455%	100.0		100.0
FO-1	USD	3/15/2020	5.897%		150.0	152.9
FP-2	CAD	6/3/2020	4.150%	125.0		125.0
FP-3	CAD	6/3/2020	4.150%	250.0		250.0
FO-2	USD	10/2/2020	6.955%		203.1	206.9
FO-3	USD	10/2/2020	6.955%		47.0	47.8
CO	USD	9/15/2021	8.875%		300.0	305.7
4A	CAD	12/31/2021	9.100%	3.5		3.5
FH-1	USD	2/1/2022	6.405%		250.0	254.8
FH-2	USD	2/1/2022	6.406%		100.0	101.9
FH-3	USD	9/16/2022	6LIBOR + 0.1295%		150.0	152.9

SERIES	CURRENCY	MATURITY	COUPON RATE	CAD $	US $	TOTAL CAD (US @ 1.0191)
C119-2	CAD	9/5/2025	3BA + 0.425%	150.0		150.0
DT	CAD	12/22/2025	7.750%	170.0		170.0
DT-2	CAD	12/22/2025	7.750%	130.0		130.0
4N	CAD	2/2/2029	5.900%	30.0		30.0
4M	CAD	2/2/2029	5.900%	30.0		30.0
FM-3	CAD	9/1/2029	6.689%	50.0		50.0
FM-2	CAD	9/1/2029	6.734%	75.0		75.0
FM-1	CAD	9/1/2029	6.634%	25.0		25.0
C119-1	CAD	9/1/2029	6.575%	100.0		100.0
CL	CAD	3/5/2031	10.500%	300.0		300.0
CLW	CAD	3/5/2031	10.500%	299.9		299.9
C116	CAD	3/5/2031	6.300%	100.0		100.0
4B	CAD	4/1/2031	5.840%	3.7		3.7
4C	CAD	4/1/2031	5.840%	1.4		1.4
4Y	CAD	5/1/2031	5.650%	4.4		4.4
CO52	CAD	10/29/2032	6.300%	30.0		30.0
FP-1	CAD	4/12/2035	5.754%	175.0		175.0
EZ5	CAD	12/3/2035	4.774%	46.0		46.0
EZ2	CAD	12/3/2035	4.774%	54.0		54.0
FA	CAD	3/5/2037	4.687%	150.0		150.0
FA-4	CAD	3/5/2037	4.505%	50.0		50.0
FJ	CAD	9/12/2037	5.104%	250.0		250.0
PB-2	CAD	3/5/2038	4.600%	300.0		300.0
FS-2D	CAD	11/1/2038	4.909%	81.0		81.0
C125-1	CAD	11/1/2038	4.767%	85.0		85.0
C125-2	CAD	11/1/2038	4.697%	19.0		19.0
C119-3C	CAD	12/1/2038	5.245%	15.0		15.0
C119-3A	CAD	12/1/2038	5.245%	50.0		50.0
C119-3B	CAD	12/1/2038	5.232%	50.0		50.0
FS-2C	CAD	3/1/2039	4.761%	100.0		100.0
FK-2	CAD	3/5/2040	4.650%	300.0		300.0
FR-2	CAD	3/5/2041	4.100%	250.0		250.0
CO40	CAD	3/5/2042	3BA + 0.179%	50.0		50.0
FT	CAD	3/5/2042	4.492%	400.0		400.0
GA	CAD	3/5/2043	3.350%	300.0		300.0
CO68	CAD	3/5/2044	4.565%	50.0		50.0
FN	CAD	3/5/2050	4.700%	200.0		200.0
FN-2	CAD	3/5/2050	4.700%	75.0		75.0
4Z	CAD	6/9/2057	7.100%	7.0		7.0
C110	CAD	3/5/2060	5.200%	125.0		125.0
C109	CAD	3/5/2063	4.625%	50.0		50.0
Total LTD				**7,604.3**	**2,038.4**	**9,681.6**

PUB/MH I-67 (Revised)

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

g) For each of the years 2004 through 2015, assuming the refinancing plan in the application, please provide weighted average term of outstanding debt, the principal amount and proportion of debt maturing within:

- **i. 10 years;**
- **ii. Twenty years; and**
- **iii. Greater than twenty years**

ANSWER:

Please see the schedule below.

The refinancing plan in the Application is based on IFF11-2 which had actual debt issuances up to September 30, 2011. The schedule was prepared using the most outward obligation dates on any debt series (the latter of physical debt or forward interest rate swap maturity dates).

MANITOBA HYDRO
PUB 1-67 (g) Revised
Actuals As At Sepember 30, 2011

Fiscal Year Ended	Debt Maturing Within 10 Years CAD$Millions	Debt Maturing Within 10 Years % of Total	Debt Maturing 10 years to 20 Years CAD$Millions	Debt Maturing 10 years to 20 Years % of Total	Debt Maturing Greater than 20 Years CAD$Millions	Debt Maturing Greater than 20 Years % of Total	Total Long Term Debt CAD$Millions	Weighted Average Term To Maturity In Years
March 31, 2004	2,586	35.1%	3,521	47.7%	1,268	17.2%	7,375	13.8
March 31, 2005	2,377	33.1%	3,346	46.5%	1,468	20.4%	7,191	13.8
March 31, 2006	2,397	33.5%	3,317	46.3%	1,443	20.2%	7,158	13.7
March 31, 2007	2,623	36.3%	3,094	42.9%	1,501	20.8%	7,218	12.9
March 31, 2008	2,996	39.5%	2,513	33.1%	2,081	27.4%	7,590	13.5
March 31, 2009	3,763	45.8%	2,026	24.7%	2,421	29.5%	8,209	13.6
March 31, 2010	3,963	46.0%	1,805	21.0%	2,846	33.0%	8,614	14.8
March 31, 2011	3,967	45.6%	2,241	25.7%	2,496	28.7%	8,704	15.3
March 31, 2012	4,841	50.7%	1,819	19.1%	2,887	30.2%	9,547	14.8
March 31, 2013	4,731	46.0%	2,699	26.2%	2,857	27.8%	10,287	14.7
March 31, 2014	3,922	35.4%	4,299	38.8%	2,857	25.8%	11,078	15.6
March 31, 2015	3,780	30.6%	5,714	46.3%	2,857	23.1%	12,352	15.4

PUB/MH I-68

Reference: MH11-2, MH09, Financing Activities, Tab 5 Schedule 5.6

Please provide a comparison of the financing activities in MH11-2 with MH09-1 and explain what factors have led MH to increase borrowings in 2012, 2013 and 2014 from that forecast in MH09-1.

ANSWER:

Please see the table below with the comparison of financing activities in MH11-2 with MH09-1.

MANITOBA HYDRO
PROJECTED CASH FLOW STATEMENT
(In $Millions Canadian Dollars)

MH11-2 vs. MH09-1 for 2011/12, 2012/13, 2013/14

	MH11-2	MH09-1	*a-b*	MH11-2	MH09-1	*a-b*	MH11-2	MH09-1	*a-b*
For the year ended March 31		**2012**			**2013**			**2014**	
OPERATING ACTIVITIES									
Cash Receipts from Customers	1,556	1,808	*(252)*	1,693	1,895	*(202)*	1,778	1,987	*(209)*
Cash Paid to Suppliers and Employees	(742)	(827)	*85*	(816)	(845)	*29*	(886)	(872)	*(14)*
Interest Paid	(406)	(479)	*73*	(466)	(541)	*75*	(475)	(550)	*75*
Interest Received	26	14	*12*	28	16	*12*	27	14	*13*
	434	516	*(82)*	439	524	*(85)*	444	579	*(135)*
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	811	600	*211*	900	540	*360*	1,630	1,600	*30*
Sinking Fund Withdrawals	23	27	*(4)*	129	103	*26*	395	483	*(88)*
Retirement of Long-Term Debt	(25)	(27)	*2*	(119)	(121)	*2*	(808)	(849)	*41*
Other	(81)	19	*(100)*	(21)	(10)	*(11)*	(14)	(14)	*0*
	729	619	*110*	889	512	*377*	1,203	1,220	*(17)*
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(1,163)	(1,004)	*(159)*	(1,226)	(989)	*(237)*	(1,481)	(1,457)	*(24)*
Sinking Fund Payment	(98)	(98)	*0*	(117)	(116)	*(1)*	(208)	(176)	*(32)*
Other	(19)	(16)	*(3)*	(20)	(17)	*(3)*	(20)	(15)	*(5)*
	(1,280)	(1,118)	*(162)*	(1,363)	(1,123)	*(240)*	(1,709)	(1,648)	*(61)*
Net Increase (Decrease) in Cash	(116)	17	*(133)*	(36)	(86)	*50*	(62)	151	*(213)*
Cash at Beginning of Year	66	(40)	*106*	(50)	(23)	*(27)*	(86)	(109)	*23*
Cash at End of Year	(50)	(23)	*(27)*	(86)	(109)	*23*	(148)	41	*(189)*

In IFF11-2, cash receipts from customers are forecast to decrease in each of the three years as compared to IFF09-1. The decrease in cash flow from operations, combined with an increase forecasted in property, plant and equipment expenditures, has led Manitoba Hydro to forecast an increase in borrowings in IFF11-2 versus that forecast in IFF09-1.

PUB/MH I-69

Reference: Tab 5 Fuel & Purchase Power - St. Joseph Wind Farm Development

a) Please file an updated of the response to PUB/MH II-8 last GRA with a summary of the final financial terms of the agreement reached with Pattern Energy.

ANSWER:

Manitoba Hydro provided $250 million of debt financing towards the total capital cost of the project. The loan is being repaid mortgage-style through blended interest and principal payments over 20 years. The principal repayments are accelerated by removing $2 million of principal from each of the last six years and spreading this $12 million equally over the first 14 years. A $10 million revolving reserve loan facility is also available to cover cash flow shortfalls. Principal and interest payments due to Manitoba Hydro will be deducted from amounts owed by Manitoba Hydro to the wind farm for the purchase of energy. Full security provisions applicable to a senior lender do apply.

PUB/MH I-69

Reference: Tab 5 Fuel & Purchase Power - St. Joseph Wind Farm Development

b) Please summarize of the terms related to any funds to be lent to Pattern Energy, including funds disbursement and use, interest rate, repayment terms, debt covenants and security.

ANSWER:

The principal terms are provided in the response to PUB/MH I-69 (a). No Obligations shall be outstanding under the Reserve Loan at the proposed time of Distribution. No dividends can be paid out unless the debt service coverage ratio in the immediately preceding 12 month period is equal to or greater than 1.20. Manitoba Hydro has a first charge on both the assets and the shares of St. Joseph Windfarm Inc. Any additional third party debt must be approved by Manitoba Hydro and must not result in the debt ratio exceeding 75% or the projected debt service coverage ratio to fall below 1.20. The interest rates are considered to be commercially sensitive information.

PUB/MH I-69

Reference: Tab 5 Fuel & Purchase Power - St. Joseph Wind Farm Development

c) Please confirm that the output from the St. Joseph wind farm at 138 MW capacity is expected to be 400 to 500 GWh. Please indicate whether there are any plans to expand the production from the facility

ANSWER:

Confirmed. Manitoba Hydro is unaware of any plans to expand the facility at this time.

PUB/MH I-69

Reference: Tab 5 Fuel & Purchase Power - St. Joseph Wind Farm Development

d) Please provide a table that details the repayment of amounts actual and forecast of the loan to Pattern over the life of the power purchase agreement.

ANSWER:

Information with respect to the repayment amounts of the loan to Pattern energy is considered to be commercially sensitive, and as such Manitoba Hydro respectfully declines to respond to this question. However, Manitoba Hydro can inform the PUB that the loan is structured such that the principal and interest is fully recovered over the term with essentially no risk to electricity ratepayers.

PUB/MH I-70

Reference: Tab 5 Appendix 5.6 Page 7 of 13 Wuskwatim Costs, Submission for interim rates page 11

a) Please provide the supporting calculations for each of the revenue requirement amounts for 2012/13 and 2013/14.

ANSWER:

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

PUB/MH I-70

Reference: Tab 5 Appendix 5.6 Page 7 of 13 Wuskwatim Costs, Submission for interim rates page 11

b) Please provide a comparison between WPLP (IFF09) versus WPLP IFF11-2 for the years 2012, 2013 and 2014.

ANSWER:

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

PUB/MH I-71

Reference: Tab 5 Section 5.1o Page 31 of 36Capital Taxes

Please provide the details of the taxable paid up capital balance for Manitoba capital tax purposes for the fiscal years 2011, and 2012 and the projected taxable capital for the fiscal years 2013 through 2014.

ANSWER:
Please see the following table for capital tax information for the years 2011 through 2014.

Taxable Paid Up Capital Calculation:
($ Billions)

	Actual 2011	**Actual 2012**	**Forecast 2013**	**Forecast 2014**
Total Debt	8.9	9.6	10.6	11.4
Retained Earnings	2.4	2.5	2.4	2.2
AOCI	0.4	0.3	0.3	0.1
Total Paid Up Capital (A)	11.6	12.4	13.3	13.7
Temporary Investments	0.1	0.0	0.0	0.0
Sinking Fund Assets	0.3	0.3	0.3	0.1
Pension Investments	0.8	0.8	0.8	0.5
Investment in Subsidiaries	0.3	0.3	0.2	0.2
Loans to Subsidiaries	0.9	1.0	1.3	1.3
Total Eligible Assets (B)	2.3	2.5	2.7	2.2
Total Assets (C)	14.0	15.0	14.4	14.4
Total Paid Up Capital	11.6	12.4	13.3	13.7
Less Investment Allowance (B/C X A)	1.9	2.0	2.5	2.1
Taxable Paid Up Capital	9.7	10.4	10.9	11.6

Capital Tax Calculation
($ millions)

Capital Tax at 0.5% X D	48	52	54	58

PUB/MH I-72

Reference: Exhibit # MH-115 2011 & 29012 GRA

a) Please provide an update to Exhibit #MH-115 from the last GRA in support of the estimated revenue requirement impact for Wuskwatim on 2012/13 and 2013/14.

ANSWER:

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

PUB/MH I-72

Reference: Exhibit # MH-115 2011 & 29012 GRA

b) Please provide detailed calculations of how the assumed revenue per KwH used for the determination of revenue attributed to WPLP and reconcile with the revenue reflected in WPLP's IFF11-2 forecast.

ANSWER:

The assumed revenue per kWh used in Exhibit #MH-115 was an approximate value for the average export sales price for 2012/13 in IFF10 and was presented for illustrative purposes only. Please see the response to PUB/MH I-134 for information related to Wuskwatim revenues.

PUB/MH I-73

Reference: Tab 5 Page36 of 36 Appendix 5.1: 2010 Annual Report Page 21,61,96, Wuskwatim Power Limited Partnership

a) Please provide the 2011/12 financial statements related to the WPLP

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-4(c).

PUB/MH I-73

Reference: Tab 5 Page36 of 36 Appendix 5.1: 2010 Annual Report Page 21,61,96, Wuskwatim Power Limited Partnership

b) Please provide the most recent financial projections for the WPLP consistent with IFF11-2.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-134.

PUB/MH I-73

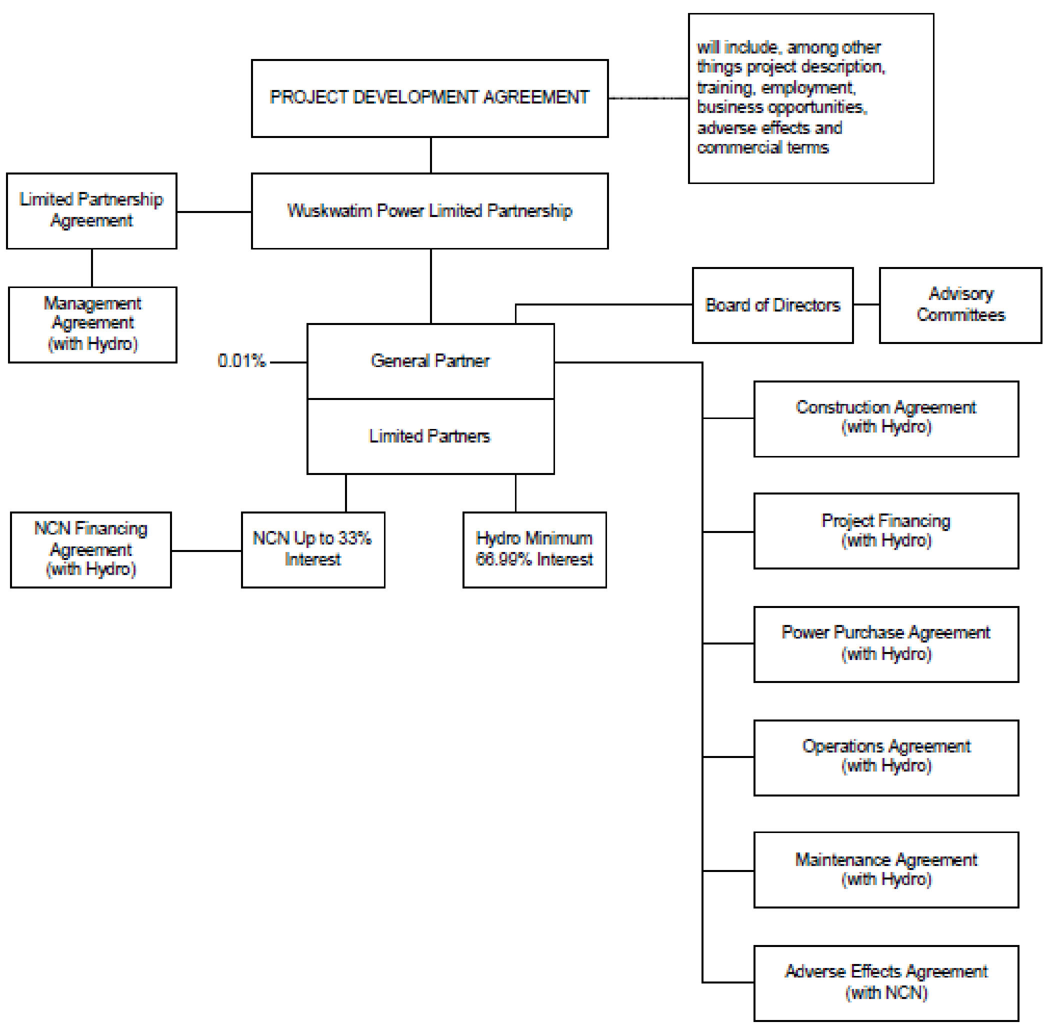
Reference: Tab 5 Page36 of 36 Appendix 5.1: 2010 Annual Report Page 21,61,96, Wuskwatim Power Limited Partnership

c) Please provide a schematic of the ownership structure for the WPLP including an indication of the current status of ownership interest.

ANSWER:

Figure 2.4 below was included in the Needs For and Alternatives to the Wuskwatim Project (NFAAT) submission to the Manitoba Clean Environment Commission in 2003 and is representative of the current ownership structure of the partnership.

FIGURE 2.4 AGREEMENT FRAMEWORK AND EQUITY OWNERSHIP FOR THE PROJECT



PUB/MH I-73

Reference: Tab 5 Page36 of 36 Appendix 5.1: 2010 Annual Report Page 21,61,96, Wuskwatim Power Limited Partnership

d) Please file a summary of the terms of the agreement MH has with TPC & NCN and indicate if there has been any changes to the agreements since negotiated.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-40(b).

PUB/MH I-73

Reference: Tab 5 Page36 of 36 Appendix 5.1: 2010 Annual Report Page 21,61,96, Wuskwatim Power Limited Partnership

e) Provide a comparison of the detailed construction cost estimate for the facility presented at the last GRA with actual/forecast cost to complete and explain any differences.

ANSWER:

An examination of the materials filed in the 2010/11 & 2011/12 General Rate Application has failed to locate the above referenced document.

PUB/MH I-73

Reference: Tab 5 Page 36 of 36 Appendix 5.1: 2010 Annual Report Page 21, 61, 96, Wuskwatim Power Limited Partnership

f) Please provide a schedule detailing all monies advanced under the WPLP agreement describing the purposes for the advances.

ANSWER:

WPLP Advances
Balances as at March 31
($ millions)

	2008	**2009**	**2010**	**2011**	**2012**
Advances for Generation Capital Costs:					
Non-Revolving Credit Facility	217	351	560	782	897
Revolving Credit Facility	5	7	8	10	12
Advances for Transmission Capital Costs:					
Interconnection Credit Facility	98	185	236	266	292
	320	543	804	1 058	1 201

PUB/MH I-73

Reference: Tab 5 Page36 of 36 Appendix 5.1: 2010 Annual Report Page 21,61,96, Wuskwatim Power Limited Partnership

g) Please explain any cost sharing arrangements the Corporation may have with the Federal Government related to any aspect of the Wuskwatim development.

ANSWER:

Manitoba Hydro, Manitoba and the Federal Government provided funding to the Hydro Northern Training and Employment Initiative (HNTEI), which ended March 31, 2010. Each funder had its own bi-lateral contribution agreement with the Wuskwatim Keeyask Training Consortium Inc. (WKTC), the legal entity established to administer the funds. Please see Manitoba Hydro's response to PUB/MH I-7(c).

PUB/MH I-74

Reference: Interim Rates & Request for Additional Information Page 7 Use of Internally Generate Funds

a) Please provide detailed calculations of the amount of internally generated fund generated and available to allocate to Major G&T projects since 2003/04 and that forecast through 2032.

ANSWER:

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

PUB/MH I-74

Reference: Interim Rates & Request for Additional Information Page 7 Use of Internally Generate Funds

b) In light of the analysis prepared for Wuskwatim and the identification of the use of internally generated funds to fund the project, please provide calculations supporting the amount of internally generated funds allocated and forecast to be allocated by major G&T project since 2003/04 through 2032 by major project and in particular, Wuskwatim, Keeyask, Bipole III and Conawapa.

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH I-22(c) and CAC/MH I-15(a).

PUB/MH I-74

Reference: Interim Rates & Request for Additional Information Page 7 Use of Internally Generate Funds

c) Please provide the revenue requirement impacts analysis for Keeyask, Conawapa and Bipole III on a similar basis as that provided for Wuskwatim.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-25(c).

PUB/MH I-74

Reference: Interim Rates & Request for Additional Information Page 7 Use of Internally Generate Funds

d) Confirm that all borrowing costs related to Major G&T projects are capitalized until the projects are placed into service in accordance with accounting standards.

ANSWER:

Confirmed.

PUB/MH I-74

Reference: Interim Rates & Request for Additional Information Page 7 Use of Internally Generate Funds

e) Please demonstrate the interest credit that has been credited back to current ratepayers in each of the years 2003/04 through 2014/15.

ANSWER:

Schedule 5.6.0 in Tab 5 (page 18) of the Application provides a breakdown of finance expense for the period 2009/10 to 2013/14 which shows the total interest on short and long-term debt being reduced by interest allocated to construction (i.e., the interest credit that has been credited back to current ratepayers).

PUB/MH I-75

Reference: Tab 5 Appendix 5.6, OM&A Comparisons

Please provide a graph with the corresponding data table of the OM&A cost per customer for Hydro Quebec, Sask Power, BC Hydro & BC Transmission Corporation.

ANSWER:

BC Hydro's OM&A is no longer directly comparable due to a significant accounting change that resulted in its OM&A expense starting in fiscal 2011, being retroactively applied back to fiscal 2010. As stated in BC Hydro's 2011 Annual report, on page 32, "Commencing in fiscal 2011, BC Hydro changed its reporting of regulatory account transfers on the statement of operations to report individual line items net of transfers to regulatory accounts, as compared to prior years in which aggregate net transfers to regulatory accounts were reported as a single separate line item and income was reported both before and after regulatory account transfers." BCTC was integrated with BC Hydro during fiscal 2011, resulting in comparability issues for fiscal 2011 and fiscal 2012.

Saskpower's OM&A is no longer directly comparable due to the conversion to IFRS starting in fiscal 2011 with the restatement of fiscal 2010 results.

As a result of these various changes, it is no longer possible to provide a meaningful and comparable OM&A cost per customer comparison based on reported financial results.

PUB/MH I-76

Reference: Tab 5 Appendix 5.6, OM&A Cost Per Customer

a) Please file a schedule in a similar format to PUB/MH Pre-Ask -14 providing a comparison of the OM&A cost per customer for the years 2012 through 2029 [IFF 11–2 to IFF 09]. In the 2nd table please separately disclosed the impact of accounting changes.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-9(e).

PUB/MH I-76

Reference: Tab 5 Appendix 5.6, OM&A Cost Per Customer

b) Please provide a similar analysis as in (a) comparing IFF 11–2 with IFF 10 for comparative years.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-9(e).

PUB/MH I-77 (Revised)

Reference: Tab 5 Appendix 5.6 Page 10 & 11 Staff Attrition

a) From 2005 through 2013 please indicate the number of staff by year by termination code.

ANSWER:

Every termination is classified into one of 14 termination codes. The termination codes are grouped into five broad termination types: retirement, resignation, health-related, involuntary termination, and job completion. For the years 2005 through 2011, resignation terminations are as follows (all numbers reported in this section exclude students and term employees):

Termination code	2005	2006	2007	2008	2009	2010	2011	Total
Resignation codes								
Another job	17	18	31	30	9	20	31	156
Leaving province/Work locale	14	12	17	11	5	9	9	77
Leaving work force	0	2	2	3	8	6	1	22
Personal/No reason given	11	15	15	18	19	19	14	111
Returning to school	2	0	1	1	5	3	8	20
Resignation sub-total	44	47	66	63	46	57	63	386
Retirement	118	127	168	138	141	146	182	1020
Health-related	12	13	17	16	17	21	10	106
Involuntary termination	8	8	14	7	7	8	7	59
Job completed	2	0	0	0	0	1	0	3
Total	184	195	265	224	211	233	262	1574

PUB/MH I-77

Reference: Tab 5 Appendix 5.6 Page 10 & 11 Staff Attrition

b) Please provide an update to the table provided in response to PUB/MH I-44 (b) indicating the total staffing level, the retirement attrition percentage by business unit and staffing levels for each year through 2024.

ANSWER:

Calendar year	Permanent active workforce at start of year	Actual retirements	Retirement rate	Number eligible in current year	Number becoming eligible in forecast year	Predicted number of retirements
2010	5783	146	2.52%			
2011	5909	182	3.08%			
2012	5891			826		165
2013					180	168
2014					195	174
2015					188	176
2016					221	185
2017					229	194
2018					216	198
2019					264	212
2020					228	215
2021					219	216
2022					198	212
2023					158	201
2024					149	190

Definitions

Permanent active workforce -- the count of all non-terminated employees whose employment type is not “Term” or “Student”. Include individuals on leaves of absence. Forecasts for the future size of this workforce are not available.

Actual retirements -- does not include disability retirements.

Retirement rate -- Actual retirements divided by the permanent active workforce.

Number eligible in current year -- those becoming eligible for a full, undiscounted pension in 2012 (based on age and years of service.) Includes individuals who were eligible in previous years but who have not taken up the retirement opportunity.

Number becoming eligible in forecast year -- those becoming eligible in each of the years in the forecast window.

Predicted number of retirements -- Based on a historical retirement take-up rate of 20%. That rate is applied to the number eligible in the current year to arrive at the retirement prediction for the current year. The remainder is carried forward to the next year and is added to the number becoming eligible in that forecast year. The take-up rate is applied to that sum to arrive at the forecast prediction for that year. The process carries forward to the end of the forecast window.

PUB/MH I-77

Reference: Tab 5 Appendix 5.6 Page 10 & 11 Staff Attrition

c) Please provide an analysis that supports the pension take up rate.

ANSWER:

The retirement take-up rate is based on historical observation. At the beginning of the calendar year, Manitoba Hydro determines the number of people eligible for a full, undiscounted pension based on age and years of service. The retirement take-up rate for a year is the portion of the fully-eligible population which actually "takes up" the retirement opportunity.

PUB/MH I-77

Reference: Tab 5 Appendix 5.6 Page 10 & 11 Staff Attrition

d) Please indicate whether there have been any changes to the retirement policies of MH including retirement eligibility.

ANSWER:

Retirement eligibility requirements for the Civil Service Superannuation Plan (CSSP) have not changed. The following discusses changes in pension contributions and eligibility.

In January 2012, Manitoba Hydro implemented a new component to the retirement benefit called the Enhanced Hydro Benefit Plan. Legislative language was finalized in 2011 and a Regulation was passed by Order of Council in August 2011. The enhancement provides small improvements to the defined benefit formula for all eligible employees participating in the CSSP.

The CSSP recently increased contribution levels. Contributions for both Manitoba Hydro and its employees were increased by 0.5% in July 2012 and will see further contribution increases as follows:

- 0.5% increase effective Jan. 1, 2013
- 0.5% increase effective Jan. 1, 2014
- 0.5% increase effective Jan. 1, 2015

Manitoba Hydro has approximately 500 employees that participate in the Winnipeg Civic Employees Benefits Program (WCEBP) which did experience significant plan changes, including retirement eligibility. These changes include:

- Four contribution rate increases of 0.5% each over 40 months
- Reduction to future cost-of-living adjustments
- Changes to early retirement provisions
- Changes to reduction for post-retirement survivor benefits

PUB/MH I-78

Reference: Appendix 5.5, Tab 5 Page 4 of 9

a) Please provide a schedule which details and supports the net adjustments to IFF11-2 by specific IFRS accounting impacts, similar to that provided in response to PUB/MH I-16 (b) for Electric operations> Please include the debt to equity, capital coverage and interest coverage ratios.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-42, Schedules C and D.

For the debt to equity, capital coverage and interest coverage ratios, please see Manitoba Hydro's response to PUB/MH I-22(a).

PUB/MH I-78

Reference: Appendix 5.5, Tab 5 Page 4 of 9

b) Please re-file a revised IFF11-2 for electric operations reflecting that rate regulated accounting would be allowed under GAAP. Please include the debt to equity, capital coverage and interest coverage ratios.

ANSWER:

Please see the following scenario for electric operations only, which assumes that rate – regulated accounting would continue to be allowed under IFRS commencing in 2013/14 until the end of the forecast period.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
PUB-MH I-78(b) - MH11-2 with Rate Regulated Accounting Allowed
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 186	1 290	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	45	106	156	208	265	325	387	455	527	603
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 693	1 778	1 873	2 007	2 114	2 224	2 320	2 466	2 769	2 957
EXPENSES											
Operating and Administrative	398	447	494	507	513	522	543	552	570	586	596
Finance Expense	385	440	450	502	535	568	637	760	800	1 143	1 105
Depreciation and Amortization	353	401	391	397	415	427	461	504	518	583	607
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	93	100	108	117	127	133	140	129	135
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 672	1 707	1 814	1 885	1 959	2 109	2 306	2 399	2 828	2 836
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	70	58	120	153	112	11	64	(62)	111
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase	0.00%	4.50%	8.16%	11.94%	15.86%	19.92%	24.11%	28.46%	32.95%	37.61%	42.42%
Financial Ratios											
Equity	26%	24%	20%	18%	17%	16%	15%	14%	14%	13%	12%
Interest Coverage	1.12	1.03	1.11	1.08	1.15	1.16	1.11	1.01	1.05	0.96	1.08
Capital Coverage	1.04	1.07	1.22	1.25	1.53	1.63	1.56	1.37	1.53	1.51	1.93

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
PUB-MH I-78(b) - MH11-2 with Rate Regulated Accounting Allowed
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
REVENUES										
General Consumers										
at approved rates	1 441	1 460	1 479	1 498	1 521	1 541	1 562	1 582	1 602	1 622
additional*	683	767	822	880	941	1 004	1 069	1 136	1 205	1 277
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
Other	19	20	20	20	21	21	22	22	23	23
	3 074	3 193	3 445	3 806	4 008	4 110	4 191	4 284	4 394	4 497
EXPENSES										
Operating and Administrative	608	620	642	654	666	678	691	704	717	730
Finance Expense	1 086	1 075	1 167	1 389	1 538	1 506	1 467	1 416	1 430	1 330
Depreciation and Amortization	609	611	642	708	757	764	775	782	815	834
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	141	146	152	154	155	156	159	160	162	163
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2 850	2 889	3 027	3 340	3 578	3 586	3 584	3 571	3 645	3 592
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	213	292	407	455	419	512	595	700	736	890
* Additional General Consumers Revenue										
Percent Increase	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.41%	52.57%	55.62%	58.73%	61.91%	65.14%	68.45%	71.82%	75.25%	78.76%
Financial Ratios										
Equity	13%	14%	15%	16%	18%	20%	22%	24%	27%	30%
Interest Coverage	1.15	1.19	1.26	1.29	1.27	1.33	1.39	1.46	1.50	1.65
Capital Coverage	1.99	2.06	2.11	2.42	2.38	2.63	2.64	2.70	3.40	3.05

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
PUB-MH I-78(b) - MH11-2 with Rate Regulated Accounting Allowed
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS											
Plant in Service	13 795	15 212	15 723	16 485	17 410	17 993	21 415	21 904	25 521	28 275	28 636
Accumulated Depreciation	(4 917)	(5 266)	(5 581)	(5 911)	(6 272)	(6 638)	(7 065)	(7 539)	(8 028)	(8 583)	(9 165)
Net Plant in Service	8 878	9 947	10 142	10 574	11 138	11 355	14 351	14 365	17 492	19 692	19 472
Construction in Progress	2 443	2 196	3 149	3 997	5 014	6 410	5 346	6 447	4 558	3 595	4 964
Current and Other Assets	1 906	1 864	1 327	1 372	1 559	1 740	1 987	1 788	1 951	2 206	2 090
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	241	241	233	225	214	200	188	175	163	154
	13 648	14 426	15 022	16 326	18 072	19 845	22 000	22 898	24 280	25 754	26 773
LIABILITIES AND EQUITY											
Long-Term Debt	9 253	9 469	10 909	12 169	13 789	15 260	17 025	18 518	19 479	20 990	22 434
Current and Other Liabilities	1 351	1 917	1 406	1 514	1 565	1 722	2 016	1 416	1 778	1 811	1 286
Contributions in Aid of Construction	317	328	341	348	355	365	376	385	396	407	418
Retained Earnings	2 391	2 411	2 445	2 503	2 624	2 776	2 889	2 900	2 964	2 903	3 013
Accumulated Other Comprehensive Income	335	302	(79)	(209)	(260)	(279)	(306)	(321)	(338)	(356)	(378)
	13 648	14 426	15 022	16 326	18 072	19 845	22 000	22 898	24 280	25 754	26 773

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
PUB-MH I-78(b) - MH11-2 with Rate Regulated Accounting Allowed
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
ASSETS										
Plant in Service	29 045	29 610	34 023	38 098	39 357	39 988	40 557	41 087	43 107	43 823
Accumulated Depreciation	(9 752)	(10 344)	(10 970)	(11 663)	(12 407)	(13 160)	(13 926)	(14 701)	(15 509)	(16 338)
Net Plant in Service	19 293	19 267	23 053	26 435	26 951	26 828	26 631	26 386	27 599	27 485
Construction in Progress	6 099	6 969	4 170	1 022	545	786	1 259	1 722	618	758
Current and Other Assets	2 205	2 281	2 528	2 520	3 127	3 538	3 813	4 059	4 628	5 298
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	145	138	133	126	118	113	109	106	103	103
	27 832	28 744	29 973	30 190	30 825	31 349	31 894	32 354	33 029	33 724
LIABILITIES AND EQUITY										
Long-Term Debt	23 437	24 039	24 392	24 595	24 796	24 738	24 489	24 391	24 179	23 152
Current and Other Liabilities	1 132	1 138	1 594	1 141	1 145	1 203	1 390	1 236	1 374	2 193
Contributions in Aid of Construction	429	440	451	462	474	486	499	511	524	538
Retained Earnings	3 226	3 519	3 926	4 381	4 800	5 312	5 907	6 607	7 342	8 233
Accumulated Other Comprehensive Income	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)	(391)
	27 832	28 744	29 973	30 190	30 825	31 349	31 894	32 354	33 029	33 724

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
PUB-MH I-78(b) - MH11-2 with Rate Regulated Accounting Allowed
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 556	1 693	1 778	1 873	2 007	2 114	2 224	2 320	2 466	2 769	2 957
Cash Paid to Suppliers and Employees	(742)	(816)	(849)	(897)	(917)	(945)	(991)	(1 021)	(1 060)	(1 078)	(1 100)
Interest Paid	(406)	(466)	(473)	(513)	(561)	(595)	(681)	(813)	(838)	(1 185)	(1 147)
Interest Received	26	28	27	20	27	34	41	43	39	36	35
	434	439	483	483	556	608	593	529	608	542	746
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	900	1 630	1 405	1 990	2 000	2 590	1 800	1 590	2 190	1 590
Sinking Fund Withdrawals	23	129	395	105	24	-	4	424	176	265	689
Retirement of Long-Term Debt	(25)	(119)	(808)	(179)	(312)	(408)	(530)	(837)	(309)	(640)	(692)
Other	(81)	(21)	(14)	(5)	(7)	(7)	(7)	(16)	(5)	26	(6)
	729	889	1 203	1 326	1 695	1 585	2 057	1 371	1 452	1 841	1 581
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1 163)	(1 226)	(1 519)	(1 647)	(1 967)	(2 015)	(2 361)	(1 592)	(1 843)	(1 878)	(1 720)
Sinking Fund Payment	(98)	(117)	(208)	(124)	(192)	(157)	(231)	(209)	(219)	(288)	(346)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1 280)	(1 363)	(1 747)	(1 792)	(2 178)	(2 218)	(2 628)	(1 830)	(2 091)	(2 201)	(2 105)
Net Increase (Decrease) in Cash	(116)	(36)	(61)	17	72	(25)	22	70	(31)	183	221
Cash at Beginning of Year	66	(50)	(86)	(147)	(130)	(58)	(82)	(61)	10	(21)	161
Cash at End of Year	(50)	(86)	(147)	(130)	(58)	(82)	(61)	10	(21)	161	383

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
PUB-MH I-78(b) - MH11-2 with Rate Regulated Accounting Allowed
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 074	3 193	3 445	3 806	4 008	4 110	4 191	4 284	4 394	4 497
Cash Paid to Suppliers and Employees	(1 129)	(1 176)	(1 189)	(1 213)	(1 251)	(1 282)	(1 307)	(1 335)	(1 360)	(1 386)
Interest Paid	(1 107)	(1 087)	(1 186)	(1 423)	(1 569)	(1 554)	(1 527)	(1 482)	(1 476)	(1 414)
Interest Received	20	21	31	36	37	49	60	64	71	84
	858	951	1 101	1 207	1 226	1 323	1 417	1 531	1 629	1 780
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	980	590	790	190	190	-	(10)	(10)	(30)	(10)
Sinking Fund Withdrawals	159	-	-	400	-	-	60	250	-	13
Retirement of Long-Term Debt	(159)	-	-	(450)	-	-	(60)	(220)	(100)	(213)
Other	(7)	(6)	(6)	(8)	(8)	(7)	(7)	(6)	(4)	(19)
	973	584	784	132	182	(7)	(17)	14	(134)	(229)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 532)	(1 423)	(1 601)	(909)	(763)	(852)	(1 021)	(972)	(895)	(834)
Sinking Fund Payment	(234)	(245)	(263)	(282)	(273)	(285)	(297)	(306)	(305)	(317)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1 795)	(1 698)	(1 891)	(1 219)	(1 066)	(1 166)	(1 346)	(1 307)	(1 229)	(1 180)
Net Increase (Decrease) in Cash	36	(163)	(5)	120	342	150	54	238	266	372
Cash at Beginning of Year	383	419	255	250	370	712	862	916	1 155	1 420
Cash at End of Year	419	255	250	370	712	862	916	1 155	1 420	1 792

PUB/MH I-79

Reference: **Appendix 5.6 pages 1 & 5 of 13, IFRS Status Update Report**

Preamble: **At last year's GRA the Corporation provide for a $15 million provision for IFRS related accounting changes and had identified $11 million in other accounting changes impacting 2012/13 and 2013/14. This year the Corporation indicates the impacts related to IFRS is substantially higher at $67 million in 2012/13 and $139.9 million in 2013/14.**

a) Please file the internal and consultant working paper/position papers in support of the overhead amounts now indicated at this GRA no longer meeting capitalization requirements in 2011/12 and 2013/13.

ANSWER:

Historically under CGAAP, Manitoba Hydro has utilized a "full cost" accounting approach to the capitalization of administrative and overhead costs. This approach recognizes that approximately 40% of Manitoba Hydro's activities are directed towards the construction of capital assets and thus, capital activities should receive a proportionate share of overhead costs. The full cost accounting approach has been used in the utility industry for decades and is permissible under Canadian Generally Accepted Accounting Principles (CGAAP).

Changes to Manitoba Hydro's overhead capitalization practices implemented to date and proposed for 2012/13 recognize industry trends to move away full cost accounting and are designed to make Manitoba Hydro's practices consistent with those of other Canadian electric utilities. These changes are also permissible under CGAAP.

MH has also been assessing the required changes to its overhead capitalization practices in order to comply with IFRS commencing in 2013/14. IFRS requires that the cost of an item of property, plant and equipment include only those costs that are "directly attributable" to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management and specifically excludes "administration and other general overhead costs" as being eligible for inclusion in the cost of an item of property, plant and equipment. Proposed changes for 2013/14 represent Manitoba Hydro's assessment of administrative and overhead charges that are not eligible for capitalization under IFRS.

The terms "directly attributable" and "administration and other general overhead costs" are not specifically defined in the IFRS standards and as such professional judgment is required in order to assess those elements of administrative and overhead costs that are eligible and ineligible for capitalization under IFRS. Through discussions with its external auditor and IFRS consultant and the review of utility industry information and accounting practices, Manitoba Hydro has generally approached the assessment of directly attributable costs as being those costs that are:

- Incremental such that they would not exist had the asset not been self-constructed;
- Non-discretionary such that there is no option to avoid such costs in the course of bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended; and
- Directly linked to a specific asset such that the link is straight forward and the process to allocate the expenditure is not overly influenced by the need for approximations.

Those costs that meet the definition of directly attributable would be eligible for capitalization while those that do not meet the definition would be ineligible.

The capitalization practices under a CGAAP full cost accounting approach are significantly different than that required under IFRS. For example, under a full cost accounting approach, costs associated with an office building such as depreciation and maintenance on that building would be charged to a capital project on the premise that the engineers designing and managing the project require office space to perform their duties and thus, the project should be charged for the engineer's portion of the overall office space. Under IFRS, such costs cannot be capitalized to the capital project on the premise that office building costs are not incremental and are not directly linked to the construction of a specific asset (i.e. office building costs would exist regardless of whether or not the capital project occurred).

The following table summarizes the administrative and overhead costs deemed ineligible for capitalization by Manitoba Hydro and the timing of the removal of those costs from capitalization:

Analysis of Capitalized Overhead (in millions of dollars)

Nature of Costs	Total Currently Capitalized	Eligible	Ineligible	Timing re: Ineligible 2012/13 Forecast	Timing re: Ineligible 2013/14 Forecast
IT Infrastructure & Related Support	$18	-	18	18	
Building Depreciation & Operating Costs	10	-	10	10	
Technical & Softskills Training	11	-	11		11
Service Areas (Management Accounting, HR, Safety, etc.)	12	3	9		9
Administrative & Clerical Support Staff	11	2	9		9
Division & Department Manager	9	2	7		7
Fleet & Stores Administration	23	21	2		2
	94	28	66	28	38

Changes under CGAAP in 2012/13

The following costs are being removed from costs that are eligible for capitalization under CGAAP in 2012/13 in order to ensure consistency with the practices of other Canadian electric utilities:

IT infrastructure and support costs - includes general IT & system support (including staff) that would exist regardless of whether or not Manitoba Hydro incurred capital spending. The primary IT system included in this category is the SAP system and its fully integrated modules including financial accounting, human resource management, materials management, and the distribution planning maintenance system. While such systems vary in size relative to the activities of the Corporation, an argument exists that such systems would be required regardless of Manitoba Hydro's level of capital activity.

Costs (including depreciation, licensing and maintenance) related to certain IT hardware and systems such as PC's and CADD are considered a tool of the employee necessary to perform their work and are eligible for capitalization where those employees are performing work related to the development of capital assets.

Building Depreciation and Operating Costs - includes depreciation, maintenance, and operating costs of common building facilities such as 360 Portage, 820 Taylor Ave. and the various operating centers. As described above, building costs would exist regardless of the level of capital activity.

Similar costs associated with buildings and related infrastructure located on major construction sites are eligible for capitalization as there is a direct link to the capital asset that is being constructed.

Changes upon Transition to IFRS in 2013/14

The following costs are being removed from costs that are eligible for capitalization in 2013/14 in order to ensure compliance with IFRS:

Technical & trades training - includes employee time and related expenses on training for operational skills, trades and apprenticeship programs. Technical and trades training programs develop specific trade skills required to perform maintenance and capital related activities in a safe and reliable manner. The costs associated with such programs include salaries and benefits, course fees, travel, and tools. Training is not considered eligible for capitalization under IFRS as entities are not able to control the benefits associated with such training and such expenditures do not meet the criteria for recognition as an asset. In other words, entities cannot prevent employees from receiving training and then assuming employment with another employer.

Soft skills training - includes training programs administered by Employee Learning & Development as well as external courses. Such training focuses on supervisory and managements skills. Consistent with the analysis related to technical trades training, such costs are not deemed eligible for capitalization as the Corporation cannot control the benefits associated with such costs.

Service areas - include department and staff costs associated with Management Accounting (including financial reporting, budgeting support, financial planning and customer accounting), Human Resources, Safety, general purchasing and other service departments. Staff within these departments perform roles that support many of the organization's capital activities such as project analysis, capital budgeting, capital reporting, hiring of staff, payroll administration, development of safety manuals, guidelines, and training. This work however, is considered several levels removed from the direct construction activities of specific capital assets and is therefore not considered directly attributable. Where time is spent in support of a specific capital project, staff in these departments will be required to time card directly to a capital project.

Administrative and clerical Support staff - includes employees within a department whose role is to support the staff that are directly "hands to tools" with respect to the maintenance, operations and construction of assets. Examples of functions performed by support staff include inventory management, material procurement, bill payments, and time & expense administration. Also included in this category are costs associated with office expenses such as postage and other general office supplies. Generally, such costs are not eligible for capitalization as they are too far removed from the development of a specific capital asset.

There are, however, instances where support staff costs may be directly attributable to the construction project of a specific asset and are thus, eligible for capitalization in the costs of that project.

Division and Department Managers - key members of a Business Unit's senior management team providing management of the strategic, financial, capital and human resource assets of the Division. Although they are active in the decision making process and have overall responsibility for the outputs of their divisions and departments, management is not typically involved in the direct management of any given capital project. Thus, such costs are generally not eligible for capitalization. There are instances, however, where senior management directs their activities to specific capital projects for an extended period of time. In such instances, their time would be considered eligible for capitalization in the costs of the specific asset.

Fleet & Stores - includes the activities related to the acquisition, maintenance and management of Manitoba Hydro's fleet of vehicles and the receiving, storing and issuing of materials and transporting materials to the jobsite. Manitoba Hydro's fleet of motor vehicles ranges from cars and vans to bucket trucks and heavy tractor equipment. Fleet vehicles are used in the maintenance, operations, and construction activities of the Corporation. Costs associated with fleet activities include maintenance, fuel, depreciation, and insurance. To the extent that vehicles are used directly for a capital project, such costs are eligible for capitalization. Costs pertaining to fleet vehicles used for maintenance or operational activities are not eligible for capitalization. Fleet management, support and administration costs, including the accounting and IT system that captures all costs for each respective vehicle, are not eligible for capitalization as they are too far removed from the construction of a specific asset.

