PUB/MH II-1

Reference: PUB/MH I - 2 (a), PUB/MH I- 22 (c)

Please provide a schedule of non-cash expenses included in revenue requirement in the years 2003/04 to 2013/14.

ANSWER:

Non-cash expenses included in the income statement include items such as depreciation and amortization, bad debt expense, amortization of pension and benefit gains and losses, amortization of debt premiums and discounts, foreign exchange gains or losses and accretion. Note that IFF11-2 assumes implementation of IFRS for 2013/14 and as such there is no amortization of pension and benefit gains and losses or amortization of acquisition and integration costs commencing in that year. Normal accruals for all line items have not been included as they are considered timing, and will be settled in cash.

The following table provides the information requested from 2008 to 2014.

($000's)	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Operating & Administrative Expense	7 167	7 567	4 073	4 730	6 501	7 789	2 749
Finance Expense	(51 508)	8 189	(36 966)	15 333	12 697	525	(1 578)
Depreciation and Amortization	323 573	340 314	358 179	364 727	353 376	400 847	354 307
Corporate Allocation	2 093	2 012	2 139	1 780	1 706	1 707	1 208

PUB/MH II-2

Reference: PUB/MH I-3 (a) & (b)

a) Please supplement the table including the credit rating of the Province, the debt level of the Province and the percentage of the Province's debt MH represents.

ANSWER:

Please see the table on the following page. Total debt for Manitoba Hydro is based on information that is available in Manitoba Hydro's Annual Reports for the period from 1992 through 2012. Information relating to the Province of Manitoba was provided by the Province.

Financial History

	Debt/Equity Ratio	Capital Coverage Ratio	Interest Coverage Ratio	Total MH Assets	MH Net Income	Total MH Debt	MH Retained Earnings	DBRS Bond Rating **	Total Province of MB Debt	Total MH Debt to Total MB Debt
2012	74:26	1.13	1.10	13,791	61	9,382	2,450	A (high)	28,698	32.7%
2011	73:27	1.25	1.27	12,882	150	8,647	2,389	A (high)	25,617	33.8%
2010	73:27	1.30	1.32	12,437	163	8,538	2,239	A (high)	24,431	34.9%
2009	77:23	1.77	1.48	11,547	266	8,187	2,076	A (high)	22,727	36.0%
2008	73:27	1.62	1.69	11,766	346	7,571	1,822	A (high)	22,056	34.3%
2007	80:20	1.10	1.23	10,922	122	7,227	1,407	A (high)	20,476	35.3%
2006	81:19	2.28	1.77	10,482	415	7,169	1,285	A (high)	19,828	36.2%
2005	85:15	1.20	1.25	9,952	136	7,204	870	A (high)	19,410	37.1%
2004	87:13	(0.32)	0.17	9,903	(436)	7,390	734	A (high)	18,206	40.6%
2003	80:20	1.10	1.14	10,234	71	7,268	1,170	A (high)	17,810	40.8%
2002	77:23	1.67	1.42	10,405	214	7,661	1,302	A	20,682	37.0%
2001	80:20	1.18	1.62	9,966	270	7,464	1,088	A	20,459	36.5%
2000	83:17	1.28	1.35	8,692	152	6,770	818	A	19,878	34.1%
1999	84:16	1.22	1.23	7,866	100	5,883	666	A	18,278	32.2%
1998	86:14	1.13	1.25	7,617	111	5,548	566	A	17,378	31.9%
1997	88:12	1.12	1.23	7,133	101	5,175	455	A	16,886	30.6%
1996	91:09	1.00	1.16	6,737	70	5,284	354	A	16,763	31.5%
1995	92:08	1.00	1.13	6,449	56	5,034	284	A	16,481	30.5%
1994	93:07	n/a	1.16	6,543	70	5,406	228	A	15,670	34.5%
1993*	95:05	n/a	0.95	6,025	(24)	4,971	159	A	14,127	35.2%
1992	94:06	n/a	1.04	6,505	18	5,441	183	A	12,776	42.6%

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

** The DBRS long term credit rating for the period from 1992-2012 is the same for both the Manitoba Hydro-Electric Board and the Province of Manitoba.

PUB/MH II-2

Reference: PUB/MH I-3 (a) & (b)

b) Please provide the credit rating scale for DBRS.

ANSWER:

The following chart shows the long term rating scale for DBRS.

LONG TERM RATING SCALE COMPARISON (H = high; L = low)

DBRS	AAA	AA (H)	AA	AA (L)	A (H)	A	A (L)	BBB (H)	BBB	BBB (L)	BB (H)	BB	BB (L)	B (H)	B	B (L)

Investment Grade
Non-Investment Grade

PUB/MH II-3

Reference: PUB/MH I-5

a) Please demonstrate in the appropriate IFF's that it is in the economic interest of MH ratepayers to advance the in-service date of Keeyask G.S. and Conawapa G.S. and as opposed to deferring these plants as indicated in alternative #1 and alternative #2 of the latest Power Resource Plan.