Approximately 90% of stores issues are for capital projects and thus, many of the activities associated with the stores functions are eligible for capitalization. Similar to Fleet, Stores management and administrative costs are not eligible for capitalization as they are too far removed from the construction of a specific asset.

PUB/MH I-79

Reference: Appendix 5.6 pages 1 & 5 of 13, IFRS Status Update Report

Preamble: At last year's GRA the Corporation provide for a $15 million provision for IFRS related accounting changes and had identified $11 million in other accounting changes impacting 2012/13 and 2013/14. This year the Corporation indicates the impacts related to IFRS is substantially higher at $67 million in 2012/13 and $139.9 million in 2013/14.

b) Please recast the analysis on page 5 indicating the amounts spent on each overhead cost line items that were capitalized in prior years and provide the compounded annual growth of each item for the years 2009/10 through 2013/14.

ANSWER:

In IFF11-2, Manitoba Hydro has assumed that IFRS is not required until the 2013/14 fiscal year. As such, Manitoba Hydro has not conducted a comprehensive analysis of IFRS changes on a retrospective basis back to 2009/10.

Manitoba Hydro has provided a detailed analysis of IFRS changes commencing in 2013/14 and beyond in the response to PUB/MH I-42.

PUB/MH I-79

Reference: **Appendix 5.6 pages 1 & 5 of 13, IFRS Status Update Report**

Preamble: **At last year's GRA the Corporation provide for a $15 million provision for IFRS related accounting changes and had identified $11 million in other accounting changes impacting 2012/13 and 2013/14. This year the Corporation indicates the impacts related to IFRS is substantially higher at $67 million in 2012/13 and $139.9 million in 2013/14.**

c) Please recast the analysis on page 1 and page 5 assuming that IFRS related adjustments proposed for 2012/13 are not made until required in 2013/14 and explain how such adjustments would be accounted for under IFRS transition.

ANSWER:

Please see the following schedules revising the analysis on page 1 and 5 of Appendix 5.6 under the scenario that the accounting changes proposed for 2012/13 are not made until 2013/14. It is noted that all accounting adjustments will be applied retroactively to 2012/13 for comparative year reporting under IFRS.

(in thousands of $)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual Increase
Electric OM&A (per Annual Report)	$ 379,697	$ 403,067	$ 410,717	$ 426,897	$ 538,238	
Less: Subsidiaries	2,146	6,121	7,414	6,531	6,945	
Accounting Changes	11,240	30,910	34,973	40,459	139,442	
Wuskwatim				7,881	9,635	
Electric OM&A after adjusting for subsidiaries, accounting changes and Wuskwatim	$ 366,311	$ 366,036	$ 368,330	$ 372,026	$ 382,216	
% Increase	4.28%	-0.08%	0.63%	1.00%	2.74%	1.71%
		-0.08%	0.55%	1.56%	4.34%	
Number of Customers	532,359	537,299	542,681	549,150	555,651	1.05%
Cost Per Customer	$ 688	$ 681	$ 679	$ 677	$ 688	
% Increase (Decrease)	3.32%	-0.99%	-0.37%	-0.19%	1.54%	0.66%
Canadian CPI	1.40%	3.30%	1.90%	2.10%	2.00%	2.14%

The cost per customer and % increase do not change as the Electric OM&A figure for 2012/13 would be reduced by the amount of the accounting changes.

SUMMARY OF ACCOUNTING CHANGES - ELECTRIC OPERATIONS
(in thousands of dollars)

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Reduction to Costs Capitalized					
Stores Overhead	$ 5,100	5,202	5,306	5,412	5,520
Executive Costs	2,000	2,040	2,081	2,122	2,165
Property Taxes on Facilities	2,000	2,040	2,081	2,122	2,165
Interest on Common Assets (Facilities & Equipment)		11,165	11,388	11,616	11,848
General & Administrative Departmental Costs		4,500	4,590	4,682	4,775
Interest on Motor Vehicles		3,780	3,856	3,933	4,011
IT Infrastructure & Related Support					17,100
Building Depreciation & Operating Costs					9,500
Technical & Softskills Training					10,450
Service Areas (Management Accounting, HR, Safety, etc.)					8,550
Administrative & Clerical Support Staff					8,550
Division & Department Manager					6,650
Fleet & Stores Administration					1,900
	9,100	28,727	29,302	29,888	93,185
Intangible Assets					
Ineligible for Capitalization	4,080	4,162	4,245	4,330	4,416
Rate Regulated Accounts					
Power Smart Program					31,713
Site Remediation					4,586
Regulatory Costs					1,344
	-	-	-	-	37,643
Pension & Benefits					
Change in Discount Rate			3,445		
Unamortized Past Service Amendments for Retiree Health Spending					(1,647)
Past Service Pension Costs					(521)
	-	-	3,445	-	(2,169)
Reclassifications					
Wire & Telecom Services	3,060	3,121	3,184	3,247	3,312
Funding Payments (Town of Gillam & Frontier School Division)	(5,000)	(5,100)	(5,202)	(5,306)	(5,412)
Operating Expense Recoveries				8,300	8,466
	(1,940)	(1,979)	(2,018)	6,241	6,366
Total	$ 11,240	$ 30,910	$ 34,973	$ 40,459	$139,442

PUB/MH I-79

Reference: Appendix 5.6 pages 1 & 5 of 13, IFRS Status Update Report

Preamble: At last year's GRA the Corporation provide for a $15 million provision for IFRS related accounting changes and had identified $11 million in other accounting changes impacting 2012/13 and 2013/14. This year the Corporation indicates the impacts related to IFRS is substantially higher at $67 million in 2012/13 and $139.9 million in 2013/14.

d) If the reduction in overheads capitalized proposed in 2011/12 and 2012/13 do not meet current GAAP standards in 2012/13 please explain how such expenditures met the standard in prior years.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-79(a).

PUB/MH I-79

Reference: **Appendix 5.6 pages 1 & 5 of 13, IFRS Status Update Report**

Preamble: **At last year's GRA the Corporation provide for a $15 million provision for IFRS related accounting changes and had identified $11 million in other accounting changes impacting 2012/13 and 2013/14. This year the Corporation indicates the impacts related to IFRS is substantially higher at $67 million in 2012/13 and $139.9 million in 2013/14.**

e) **Please recast the analysis on page 1 and page 5 assuming the continuation of rate regulated accounting in 2013/14 for rate setting purposes.**

ANSWER:

Please see the following schedules revising the analysis on page 1 and 5 of Appendix 5.6 under the scenario that assumes the continuation of rate regulated accounting in 2013/14.

(in thousands of $)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual Increase
Electric OM&A (per Annual Report)	$ 379,697	$ 403,067	$ 410,717	$ 453,497	$ 501,127	
Less: Subsidiaries	2,146	6,121	7,414	6,531	6,945	
Accounting Changes	11,240	30,910	34,973	67,059	102,331	
Wuskwatim				7,881	9,635	
Electric OM&A after adjusting for subsidiaries, accounting changes and Wuskwatim	$ 366,311	$ 366,036	$ 368,330	$ 372,026	$ 382,216	
% Increase	4.28%	-0.08%	0.63%	1.00%	2.74%	1.71%
Number of Customers	532,359	537,299	542,681	549,150	555,651	1.05%
	0.93%	0.91%	0.98%	1.23%	1.18%	
Cost Per Customer	$ 688	$ 681	$ 679	$ 677	$ 688	
% Increase (Decrease)	3.32%	-0.99%	-0.37%	-0.19%	1.54%	0.66%
Canadian CPI	1.40%	3.30%	1.90%	2.10%	2.00%	2.14%

The cost per customer and % increase do not change as the Electric OM&A figure for 2013/14 would be reduced by the amount of the accounting changes.

SUMMARY OF ACCOUNTING CHANGES - ELECTRIC OPERATIONS
(in thousands of dollars)

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Reduction to Costs Capitalized					
Stores Overhead	$ 5,100	5,202	5,306	5,412	5,520
Executive Costs	2,000	2,040	2,081	2,122	2,165
Property Taxes on Facilities	2,000	2,040	2,081	2,122	2,165
Interest on Common Assets (Facilities & Equipment)		11,165	11,388	11,616	11,848
General & Administrative Departmental Costs		4,500	4,590	4,682	4,775
Interest on Motor Vehicles		3,780	3,856	3,933	4,011
IT Infrastructure & Related Support				17,100	17,442
Building Depreciation & Operating Costs				9,500	9,690
Technical & Softskills Training					10,450
Service Areas (Management Accounting, HR, Safety, etc.)					8,550
Administrative & Clerical Support Staff					8,550
Division & Department Manager					6,650
Fleet & Stores Administration					1,900
	9,100	28,727	29,302	56,488	93,717
Intangible Assets					
Ineligible for Capitalization	4,080	4,162	4,245	4,330	4,416
Rate Regulated Accounts					
Power Smart Program					
Site Remediation					
Regulatory Costs					
	-	-	-	-	-
Pension & Benefits					
Change in Discount Rate			3,445		
Unamortized Past Service Amendments for Retiree Health Spending					(1,647)
Past Service Pension Costs					(521)
	-	-	3,445	-	(2,169)
Reclassifications					
Wire & Telecom Services	3,060	3,121	3,184	3,247	3,312
Funding Payments (Town of Gillam & Frontier School Division)	(5,000)	(5,100)	(5,202)	(5,306)	(5,412)
Operating Expense Recoveries				8,300	8,466
	(1,940)	(1,979)	(2,018)	6,241	6,366
Total	$ 11,240	$ 30,910	$ 34,973	$ 67,059	$102,331

PUB/MH I-79

Reference: Appendix 5.6 pages 1 & 5 of 13, IFRS Status Update Report

Preamble: At last year's GRA the Corporation provide for a $15 million provision for IFRS related accounting changes and had identified $11 million in other accounting changes impacting 2012/13 and 2013/14. This year the Corporation indicates the impacts related to IFRS is substantially higher at $67 million in 2012/13 and $139.9 million in 2013/14.

f) Please indicate to what extent a deferral of changes in overhead capitalized until IFRS is implemented and continued recognition of rate-regulated accounting would impact net income in 2012/13 and 2013/14 and retained earnings given MH' PP&E IFRS transition election.

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH I-61(a) and PUB/MH I-78(b).

Manitoba Hydro's PP&E IFRS transitional election that permits the carry forward of the Canadian GAAP net book value of Manitoba Hydro's PP&E assets is effective for April 1, 2012; which is the opening date for the comparative IFRS financial reporting period of 2012/13. Any changes made under Canadian GAAP up to the end of the 2011/12 reporting period will be carried forward in the opening net book value of PP&E assets as of April 1, 2012.

PUB/MH I-79

Reference: **Appendix 5.6 pages 1 & 5 of 13, IFRS Status Update Report**

Preamble: **At last year's GRA the Corporation provide for a $15 million provision for IFRS related accounting changes and had identified $11 million in other accounting changes impacting 2012/13 and 2013/14. This year the Corporation indicates the impacts related to IFRS is substantially higher at $67 million in 2012/13 and $139.9 million in 2013/14.**

g) **Please provide a list of the planning studies that were undertaken in 2011/12 and those forecast to be undertaken in 2012/13 and 2013/14 including the amount, the classification, next generation and transmission or emerging energy studies, description of the study, the specific generation and transmission project they relate, and the rational for it not meeting the criteria for capitalization.**

ANSWER:

The following is a listing of planning studies undertaken and expensed in 2011/12 and those forecast to be undertaken in 2012/13 and 2013/14.

		Actual	Forecast	Forecast
PLANNING STUDIES	CLASSIFICATION	2011/12	2012/13	2013/14
Next Generation Studies	Next Generation	$ 546,141	$ 716,000	$ 730,000
Transmission Planning Studies	Transmission	270,377	292,500	298,350
Emerging Energy Studies	Emerging Energy	453,337	450,000	459,000
Total		$ 1,269,855	$ 1,458,500	$ 1,487,350

The individual classifications are comprised of numerous studies associated with new future generation options, transmission load impacts and interconnections as well as studies related to wind, solar, geothermal and other technological initiatives.

The planning studies identified above do not meet the criteria for capitalization. Expenditures for next generation and transmission plant are only recognized as a tangible asset when there is reasonable assurance that a commitment to construction will be made. At this time, Manitoba Hydro has not made a commitment to construction of these assets. The planning studies for emerging energy result in the accumulation of information and/or research data, this information does not result in the creation of a separate intangible or tangible asset and therefore does not meet the criteria for recognition of an asset.

PUB/MH I-79

Reference: **Appendix 5.6 pages 1 & 5 of 13, IFRS Status Update Report**

Preamble: **At last year's GRA the Corporation provide for a $15 million provision for IFRS related accounting changes and had identified $11 million in other accounting changes impacting 2012/13 and 2013/14. This year the Corporation indicates the impacts related to IFRS is substantially higher at $67 million in 2012/13 and $139.9 million in 2013/14.**

h) **Please describe how MH will determine when a reasonable assurance that a commitment to construction will be made to determine when planning studies will be capitalized to a specific project.**

ANSWER:

For determining when planning studies will be capitalized to a specific project, reasonable assurance that a commitment to construction exists when process agreements or similar arrangements are signed with impacted communities, the date of application to commence the environmental licencing or regulatory process is determined, the date of a commitment to commence capital construction is determined, or such other date as specifically approved by Executive Committee.

PUB/MH I-80 (Revised)

Reference: Appendix 5.6 page 7 of 13

Please refile the analysis including the years 2003/04 to 2013/14.

ANSWER:

Please see the following Operating, Maintenance and Administrative Costs by Cost Element Schedule from 2004/05 to 2013/14.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual % Inc/(Dec)
Wages & Salaries	$ 320,808	$ 332,257	$ 344,701	$ 359,249	$ 380,031	$ 407,988	$ 425,158	$ 451,925	$ 476,887	$ 486,425	4.7%
Overtime	33,842	38,032	38,896	41,781	45,890	50,307	50,704	54,987	56,005	57,126	6.1%
Employee Benefits	68,442	70,184	73,636	76,807	83,671	83,013	95,376	104,444	109,649	111,842	5.7%
Employee Safety & Training	5,275	3,686	3,487	3,646	4,145	4,284	3,863	3,909	4,914	5,013	0.6%
Travel Expenses	23,534	26,212	27,729	28,331	31,812	32,435	32,594	31,266	32,405	33,053	4.0%
Motor Vehicle	17,726	19,380	19,731	22,423	24,126	24,281	24,436	28,676	24,784	25,280	4.4%
Materials & Tools	23,893	26,046	25,414	27,824	29,345	26,897	28,105	26,663	27,173	27,716	1.8%
Consulting & Professional Fees	7,269	7,229	8,498	7,503	9,704	14,814	11,157	10,250	11,639	11,872	7.8%
Construction & Maintenance Services	13,345	13,700	13,711	15,938	18,378	20,109	22,657	21,228	18,706	19,080	4.5%
Building & Property Services	21,031	22,973	24,697	25,740	28,947	22,931	21,944	21,386	22,399	22,843	1.4%
Equipment Maintenance & Rentals	9,546	10,720	11,606	11,719	13,029	14,379	14,165	13,388	14,476	14,766	5.1%
Consumer Services	4,203	4,301	4,316	4,651	5,284	5,798	5,086	5,365	5,284	5,389	3.1%
Collection Costs	5,161	6,790	7,218	5,256	5,019	4,599	4,497	4,035	4,347	4,434	-0.6%
Customer & Public Relations	5,223	5,585	6,493	6,664	6,901	8,155	7,905	8,093	6,949	7,088	3.9%
Sponsored Memberships	1,149	1,012	1,187	1,192	1,465	1,325	1,917	1,608	1,081	1,103	1.9%
Office & Administration	15,447	15,902	14,939	14,427	14,652	15,320	14,316	14,277	15,263	15,569	0.2%
Computer Services	3,959	4,293	2,622	1,131	858	983	1,003	861	909	927	-11.3%
Communication Systems	1,844	1,447	1,866	1,353	1,449	1,772	1,678	1,683	1,683	1,717	0.7%
Research & Development Costs	3,685	2,874	3,251	2,979	3,059	3,952	3,651	2,797	3,509	3,579	1.2%
Miscellaneous Expense	2,470	2,811	2,422	3,292	903	1,190	1,264	2,032	1,213	1,237	2.6%
Contingency Planning	-	-	-	-	-	-	-	-	275	2,875	0.0%
Operating Expense Recovery	(18,105)	(19,205)	(20,570)	(23,314)	(21,519)	(21,580)	(23,004)	(21,716)	(9,787)	(9,983)	-3.6%
Total Costs	569,749	596,229	615,849	638,594	687,149	722,951	748,471	787,155	829,765	848,951	4.5%
Capital Order Activities	(157,730)	(170,458)	(176,992)	(192,338)	(203,077)	(224,298)	(243,545)	(268,651)	(246,065)	(250,986)	5.5%
Capitalized Overhead	(58,174)	(62,028)	(61,887)	(67,289)	(65,743)	(60,151)	(47,336)	(53,084)	(69,434)	(70,823)	3.1%
Operating and Administration Charged to Centra	(55,232)	(53,085)	(53,505)	(56,270)	(59,042)	(60,951)	(60,645)	(62,117)	(67,300)	(68,646)	2.5%
Subsidiaries	3,182	4,613	3,852	1,485	4,816	2,146	6,121	7,414	6,531	6,945	
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	**$ 301,795**	**$ 315,271**	**$ 327,317**	**$ 324,181**	**$ 369,103**	**$ 379,697**	**$ 403,067**	**$ 410,717**	**$ 453,497**	**$ 538,770**	
Less:											
Subsidiaries	3,182	4,613	3,852	1,485	4,816	2,146	6,121	7,414	6,531	6,945	
Accounting Changes						11,240	30,910	34,973	67,059	139,974	
Wuskwatim						-	-	-	7,881	9,635	
OM&A Attributable to Electric Operations after adjusting for subsidiaries, accounting changes and Wuskwatim	**$ 298,613**	**$ 310,658**	**$ 323,465**	**$ 322,697**	**$ 364,287**	**$ 366,311**	**$ 366,036**	**$ 368,330**	**$ 372,026**	**$ 382,216**	2.9%

PUB/MH I-81 (Revised)

Reference: Tab 5 Page 23 -24, - Schedule 5.7.0 Depreciation & Amortization

a) Please re-file the schedule including the years 2003/04 through 2013/14/.

ANSWER:

Please see the following table.

MANITOBA HYDRO Schedule 5.7.
DEPRECIATION AND AMORTIZATION EXPENSE (000's)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Generation											
Hydraulic Generating Stations	62 504	64 436	66 100	64 033	70 817	70 911	74 310	76 128	75 064	97 254	97 852
Thermal Generating Stations	17 098	16 857	17 019	17 191	17 170	17 276	17 612	9 771	8 680	16 036	16 496
Demand Side Management	5 024	5 957	7 247	9 098	11 357	19 157	22 064	23 994	26 191	28 664	-
Diesel Generating Stations	2 742	3 029	3 126	3 197	4 067	3 933	3 552	3 691	1 359	1 407	1 368
Amortization of Contributions	(37)	(22)	(1 335)	(2 660)	(2 774)	(2 796)	(2 796)	(2 796)	(718)	(1 033)	(1 092)
	$ 87 331	$ 90 257	$ 92 157	$ 90 859	$ 100 637	$ 108 481	$ 114 743	$ 110 788	$ 110 576	$ 142 328	$ 114 624
Transmission											
Transmission	11 363	11 552	11 699	12 163	14 120	14 317	14 328	14 471	13 920	16 995	14 179
Amortization of Contributions	(1 655)	(1 655)	(1 671)	(1 683)	(1 631)	(1 638)	(1 638)	(1 629)	(1 357)	(1 358)	(1 360)
	$ 9 708	$ 9 897	$ 10 028	$ 10 480	$ 12 489	$ 12 680	$ 12 690	$ 12 842	$ 12 563	$ 15 636	$ 12 819
Stations											
Substations	56 454	58 382	61 010	62 980	70 616	72 512	74 123	76 747	79 157	87 181	80 893
Transformers	2 463	2 667	7 070	6 102	3 681	2 288	2 121	1 653	1 691	1 983	2 200
Amortization of Contributions	(1 159)	(1 169)	(1 230)	(1 186)	(1 461)	(1 462)	(1 464)	(1 470)	(1 247)	(1 235)	(1 235)
	$ 57 758	$ 59 880	$ 66 850	$ 67 896	$ 72 836	$ 73 338	$ 74 780	$ 76 930	$ 79 601	$ 87 929	$ 81 858
Distribution											
Subtransmission Lines	6 791	7 128	7 329	7 682	8 905	9 166	9 469	9 892	5 974	6 215	5 423
Distribution Lines	65 688	69 898	73 942	77 762	72 410	77 730	82 679	87 194	55 547	59 820	52 309
Meters & Metering Transformers	1 130	1 178	1 200	1 253	1 551	1 597	1 590	1 615	4 205	5 019	5 603
Amortization of Contributions	(8 052)	(8 315)	(8 582)	(8 891)	(9 769)	(10 180)	(10 443)	(10 710)	(4 774)	(5 318)	(5 551)
	$ 65 557	$ 69 889	$ 73 889	$ 77 806	$ 73 097	$ 78 312	$ 83 295	$ 87 991	$ 60 952	$ 65 736	$ 57 784
Other											
Communications	9 837	12 910	12 634	13 591	17 636	19 473	20 947	22 518	20 118	25 153	29 634
Motor Vehicles	6 555	7 169	7 879	8 324	8 275	8 691	8 760	9 500	10 374	9 935	12 010
Structures & Improvements	3 033	2 798	3 173	3 309	3 216	5 692	6 590	7 422	7 618	8 509	9 495
General Equipment	21 173	21 091	19 045	18 390	20 572	17 674	18 006	17 172	23 493	23 011	21 226
Computer Development	11 250	12 624	13 093	15 181	13 582	14 081	14 454	15 253	18 895	16 376	18 937
Affordable Energy Fund				875	625	1 441	3 058	3 468	7 472	8 870	8 710
Miscellaneous	3 903	4 470	4 126	5 724	2 701	2 463	2 995	2 623	3 420	3 760	(3 418)
Corporate Allocation	(1 867)	(1 782)	(1 661)	(1 521)	(2 093)	(2 012)	(2 139)	(1 780)	(1 706)	(1 707)	(1 208)
Target Adjustment									-	(4 691)	(8 163)
	$ 53 883	$ 59 280	$ 58 288	$ 63 873	$ 64 514	$ 67 503	$ 72 671	$ 76 176	$ 89 684	$ 89 217	$ 87 223
Total Depreciation and Amortization Expense	$ 274 237	$ 289 202	$ 301 213	$ 310 914	$ 323 573	$ 340 314	$ 358 179	$ 364 727	$ 353 376	$ 400 846	$ 354 307

PUB/MH I-81

Reference: Tab 5 Page 23 -24, - Schedule 5.7.0 Depreciation & Amortization

b) Please re-file the schedule assuming the continuation of rate-regulated accounting and the use of Average Service Lives methodology rather than the Equal Life Group methodology.

ANSWER:

Please see attached schedule.

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE

Schedule 5.7.0
(000's)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast Base	2013/14 Forecast Base + Rate Reg	2013/14 Forecast Base + Rate Reg ASL
Generation									
Hydraulic Generating Stations	68 451	70 911	74 310	76 128	75 064	97 254	97 852	97 852	89 025
Thermal Generating Stations	17 170	17 276	17 612	9 771	8 680	16 036	16 496	16 496	15 163
Amortization of Planning Studies	2 366	-				-	-	-	-
Demand Side Management	11 357	19 157	22 064	23 994	26 191	28 664	-	31 395	31 395
Diesel Generating Stations	4 067	3 933	3 552	3 691	1 359	1 407	1 368	1 433	1 327
Amortization of Contributions	(2 774)	(2 796)	(2 796)	(2 796)	(718)	(1 033)	(1 092)	(1 092)	(1 092)
	$ 100 637	$ 108 481	$ 114 743	$ 110 788	$ 110 576	$ 142 328	$ 114 624	$ 146 084	$ 135 818
Transmission									
Transmission	14 120	14 317	14 328	14 471	13 920	16 995	14 179	14 179	12 774
Amortization of Contributions	(1 631)	(1 638)	(1 638)	(1 629)	(1 357)	(1 358)	(1 360)	(1 360)	(1 360)
	$ 12 489	$ 12 680	$ 12 690	$ 12 842	$ 12 563	$ 15 636	$ 12 819	$ 12 819	$ 11 414
Stations									
Substations	70 616	72 512	74 123	76 747	79 157	87 181	80 893	80 893	76 150
Transformers	3 681	2 288	2 121	1 653	1 691	1 983	2 200	2 200	2 055
Amortization of Contributions	(1 461)	(1 462)	(1 464)	(1 470)	(1 247)	(1 235)	(1 235)	(1 235)	(1 235)
	$ 72 836	$ 73 338	$ 74 780	$ 76 930	$ 79 601	$ 87 929	$ 81 858	$ 81 858	$ 76 970
Distribution									
Subtransmission Lines	8 905	9 166	9 469	9 892	5 974	6 215	5 423	5 423	4 720
Distribution Lines	72 410	77 730	82 679	87 194	55 547	59 820	52 309	52 309	45 566
Meters & Metering Transformers	1 551	1 597	1 590	1 615	4 205	5 019	5 603	5 603	4 980
Amortization of Contributions	(9 769)	(10 180)	(10 443)	(10 710)	(4 774)	(5 318)	(5 551)	(5 551)	(5 551)
	$ 73 097	$ 78 312	$ 83 295	$ 87 991	$ 60 952	$ 65 736	$ 57 784	$ 57 784	$ 49 714
Other									
Communications	17 636	19 473	20 947	22 518	20 118	25 153	29 634	29 634	24 318
Motor Vehicles	8 275	8 691	8 760	9 500	10 374	9 935	12 010	12 010	10 249
Structures & Improvements	3 216	5 692	6 590	7 422	7 618	8 509	9 495	9 495	9 174
General Equipment	20 572	17 674	18 006	17 172	23 493	23 011	21 226	21 226	21 226
Computer Development	13 582	14 081	14 454	15 253	18 895	16 376	18 937	18 937	17 918
Affordable Energy Fund	625	1 441	3 058	3 468	7 472	8 870	8 710	8 710	8 710
Miscellaneous	2 701	2 463	2 995	2 623	3 420	3 760	(3 418)	1 915	1 915
Corporate Allocation	(2 093)	(2 012)	(2 139)	(1 780)	(1 706)	(1 707)	(1 208)	(1 208)	(1 208)
Target Adjustment					-	(4 691)	(8 163)	(8 163)	(7 426)
	$ 64 514	$ 67 503	$ 72 671	$ 76 176	$ 89 684	$ 89 217	$ 87 223	$ 92 556	$ 84 876
Total Depreciation and Amortization Expense	$ 323 573	$ 340 314	$ 358 179	$ 364 727	$ 353 376	$ 400 846	$ 354 307	$ 391 099	$ 358 792

PUB/MH I-82

Reference: Tab 5.0/Appendix 5.7/Gannett Fleming

a) Physical Asset Review (GF – P. II-24)
Please confirm that MH has "recreated a database of aged plant accounting retirements and balances" which Gannett Fleming used "to perform a detailed Retirement Rate Analysis" please provide MH's data base of aged plant and accounting retirements and balances:

ANSWER:

Confirmed.

Manitoba Hydro's database of aged plant accounting retirements and balances is voluminous. The attachment to PUB/MH I-84(d) contains a summary of the requested data and the corresponding retirement rate analysis.

PUB/MH I-82

Reference: Tab 5.0/Appendix 5.7/Gannett Fleming

b) Asset Condition Assessment (B.O. 150/08 – Directive 7)

Please explain whether above database document (or a summary version) in effect forms the core of the PUB-requested Asset Condition Assessment Study; also define what additional components are required for the Study. Please provide a specific date for the submission of Asset Condition Assessment will be filed.

ANSWER:

No, the Gannett-Fleming document does not form the core of an Asset Condition Assessment Study. The status of asset condition reporting in each of Manitoba Hydro's Business Units is reviewed below:

Power Supply:

Generation South and Generation North

Power Supply is using a templated Equipment Health Rating (EHR) system for 8 significant equipment categories for 104 generating units at 14 hydraulic generating stations or 832 scorecards. In addition, they have an EHR process for Earth Dams and Concrete Water Retaining Structures. The majority of the asset types selected for attention are the main drive train components that if failed would result in a prolonged outage and stranding of power. Presently the majority of assets in Generation South have been assessed on a screening level and some assets with low EHR scores are being reassessed using more complicated tools.

Power Supply is also implementing Asset Investment Program (AIP) software and process change to facilitate 20 year capital planning for aging assets rehabilitation or replacement based on asset condition and performance. Once all the required input data is validated by Manitoba Hydro specialists, the AIP tool will provide the basis for condition assessment reporting as well as long-term capital planning projects.

HVDC

HVDC has identified major assets as those which require significant capital investment for replacement, require lengthy outages for replacement or could result in significant outage costs should a failure occur.

These assets receive additional attention in terms of condition monitoring and health assessment and are identified on a long term replacement plan.

Generally these assets are categorized as:

- Converter Transformers
- Controls and Protection
- HVDC Converter Equipment
- DC Switchyard Equipment
- AC Switchyard Equipment
- Synchronous Condensers
- Plant Auxiliaries

Asset Inventory:

HVDC currently has identified major assets and have detailed them in a report "Future Projects for HVDC Converter Stations" or on component specific tracking spread sheets. The report and spread sheets are revised as asset conditions are re-evaluated or work is completed that prolongs an asset's life.

Asset Condition Monitoring and Health Assessment:

Asset Condition Monitoring is achieved through ongoing performance management at the plant level, by analyzing all outages and maintenance issues to identify root cause of failures. Standard maintenance procedures include specific testing and data collection necessary for condition monitoring and health assessment.

Additionally HVDC system performance is tracked and compared on a monthly basis at the valve group, pole and bipole level.

Asset Condition Report:

Condition reports are currently completed as issues are identified and changes are initiated to the capital plan or requirements are documented for increased monitoring and data collection.

Currently HVDC is integrating condition assessment data into the new Asset Investment Planning (AIP) software system. This system will assist in tracking asset condition and capital planning. The goal is to have sufficient data loaded in the AIP software to assist in development of the overall Power Supply asset condition report and long-term capital plan. Timing for this work is consistent with Generation South and North milestone dates

Transmission:

Transmission is in the process of performing a detailed review of three critical asset categories:

1. Transmission Lines
2. Substation Transformers
3. Breakers.

Once the detailed study of these assets is complete, a plan for the remaining transmission assets (switches, capacitors, etc.) will be developed.

For the three critical asset categories, the strategy is to work with a consultant to conduct a thorough analysis of asset condition assessment opportunities. A Request for Proposal for consulting services was issued and a consultant was selected to provide the services beginning in January 2012. A Transmission Asset Condition Report is expected to be completed by December 31, 2012.

Distribution:

A Distribution Asset Condition report has been prepared that details the condition of the eight critical asset categories comprising the electrical distribution system. The report will be reviewed for the purpose of including it in the Corporation's Asset Condition Report.

As indicated in the response to this Information Request, the development of Asset Condition Assessments is underway in all Business Units and good progress is being made. Manitoba Hydro intends to file Condition Assessments with the PUB at periodic intervals as these assessments are completed.

PUB/MH I-82

Reference: Tab 5.0/Appendix 5.7/Gannett Fleming

c) Life span estimates of hydraulic generating station (GF – P. II-29 and III-12 to III-16)

Please provide a detailed discussion for each of MH's hydraulic G.S. to support the increased service life of 140 years (up from 100 years).

ANSWER:

For depreciation study purposes, the use of an overall life span recognizes that all of the components associated with a generating station are subject to a life constraining factor in addition to the expected life of the component itself. For hydraulic generating stations, the expected life of the major civil components has been determined to be the main constraining factor. During the depreciation study, it was determined that the overall life span estimate of 100 years for hydraulic generating facilities required revision, as four of the generating stations will reach 100 years of age within the CEF11 planning horizon. Pointe du Bois reached 100 years of age in 2011; Great Falls will reach 100 years of age in 2023, and both Slave Falls and Seven Sisters will reach 100 years of age in 2031. Manitoba Hydro expects to continue operating these generating stations well beyond the age of 100 years.

The revised overall life span estimate of 140 years for hydraulic generation facilities was developed through discussions with MH's engineers, considering the age and condition of the existing generating stations, expectations for continued operation as evidenced in the Power Resource Plan, and any plans in place for future decommissioning or major refurbishment.

Eight of MH's 14 hydraulic generating stations exceed 50 years of age, with an overall average age of 59 years. In general, the major civil structures at the generating stations are in good to excellent condition. An exception to this generality occurs with Pointe du Bois, where the civil structures are showing significant signs of wear. CEF11 includes plans to rebuild the Pointe du Bois powerhouse, with an expected in-service date of 2031, at which time the generating station will be 120 years old.

Pointe du Bois was constructed prior to the development of local sources of cement, and used a product acquired from eastern Canada in its concrete formulation. All of the other hydraulic generating stations were constructed using a cement product locally produced in Manitoba.

The product used in Pointe du Bois has been found to be much more reactive than the locally supplied product, causing a faster deterioration of the concrete structures than has been experienced with the other generating stations. Considering the differences in concrete formulation, and the advancement of other construction products and techniques over the 100 years since Pointe du Bois was constructed, it is reasonable to assume, in general, that the other generating stations will have a significantly longer life than Pointe du Bois. For depreciation study purposes, the expected retirement date for Pointe du Bois was set to 2031 (120 years) to coincide with the planned in-service date for the powerhouse rebuild, and the overall life span for other generating stations was estimated to be 140 years.

This assumption was validated by a review of the most recent capital forecast. Except in the case of Pointe du Bois, CEF11 does not identify any significant work to be performed on dams, dykes, weirs, or powerhouses. The majority of the work planned for the hydraulic generating stations focuses on mechanical and electrical equipment.

MH’s engineers considered each generating station and identified two additional exceptions to the general rule.

The major civil structures at the Grand Rapids generating station were constructed using a locally supplied limestone based aggregate for its concrete formulation, as compared to the granite based aggregates which were used in the construction of all of the other generating stations. The Grand Rapids civil structures are showing more wear for their age than civil structures at the other generating stations. In recognition of this increased level of wear, the overall life span for the Grand Rapids generating station was estimated to be 125 years, in recognition that it is likely to have a shorter life span than the other generating stations.

Laurie River generating station is a much smaller electrical producer than the other generating stations. Generally, there is an expectation that the turbines in a generating station will be replaced or re-runnered at least once during the life span of the station. Due to its smaller electrical production, it is less likely to be economically feasible to replace the turbines and generators at Laurie River when they reach the end of their life, as compared with the other generating stations. For depreciation purposes, it was determined to be more reasonable to base the overall life expectancy for Laurie River on the turbines and generators, which have been assigned a 65 year average service life. Since CEF11 does not include any plans to decommission the facility, the expected retirement date was set to 2032 for depreciation purposes, which places it just beyond the CEF11 planning horizon. At that time the turbines are generators will be 83 years old. Although this exceeds the 65 year average life, the MH engineers indicated that it was reasonable to expect the turbines and generators to last for another 20 years, given that they are currently 63 years old and are in very good condition.

PUB/MH I-82

Reference: Tab 5.0/Appendix 5.7/Gannett Fleming

d) Life span estimates of transmission (GF – P. II-31)
Please provide detailed discussion for each of MH"s HVDC and major HVAC facilities to support the increased service line of 85 years (up from 50-65 years).

ANSWER:

It should be noted that the 50-65 years identified in the question is an industry average quoted by Gannett Fleming in the referenced depreciation study, and not Manitoba Hydro's service life from the 2005 depreciation study.

In the referenced depreciation study, the Transmission Metal Towers and Concrete Poles component was assigned an average service life of 85 years.

In the 2005 depreciation study, the predecessor accounts were assigned average service lives as follows: Transmission Metal Towers were assigned an average service life of 85 years and Transmission Concrete Poles were assigned an average service life of 75 years.

PUB/MH I-82

Reference: Tab 5.0/Appendix 5.7/Gannett Fleming

e) Life span estimates of distribution (GF – P. II-34)
Please explain the rationale for increasing the service life of distribution assets to 55-60 years from MH's previous statistically developed 34 years.

ANSWER:

The following response was prepared by Gannett Fleming.

In the current depreciation study, the average service life estimates for the two largest Distribution Accounts (4000J – Poles and Fixtures and 4000L – Overhead Conductors and Devices) have increased dramatically. In the 2005 study these assets were formally in the Distribution – Poles, Conductor and Attachments accounts for Distribution (with a 31-year life) and Sub-Transmission (with a 38-year life). The average service life estimates in the 2005 depreciation study were based predominantly on the results of a study where the original installation years of retirements were not known, but rather were statistically developed using the computed mortality method. The interviews with Manitoba Hydro operational staff in 2005 did not provide an indication that the lives were materially short. The peer group analysis undertaken for the 2005 study indicated average service life estimates from 30 to 52 years.

However, the in current study, the Manitoba Hydro operational staff were confident that the life estimate for Poles should be materially lengthened from the life estimates as determined in the statistical retirement study. Gannett Fleming has also witnessed a trend to longer average service life estimates among the peer group analyzed. Additionally, the Province of Ontario has recently released the results of a depreciation study related to electric distribution assets that have indicated average service life estimates much longer than the currently used Manitoba life estimates. While the statistically generated studies have only indicated a small increase in life estimates, Gannett Fleming placed an increased amount of reliance on the industry trends and comments received from the Manitoba Hydro operational staff. Gannett Fleming notes that a significant amount of review of life characteristics has been undertaken by the MH operational staff over the past 18 month period. During the operational interviews the Manitoba Hydro operational staff was able to provide empirical evidence that the results of the life study were resulting in life estimates that were too short for the plant currently in service. Gannett Fleming feels that it is prudent at this time to place greater relevance on the comments of the MH operational staff than on the results of the mortality study for these two accounts. Based on these factors, Gannett Fleming viewed that the use of a life estimate no longer than the longest of the peer group was appropriate.

PUB/MH I-83

Reference: Appendix 5.7 (P. 5 through P. 10)

a) Pointe Du Bois
Please provide detailed explanation and correlation of Depreciation Rates effective 2011 and 2013 with the main 2007 categories (civil, turbines and generations, accessory station equipment, other).

ANSWER:

The depreciable groups and rates effective April 1, 2007 are those reflected in the 2005 Depreciation Study, which has been filed as an attachment to the response to MIPUG/MH I-15(g). The rates were calculated by Gannett Fleming based on electrical plant in service as at March 31, 2005, using the ASL Procedure with an expected retirement year 2015.

The depreciable groups and rates effective April 1, 2011 and April 1, 2013 are those reflected in the attachments to the referenced document Appendix 5.7. The depreciable groups reflect the component changes implemented for the 2010 depreciation studies. The depreciation rates were calculated by Gannett Fleming based on electrical plant in service as at March 31, 2010, using an expected retirement year of 2017 for the existing spillway and 2031 for all other existing depreciable components. The depreciation rates effective March 31, 2011 are the rates calculated by Gannett Fleming using the ASL Procedure, as shown in Appendix 5.7 in Schedule 1 to the letter dated January 13, 2012. The depreciation rates effective March 31, 2013 are the rates calculated by Gannett Fleming using the ELG Procedure, as shown in Appendix 5.7 in Schedule 1 to the 2010 Depreciation Study.

The following table shows the relationship between the 2005 and 2010 components, and includes the survivor curve assumptions used in each depreciation study. Within each section in the table, the 2005 depreciable group was the primary source for the corresponding 2010 depreciable groups. Depreciation rates were not developed for the Spillway – New or the Licence Renewal components in the 2005 Depreciation Study.

2005 Depreciation Study			2010 Depreciation Study			
Depreciable Group	**Estimated Survivor Curve**	**Effective April 1, 2007 (ASL)**	**Depreciable Group**	**Estimated Survivor Curve**	**Effective April 1, 2011 (ASL)**	**Effective April 1, 2013 (ELG)**
POINTE DU BOIS			**POINTE DU BOIS**			
Terminal Year 2015			Terminal Year 2031 (exceptions indicated)			
Civil	100-R3	11.75	Dams, Dykes & Weirs	125-R4	3.68	3.16
			Powerhouse	125-R4	4.41	3.91
			Powerhouse Renovations	25-SQ	5.24	4.84
			Spillway - Original (Terminal Date 2017)	75-R2	10.76	8.41
			Water Control Systems	50-S4	3.35	2.81
Turbines and Generators	65-R4	11.59	Turbines & Generators	65-S3	4.04	3.53
			Governors & Excitation System	50-R4	5.24	5.04
Accessory Station Equipment	50-R3	11.48	A/C Electrical Power Systems	50-R3	4.58	4.16
			Instrumentation, Control & D/C Systems	23-L2	5.12	5.14
			Auxiliary Station Processes	40-R2.5	4.03	3.68
Other	50-R1.5	11.46	Support Buildings	65-R3	2.93	2.41
			Support Building Renovations	20-SQ	5.50	5.00
			Roads & Site Improvements	50-R3	3.36	2.87
			Spillway - New (No terminal date identified)	75-R2	1.47	1.33
			Licence Renewal	50-SQ	4.76	4.76

PUB/MH I-83

Reference: Appendix 5.7 (P. 5 through P. 10)

b) Jenpeg
Please explain 2011 and 2013 Depreciation Rates (relative to 2007) with respect to Powerhouse renovations, spillway water control systems and in particular the turbine modifications in 2011.

ANSWER:

The depreciable groups and rates effective April 1, 2007 are those reflected in the 2005 Depreciation Study, which has been filed as an attachment to the response to MIPUG/MH I-15(g). The rates were calculated by Gannett Fleming based on electrical plant in service as at March 31, 2005, using the ASL Procedure with an expected retirement year 2078.

The depreciable groups and rates effective April 1, 2011 and April 1, 2013 are those reflected in the attachments to the referenced document Appendix 5.7. The depreciable groups reflect the component changes implemented for the 2010 depreciation studies. The depreciation rates were calculated by Gannett Fleming based on electrical plant in service as at March 31, 2010, using an expected retirement year of 2118. The depreciation rates effective March 31, 2011 are the rates calculated by Gannett Fleming using the ASL Procedure, as shown in Appendix 5.7 in Schedule 1 to the letter dated January 13, 2012. The depreciation rates effective March 31, 2013 are the rates calculated by Gannett Fleming using the ELG Procedure, as shown in Appendix 5.7 in Schedule 1 to the 2010 Depreciation Study.

During the execution of the 2010 depreciation study, the turbine modifications identified in the question were not yet complete, and as such, asset additions and retirements associated with that project were not included in data set for the 2010 Depreciation Study. The turbine work underway at Jenpeg was discussed with Gannett Fleming, and factored into the selection of the 65-S3 survivor curve for Hydraulic Generation Turbines and Generators.

For the 2005 depreciation study, costs relating to powerhouse renovations and spillway water control systems were included in the Civil depreciable group. For the 2010 depreciation study, the former “Civil” depreciable group was componentized into a number of new depreciable groups as shown in the following table:

2005 Depreciation Study			2010 Depreciation Study			
Depreciable Group	**Estimated Survivor Curve**	**Effective April 1, 2007 (ASL)**	**Depreciable Group**	**Estimated Survivor Curve**	**Effective April 1, 2011 (ASL)**	**Effective April 1, 2013 (ELG)**
JENPEG			**JENPEG**			
Terminal Year 2078			Terminal Year 2118			
Civil	100-R3	1.25	Dams, Dykes & Weirs	125-R4	3.47	3.02
			Powerhouse	125-R4	4.25	3.80
			Powerhouse Renovations	25-SQ	5.00	4.55
			Spillway	75-R2	3.88	3.49
			Water Control Systems	50-S4	3.84	3.39
Turbines and Generators	65-R3	1.66	Turbines & Generators	65-S3	4.49	4.04
			Governors & Excitation System	50-R4	4.70	4.26
Accessory Station Equipment	50-R3	1.93	A/C Electrical Power Systems	50-R3	4.08	3.70
			Instrumentation, Control & D/C Systems	23-L2	7.23	7.30
			Auxiliary Station Processes	40-R2.5	4.30	4.03
Other	50-R1.5	1.58	Support Buildings	65-R3	3.75	3.34
			Support Building Renovations	20-SQ	5.50	5.00
			Roads & Site Improvements	50-R3	4.01	3.63
			Licence Renewal	50-SQ	4.55	4.55

PUB/MH I-83

Reference: Appendix 5.7 (P. 5 through P. 10)

d) Brandon Units 6 and 7
Please explain in terms of the $ magnitude the change in combustion turbine overhauls in Depreciation Rates from 2007 to 2011 and 2013.

ANSWER:

The depreciable groups and rates effective April 1, 2007 are those reflected in the 2005 Depreciation Study, which has been filed as an attachment to the response to MIPUG/MH I-15(g). The rates were calculated by Gannett Fleming based on electrical plant in service as at March 31, 2005.

The depreciable groups and rates effective April 1, 2011 and April 1, 2013 are those reflected in the attachments to the referenced document Appendix 5.7. The depreciable groups reflect the component changes implemented for the 2010 depreciation studies. The depreciation rates were calculated by Gannett Fleming based on electrical plant in service as at March 31, 2010. The depreciation rates effective March 31, 2011 are the rates calculated by Gannett Fleming using the ASL Procedure, as shown in Appendix 5.7 in Schedule 1 to the letter dated January 13, 2012. The depreciation rates effective March 31, 2013 are the rates calculated by Gannett Fleming using the ELG Procedure, as shown in Appendix 5.7 in Schedule 1 to the 2010 Depreciation Study.

For the Thermal Generation – Brandon Units 6 & 7 asset category, in the 2005 Depreciation Study, all costs associated with the Brandon Units 6 & 7 generating station were included in a single account, “Brandon Combustion Turbine” for depreciation purposes. The 2005 depreciation study did not include a “Combustion Turbine Overhauls” account. For the 2010 depreciation study, the assets for the Brandon Unit 6 & 7 generating station were examined and componentized into a number of new depreciable groups, consistent with the approach taken for other generating stations.

Please refer to the following table for quantification of the impacts of the referenced depreciation rate changes:

Depreciable Group	Surviving Original Cost at March 31, 2010 ($ thousands)	Rates Effective April 1, 2007 % (ASL)	Depreciation Expense [1] ($ thousands)	Rates Effective April 1, 2011 % (ASL)	Depreciation Expense [1] ($ thousands)	Impact of Rate Changes [2] ($ thousands)	Rates Effective April 1, 2013 % (ELG)	Depreciation Expense [1] ($ thousands)	Impact of Rate Changes [2] ($ thousands)
BRANDON UNIT 6 & 7									
Powerhouse	14,925	4.40	657	1.65	246	(411)	1.57	235	(11)
Powerhouse Renovations		4.40	-	4.40	-	-	4.00	-	-
Thermal Turbines And Generators	9,824	4.40	432	2.12	208	(224)	2.04	201	(8)
Governors And Excitation System		4.40	-	2.20	-	-	2.00	-	-
Combustion Turbine	143,284	4.40	6,304	4.05	5,810	(494)	3.99	5,718	(93)
Licence Renewal		4.40	-	2.00	-	-	2.00	-	-
Combustion Turbine Overhauls		4.40	-	11.00	-	-	10.00	-	-
A/C Electrical Power Systems	6,253	4.40	275	2.12	133	(142)	2.17	136	3
Instrumentation, Control And D/C Systems	1,114	4.40	49	4.58	51	2	5.20	58	7
Auxiliary Station Processes	10,639	4.40	468	2.64	280	(188)	2.80	298	17
Brandon Units 6 and 7	**186,039**		**8,186**		**6,729**	**(1,457)**		**6,645**	**(84)**

[1] Depreciation Expense shown is calculated for surviving original cost at March 31, 2010. No provision has been made for ongoing asset additions and retirements.

[2] Impact of Rate Changes shown is calculated for surviving original cost at March 31, 2010. No provision has been made for ongoing asset additions and retirements.

PUB/MH I-84

Reference: Appendix 5.7 Page II-26 – II-29, Average Service Life Estimates

a) Please articulate the expectations of operational staff that led to the determination of extending the service lives of Dams, Dykes and Weirs.

ANSWER:

The Dams, Dykes and Weirs component of hydraulic generating stations was assigned an average service life of 125 years in the most recent depreciation study, as compared with the life of 100 years which was assigned to the Civil component in the prior (2005) depreciation study, which included Dams, Dykes and Weirs.

In discussion with MH Operational and Engineering staff, it was determined that the Dams, Dykes and Weirs at the Manitoba Hydro Generating stations are generally in very good to excellent condition, and provided that maintenance activities continue, it would not be unreasonable to expect these structures to last, on average, well in excess of the 140 years, which has been used as the theoretical overall life expectancy of the hydraulic generating stations. However, since the economic benefit related to these structures is tied to the productive capabilities of the generating stations, for depreciation purposes, the average service life has been matched to the 125 year average service life assigned to the Powerhouse component.

PUB/MH I-84

Reference: Appendix 5.7 Page II-26 – II-29, Average Service Life Estimates

b) Please provide the average services lives of MH Dams Dykes and Weirs and comparison with the life expectation of Canadian electric generation utilities.

ANSWER:

The following response was provided by Manitoba Hydro and Gannett Fleming.

Manitoba Hydro has assigned an average service life of 125 years to the Dams, Dykes and Weirs component of hydraulic generating stations.

In response to Manitoba Hydro's survey of other Canadian utilities, many of the industry peers indicated use of a 100 year service life estimate. One other utility indicated use of a 125 year service life for their Channel and Waterway Structures component. Manitoba Hydro is not able to identify the utility as this information was provided in confidence.

Gannett Fleming confirms that the above indications of most utilities using a 100 year life estimate for these assets is consistent with the experience of Gannett Fleming for regulated Canadian electric generation utilities.

PUB/MH I-84

Reference: Appendix 5.7 Page II-26 – II-29, Average Service Life Estimates

c) Please explain why the hydraulic generation powerhouses are being matched to the estimated retirement rate of the Dams, Dykes and Weirs.

ANSWER:

Manitoba Hydro assigned an average service life of 125 years to the hydraulic generation Powerhouse component.

The 125 year component average service life was developed by Gannett Fleming in consideration of the overall generating station expected life span of 140 years and the expected level of interim retirement activity for the component.

The average service life for the Dams Dykes and Weirs component was matched to the average service life for the Powerhouse component as the Powerhouse is generally considered to be the life constraining factor for hydraulic generating stations.

PUB/MH I-84

Reference: Appendix 5.7 Page II-26 – II-29, Average Service Life Estimates

d) Please file the retirement analysis section IV.

ANSWER:

The following response was prepared by Gannett Fleming.

Please see Appendix 16.

PUB/MH I-84

Reference: Appendix 5.7 Page II-26 – II-29, Average Service Life Estimates

e) Please provide the supporting rational for extending the economic service lives hydraulic generation plants from 100 years to 140 years.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-82(c).

PUB/MH I-84

Reference: Appendix 5.7 Page II-26 – II-29, Average Service Life Estimates

f) Please explain why and how the economic life of generation plants of Point du Bois, Grand Rapids and Laurie River were modified. What are the implications on depreciation expense related to the changes?

ANSWER:

The following response was provided by Manitoba Hydro and Gannett Fleming.

Please refer to PUB/MH I-82(c) for a discussion of the rational for modifying the overall life span of the Pointe du Bois, Grand Rapids and Laurie River generating stations from the revised general assumption of an overall expected life span of 140 years for hydraulic generating facilities.

In the case of Pointe du Bois, for depreciation study purposes, the overall expected life has been set to coincide with capital plans related to the rebuild of the Pointe du Bois powerhouse. With plans in place to rebuild this facility, it would not be appropriate to adopt the generic 140 year expected life assumption for depreciation purposes.

The use of a shorter life span on these three plants results in a increase in the depreciation expense specific to these plants as compared to the depreciation expense that would have resulted from the use of a 140 year life span date. However, this increase has been partially offset by the fact that both of the Pointe Du Bois and the Grand Rapids stations have a surplus of booked accumulated depreciation balances, the true-up of the surplus would have been amortized over a longer period with the use of a 140 year life span date.

PUB/MH I-85

Reference: **Appendix 5.7 Page 1&2, Depreciation Rates**

Preamble: **Gannet Flemming states that the requirements and implementation of IFRS are generally aligned with the appropriate and reasonable depreciation practices and procedures commonly used for regulatory purposes.**

a) **Please indicate the depreciation methodology employed in other Canadian jurisdictions and in particular where Equal Life Group (ELG) has adopted for rate-setting purposes.**

ANSWER:

The following response was prepared by Gannett Fleming.

Please refer to the attachment document which provides a detailed listing the utilities throughout North America that are currently using the ELG procedure. Virtually all other utilities not on the attached list would be using the ASL procedure or would not yet have received authorization from their regulator to use the ELG procedure:

DETAILED LIST OF UTILITIES THROUGHOUT NORTH AMERICA USING ELG PROCEDURE

Company Name	Approved by:
Allegheny Energy Supply, Inc.	Gannett Fleming cannot confirm that ELG has been approved
AltaGas Utilities Inc.	Alberta Utilities Commission
ATCO Gas	Alberta Utilities Commission
ATCO Electric	Alberta Utilities Commission
CenterPoint Energy - General (Oklahoma)	Oklahoma Corporation Commission Public Utility Division
CenterPoint Energy Arkansas	Arkansas Public Service Commission
CenterPoint Energy Arkla - General	Louisiana Public Service Commission
CenterPoint Energy Arkla - Services	Louisiana Public Service Commission
CenterPoint Energy Arkla Louisiana	Louisiana Public Service Commission
CenterPoint Energy Entex - Texas Division	Public Utility Commission of Texas
CenterPoint Energy Oklahoma	Oklahoma Corporation Commission Public Utility Division
Citizens Energy Group	Gannett Fleming can not confirm that ELG has been approved
Columbia Gas of Kentucky	Kentucky Public Service Commission
Duke Energy Indiana	Indiana Utility Regulatory Commission
Duke Energy Kentucky	Kentucky Public Service Commission
East Kentucky Power Cooperative	Kentucky Public Service Commission
Enmax Power Corporation	Alberta Utilities Commission
Entergy Arkansas, Inc.	Arkansas Public Service Commission
Entergy Gulf States Louisiana, LLC.	Louisiana Public Service Commission
Entergy Louisiana, LLC.	Louisiana Public Service Commission
Entergy Mississippi, Inc.	Mississippi Public Service Commission
Entergy Texas, Inc.	Public Utility Commission of Texas
FortisAlberta Utilities, Inc.	Alberta Utilities Commission
Kentucky Utilities	Kentucky Public Service Commission
Kokomo Gas and Fuel Company	Indiana Utility Regulatory Commission
Louisville Gas & Electric	Kentucky Public Service Commission
Newfoundland Power Limited	Newfoundland and Labrador Board of Commissioners of Public Utilities
Northern Indiana Fuel and Light Company Inc.	Indiana Utility Regulatory Commission
Northern Indiana Public Service Company	Indiana Utility Regulatory Commission
Northland Utilities (NWT) Limited	Northwest Territories Public Utilities Board

Company Name	Approved by:
Northland Utilities (Yellowknife) Limited	Northwest Territories Public Utilities Board
Nova Scotia Power, Inc.	Nova Scotia Utility and Review Board
Public Service Company of Colorado	Colorado Public Utilities Commission
Quilliq Power Corporation	Nunavut Utility Rates Review Council
UGI Penn Natural Gas, Inc.	Pennsylvania Public Utilities Commission
UGI Utilities, Inc. - Electric Division	Pennsylvania Public Utilities Commission
Union Light Heat and Power Co.	Kentucky Public Service Commission

PUB/MH I-85

Reference: **Appendix 5.7 Page 1&2, Depreciation Rates**

Preamble: **Gannet Flemming states that the requirements and implementation of IFRS are generally aligned with the appropriate and reasonable depreciation practices and procedures commonly used for regulatory purposes.**

b) **Please illustrate how the use of the ASL method of depreciation versus ELG proposed in the application will impact revenue requirement in 2013/14, 2014/15 and 2015/16.**

ANSWER:

The use of the ASL method of depreciation versus ELG method of depreciation would decrease the depreciation expenses and resulting revenue requirement in 2013/14, 2014/15 and 2015/16 as follows:

	Depreciation Expense ($ 000's)		
MH11-2	**2014**	**2015**	**2016**
Use of ASL vs ELG	(32,307)	(33,315)	(35,078)

PUB/MH I-85

Reference: **Appendix 5.7 Page 1&2, Depreciation Rates**

Preamble: **Gannet Flemming states that the requirements and implementation of IFRS are generally aligned with the appropriate and reasonable depreciation practices and procedures commonly used for regulatory purposes.**

c) **Please provide the composite weighted average rate by Class under the ASL versus ELG methodology.**

ANSWER:

Please refer to the following table:

Class	ASL [1] RATE (%)	ELG [2] RATE (%)
Generation		
Hydraulic Generation	1.48	1.40
Thermal Generation	3.44	3.45
Diesel Generation	2.42	2.39
Transmission	1.71	1.38
Substations	3.16	2.82
Distribution		
Distribution Lines [3]	2.41	2.00
Meters	8.88	9.99
Other		
Communication	5.90	6.49
Motor Vehicles	5.96	6.98
Buildings	2.03	2.14
General Equipment	14.28	14.28
Easements	1.28	1.49
Computer Software and Development	10.57	11.17
Depreciable Assets	**2.59**	**2.44**

[1] Appendix 5.7/Gannett Fleming Schedule 1 - Use of the ASL Methodology: Pages 1-8

[2] Appendix 5.7/Gannett Fleming Schedule 1: Pages III-4 - III-11

[3] Includes Sub-transmission Lines

PUB/MH I-85

Reference: **Appendix 5.7 Page 1&2, Depreciation Rates**

Preamble: **Gannet Flemming states that the requirements and implementation of IFRS are generally aligned with the appropriate and reasonable depreciation practices and procedures commonly used for regulatory purposes.**

d) Please indicate whether ASL is a methodology that can be used under IFRS.

ANSWER:

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

PUB/MH I-86

Reference: Appendix 5.5 page 25 PP&E Componentization

MH indicates that it has determined that further componentization is required for generation and distribution assets. Has MH's consultant provided advice on this additional componentization in its filed report or is additional work required. If so, please file.

ANSWER:

The further componentization indicated in Appendix 5.5, page 25, PP&E Componentization has been reflected in Appendix 5.7 - Depreciation Study, and was implemented effective March 31, 2011. Manitoba Hydro is not contemplating any further componentization of its plant at this point in time. As operational changes occur over time, the components will be reviewed to ensure they remain appropriate.

PUB/MH I-87

Reference: Appendix 5.7/Gannett Fleming (Part III Schedule I – P. 1 to 19)

Please provide summary table showing the following components:

Remaining (Years)	Original Asset Value ($M)	Surviving Original Cost to Mar/ 31/10 ($M)	F2010 ($M)	F2011 ($M)	F2012 ($M)	Life
Hydraulic Generation						
Thermal Generation						
HVDC Transmission						
Other Transmission						
Distribution						
Other						
Total System						

ANSWER:

The following table provides a summary of the information contained in the reference document Appendix 5.7/Gannett Fleming (Part III Schedule I – P. 1 to 19) with original asset values analyzed as part of the depreciation study.

Asset Category	Original Asset Value [1] ($ millions)	Surviving Original Cost to Mar/31/10 ($ millions)	Calculated Annual Depreciation Expense [2] ($millions)	Weighted Average Remaining Life (Years)
Hydraulic Generation	$ 4 752	$ 4 716	$ 66	59
Thermal Generation	481	431	15	21
Diesel Generation	49	45	1	16
Transmission	763	756	10	50
Stations	2 320	2 447	69	23
Distribution [3]	2 830	2 426	52	35
Other	1 611	1 247	81	29
Total System	$ 12 806	$ 12 068	$ 294	42

[1] Represents original asset costs analyzed during the depreciation study.
[2] As shown in the referenced depreciation study.
[3] Includes Distribution Lines and Meters.

The depreciation expense shown in the study was calculated at a point in time for surviving assets as at March 31, 2010 and does not include any provision for ongoing asset activity such as additions and retirements. Please refer to PUB/MH I-81(a) for a breakdown of actual depreciation costs for the 2010-2012 fiscal years.

PUB/MH I-88

Reference: Appendix 5.7 (P. 1 to 10)

Please quantify the new Depreciation Study impacts of the following items on Annual Depreciation Expenses:

	F2010 ($M)	F2011 ($M)	F2012 ($M)	F2013 ($M)	F2014 ($M)	F2015 ($M)
Hydraulic Generation						
- **Service Life Extension**						
- **Removal of Retirement Costs**						
- **Change of ELG Methodology**						
Thermal						
- **Service Life Extension**						
- **Removal of Retirement Costs**						
- **Change of ELG Methodology**						
HVDC Transmission						
- **Service Life Extension**						
- **Removal of Retirement Costs**						
- **Change to ELG Methodology**						
Other Transmission						
-						
Distribution						
-						
Total System						

<u>ANSWER</u>:

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

PUB/MH I-89

Reference: Updated CEF forecast

Please file CEF12.

ANSWER:

CEF12 will not be available for filing until after it is approved by the Manitoba Hydro-Electric Board, which is expected in late November 2012.

PUB/MH I-90

Reference: **CEF11 Major G&T Projects/ Appendix 3.1 Corporate Strategic Plan maintain corporate financial strength**

a) Please file copies of all Major G&T most recent Capital Project Justifications.

ANSWER:

Tab 6 of Manitoba Hydro's Application summarizes the Capital Expenditure Forecast (CEF11), a copy of which is included as Appendix 6.1. The CEF provides the description of the major generation and transmission projects to be undertaken, and the justification for the projects.

PUB/MH I-90

Reference: CEF11 Major G&T Projects/ Appendix 3.1 Corporate Strategic Plan maintain corporate financial strength

b) Please explain the Corporation determines and prioritizes which projects can be displaced to retain spending within overall approved CEF limits.

ANSWER:

The Corporation reviews its capital expenditure forecast and individual projects on an ongoing basis. A Capital Project Justification ("CPJ") framework is used to assist staff in summarizing technical, economic and financial information for a project that is being proposed or revised for inclusion in the capital program. Information provided in the CPJ, including business case, risk assessment, resourcing requirements and other pertinent details is reviewed for their requirement and projects are adjusted or deferred as appropriate on the basis of safety, system reliability, customer load growth, environmental sustainability and efficiency of operations. Proposed CPJ's are reviewed and approved by Executive Committee prior to their inclusion in the Capital Expenditure Forecast. Actual expenditures against that forecast are reviewed by Executive Committee on a regular basis.

PUB/MH I-90

Reference: CEF11 Major G&T Projects/ Appendix 3.1 Corporate Strategic Plan maintain corporate financial strength

c) Provide examples of projects that have been displaced.

ANSWER:

The following are examples of projects which have been deferred based on risk analysis and financial constraints.

- Pine Falls Units 1-4 Re-Runnering
- Great Falls Unit 4 Overhaul
- Grand Rapids Transformer Refurbishment
- Neepawa 230-66 kV Station
- Stanley Station 230-66 kV Permanent Bank Addition

Manitoba Hydro's risk assessment considers the consequences of deferral with respect to safety, reliability, load growth, environmental and regulatory requirements. Additional actions may be taken where necessary to mitigate the risk. For example a single phase spare transformer was purchased for the Grand Rapids G.S. to mitigate the risk of failure.

PUB/MH I-91

Reference: CEF11-2/CEF10

Please confirm that MH has indicated:

a) A $100M capital cost increase for Wuskwatim G.S. from the $1.6B indicated in CEF10.

ANSWER:

The capital cost estimate for Wuskwatim GS increased by $100 million from CEF10 to CEF11. Note, however, that the total of $1.6 billion includes Wuskwatim Transmission in the amount of $297 million.

PUB/MH I-91

Reference: CEF11-2/CEF10

Please confirm that MH has indicated:

b) No increase in capital costs for Keeyask G.S. from the $5.2B indicated in CEF10.

ANSWER:

CEF11-2 does not include any increase in the capital cost estimate for Keeyask GS compared to CEF10.

PUB/MH I-91

Reference: CEF11-2/CEF10

Please confirm that MH has indicated:

c) No increase in capital costs for Conawapa G.S. from the $7.6B indicated in CEF10.

ANSWER:

CEF11-2 does not include any increase in the capital cost estimate for Conawapa GS compared to CEF10.

PUB/MH I-91

Reference: CEF11-2/CEF10

Please confirm that MH has indicated:

d) No increase in capital costs for Pointe Du Bois G.S. Powerhouse and Spillway from $1.6B indicated in CEF10.

ANSWER:

There were no capital cost increases for Pointe Du Bois GS Powerhouse Rebuild from $1.538B, or for the Pointe Du Bois Spillway Replacement from $398M.

PUB/MH I-91

Reference: CEF11-2/CEF10

Please confirm that MH has indicated:

e) No increase in capital costs for Bipole III Transmission Lines/Converter Stations/Collector Lines from $3.2B indicated in CEF10.

ANSWER:

Confirmed.

PUB/MH I-92

Reference: CEF11-2/CEF09

a) A $100M capital cost increase for Wuskwatim G.S. from the $1.6B indicated in CEF09/CEF08.

ANSWER:

The Wuskwatim GS capital cost estimates increased $100M from $1.274B in CEF09 and CEF08.

PUB/MH I-92

Reference: CEF11-2/CEF09

b) A $1.0B increase in capital costs for Keeyask G.S. from the $4.6B indicated in CEF09/CEF08.

ANSWER:

Confirmed.

PUB/MH I-92

Reference: CEF11-2/CEF09

c) A $1.5B increase in capital costs for Conawapa from the $6.3B indicated in CEF09/CEF08.

ANSWER:

Confirmed.

PUB/MH I-92

Reference: CEF11-2/CEF09

d) A $1.0B increase in capital costs for Pointe Du Bois G.S. indicated in CEF09 over CEF08.

ANSWER:

From CEF08 to CEF09, Pointe du Bois G.S. changed in scope from a powerhouse and spillway modernization project to the spillway replacement project and decreased $0.5 billion. From CEF09 to CEF10, the spillway project increased $80 million. Also in CEF10, the powerhouse rebuild project was reintroduced to the forecast at a projected cost of $1.5 billion. There were no further increases to either the spillway or powerhouse rebuild projects in CEF11.

PUB/MH I-92

Reference: CEF11-2/CEF09

e) A $1.0B increase in capital costs for Bipole III Transmission Lines/Converter Stations/Collector Lines from $2.25B indicated in CEF09/CEF08.

ANSWER:

Confirmed.

PUB/MH I-93

Reference: Tab 6 CEF11-2, PUB/MH I-56 (2010 GRA)

a) Please provide an update to the following table (updates of PUB/MH I-56 - 2010 GRA) of CEF progression of major G&T projects CEF03 to CEF11.

Progression of Project Costs in $ M										
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09	CEF 10	CEF 11	CEF 12
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275			
Wuskwatim Transmission		199	200	257	320	316	316			
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591			
Herblet Lake Transmission	57	55	54	54	95	93	93			
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248			
Riel C.S.	96	101	103	103	105	268	268			
Kelsey G.S.	121	121	166	166	184	190	190			
Kettle G.S.		61	61	61	61	76	76			
Pointe du Bois	421	288	692	834	818	818	318			
Pointe du Bois Trans.					83	86	86			
Slave Falls G.S.				179	192	198	198			
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325			
Keeyask G.S.						3,700	4,592			
500 KV Dorsey U.S. Border						205	205			
Generation Station Improvements and Upgrades										

ANSWER:

Progression of Project Costs in $ M									
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09	CEF-10	CEF-11
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275	1,275	1,375
Wuskwatim Transmission		199	200	257	320	316	316	291	298
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591	1,566	1,673
Herblet Lake Transmission	57	55	54	54	95	93	93	75	75
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248	3,280	3,280
Riel C.S.	96	101	103	103	105	268	268	268	268
Kelsey G.S.	121	121	166	166	184	190	190	302	302
Kettle G.S.		61	61	61	61	76	76	166	166
Pointe du Bois Improvements and Upgrades	421	288	692	834	818	818			
Pointe du Bois Spillway							318	398	398
Pointe du Bois Trans.					83	86	86	86	86
Pointe du Bois Rebuild								1,538	1,538
Slave Falls G.S.				179	192	198	198	223	230
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325	7,771	7,771
Keeyask G.S.						3,700	4,592	5,637	5,637
500 KV Dorsey U.S. Border						205	205	205	205

PUB/MH I-93

Reference: Tab 6 CEF11-2, PUB/MH I-56 (2010 GRA)

b) Please explain the addition of the $649M Generation Station Improvements and Upgrades to major new G&T Project List in CEF11 (when there was no such item in the first 10 years of CEF10 for either major new generation or power supply).

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-96(a).

PUB/MH I-93

Reference: Tab 6 CEF11-2, PUB/MH I-56 (2010 GRA)

c) Please provide the appropriate sections from MH's Asset Condition Assessment and/or Life Expectancy Reports to support the above and other additional capital expenditures.

ANSWER:

Projects identified in the Capital Expenditure Forecast (CEF) have always been based on an assessment of asset condition (together with the criteria of safety, reliability, efficiency and environmental management). In recent years, tools have been developed or are in the process of being developed, to increase the sophistication and accuracy for assessing asset condition.

PUB/MH I-94

Reference: CEF112/CEF10

a) Please provide an overview of MH's HVDC Bipole I and II 20 year project expenditures summarizing the costs as follows:

	CEF9	CEF10	CEF11
Converter Station Costs			
Transmission Line Costs			
Collector System Costs			
Dorsey Station Costs			

ANSWER:

Please see the following schedule:

	CEF09	CEF10	CEF11
Converter Station Costs*	259	243	1,202

*Dorsey Station is a Converter Station and is included in Converter Station Costs.

PUB/MH I-94

Reference: CEF112/CEF10

b) Please confirm that these costs reflect normally anticipated life extension expenditures for HVDC facilities where converter stations (particularly) have about a 40-year life expectancy.

ANSWER:

Manitoba Hydro cannot determine the source of the 40 year life expectancy stated in the question. The components within HVDC converter station facilities are depreciated over average service lives ranging from 15 to 65 years. The capital costs included in CEF11-2 reflect the planned construction of the two new HVDC converter stations required for operation of Bipole III, and normally anticipated expenditures for on-going replacement and refurbishment of individual pieces of equipment at the existing HVDC facilities.

PUB/MH I-94 (Revised)

Reference: CEF112/CEF10

c) Please explain why MH does not treat these $1.0B plus expenditures as a major G&T project (similar to generation station improvements and upgrades at $649M).

ANSWER:

By definition HVDC items fall under Base Capital because the projects extend the life of the HVDC system, however do not add new generation or increased capacity. The Bipole I and II converter station costs included in Power Supply's base capital is a general provision for rehabilitation work on converter stations which do not increase generation capability.

Generating Station Improvements and Upgrades under New Major G&T is a general provision for overhauls on the northern generating stations which increase capacity and/or generation. For long-term forecast purposes, general provisions are made to reflect expenditures that may be necessary to maintain the existing generating station, transmission and distribution systems but for which detailed planning and engineering has not been completed nor received specific project approval. As specific projects are identified and approved, the general provisions will be reduced.

PUB/MH I-94

Reference: CEF112/CEF10

d) Please file the CPJ's for these items.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-90(a).

PUB/MH I-95

Reference: CEF11-2

a) Please confirm that MH has identified Capital Project Expenditures in CEF11-2 for 2.1 year electric utility total of:

	Projects As Listed	Target Adjustments	Net
Major New G&T	**$19.9B**	**$0.3B**	**$19.6B**
Power Supply	**$3.05B**	**$0.35B**	**$ 2.7B**
Transmission	**$ 2.2B**	**$0.05B**	**$2.15B**
Customer Service And Distribution	**$ 4.4B**	**$0.25B**	**$4.15B**
Finance and Administration	**$ 1.2B**	**$0.05B**	**$1.15B**
Total	**$30.9B**	**$1.0B**	**$29.9B**

ANSWER:

The table below summarizes MH's electric Capital Project Expenditures in CEF11-2:

Capital Project Expenditures
CEF 11-2
$ in Billions

	Projects As Listed	Target Adjustments	Net
Major New Generation & Transmission	19.930	0.317	19.613
Power Supply	3.029	0.336	2.694
Transmission	2.186	0.042	2.144
Customer Service & Distribution	4.408	0.257	4.151
Customer Care & Marketing	0.120	0.022	0.098
Finance & Administration	1.186	0.020	1.166
Total	**30.859**	**0.995**	**29.865**

PUB/MH I-95

Reference: CEF11-2

b) Please explain how target adjustments are employed in MH's annual budgetary process.

ANSWER:

Target adjustments are used to maintain bottom-line approved Forecast totals from the date that the CEF is approved by the Manitoba Hydro Board (normally in the fall of each year) until the Forecast is next presented to the Manitoba Hydro Board for approval. Between Board approval dates, CPJ's that are approved by Executive Committee increase or decrease the target adjustment in order to maintain the same bottom-line approved CEF until re-presented to the Board for approval.

Target adjustments are also used to facilitate the achievement of financial targets at the Corporate level. Capital project estimates are based on known conditions with assumptions on resource availability, delivery schedules for material, weather and soil conditions etc. Contingencies are also included in project estimates to provide for unforeseen events which typically results in an overall under-expenditure in the Capital Expenditure Forecast. Recognizing this, management develops target adjustments for each Business Unit which typically reduces the overall Capital Expenditure Forecast (target adjustments may also increase the CEF). While the establishment of target adjustments involves a degree of judgment, it does impose additional rigor in the management of capital expenditures and requires continuous review of highest priority projects by line management.

PUB/MH I-96

Reference: CEF11-2/CEF10 – Power Supply

a) Please explain the difference between the $385M Generation South Overhauls and Improvements in the power resource section and the $649M item for Generation Station Improvements and Upgrades shown under new major G&T in CEF11.

ANSWER:

Generation South Overhauls and Improvements included in Power Supply's base capital is a general provision for rehabilitation work on the southern generating stations which do not increase generation capability. Generating Station Improvements and Upgrades under New Major G&T is a general provision for overhauls on the northern generating stations which increase capacity and/or generation. For long-term forecast purposes, general provisions are made to reflect expenditures that may be necessary to maintain the existing generating station, transmission and distribution systems but for which detailed planning and engineering has not been completed nor received specific project approval. As specific projects are identified and approved, the general provisions will be reduced.

PUB/MH I-96

Reference: CEF11-2/CEF10 – Power Supply

b) Please describe the components of this item, which were additional to CEF10 (10 year) forecast.

ANSWER:

There were no additional components to Generation South Overhauls and Improvements under Power Supply or Generation Station Improvements and Upgrades under MNG&T between CEF10-2 and CEF11-2. An additional year of cash flow was added to Generation Station Improvements and Upgrades under CEF11-2.

PUB/MH I-96

Reference: CEF11-2/CEF10 – Power Supply

c) Please provide the in-service dates and capital cost for Bipoles II and I.

ANSWER:

The date of first power for Bipole I and II transmission facilities was May 1971. The transmission lines and intermediary equipment and structures were constructed by Atomic Energy of Canada Limited (AECL) at a cost of approximately $150 million. Manitoba Hydro began making lease payments on these facilities in 1974 to the Government of Canada and was responsible for the operations and maintenance of these facilities until September 30, 1991 at which time Manitoba Hydro bought out the lease obligation for $198.1 million.

PUB/MH I-96

Reference: CEF11-2/CEF10 – Power Supply

d) Please provide the cumulative capital expenditures separately for Bipoles I and II.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-96(c).

PUB/MH I-97

Reference: In-Service Dates

Major Project	**In-Service Date**	
	CEF 09-1	**CEF 08-1**
Wuskwatim G.S.	**September 2011**	**September 2011**
Wuskwatim Transmission	**September 2011**	**September 2011**
Keeyask G.S.	**December 2018**	**December 2018**
Conawapa G.S.	**May 2022**	**May 2022**
Bipole West Route	**October 2017**	**October 2017**
Pointe du Bois Rebuild	**May 2014**	**October 2022**
Slave Falls G.S. Upgrade	**December 2017**	**December 2017**

a) Please provide an updated to the above table for the in service dates reflecting CEF10, CEF11 and CEF12.

ANSWER:

Please see the following table.

Major Project	**In-Service Date**			
	CEF08	**CEF09**	**CEF10**	**CEF11**
Wuskwatim G.S.	September 2011	September 2011	September 2011	March 2012
Wuskwatim Transmission	September 2011	September 2011	September 2011	March 2012
Keeyask G.S.	December 2018	December 2018	November 2019	November 2019
Conawapa G.S.	May 2022	May 2022	May 2023	May 2024
Bipole III	October 2017	October 2017	October 2017	October 2017
Pointe du Bois Improvement & Upgrades	October 2014	-	-	-
Pointe du Bois Spillway	-	October 2014	November 2014	November 2014
Pointe du Bois Rebuild	-	-	May 2030	May 2030
Slave Falls G.S. Upgrade	December 2017	December 2017	March 2019	March 2019

PUB/MH I-98

Reference: 2010 GRA PUB/MH I-56 Revenue Requirement Impacts of Major G&T

Please provide a schedule of all major capital projects expenditures from 2003/04 to date. This schedule should include the history of each Major G&T project and yearly reflecting:

- **Base capital expenditures**
- **All major capital expenditures**
- **Total capital expenditures**
- **Internally-generated funds total**
- **Internally-generated funds applied to major projects**
- **Debt incurred for major projects**

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH I-22(c) and PUB/MH I-93(a).

PUB/MH I-99 (Revised)

Reference: Mitigation Costs

a) Please provide a schedule 9 in a similar format to PUB/MH II-65 (g) last GRA) detailing and accounting for the total mitigation costs (capitalized) prior to 2005 and the amounts incurred in each year by each project for 2005 to 2014 by major projects

ANSWER:

Please see the following table for expenditures incurred or settlements reached to mitigate the impacts of capital projects for 2004/05 through 2013/14.

Mitigation Capital Spending **(in millions)**

	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Forecast	2014 Forecast
CRD & LWR (NFA)	26.7	14.9	13.7	26.7	20.1	15.2	17.2	44.6	22.5	7.6
CRD & LWR (Non-NFA)	0.6	2.6	3.3	1.4	0.6	1.8	7.5	1.6	5.3	6.6
Grand Rapids	4.1	10.2	0.1	8.4	1.0	8.2	61.8	52.5	2.4	2.4
Winnipeg River	0.1	0.2	0.2	0.3	0.3	0.4	0.6	19.2	0.1	0.0
Waterways Management Program [1]	2.6	3.6	4.3	4.6	4.7	5.0	5.5	5.3	5.5	5.6
	$ 34.1	**$ 31.5**	**$ 21.6**	**$ 41.4**	**$ 26.6**	**$ 30.5**	**$ 92.5**	**$ 123.3**	**$ 35.8**	**$ 22.3**

Notes:
CRD - Churchill River Diversion
LWR - Lake Winnipeg Regulation
NFA - Northern Flood Agreement

Note 1: The Waterways Management Program was reclassified in fiscal 2012 to be included with mitigation capital.

PUB/MH I-99

Reference: Mitigation Costs

b) Please provide a schedule of Provincial mitigation cost obligations assumed by MH.

ANSWER:

Please see the following table for the Provincial mitigation cost obligations for 2007/08 through 2012/13.

Provincial Obligations Paid or to be Paid by Manitoba Hydro (associated with the Water Power Rental Agreement) **(in millions)**

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	* 2013 Forecast
Moose Lake/Grand Rapids Settlement	1.2	-	-	-	-	-
Cross Lake Settlement and Negotiating	0.4	0.4	0.2	-	-	7.5
South Indian Lake Road and Ferry	-	-	-	-	-	-
Continuing NFA Settlement Costs	-	-	-	-	-	1.0
South Indian Lake Water/Sewer	-	-	-	-	-	-
Other South Indian Lake Upgrades	-	-	-	-	-	-
Cross Lake Sewer Treatment Plant	-	-	-	-	-	-
NetNak Bridge - Cross Lake	-	-	-	-	-	-
Fox Lake	-	-	-	-	-	-
War Lake	0.1	0.1	0.1	0.1	0.1	0.6
Cormorant Sewage Treatment Plant	0.4	-	-	-	-	-
Nelson House Water Treatment Plant	-	-	-	-	0.8	-
Labour Market Surveys for Aboriginal Peoples	-	-	-	0.1	0.1	-
Cross Lake Community Fire Hall / Administration Buildings	-	-	-	0.3	-	-
Total Payments	**$ 2.1**	**$ 0.4**	**$ 0.2**	**$ 0.5**	**$ 0.9**	**$ 9.1**

* 2013 forecast reflects payments for total obligation outstanding due to the timing uncertainty of payments.

PUB/MH I-99

Reference: Mitigation Costs

c) Please provide a schedule detailing all consulting fees paid by consultant on major G&T projects for the years 2005 to 2012 and describe the nature of the assignment

ANSWER:

Please see the response to PUB/MH I-10(a) for the consulting fees paid on major new generation and transmission projects. Manitoba Hydro is unable to provide information identifying individual consultants without their consent.

PUB/MH I-100

Reference: **IFF11-2 Page 12, Appendix 6.2 Debt Management Strategy 2011 & 2012 GRA, Tab 2 Page 3 of 5**

a) Please file an updated Debt Management Strategy for 2011/12 and 2012/13.

ANSWER:

Please see the Debt Management Strategy filed in Appendix 17.

PUB/MH I-100

Reference: IFF11-2 Page 12, Appendix 6.2 Debt Management Strategy 2011 & 2012 GRA, Tab 2 Page 3 of 5

b) Please provide the most recent bond/ credit rating agencies report on Manitoba Hydro from DBRS, Moody, and Standards & Poors.

ANSWER:

Please see the credit rating reports filed in Appendix 20.

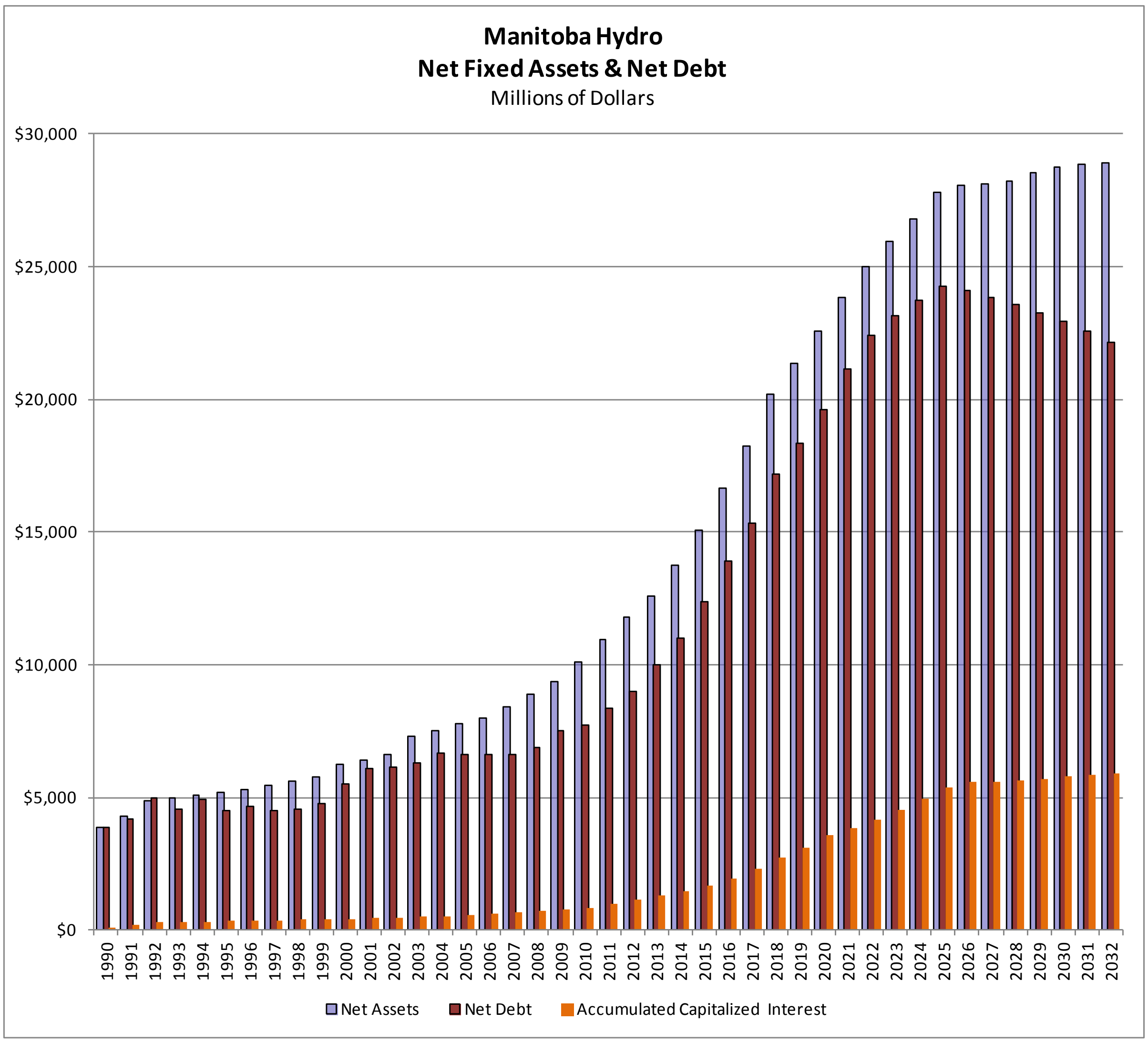
PUB/MH I-101

Reference: Appendix 6.2 Debt Management Strategy 2011 & 2012 GRA

a) Please refile an updated response to PUB/MH I-69 (a) based on IFF11-2 including an updated the graph of Net Fixed Assets & Net Debt for the years 1990 through 2032 identifying the level of accumulated capitalized interest in each year. Please provide a table of corresponding data points.

ANSWER:

The values for the years 1990 to 2012 are based on actuals, and 2013 to 2032 values are based on the forecast IFF11-2 (Consolidated Operations).



The chart illustrates the growth in net fixed assets and net long term debt that has occurred over the past 20 years, as well as the projected growth to 2032. While net debt is expected to grow to approximately $22.2 billion as at March 31, 2032, the corresponding investment in generation, transmission, distribution and other assets is expected to grow to a net book value of approximately $28.9 billion at March 31, 2032.

A table of corresponding data points is as follows:

Year Ending	Net Assets	Capitalized Interest	Accumulated Capitalized Interest	Net Debt
1990	3,882	97	97	3,889
1991	4,267	110	207	4,199
1992	4,857	72	279	4,972
1993	4,983	32	312	4,533
1994	5,067	16	328	4,948
1995	5,170	15	342	4,508
1996	5,310	19	361	4,685
1997	5,464	16	377	4,493
1998	5,608	20	396	4,559
1999	5,774	20	416	4,772
2000	6,235	15	431	5,488
2001	6,428	16	447	6,114
2002	6,626	26	473	6,146
2003	7,305	28	501	6,320
2004	7,536	32	532	6,675
2005	7,776	33	565	6,642
2006	8,010	34	600	6,614
2007	8,415	47	647	6,597
2008	8,912	60	707	6,870
2009	9,382	56	763	7,521
2010	10,128	68	831	7,716
2011	10,954	138	969	8,365
2012	11,797	170	1,139	9,010
2013	12,608	142	1,280	9,984
2014	13,771	178	1,458	11,019
2015	15,056	221	1,679	12,354
2016	16,644	280	1,960	13,905
2017	18,263	365	2,325	15,331
2018	20,204	403	2,727	17,176
2019	21,331	387	3,114	18,358
2020	22,581	447	3,561	19,610
2021	23,830	285	3,846	21,146
2022	24,991	291	4,137	22,392
2023	25,959	378	4,515	23,161
2024	26,816	452	4,967	23,715
2025	27,816	403	5,370	24,255
2026	28,062	203	5,573	24,126
2027	28,113	31	5,604	23,850
2028	28,244	45	5,650	23,566
2029	28,531	68	5,717	23,270
2030	28,761	95	5,812	22,966
2031	28,882	45	5,857	22,562
2032	28,920	47	5,904	22,172

PUB/MH I-101

Reference: Appendix 6.2 Debt Management Strategy 2011 & 2012 GRA

b) Please refile and updated response to PUB/MH I-69 (b) provide a corresponding table of Net Assets, Net Debt, Retained Earnings, Debt to Equity ratio, Capital Coverage ratio, and Interest Coverage ratio of the corresponding year.

ANSWER:

Please see the attached schedule.

Year Ending	Net Assets	Net Debt	Retained Earnings	D/E Ratio	I/C Ratio	C/C Ratio
	Millions of dollars	*Millions of dollars*	*Millions of dollars*			
1990	3,882	3,889	117	95:05	1.07	
1991	4,267	4,199	165	94:06	1.13	
1992	4,857	4,972	183	94:06	1.04	
1993	4,983	4,533	159	95:05	0.95	
1994	5,067	4,948	228	93:07	1.16	
1995	5,170	4,508	284	92:08	1.13	1.00
1996	5,310	4,685	354	91:09	1.16	1.00
1997	5,464	4,493	455	88:12	1.23	1.10
1998	5,608	4,559	566	86:14	1.25	1.13
1999	5,774	4,772	666	84:16	1.23	1.22
2000	6,235	5,488	818	83:17	1.35	1.28
2001	6,428	6,114	1,088	80:20	1.62	1.18
2002	6,626	6,146	1,302	77:23	1.42	1.67
2003	7,305	6,320	1,170	80:20	1.14	1.10
2004	7,536	6,675	734	87:13	0.17	(0.32)
2005	7,776	6,642	870	85:15	1.25	1.20
2006	8,010	6,614	1,285	81:19	1.77	2.28
2007	8,415	6,597	1,407	80:20	1.23	1.10
2008	8,912	6,870	1,822	73:27	1.69	1.62
2009	9,382	7,521	2,076	77:23	1.49	1.77
2010	10,128	7,716	2,239	73:27	1.32	1.30
2011	10,954	8,365	2,389	73:27	1.27	1.25
2012	11,797	9,010	2,450	74:26	1.10	1.13
2013	12,608	9,984	2,483	76:24	1.05	1.19
2014	13,771	11,019	2,203	82:18	1.12	1.18
2015	15,056	12,354	2,277	84:16	1.10	1.22
2016	16,644	13,905	2,414	85:15	1.16	1.47
2017	18,263	15,331	2,587	85:15	1.18	1.58
2018	20,204	17,176	2,722	86:14	1.12	1.51
2019	21,331	18,358	2,754	87:13	1.03	1.32
2020	22,581	19,610	2,839	87:13	1.07	1.49
2021	23,830	21,146	2,796	88:12	0.97	1.45
2022	24,991	22,392	2,924	88:12	1.09	1.85
2023	25,959	23,161	3,150	88:12	1.15	1.92
2024	26,816	23,715	3,455	87:13	1.19	1.97
2025	27,816	24,255	3,872	86:14	1.26	2.02
2026	28,062	24,126	4,338	84:16	1.28	2.32
2027	28,113	23,850	4,768	82:18	1.26	2.28
2028	28,244	23,566	5,292	80:20	1.33	2.52
2029	28,531	23,270	5,898	78:22	1.38	2.54
2030	28,761	22,966	6,607	76:24	1.45	2.60
2031	28,882	22,562	7,350	73:27	1.48	3.23
2032	28,920	22,172	8,245	70:30	1.62	2.92

PUB/MH I-102

Reference: DSM Expenditures

Please provide details of the actual DSM expenditures by electric program for 2010/11, 2011/12, 2012/13 and 2013/14 breaking out the costs between internal and external costs.

ANSWER:

Expenditure Breakdown (1000s)												
	2010/11- Actual			2011/12 - Actual			2012/13 - Forecast			2013/14- Forecast		
	Total	Internal	External	Total	Internal	External	Total	Internal	External	Total	Internal	External
RESIDENTIAL												
Home Insulation	$1,365	$116	$1,249	$1,255	$149	$1,107	$1,143	$97	$1,046	$1,052	$90	$962
Appliances	$91	$84	$8	$1	$1	$0	$0	$0	$0	$0	$0	$0
Residential Lighting	$1,247	$279	$968	$312	$88	$224	$0	$0	$0	$0	$0	$0
New Homes	$210	$122	$88	$249	$146	$104	$512	$297	$215	$549	$318	$231
Seasonal LED Lighting	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lower Income Energy Efficiency	$131	$22	$110	$97	$27	$70	$397	$66	$331	$386	$64	$322
Water & Energy Saver	$457	$80	$377	$439	$74	$365	$876	$153	$723	$794	$138	$656
Fridge Recycling	$0	$0	$0	$1,479	$213	$1,267	$2,231	$2,046	$185	$2,144	$1,966	$178
	$3,503	$704	$2,799	$3,833	$697	$3,137	$5,158	$2,658	$2,500	$4,925	$2,577	$2,348
COMMERCIAL												
Commercial Lighting	$6,650	$1,821	$4,828	$6,336	$1,794	$4,542	$5,639	$1,545	$4,095	$5,086	$1,393	$3,693
Building Envelope	$1,474	$137	$1,337	$1,217	$144	$1,074	$1,060	$99	$961	$1,060	$99	$961
Agricultural Heat Pads	$99	$27	$72	$8	$8	$0	$5	$1	$4	$5	$1	$4
Parking Lot Controllers	$529	$64	$466	$281	$31	$250	$4	$0	$3	$0	$0	$0
Spray Valves	$5	$1	$5	$0	$0	$0	$1	$0	$1	$0	$0	$0
Internal Retrofit	$1,848	$196	$1,652	$744	$116	$628	$1,481	$157	$1,324	$1,181	$126	$1,056
Commercial Geothermal	$298	$96	$201	$290	$121	$169	$244	$79	$165	$256	$83	$173
Commercial Refrigeration	$170	$80	$91	$335	$131	$203	$201	$94	$107	$208	$97	$111
HVAC - Chillers	$315	$18	$297	$209	$17	$192	$143	$8	$135	$146	$8	$137
Custom	$230	$88	$143	$237	$135	$102	$155	$59	$96	$168	$64	$104
Commercial Building Optimization	$36	$26	$10	$39	$26	$13	$134	$97	$37	$140	$102	$38
City of Winnipeg Agreement	$79	$11	$68	-$45	-$13	-$32	$38	$5	$33	$0	$0	$0
Commercial Kitchen Appliances	$36	$12	$24	$31	$17	$14	$126	$41	$84	$146	$48	$98
Commercial Clothes Washers	$64	$41	$23	$63	$35	$28	$68	$44	$24	$71	$46	$26
New Construction	$307	$193	$114	$335	$220	$115	$1,144	$718	$426	$1,056	$662	$393
Power Smart Energy Manager	$65	$62	$3	$22	$22	$0	$0	$0	$0	$0	$0	$0
Network Energy Manager	$83	$70	$13	$23	$23	$0	$240	$203	$37	$266	$225	$41
Power Smart Shops	$142	$132	$10	$46	$46	$0	$0	$0	$0	$0	$0	$0
CO2 Sensors	$0	$0	$0	$0	$0	$0	$5	$0	$5	$5	$0	$5
	$12,431	$3,075	$9,356	$10,172	$2,874	$7,298	$10,689	$3,152	$7,537	$9,794	$2,954	$6,840
INDUSTRIAL												
Performance Optimization	$2,768	$361	$2,407	$2,932	$389	$2,543	$2,736	$357	$2,379	$2,736	$357	$2,379
Emergency Preparedness	$7	$7	$0	$1	$1	$0	$727	$710	$17	$1,532	$1,496	$36
	$2,775	$368	$2,407	$2,933	$390	$2,543	$3,463	$1,067	$2,396	$4,268	$1,853	$2,415
CUSTOMER SELF-GENERATION												
Bioenergy Optimization	$1,605	$135	$1,469	$1,721	$183	$1,538	$4,215	$356	$3,859	$4,342	$366	$3,976
RATE/LOAD MANAGEMENT												
Curtailable Rates	$5,741	$7	$5,734	$5,788	$9	$5,779	$5,952	$7	$5,945	$5,952	$7	$5,945
Option 1 & CSI	$1,795	$1,456	$339	$2,034	$1,679	$354	$3,041	$2,467	$574	$3,040	$2,466	$574
Support Activity & Continency	$1,513	$627	$885	$1,746	$795	$951	$1,891	$784	$1,107	$2,391	$992	$1,400
Total Utility Cost - Electric	**$29,362**	**$6,372**	**$22,990**	**$28,227**	**$6,627**	**$21,600**	**$34,409**	**$10,490**	**$23,918**	**$34,712**	**$11,215**	**$23,497**

PUB/MH I-103

Reference: DSM Accounting Treatment

a) Please provide the accounting treatment followed by other Canadian electric utilities related to DSM program costs and compare them with the proposed accounting policies followed by MH.