ANSWER:

Manitoba Hydro notes that Government confirmed, by letter dated January 13, 2011 (a copy of which was filed in the 2010/11, 2011/12 General Rate Application as Exhibit MH- 162) its intention to assign responsibility to an independent body for carrying out an Needs For and Alternatives To (NFAT) assessment of major new hydro generation projects. To date the independent panel has not been announced however Manitoba Hydro expects that the NFAT process will commence in 2013.

As such, Manitoba Hydro respectfully declines to respond to this question at this time.

PUB/MH II-4

Reference: PUB/MH I-7 (c)

a) Please file a copy of any post implementation report on the project.

ANSWER:

Please see Appendix 42 for the Wuskwatim and Keeyask Training Consortium Inc. Annual Report for the year ending March 31, 2010.

PUB/MH II-4

Reference: PUB/MH I-7 (c)

b) Please explain the job training provided under the program.

ANSWER:

The following types of training were provided under the Hydro Northern Training and Employment Initiative:

- Designated trades (apprenticeship trades included carpenters, cooks, crane operators, electricians, heavy duty equipment mechanics, ironworkers, millwrights, plumbers and welders)
- Construction support (caterers, environmental monitoring, facility technicians, and security guards)
- Non-designated trades (heavy equipment operators, skilled labourers, truck drivers, and warehousing)
- Professional and administrative work
- Non-occupational (educational upgrading and life skills)

PUB/MH II-4

Reference: PUB/MH I-7 (c)

c) Please explain why $600,000 was disbursed under the agreement in 2011 to present and the purpose of the payment given the program completed in 2009/10.

ANSWER:

There were unspent Manitoba Hydro funds at the end of 2009/10. Manitoba Hydro agreed to provide funding to the Aboriginal Partners under separate bi-lateral agreements to support further training of program participants.

PUB/MH II-4

Reference: PUB/MH I-7 (c)

d) Please explain how the costs under this program have been accounted for rate setting purposes.

ANSWER:

The costs associated with the Hydro Northern Training and Employment Initiative has been charged 75% to the Keeyask Generating Station capital project and 25% to the Wuskwatim Generating Station capital project.

The costs associated with the Wuskwatim project have been allocated to the Wuskwatim Power Limited Partnership (WPLP). Manitoba Hydro as both General and Limited Partner has approximately 67% interest in the WPLP. The generating station has been placed in-serviced in fiscal 2013 and the costs apportioned to Manitoba Hydro will be depreciated over the life of the assets.

The costs associated with the Keeyask project remain in Construction Work in Process (CWIP) until in-service of the generating station at which time they will be depreciated over the life of the assets.

PUB/MH II-5

Reference: PUB/MH I-9 (a)

a) Please provide the requested analysis for the years 2000/02 through 2011/12 and indicate what IFF was utilized for developing the CSP target.

ANSWER:

Please see the following table for the requested information. Fiscal year 2003/04 is the first year that is provided as this is the first year that has Winnipeg Hydro full integrated in Manitoba Hydro's operations.

	Actual								
	2004	2005	2006	2007	2008	2009	2010	2011	2012
OM&A expense 'electric only' (in millions of $)	283	299	311	323	323	364	378	397	403
# of Customers	501,650	505,666	509,791	516,861	521,599	527,472	532,359	537,299	542,681
OM&A (electric only) per customer (in dollars)	565	591	609	626	619	691	709	739	743
CSP Target*	600	584	600	612	640	665	673	708	739
IFF used to develop target						IFF07	IFF08	IFF09	IFF10

*Prior to IFF07, the CSP target was set at a high-level target as opposed to tying to detailed forecasts.

PUB/MH II-5

Reference: PUB/MH I-9 (a)

b) Please explain what factors resulted in the OM&A cost per customer to be in excess of CSP target for each of the years 2009 to 2012.

ANSWER:

The following factors resulted in OM&A cost per customer exceeding the CSP target for the years 2009 through 2012:

2009

Higher OM&A costs than forecasted due to:

i) Changes in Canadian Accounting Standards with respect to the removal of capitalized interest and facility costs from stores overhead as well as the ineligibility of certain costs for capitalization as an intangible asset;

ii) Increased trainee levels to address existing staff shortages, higher overtime costs for storm restoration and higher benefit costs.

2010

Higher OM&A costs than forecasted due to:

i) Changes in Canadian Accounting Standards resulting in the ineligibility of certain costs for capitalization as an intangible asset;

ii) Changes in Manitoba Hydro's overhead capitalization practices eliminating certain cost components from its overhead capitalized;

iii) Impact of contract settlements, higher pension costs due to the amortization of investment losses, increased trainee levels to address existing staff shortages and costs associated with the IBEW strike.

2011

Higher OM&A costs than forecasted primarily due to changes in Manitoba Hydro's overhead capitalization practices eliminating various cost components from its capitalized overhead.

2012

Higher OM&A costs than forecasted primarily due to the impact of the change in the discount rate on pension and other benefit costs.