ANSWER:

A review of the recent annual and quarterly reports for other Canadian electric utilities identified the following information with respect to the accounting for DSM program costs:

BC Hydro – For the year ended March 31, 2012, BC Hydro reported $646 million of unamortized DSM program costs as regulatory assets. BC Hydro has recently changed the amortization period of the DSM costs to 15 years.

Commencing April 1 2012, BC Hydro adopted financial reporting provisions as prescribed by the Province of British Columbia pursuant to the Budget Transparency and Accountability Act. In accordance with this legislation, BC Hydro will prepare financial statements in accordance with IFRS, except it will continue to apply regulatory accounting in accordance with US GAAP Codification 980 (ASC 980), Regulated Operations. The application of ASC 980 will result in the continued deferral and amortization of demand side management program costs.

Fortis Inc. - At December 31, 2011, Fortis reported unamortized deferred energy management costs of $36 million as regulatory assets. The FortisBC Energy companies, FortisBC Electric, Newfoundland Power and Maritime Electric provide various energy management services to promote energy efficiency programs to their customers and these utilities have deferred these expenditures and will amortize them on a straight line basis over periods ranging from 4 to 10 years.

Commencing January 1, 2012, Fortis adopted US GAAP after the Ontario Securities Commission issued a decision allowing Fortis and its reporting subsidiaries to prepare their financial statements effective January 1, 2012 through to December 31, 2014, in accordance with US GAAP without qualifying as U.S. Securities and Exchange Commission issuers.

Hydro Quebec – In fiscal 2011, Hydro Quebec reclassified their deferred Energy Efficiency Plan (EEP) expenditures from a regulatory asset to an intangible asset. At December 31, 2011 Hydro Quebec reported an unamortized balance of Energy Efficiency Plan costs of $974 million that will be amortized on a straight line basis over a 10 year period.

Based on its quarterly financial statements to March 31, 2012, Hydro Quebec had opted to defer the transition to IFRS until January 1, 2013 in accordance with the additional optional one-year deferral that was extended by the AcSB in March of 2012 to entities with qualifying rate-regulated activities. Manitoba Hydro is not aware if Hydro Quebec will opt for the further additional optional one-year deferral of IFRS that was recently announced by the AcSB on September 19, 2012 and in doing so adjust their transition date to IFRS to January 1, 2014.

Emera Inc. – At December 31, 2011, the consolidated statements of Emera Inc. reported an unamortized regulatory asset of $5.4 million related to the deferral of demand side management costs incurred by Nova Scotia Power, a subsidiary of Emera Inc., to be amortized over a six year period. Effective January 1, 2011, Emera changed the basis of presentation of its financial statements from CGAAP to US GAAP.

Under current CGAAP, the accounting treatment followed by other Canadian utilities is very similar to MH where DSM program costs are recognized as a regulatory asset and are deferred and amortized over 10 years.

It is expected that those utilities transitioning to US GAAP will continue with their current method of accounting for DSM program costs as US GAAP permits the recognition of rate-regulated assets.

Utilities transitioning to IFRS will be required to expense DSM expenditures as incurred unless an argument can be developed that supports their recognition as an asset in accordance with the existing IFRS framework and standards. IFF11-2 assumes that upon adoption of IFRS, Manitoba Hydro will no longer be permitted to defer expenditures on rate-regulated items, and as such, expenditures for DSM programs will be required to be expensed in the year incurred and any unamortized balance will be written-off to retained earnings.

PUB/MH I-103

Reference: DSM Accounting Treatment

b) Please provide a continuity schedule showing spending, amortization expense, amortization rates and balances for demand side management for the years 2004/05 through 2014/15 assuming the continuation of deferral under rate regulated accounting.

ANSWER:

Please see the following schedule.

MANITOBA HYDRO
DSM CONTINUITY SCHEDULE

Fiscal Year	Beginning Balance	additions	amortization	transfer	Adjustment *	Ending Balance	Rate
Actual 2007/08	$ 122,775,656	37,773,794	(11,357,463)	(664,968)		148,527,019	6.7%
Actual 2008/09	148,527,019	35,630,172	(20,022,389)	(452,011)		163,682,791	10%
Actual 2009/10	163,682,791	31,596,457	(22,063,927)	(47,627)	(4,634,995)	168,532,699	10%
Actual 20010/11	168,532,699	28,506,968	(23,994,359)	(110,072)	(237,294)	172,697,942	10%
Actual 2011/12	172,697,942	27,461,523	(26,190,555)	(144,628)		173,824,281	10%
Forecast 2012/13	173,824,281	33,635,230	(28,664,339)			178,795,173	10%
Forecast 2013/14	178,795,173	33,933,032	(31,394,981)			181,333,223	10%

* The adjustment is a result of the change in accounting standard section 3064 and the removal of ineligible costs related to research and promotions.

PUB/MH I-104

Reference: DSM GHG Impact

a) Please confirm that MH allocated all export to coal generation displacement prior to 2001.

ANSWER:

For the purposes of estimating the impacts of electricity-based DSM programs, prior to 2001 Manitoba Hydro assumed that exports displaced primarily coal generation.

PUB/MH I-104

Reference: DSM GHG Impact

b) Please provide the calculation MH uses to calculate GHG emissions savings per unit of KW.h saved and provide historical results.

ANSWER:

As stated in the response to PUB/MH I-104(a), prior to 2001 Manitoba Hydro assumed that exports displaced primarily coal generation which corresponds to emissions of approximately 1.0 kg/kW.h.

Today a more conservative estimate of 0.75 kg/kW.h is assumed. This reflects the displacement of a mixture of fossil-fuel resources and a variety of technologies and efficiencies.

The table below shows historical DSM GHG results for the previous 10 years:

Fiscal Year Ending	Electric Energy Savings (at generation) - Power Smart Portfolio (GW.h)[1]	Total Annual Greenhouse Gas Emission Reductions due to Electric Savings (kilotonnes CO_2eq)	Emission Factor (kg/kW.h)[2]
10/11	1,832	1,237	0.75
09/10	1,660	1,121	0.75
08/09	1,509	1,018	0.75
07/08	1,359	917	0.75
06/07	1,270	857	0.75
05/06	1,037	743	0.80
04/05	904	691	0.85
03/04	801	650	0.90
02/03	743	639	0.96
01/02	659	598	1.01

Notes:

(1) Electric energy savings at generation are adjusted by a factor of 0.9 to estimate savings at the southern system bus prior to utilizing the emission factor.

(2) 1 tonne CO_2eq = 1,000 kg CO_2eq. Column rounded to 2 decimal places.

PUB/MH I-104

Reference: DSM GHG Impact

c) Please describe how MH currently allocates exports to coal generation reduction and natural gas generation reduction and the reflective savings.

ANSWER:

A conservative estimate of 0.75 kg/kWh is assumed by Manitoba Hydro. It reflects the displacement of a mixture of fossil-fuel resources and a variety of technologies and efficiencies.

PUB/MH I-104

Reference: DSM GHG Impact

d) Please provide unit consumption (GWh/ customer) levels for the last five years in Saskatchewan and BC for residential [standard & all electric], commercial and industrial customers.

ANSWER:

The unit consumption levels for SaskPower and BC Hydro were derived from their annual reports. The usage figures are in kWh per customer. Neither utility provides a residential breakdown by standard and electric heat.

SaskPower
kW.h/account

	2011	2010	2009	2008	2007
Residential	8,692	8,464	8,560	8,278	8,229
Farm	20,776	20,982	21,496	20,825	20,967
Commercial	59,310	60,775	60,999	60,682	60,630
Oilfield	187,925	190,224	189,613	192,506	193,276
Power	73,949,495	70,734,694	73,083,333	88,435,897	85,675,000
Reseller	626,500,000	627,000,000	637,000,000	637,000,000	643,500,000
Total	39,889	39,361	38,014	39,547	39,678

Source: 2011 SaskPower Annual Report

BC Hydro
kW.h/customer

	2012	2011	2010	2009	2008
Residential	11,006	10,759	10,770	11,120	11,191
Light industrial and commercial	91,017	92,384	92,036	95,485	94,457
Large industrial	80,488,095	79,301,205	79,877,301	88,290,123	96,125,000
Other	651,862	471,920	523,589	606,581	575,411
Trade	206,621,212	184,442,379	170,181,185	175,168,966	201,614,786
Total	56,987	54,103	54,110	57,353	59,481

Source: 2012 BC Hydro Annual Report

PUB/MH I-104

Reference: DSM GHG Impact

e) Please compare and explain the different growth levels [in unit consumption levels] in the context of DSM activities within these jurisdictions listed in (d) and Manitoba.

ANSWER:

There are major regional and load reporting differences between Saskatchewan and Manitoba that make direct comparisons challenging. DSM activities are only one of a number of factors that impact growth rates in unit consumption levels. Other factors include provincial differences in economic growth, specific customer and industry sector growth, electricity and natural gas prices, use of electricity for heating and ongoing fuel switching activities driven by fluctuating energy prices and fuel choices. In addition, customer rate classification differences, method of weather adjustment and year-to-year random effects (industrial facility closures/startups) can significantly affect the growth rate. As a result, it is challenging to identify and explain the specific reasons as to why the growth rates differ and to assess accurately how the respective growth rates relate to DSM activities within each region.

<u>PUB/MH I-105</u>

Reference: Manitoba GHG Emissions

Please provide the most current data on the major sources of GHG emissions in Manitoba including amount and percentage.

<u>ANSWER</u>:

Manitoba Hydro is not responsible for tracking or reporting Provincial GHG emissions. Publicly available data on the major sources of GHG emissions in Manitoba is available in the 1990-2010 National Inventory Report (NIR) of Greenhouse Gas Sources and Sinks in Canada. This document is available from Environment Canada's website at http://www.ec.gc.ca/ges-ghg/. In this document, Table A14–14 presents the 1990-2010 GHG Emission Summary for Manitoba.

PUB/MH I-106

Reference: Load Saving Profile

Please provide an overall monthly DSM load savings profile separately defining peak, shoulder, and off-peak load.

ANSWER:

The following tables provide the monthly energy savings during on and off peak hours. Shoulder savings are not measured for DSM initiatives.

Monthly On Peak Energy Distribution (GW.h @ generation)

	April	May	June	July	August	September	October	November	December	January	February	March	Program On Peak Annual Energy
2011	9	9	9	9	9	9	9	10	10	11	10	10	112
2012	14	14	14	14	14	14	14	16	17	18	16	16	182
2013	20	19	19	20	20	19	20	22	24	25	23	22	254
2014	24	24	23	24	24	24	25	27	31	32	29	28	315
2015	29	28	27	28	28	28	30	33	37	38	35	33	374
2016	33	31	31	31	31	31	34	38	43	45	41	39	428
2017	33	32	31	31	31	31	34	39	45	47	43	40	438
2018	37	34	33	34	34	34	38	43	51	53	48	45	485
2019	40	37	36	36	37	37	41	47	55	57	51	48	520
2020	42	39	38	39	39	39	43	50	58	61	55	51	554
2021	44	40	39	40	40	40	44	51	60	63	56	53	571
2022	45	42	40	41	41	42	46	53	62	65	59	55	590
2023	46	43	41	42	42	43	47	54	64	67	60	57	607
2024	48	44	42	43	43	44	48	56	66	69	62	58	623
2025	48	44	42	43	43	44	49	57	67	70	63	59	631

Monthly Off Peak Energy Distribution (GW.h @ generation)

	April	May	June	July	August	September	October	November	December	January	February	March	Program Off Peak Annual Energy
2011	6	5	5	5	5	5	6	6	7	7	6	6	71
2012	9	8	8	8	8	8	9	10	11	11	10	10	111
2013	13	12	11	11	11	11	12	14	16	16	15	14	156
2014	16	14	13	13	13	14	15	17	20	21	18	18	193
2015	19	17	16	16	16	16	18	21	25	26	23	22	234
2016	21	19	17	17	18	18	21	24	28	30	26	25	265
2017	21	18	16	16	16	17	20	24	29	30	26	25	257
2018	23	19	17	17	17	19	22	27	33	34	30	28	286
2019	24	21	18	18	19	20	24	29	35	37	32	30	306
2020	26	22	20	19	20	21	25	31	37	39	34	32	325
2021	27	23	20	20	20	22	26	32	39	41	35	33	340
2022	28	24	21	21	21	23	27	34	40	43	37	35	353
2023	29	25	22	21	22	23	28	35	42	44	38	36	363
2024	30	25	22	22	22	24	28	35	43	45	39	37	372
2025	30	25	22	22	22	24	29	36	43	46	40	38	377

PUB/MH I-107

Reference: Tab 7 Section 2.3 Pages 14

a) Please indicate the marginal cost and its derivation that MH is currently using to evaluate new and existing DSM initiatives

ANSWER:

The levelized marginal value used for the analysis in the 2011 Power Smart Plan is 8.52 cents per kW.h (at meter). The marginal cost contains the expected value of electricity exports which is commercially sensitive. Therefore, detailed information on the derivation of the marginal cost cannot be provided.

PUB/MH I-107 (Revised)

Reference: Tab 7 Section 2.3 Pages 14

b) Please update section 2.3 table on page 14. RIM calculations using current marginal cost (Appendix 10.7 pages 9 & 10) and explain how MH re-evaluates the past DSM initiatives to reflect the post 20098/09 drop in the average price of export prices.

ANSWER:

Manitoba Hydro does not undertake multiple calculations using various marginal costs values either for evaluation or planning purposes. The information requested would require substantive effort to complete for the complete portfolio of programs. However, to demonstrate the impacts of lower marginal values, the RIM calculations have been updated as requested for a program within each of the three market sectors.

		Rate Impact Measure Benefit/Cost Ratio	
		2011 Power Smart Plan	updated marginal values
Residential	Home Insulation	1.5	1.3
Commercial	Commercial Lighting	1.2	1.1
Industrial	Performance Optimization	1.3	1.1

To address changes occurring within the market on a go forward basis, Manitoba Hydro revisits its DSM plan on an annual basis and adjusts its DSM offerings and strategies to respond to these changes. As part of this exercise, revised metrics including RIM's are calculated.

The table in section 2.3 includes the marginal costs that were in place at the time the 2011 Power Smart Plan was developed, which reflected the information available at that time.

PUB/MH I-107

Reference: Tab 7 Section 2.3 Pages 14

c) Please explain the logical basis for future DSM initiatives when export revenue rates fall below:

i. Residential energy rates
ii. New incremental hydraulic generation costs
iii. Wind energy purchases.

ANSWER:

In addition to value derived over the long term from the export market, the marginal values used to assess DSM initiatives also include components reflecting the avoided cost of new transmission and distribution infrastructure. If incremental export revenues were to decline to a level where they no longer offered an offsetting value, then the marginal benefits of DSM would then shift from the value of export market to a valuation of the benefit of deferring new generation facilities recognizing that there is an economic benefit to achieving load savings in the province.

Manitoba Hydro revisits its DSM plan on an annual basis utilizing the latest marginal values and domestic rate forecasts. Each DSM program is assessed using the latest market information and these updated values to determine the appropriate level of investment in the DSM program. This flexibility of DSM allows Manitoba Hydro to increase or decrease its intensity in programs in response to economic conditions and to continue to pursue all cost-effective DSM.

PUB/MH I-107

Reference: Tab 7 Section 2.3 Pages 14

d) Please explain the other benefits of domestic customer energy conservation measures, if future export sales remain at their current low levels.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-107(c).

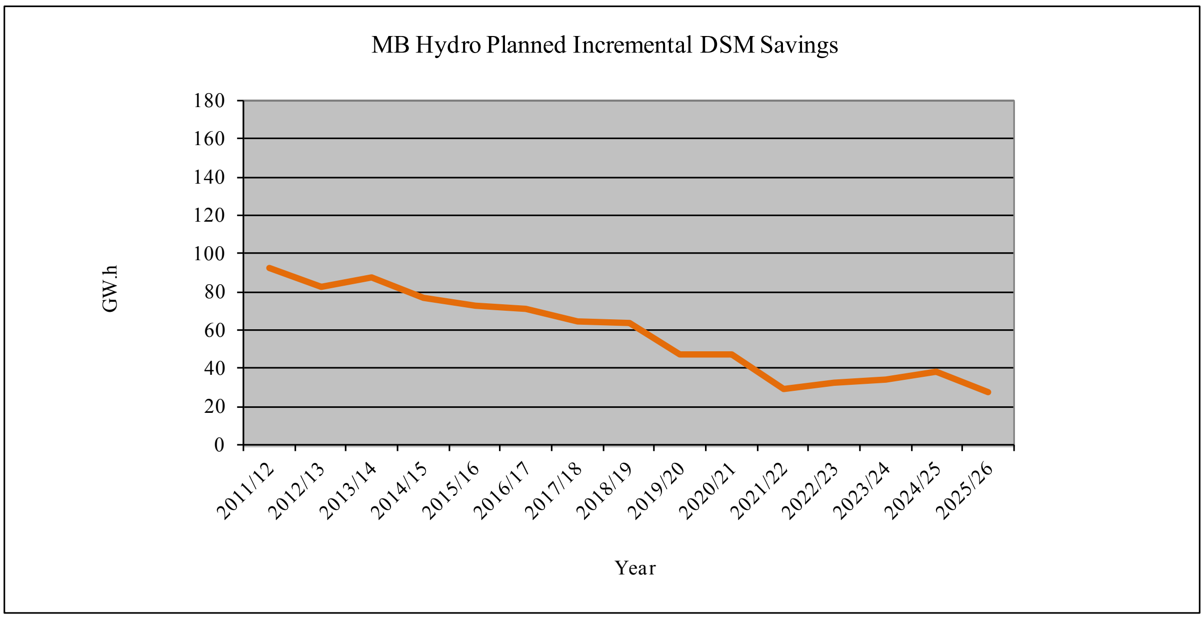
PUB/MH I-107

Reference: Tab 7 Section 2.3 Pages 14

e) Please update MH's planned DSM savings (2011 GRA- RCM/TREE #6) to reflect the lower MC of energy.

ANSWER:

Please see the following graph which is based on the information provided in Appendix A.3 of the 2011Power Smart Plan, which was filed as Appendix 7.1 of the Application.



PUB/MH I-108

Reference: 2011 Power Smart Plan Section 2.3 – /Electric DSM Cost Effectiveness

a) The 2011 Power Smart Plan provides the results of the TRC, RIM, and LUC cost-effectiveness measures, but does not provide the inputs to undertake the calculation of the ratios for these measures. Please provide the following for each of the Incentive – based electric DSM program:

- **i. The revenue realized by MH from conserved electricity sold in the export market;**
- **ii. The avoided cost of new infrastructure;**
- **iii. The total program administration costs, and utility program administration costs [if different];**
- **iv. The incremental product costs;**
- **v. The revenue loss resulting from reduced consumption;**
- **vi. The cost of incentives; and**
- **vii. The energy saved.**

ANSWER:

The following table outlines the inputs for the various cost-effectiveness measures of each incentive-based program in the 2011 Power Smart Plan. A single marginal benefit value is provided for (i) and (ii) as these values are not independently calculated. As a proxy, it is estimated that approximately 75% of the marginal value is from export revenue and 25% of the marginal value is from the avoided cost of new infrastructure.

	Marginal Benefits		Program Admin Costs		Incremental Product Cost	Revenue Loss	Incentives		Energy Saved
	INPUT i & ii		*INPUT iii*		*INPUT iv*	*INPUT v*	*INPUT vi*		*INPUT vii*
	PV of Marginal Benefit	*PV of Non-Energy (Water) Benefits*	*PV of Utility Program Admin Costs*	*PV of AEF Program Admin Costs*	*PV of Incremental Product Costs*	*PV of Revenue Loss*	*PV of Utility Incentives*	*PV of AEF Incentives*	*PV of Energy Saved @ Gen*
Residential									
New Home Program	$ 40,653,914	$ -	$ 1,745,839	$ -	$ 24,376,756	$ 24,267,878	$ 815,948	$ -	$ 341,791,866
Home Insulation Program	$ 34,619,594	$ -	$ 1,761,997	$ -	$ 6,604,862	$ 18,123,584	$ 3,681,432	$ -	$ 264,307,900
Water and Energy Saver Program	$ 14,812,268	$ 4,187,053	$ 2,019,481	$ -	$ 1,008,346	$ 12,206,609	$ 1,074,042	$ -	$ 190,316,809
Lower Income Energy Efficiency Program	$ 19,475,748	$ 3,762,889	$ 505,020	$ 1,206,350	$ 9,738,463	$ 11,011,393	$ 1,231,673	$ 2,722,473	$ 163,616,981
EE Light Fixtures	$ 549,710	$ -	$ 226,014	$ -	$ 63,260	$ 439,687	$ 100,993	$ -	$ 6,885,728
Fridge Recycling Program	$ 18,893,869	$ -	$ 4,145,790	$ -	$ 6,197,785	$ 17,832,985	$ 1,267,967	$ -	$ 282,821,001
Commercial									
Commercial Lighting Program	$ 196,353,587	$ -	$ 17,806,478	$ -	$ 90,701,962	$ 120,713,550	$ 29,982,958	$ -	$ 2,031,187,005
Commercial Custom Measures Program	$ 7,832,185	$ -	$ 525,936	$ -	$ 3,808,027	$ 4,204,402	$ 1,202,685	$ -	$ 89,825,875
Commercial Windows Program	$ 41,451,728	$ -	$ 977,805	$ -	$ 2,571,567	$ 22,578,037	$ 2,057,246	$ -	$ 363,116,601
Commercial HVAC Program - Chiller	$ 3,391,508	$ -	$ 107,555	$ -	$ 2,444,826	$ 2,357,226	$ 806,407	$ -	$ 72,310,986
City of Winnipeg Power Smart Agreement	$ 1,045,423	$ -	$ 4,000	$ -	$ 73,806	$ 616,050	$ 69,797	$ -	$ 10,292,438
Commercial Refrigeration Program	$ 23,118,753	$ -	$ 790,606	$ -	$ 4,069,901	$ 16,037,301	$ 1,687,707	$ -	$ 281,873,249
Commercial Insulation Program	$ 76,745,471	$ -	$ 346,270	$ -	$ 10,864,180	$ 38,268,968	$ 6,630,362	$ -	$ 544,761,602
Commercial Earth Power Program	$ 45,599,359	$ -	$ 1,862,949	$ -	$ 17,420,132	$ 25,392,821	$ 3,077,071	$ -	$ 374,158,079
Commercial New Construction Program	$ 112,385,646	$ -	$ 1,317,300	$ -	$ 19,634,031	$ 70,470,113	$ 8,321,149	$ -	$ 1,157,179,262
Commercial Building Optimization Program	$ 15,098,211	$ -	$ 504,111	$ -	$ 2,000,035	$ 7,749,769	$ 1,130,892	$ -	$ 135,436,627
Internal Retrofit Program	$ 33,427,226	$ -	$ 928,870	$ -	$ 24,828,365	$ -	$ -	$ -	$ 378,781,815
Commercial Kitchen Appliance Program	$ 3,861,483	$ 4,495,444	$ 80,364	$ -	$ 1,143,502	$ 2,268,763	$ 845,492	$ -	$ 33,665,790
Commercial Clothes Washers Program	$ 1,670,446	$ 846,668	$ 133,571	$ -	$ 1,089,608	$ 805,780	$ 252,273	$ -	$ 8,844,769
Network Energy Management Program	$ 5,740,865	$ -	$ 249,942	$ -	$ 2,541,701	$ 3,766,634	$ 468,348	$ -	$ 89,092,854
CO2 Sensors	$ 835,595	$ -	$ 20,056	$ -	$ 78,346	$ 382,756	$ 14,249	$ -	$ 12,181,695
Industrial									
Performance Optimization Program	$ 149,670,251	$ -	$ 9,317,074	$ -	$ 47,155,950	$ 90,835,585	$ 18,694,036	$ -	$ 1,900,186,099
Emergency Preparedness Program	$ 76,004,723	$ -	$ 2,060,092	$ -	$ 25,492,602	$ 53,116,849	$ 14,441,615	$ -	$ 427,754,677
Customer Self Generation									
Bioenergy Optimization Program	$ 77,213,374	$ -	$ 1,387,366	$ -	$ 44,739,887	$ 39,416,475	$ 18,168,702	$ -	$ 1,093,318,028

PUB/MH I-108

Reference: 2011 Power Smart Plan Section 2.3 – /Electric DSM Cost Effectiveness

b) Please explain the methodology for determining the Present Value of each of these inputs in the cost-effectiveness ratios including the various required input factors such as discount rate used.

ANSWER:

The Present Value of each input of the cost-effectiveness ratios was determined by taking the annual dollar amounts for each input and discounting them over a 30-year period using Manitoba Hydro's real weighted average cost of capital. The discount rate used for the 2011 Power Smart Plan was 6.1%.

PUB/MH I-109

Reference: 2011 Power Smart Plan Page 11 - LIEEP

a) Please provide demographic data on Low income households broken down by dwelling type and ownership [actual numbers and % of total]

ANSWER:

Please see the following table:

LICO-125 Households in Manitoba Manitoba Hydro Residential Energy Use Survey - 2009						
Dwelling Type	**Own**	**% of Total LICO-125**	**Rent**	**% of Total LICO-125**	**Total By Dwelling Type**	**% of Total LICO-125**
Single Detached	67 410	64%	4 292	4%	71 703	68%
Multi-Attached	6 647	6%	3 752	4%	10 399	10%
Apartment Suite	5 221	5%	17 763	17%	22 984	22%
Total by Ownership	79 278	75%	25 808	25%	105 086	100%

PUB/MH I-109

Reference: 2011 Power Smart Plan Page 11 - LIEEP

b) Please provide details by measure on the forecasted spending on Electric LIEEP for the years 2011/12, 2012/13 and 2013/14.

ANSWER:

Please see the following table:

Spending by Measure	**Electric Forecast Spending From 2011 Power Smart Plan**			
	2011-12	**2012-13**	**2013-14**	**Total 2011-14**
Electric Participation	**533**	**533**	**513**	**1578**
Power Smart				
Basic Energy Efficiency Items & Draft Proofing	$ 32,000	$ 32,000	$ 32,000	$ 96,000
Insulation - Attic	$ 163,000	$ 163,000	$ 156,000	$ 482,000
Insulation - Basement/Crawl	$ 80,000	$ 80,000	$ 76,000	$ 235,000
Insulation - Wall	$ 11,000	$ 11,000	$ 10,000	$ 31,000
Total Insulation	$ 253,000	$ 253,000	$ 243,000	$ 748,000
Total Incentives	**$ 285,000**	**$ 285,000**	**$ 274,000**	**$ 845,000**
Total Administration	$ 112,000	$ 112,000	$ 112,000	$ 335,000
Total Power Smart	**$ 397,000**	**$ 397,000**	**$ 386,000**	**$ 1,180,000**

Spending by Measure	**Budgeted Costs**			
	2011-12	**2012-13**	**2013-14**	**Total**
AEF				
Basic Energy Efficiency Items & Draft Proofing	$ 5,000	$ 5,000	$ 5,000	$ 14,000
Insulation - Attic	$ 68,000	$ 68,000	$ 66,000	$ 203,000
Insulation - Basement/Crawl	$ 514,000	$ 514,000	$ 499,000	$ 1,528,000
Insulation - Wall	$ 41,000	$ 44,000	$ 40,000	$ 121,000
Total Insulation	$ 624,000	$ 624,000	$ 605,000	$ 1,852,000
Total Incentives	**$ 628,000**	**$ 628,000**	**$ 609,000**	**$ 1,866,000**
Total Administration	$ 68,000	$ 268,000	$ 268,000	$ 803,000
Total AEF	**$ 896,000**	**$ 896,000**	**$ 877,000**	**$ 2,669,000**
Grand Total PS and AEF	**$ 1,293,000**	**$ 1,293,000**	**$ 1,263,000**	**$ 3,849,000**

PUB/MH I-109

Reference: 2011 Power Smart Plan Page 11 - LIEEP

c) Please provide a comparison of the forecast spending by measure at the last GRA with that currently forecast in (a) and explain any differences.

ANSWER:

The attached chart provides a comparison of forecast spending between the data provided in PUB/MH I-111b and PUB/MH II-104 in the 2010/11 & 2011/12 GRA and the data in the 2011 Power Smart Plan referred to in PUB/MH I-109(b).

The primary difference in the total forecast spending is due to changes in the forecast participation of electrically heated homes. Under the 2009 Power Smart Plan provided in the last GRA, participation was projected at an average of 883 homes per year. Participation under the 2011 Power Smart Plan is projected to be an average of 526 homes per year which has been revised to reflect actual experience with the program to date.

Forecast spending is also influenced by differences in the estimated average cost per home requiring upgrades. Under the 2009 Power Smart Plan, the investment was projected to be $4,051/home compared to $2,440/home in 2011 Power Smart Plan. The average cost per home was similar between the two Plans at $796 for 2009 compared to $748 in 2011. The Affordable Energy Fund component however was much higher per home in 2009 at $3,255 compared to $1,692 per home in 2011. Based on actual experience, forecast spending for insulation measures is lower.

The forecast spending per home for administration was also higher in the past forecast.

Spending by Measure	Electric Forecast Spending From Last GRA ($000s) 2009-10	2010-11	Total	Electric Forecast Spending From 2011 Power Smart Plan ($000s) 2011-12	2012-13	2013-14	Total 2011-14
Electric Participation	**803**	**963**	1766	**533**	**533**	**513**	**1578**
Power Smart							
Basic Energy Efficiency Items & Draft Proofing	$ 14	$ 15	$ 29	$ 32	$ 32	$ 32	$ 96
Insulation - Attic	$ 223	$ 267	$ 490	$ 163	$ 163	$ 15	$ 482
Insulation - Basement/Crawl	$ 100	$ 124	$ 223	$ 80	$ 80	$ 76	$ 235
Insulation - Wall	$ 144	$ 173	$ 316	$ 11	$ 11	$ 10	$ 31
Total Insulation	$ 466	$ 563	$ 1,030	$ 253	$ 253	$ 243	$ 748
Total Incentives	**$ 480**	**$ 577**	$ 1,057	$ 285	$ 285	$ 274	$ 845
Total Administration	**$ 170**	**$ 178**	$ 348	$ 112	$ 112	$ 112	$ 336
Total Power Smart	**$ 651**	**$ 756**	$ 1,407	$ 397	$ 397	$ 386	$ 1,180
AEF							
Basic Energy Efficiency Items & Draft Proofing	$ 187	$ 209	$ 396	$ 5	$ 5	$ 5	$ 14
Insulation - Attic	$ 154	$ 174	$ 327	$ 68	$ 68	$ 66	$ 203
Insulation - Basement/Crawl	$ 1,323	$ 1,516	$ 2,838	$ 515	$ 515	$ 499	$ 1,528
Insulation - Wall	$ 193	$ 210	$ 403	$ 41	$ 41	$ 40	$ 121
Total Insulation	$ 1,669	$ 1,900	$ 3,568	$ 624	$ 624	$ 605	$ 1,852
Fridges	$ 468	$ 494	$ 962				
Total Incentives	**$ 2,324**	**$ 2,603**	$ 4,926	$ 628	$ 628	$ 609	$ 1,866
Total Administration	**$ 892**	**$ 892**	$ 1,785	$ 268	$ 268	$ 268	$ 803
Total AEF	**$ 3,216**	**$ 3,495**	$ 6,711	$ 896	$ 896	$ 877	$ 2,669
Grand Total PS and AEF	**$ 3,867**	**$ 4,251**	$ 8,118	$ 1,293	$ 1,293	$ 1,263	$ 3,849

PUB/MH I-110

Reference: LIEEP , Appendix 11.1 Page 5

Please provide a full description of the efforts currently being undertaken and delivered under the LIEEP on First Nations Communities.

ANSWER:

Manitoba Hydro currently works with First Nation communities to improve the energy efficiency of their homes by providing materials for insulation upgrades as well as basic energy efficiency materials such as caulking, faucet aerators and low flow showerheads. In addition, Manitoba Hydro provides training and funding for labour so that local residents can install the materials, and Manitoba Hydro pays reasonable costs to ship materials to the communities. Manitoba Hydro's First Nation Energy Advisor works directly with each community to determine which homes need upgrades and then, works with the First Nation community to develop a plan for retrofitting the targeted homes.

To date, 597 homes have been upgraded through the First Nations Power Smart Program in 24 different communities as follows:

Fiscal Year	**# of Completed Homes**
2009-10	29
2010-11	133
2011-12	244
2012-13 (to August 24, 2012)	191
Total Completed to Date	**597**

Plans are in place to upgrade additional First Nation homes over the next 5 years as follows.

Target # of Completed Homes in Each Fiscal Year	
Fiscal Year	**Target # of Completed Homes**
2012 – 13	230
2013 – 14	207
2014 – 15	186
2015 – 16	168
2016 – 17	151

As of August 24th, 2012, Manitoba Hydro's staff has approached all 63 communities, however progress with participating in Manitoba Hydro's Lower Income Program varies with each community.

PUB/MH I-111

Reference: Load Forecast - Top Consumers

a) Please indicate the number of GSL >100, GSL 30-100, and GSL <30 customers included in the Top Consumers listing.

ANSWER:

At the end of the 2010/11 fiscal year, there were 17 Top Consumers that were counted as 25 customers. Companies with more than one distinct operation within the Province are included as multiple customers. The breakdown by rate classification is as follows:

Rate Class	Customers
GSL>100	13
GSL 30kV-100kV	8
GSL <30kV	3
GS Medium	1
Total Customers	25

PUB/MH I-111 (Revised)

Reference: Load Forecast - Top Consumers

b) Please categorize these Top Consumers and their annual energy demands (MW/GWh) by sector for 2005/06 to 2008/09 inclusive:

- **i. Chemical.**
- **ii. Petroleum Transport.**
- **iii. Primary Metals.**
- **iv. Pulp and Paper.**
- **v. Mining.**
- **vi. Food and Beverage.**
- **vii. Colleges and Universities.**
- **viii. Other.**

ANSWER:

The actual energy use is shown below back to 2005/06.

GW.h	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Chemicals	1,841	1,847	1,865	1,929	1,912	1,977
Petroleum	849	899	879	944	903	728
Primary Metals	2,237	2,248	2,300	2,237	2,033	2,153
Pulp/Paper	763	742	764	674	332	185
Mining	5	4	4	4	3	3
Food/Beverage	182	176	188	202	204	201
College	70	73	75	75	74	76
Other	0	0	0	0	0	0
Total GW.h	**5,948**	**5,989**	**6,075**	**6,065**	**5,461**	**5,324**

PUB/MH I-111

Reference: Load Forecast - Top Consumers

c) What are the sector-by-sector industry growth forecasts for Fiscal 2012, 2013 and 2014?

ANSWER:

Please see the following table:

2011 FORECAST – SECTOR GROWTH

	2011/12 (Actual)	2012/13 (Forecast)	2013/14 (Forecast)
Chemicals	28	60	50
Petroleum	62	110	205
Primary Metals	219	58	70
Pulp/Paper	94	-11	0
Mining	-3	0	0
Food/Beverage	6	2	6
College	1	2	2
Other	0	0	0
Total GW.h	**406**	**221**	**333**

PUB/MH I-112

Reference: Tab 8 2011 Load Forecast P. 15

a) Please confirm (and explain why) 62,000 residential customers (over next 20 years) would choose electric space heating when electricity rates will be increasing from 7¢/kWh (2010/11) to 12.50¢/kWh (2030/31) and average annual electric heating costs could rise from $1100/yr. to $2000/yr.

ANSWER:

In the 2011 Electric Load Forecast, over the next twenty years the number of Residential Basic customers who are billed for heating their dwelling unit with electric space heat is forecast to increase from 158,012 customers in 2010/11 to 222,939 customers in 2030/31, which is an increase of approximately 65,000 customers.

Of the 65,000 increase, approximately 20,000 are projected to be in areas where natural gas is not available. Approximately 24,000 are apartments and multi-family dwellings that are individually metered units with individual suite heating systems, which has the advantage to property owners of allowing heating costs to be borne by the tenant. In gas available areas outside of Winnipeg, approximately half of the new homes built, 20,000 out of 40,000, are forecast to be built with electric space heat for various reasons, including preferences by builders and/or customers, capital cost of the initial service hookup and/or the higher capital cost of a natural gas furnace. Customers in Winnipeg tend to install natural gas in single detached homes, with only 1,000 electrically heated homes forecast within this region.

PUB/MH I-112

Reference: Tab 8 2011 Load Forecast P. 15

b) Please confirm (and explain why) only 43000 residential customers in the next 20 years would choose natural gas (or other) space heating with annual heating costs currently at $500/yr. and likely to remain low for at least 5-10 years.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-112(a).

PUB/MH I-112

Reference: Tab 8 2011 Load Forecast P. 15

c)

	Electric Heat Customer/GWh		Other Non-Electric Heat Customer/GWh	
2005/06	**128,109**	**3126**	**295,733**	**3045**
2006/07	**130,749**	**3273**	**297,137**	**3167**
2007/08	**133,858**	**3499**	**298,287**	**3267**
2008/09	**137,410**	**3604**	**299,852**	**3243**
2009/10				

Verify and update the above data points in the table.

ANSWER:

	Electric Heat		Standard	
	Customers	GW.h	Customers	GW.h
2005/06	128,009	3,126	295,733	3,045
2006/07	130,749	3,275	297,137	3,167
2007/08	133,858	3,499	298,287	3,237
2008/09	137,410	3,604	299,852	3,243
2009/10	140,563	3,544	301,147	3,243
2010/11	158,012	4,036	287,870	2,916
2011/12	161,078	3,910	289,670	2,908

Analysis of the 2009 Residential Energy Use Survey indicated that Manitoba Hydro’s customer information database underestimated the number of customers with electric space heat. Further analysis identified the saturation of electric heat customers and was incorporated into the 2011 Electric Load Forecast.

PUB/MH I-113

Reference: GSL Revisions – MH Workshop Aug. /12, Load Profiles, Energy Intensive Industry Rates (EIIR)

a) **Please provide subclass load profiles for GSL >100 and GSL 30-100 customers defining peak, shoulder and off-peak energy usage for the years 2005/06 to 2010/11 (actual) and the years 2011/12 to 2021/22 (forecast).**

ANSWER:

Manitoba Hydro does not forecast peak, shoulder and off-peak energy usage for General Service Large >100 kV and General Service Large 30 – 100 kV customers as the typical usage patterns are reasonably consistent between peak, shoulder and off-peak periods. Subclass energy consumption in the peak, shoulder and off-peak periods as defined by the Surplus Energy Program is shown for the available years.

Rate Class	GS Large > 100KV

Fiscal	Off-Peak	On-Peak	Shoulder	Total
2006-07	1,719,707,631	1,148,182,741	2,224,482,610	5,092,372,982
2007-08	1,767,459,970	1,174,677,101	2,294,663,991	5,236,801,062
2008-09	1,769,410,660	1,191,097,923	2,272,771,034	5,233,279,616
2009-10	1,546,885,108	1,037,775,220	1,991,153,498	4,575,813,825
2010-11	1,490,378,150	988,588,602	1,922,586,127	4,401,552,878
2011-12	1,483,055,243	984,310,554	1,919,734,568	4,387,100,364

Rate Class	GS Large 30-100KV

Fiscal	Off-Peak	On-Peak	Shoulder	Total
2006-07	285,773,547	190,978,655	371,398,800	848,151,001
2007-08	302,497,473	202,431,916	398,043,013	902,972,402
2008-09	313,111,455	211,429,039	407,147,759	931,688,253
2009-10	317,261,807	208,309,055	408,435,566	934,006,427
2010-11	328,316,035	217,195,527	424,436,045	969,947,608
2011-12	381,605,785	250,477,351	490,858,293	1,122,941,428

PUB/MH I-113

Reference: GSL Revisions – MH Workshop Aug. /12, Load Profiles, Energy Intensive Industry Rates (EIIR)

b) Please confirm that IFF11 does not include any EIIR revenues

ANSWER:

Confirmed.

PUB/MH I-114

Reference: **SEP Adjustments – Tab 10.6, New Option 1 Customers, Time-of-Use (TOU) in SEP Rates**

a) Please provide potential customer load profiles defining time-of-use (peak/shoulder/off-peak) energy usage under the SEP Option No. 1 scenario going out to 2021/22.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-113(a) providing total annual consumption by Surplus Energy Program time-of-use periods for the General Service Large 30 – 100 kV and General Service Large >100 kV rate subclasses.

Potential Surplus Energy Program load subscriptions under Option 1 are limited by several factors including the following:

i) A customer's Total Demand (including SEP demand) must be greater than 1,000 kVA,

ii) Individual customer demand associated with Surplus Energy Program cannot exceed 50 MVA unless the load factor is guaranteed to exceed 25 percent on a weekly basis,

iii) Customer load nominated for the Surplus Energy Program cannot be served under the Curtailable Rate Program,

iv) Customer power factor must be maintained at greater than 0.90 (at Manitoba Hydro's discretion), and

v) A customer's Reference Level of Demand in any period must be equal to at least 75 percent of Total Demand.

Further considerations impacting Surplus Energy Program subscriptions include:

i) Surplus Energy Program load is not considered to be firm load, and is therefore subject to interruption on 36 hours notice; and

ii) Interruption periods are not limited in duration and may therefore be extended as required by Manitoba Hydro.

Based on existing customer analysis and feedback, it is not possible for Manitoba Hydro to provide potential customer load profiles defining time-of-use energy usage under the Surplus Energy Program Option 1, as at present no customers have indicated a serious interest in shifting existing or new load to Option 1.

PUB/MH I-114

Reference: SEP Adjustments – Tab 10.6, New Option 1 Customers, Time-of-Use (TOU) in SEP Rates

b) Please define the probable maximum potential revenue impact of allowing SEP to nominate different levels of SEP energy during peak/shoulder/off-peak periods; in particular, address the potential uptake in the large chemical and petroleum transport industry sectors.

ANSWER:

Demand profiles for potential Option 1 customers in the General Service Large rate subclasses served at Greater than 30 kV are relatively uniform across the time-of-use periods defined by the Surplus Energy Program. On a rate subclass basis, variation between time periods has historically been less 0.5 percent in the General Service Large >100 kV rate subclass and less than 2.0 percent in the General Service Large 30 – 100 kV rate subclass.

The current revenue impact of Option 1 load is zero, based on the fact that no customers are currently subscribing to this option. Allowing customers to nominate different reference levels in the various time periods may encourage some customers to participate, but the level of participation will be limited by the monthly demand charge, which will be equal to the highest designated monthly Reference Level of Demand (if different reference levels are provided for each of the time periods). It is anticipated that differences in reference levels between the time-of-use periods will be modest.

For discussion purposes, a 10.0 MVA uptake under Option 1 of the Surplus Energy Program (slightly more than 1 percent of the General Service Large load served at Greater than 30 kV) would yield annual consumption of approximately 70 GWh if operated at a load factor of 80 percent over all time periods. The Surplus Energy Program revenue provided by such a load would be approximately $1.5 Million (one year historical average rate), $1.75 Million (three year historical average rate), or $2.25 Million (five year historical average rate). The equivalent load served at domestic rates, would provide revenue of approximately $2.7 Million at General Service Large >100 kV rates. These impacts do not account for the long-term effects of freeing up firm energy for domestic or export sales.

The large chemical sector is substantially subscribed under the Curtailable Rates Program (approximately 195 MW), reducing the available load that is eligible for Surplus Energy Program subscription considerably. Large scale addition of Option 1 would require this sector to add substantial additional production capacity into the market, necessitating a significant capital and operating investment, recovery of which may not be supported by non-firm Surplus Energy Program supply and variable rates.

Demand levels in the petroleum and natural gas transportation sector have been highly variable in recent years, impacted by eastern shale gas developments and the low price of natural gas. The cost structure for customers in the petroleum transportation sector limits the acceptance of an interruptible energy product without the ability to secure guaranteed energy at market price in the event of an interruption, a feature that is not provided under the Surplus Energy Program.

PUB/MH I-115

Reference: Appendix 8.1 2011 Load Forecasts

a) Residential Consumption from 2006/07 to 2008/09

Please confirm that over next 20 years MH anticipates:

- **40% increase in electric heat customer usage;**
- **25% increase in non-electric heat customer usage;**
- **35% increase in total residential customer usage.**

ANSWER:

In the 2011 Electric Load Forecast, Residential Basic electric heat customers' energy usage was forecast to increase from 4,036 GW.h in 2010/11 to 5,759 GW.h in 2030/31, which was an increase of 43%. The increase in energy usage of standard (non-electric heat) customers was forecast to increase from 2,916 GW.h in 2010/11 to 3,630 GW.h in 2030/31, which was an increase of 24%. The total energy usage for the Residential Basic sector was forecast to increase from 6,952 in 2010/11 to 9,389 in 2030/31, which was an increase of 35%.

PUB/MH I-115

Reference: Appendix 8.1 2011 Load Forecasts

b) Residential Customers

Please confirm that over next 20 years MH anticipates:

- **40% increase in number of electric heat customers;**
- **15% increase in number of non-electric heat customers;**
- **23% increase in total number of residential customers.**

ANSWER:

In the 2011 Electric Load Forecast, Manitoba Hydro forecast the number of Residential Basic electric heat customers to increase from 158,012 customers in 2010/11 to 222,939 by 2030/31, which was an increase of 41%. The number of Residential Basic standard (non-electric heat) customers was forecast to increase from 287,870 in 2010/11 to 332,203 customers in 2030/31, which was an increase of 15%. The total number of residential customers was forecast to increase from 445,882 in 2010/11 to 555,142 by 2030/31, which was an increase of 25%.

PUB/MH I-115

Reference: Appendix 8.1 2011 Load Forecasts

c) Please confirm the following average electric heat customer unit consumption and cost forecasts:

				Total Bill	Heating Component
2010/11	**-**	**25545 kWh/yr @**	**7.13¢/kWh**	**$1800/yr**	**$1100/yr**
2020/21	**-**	**25616 kWh/yr @**	**9.50¢/kWh**	**$2500/yr**	**$1500/yr**
2030/31	**-**	**25830 kWh/yr @**	**12.40¢/kWh**	**$3200/yr**	**$2000/yr**

ANSWER:

Manitoba Hydro can confirm the average use (kWh/yr) figures shown above are correct as shown on Page 15 of the 2011 System Load Forecast (Appendix 8.1) for the Residential Basic “Electric Heat Billed” customers. Manitoba Hydro is not able to confirm the cost data in the table.

PUB/MH I-116

Reference: Historical Load Forecast Since 2006

Preamble: Please provide a tabular and graphical comparison of the 2011, 2010, 2009, 2008 and 2007 electric load forecasts; separately illustrating:

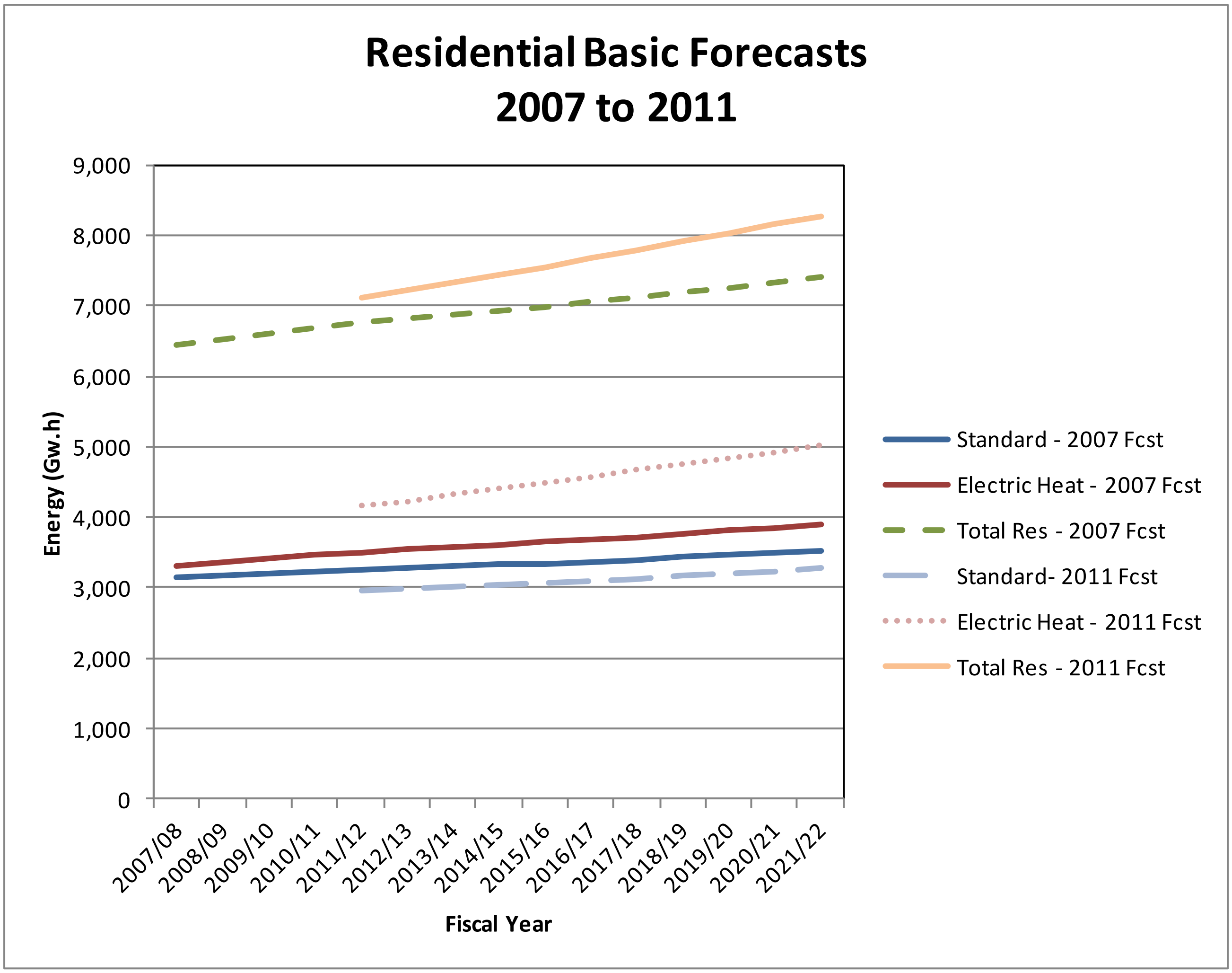
a) Residential Basic Sales: (See for Example: Figure 8.1)

- **Electric heat billed (2011 and 2007 only)**
- **Non-electric heat (other) (2011 and 2007 only)**
- **Total residential basic**

ANSWER:

Residential Basic Forecast Comparison

Fiscal Yr	Standard - 2007 Fcst	Electric Heat - 2007 Fcst	Total Res - 2007 Fcst	Standard- 2011 Fcst	Electric Heat - 2011 Fcst	Total Res - 2011 Fcst
2007/08	3,146	3,300	6,447			
2008/09	3,173	3,358	6,531			
2009/10	3,199	3,413	6,613			
2010/11	3,227	3,466	6,692			
2011/12	3,255	3,506	6,761	2,961	4,157	7,118
2012/13	3,272	3,540	6,812	2,983	4,232	7,216
2013/14	3,296	3,576	6,872	3,010	4,316	7,326
2014/15	3,323	3,612	6,935	3,037	4,400	7,438
2015/16	3,348	3,647	6,995	3,067	4,487	7,554
2016/17	3,374	3,681	7,055	3,098	4,575	7,673
2017/18	3,401	3,716	7,117	3,130	4,664	7,794
2018/19	3,429	3,759	7,188	3,163	4,753	7,916
2019/20	3,459	3,805	7,264	3,197	4,841	8,039
2020/21	3,490	3,850	7,340	3,233	4,929	8,162
2021/22	3,521	3,894	7,415	3,269	5,016	8,285


Residential Basic Forecasts
2007 to 2011
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Energy (Gw.h)
2007/08
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
Fiscal Year
Standard - 2007 Fcst
Electric Heat - 2007 Fcst
Total Res - 2007 Fcst
Standard- 2011 Fcst
Electric Heat - 2011 Fcst
Total Res - 2011 Fcst

PUB/MH I-116

Reference: Historical Load Forecast Since 2006

Preamble: Please provide a tabular and graphical comparison of the 2011, 2010, 2009, 2008 and 2007 electric load forecasts; separately illustrating:

b) Total General Service Sales; (See for Example: Figure 8.2)

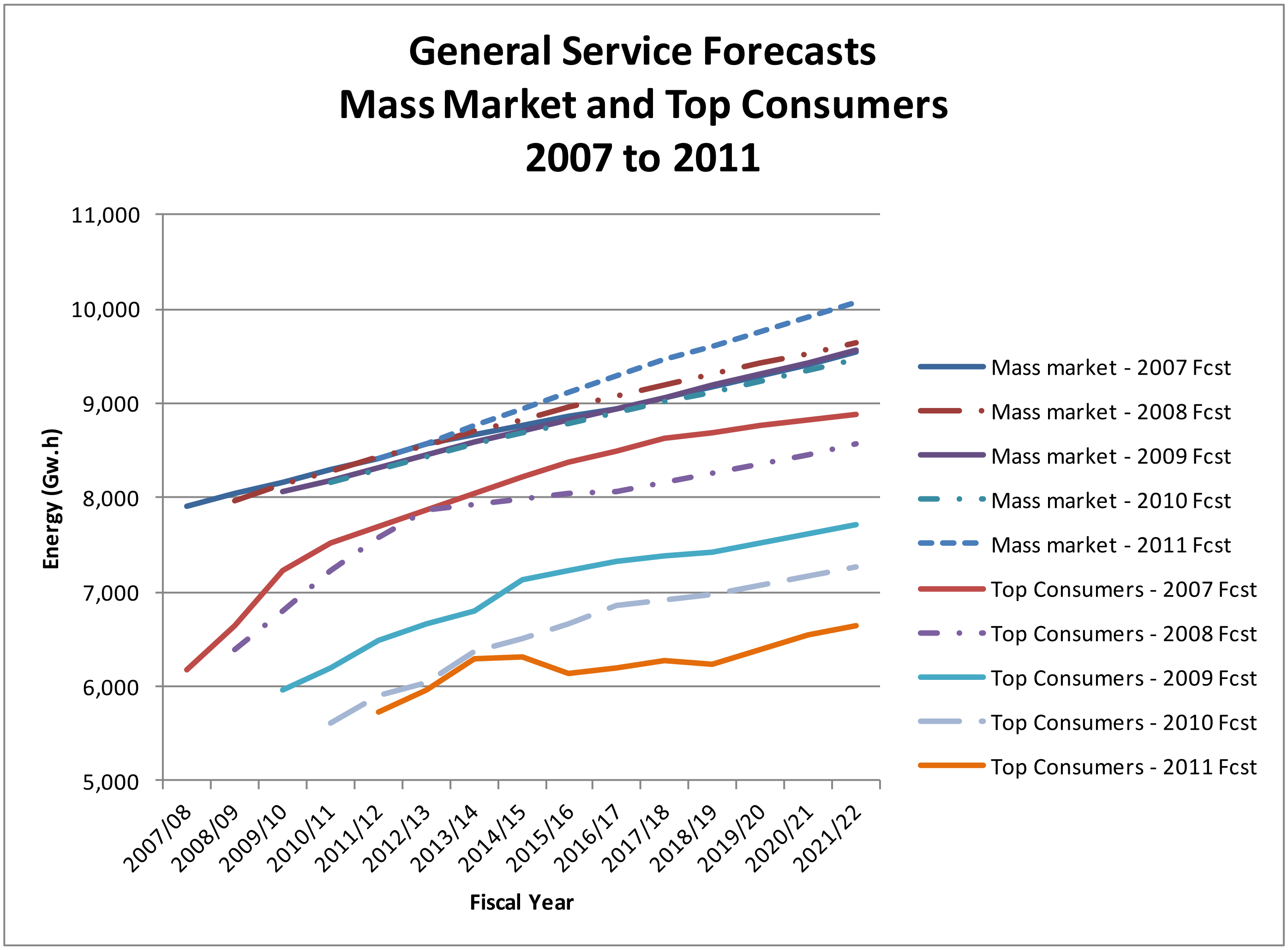
- **Mass market**
- **Top consumers**
- **Total general service (See for Example: Figure 8.3)**

ANSWER:

Please see the following tables and graphs:

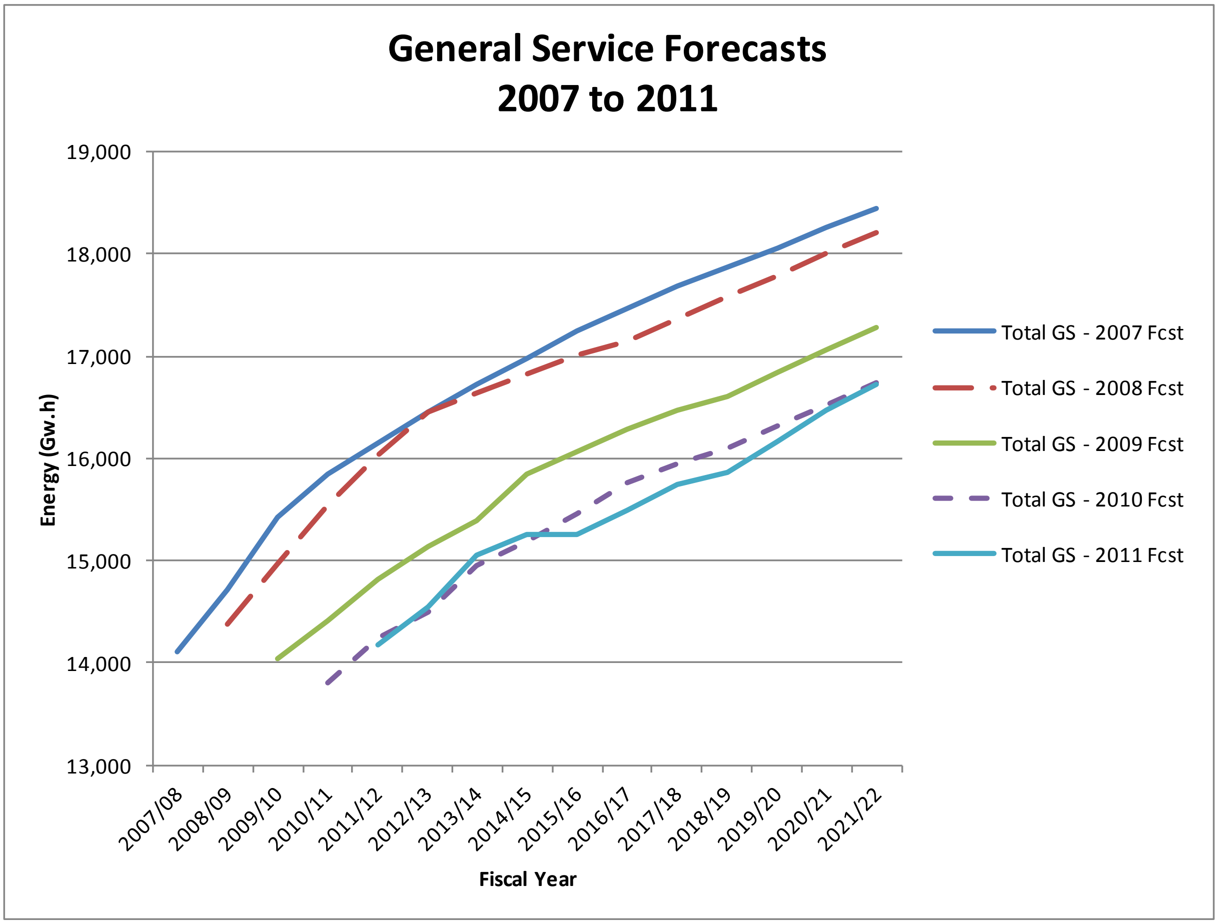
Mass Market and Top Consumers Forecast Comparison (GW.h)

Fiscal Yr	Mass market - 2007 Fcst	Mass market - 2008 Fcst	Mass market - 2009 Fcst	Mass market - 2010 Fcst	Mass market - 2011 Fcst	Consumers - 2007 Fcst	Consumers - 2008 Fcst	Consumers - 2009 Fcst	Consumers - 2010 Fcst	Consumers - 2011 Fcst
2007/08	7,898					6,173				
2008/09	8,036	7,960				6,646	6,390			
2009/10	8,166	8,133	8,059			7,228	6,795	5,956		
2010/11	8,289	8,285	8,183	8,165		7,514	7,220	6,196	5,610	
2011/12	8,415	8,426	8,316	8,305	8,408	7,698	7,575	6,482	5,909	5,730
2012/13	8,566	8,559	8,447	8,439	8,566	7,874	7,860	6,657	6,033	5,951
2013/14	8,666	8,709	8,587	8,569	8,762	8,050	7,920	6,795	6,375	6,283
2014/15	8,759	8,832	8,705	8,681	8,937	8,212	7,980	7,126	6,499	6,305
2015/16	8,853	8,953	8,824	8,786	9,113	8,374	8,040	7,226	6,666	6,135
2016/17	8,949	9,071	8,944	8,899	9,287	8,500	8,060	7,326	6,857	6,190
2017/18	9,047	9,188	9,065	9,010	9,456	8,626	8,160	7,386	6,917	6,275
2018/19	9,167	9,303	9,187	9,123	9,611	8,692	8,260	7,413	6,963	6,240
2019/20	9,290	9,417	9,311	9,236	9,763	8,758	8,360	7,513	7,063	6,390
2020/21	9,414	9,529	9,435	9,351	9,914	8,824	8,460	7,613	7,163	6,550
2021/22	9,540	9,640	9,559	9,467	10,063	8,890	8,560	7,713	7,263	6,650


General Service Forecasts
Mass Market and Top Consumers
2007 to 2011
Energy (Gw.h)
11,000
10,000
9,000
8,000
7,000
6,000
5,000
2007/08
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
Fiscal Year
Mass market - 2007 Fcst
Mass market - 2008 Fcst
Mass market - 2009 Fcst
Mass market - 2010 Fcst
Mass market - 2011 Fcst
Top Consumers - 2007 Fcst
Top Consumers - 2008 Fcst
Top Consumers - 2009 Fcst
Top Consumers - 2010 Fcst
Top Consumers - 2011 Fcst

General Service Forecast Comparison (GW.h)

Fiscal Yr	Total GS - 2007 Fcst	Total GS - 2008 Fcst	Total GS - 2009 Fcst	Total GS - 2010 Fcst	Total GS - 2011 Fcst
2007/08	14,105				
2008/09	14,716	14,383			
2009/10	15,428	14,960	14,048		
2010/11	15,838	15,538	14,405	13,806	
2011/12	16,148	16,034	14,823	14,245	14,174
2012/13	16,450	16,452	15,130	14,504	14,553
2013/14	16,727	16,640	15,393	14,955	15,055
2014/15	16,982	16,823	15,842	15,190	15,252
2015/16	17,239	17,004	16,061	15,463	15,259
2016/17	17,461	17,143	16,281	15,767	15,488
2017/18	17,685	17,359	16,462	15,938	15,742
2018/19	17,872	17,574	16,612	16,097	15,862
2019/20	18,060	17,788	16,836	16,310	16,164
2020/21	18,251	18,001	17,060	16,525	16,475
2021/22	18,443	18,212	17,284	16,742	16,725

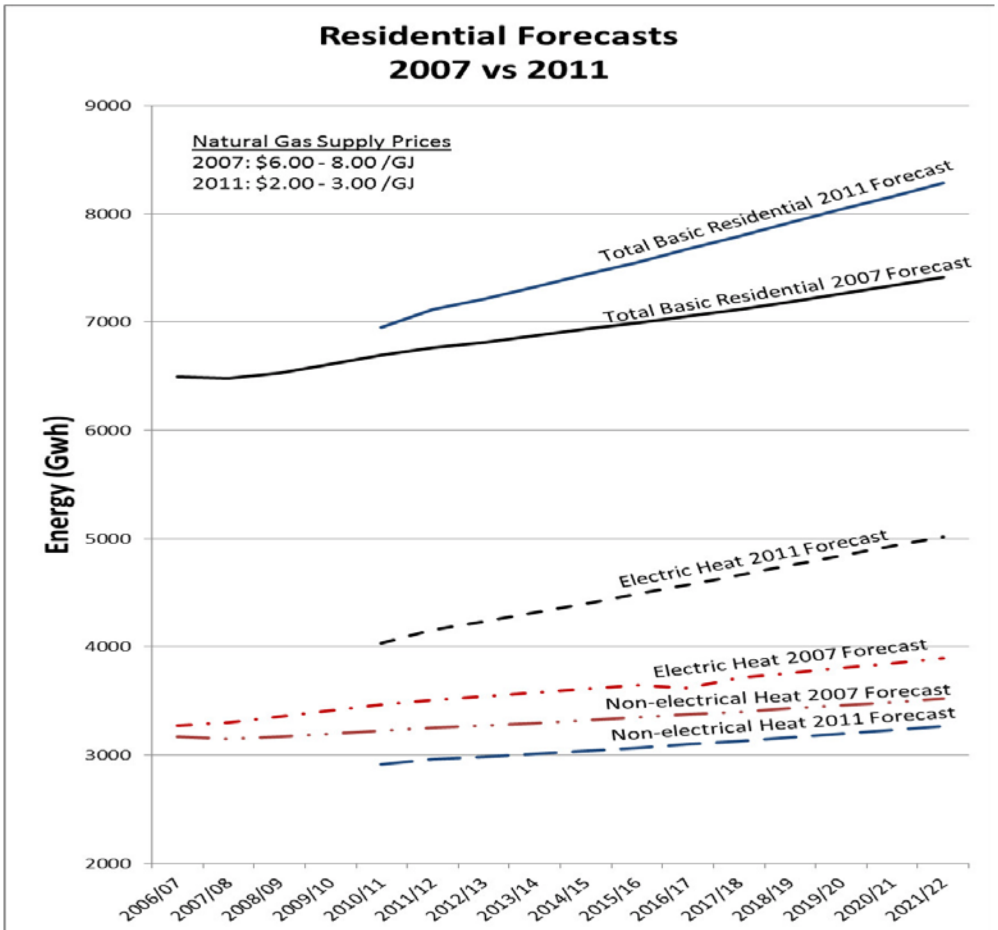


PUB/MH I-116

Reference: **Historical Load Forecast Since 2006**

Preamble: **Please provide a tabular and graphical comparison of the 2011, 2010, 2009, 2008 and 2007 electric load forecasts; separately illustrating:**

c) **Please provide MH's own version and data points for example 8.1 Residential Forecasts (2007 vs. 2011) as illustrated on the following page.**



Example Figure 8.1

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-116(a).

PUB/MH I-117

Reference: **Tab 8 2011 Load Forecast P. 15/Prior Load Forecasts**

Preamble: **Please provide a tabular and graphical comparison of the 2011, 2010, 2009, 2008 and 2007 electric load forecasts; separately illustrating:**

a) Heating Fuel Choice

Please provide the recent customer numbers/energy usage growth history from 2004/05 to 2011/12 of electric heat customers and natural gas heat customers; please also indicate the percentage of new electric heat customers that did not have a natural gas option available to them.

ANSWER:

Please see Manitoba Hydro's response to PUB-MH I-112(c) for historical customer numbers and energy usage history.

The 2009 Residential Energy Use Survey indicated that about one-third of new electric heat customers did not have a natural gas option available to them.

PUB/MH I-117

Reference: Tab 8 2011 Load Forecast P. 15/Prior Load Forecasts

Preamble: Please provide a tabular and graphical comparison of the 2011, 2010, 2009, 2008 and 2007 electric load forecasts; separately illustrating:

b) Fuel Switching MH Projection of Electric Heat Energy Usage

Please reconcile the 2011 forecast with the 2007 to 2009 forecasts of electric heat customer numbers and their usage; also provide data for non-electric.

ANSWER:

Number of Residential Customers					
	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast
	Electric Heat	Electric Heat	Electric Heat	Electric Heat	Electric Heat
2007/08	134,544				
2008/09	136,698	137,798			
2009/10	138,745	140,160	141,121		
2010/11	140,679	142,416	143,520	145,295	
2011/12	142,505	144,581	145,960	147,686	160,849
2012/13	144,265	146,709	148,406	149,867	164,043
2013/14	145,975	148,795	150,839	151,902	167,547
2014/15	147,646	150,842	153,254	153,919	171,056
2015/16	149,286	152,881	155,639	155,913	174,627
2016/17	150,893	154,893	157,990	157,878	178,242
2017/18	152,474	156,884	160,305	159,817	181,856
2018/19	154,031	158,856	162,589	161,728	185,430
2019/20	155,561	160,799	164,838	163,606	188,955
2020/21	157,058	162,714	167,049	165,456	192,427
2021/22	158,523	164,597	169,221	167,276	195,838
2022/23	159,955	166,452	171,355	169,065	199,181
2023/24	161,354	168,275	173,451	170,825	202,451
2024/25	162,720	170,070	175,509	172,555	205,640
2025/26	164,055	171,835	177,530	174,256	208,745
2026/27	165,358	173,570	179,513	175,926	211,763
2027/28	166,627	175,274	181,459	177,567	214,693
2028/29		176,950	183,369	179,179	217,533
2029/30			185,249	180,763	220,281
2030/31				182,325	222,939

Residential Electric Load (GW.h)					
	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast
	Electric Heat	Electric Heat	Electric Heat	Electric Heat	Electric Heat
2007/08	3,300				
2008/09	3,358	3,473			
2009/10	3,413	3,538	3,505		
2010/11	3,466	3,599	3,563	3,661	
2011/12	3,506	3,659	3,624	3,717	4,157
2012/13	3,540	3,716	3,686	3,773	4,232
2013/14	3,576	3,773	3,749	3,824	4,316
2014/15	3,612	3,828	3,812	3,874	4,400
2015/16	3,647	3,882	3,876	3,925	4,487
2016/17	3,681	3,937	3,939	3,975	4,575
2017/18	3,716	3,991	4,002	4,026	4,664
2018/19	3,759	4,046	4,065	4,078	4,753
2019/20	3,805	4,100	4,127	4,129	4,841
2020/21	3,850	4,154	4,189	4,181	4,929
2021/22	3,894	4,208	4,252	4,233	5,016
2022/23	3,938	4,261	4,314	4,286	5,103
2023/24	3,981	4,314	4,376	4,339	5,188
2024/25	4,024	4,367	4,438	4,392	5,273
2025/26	4,066	4,419	4,499	4,447	5,356
2026/27	4,108	4,471	4,561	4,501	5,439
2027/28	4,150	4,523	4,622	4,556	5,520
2028/29		4,574	4,683	4,612	5,601
2029/30			4,744	4,667	5,680
2030/31				4,723	5,759

Number of Residential Customers					
	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast
	Standard	Standard	Standard	Standard	Standard
2007/08	297,940				
2008/09	299,314	299,842			
2009/10	300,733	301,486	302,463		
2010/11	302,207	303,212	304,099	303,576	
2011/12	303,729	305,006	305,664	306,243	289,550
2012/13	305,256	306,830	307,195	308,647	291,571
2013/14	306,775	308,673	308,710	310,880	293,806
2014/15	308,274	310,529	310,213	313,105	296,032
2015/16	309,744	312,377	311,718	315,323	298,314
2016/17	311,188	314,218	313,228	317,542	300,648
2017/18	312,599	316,054	314,744	319,757	303,011
2018/19	313,974	317,881	316,263	321,970	305,381
2019/20	315,318	319,705	317,788	324,182	307,753
2020/21	316,635	321,526	319,322	326,390	310,120
2021/22	317,924	323,350	320,865	328,594	312,475
2022/23	319,188	325,173	322,418	330,793	314,813
2023/24	320,426	326,998	323,980	332,985	317,125
2024/25	321,636	328,823	325,550	335,172	319,406
2025/26	322,820	330,649	327,130	337,352	321,650
2026/27	323,976	332,476	328,717	339,526	323,853
2027/28	325,105	334,304	330,313	341,694	326,013
2028/29		336,132	331,918	343,856	328,126
2029/30			333,538	346,014	330,190
2030/31				348,175	332,203

Residential Electric Load (GW.h)					
	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast
	Standard	Standard	Standard	Standard	Standard
2007/08	3,146				
2008/09	3,173	3,203			
2009/10	3,199	3,227	3,249		
2010/11	3,227	3,251	3,271	3,391	
2011/12	3,255	3,276	3,294	3,432	2,961
2012/13	3,272	3,301	3,319	3,468	2,983
2013/14	3,296	3,326	3,344	3,504	3,010
2014/15	3,323	3,351	3,370	3,543	3,037
2015/16	3,348	3,375	3,397	3,584	3,067
2016/17	3,374	3,401	3,425	3,627	3,098
2017/18	3,401	3,427	3,454	3,671	3,130
2018/19	3,429	3,454	3,484	3,717	3,163
2019/20	3,459	3,482	3,515	3,764	3,197
2020/21	3,490	3,510	3,547	3,813	3,233
2021/22	3,521	3,539	3,580	3,864	3,269
2022/23	3,552	3,569	3,615	3,917	3,305
2023/24	3,583	3,600	3,651	3,972	3,343
2024/25	3,615	3,631	3,689	4,029	3,382
2025/26	3,646	3,663	3,727	4,088	3,421
2026/27	3,678	3,696	3,767	4,149	3,461
2027/28	3,709	3,729	3,808	4,211	3,502
2028/29		3,763	3,849	4,274	3,544
2029/30			3,892	4,338	3,586
2030/31				4,404	3,630

Please also see Manitoba Hydro’s response to PUB/MH I-112(c).

PUB/MH I-117

Reference: Tab 8 2011 Load Forecast P. 15/Prior Load Forecasts

Preamble: Please provide a tabular and graphical comparison of the 2011, 2010, 2009, 2008 and 2007 electric load forecasts; separately illustrating:

c) Please confirm (and explain why) 62,000 additional residential customers (over next 20 years) would choose electric space heating when electricity rates will be increasing from 7¢/kWh (2010/11) to 12.50¢/kWh (2030/31) and average annual electric heating costs could rise from $1100/yr to $2000/yr.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-112(a).

PUB/MH I-117

Reference: **Tab 8 2011 Load Forecast P. 15/Prior Load Forecasts**

Preamble: **Please provide a tabular and graphical comparison of the 2011, 2010, 2009, 2008 and 2007 electric load forecasts; separately illustrating:**

d) Natural Gas Heating

Please confirm (and explain why) only 43,000 additional residential customers in the next 20 years would choose natural gas (or other) space heating with annual heating costs currently at $500/yr and likely to remain low for at least 5-10 years.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-112(a).

PUB/MH I-117

Reference: Tab 8 2011 Load Forecast P. 15/Prior Load Forecasts

e) Please provide the most recent version of typical Space Heating and Water Heating Cost Comparison.

ANSWER:

Please see attached Space and Water Heating Cost Comparison Chart based on energy prices current as of August 1, 2012.

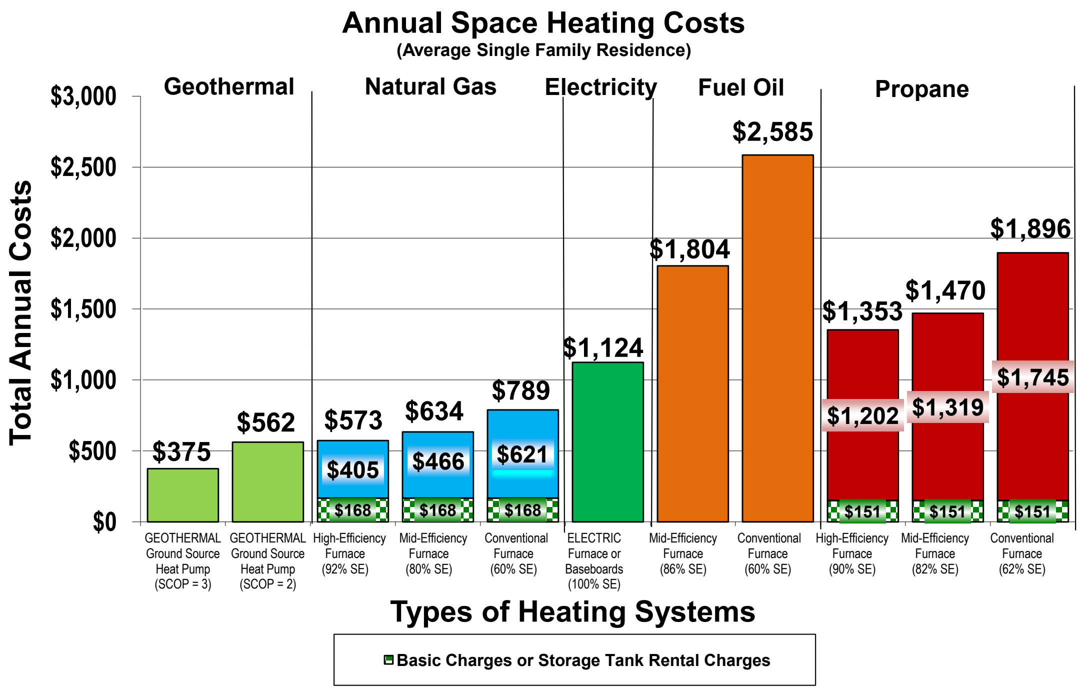
Typical space & water heating costs

Average single family residence at rates in effect August 1, 2012

1

Wondering about your energy options for heating?

1. Consult the charts to identify the costs of your current home heating and water heating systems.
2. Review the costs of other systems to see how your costs compare.
3. Consult the accompanying notes for guidance if you are thinking of switching systems or building a new home.



Energy rates

Natural gas:
$0.2321/cubic metre

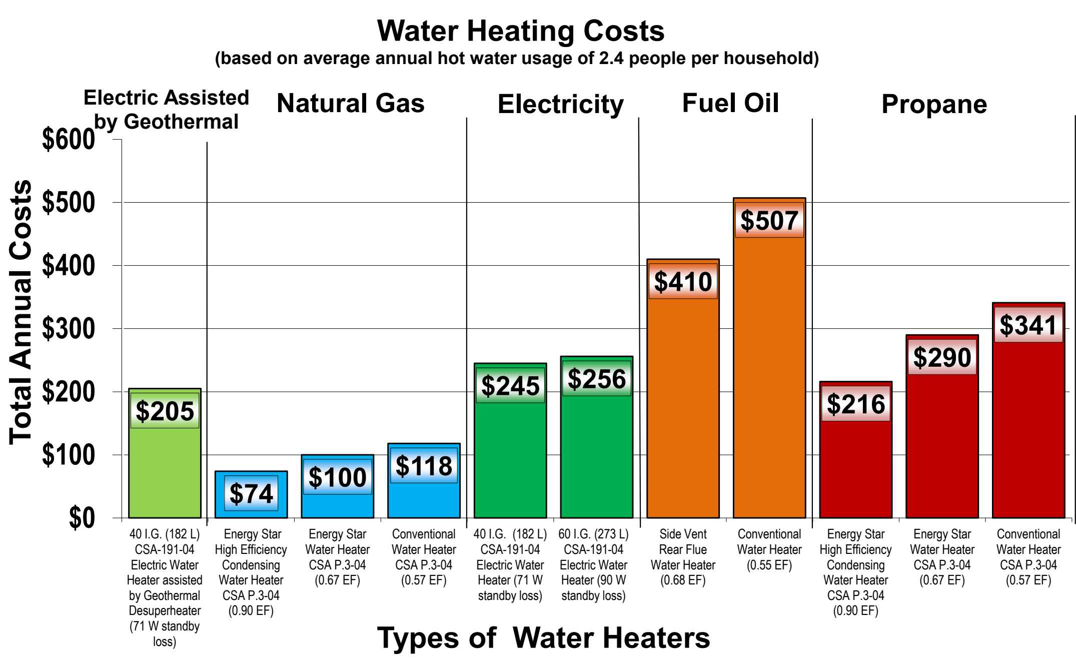
Electricity:
$0.0677/kilowatt-hour

Fuel oil:
$0.999/litre

Propane:
$0.462/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



Typical space & water heating costs

Average single family residence at rates in effect August 1, 2012

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water-heating costs are based on typical usage of the average Manitoba household of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on August 1, 2012.

Your actual annual costs will vary, since natural gas rates change four times a year, while propane and oil rates can change weekly. Note that Primary Gas represents the bulk of the gas used. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.0967 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of 0.2321 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

Key points if you are thinking of converting

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Conventional furnaces no longer manufactured

The space heating chart includes conventional natural gas, fuel oil, and propane furnaces. These conventional furnaces have not been manufactured since 1992, but many are still in operation.

High efficiency furnaces are now required by law

Effective December 30, 2009 the Province of Manitoba enacted legislation controlling the sale and lease of gas and propane heating equipment. Visit www.greenmanitoba.ca (click on the energy tab) for more information on this regulation.

Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

Issues that can arise once the natural gas water heater vents alone on the old chimney include: flue gases condensing in the chimney, or flue gas spillage into the home. If these venting problems occur, you may need to upgrade you venting system or have other work performed to rectify them. If the upgrades are costly, other options to consider are replacing the conventional heater with a side-wall vented gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency gas furnace will reduce the uncontrolled ventilation provided by the chimney. The uncontrolled chimney ventilation will be completely eliminated if you also replace your conventional gas water heater and either remove or cap off the chimney.

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

The increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

- improved weatherstripping and caulking on doors and windows and other areas of air leakage (but not on storm doors)
- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

Manitoba Hydro
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Typical space & water heating costs

Average single family residence at rates in effect August 1, 2012

3

Carbon monoxide safety

If you are burning heating oil, diesel, propane, kerosene, natural gas, wood, or coal in your home, or if you have an attached garage, we recommend that you install at least one carbon monoxide detector in your home.

The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on “Carbon monoxide safety — Because your family comes first!”

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

The result is the number of years it will take for the new system to pay for itself.

Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro’s system average for natural gas heated homes.
- Water heating usage is based on Manitoba Hydro’s average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day that are heated up an average temperature rise of 50 C.
- The Electric water heating assisted by geothermal desuperheater option is based on Manitoba Hydro’s field monitoring of nine homes with geothermal heating and desuperheaters where 80 per cent of the average water heating load was provided by the electric heating elements of the water tank and 20 per cent by the desuperheater.
- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. See table below. This charge may not apply to all customers and may vary.
- The cost of space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
- Energy Factor (EF) is an overall efficiency rating of the water heater. The higher the EF, the more efficient the model. Electric water heaters are required to have maximum standby losses of 71 watts for a 40 gallon and 90 Watts for a 60 gallon.
- SCOP (Seasonal Coefficient of Performance) = 2 and = 3 appears in the home heating chart under geothermal closed loop heat pump. It refers to the Seasonal Coefficient of Performance of the heat pump over an entire heating season.

  SCOP is defined as the total heat output of the system during the heating season, divided by the total energy input to the system.

  The SCOP of a geothermal heat pump system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer’s COP rating of the heat pump “unit”. The overall system SCOP will therefore always be significantly lower than the unit COP.

  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at 0.0967 per cubic metre. Primary Gas currently comprises 94 per cent of the gas supplied (supplemental gas is 6 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect August 1, 2012

	Commodity charge	Heating value	
Natural gas	$0.2321/cubic metre	35,310	Btu/cubic metre
Electricity	$0.0677/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$0.999/litre	36,500	Btu/litre
Propane	$0.462/litre	24,200	Btu/litre

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PUB/MH I-117

Reference: **Tab 8 2011 Load Forecast P. 15/Prior Load Forecasts**

Preamble: **Please provide a tabular and graphical comparison of the 2011, 2010, 2009, 2008 and 2007 electric load forecasts; separately illustrating:**

f) Please explain what fuel switching assumptions (customer numbers) MH made in defining the electric heating and non-electric heating customer growth.

ANSWER:

For the 2007, 2008, 2009, and 2010 Electric Load Forecasts, fuel switching assumptions were not explicitly modeled. The market share of electric space heat was forecast using econometric models.

For the 2011 Electric Load Forecast, the number of new homes using electric space heat was forecast using an econometric model as described in the 2011 Electric Load Forecast on pages 67-68. The 2011 Electric Load Forecast can be found in Appendix 8.1 of this Application.

PUB/MH I-118

Reference: 2011 GRA Exhibit - #MH 38/2011 Load Forecast Page 23, Prior Load Forecast

a) Industry Load History

Please file an updated version of GRA 2010 CAC/MH II 220 to include 2010/11 and 2011/12 industry sector demands and energy consumption.

ANSWER:

The tables below provide the 7 year historical data for the GSL >30 kV customers by industry type. The contract demand commitments were derived by adding the maximum kVA recorded over the 7 year period for each customer in each industry sector.

Note that the 'Pipeline' industry previously shown in response to PUB/MH II 220 of the last rate hearing has now been combined with the 'Petroleum' industry. Also, the 'University' sector previously shown is no longer included as these accounts should have been billed as Large 750-30 kV and therefore not included in the response.

CHEMICAL (contract demand commitments = 268,335 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	148,601,183	155,892,021	157,927,794	176,891,767	146,405,193	168,686,958	179,219,973
May	146,781,207	152,247,362	146,944,903	168,708,061	134,806,557	169,663,833	177,915,549
Jun	149,290,582	154,831,998	140,606,667	169,713,271	160,468,355	156,771,887	129,556,509
Jul	157,589,204	159,534,571	156,949,601	154,281,069	171,009,832	162,927,407	171,959,769
Aug	154,873,461	160,498,597	159,295,545	172,911,909	174,636,600	171,890,428	174,111,870
Sep	151,860,894	136,798,401	150,627,759	169,165,142	158,381,897	166,860,223	167,352,627
Oct	161,588,348	158,015,891	159,327,729	174,235,816	175,117,431	172,660,610	175,344,159
Nov	155,237,054	156,100,283	151,846,285	171,896,675	163,471,668	177,017,628	174,103,470
Dec	154,159,102	163,256,634	163,808,332	132,627,931	178,355,248	181,196,732	180,121,233
Jan	161,152,004	162,532,896	168,328,709	173,512,201	181,902,400	179,469,032	179,639,750
Feb	147,732,278	144,273,938	160,259,063	145,493,335	170,208,155	163,370,410	164,570,627
Mar	163,694,945	155,015,952	177,169,640	174,554,890	153,366,637	173,689,113	183,318,180
Total	**1,852,560,262**	**1,858,998,544**	**1,893,092,027**	**1,983,992,067**	**1,968,129,973**	**2,044,204,261**	**2,057,213,716**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	224,547	227,921	231,027	258,752	222,893	260,387	258,626
May	225,366	232,489	229,245	253,699	222,726	254,402	249,624
Jun	225,544	229,860	229,540	254,554	237,036	248,314	249,015
Jul	225,576	229,772	229,668	254,921	253,939	245,161	250,010
Aug	221,586	230,693	230,635	254,097	254,680	250,359	250,425
Sep	224,652	204,407	229,745	254,254	254,116	249,791	249,634
Oct	180,910	230,022	232,565	253,064	253,581	249,361	252,211
Nov	228,758	230,009	232,358	253,177	259,069	259,877	258,520
Dec	221,845	229,993	233,436	210,632	259,610	260,091	254,846
Jan	229,939	229,469	235,015	258,715	258,942	260,011	258,812
Feb	228,909	231,120	255,829	252,078	265,755	260,927	259,768
Mar	229,951	230,309	260,317	258,771	231,428	260,096	259,329
Total	**2,667,584**	**2,736,065**	**2,829,378**	**3,016,714**	**2,973,774**	**3,057,776**	**3,050,820**

FOOD AND BEVERAGE (contract demand commitments = 22,714 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	7,331,721	7,940,843	7,978,390	8,194,913	9,351,095	9,828,558	9,017,071
May	6,804,038	8,074,449	7,745,234	8,628,881	9,806,690	9,946,207	8,367,125
Jun	7,069,018	7,814,565	8,443,883	9,219,983	10,179,624	10,093,965	9,301,871
Jul	6,762,615	7,909,607	8,618,722	8,809,288	8,736,116	9,125,853	7,908,536
Aug	7,097,174	7,508,813	9,225,730	8,357,472	9,597,020	8,328,025	8,615,886
Sep	7,189,369	8,325,854	9,266,409	9,660,346	9,773,546	9,599,494	7,708,840
Oct	6,815,200	8,764,392	9,207,625	10,331,645	9,762,676	8,741,053	9,171,225
Nov	7,646,995	9,122,564	9,458,058	10,166,645	9,000,635	7,896,878	9,297,619
Dec	7,782,850	8,782,313	9,181,531	9,597,913	10,038,982	9,204,737	9,679,053
Jan	7,886,723	8,648,604	9,695,433	9,831,074	9,729,823	9,787,585	9,759,370
Feb	7,956,942	8,753,895	8,815,121	9,478,288	8,920,691	8,739,816	9,226,170
Mar	8,079,588	8,569,844	8,977,461	8,819,300	8,793,745	9,553,683	9,144,926
Total	**88,422,233**	**100,215,743**	**106,613,597**	**111,095,748**	**113,690,643**	**110,845,854**	**107,197,692**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	16,696	16,978	18,500	18,966	19,335	19,950	20,020
May	16,700	17,509	18,357	18,710	19,907	20,305	20,459
Jun	17,136	17,791	19,249	18,674	19,958	19,966	20,752
Jul	17,936	17,935	19,378	18,559	19,628	18,367	19,710
Aug	16,747	19,071	19,163	19,407	19,952	20,229	18,759
Sep	16,568	17,622	20,021	19,650	19,960	19,647	18,121
Oct	16,461	17,974	19,452	19,051	19,881	19,407	19,970
Nov	16,263	18,216	19,188	19,183	19,090	18,947	19,909
Dec	17,242	18,112	19,338	19,007	19,124	19,234	19,742
Jan	17,185	18,288	19,064	18,999	19,376	19,451	19,781
Feb	17,152	18,301	19,017	19,100	19,172	19,586	19,397
Mar	17,092	18,475	18,833	19,376	19,141	19,216	19,669
Total	**203,178**	**216,273**	**229,561**	**228,681**	**234,524**	**234,305**	**236,289**

MINING (contract demand commitments = 24,299 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	3,327,731	5,025,099	4,891,176	5,401,801	7,159,513	6,533,036	7,481,317
May	2,807,664	2,059,903	4,308,792	4,692,516	6,508,480	6,784,371	7,097,513
Jun	3,065,689	3,437,747	3,793,876	4,609,059	5,240,836	5,941,992	6,155,572
Jul	2,653,635	3,299,686	3,860,997	4,824,177	5,705,635	6,543,732	7,111,386
Aug	2,594,475	3,157,047	3,929,730	4,400,529	4,562,212	6,170,413	6,874,108
Sep	2,570,100	3,475,376	3,824,034	4,302,224	4,243,254	6,427,987	7,976,695
Oct	2,810,304	3,489,820	3,743,476	5,178,034	5,214,065	6,818,045	7,906,458
Nov	3,416,305	3,723,049	5,020,588	5,542,167	5,543,285	6,133,290	8,780,800
Dec	3,427,185	4,280,880	4,846,813	5,785,477	5,427,867	6,594,433	9,503,691
Jan	3,573,438	4,476,594	5,299,429	6,456,118	5,694,618	7,275,482	10,682,180
Feb	3,830,498	4,912,986	5,346,203	6,712,561	5,893,792	7,746,525	9,134,934
Mar	3,727,073	4,658,074	5,073,788	7,253,063	5,626,032	7,077,957	9,832,632
Total	**37,804,097**	**45,996,261**	**53,938,902**	**65,157,726**	**66,819,589**	**80,047,263**	**98,537,286**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	9,026	8,297	10,034	10,825	13,979	13,898	13,835
May	8,689	7,857	9,445	10,404	13,378	13,999	14,706
Jun	8,666	8,374	9,079	9,841	11,665	12,909	13,578
Jul	8,395	8,162	8,637	10,031	11,609	12,703	14,582
Aug	8,452	7,672	7,574	9,977	10,800	12,643	14,836
Sep	8,608	7,858	7,870	9,913	11,483	13,225	15,330
Oct	8,991	6,963	8,293	10,623	12,258	14,359	16,478
Nov	6,840	8,745	9,799	10,788	12,653	13,928	17,234
Dec	6,779	9,116	10,250	11,775	9,971	13,578	18,808
Jan	7,656	9,951	10,060	13,011	10,498	13,843	19,845
Feb	7,323	9,824	10,463	13,851	12,137	14,044	19,310
Mar	7,616	9,756	11,066	14,731	11,843	14,347	19,043
Total	**97,041**	**102,574**	**112,570**	**135,772**	**142,275**	**163,476**	**197,588**

MISC. INDUSTRY (contract demand commitments = 18,870 kVA per month)

kWh	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Apr	2,405,700	2,442,552	4,003,706	3,641,075	5,228,683	5,289,854	4,198,702
May	2,296,200	2,235,647	3,822,673	3,319,108	4,542,723	4,205,431	4,574,184
Jun	2,404,500	2,303,544	3,995,373	3,554,598	4,187,744	4,678,700	4,096,759
Jul	2,470,500	2,565,451	4,323,107	3,558,923	3,837,595	4,321,694	4,599,300
Aug	2,520,000	2,574,190	3,884,738	3,461,263	3,925,088	4,294,037	4,622,009
Sep	2,504,700	2,530,603	3,612,707	3,444,621	3,741,488	4,150,956	4,335,208
Oct	2,457,300	3,640,820	3,632,903	3,972,671	3,868,445	4,297,398	3,982,644
Nov	2,777,100	3,410,570	3,644,743	6,817,232	3,819,334	3,712,833	4,047,534
Dec	2,655,000	3,502,950	3,767,931	4,111,100	4,024,852	3,681,746	4,153,843
Jan	2,844,300	3,480,737	3,813,912	4,096,530	4,209,609	3,975,747	4,258,170
Feb	2,810,100	3,787,826	3,721,935	4,143,184	3,911,511	4,281,996	4,082,395
Mar	2,643,977	3,764,979	3,797,911	4,540,236	3,262,965	4,726,440	4,488,193
Total	**30,789,377**	**36,239,869**	**46,021,639**	**48,660,541**	**48,560,037**	**51,616,832**	**51,438,941**

kVA	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Apr	5,615	6,759	11,367	10,595	11,431	16,502	13,300
May	5,578	6,751	10,862	10,503	11,305	12,519	12,913
Jun	6,537	6,109	10,997	9,762	12,095	12,865	12,631
Jul	6,726	8,237	12,459	9,913	13,560	13,178	13,659
Aug	6,582	6,818	11,020	11,031	12,068	12,601	13,879
Sep	6,189	6,982	10,230	10,513	11,868	10,955	13,242
Oct	6,174	10,181	10,406	10,762	12,072	11,059	12,569
Nov	6,333	9,622	9,499	16,152	11,095	11,042	12,160
Dec	6,453	9,246	9,164	10,289	11,365	10,095	12,649
Jan	6,383	9,766	9,860	11,107	11,032	11,779	12,786
Feb	7,178	10,416	10,555	11,708	9,656	13,329	12,981
Mar	6,655	10,525	11,055	12,431	8,379	13,960	13,807
Total	**76,403**	**101,414**	**127,474**	**134,766**	**135,925**	**149,885**	**156,576**

PETROLEUM (contract demand commitments = 255,754 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	68,684,760	77,252,876	74,915,154	76,770,611	73,269,161	60,303,779	66,034,378
May	64,512,976	68,937,372	64,629,758	70,560,836	70,410,420	67,818,451	64,959,126
Jun	63,243,195	66,828,266	67,429,250	77,140,533	84,788,210	63,889,975	63,074,332
Jul	69,240,765	72,584,134	72,747,357	79,578,937	87,259,561	67,104,793	71,429,490
Aug	69,106,224	77,225,485	83,130,272	80,039,315	73,473,067	57,398,568	70,428,607
Sep	67,357,484	75,516,115	72,646,716	74,894,904	72,036,262	54,100,095	74,880,345
Oct	71,572,688	80,753,890	71,681,068	82,374,133	71,231,601	59,627,334	70,482,931
Nov	71,685,494	78,434,802	78,124,094	86,970,224	73,112,755	52,968,462	67,044,859
Dec	82,569,859	80,759,036	75,234,007	91,095,650	77,112,343	69,492,995	74,608,429
Jan	84,217,077	77,181,923	81,535,327	84,750,806	82,458,671	74,333,710	82,197,737
Feb	75,497,443	75,189,964	69,059,186	74,278,174	70,201,618	74,975,226	73,833,057
Mar	75,555,518	81,827,612	81,792,569	76,293,721	79,996,008	77,916,161	88,011,112
Total	**863,243,483**	**912,491,475**	**892,924,758**	**954,747,844**	**915,349,677**	**779,929,549**	**866,984,403**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	134,272	161,135	168,636	162,647	163,627	172,856	185,288
May	141,933	154,803	151,068	147,850	175,099	157,745	168,770
Jun	146,422	149,325	153,487	164,373	182,462	156,851	169,409
Jul	143,477	156,362	168,586	161,835	182,801	155,433	169,955
Aug	135,618	157,984	170,811	160,281	178,588	152,828	179,030
Sep	138,228	158,361	165,808	160,831	182,796	158,369	177,090
Oct	143,669	170,922	167,574	167,132	181,289	151,675	177,151
Nov	155,434	173,154	168,701	173,183	179,450	150,023	178,178
Dec	153,289	168,973	171,837	185,598	174,098	171,568	185,754
Jan	164,971	166,609	174,420	169,004	190,160	180,184	185,481
Feb	164,717	175,755	165,937	169,088	183,593	203,541	184,333
Mar	155,780	172,466	167,169	163,993	181,044	203,256	209,886
Total	**1,777,810**	**1,965,849**	**1,994,036**	**1,985,815**	**2,155,006**	**2,015,330**	**2,170,326**

PRIMARY METALS (contract demand commitments = 389,607 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	188,933,503	182,660,783	192,869,654	188,356,310	165,806,506	170,930,480	183,632,714
May	193,912,944	189,271,715	198,145,512	194,225,067	168,124,697	162,922,639	190,831,891
Jun	186,043,477	180,118,914	183,846,440	176,883,947	161,320,690	168,946,514	174,985,311
Jul	159,245,576	176,349,365	156,810,451	170,763,210	161,332,967	149,259,541	151,169,440
Aug	139,056,043	168,040,469	173,229,085	178,074,758	122,339,720	130,877,418	125,456,109
Sep	156,304,142	170,022,971	186,862,349	183,837,410	162,845,897	173,146,708	165,458,114
Oct	195,536,921	184,824,548	196,429,849	188,825,363	181,313,054	181,308,751	194,151,393
Nov	201,328,038	194,629,494	193,096,365	202,126,743	178,423,574	196,281,835	207,459,235
Dec	204,010,494	200,825,326	202,395,382	189,992,499	184,774,310	198,394,034	216,757,803
Jan	207,060,363	205,807,881	209,213,905	203,256,945	190,035,940	212,314,850	207,574,796
Feb	194,131,728	186,197,229	198,770,197	173,143,331	175,374,034	192,608,108	191,566,837
Mar	211,789,797	209,123,472	207,962,371	187,726,350	181,634,902	216,502,043	191,259,852
Total	**2,237,353,026**	**2,247,872,167**	**2,299,631,560**	**2,237,211,933**	**2,033,326,291**	**2,153,492,921**	**2,200,303,495**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	315,688	325,184	345,058	338,326	314,896	306,163	344,166
May	313,981	320,316	333,118	329,242	315,863	307,288	336,883
Jun	305,536	318,425	319,189	311,789	310,782	314,377	319,290
Jul	301,951	309,100	307,496	307,594	298,947	283,846	380,351
Aug	285,061	307,638	311,822	309,364	283,131	285,935	282,923
Sep	313,719	298,888	323,564	316,759	304,226	319,945	305,290
Oct	319,062	300,404	326,699	328,598	309,465	335,684	339,023
Nov	334,618	335,072	330,821	336,426	319,170	347,340	365,052
Dec	341,097	342,169	327,913	345,809	316,701	356,695	365,955
Jan	343,164	352,539	338,853	345,647	315,712	360,158	355,089
Feb	344,686	346,504	340,457	328,975	320,229	361,523	334,828
Mar	333,571	340,696	344,757	327,442	327,983	362,808	324,401
Total	**3,852,134**	**3,896,935**	**3,949,748**	**3,925,971**	**3,737,106**	**3,941,761**	**3,981,252**

PULP & PAPER (contract demand commitments = 196,177 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	65,462,742	62,392,907	63,892,905	56,406,230	66,963,654	15,208,824	15,270,834
May	64,966,706	63,763,003	65,613,499	61,475,290	69,931,644	18,479,659	16,516,480
Jun	63,134,669	64,076,655	63,348,587	61,651,751	41,436,505	18,433,792	17,282,236
Jul	69,639,800	66,763,152	74,068,655	63,595,564	18,784,805	17,119,610	16,956,617
Aug	69,556,426	63,261,771	69,920,817	62,752,543	38,994,446	16,626,426	10,018,069
Sep	68,909,784	63,442,432	59,295,535	58,714,842	15,697,408	16,643,953	14,184,112
Oct	64,115,364	57,087,426	65,021,461	60,512,807	13,591,911	13,169,880	14,439,523
Nov	61,352,244	57,980,835	61,628,186	57,459,095	12,835,293	14,468,904	14,608,567
Dec	62,626,292	62,240,933	59,660,710	42,852,821	14,028,490	12,582,387	13,887,203
Jan	66,102,928	62,617,615	62,508,975	53,310,089	12,902,400	13,991,323	13,969,403
Feb	59,298,869	57,355,092	56,614,098	34,792,372	11,789,316	12,816,607	11,519,528
Mar	64,540,726	62,930,087	64,721,804	62,445,715	16,622,693	16,765,591	13,419,998
Total	**779,706,550**	**743,911,908**	**766,295,232**	**675,969,119**	**333,578,565**	**186,306,946**	**172,072,570**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Apr	103,871	101,375	98,583	100,093	112,534	32,410	33,870
May	105,121	103,285	99,913	101,008	113,010	27,937	29,905
Jun	111,322	106,451	104,703	102,802	100,993	37,093	39,008
Jul	113,744	103,716	118,396	111,743	96,288	18,748	30,153
Aug	111,256	103,643	115,567	105,109	99,066	27,929	27,466
Sep	108,994	101,776	114,412	102,836	89,500	27,540	37,206
Oct	121,180	99,482	103,593	103,954	78,102	30,335	25,530
Nov	107,181	103,430	111,176	102,181	80,997	29,607	28,762
Dec	106,113	98,789	104,984	99,358	45,250	29,680	29,999
Jan	102,808	102,108	102,334	99,726	46,764	29,452	30,579
Feb	102,258	100,487	101,955	102,908	44,813	29,076	28,306
Mar	117,574	99,784	118,259	113,504	55,919	30,449	26,556
Total	**1,311,422**	**1,224,326**	**1,293,876**	**1,245,222**	**963,236**	**350,256**	**367,338**

PUB/MH I-118

Reference: 2011 GRA Exhibit - #MH 38/2011 Load Forecast Page 23, Prior Load Forecast

b) Industry Load Projections

Please extend the tables to indicate industry sector forecast demand and consumption for the years from 2012/13 to 2017/18; and explain how and when the two Northern Manitoba smelter closures will be offset.

ANSWER:

The forecast for the Large >30 kV customer class is comprised of 27 "Top Consumers" and 26 "Mass Market" customers. Only the Top Consumers are forecasted on an individual basis. The Mass Market customers are forecasted as a group, therefore segregating the forecast data by industry sector is not possible for all the customers.

Please see Manitoba Hydro's response to PUB/MH I-111(c) for the forecast growth of the Top Consumers for 2011/12, 2012/13 and 2013/14. The growth is 960 GWh over the three years, which more than offsets the effect of the smelter closure.

Manitoba Hydro is aware that one smelter did recently close, but this smelter had little impact on Manitoba Hydro as its primary fuel was not electricity. Another smelter is expected to close in the near future. This closure has been accounted for in the System Load Forecast included as Appendix 8.1 in the current filing. Due to customer confidentiality Manitoba Hydro cannot elaborate on the specifics of this closure.

PUB/MH I-118

Reference: 2011 GRA Exhibit - #MH 38/2011 Load Forecast Page 23, Prior Load Forecast

c) **Please re-file 2011Load Forecast Table 11 (p.23) Total General Service Sales in same format as Table 8 (p.27) of 2009 Load Forecast also showing customer numbers and average customer consumption for both mass market and top consumers.**

ANSWER: Please see the following table.

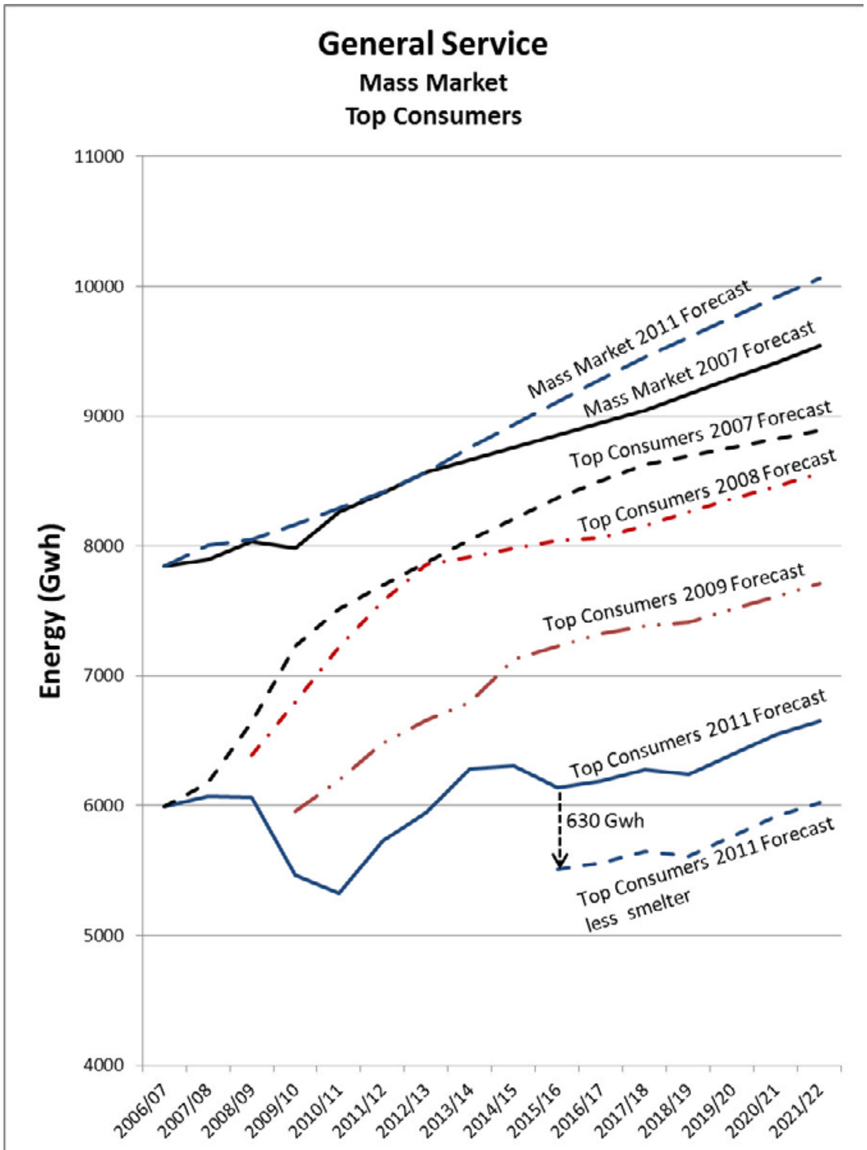
BASIC GENERAL SERVICE SALES
2011 Base Forecast
2000/01 - 2030/31

Fiscal	Mass Market			Top Consumers			Total General Service Basic		
Year	(Mtrs.)	(GW.h)	(Avg.)	(Mtrs.)	(GW.h)	(Avg.)	(Mtrs.)	(GW.h)	(Avg.)
2000/01	59759	7110	118970	31	4515	145639850	59790	11624	194420
2001/02	60086	7084	117902	25	4818	192739001	60111	11903	198013
2002/03	60265	7467	123900	26	5282	203139444	60291	12748	211449
2003/04	60672	7460	122955	27	5423	200857671	60699	12883	212245
2004/05	60924	7516	123362	26	5714	219774330	60950	13230	217060
2005/06	61491	7587	123380	26	5948	228753323	61517	13534	220009
2006/07	63596	7839	123269	26	5989	230346465	63622	13828	217353
2007/08	63855	8006	125382	26	6075	233643398	63881	14081	220425
2008/09	64140	8049	125485	26	6065	233277664	64166	14114	219958
2009/10	64758	7985	123304	26	5461	210031369	64784	13446	207547
2010/11	65193	8258	126663	26	5324	204766799	65219	13581	208244
2011/12	65711	8408	127956	31	5730	184851613	65742	14139	215061
2012/13	66291	8566	129224	31	5951	191964516	66322	14517	218891
2013/14	66958	8762	130853	31	6284	202693548	66989	15045	224591
2014/15	67607	8937	132183	31	6306	203403226	67638	15242	225347
2015/16	68256	9113	133512	32	6136	191734375	68288	15248	223297
2016/17	68898	9287	134795	32	6191	193453125	68930	15478	224541
2017/18	69529	9456	135999	32	6276	196109375	69561	15731	226153
2018/19	70127	9611	137044	32	6241	195015625	70159	15851	225930
2019/20	70701	9763	138084	32	6391	199703125	70733	16153	228368
2020/21	71267	9914	139111	32	6551	204703125	71299	16465	230922
2021/22	71824	10063	140110	32	6651	207828125	71856	16714	232600
2022/23	72372	10211	141096	32	6751	210953125	72404	16962	234267
2023/24	72909	10357	142054	32	6851	214078125	72941	17208	235910
2024/25	73433	10502	143013	32	6951	217203125	73465	17452	237560
2025/26	73944	10643	143939	32	7051	220328125	73976	17694	239185
2026/27	74443	10783	144845	32	7151	223453125	74475	17933	240795
2027/28	74928	10921	145748	32	7251	226578125	74960	18171	242411
2028/29	75399	11052	146577	32	7351	229703125	75431	18402	243962
2029/30	75855	11181	147399	32	7451	232828125	75887	18631	245515
2030/31	76298	11308	148212	32	7551	235953125	76330	18859	247069

PUB/MH I-119

Reference: 2011 Load Forecast

Please file MH's own version and data points of Example Figure 8.2 General Service – Mass Market/Top Consumers (2011 and prior years forecasts) less the Northern Manitoba smelter closure.



Example Figure 8.2

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-116(b) for the data points and graphical comparison. The 2011 Electric Load Forecast includes the forecast impact of the reported Northern Manitoba smelter closure.

PUB/MH I-120

Reference: 2011 Load Forecast – Appendix 8.1 Page 39 – Total Energy Forecast

a) Please confirm that MH's 2011 Net Forecast Energy Load at Generation (in 2021/22) has dropped by about 900 GWh since 2007 and about 250 GWh since 2009.

ANSWER:

Manitoba Hydro's 2011 Net Firm Energy Load Forecast at Generation for the year of 2021/22 has dropped by 916 GW.h from the 2007 Load Forecast and 276 GW.h from the 2009 Load Forecast.

PUB/MH I-120

Reference: 2011 Load Forecast – Appendix 8.1 Page 39 – Total Energy Forecast

b) Please confirm that in the absence of an offsetting new industrial load, the Northern Manitoba smelter closure will reduce MH total net forecast energy by about 600 GWh after 2016 and possibly past

ANSWER:

The 2011 Load Forecast includes the forecast impact of the reported Northern Manitoba smelter closure.

PUB/MH I-120

Reference: 2011 Load Forecast – Appendix 8.1 Page 39 – Total Energy Forecast

c) Please define MH's domestic marketing initiatives which could see new load growth in the top consumers category.

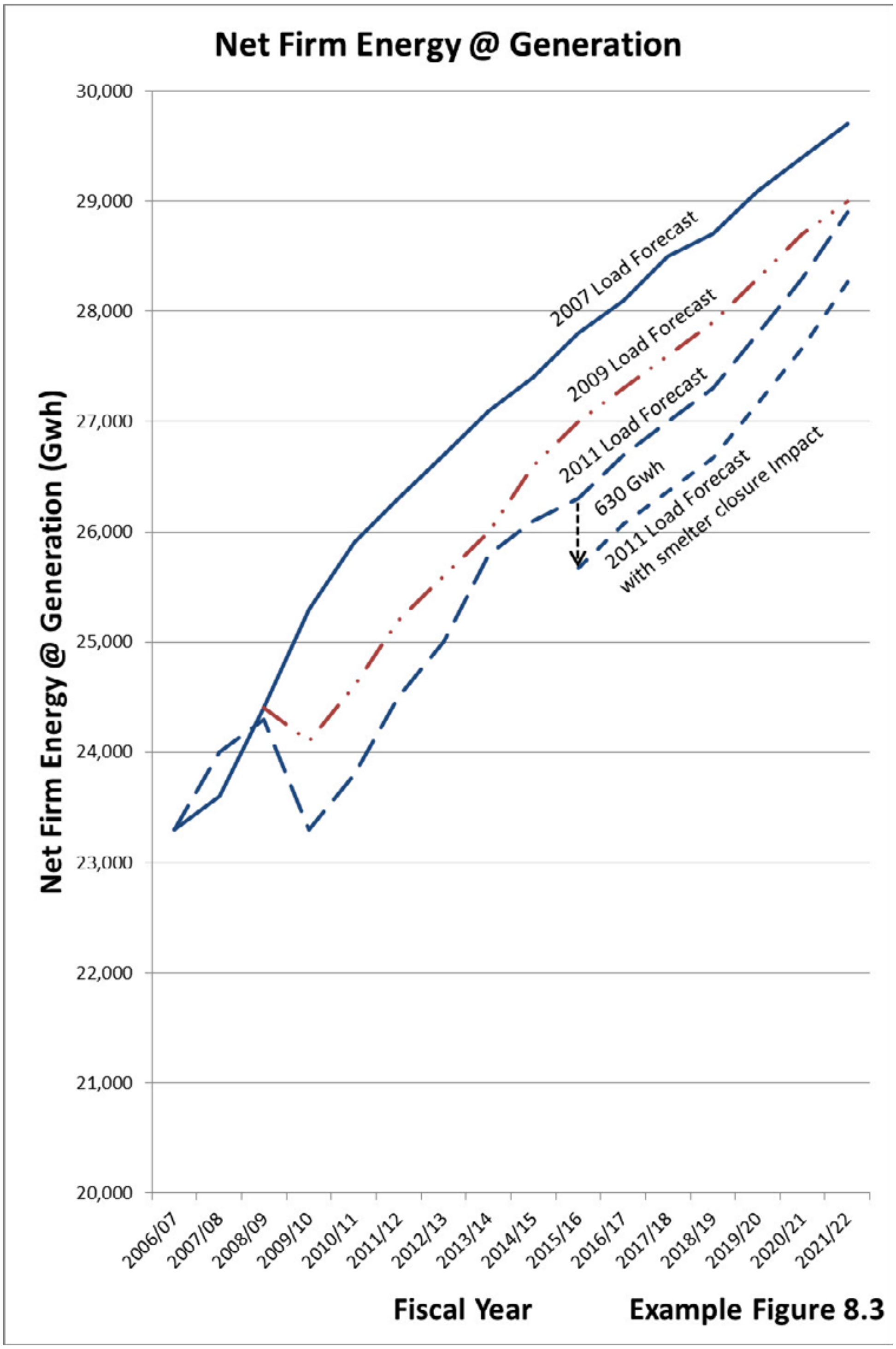
ANSWER:

Manitoba Hydro responds to prospective requests for electrical services for new loads. Requests may originate from various Economic Development agencies or provincial departments. Manitoba Hydro’s role is to support agencies that are responsible for investment attraction, including: preparing the energy section of proposals, preparing energy operating cost estimates and comparisons, explaining rate structures, and preparing service extension cost estimates for electricity and natural gas. Due to the commercially sensitive information involved, all requests are treated confidentially.

PUB/MH I-120

Reference: 2011 Load Forecast – Appendix 8.1 Page 39 – Total Energy Forecast

d) Please file MH's own version and data points of Example Figure 8.3 Net Firm Energy at Generation (2011 and prior years forecasts).

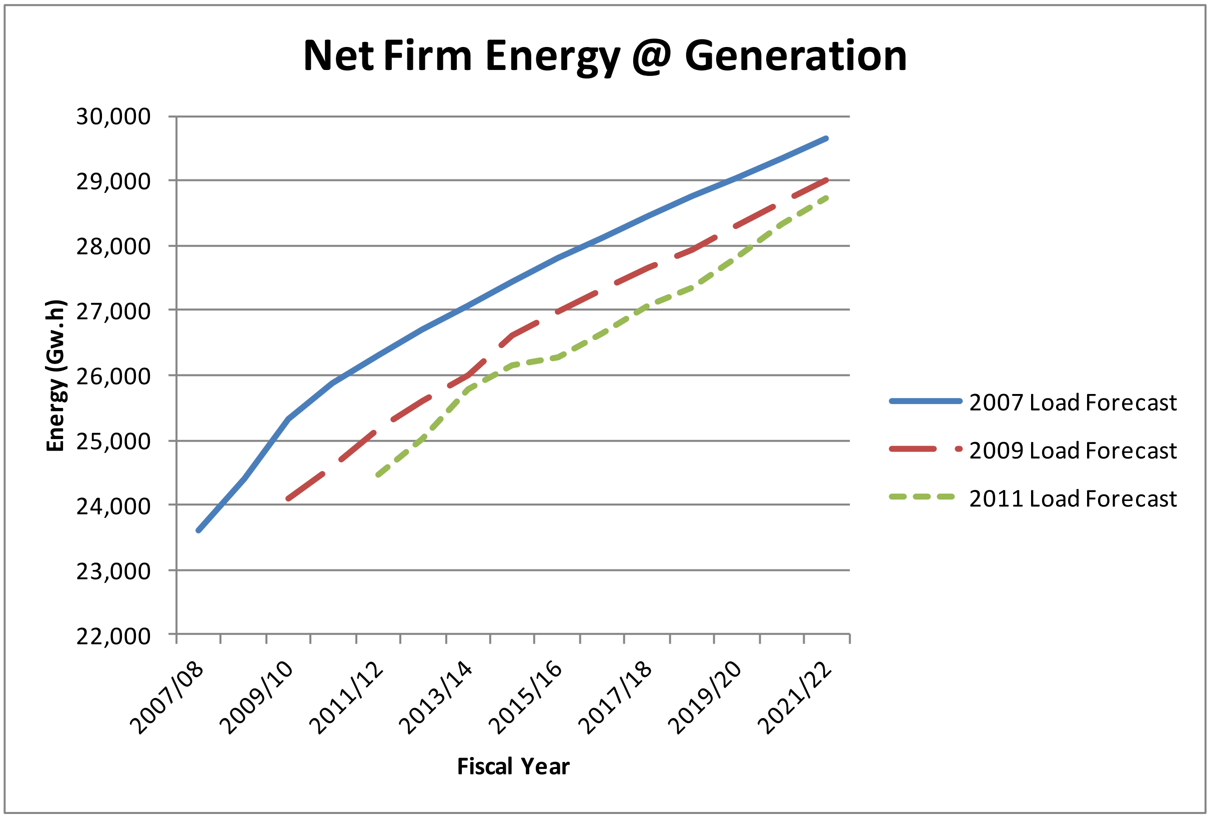


Example Figure 8.3

ANSWER:

The 2011 Electric Load Forecast includes the forecast impact of the reported Northern Manitoba smelter closure, which can be seen in the graph as the decrease beginning in 2014/15 and 2015/16.

Net Firm Energy @ Generation (Gw.h)			
Fiscal Yr	2007 Load Forecast	2009 Load Forecast	2011 Load Forecast
2007/08	23,596		
2008/09	24,398		
2009/10	25,323	24,080	
2010/11	25,869	24,600	
2011/12	26,290	25,159	24,475
2012/13	26,706	25,599	25,030
2013/14	27,079	26,012	25,787
2014/15	27,441	26,618	26,141
2015/16	27,804	26,973	26,264
2016/17	28,126	27,331	26,651
2017/18	28,453	27,644	27,062
2018/19	28,748	27,923	27,338
2019/20	29,050	28,288	27,823
2020/21	29,355	28,654	28,319
2021/22	29,660	29,021	28,744



Net Firm Energy @ Generation
Energy (Gw.h)
30,000
29,000
28,000
27,000
26,000
25,000
24,000
23,000
22,000
2007/08
2009/10
2011/12
2013/14
2015/16
2017/18
2019/20
2021/22
Fiscal Year
2007 Load Forecast
2009 Load Forecast
2011 Load Forecast

PUB/MH I-121

Reference: Tab 8 – Energy Supply - Seasonal

a) Please provide seasonal precipitation data on an average individual watershed basis for the winter (October to February), spring (March/April), and summer (May to September) periods for the period from 2000-2012.

ANSWER:

The seasonal weighted average precipitation (in millimeters) for individual watershed basins for the period 2000-2012 are as follows:

October to February

	Basin			
	Winnipeg River	Sask. River	Nelson River	Churchill River
2000 - 01	185.5	68.4	137.6	94.4
2001 - 02	167.2	77.1	92.5	93.5
2002 - 03	103.8	82.0	85.9	83.1
2003 - 04	145.3	109.9	101.8	115.8
2004 - 05	224.8	124.7	145.2	148.8
2005 - 06	210.4	105.5	123.6	132.3
2006 - 07	128.6	121.9	130.2	142.2
2007 - 08	198.9	96.0	139.1	185.3
2008 - 09	202.3	96.8	151.8	129.0
2009 - 10	134.8	93.2	115.3	111.5
2010 - 11	161.9	82.7	128.9	78.7
2011 - 12	135.9	86.5	95.8	81.3

March to April

	Basin			
	Winnipeg River	Sask. River	Nelson River	Churchill River
2000	68.8	47.6	46.5	48.8
2001	100.9	51.3	50.2	41.6
2002	76.7	73.4	63.4	52.8
2003	55.0	80.3	40.0	49.2
2004	81.3	42.7	66.1	47.0
2005	64.9	40.8	47.2	56.3
2006	60.9	44.6	43.0	30.3
2007	70.4	61.4	56.7	54.4
2008	83.2	40.2	43.2	52.0
2009	96.1	52.1	66.3	59.2
2010	54.0	65.0	52.8	53.1
2011	92.0	54.4	62.2	17.8
2012	99.1	69.1	64.9	67.9

May to September

	Basin			
	Winnipeg River	Sask. River	Nelson River	Churchill River
2000 - 01	492.8	317.3	391.1	376.7
2001 - 02	441.2	233.8	352.8	335.2
2002 - 03	493.9	291.2	343.5	320.4
2003 - 04	457.1	219.2	300.9	316.3
2004 - 05	489.1	367.3	360.7	275.8
2005 - 06	469.5	474.8	449.0	460.2
2006 - 07	318.2	309.8	295.5	333.8
2007 - 08	485.2	315.3	341.9	295.6
2008 - 09	464.9	310.8	349.5	277.1
2009 - 10	437.5	250.7	311.6	337.7
2010 - 11	584.4	394.0	483.7	310.7
2011 - 12	339.5	318.5	333.5	252.9

PUB/MH I-121 (Revised)

Reference: Tab 8 – Energy Supply - Seasonal

b) Please provide seasonal runoff (inches) on an average major watershed basis for the April to July period and the August to October period for the 2000 to 2012 time frame.

ANSWER:

The tables below show calculated net runoff using the drainage basin areas and average flow data provided in PUB/MH II-87(a) and (b).

The calculated values ignore factors such as reservoir regulation, direct lake precipitation, evaporation and lag times between the point of runoff (or groundwater flow) entering the water course (i.e., river or lake) and the flow reporting location. For the Burntwood River near Thompson and Nelson River at Kettle G.S., the values do not include the water released at the Missi Falls control structure.

Manitoba Hydro cautions that the information in the tables below is provided for the purpose of responding to this IR, and is not based on a rigorous calculation of runoff; this data is not endorsed by Manitoba Hydro as being indicative of actual runoff values. Manitoba Hydro does not have measured historic runoff records that are consistent with the definition of runoff used in the field of hydrology for the requested time period.

Net Runoff Value (mm) (April - July)						
Year	Winnipeg Rvr. @ Great Falls	Red River @ Lockport	Sask River @ Grand Rapids	Nelson Rvr. @ Kelsey	Burntwood Rvr Near Thomp	Nelson Rvr @ Kettle GS
2000	87	21	11	21	38	27
2001	145	55	6	36	30	38
2002	112	27	11	21	32	26
2003	28	16	11	16	23	19
2004	120	39	11	22	21	22
2005	158	61	29	43	32	46
2006	81	46	25	38	38	41
2007	72	40	28	26	41	31
2008	116	16	14	29	39	32
2009	156	70	6	42	32	42
2010	75	46	14	27	35	29
2011	115	87	41	48	27	43
2012	65	14	26	23	37	28

Net Runoff Value (mm) (August - October)						
Year	Winnipeg Rvr. @ Great Falls	Red River @ Lockport	Sask River @ Grand Rapids	Nelson Rvr. @ Kelsey	Burntwood Rvr Near Thomp	Nelson Rvr @ Kettle GS
2000	74	6	6	19	30	24
2001	78	9	2	23	21	25
2002	67	8	8	21	17	21
2003	20	2	5	8	17	10
2004	81	8	12	21	21	22
2005	58	11	28	37	23	41
2006	21	3	12	18	30	22
2007	51	4	12	24	28	27
2008	79	7	9	31	25	31
2009	86	6	9	34	20	33
2010	81	21	18	37	23	35
2011	18	19	26	43	18	38

PUB/MH I-122

Reference: 2011/12 PRP – Tab 9/Attachment 3 (July 20/12)

Please provide 20 year IFF Projections and Revenue/Cost Assumptions (July 2012 Attachment 5 format) of electric utility operations for:

- **PRP Alternative Development Plan 1-250MW inter-tie (PRP p. 51);**
- **PRP Alternative Development Plan 2-no new inter-ties (PRP p. 53).**

ANSWER:

Examination of matters related to Manitoba Hydro's major capital development plans and alternatives, including DSM, is expected to take place in the context of a Needs For and Alternatives To (NFAT) hearing, which is expected to commence in 2013.

PUB/MH I-123

Reference: 2011/12 PRP – P. 49

Please provide a historical perspective for 2005/06 to 2011/12 on MH's actual non-hydraulic energy supplies, showing the average costs (¢/kWh) for:

	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Thermal Generation							
- Coal							
- N. Gas							
Wind Generation							
DSM Expenditures							
Imports							
Total Non-Hydraulic Resources							

ANSWER:

See table below.

	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh
Thermal Generation							
- Coal	2.3	2.3	2.5	2.9	3.6	3.7	9.9
- N. Gas	15.9	13.2	15.8	20.4	10.6	9.4	14.5
Wind Generation (1)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
DSM Expenditures (2)	2.0	2.0	2.4	2.4	2.3	2.0	n/a
Power Purchased (Imports + Wind) (3)	3.8	4.6	4.9	4.9	3.2	3.7	4.7
Total Non-Hydraulic Resources	18.2	29.7	22.4	24.7	18.1	18.6	50.2

Notes:

1. Unable to provide separately due to confidentiality - included in Power Purchased
2. Data unavailable for 2011/12
3. Includes purchased wind generation
4. Year to year variability in average costs are partly due to accounting adjustments, particularly for low volume resources (*i.e.*, coal and natural gas).

PUB/MH I-124

Reference: 2011/12 PRP – P. 49 Average Flow Conditions

Please provide MH's average peak and off-peak opportunity sales prices (¢/kWh) for 2005/06 to 2011/12 (similar to 2010 GRA CAC/MSOS/MH I-13 d).

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-11(a) and (b).

PUB/MH I-125

Reference: 2011/12 PRP – P. 48 and P. 49

Preamble: Please confirm that MH's pending export contracts essentially preclude:

a) The use of non-hydraulic resources in meeting firm contract energy commitments (due to a combination of clean energy requirements and assured dispatchability).

ANSWER:

Manitoba Hydro is entitled to use all available resources to serve its export obligations. This includes the new supply obligations that Manitoba Hydro will have as a result of the new export contracts. A condition of those contracts is that Manitoba Hydro will build major new hydraulic generation. Should this happen, the vast majority of energy that will serve the sale obligations will be surplus dependable energy produced by the new generating stations.

PUB/MH I-125

Reference: 2011/12 PRP – P. 48 and P. 49

Preamble: Please confirm that MH's pending export contracts essentially preclude:

b) The use of non-hydraulic resources other than wind in meeting the total energy sales to NSP, MP and WPS utilities.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-125(a).

PUB/MH I-126

Reference: NEW CONTACTS WITH NSP/MP/WPS

a) Please confirm that MH has signed/or is in the process of signing contracts for capacity and firm energy supply as follows:
NSP

NSP

• 375 MW Summer (5x16)	780 GWh/yr[1] 2015-2025		
• 325 MW Winter (5x12)	580 GWh/yr[1] 2015-2025	-	1360 GWh
• 350 MW Summer Diversity (7x4)	270 GWh/yr[2] 2015-2025	-	270 GWh
• 125 MW Summer (5x16)	260 GWh/yr[1] 2020-2025		
• 125 MW Winter (5x12)	200 GWh/yr[1] 2020-2025	-	460 GWh
Sub-total			2090 GWh/yr

MP

• 250 MW Summer/ Winter (5x16)	1030 GWH/yr[1] 2020-2035	-	1030 GWh
• 250 MW Summer Weekend (2x16)	205 GWh/yr[2] 2020-2035	-	
• 250 MW Winter Weekend (2x16)	205 GWh/yr[2] 2020-2035	-	410 GWh
Sub-total			1440 GWh/yr

WPS

• 100 MW Summer/Winter (5x16)	410 GWh/yr[1] 2020-2035		410 GWh
• 100 MW Summer Weekend (2x16)	80 GWh/yr[2] 2020-2035	-	
• 100 MW Winter Weekend (2x16)	80 GWh/yr[2] 2020-2035	-	160 GWh
Sub-total			570 GWh/yr

[1] Fixed contract prices for capacity and energy.

[2] Market based prices for energy/no demand charge.

Totals	**Fixed Price Energy**	**2800 GWh**
	Market Based Energy	**1300 Gwh**

ANSWER:

MH has signed the following export contracts

NSP

- 375/325 MW System Power Sale (2015-2025)
- 350 MW Diversity Agreement (2015-2025)
- 125 MW System Power Sale (2021-2025)

MP

250 MW System Power Sale (2020-2035)

WPS

100 MW System Power Sale (2021-2027)

The firm energy volume associated with these contracts is listed by year on pages 38 & 39 of the 2011/12 Power Resource Plan (Attachment #3). Manitoba Hydro cannot confirm the contract numbers presented in the question and is not prepared to provide them on the public record as same would facilitate reverse engineering of confidential export contract pricing.

PUB/MH I-126

Reference: NEW CONTRACTS WITH NSP/MP/WPS

Preamble: Please confirm that MH's pending export contracts essentially preclude:

b) Please provide sample calculations for each of the weekly time periods defined for energy supply.

ANSWER:

The weekly time periods that are sold by Manitoba Hydro are on-peak (5x16) product, a weekend (2x16) product, an off-peak (7x8) product, a wrap (2x16 & 7x8) product and a must-offer energy (7x4) product. An example of the energy schedules associated with these products assuming 100 MWh per hour of hydro energy deliveries on-peak, 75 MWh per hour of hydro energy on weekend days, 50 MWh per hour of hydro energy deliveries off-peak and with a must-offer obligation of 100 MW is provided below. Please note that the hours of must-offer obligation are outlined in the table with a box spanning HE 13 to HE 17 daily. During the weekend Manitoba Hydro would fulfill its must offer obligation from out-of-the-money capacity, with only 75 MW of hydro energy resources clearing the market.

Hour Ending	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
1	50	50	50	50	50	50	50
2	50	50	50	50	50	50	50
3	50	50	50	50	50	50	50
4	50	50	50	50	50	50	50
5	50	50	50	50	50	50	50
6	50	50	50	50	50	50	50
7	100	100	100	100	100	75	75
8	100	100	100	100	100	75	75
9	100	100	100	100	100	75	75
10	100	100	100	100	100	75	75
11	100	100	100	100	100	75	75
12	100	100	100	100	100	75	75
13	100	100	100	100	100	75	75
14	100	100	100	100	100	75	75
15	100	100	100	100	100	75	75
16	100	100	100	100	100	75	75
17	100	100	100	100	100	75	75
18	100	100	100	100	100	75	75
19	100	100	100	100	100	75	75
20	100	100	100	100	100	75	75
21	100	100	100	100	100	75	75
22	100	100	100	100	100	75	75
23	50	50	50	50	50	50	50
24	50	50	50	50	50	50	50

		Total MWh
Onpeak (5x16) Product		8000
Weekend		2400
Off-Peak		2800
Wrap (Weekend + Off-Peak)		5200
7x4		2600

PUB/MH I-126

Reference: NEW CONTRACTS WITH NSP/MP/WPS

c) Optional Supply Implications

Please confirm that in addition to the firm commitments of about 3100 GWh, the three contracts will facilitate optional energy purchases by NSP/MP/WPS during non-peak-periods that could add up to another 4000 GWh/year.

ANSWER:

Manitoba Hydro cannot confirm either the 3100 GWh or the 4000 GWh numbers.

MH confirms additional surplus energy can be sold beyond our firm commitments during both on and off-peak periods. Manitoba Hydro's firm commitments and additional surplus energy volumes are indicated on page 49 of the 2011/12 Power Resource Plan (see Attachment #3). The additional volumes (based upon the average of all flow years) shown on the line labeled "Exportable System Surplus" vary from year to year depending upon load growth, firm export commitments, and generation and tie-line capacity.

PUB/MH I-127

Reference: 2011/12 Power Resource Plan/Tab 9/Attachment 3

a) Please confirm that MH's Recommended Plan and both Alternative Development Plans 1 and 2 involve the same export sales scenarios until 2019/20.

ANSWER:

Confirmed.

PUB/MH I-127

Reference: 2011/12 Power Resource Plan/Tab 9/Attachment 3

b) Please confirm that the average year export sales between 2015/16 and 2019/20 consist of approximately:

• **Long-term firm contract sales**	**1300 GWh**
• **Short-term bilateral sales**	**700 GWh**
• **Contract sales transmission losses**	**200 GWh**
• **Sub-total firm energy @ generation**	**2200 GWh**
• **Opportunity market sales**	**4600 GWh**
• **Opportunity export transmission losses**	**500 GWh**
• **Sub-total opportunity energy @ generation**	**5100 GWh**
Total sales @ generation	**7300 GWh**

ANSWER:

Not confirmed.

Manitoba Hydro can confirm that as per the table found on page 49 of Attachment 3 (2011/12 Power Resource Plan), the forecast export sales between 2015/16 and 2019/20 consist of:

Fiscal Year	Current Exports [GWh]	Proposed Exports [GWh]	Exportable System Surplus [GWh]	**Total [GWh]**
2015/16	2265	0	5379	**7644**
2016/17	2161	0	5239	**7400**
2017/18	2161	0	5103	**7264**
2018/19	2161	0	4888	**7049**
2019/20	2161	0	5052	**7213**
Average	**2182**	**0**	**5132**	**7314**

Manitoba Hydro cannot confirm further breakdown of this export energy as it allows the determination of commercially-sensitive contract specific information on a go-forward basis.

PUB/MH I-127

Reference: 2011/12 Power Resource Plan/Tab 9/Attachment 3

c) Please confirm that between 2021/22 and 2024/25 the average year sales consist of approximately:

	Recommended Plan Alternative Plan 1	**Alternative Plan 2 CCCT**
• **L.T. firm contract sales**	**3200 GWh**	**1300 GWh**
• **S.T. bilateral sales**	**500 GWh**	**600 GWh**
• **Contract sales transmission losses**	**400 GWh**	**200 GWh**
Sub-total firm energy @ generation	**4100 GWh**	**2100 GWh**
• **Opportunity market sales**	**5500 GWh**	**4500 GWh**
• **Opportunity export transmission losses**	**500 GWh**	**400 GWh**
Sub-total opportunity energy @ Generation	**6000 GWh**	**4900 GWh**
Total sales @ generation	**10,100 GWh**	**7000 GWh**

ANSWER:

Not confirmed.

Manitoba Hydro can confirm that as per the table found on page 51 of Attachment 3 (2011/12 power resource plan), the forecast export sales between 2021/22 and 2024/25 for the Alternative Development Plan 1 consist of:

Fiscal Year	Current Exports [GWh]	Proposed Exports [GWh]	Exportable System Surplus [GWh]	**Total [GWh]**
2021/22	4139	0	5901	**10040**
2022/23	4213	0	5672	**9885**
2023/24	4213	0	5218	**9431**
2024/25	4213	0	6351	**10564**
Average	**4195**	**0**	**5786**	**9980**

Manitoba Hydro can also confirm that as per the table found on page 53 of Attachment 3 (2011/12 power resource plan), the forecast export sales between 2021/22 and 2024/25 for the Alternative Development Plan 2 consist of:

Fiscal Year	Current Exports [GWh]	Proposed Exports [GWh]	Exportable System Surplus [GWh]	**Total [GWh]**
2021/22	2161	0	5304	**7465**
2022/23	2161	0	4948	**7109**
2023/24	1996	0	4750	**6746**
2024/25	1963	0	4463	**6426**
Average	**2070**	**0**	**4866**	**6937**

Manitoba Hydro cannot confirm further breakdown of this export energy as it allows the determination of commercially-sensitive contract specific information on a go-forward basis.

Manitoba Hydro notes that a review of matters related to Alternative Plan 1 and Alternative Plan 2 are expected to take place in the context of A Needs For and Alternatives To (NFAT) hearing, which process is expected to commence in 2013.

PUB/MH I-127

Reference: 2011/12 Power Resource Plan/Tab 9/Attachment 3

d) Please confirm that from 2025/26 onward MH will have firm commitments for 250 MW-MP and 100 MW-WPS 7x16 energy sales within the Recommended Plan and Alternative 1 but assumes zero firm sales in Alternative 2.

ANSWER:

The 250 MW Minnesota Power Sale and the 100 MW Wisconsin Public Service Sale are both contingent on the construction on new hydroelectric generation with an in-service date of June 1, 2020. Both the Recommended Development Plan and Alternative Development Plan 1 include Keeyask G.S. with an in-service date of 2019/20 and therefore the sales are included. Alternative Development Plan 2 does not include new hydroelectric generation until 2027/28 with the ISD of the Conawapa G.S. and therefore this development plan does not include the 250 MW Minnesota Power Sale or the 100 MW Wisconsin Public Service Sale.

PUB/MH I-128

Reference: 2012/13 and 2013/14 GRA- Attachment 2 (P.R.P. Page 26)

Preamble: Please explain the availability limitations of energy supply and/or transmission with respect to:

a) Brandon Coal Plant;

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-5(b).

PUB/MH I-128

Reference: **2012/13 and 2013/14 GRA- Attachment 2 (P.R.P. Page 26)**

Preamble: **Please explain the availability limitations of energy supply and/or transmission with respect to:**

b) Contracted energy imports (are they buy-backs?);

ANSWER:

The contracted energy imports are not buy-backs. Manitoba Hydro is entitled to physically import contracted energy imports.

PUB/MH I-128

Reference: **2012/13 and 2013/14 GRA- Attachment 2 (P.R.P. Page 26)**

Preamble: **Please explain the availability limitations of energy supply and/or transmission with respect to:**

c) Non-contracted energy imports (summer and winter);

ANSWER:

Non contracted energy imports are assumed to be delivered directly from the MISO market during the off-peak period on firm transmission service. Due to the nature of MISO as a predominantly thermal system, there is a significant amount of surplus energy available from the 130,000 MW of generation resources in the MISO market footprint during the off-peak hours. This energy will be available to Manitoba Hydro unless emergency conditions exist.

Please see Manitoba Hydro's response to PUB/MH I-20(c) for information on transmission import limits.

PUB/MH I-128

Reference: **2012/13 and 2013/14 GRA- Attachment 2 (P.R.P. Page 26)**

Preamble: **Please explain the availability limitations of energy supply and/or transmission with respect to:**

d) Adverse water energy (summer and winter).

ANSWER:

Energy is available under adverse water provisions without restriction up to the quantities specified in the contracts.

PUB/MH I-129

Reference: 2012/13 and 2013/14 GRA – Attachment 3 (P.R.P. Page 20)

Please explain how Table 3 (p.20) Supply-Demand Balances evolved from PRP(s) 2008 to 2009 to 2010 for the specific components of dependable energy resources and load demand in 2014/15, 2018/19 and 2022/23.

ANSWER:

The following tables detail the change in system surpluses beginning with 2008/09 power resource plan through to the 2011/12 power resource plan, assuming no new generation, for the years 2014/15, 2018/19 and 2022/23.

Changes to Supply and Demand Balance
Winter Peak Capacity (MW)
2008/09 to 2011/12 Power Resource Plans
No New Generation

	2014/15	2018/19	2022/23
Balance in 2008/09 Power Resource Plan	**359**	**563**	**-26**
MB Load Decrease	162	149	129
DSM Increase	46	29	40
Impact on Planning Reserves	25	22	20
Kelsey Rerunnering Rating Change	2	2	2
Balance in 2009/10 Power Resource Plan	**594**	**765**	**165**
MB Load Increase	-77	-133	-140
DSM Changes	-29	9	4
Impact on Planning Reserves	-13	-42	-16
Point du Bois Rebuild Deferral		-43	-43
Thermal Plant Rating Change	-18	-18	-18
Export Sale Changes		-193	27
Balance in 2010/11 Power Resource Plan	**457**	**345**	**-21**
MB Load Changes	2	-9	-82
DSM Decrease	-57	-41	-29
Impact on Planning Reserves	-7	-5	-13
Balance in 2011/12 Power Resource Plan	**395**	**291**	**-146**

Changes to Supply and Demand Balance
Dependable Energy (GW.h)
2008/09 to 2011/12 Power Resource Plans
No New Generation

	2014/15	**2018/19**	**2022/23**
Balance in 2008/09 Power Resource Plan	**367**	**1144**	**-980**
MB Load Decrease	938	866	755
DSM Increase	80	79	126
Wind Capacity Factor Change	25	25	25
Thermal Plant Rating Change	-179	-179	-153
Balance in 2009/10 Power Resource Plan	**1231**	**1935**	**-227**
MB Load Decrease	601	431	435
DSM Changes	-106	9	-40
Point du Bois Rebuild Deferral		-150	-150
- PDB Construction Power	30		
Wind decrease from 300 MW to 138 MW	-471	-471	-471
Export Sale Changes	-33	-117	-117
Balance in 2010/11 Power Resource Plan	**1252**	**1637**	**-570**
MB Load Changes	-103	176	-191
DSM Decrease	-227	-184	-132
Wind Generation Changes	35	37	37
Export Sale Changes	33		
Balance in 2011/12 Power Resource Plan	**990**	**1666**	**-856**

PUB/MH I-130

Reference: 2011/12 Power Resource Plan (P. 37)

a) Please confirm the following data:

Hydraulic Generation Output

	Station Installed Capacity MW	**Dependable Flow GWh**	**Average Flow GWh**	**High Flow GWh**	**Maximum Theoretical GWh**
Wuskwatim G.S.	**200**	**1220**	**1520**	**1420**	**1700**
Keeyask G.S.	**630**	**2900**	**4430**	**4740**	**5500**
Conawapa G.S.	**1300**	**4550**	**7000**	**9760**	**10500**

ANSWER:

Manitoba Hydro can confirm only some of the data in the table and a revised table has been prepared below. An additional column indicating the net increase in the system winter capacity due to the addition of each generating station is also included. This value differs from the installed capacity in that it reflects the restrictions in capacity due to ice conditions, reduction in other generating station capability due to the addition of the station, and does not include capacity that is only available under specific water conditions.

The values presented under the High Flow column indicate the maximum generation that could have been achieved during the highest historic inflow condition. The theoretical maximum generation values are not achievable, as inflow equal to the maximum plant flow would not be available during the entire year, head conditions would vary from ideal, and equipment outages during the year would all reduce the potential generation.

Hydraulic Generation Output

Station	Installed Capacity MW	Increase Sys Winter Capacity (MW)	Dependable Flow GWh	Average Flow GWh	High Flow GWh	Maximum Theoretical GWh
Wuskwatim G.S.	200	200	1250	1520	1650	1750
Keeyask G.S.	695	630	2900	4430	5300	5500
Conawapa G.S.	1485	1300	4550	7000	8850	11400

PUB/MH I-130

Reference: 2011/12 Power Resource Plan (P. 37)

b) Please confirm that MH can achieve the entire station dependable hydraulic generation output from:

- **Wuskwatim G.S. with 2.15 units in operation**
- **Keeyask G.S. with 5.27 units in operation**
- **Conawapa G.S. with 4.33 units in operation**

ANSWER:

Not confirmed.

The theoretical minimum number of units to pass dependable flows is not a meaningful number for the following reasons:

- Hydraulic inflows are not constant on an annual basis
- Generators require outages for maintenance
- The load is not constant on a daily, weekly, monthly or annual basis. Some portion of the generation in the system must operate to follow changes in the load.

In addition, designing for dependable flows would result in a large volume of water than could be used to produce renewable energy being spilled in excess of 90% of the time (i.e. under all flow conditions but dependable flow conditions).

PUB/MH I-130

Reference: 2011/12 Power Resource Plan (P. 37)

c) Please confirm that energy in excess of MH's dependable energy requirements for domestic load and firm import commitments typically goes to achieve opportunity export sales.

ANSWER:

Note that in preparing the response to this question, Manitoba Hydro assumed the reference to firm import commitments was intended to be firm export commitments.

As the hydraulic generation from Manitoba Hydro's system increases above the dependable energy quantity, the additional hydraulic energy is first used to displace any thermal generation or imports that may have been otherwise used to meet Manitoba Hydro's commitments. As the hydraulic generation from Manitoba Hydro's system further increases, the additional hydraulic energy is used for opportunity export sales, or as supplemental energy to existing long term dependable sales.

PUB/MH I-131

Reference: 2010 GRA PUB-MH 2012 GRA Tab 9 (Page 8 and 9) /2011 GRA EX # PUB 25 (June 9/11)

a) New Generation Incremental Energy Cost

Please confirm that the in-service incremental cost of new generation could be approximately determined as follows:

	F/D/OM&A 9% of Capital Cost ($M/year)	Calculated on Dependable Energy Unit Cost (¢/kWh)	Calculated on Average Year Energy Unit Cost (¢/kWh)
Wuskwatim G.S.	145	12.0	9.5
Keeyask G.S.	500	17.0	11.3
Conawapa G.S.	700	15.4	10.0

ANSWER:

Not confirmed.

The unit cost of Wuskwatim is 7.9¢/kWh in nominal dollars, levelized over the life of the plant.

Review of matters related to Manitoba Hydro’s Preferred Development Plan, including the Keeyask and Conawapa generation stations, will take place in the context of a Needs For and Alternatives To (NFAT) hearing, which process is expected to commence in 2013.

PUB/MH I-132

Reference: 2012 GRA – Attachment 3 (July 20/12)

a) Non-Hydraulic Resources Cost Implications

Please confirm that when MH employs non-hydraulic resources to facilitate additional summer export sales in average flow years, these are at best marginally profitable. Also verify that in IFF11-2 Revenue Assumptions Attachment 3, MH is projecting costs for thermal generation, wind and imports (combined average) as follows:

		¢/kWh
2012/13	**-**	**3.5 (equivalent to $3.00/GJ natural gas)**
2013/14	**-**	**5.0**
2014/15	**-**	**5.3**
2015/16	**-**	**5.8**
2016/17	**-**	**6.0**
2017/18	**-**	**6.3**
2018/19	**-**	**6.6 (equivalent to $7.00/GJ natural gas)**
2019/20	**-**	**7.0**

ANSWER:

It is correct to state the use of non-hydraulic resources to facilitate opportunity export sales has a lower margin than when hydraulic resources are utilized. Such sales are evaluated as opportunities arise and are only entered into if there is an expectation of profit. Any profit serves to reduce Manitoba Hydro's revenue requirement from domestic customers and hence Manitoba Hydro is continually looking for such opportunities.

Manitoba Hydro is unable to verify the values provided in this information request. With reference to the Average Price Calculation (Page 1 of Attachment 5), the average unit cost for non-hydraulic energy (including Manitoba Hydro thermal, wind and imports) is given as follows:

2012/13	-	3.6
2013/14	-	5.1
2014/15	-	5.5
2015/16	-	5.7

2016/17	-	6.0
2017/18	-	6.2
2018/19	-	6.6
2019/20	-	6.7

As noted in the response to PUB/MH I-18(b) there are a wide variety of generation types and pricing factors that contribute to the determination of prices in a power market and hence it is not appropriate to imply a specific natural gas price can translate into a specific market price.

PUB/MH I-132

Reference: 2012 GRA – Attachment 3 (July 20/12)

b) Opportunity Market Prices
With coal generation costs likely remaining below 3¢/kWh, please confirm MISO Market prices for opportunity sales are unlikely to exceed 5.0¢/kWh.

ANSWER:

Manitoba Hydro cannot confirm the statement made in this information request. For example, in July 2012, power prices at MISO's Minnesota Hub exceeded US$100/ MWh (10 cents/ kWh) for 15 hours, and exceeded US$50/ MWh (5 cents/ kWh) for around 150 hours.

PUB/MH I-133

Reference: 2010 GRA – Risk Scenarios PUB/MH I-150/2011/12 Power Resource Plan Drought Risk Reserves

a) Please provide an update of 2010 GRA – PUB/MH I-150 showing the energy supply/costs and net revenue impacts for a 5 year drought commencing in 2014/15 with the Recommended Development Plan; also identify overall financial costs.

ANSWER:

Manitoba Hydro has not completed a five year drought impact calculation for a drought beginning in 2014/15. Manitoba Hydro's methodology for the calculation of the five-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, rather than 2014/15 as specified in this request.

Page 25 of Tab 9 of the 2012/13 GRA states "Based on the 2011/12 update, if a five year drought occurred from 2013/14 to 2017/18 net revenues would be about $1.4 billion less than expected over the same five year period. This impact on net revenues would increase to $1.6 billion with consideration of financing costs associated with additional borrowing requirements up to the year 2017/18."

A detailed calculation of the impact of the five-year drought beginning in 2013/14 is given in MIPUG/MH I-36(a). Finance costs are identified in Manitoba Hydro's response to MIPUG/MH I-36(b).

PUB/MH I-133

Reference: 2010 GRA – Risk Scenarios PUB/MH I-150/2011/12 Power Resource Plan Drought Risk Reserves

b) Please provide a similar analysis of energy supply/costs and net revenue impacts for a 7 year drought commencing in 2021/22 with three development scenarios:

- **Recommended Plan**
- **Alternative Plan 1 (with 250 MW – MP interconnection)**
- **Alternative Plan 2 (CCCT without new interconnection)**

ANSWER:

Manitoba Hydro does not have available an analysis for a 7 year drought commencing in 2021/22. Manitoba Hydro would be required to undertake substantial additional work which cannot be completed within the time frame allocated for Information Request responses.

Please see Manitoba Hydro's response to MIPUG/MH I-36a for details of the cost of a 7 year drought, which for the 2011/12 forecast has a start date for the impact of the drought in year 2013/14. 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.

In addition, a review of matters related to Alternative Plan 1 and Alternative Plan 2 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. Therefore Manitoba Hydro respectfully declines to file a response as it relates to Alternative Plan 1 and Alternative Plan 2.

PUB/MH I-133

Reference: **2010 GRA – Risk Scenarios PUB/MH I-150/2011/12 Power Resource Plan Drought Risk Reserves**

c) Please provide MH's recommendation for the appropriate drought reserve level within an overall retained earnings target; include a discussion of the rationale.

ANSWER:

Please see PUB/MH I-33 for a discussion on the adequacy of retained earnings levels.

Financial targets are currently under review. The results of that review will be presented to the Manitoba Hydro Board in conjunction with the presentation of IFF12 (expected to be presented in November 2012).

PUB/MH I-133

Reference: 2010 GRA – Risk Scenarios PUB/MH I-150/2011/12 Power Resource Plan Drought Risk Reserves

d) Please provide MH"s Drought Mitigation Plan or alternatively define the appropriate steps that MH intends to undertake to minimize the financial impacts of both a five year and seven year drought.

ANSWER:

Manitoba Hydro operates and dispatches its generation fleet and manages its export obligations on an ongoing and continuous basis in a manner that maximizes net revenue while maintaining a reliable and dependable supply for Manitobans. This practice is used under all water conditions, including during droughts. So to the extent that the cost of drought can be mitigated this goal will be achieved as a matter of course.

During lower flow and drought conditions when hydraulic supplies are insufficient to meet the provincial demand, Manitoba Hydro augments the hydraulic supply with more expensive thermal or purchased electricity, whether produced in province or in the extra-provincial markets. Under extremely low flow conditions Manitoba thermal generation may be dispatched in order to provide voltage or contingency support. Additional energy beyond these reliability needs is generally purchased in the external markets given that Manitoba thermal generation is generally much more expensive than energy purchased in the external markets.

Under drought conditions The Climate Change and Emissions Reduction Act permits Manitoba Hydro to operate the coal fired unit at Brandon G.S. The decision to operate the station during extreme drought conditions will be made at that time by the Executive of Manitoba Hydro having considered all the relevant factors. Should Manitoba Hydro elect to operate the coal fired unit, there may be some cost savings to the Corporation depending upon whether Brandon coal fired energy displaces higher priced market energy.

To the extent that Manitoba Hydro is exposed to additional financial risk during drought as a result of uncertain market and natural gas prices, Manitoba Hydro may choose to hedge that risk by purchasing electricity/natural gas forward contracts or options. The decision to hedge to manage Manitoba Hydro's financial risk will be made by the Executive of Manitoba Hydro having considered all the relevant factors at that time.

PUB/MH I-134

Reference: 2010 GRA – WPLP Agreement/2011 GRA – PUB/MH II-38/PUB/MH I-42 Wuskwatim Partnership (WPLP)

Please re-file PUB/MH II-38 and PUB/MH I -142 updated and provide a detailed illustration of WPLP revenue calculation process including 2013/14 components of:

a) Contract sales and prices (if applicable)
b) Opportunity peak sales and prices
c) Opportunity off-peak sales and prices
d) Domestic sales and prices (if applicable)

ANSWER:

Please see the attached schedules for updates to PUB/MH II-38 and PUB/MH I-42 from the 2010/11 & 2011/12 General Rate Application.

Wuskwatim's revenue related to energy generated during the on-peak hours is determined based on the average price Manitoba Hydro realizes for long-term export sales and import transactions. Wuskwatim's revenue related to energy generated during the off-peak hours is determined from the average price Manitoba Hydro realizes for all on-peak and off-peak opportunity export and import transactions, excluding the on-peak long-term transactions. The total of gross revenue related to on-peak and off-peak energy is reduced by transmission and related market participation charges and Manitoba Hydro's 3% marketing risk fee.

The WPLP revenue calculation cannot be broken down further as requested as contract and opportunity sales and prices are commercially sensitive information. Domestic sales are not included in the determination of the WPLP revenue.

Please note that the WPLP projected financial statements were prepared assuming a March 2012 in-service date for the first generating unit and the electric operations forecast was subsequently adjusted to reflect the deferral to June 2012 for the finalization of IFF11-2.

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
Revenue	1	57	57	69	90	99	108	117	124	125	133
	1	57	57	69	90	99	108	117	124	125	133
EXPENSES											
Operating and Administrative	1	10	10	10	10	10	10	10	10	11	11
Finance Expense	3	62	71	73	75	74	73	72	70	68	66
Depreciation and Amortization	1	23	25	25	25	25	25	25	25	25	25
Water Rentals and Assessments	0	5	5	5	5	5	5	5	5	5	5
	5	99	110	113	115	114	113	112	110	109	106
Net Income	(3)	(42)	(54)	(44)	(25)	(15)	(5)	5	14	17	27
Financial Ratios											
Debt	75%	78%	82%	85%	85%	85%	85%	84%	83%	81%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
REVENUES										
Revenue	139	141	147	143	146	151	155	159	164	168
	139	141	147	143	146	151	155	159	164	168
EXPENSES										
Operating and Administrative	11	11	12	12	12	11	11	11	12	12
Finance Expense	61	60	59	58	57	56	55	54	53	52
Depreciation and Amortization	25	25	25	25	25	25	25	25	25	25
Water Rentals and Assessments	5	5	5	5	5	5	5	5	5	5
	102	101	101	100	99	98	96	96	95	94
Net Income	36	40	46	43	47	53	58	64	69	74
Financial Ratios										
Debt	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ASSETS										
Plant in Service	446	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337
Accumulated Depreciation	(1)	(17)	(36)	(55)	(74)	(93)	(111)	(130)	(149)	(168)
Net Plant in Service	445	1,319	1,300	1,282	1,263	1,244	1,225	1,207	1,188	1,169
Construction in Progress	821	(6)	0	0	0	0	0	0	0	0
Current and Other Assets	297	299	303	308	315	321	329	336	345	353
	1,563	1,612	1,604	1,590	1,577	1,566	1,554	1,543	1,532	1,522
LIABILITIES AND EQUITY										
Long-Term Debt	800	998	1,052	1,102	1,102	1,102	1,102	1,102	1,102	1,102
Current and Other Liabilities	450	327	316	297	285	278	272	255	231	204
Partners Capital	314	287	235	191	190	185	180	185	199	216
	1,563	1,612	1,604	1,590	1,577	1,566	1,554	1,543	1,532	1,522

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340
Accumulated Depreciation	(206)	(224)	(243)	(262)	(281)	(300)	(319)	(338)	(357)	(375)
Net Plant in Service	1,134	1,116	1,097	1,078	1,059	1,040	1,021	1,003	984	965
Construction in Progress	0	0	0	0	0	0	0	0	0	0
Current and Other Assets	373	384	395	407	420	433	448	463	479	496
	1,507	1,499	1,492	1,485	1,479	1,474	1,469	1,466	1,463	1,461
LIABILITIES AND EQUITY										
Long-Term Debt	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102
Current and Other Liabilities	151	141	143	140	141	144	146	149	153	158
Partners Capital	254	256	246	243	235	228	221	214	208	201
	1,507	1,499	1,492	1,485	1,479	1,474	1,469	1,466	1,463	1,461

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1	57	57	69	90	99	108	117	124	125	133
Cash Paid to Suppliers and Employees	(1)	(15)	(15)	(15)	(15)	(16)	(16)	(15)	(16)	(16)	(16)
Interest Paid	(39)	(66)	(71)	(74)	(76)	(76)	(75)	(75)	(74)	(72)	(71)
Interest Received	-	-	0	1	1	2	2	3	4	4	5
	(39)	(24)	(29)	(19)	0	10	20	30	39	42	52
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	200	-	50	50	-	-	-	-	-	-	-
Other	42	15	0	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
	242	15	50	49	(1)	(1)	(1)	(2)	(2)	(2)	(2)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(133)	(60)	(6)	-	-	(0)	-	-	-	-	(0)
Sinking Fund Payment	-	(8)	(10)	(11)	(12)	(13)	(13)	(14)	(14)	(15)	(15)
Other	-	198	4	-	-	23	10	-	-	-	-
	(133)	130	(12)	(11)	(12)	11	(3)	(14)	(14)	(15)	(16)
Net Increase (Decrease) in Cash	71	122	10	18	(13)	19	15	15	23	25	34
Cash at Beginning of Year	(223)	(152)	(31)	(21)	(3)	(16)	3	18	33	56	81
Cash at End of Year	(152)	(31)	(21)	(3)	(16)	3	18	33	56	81	115

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	139	141	147	143	146	151	155	159	164	168
Cash Paid to Suppliers and Employees	(16)	(16)	(17)	(17)	(17)	(16)	(16)	(16)	(17)	(17)
Interest Paid	(67)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)
Interest Received	6	6	7	8	9	9	10	11	12	13
	61	65	71	68	71	78	83	89	94	99
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)
	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(3)	-	-	-	(0)	-	-	-	-	(0)
Sinking Fund Payment	(16)	(17)	(17)	(18)	(19)	(20)	(20)	(21)	(22)	(23)
Other	44	(70)	(38)	(56)	(46)	(54)	(61)	(65)	(71)	(76)
	25	(86)	(55)	(75)	(65)	(73)	(81)	(86)	(93)	(99)
Net Increase (Decrease) in Cash	84	(23)	14	(9)	4	2	(0)	(1)	(2)	(3)
Cash at Beginning of Year	115	199	176	189	181	184	186	186	185	184
Cash at End of Year	199	176	189	181	184	186	186	185	184	181

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST OM&A COSTS
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Operating and Administrative											
Generating Station O&A	1	9	9	9	9	9	9	9	9	9	10
Transmission Related O&A	0	0	0	0	0	1	1	1	1	1	1
Development Fund	-	1	1	1	1	1	1	1	1	1	1
	1	10	10	10	10	10	10	10	10	11	11

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST OM&A COSTS
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Operating and Administrative										
Generating Station O&A	10	10	10	10	11	10	10	10	10	10
Transmission Related O&A	1	1	1	1	1	1	1	1	1	1
Development Fund	1	1	1	1	1	1	1	1	1	1
	11	11	12	12	12	11	11	11	12	12

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FINANCE EXPENSE FORECAST
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Finance Expense											
Interest on Long Term Debt	36	48	53	56	59	60	60	60	60	60	60
Interest on Short Term Debt	2	1	1	1	0	(0)	(1)	(2)	(3)	(4)	(5)
Interest on Interconnection Credit Facility	1	17	17	17	16	16	16	16	16	16	16
Sinking Fund Admin Fee	-	-	0	0	0	0	0	0	0	0	0
Interest Income	-	-	(0)	(1)	(1)	(2)	(2)	(3)	(4)	(4)	(5)
Capitalized Interest	(37)	(4)	-	-	-	(0)	-	-	-	-	(0)
	3	62	71	73	75	74	73	72	70	68	66

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FINANCE EXPENSE FORECAST
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Finance Expense										
Interest on Long Term Debt	60	60	60	60	60	60	60	60	60	60
Interest on Short Term Debt	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Interest on Interconnection Credit Facility	16	16	16	15	15	15	15	15	15	15
Sinking Fund Admin Fee	0	0	0	0	0	0	0	0	0	0
Interest Income	(6)	(6)	(7)	(8)	(9)	(9)	(10)	(11)	(12)	(13)
Capitalized Interest	(0)	-	-	-	(0)	-	-	-	-	(0)
	61	60	59	58	57	56	55	54	53	52

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST INTEREST RATES
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Short Term Debt Interest Rate w/ PGF	1.90%	2.25%	3.20%	4.80%	5.05%	5.25%	5.30%	5.30%	5.30%	5.30%	5.30%
Long Term Debt Interest Rate w/ PGF	4.75%	4.70%	5.05%	6.40%	6.90%	7.20%	7.40%	7.40%	7.40%	7.40%	7.40%
Equity Loan Credit Facility Interest Rate	2.90%	3.25%	6.05%	7.40%	7.90%	8.20%	8.40%	8.40%	8.40%	8.40%	10.40%

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST INTEREST RATES
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Short Term Debt Interest Rate w/ PGF	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%
Long Term Debt Interest Rate w/ PGF	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Equity Loan Credit Facility Interest Rate	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST REVENUE
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Average Generation (GW.h)	41	1,469	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Wuskwatim Revenue	2	59	58	71	93	102	112	121	128	129	138
Marketing Risk Fee	(0)	(2)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Wuskwatim Net Revenue	1	57	57	69	90	99	108	117	124	125	133
Average Price ($/MW.h) net of Risk Fee	35.98	38.79	37.29	45.38	59.45	65.49	71.42	77.22	81.95	82.71	87.99

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST REVENUE
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Average Generation (GW.h)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Wuskwatim Revenue	143	146	151	147	150	155	160	164	169	174
Marketing Risk Fee	(4)	(4)	(5)	(4)	(5)	(5)	(5)	(5)	(5)	(5)
Wuskwatim Net Revenue	139	141	147	143	146	151	155	159	164	168
Average Price ($/MW.h) net of Risk Fee	91.40	93.08	96.78	94.28	96.10	99.33	102.04	104.98	107.98	110.97

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST WATER RENTALS
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Average Generation (GW.h)	41	1,469	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Water Rental Rate ($/MW.h)	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341
Water Rentals	0	5	5	5	5	5	5	5	5	5	5

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST WATER RENTALS
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Average Generation (GW.h)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Water Rental Rate ($/MW.h)	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341
Water Rentals	5	5	5	5	5	5	5	5	5	5

PUB/MH I-135

Reference: 2010 GRA – Keeyask Partnership Agreement

Please refile 2011 GRA – PUB/MH II-7 and provide a detailed illustration of Keeyask Partnership average flow year revenue calculation process in the first full year of generation separately defining:

a) peak period energy pricing methodology

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-25(c).

PUB/MH I-135

Reference: 2010 GRA – Keeyask Partnership Agreement

Please refile 2011 GRA – PUB/MH II-7 and provide a detailed illustration of Keeyask Partnership average flow year revenue calculation process in the first full year of generation separately defining:

b) off-peak period energy pricing methodology

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-25(c).

PUB/MH I-135

Reference: 2010 GRA – Keeyask Partnership Agreement

Please refile 2011 GRA – PUB/MH II-7 and provide a detailed illustration of Keeyask Partnership average flow year revenue calculation process in the first full year of generation separately defining:

c) minimum revenues (if applicable)

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-25(c).

PUB/MH I-135

Reference: 2010 GRA – Keeyask Partnership Agreement

Please refile 2011 GRA – PUB/MH II-7 and provide a detailed illustration of Keeyask Partnership average flow year revenue calculation process in the first full year of generation separately defining:

d) treatment of transmission losses (to point of export sale)

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-25(c).

PUB/MH I-136

Reference: 2012 GRA TAB 9/Attach 9 (July 20/12)

Preamble: Recent Actual and Forecast Flow and Water Level Data

a) Please provide MH's most recent Nelson River and Churchill River stream flow and lake level 90-day forecasts as typically required under the Northern Flood Agreement and supplied to affected communities.

ANSWER:

Manitoba Hydro is required to issue 60-day forecasts under the Northern Flood Agreement. Forecasts issued on August 30th, 2012 are provided in Appendix 18.

MH also posts historic and forecast information on its external website (http://www.hydro.mb.ca/corporate/water_regimes/general_information.shtml).

PUB/MH I-136

Reference: **2012 GRA TAB 9/Attach 9 (July 20/12)**

Preamble: **Recent Actual and Forecast Flow and Water Level Data**

b) Please provide MH's forecast of Nelson River monthly flows at Kelsey G.S. and Kettle G.S. out to the end of fiscal 2012/13; also include Lake Winnipeg water levels forecasts.

ANSWER:

The table below indicates Manitoba Hydro's forecasts of Nelson River monthly average flows at Kelsey G.S., Kettle G.S. and beginning of month elevations for Lake Winnipeg as of September 5, 2012.

	Kelsey G.S flow(kcfs*)	Kettle G.S. flow (kcfs)	Lake Winnipeg Elev. (ft)
September	82.8	130.0	714.5
October	75.9	117.4	714.4
November	86.9	122.8	714.1
December	86.9	121.6	713.9
January	91.7	127.2	713.8
February	90.5	127.2	713.8
March	86.0	122.5	713.8
April 1st			713.7

kcfs – thousands of cubic-feet-per-second

PUB/MH I-136

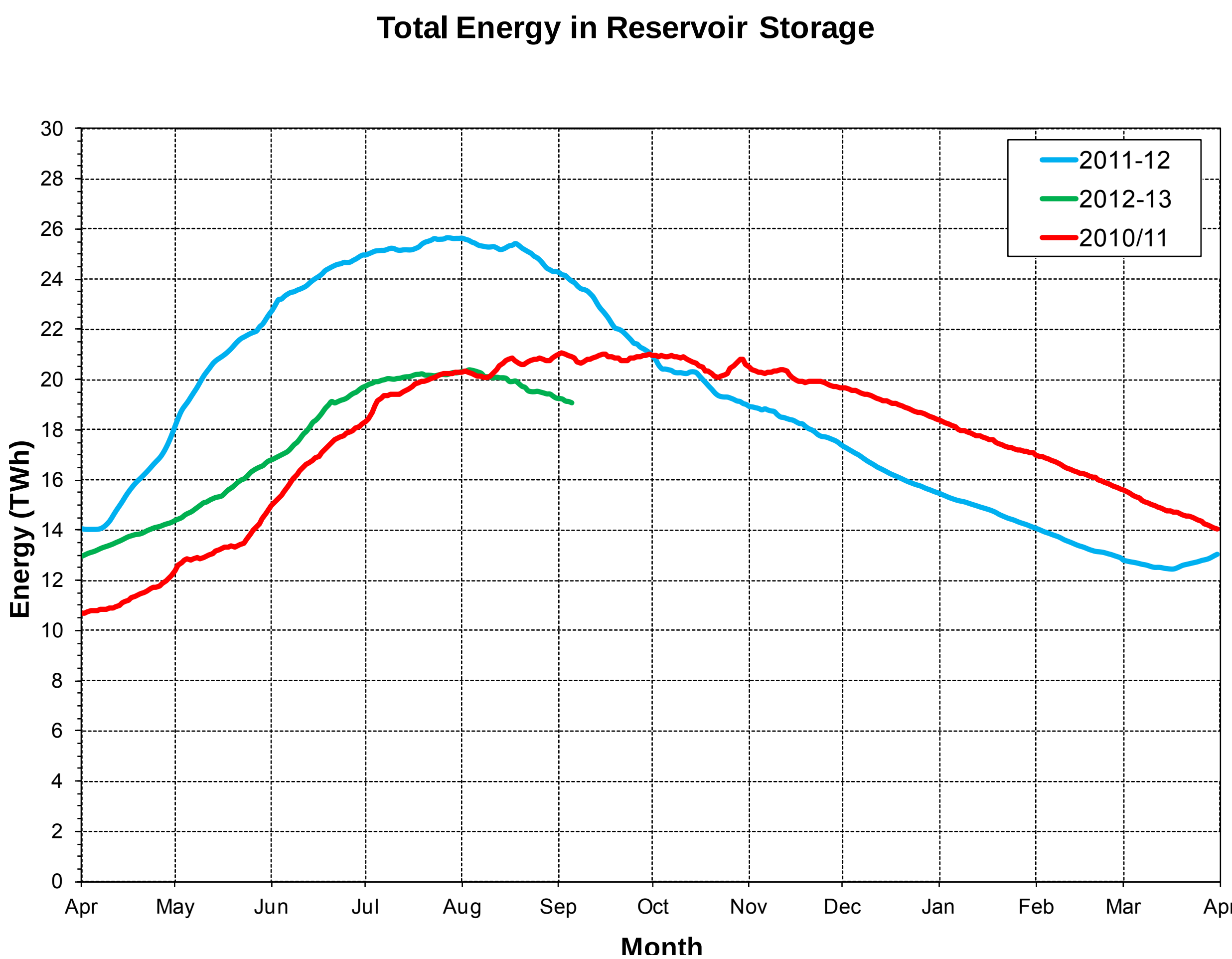
Reference: 2012 GRA TAB 9/Attach 9 (July 20/12)

Preamble: Recent Actual and Forecast Flow and Water Level Data

c) Please provide MH's energy-in-storage curves for 2012/13, 2011/12 and 2010/11.

ANSWER:

Below is the total energy in reservoir storage (all basins) for fiscal years 2010/11, 2011/12 and 2012/13.



PUB/MH I-136

Reference: **2012 GRA TAB 9/Attach 9 (July 20/12)**

Preamble: **Recent Actual and Forecast Flow and Water Level Data**

d) Please provide a chart of MH"s monthly hydraulic generation (GWh) from 2000/01 to date separately defining output for generation on:

- **Winnipeg River**
- **Saskatchewan River**
- **Upper Nelson River**
- **Lower Nelson River**

ANSWER:

	HYDRAULIC GROSS GENERATION (GWh)			
Month	**Winnipeg River**	**Saskatchewan River**	**Upper Nelson**	**Lower Nelson**
Jan-00	399	229	237	1824
Feb-00	376	168	220	1780
Mar-00	407	145	254	1962
Apr-00	349	93	250	1744
May-00	339	76	215	1826
Jun-00	364	62	232	1566
Jul-00	390	75	268	1927
Aug-00	408	59	264	2038
Sep-00	397	45	253	1944
Oct-00	397	73	264	2131
Nov-00	377	93	246	1971
Dec-00	399	203	227	2012
Jan-01	409	59	219	2095
Feb-01	358	80	189	1977
Mar-01	390	44	223	2144
Apr-01	367	76	226	1909
May-01	379	57	258	2345
Jun-01	353	22	220	2316
Jul-01	364	28	215	2383
Aug-01	383	28	256	2148
Sep-01	391	15	240	1982

	HYDRAULIC GROSS GENERATION (GWh)			
Month	Winnipeg River	Saskatchewan River	Upper Nelson	Lower Nelson
Oct-01	373	24	268	1987
Nov-01	377	33	244	1933
Dec-01	417	39	223	1883
Jan-02	414	51	233	2005
Feb-02	368	48	218	1610
Mar-02	386	126	236	1643
Apr-02	362	69	231	1474
May-02	388	72	224	1608
Jun-02	372	75	231	1780
Jul-02	355	89	224	1816
Aug-02	376	87	254	1869
Sep-02	372	54	254	1778
Oct-02	316	85	268	1868
Nov-02	287	73	254	1638
Dec-02	295	58	235	1821
Jan-03	296	146	227	1905
Feb-03	278	189	205	1499
Mar-03	289	126	221	1521
Apr-03	220	58	214	1323
May-03	184	50	229	1342
Jun-03	145	75	199	1079
Jul-03	132	122	208	1185
Aug-03	145	121	198	1014
Sep-03	125	16	132	841
Oct-03	217	8	126	816
Nov-03	257	7	160	870
Dec-03	340	12	174	1067
Jan-04	369	62	166	1065
Feb-04	364	37	167	991
Mar-04	379	79	184	1179
Apr-04	392	106	178	996
May-04	380	93	215	1253
Jun-04	348	37	229	1609
Jul-04	383	94	255	1903
Aug-04	407	112	265	1933
Sep-04	380	147	252	1814
Oct-04	382	129	258	2008
Nov-04	378	101	250	2113
Dec-04	405	199	241	2015

	HYDRAULIC GROSS GENERATION (GWh)			
Month	Winnipeg River	Saskatchewan River	Upper Nelson	Lower Nelson
Jan-05	403	191	219	2206
Feb-05	366	149	184	2066
Mar-05	402	224	196	2232
Apr-05	375	100	195	2230
May-05	395	149	184	2418
Jun-05	351	292	182	2255
Jul-05	350	295	182	2384
Aug-05	395	186	181	2293
Sep-05	362	309	176	2032
Oct-05	328	355	206	2170
Nov-05	323	226	243	2400
Dec-05	409	253	231	2217
Jan-06	413	245	230	2358
Feb-06	373	298	191	2120
Mar-06	405	214	210	2446
Apr-06	390	103	198	2146
May-06	402	221	195	2401
Jun-06	367	233	218	2320
Jul-06	256	234	275	2449
Aug-06	193	181	275	2397
Sep-06	157	68	220	1873
Oct-06	152	129	206	1478
Nov-06	140	152	228	1483
Dec-06	195	163	219	1857
Jan-07	253	272	216	1959
Feb-07	244	293	183	1607
Mar-07	261	175	208	1716
Apr-07	276	155	211	1620
May-07	246	183	216	2060
Jun-07	377	294	238	2002
Jul-07	408	234	233	2418
Aug-07	385	172	231	2491
Sep-07	303	109	248	2126
Oct-07	361	111	261	2143
Nov-07	362	138	240	2368
Dec-07	395	250	220	2073
Jan-08	387	246	207	2222
Feb-08	349	248	193	2041
Mar-08	377	144	206	2043

	HYDRAULIC GROSS GENERATION (GWh)			
Month	Winnipeg River	Saskatchewan River	Upper Nelson	Lower Nelson
Apr-08	364	71	202	2049
May-08	371	86	232	1978
Jun-08	345	106	258	1816
Jul-08	334	156	217	2347
Aug-08	336	121	207	2483
Sep-08	334	97	250	2291
Oct-08	342	67	264	2347
Nov-08	373	77	238	2323
Dec-08	388	154	207	2130
Jan-09	388	185	209	2103
Feb-09	354	174	189	1881
Mar-09	391	90	212	1999
Apr-09	354	29	203	1982
May-09	337	64	186	2134
Jun-09	317	44	180	2128
Jul-09	357	45	195	2347
Aug-09	385	52	197	2294
Sep-09	357	93	224	2072
Oct-09	390	121	275	2373
Nov-09	369	58	261	2168
Dec-09	382	180	232	2039
Jan-10	381	187	216	2148
Feb-10	351	167	202	1895
Mar-10	392	129	236	2028
Apr-10	361	62	237	1835
May-10	275	31	226	1464
Jun-10	369	77	235	1811
Jul-10	377	262	159	2175
Aug-10	350	221	161	2311
Sep-10	335	165	153	2159
Oct-10	363	193	170	2296
Nov-10	348	165	172	2339
Dec-10	379	190	169	2381
Jan-11	368	197	166	2345
Feb-11	339	154	134	2172
Mar-11	368	202	162	2397
Apr-11	348	143	168	2119
May-11	332	220	180	2106
Jun-11	329	335	175	1846

	HYDRAULIC GROSS GENERATION (GWh)			
Month	**Winnipeg River**	**Saskatchewan River**	**Upper Nelson**	**Lower Nelson**
Jul-11	344	342	177	2324
Aug-11	166	340	172	2358
Sep-11	128	186	175	2044
Oct-11	158	196	239	2102
Nov-11	166	163	232	2171
Dec-11	241	191	215	2133
Jan-12	268	175	233	2226
Feb-12	263	121	232	1882
Mar-12	267	122	258	1811
Apr-12	251	168	248	1557
May-12	263	190	255	1751
Jun-12	292	189	269	1797
Jul-12	371	280	276	2212
Aug-12	349	299	291	2128

Winnipeg River: Pointe du Bois, Slave Falls, Seven Sisters, McArthur, Great Falls, Pine Falls
Saskatchewan River: Grand Rapids
Upper Nelson: Jenpeg, Kelsey
Lower Nelson: Kettle, Long Spruce, Limestone

PUB/MH I-137

Reference: 2011 and 2012 Annual Reports/2011/12 Power Resource Plan

a) Please provide a historical summary of MH's actual annual wind generation supply to Mar.31/12 defining:

- **Monthly outputs for**
  - **St. Leon**
  - **St. Joseph**
  - **Annual peak and off-peak energy output during June/July/August and during December/January/February periods.**
  - **Annual non-availability of wind energy (at St. Leon/St. Joseph) due to:**
    - **Cold weather restrictions on operations**
    - **Other mechanical or electrical problems**

ANSWER:

Manitoba Hydro is unable to provide wind farm specific production information as it is commercially sensitive and confidential. Therefore any wind generation data prior to April, 2011 when only one wind farm was in production, cannot be provided.

Quarterly aggregated wind generation data (MWh) is provided as follows:

Quarter	Total	On Peak (5x16)	Wrap
April- June, 2011	202,029	96,316	105,713
July- Sept, 2011	182,100	84,925	97,175
Oct- Dec, 2011	270,109	113,285	156,824
Jan-Mar, 2012	254,029	120,726	133,303

Manitoba Hydro understands that the wind turbines at both wind farms are equipped to operate under cold weather conditions. However operation is restricted once the ambient temperature reaches -30C.

Manitoba Hydro is unaware of any significant mechanical or electrical issues with the wind farms. Manitoba Hydro does not have the requested information on non-availability of wind energy as a result of these factors or cold weather restrictions.

PUB/MH I-137

Reference: 2011 and 2012 Annual Reports/2011/12 Power Resource Plan

b) Please provide 2009.10, 2010/11 and 2011/12 actual levels of dependable energy available to MH in:

- **Summer (6) months – peak**
- **Summer (6) months – off-peak**
- **Winter (6) months – peak**
- **Winter (6) months – off-peak**

ANSWER:

Dependable wind energy is an estimate of the amount of energy which is expected to be produced in a year from a wind farm with 95% confidence. It is not based upon actual operating data but on long term meteorological data and computer modeling.

Please see page 14 and 15 from the 2011 Power Resource Plan (Attachment 3) where a description of how the amount of dependable wind energy is estimated by Manitoba Hydro.

PUB/MH I-137

Reference: 2011 and 2012 Annual Reports/2011/12 Power Resource Plan

c) Please comment on various factors that impact on the reliability and effective use of wind energy.

ANSWER:

The factors that impact on the reliability and effective use of wind energy are:

1. Equipment reliability
2. Cold weather operating restrictions
3. Accuracy of short term wind forecasts
4. Amount of additional operating reserves required by Manitoba Hydro to backstop wind generation
5. Ability of the Manitoba Hydro hydraulic system to shape wind generation to match market requirements under the full range of water conditions

PUB/MH I-137

Reference: 2011 and 2012 Annual Reports/2011/12 Power Resource Plan

d) Please explain MH's contract obligations and responsibilities with respect to wind energy to NSP, MP and WPS.

ANSWER:

Manitoba Hydro's contractual obligations with respect to wind energy are commercially sensitive and confidential.

With regard to the MH's contract with MP, Minnesota Power's May 24, 2011 Press Release stated

> "the agreement, ….calls for Manitoba Hydro to sell 250 megawatts (MW) of electricity to Minnesota Power for 15 years beginning in 2020. A unique aspect of the power purchase agreement is the inclusion of a "wind storage" provision that entitles Minnesota Power to transmit electric energy northward from its wind farms in North Dakota when wind production is high or electric loads are low. When Minnesota Power transmits power northward, Manitoba Hydro will absorb it into its system – in essence storing the wind power, using the Manitoba system as a rechargeable battery. This wind storage provision will allow Minnesota Power to balance its energy position and maximize the value of its wind resources."

PUB/MH I-138

Reference: GSL – MH Workshop Aug.15/12 – Time-Of-Use Rates

a) GSL > 30 kVA Load Profiles

Please provide subclass load profiles for GSL >100 and GSL 30-100 kVA customers defining peak, shoulder and off-peak energy usage for the years 2005/06 to 2010/11 (actual) and the years 2011/12 to 2021/22 (forecast).

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-113(a).

PUB/MH I-138

Reference: GSL – MH Workshop Aug.15/12 – Time-Of-Use Rates

b) Time-of-Use (TOU) Rates

Please provide a probable timeline for MH's TOU implementation for GSL > 30 kVA customers.

ANSWER:

A recommendation with respect to Time-of-Use rates (TOU) for General Service Large (>30kv) customers will go before the Manitoba Hydro-Electric Board ("MHEB") for approval in September 2012. If approved by the MHEB, Manitoba Hydro will seek PUB approval of TOU rate schedules to be effective April 1, 2013, and this Application may be amended at that time.

PUB/MH I-138

Reference: GSL – MH Workshop Aug.15/12 – Time-Of-Use Rates

c) Load Shifting

Please provide MH's forecast on load shifting/revenue losses that could flow from; lower off-peak rates for energy and demand charge reductions.

ANSWER:

Load shifting from the higher cost on-peak period to the lower-cost off-peak period would result in lower domestic revenues being provided to Manitoba Hydro from the General Service Large >100 kV and 30 – 100 kV rates classes. The degree of load shifting that customers may undertake is impacted by several factors, including the availability of capacity in the off-peak period, either through a customer's electric supply contract or within the production capabilities of their facility, load factor, and the minimum monthly contract amount (50 percent of contract). Given these constraints, there are some limitations to the degree of load shifting that can occur in the short-term.

Manitoba Hydro has not forecast load shifting and revenue losses that could flow from load shifting. A sensitivity analysis undertaken on 2011-12 consumption profiles, which applied present contract demand limits to off-peak demand growth, yielded a maximum theoretical industrial load shift of approximately 100 MVA and 300 GWh (approximately 5 percent of the total industrial consumption served at greater than 30 kV). The sensitivity analysis did not take into account limitations in customer processes and off-peak production capacity. Based on customer feedback, these limitations will dramatically reduce the potential opportunity for load shifting in the short term, requiring significant capital investment to adjust processes and add off-peak capacity in the long-term.

The determination and impact of revenue gain/loss determination would be dependent on the additional revenue that could be obtained from the sale of freed on-peak capacity to other domestic customers and export markets. The firmness of this freed capacity will be established over the first two to three years of time-of-use implementation. Significant load shifting should also reduce Manitoba Hydro's net cost to serve these customers over the long-term.

PUB/MH I-138

Reference: GSL – MH Workshop Aug.15/12 – Time-Of-Use Rates

d) Demand Concessions

Please confirm that MH has repaid in full for the temporarily foregone revenues associated with the 2009/10 Demand Concessions to particular industrial customers; and that MH sees no further need for a similar process in the future.

ANSWER:

All customers participating in the Distressed Industry Billing Demand Deferral Program have either repaid or made arrangements to repay the full amount of their deferral, plus interest and applicable federal, provincial and municipal taxes.

Manitoba Hydro cannot confirm that there will be no need for a similar process at some point in the future.

PUB/MH I-138

Reference: GSL – MH Workshop Aug.15/12 – Time-Of-Use Rates

e) Energy Intensive Industry Rates (EIIR)

Please confirm that IFF11 does not include any EIIR revenues and explain why MH is no longer pursuing an EIIR process.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-113(b).

Manitoba Hydro has determined that introduction of a Time-of-Use rate, with on peak prices set to approximate firm values in the export market, provides some protection of export revenue, offers the opportunity to track market prices for firm energy sales in the long run and addresses the key criteria set forth in Order 112/09.

The introduction of a TOU rate enables Manitoba Hydro to provide more appropriate price signals to large energy users, providing a clear indication of the value of energy to Manitoba Hydro while maintaining revenue neutrality and preserving Manitoba's competitive industrial rate position relative to other provinces and states. Such a rate also partially addresses Manitoba Hydro's concerns about load growth by energy-intensive industries and the potential impact that such growth may have on profitable on-peak export sales through the creation of a rate structure that is representative of the pricing trends and behavior in the MISO power market, particularly during the on-peak period.

The TOU rate design provides greater flexibility in rate application, such that the on-peak rate can be tailored to more closely track the value of long term firm export energy, thereby creating an implicit link to market-based rates without the complexity and instability in pricing that market-based rates typical demonstrate. The proposed TOU rate is also simpler to implement and administer than alternative rates, such as inverted rates or rates applied to load expansions only, which require complex determination of baselines and application of two-tier rates.

Finally the TOU rate design addresses all of the criteria set forth in PUB Order 112/09. The criteria were summarized on page 137 of that Order.

1) Applies to all non-government GSL>30 customers.
The proposed TOU rate will apply to all customers served at > 30 kV, including government customers.

2) EIIR only applicable to on-peak load growth above an existing aggregated baseline.
The proposed TOU rate will apply to all usage of all customers served at > 30 kV. There will be no baseline calculation.

3) Baseline adjustments will only be permitted relative to Curtailable Rates Program; Self-Generation and mandated energy efficiency.
Since there are no baselines, there will be no baseline adjustments.

4) Proxy rate of 5.53 cents/kW.h adjusted downward by 0.9 cents/kW.h to remove the demand component, to apply for the initial three year test period.
The proposed TOU on peak rate is seasonally differentiated at 4.2 cents for non-winter and 5.2 cents for winter months. On a weighted average basis the energy rate is 4.53 cents per kW.h (GS large > 100 kV) which is very close to that directed in Order 112/09.

5) New to Manitoba GSL>30 customers are entitled to 50% of on-peak energy at embedded cost rates, for a period of three years, after which an adjustment may be made.
The TOU rate will apply to all usage by all customers, existing or new, hence it is both simple and fair.

PUB/MH I-138

Reference: GSL – MH Workshop Aug.15/12 – Time-Of-Use Rates

f) Service Extension Policy

Please file MH's current service extension policy and a summary of its actual usage in the last 5 years.

ANSWER:

The current service extension policy is shown below. Manitoba Hydro tracks these projects individually and as these are larger customers only a few extensions are undertaken each year. Several projects are also initiated but do not proceed.

Maximum Allowance - Customer-Owned Transformation

Effective 2005 06 23 and until further notice, no Corporate allowance will be made in facilities required to serve new loads exceeding 30 kV or loads in excess of 5 MW without approval of Manitoba Hydro's Executive Committee.

The maximum allowance for primary voltage service, other than those exceeding 30 kV or loads exceeding 5 MW, where the customer owns the transformation, is three times the estimated annual revenue, applied to specific Corporate facilities, as follows:

a) Not exceeding 30 kV – applicable to facilities which are not on private property;

b) Exceeding 30 kV – applicable to the cost of upgrading the Corporation's existing common integrated system on the supply side of the point where facilities tap into the system.

PUB/MH I-139

Reference: Tab 10.6 – SEP Term and Conditions

a) New SEP Option 1 Customers

Assuming maximum uptake by all eligible customers, please provide potential customer monthly load profiles by major industry sector defining the actual time-of-use (peak/shoulder/off-peak) energy usage under the SEP Option No. 1 scenario for the test years; also produce an annual usage forecast going out to 2021/22.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-114(a) and (b).

Based on the historical uniformity of industrial consumption between time-of-use periods, it has not been necessary for Manitoba Hydro to forecast time-of-use energy consumption for industrial accounts. Customers have indicated that the non-firm, interruptible nature of the Surplus Energy Program is a serious impediment to significant allocations of load under Option 1. This assessment has been confirmed by the fact that no energy has been consumed under the under Option 1 of the Surplus Energy Program in previous years. Time-of-use specific load profiles are dependent on customer investment in production/process capacity and willingness to engage the risk of interruption to Option 1 load. It is highly unlikely that customers will allocation load under Option 1 during the test years based on these stated concerns and the need to assess implications for investment and facility operations.

PUB/MH I-139

Reference: Tab 10.6 – SEP Term and Conditions

b) Industry Interest

Please indicate/quantify on an industry sector basis the level of interest in the revised Option 1 – TOU – SEP Rates.

ANSWER:

To-date, interest by all industry sectors in the revised Option 1 for Surplus Energy Program rates has been minimal. One customer in the metals sector has expressed some interest in exploring use of the rate for a portion of their facility load. Concerns over the non-firm, interruptible nature of the program are a primary impediment for most industrial users.

PUB/MH I-139

Reference: Tab 10.6 – SEP Term and Conditions

c) Time-of-Use (TOU) in SEP Rates

Please define the probable maximum potential revenue impact of allowing large SEP customers under Option 1 to nominate different levels of SEP energy during peak/shoulder/off-peak periods; in particular, address the potential uptake in the large chemical and petroleum transport industry sectors if there are no program limits.

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH I-114(a) and (b).

The Surplus Energy Program proposed Terms and Conditions contain terms that serve to limit the level of potential uptake.

PUB/MH I-139

Reference: Tab 10.6 – SEP Term and Conditions

d) TOU Benefits to MH

Please explain the benefits and risks to MH of a significant uptake of SEP Option 1 - energy in peak, shoulder or off-peak hours.

ANSWER:

The benefits available to Manitoba Hydro of a significant uptake of Option 1 under the Surplus Energy Program by new load include additional revenue with full incremental cost recovery, particularly during periods of high flow when transmission constraints may limit the ability of the Corporation to deliver that energy to the export market. During periods when transmission capacity is available, Surplus Energy Program usage provides revenues equivalent to those that may be obtained in the short-term export market.

The risks to Manitoba Hydro lay mainly in the area of domestic cost recovery during periods of sustained low market rates, if significant existing load should transfer to the Surplus Energy Program. Lower short-term market rates may provide less revenue than domestic rates, resulting in a net revenue loss to the Corporation. The magnitude of this risk is limited by several considerations, including customer requirements for firm, dependable supply (not provided under the Surplus Energy Program) and the 75 percent Program requirement for Reference Levels of Demand, which limit the amount of load that is eligible under Option 1 of the Surplus Energy Program. A distribution and transmission cost recovery component is also factored into energy pricing for the Surplus Energy Program, providing a guarantee of at minimum of partial cost recovery for these assets. In the long-term, adverse short-term revenue effects may be offset by generation capital cost deferrals and/or beneficial long term export sales if the migration to Option 1 of the Surplus Energy Program is permanent and the obligation to provide firm supply for this load is eliminated.

PUB/MH I-139

Reference: Tab 10.6 – SEP Term and Conditions

e) SEP Option 2 - Manitoba Government Mandate on Discontinuance the Use of Coal in Space and Water Heating

Please indicate the potential increase in SEP – Option 2 off-peak energy usages; and define any load limits that MH expects to impose.

ANSWER:

Manitoba Hydro has seen interest in the SEP program since the coal discontinuance mandate from the Province was announced. However, to date, only one new customer has been confirmed. While this program is attractive to eligible customers there are some barriers to entrance: the service extension costs to serve the SEP load (and cost to the customer) can be high, and the uncertainty of its future, as the program has not been confirmed by the PUB as a permanent rate offering. Manitoba Hydro has not prepared a forecast specifically related to any potential increase in off-peak energy consumption.

Manitoba Hydro does not expect to impose any additional restrictions other than those that have always been required to be eligible for the program.

SEP - Option 2 is available to heating loads which meet the following qualifications:

a) Demand must be 200 kW or greater; and
b) The electricity is to be used for space and/or water heating only; and
c) The load must be metered separately from the customer's firm load; and
d) The customer has an alternate energy source as a back-up facility for the entire SEP load; and
e) Demand associated with SEP does not exceed 50 MVA **except** where the load factor of such load is guaranteed by the customer, in writing, to exceed 25% on a weekly basis; and
f) The load is not being served under the Curtailable Rate Program.

PUB/MH I-140

Reference: Appendix 10.7 (P. 9 and 10)/MH-GSL Workshop (P. 7)

a) Overall SEP Sales vs. Marginal Cost (MC)

Please confirm the following calculations of MH's Marginal Cost (MC) of energy with MH's SEP revenues (not including distribution or basic charge) and also MISO pricing:

	Marginal Cost (¢/kWh)	SEP Revenue from Energy Sales (¢/kWh)	MISO Day-Ahead Pricing Average (¢/kWh)	Peak (¢/kWh)	Off-peak (¢/kWh)
2000/01	4.9	5.5			
01/02	3.5	4.0			
02/03	5.4	6.1			
03/04	5.1	6.9			
04/05	5.0	5.8			
05/06	5.0	6.1			
06/07	6.3	7.1	5.4	7.2	3.9
07/08	5.1	5.8	4.9	6.6	3.5
08/09	3.6	4.7	4.1	5.6	2.8
09/10	2.9	3.7	2.6	3.3	2.0
10/11	2.4	3.4	2.6	3.2	2.0
11/12	?	<3.0 est.	2.2	2.8	1.7

ANSWER:

The MISO prices provided in the above table appear to have been taken from Slide 7 of the Time-of-Use Stakeholders Presentation held on August 15, 2012. Please see GAC/MH I-24 for a copy of this presentation.

It is important to recognize that these values are "weighted" average values that result from application of MISO day-ahead hourly prices against Manitoba Hydro's industrial load profile for customers served at Greater than 30 kV. The numbers shown are not a simple average of MISO hourly prices.

The SEP average values appear to be based on revenue obtained from SEP sales divided by energy sold, which will also be weighted by time of year (heating) and may not be a simple average of weekly SEP rates.

With the above caveats, the numbers in the table can be confirmed except as follows:

- Marginal Cost for 2005/06 should be 5.1 not 5.0;
- Marginal Cost for 2009/10 should be 3.0 not 2.9; and,
- SEP Revenue for 2010/11 should be 3.3 not 3.4.

Manitoba Hydro has not yet compiled the SEP and marginal cost data for 2011/12.

PUB/MH I-141

Reference: Curtailable Rates Program (CRP)/2011/12 PRP

a) Program Limits

Please provide details on MH's CRP limit of 180MW including:

? ___MW spinning reserve
? ___MW non-spinning reserve
? ___MW planning reserve

ANSWER:

Manitoba Hydro currently relies on up to 50 MW of Option 'R' Curtailable Load to provide non-spinning reserve.

Option 'A' Load is relied upon to re-establish contingency reserves and to respond to emergencies. Manitoba Hydro is proposing a limit of 180 MW Option 'A' load, assuming Option 'C' Load converts to Option 'A'. If not, the proposed limit on Option 'A' load is 150 MW.

The Mid-Continent Area Power Pool Generation Reserve Sharing Pool retired on January 1, 2010. As a result, MH's Option 'A' load was no longer necessary to fulfill obligations to meeting after-the-fact reporting of capacity. However, MH anticipates that there will be a capacity market developing in the MISO Market. At that time, Option 'A' Load will be used to support term capacity sale obligations.

In fulfilling Manitoba Hydro planning reserves, Manitoba Hydro does not rely on any curtailable load in its long-term resource adequacy plans because CRP customers are not obligated to make long-term commitments. However, CRP load is considered available to protect firm load in the mid-term planning horizon.

Manitoba Hydro does not rely on curtailable load to provide spinning reserves; however the CRP does provide reliability and economic benefits to Manitoba Hydro.

Please also see Manitoba Hydro's response to CAC/MH I-84(e).

PUB/MH I-141

Reference: Curtailable Rates Program (CRP)/2011/12 PRP

b) Please explain how these reserves are reflected in MH's 2011/12 Power Resource Plan – DSM – Demand indicates:

2011/12 – 25MW
2012/13 – 47MW
2013/14 – 72MW
2020/21 – 214MW
2025-26 – 256MW

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-141(a).

PUB/MH I-141

Reference: Curtailable Rates Program (CRP)/2011/12 PRP

c) Please reconcile the values in b) with MH's incremental DSM of 256MW (2011/12) and 1008 GWh (2025/26) on P.18 of 2011/12 PRP.

ANSWER:

Manitoba Hydro's incremental DSM of 256 MW:

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Residential	6	12	18	23	26	31	35	38	42	45	46	47	48	48	49
Commercial	17	29	41	53	64	75	87	98	106	113	117	122	127	133	137
Industrial	2	6	13	23	37	43	47	50	53	56	59	62	65	68	71
Self Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total MW	25	47	72	99	127	150	169	186	200	214	222	231	240	249	256

Manitoba Hydro's incremental DSM of 1008 GWh:

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Residential	23	52	80	93	100	113	122	130	138	146	148	149	145	135	125
Commercial	68	118	170	221	270	320	369	417	447	476	489	504	520	541	549
Industrial	14	30	49	72	97	116	132	147	162	177	192	207	222	237	252
Self Generation	78	94	112	122	140	147	76	79	83	83	83	83	83	83	83
Total GW.h	183	293	411	508	608	696	699	774	830	882	911	943	970	995	1008

PUB/MH I-141

Reference: Curtailable Rates Program (CRP)/2011/12 PRP

d) Please explain how the DSM resource and the CRP resource needs are determined.

ANSWER:

The Curtailable Rates Program (CRP) has been developed over many years in conjunction with Manitoba Hydro's large industrial customers. The size of the CRP initially reflected the capability of our customers to supply capacity under terms and conditions that make the resource useful at a price equivalent to Manitoba Hydro's resource alternative. The DSM resource for the CRP is determined by aggregating the load available to be curtailed by participating customers.

In February 2005, Manitoba Hydro capped the CRP resource at 230 MW for Options A and C combined and 100 MW for Option R. At that time, Manitoba Hydro advised that the purpose for the upper limit on load subscription to the CRP was to ensure that Curtailable Load would have value for Manitoba Hydro commensurate with the Reference Discount being offered at that time.

The current GRA includes provisions to eliminate Option C and to further reduce the upper subscription limit on Option A from 230 MW to either 180 MW (if the current Option C customers opts to move their curtailable load to Option A) or 150 MW (if the current Option C customer elects to exit the program entirely). It is also proposed to reduce the maximum subscription under Option R from 100 MW to 50 MW.

Please see Manitoba Hydro's responses to PUB/MH I-141(a) and CAC/MH I-84(c) for further discussion of these proposed revisions to the CRP.

PUB/MH I-142

Reference: Appendix 10.5 (P. 8 & 9)

a) Curtailable Energy Program Value

Please provide the detailed calculation of the value of CRP capacity, updating the annual capacity cost of a SCCT Generating facility.

ANSWER:

The CRP capacity value for the Curtailable Rates Program for 2012/13 is based on 42% of the annualized carrying cost of a simple cycle combustion turbine (SCCT). The annualized carrying cost of a SCCT is equal to the sum of the annualized cost of a SCCT plus the annualized operations and maintenance cost and the cost of gas transport & supply (all expressed in $/KW-year), as shown below:

Annualized Cost [$/kW]	O & M [$/kW/year]	Gas Transport & Supply [$/kW/year]	$/kW/year	$/kW/ month	$/kW/month at 42%
85.0	16.5	1.0	102.5	8.5	3.6

PUB/MH I-142

Reference: Appendix 10.5 (P. 8 & 9)

b) Curtailable Energy Program Value

Please indicate whether this SCCT value reflects MH's own Brandon units G&T capital cost of the current capital cost of a SCCT plant.

ANSWER:

The SCCT value represents the current capital cost of a new SCCT plant, and does not reflect MH's own Brandon units G&T capital cost.

PUB/MH I-143

Reference: Appendix 10.8 LUBD Report Mar./12

a) Please confirm LUBD customers receive an annual rate subsidy with an aggregate value of $295,000 (2010/11) and equivalent of about 20% of gross billings otherwise incurred.

ANSWER:

Manitoba Hydro can confirm that, had LUBD customers been billed on the regular General Service rates, their bills would have been $295,000 higher in 2011/12.

PUB/MH I-143

Reference: Appendix 10.8 LUBD Report Mar./12

b) Please indicate whether any LUBD customers could be eligible for the pending GSL > 30 kVA TOU rates; and, if so, would the new TOU rate be more attractive and possibly negate the need for LUBD?

ANSWER:

There are currently only two Large >30 kV customers on the LUBD rate. Although Manitoba Hydro has not yet finalized its TOU rates, it is expected that these customers would still benefit more from the LUBD rate.

PUB/MH I-144

Reference: MH Annual Reports Comparable North American Energy Prices

a) Rate Comparisons

Please confirm and complete the following tabulation of:

Retail Price of Electricity (¢/kWh CDN)

	2011/12	2010/11	2009/10	2008/09	2007/08	2006/07
Man	?	5.7	5.4	5.2	5.1	5.0
Alta	?	N/A	N/A	N/A	N/A	N/A
Sask	?	8.5	8.0	7.6	7.6	7.3
BC	?	6.8	5.8	5.4	5.3	5.3
Ont	?	N/A	N/A	N/A	N/A	9.9
Que	?	6.2	6.4	6.1	6.0	5.6
N.D.	?	6.7	6.5	8.2	7.1	7.3
Minn	?	8.2	8.0	9.7	8.2	7.5
S.D.	?	7.4	7.3	8.7	N/A	N/A
Wisc	?	9.4	9.2	11.4	9.3	9.2

ANSWER:

The figures shown in the table above are confirmed. Provided below are the updated figures for 2011/12.

Man	5.9
Alta	N/A
Sask	8.7
BC	6.9
Ont	N/A
Que	6.3
N.D.	7.6
Minn	8.3
S.D.	8.0
Wisc.	10.2

PUB/MH I-144

Reference: MH Annual Reports Comparable North American Energy Prices

b) Rate Comparisons

Please confirm that the retail price of electricity in the Northern MISO states peaked in 2008/09 and has declined by 10 to 20% in the last 2-3 years, as MH's export prices fell from 6¢/kW to 3¢/kWh.

ANSWER:

Manitoba Hydro cannot confirm this statement. Although the prices shown in the table in PUB/MH I-144(a) appear to have peaked in 2008/09, they have in fact continued to increase from year to year. The decline of the US dollar relative to the Canadian dollar is the contributing factor to explain this misperception. The table below shows the actual prices (in US dollars) indicative of the retail price of electricity in each of the MISO states. The US exchange rate used in converting these values to Canadian dollars is also provided below for comparison purposes:

	2011/12	2010/11	2009/10	2008/09	2007/08
N.D.	7.6	6.9	6.4	6.5	6.2
Minn	8.2	8.4	7.9	7.7	7.1
S.D.	8.0	7.6	7.2	6.9	6.7
Wisc.	10.2	9.7	9.1	9.0	8.1
Exchange rate:	1.0009	0.9718	1.0156	1.2643	1.1561

*Note: Source data for 2006/07 no longer available.

PUB/MH I-145

Reference: Proof of Revenue – Attachment 7/8 (July 20/12)/Billing Schedules Appendix 10.2

Demand-Energy Rate Rebalancing - Rebalancing Progress

On a subclass basis, please provide a summary of MH's progressive shift to a higher energy component in billing; from 2004/05 to date show the annual:

- **Total and unit energy revenues/total and unit demand revenues**
- **% of energy in total bill**

ANSWER:

Please see response below:

	SMALL DEMAND				MEDIUM DEMAND			
	Energy $	Demand $	Total $	% Energy	Energy $	Demand $	Total $	% Energy
2004/05	75,608,796	16,418,056	92,026,852	82%	64,614,315	64,585,530	129,199,845	50%
2005/06	85,680,681	17,039,085	102,719,766	83%	69,746,902	64,761,071	134,507,973	52%
2006/07	98,087,620	17,039,085	115,126,705	85%	73,033,291	66,634,781	139,668,072	52%
2007/08	81,314,894	18,175,329	99,490,223	82%	77,025,272	68,290,297	145,315,569	53%
2008/09	85,882,455	18,174,457	104,056,912	83%	89,082,246	60,040,148	149,122,394	60%
2009/10	89,789,694	18,531,092	108,320,786	83%	97,045,652	58,339,159	155,384,811	62%
2010/11	95,142,814	18,186,413	113,329,227	84%	105,450,778	57,518,336	162,969,114	65%
2011/12	97,913,634	18,947,229	116,860,863	84%	108,217,635	58,133,169	166,350,804	65%

Total $ excludes revenue from Basic Charge / 3 Phase Charge where applicable.

	LARGE DEMAND 75 V - 30 KV				LARGE DEMAND 30 KV - 100 KV			
	Energy $	Demand $	Total $	% Energy	Energy $	Demand $	Total $	% Energy
2004/05	31,704,942	24,906,995	56,611,937	56%	16,295,208	9,715,532	26,010,740	63%
2005/06	34,943,935	25,857,596	60,801,531	57%	17,183,178	9,922,023	27,105,201	63%
2006/07	35,260,957	25,245,923	60,506,880	58%	19,000,040	10,980,409	29,980,449	63%
2007/08	36,739,737	25,877,620	62,617,357	59%	20,719,505	11,546,521	32,266,026	64%
2008/09	38,930,398	25,539,817	64,470,215	60%	22,717,285	11,664,898	34,382,183	66%
2009/10	42,179,309	26,114,736	68,294,045	62%	24,282,322	12,551,854	36,834,176	66%
2010/11	46,956,480	27,715,712	74,672,192	63%	26,136,001	12,816,140	38,952,141	67%
2011/12	47,481,620	26,815,628	74,297,248	64%	32,254,731	15,815,879	48,070,610	67%

	LARGE DEMAND >100 KV			
	Energy $	Demand $	Total $	% Energy
2004/05	101,036,903	43,471,871	144,508,774	70%
2005/06	111,869,517	45,316,081	157,185,598	71%
2006/07	116,569,896	46,339,750	162,909,646	72%
2007/08	116,464,185	46,551,261	163,015,446	71%
2008/09	122,297,768	47,171,290	169,469,058	72%
2009/10	113,993,664	44,405,896	158,399,560	72%
2010/11	115,317,435	41,267,388	156,584,823	74%
2011/12	118,715,400	40,780,129	159,495,529	74%

PUB/MH I-146

Reference: Quebec Hydro Nov. 2011 Report (P. 43 and P. 49)

a) Comparison to Other Jurisdictions

Please provide a copy of the Quebec Hydro Report.

ANSWER:

Please see Appendix 19 - Quebec Hydro's "Comparison of Electricity Prices in Major North American Cities" that was amended in November 2011.

PUB/MH I-146

Reference: Quebec Hydro Nov. 2011 Report (P. 43 and P. 49)

b) Please provide calculations determining the non-energy usage component ($ and %) of monthly billing for the following small and large industry customer groupings:

	500 KW	**1000 KW**	**5000 KW**	**50,000 KW**
Quebec Hydro				
B.C. Hydro				
Manitoba Hydro				

ANSWER:

Manitoba Hydro does not have access to the calculations obtained by Hydro Quebec in the preparation of the above referenced report. As such, Manitoba Hydro is unable to provide the information requested.

PUB/MH I-146

Reference: Quebec Hydro Nov. 2011 Report (P. 43 and P. 49)

c) Please explain MH's demand-energy balance in billing rates relative to Quebec Hydro and B.C. Hydro billing practises.

ANSWER:

Manitoba Hydro is unable to comment on the details and rationale which underlie the billing of demand for customers served by Hydro Quebec and BC Hydro.

PUB/MH I-146

Reference: Quebec Hydro Nov. 2011 Report (P. 43 and P. 49)

d) Please indicate MH intentions with respect to further rate increases being applied only to energy.

ANSWER:

Beginning with its 2004 General Rate Application, Manitoba Hydro has requested rates for all Demand Billed classes (General Service Small Demand, General Service Medium and General Service Large) which applied all of any requested rate increase to the Energy Charges and maintained the Demand Charges at the levels established prior to the 2004 rate change. This approach to General Service rate design was driven by two factors:

1) The PUB had directed Manitoba Hydro to review its balance between demand and energy charges in Order 7/03. That Order, dated February 3, 2003, directed Manitoba Hydro to file with the Board "*a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge.*" In making this directive the PUB expressed an opinion that some of Manitoba Hydro's Demand Charges were in the mid-to-high range as compared to other Canadian jurisdictions, while the utility's Energy Charges were amongst the lowest in Canada.

2) Trends in a number of jurisdictions were such that recovery of supply (ie. Generation) cost was transitioning from both demand and energy charges to recovery through energy charges only, sometimes differentiated by time of use period.

As a result of these factors, Manitoba Hydro believed it was appropriate to emphasize the energy charge in its rate increase proposals, and this has been accepted by the PUB in subsequent GRA Orders. Acceptance of this approach was provided in Order 101/04, pp. 28, 29; 143/04, p. 98; 116/08, pp. 308-09 and, especially, p. 288 where the Order stated:

MH's rate structure has for many years been over-collecting on demand charges and under-collecting on energy charges relative to COSS allocations. In response to Board direction, MH has, since 2003, been assigning rate increases entirely to the energy portion of rates.

The PUB has also supported Manitoba Hydro's comparison of demand and energy revenues to embedded cost as at least one benchmark to track the progress of Manitoba Hydro's rebalancing (Order 116/08, pages 288-289). Moreover, implicit support has also been provided in that Manitoba Hydro's rate structure proposals have always been approved by the PUB since 2004, until the last interim approval in Order 117/12.

A review of current (interim) rates and costs indicates that, while rebalancing has occurred throughout the 2004-2012 period, rates to some of the affected General Service classes are still not fully balanced against the embedded cost benchmark. Manitoba Hydro acknowledges that factors other than embedded cost should also be considered in the allocation of revenue recovery between demand and energy components of the rate structure. These could include: marginal cost, price-responsiveness, time of use considerations and customer characteristics. Most of these factors also favour continuing emphasis on energy charges. Manitoba Hydro intends to continue to emphasize energy charges whenever rate increases are being proposed for General Service classes.

PUB/MH I-147

Reference: Tab 10 Page 3 of 10 Basic Monthly Charge

a) Please discuss and quantify the costs (both fixed and variable) that are theoretically to be recovered from the electric BMC.

ANSWER:

A response to this same question was provided in the 2010/11 & 2011/12 GRA (PUB/MH 1-133 (a)), which has been reproduced below.

PUB/MH I-133

ANSWER:

Currently, the electric BMC for residential customers is $6.85, which recovers approximately 34% of the fixed customer related costs as determined in PCOSS10. If all fixed customer related costs were recovered through the BMC, Manitoba Hydro would need to increase its BMC to approximately $20 per customer per month (as per Appendix 11.1, page 16 of the Application). From a theoretical perspective a basic monthly charge is put in place to recover only fixed customer costs; those costs which can be identified to vary exclusively with the number of customers regardless of whether the customer imposes any demand or energy requirements on the system. The costs recoverable through the BMC include some of the costs associated with distribution circuits as well as the costs associated with customer service lines, meters, meter reading, billing and general customer service.

It is arguable that customer hook-up and usage is much less influenced by the level of the Basic Monthly Charge than the level of the Demand or Energy charges. Consequently, in a situation such as Manitoba Hydro's in which embedded costs are significantly lower than marginal costs, it is not unreasonable for fixed charges to under-recover relative to fixed costs, to assist in maintaining flexibility to move the more price elastic part of the rate structure, the energy charge, closer to marginal cost. A lower fixed charge and therefore a higher variable rate also assists in allowing the customer greater control over the level of their bill. Additionally, basic monthly charges are typically not well understood or accepted by customers. It is therefore not uncommon for utilities to set the level of the charge below the fully embedded customer costs, a trade off between establishing strictly cost based rates and the practical realities of providing customers with service.

PUB/MH I-147

Reference: Tab 10 Page 3 of 10 Basic Monthly Charge

b) What percentage of costs is currently being recovered in the residential BMC?

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-147(a).

PUB/MH I-147

Preamble: Comparison to Other Jurisdictions

c) Please indicate whether MH intends to increase or decrease the BMC.

ANSWER:

Manitoba Hydro currently has no plans to change the BMC for electric customers. However as noted in response to PUB/MH I-148, the BMC for the General Service Small (Demand) class will have to change to fully consolidate this class with the General Service Medium class.

PUB/MH I-147

Reference: Tab 10 Page 3 of 10 Basic Monthly Charge

d) If so, please provide the rationale that supports any change to the BMC.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-147(c).

PUB/MH I-148

Reference: Appendix 10 .2 - Class Consolidation

Please provide an update on the progress toward a common rate structure for GSS (D) and GSM classes.

ANSWER:

Currently the only difference between the GSS (D) and GSM rates is the monthly Basic Charge. Manitoba Hydro has, over the last several rate increases, proposed increases to the monthly Basic Charge for the GSS class in order for this class to eliminate the difference.

The rates Manitoba Hydro was initially considering for April 1, 2013 would have resulted in the two classes (GSS and GSM) being fully consolidated. However based on the PUB's instructions provided to Manitoba Hydro in the preparation of rate schedules for approval for September 1, 2012 the consolidation of these two classes will probably be delayed by at least two rate changes.

PUB/MH I-149

Reference: Appendix 10.2 MH Inverted Rates Plan of Action

Please indicate MH's intentions in the 2012 GRA for pursuing inverted rates in any or all classes.

ANSWER:

Manitoba Hydro has not advanced a plan to implement inverted rates in the current GRA.

With respect to the Residential class, while Manitoba Hydro had inverted rates from 2008 to 2010, the PUB has made clear that any further proposal for inverted rates in the future should make accommodation for those who may be adversely affected by inverted rates, such as those who do not have a choice in their primary heat source (i.e. lack of access to natural gas service). Manitoba Hydro continues to review this topic but to date has no formal timetable as to an inverted rate structure for residential customers.

PUB/MH I-150

Reference: Tab 11 Diesel Communities

a) Please file an update of the status of alternatives to diesel generation that MH is still considering and the timeline that is currently achievable for these alternatives.

ANSWER:

Please see Attachment 1 to Appendix 11.1 of the Application, Summary of Service Enhancement Options for Diesel Communities, which was originally filed in the December 2011 Diesel Application.

Subsequent to the items noted in this attachment, Manitoba Hydro continues to actively review specific energy and conservation options. Ongoing efforts include:

- *Wind/Diesel:* In moving forward in considering a potential wind pilot project in one of the diesel communities, Manitoba Hydro identified concerns regarding cost and other project risk. These included logistical and transportation challenges, Nav Canada right of way restrictions and related distribution line requirements, community siting issues, safety concerns, wind availability and challenges associated with integration with the existing diesel engines. While Manitoba Hydro will continue to consider the feasibility of wind generation in the diesel communities, based on these learnings, focus has shifted to pursuing a green pilot.

- *Green Pilot:* Manitoba Hydro is investigating the technical and economic feasibility of a 50 kW Organic Rankine Cycle (ORC) waste heat power generator, a micro-gasifier power generator fuelled by local biomass feedstocks, and the use of pyrolysis oil in a modified diesel engine generator to replace diesel fuel for power generation in a remote diesel community. Manitoba Hydro has been allocated $255,000 in approved Federal funding and $400,000 has been allocated from the Affordable Energy Fund for a pilot if a technology appears to be technically and economically feasible to pursue.

- *Collaborative efforts with other jurisdictions:* Manitoba Hydro is pursuing collaborative dialogue with other utilities to share information on activities and ideas that could help identify solutions to reduce diesel usage. Manitoba Hydro continues to collaborate with other utilities on operational matters via the Canadian Off-Grid Utility Association (COGUA).

- *Shamattawa grid line analysis:* A Working Group has been established with representation from Manitoba Hydro, Shamattawa and the province to review the costs and benefits associated with a land line to the community. The intent of this work is to develop a collective proposal in the event that a future funding opportunity arises.

- *Liquefied Natural Gas*: Manitoba Hydro is exploring the applicability of liquefied natural gas for energy needs in remote diesel communities.

- *Single Wire Earth Return HVDC Transmission:* Manitoba Hydro was unsuccessful in a November 2011 application for funding under the ecoEnergy Innovation Initiative Program to study the concept of single wire earth return HVDC transmission, which could potentially provide landline service at lower cost than the current grid line option. On May 28, 2012, however, the Minister of Natural Resources announced that $184 million will be added to the ecoEnergy Innovation Initiative Program. Manitoba Hydro is awaiting response to its inquiry of whether another round of project funding will be announced to determine whether this technology could be considered further.

- *First Nations Power Smart Program*: Manitoba Hydro is implementing Power Smart initiatives to upgrade insulation and provide basic energy efficiency materials in homes in the remote diesel communities. To date, 116 homes have been completed. It is estimated that a further 85 homes may be eligible for upgrades, which are anticipated to be completed by 2013/14.

- *Forestry biomass:* Work continues to evaluate the feasibility of implementing a biomass generation option in Brochet having regard to the sustainability of supply, costs and risk issues.

PUB/MH I-150

Reference: Tab 11 Diesel Communities

b) Please provide an analysis for each of the four diesel communities in the last five years of:

- **Fixed Costs**
- **Variable non-fuel costs**
- **Fuel Purchase costs**
- **Fuel Transport costs**

ANSWER:

Please see the table below. Note that data are aggregated over all four diesel communities and fuel hauling and purchase costs are combined.

	Diesel Service Costs 2008 – 2012 ($000s)				
	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast
Distribution Operating Cost	460	506	458	601	584
Interest on Fuel Inventory	n/a	294	325	325	393
Landed Fuel Cost	4,179	4,454	3,871	3,925	4,424
Other Generation Operating	2,149	2,074	1,455	1,565	1,703
Fixed Costs*	6,130	5,400	4,882	5,102	6,418
Total	12,918	12,728	10,991	11,518	13,522

*Fixed costs consist of Capital Tax, Depreciation and Interest. The majority of these costs are notional, as most capital is contributed.

PUB/MH I-150

Reference: Tab 11 Diesel Communities

c) Grid Access: recognizing the actual experience of the North-Central access to grid-power, please provide the estimate of the cost of space and water heating at grid rates for each of the four diesel communities; if they attained grid service and indicate the comparable level of expense incurred in each community for electricity and for fuel oil heating.

ANSWER:

Most diesel customers already use electricity for water heating and therefore, those customers would not be impacted for this end use application regardless of the communities being connected to Manitoba Hydro's electric grid.

Manitoba Hydro does not have record of the amount of fuel oil consumed for heating in the four diesel communities and therefore only a high level estimate can be provided.

Estimated Incremental Cost at Grid Rates
For Heating in Diesel Communities

	Brochet	Lac Brochet	Tadoule Lake	Shamattawa
Electric Space Heating Cost	$280,000	$371,000	$312,000	$417,000
Fuel Oil Space Heating Cost	$699,000	$926,000	$779,000	$1,042,000

Note: Calculations based on September 1st, 2012 Electric Rates using 6.94¢ per kW.h & Fuel oil cost of $0.999/litre

PUB/MH I-150

Reference: Tab 11 Diesel Communities

d) Please refile an update to 2011/12 the response to PUB/MH I-184 (a) & (b) last GRA showing consumption growth for each of the North-Central communities and GHG emissions (in aggregate).

ANSWER:

	Total GW.h	A GW.h	B GW.h	C GW.h	D GW.h	E GW.h	F GW.h	G GW.h
1992/93	19.0	3.6	3.1	0.9	1.2	3.7	4.8	1.9
1993/94	20.5	3.6	3.2	1.0	1.3	4.0	5.3	2.1
1994/95	21.5	3.7	3.4	1.0	1.4	4.2	5.7	2.2
1995/96	23.4	3.6	3.9	1.1	1.8	4.6	5.9	2.4
1996/97	25.0	4.2	4.2	1.4	1.9	4.7	6.1	2.4
1997/98	29.6	6.1	5.3	2.0	1.9	5.0	6.6	2.8
1998/99	36.3	6.6	9.1	3.4	1.9	5.1	7.1	3.0
1999/00	47.1	9.4	10.4	4.3	3.0	7.6	9.2	3.4
2000/01	58.4	10.7	11.5	5.2	3.8	9.5	13.5	4.3
2001/02	69.1	14.0	12.1	5.3	4.4	10.6	16.7	5.9
2002/03	77.4	12.0	14.3	6.1	4.9	12.6	20.1	7.6
2003/04	78.9	14.5	13.6	5.6	5.5	13.0	19.5	7.3
2004/05	91.3	17.2	15.4	6.6	6.6	16.1	21.2	8.3
2005/06	88.2	16.5	14.8	6.2	6.4	15.2	20.8	8.3
2006/07est	92.6	18.4	15.2	6.4	6.6	17.0	20.4	8.7
2007/08	97.1	20.4	15.6	6.7	6.8	18.7	19.9	9.0
2008/09	100.6	21.1	15.1	6.7	6.9	19.7	21.6	9.5
2009/10	97.5	20.1	14.8	6.9	6.7	18.9	20.9	9.2
2010/11	104.9	19.8	15.7	7.6	7.0	23.7	20.7	10.4
2011/12	106.1	20.1	15.7	7.3	7.7	23.9	20.9	10.5

A = Oxford House
B = God's Lake Narrows
C = God's River
D = Red Sucker Lake
E = St. Theresa Point
F = Garden Hill
G = Wasagamack

As outlined in Manitoba Hydro's response to PUB/MH I-184(b) of the 2010/11 & 2011/12 Electric General Rate Application, Manitoba Hydro does not have or cannot locate records regarding the fuel used to generate electricity by diesel generation in the communities that were connected to the provincial electrical grid by the North Central Project. Manitoba Hydro also does not have any records related to the use of fossil fuels in these communities for purposes other than generating electricity.

PUB/MH I-151

Reference: Interim Diesel Rate Orders

Please explain what rates MH will request if all of the interim diesel rate Orders are not approved as final.

ANSWER:

Manitoba Hydro requires an understanding of the basis for not approving interim diesel rate orders as final in order to formulate a position in responce to this question. However, if Interim rates are not approved as final due to administrative obstacles (as opposed to fundamental disagreement with the rates and rate design approved in the interim orders), Manitoba Hydro would expect the interim orders to remain in place and request diesel rates proposed in this Application also be approved on an interim basis.

PUB/MH I-152

Reference: Appendix 11.1, Diesel Rate Application

a) MH states that Appendix 11.1 is superseded by the current rate application. Please explain how Appendix 11.1 relates to the current request to raise Diesel Rates effective September 1, 2012.

ANSWER:

Appendix 11.1 is the derivation of the true full cost rate and resulting surcharge rates that flow from using these costs. For example, Appendix 11.1 shows that the Surcharge rate would need to be $2.54/kWh to support the Residential and General Service rates that were in place during 2012 until September 1. The rates in this appendix were provided as indicative, and for information to the Board. The rates proposed in the current application, on the other hand, do not recover the full cost, but, contain a rate increase equal to the same percentage as grid rates have increased since the Diesel government rates were last increased on January 1, 2011.

Note that the costs are the same in the two filings.

PUB/MH I-152

Reference: Appendix 11.1, Diesel Rate Application

b) Please provide an update on diesel fuel rates and compare with that used in Appendix 11.1 application.

ANSWER:

The actual average fuel price for fiscal year 2011/12 is $1.21/litre which compares to a forecast price of $1.14/litre.

PUB/MH I-152

Reference: Appendix 11.1, Diesel Rate Application

c) Please indicate what, if any, changes in Diesel Rates MH are proposing for April 1, 2013 in this rate application.

ANSWER:

Manitoba Hydro is not proposing any change to diesel rates other than those portions of the residential and general service rates that are equivalent to grid rates.

PUB/MH I-152

Reference: Appendix 11.1, Diesel Rate Application

d) Please provide an update on the status to recovery of capital costs and explain why MH is now seeking recovery of disallowed capital costs.

ANSWER:

Manitoba Hydro does not understand the meaning or the significance of the term "disallowed capital costs" in the question. The response below assumes that the reference was intended to be to capital costs that, to date, AANDC has declined to fund.

To date contributions have been received for most items from AANDC ($6,960,039). Those costs not funded by AANDC were included in the PDCOSS revenue requirement as a capital add-on, or as noted in the application, the $747,607 for interest and depreciation expense.

The current recovery sought is for all capital costs since 2004 to March 31, 2011.

PUB/MH I-152

Reference: Appendix 11.1, Diesel Rate Application

e) Please refile the schedules in appendix 11.1 and 11.2 where necessary, removing the $747,607 in interest and depreciation expense included and comment on the difference between the indicative rate and proposed rates in this application.

ANSWER:

Schedule 1 of Appendix 3 in 11.1 shows unit costs both with the capital portion 59.2¢/kWh), and without the capital portion (53.5¢/kWh).

The Indicative Rate Schedules filed on December 22, 2011, show rates and revenue assuming that:

1) The General Service tail block rate was not increased and remained at the 35¢/ kWh that was in place prior to the recent September 1, 2012, rate change.

2) The Government rate was calculated to incorporate all of the shortfall between the costs to serve the Residential and General Service classes and the revenues resulting from rates to those classes plus the explicit RCC subsidy provided by Manitoba Hydro. The Indicative Government rate was $2.54 per kWh.

The diesel rate schedules filed in the current proceeding and approved for implementation September 1, 2012 in Order 117/12 differed from the December 22 Indicative Rates in that the tail block rate for General Service and the Government Rate were both set by increasing the then current rates by 6.5% reflecting the increases to customers served by the grid since the then-current diesel rates were put in place. This resulted in a rate higher than the Indicative Rate for General Service (37.3¢/ kWh vs. 35¢/ kWh) and a rate lower than the Indicative Rate for Government ($2.27/ kWh vs. $2.54/ kWh).

The table below illustrates the difference in the Indicative rates and Sept 1 rates with and without the capital portion included in the full costs rate (59.16¢/kWh vs. 53.48¢/kWh):

	With Capital Included		With No Capital Included	
	Indicative Rates	Sept 2012 Rates	Indicative Rates	Sept 2012 Rates
Revenue Requirement	$7,964,651	$7,964,651	$7,202,651	$7,202,651
Revenue	$6,904,058	$6,402,110	$6,239,273	$6,402,110
Shortfall	$1,060,593	$1,562,541	$963,378	$800,541
	Difference	$501,948		($162,837)
Revenue per kWh	$0.513	$0.476	$0.464	$0.476
Cost per kWh	$0.592	$0.592	$0.535	$0.535

PUB/MH I-153

Reference: Appendix 11.1, Grid Rates in Diesel Communities

a) Please provide an update on the actions and investigations listed on page 2 and 3.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-150(a).

PUB/MH I-153

Reference: Appendix 11.1, Grid Rates in Diesel Communities

b) Please provide an update on the discussions with the four communities and AANDC

ANSWER:

Meetings were held with all four diesel served communities over December 2011 and January 2012 to present information on a potential wind pilot project. While the initial feedback on the pilot project from the Sayisi Dene, Northlands and Barren Lands First Nations was generally positive, all three requested time to further consider their involvement. In the second meeting with the Northlands First Nation a strong interest in hosting the project was expressed by the community. The Shamattawa First Nation indicated that they were not interested in the wind pilot and did not wish to explore any alternatives to diesel other than a land line connection. As noted in PUB/MH I-150 (a), while Manitoba Hydro will continue to consider the feasibility of wind generation in the diesel communities, project challenges have resulted in a renewed focus on a bioenergy green pilot.

With respect to Shamattawa, as noted in PUB/MH I-150 (a), a Working Group has been established with representation from Manitoba Hydro, Shamattawa and the province to review the costs and benefits associated with a land line to the community. AANDC has been invited to participate in this process.

As noted in Appendix 11.1, discussions with local AANDC representatives took place on August 12, 2011 and November 25, 2011 to share information on the strategic initiatives that Manitoba Hydro has been reviewing and to discuss funding opportunities.. AANDC expressed the difficulty they have in obtaining funding for capital projects, particularly for unproven technology.

PUB/MH I-154

Reference: Response to 150/08 (Directive 2)

Export Program

Please file the Export Program Report as requested in 2009.

ANSWER:

As noted in Manitoba Hydro's report regarding the Status of Public Utilities Board Directives to Manitoba Hydro, located at Tab 12, p. 9, Directive 2 of Order 150/08 was satisfied through meetings held in November and December 2009 with the PUB advisors, detailed presentations delivered to the PUB, its advisors and Intervenors in May 2010, through reports filed pursuant to the risk review portion of the 2010/11 & 2011/12 General Rate Application, the responses to information requests, the hearings and the two orders that were issued pursuant to that proceeding. Manitoba Hydro notes that hard copies of the above noted presentations were filed in Appendix 56 to the 2010/11 & 2011/12 General Rate Application in fulfillment of Order 150/08, Directive 2 (see PUB/MH II-172a).

PUB/MH I-155

Reference: Response to 150/08 (Directive 3)

Quarterly Reports on Energy Supply

a) Please file on a quarterly basis the actual results of hydraulic generation, thermal generation, wind purchases and imports (peak and off-peak) since 2009.

ANSWER:

The Manitoba Hydro-Electric Board (MHEB) Quarterly Reports provide generation results for hydraulic generation, thermal generation, wind purchases and energy imports for the quarter.

The MHEB Quarterly Reports back to the first quarter of 2010 are available on Manitoba Hydro's website at the link below:

http://www.hydro.mb.ca/corporate/past_reports.shtml

PUB/MH I-156

Reference: Response to 150/08 (Directive 6)

OM&A Benchmarking

a) Please provide summary of actions to date.

ANSWER:

In a letter dated April 1, 2010, Manitoba Hydro advised the PUB that it was not prepared to initiate any action on this directive until the implementation of IFRS had been completed:

With respect to Directive 6, IFRS compliance accounting will commence April 1 2011, with 2011/12 being the first full year of reporting under IFRS. Accordingly, this directive will be addressed commencing April 1, 2012, with reporting of progress and results at the earliest opportunity that resources and work progress permit.

Since that time, the implementation of IFRS for rate-regulated entities has been deferred several times as a result of the uncertainty surrounding the treatment of rate-regulated assets and liabilities under IFRS. As a result, there is growing divergence in practice with respect to the financial reporting frameworks (CGAAP, US GAAP) used by Canadian electric utilities which could seriously complicate a benchmarking exercise.

Moreover, benchmarking among utilities with respect to cost performance has always been problematic due to differences in resource endowment, distribution of customers, customer density, market environment, policy environment and other variables. Manitoba Hydro is concerned that detailed benchmarking of operating costs could be a costly exercise, likely to yield inconclusive results at best.

Manitoba Hydro's current corporate strategic planning process provides high level targets and indicators which reflect the cost and effectiveness of providing service to customers. The relevant objectives, with indicators described in brackets, are:

- Provide customers with exceptional value (System Average Interruption Duration Index; system Average Interruption Frequency Index; Customer Satisfaction Index; Retail Rates comparison)

- Maintain a strong financial structure (Interest Coverage; Debt Equity Ratio; Capital Coverage; Annual Growth in Operating, Maintenance and Administration cost per customer.)

PUB/MH I-156

Reference: Response to 150/08 (Directive 6)

OM&A Benchmarking

b) Please file T of R and timeline for completion/filing.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I- 156(a).

PUB/MH I-157

Reference: Response to 150/08 (Directive 7)

Asset Condition Assessment

a) Please provide a summary of actions to date on this Directive.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-82(b).

PUB/MH I-157

Reference: Response to 150/08 (Directive 7)

Asset Condition Assessment

b) Please file T of R and timeline for completion and filing of the report.

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH I-82(b).

PUB/MH I-158

Reference: Response to 150/08 (Directive 11)

Capital Program Regulatory Review

Please update the status of the pending NFAAT Review process for MH's major G&T projects.

ANSWER:

By letter dated January 13, 2011 from Minister Wowchuk to Victor Schroeder, Chairman of Manitoba Hydro's Board of Directors , regarding the regulatory processes to be applied to major new hydro generation projects, Manitoba Hydro was advised "that in addition to review and licensing under applicable provincial statures (including but not necessarily limited to *The Environment Act* and *The Water Power Act)*, it is the provincial government's intention to assign responsibility to an independent body for carrying out an NFAT (Needs For and Alternatives To) assessment of such projects." The public review panel entity and the Terms of Reference have not been announced.

The NFAT filing is expected to present the business case for the preferred capital development plans for domestic demand along with the value of export sales and US interconnection opportunities along with alternatives.

To protect an in-service date of 2019 for Keeyask, an Order in Council is required by June 2014. To achieve the June 2014 date, Manitoba Hydro is actively preparing its NFAT Submission anticipating a spring 2013 filing.

PUB/MH I-159

Reference: Response to 150/08 (Directive 14)

Risk Mitigation Measures

Please confirm that MH has not filed a Post-Risk Hearing Report on MH's Recommended Risk Mitigation Measures.

ANSWER:

As noted in Manitoba Hydro's report regarding the Status of Public Utilities Board Directives to Manitoba Hydro, located at Tab 12, p. 9, Directive 14 of Order 150/08 was fully satisfied through the reports filed pursuant to the risk review portion of the 2010/11 & 2011/12 General Rate Application, the responses to information requests, the hearings and the two orders that were issued pursuant to that proceeding. Manitoba Hydro is not aware of any further directives with respect to this matter.

PUB/MH I-160

Reference: Response to 150/08 (Directive 23)

Inverted Rates

a) Please confirm that the PUB did not indicate that inverted rates would no longer be entertained.

ANSWER:

Confirmed.

PUB/MH I-160

Reference: Response to 150/08 (Directive 23)

b) Inverted Rates
Please indicate the submission timeline for filing a Rate Plan for electrically-heated residences.

ANSWER:

Manitoba Hydro will propose a rate plan for electrically-heated customers in the event that inverted rates (or a variation thereof) is submitted to the PUB for approval.