PUB/MH II-5

Reference: PUB/MH I-9 (a)

c) Please discuss measures followed by MH to address not meeting CSP targets for this metric.

ANSWER:

As outlined in Appendix 5.6, section 7.0, Manitoba Hydro has employed a number of cost constraint measures in order to continue to effectively manage and control OM&A expenditures. These measures include:

- External hiring freeze (unless specifically approved by the President & CEO)
- Restrictions on out-of-province travel
- Overtime restrictions (except to respond to system emergencies and to maintain the safety and reliability of the energy supply system)
- Reductions in community sponsorships and donations
- Further leveraging of technology to improve operational efficiencies

As noted in PUB/MH II-5(b), increases above the CSP target are primarily due to changes in accounting standards and practices. The calculation of the CSP targets was based on forecast information which did not yet incorporate the accounting changes adopted by Manitoba Hydro.

PUB/MH II-6

Reference: PUB/MH I-9 (b)/ PUB/MPI I-75

The question requested the comparison with electric utilities in Canada including BC, Saskatchewan, Ontario and Quebec.

a) Please provide the OM&A comparisons with Ontario, Quebec, Saskatchewan and Alberta.

ANSWER:

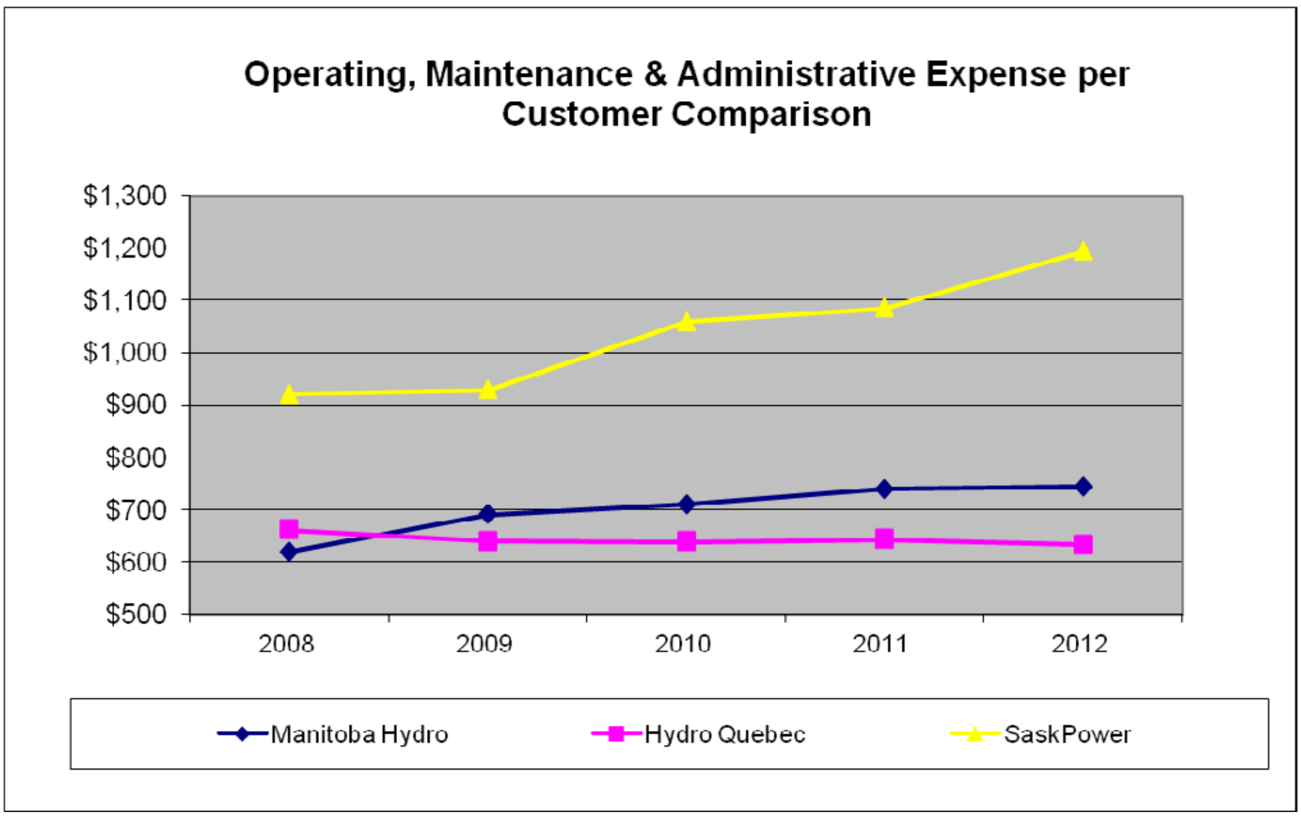
Please see the following table and charts for an OM&A comparison of Manitoba Hydro, Hydro Quebec and SaskPower. The province of Ontario and the province of Alberta do not have vertically integrated electric utilities and therefore are not comparable to Manitoba, Quebec and Saskatchewan.

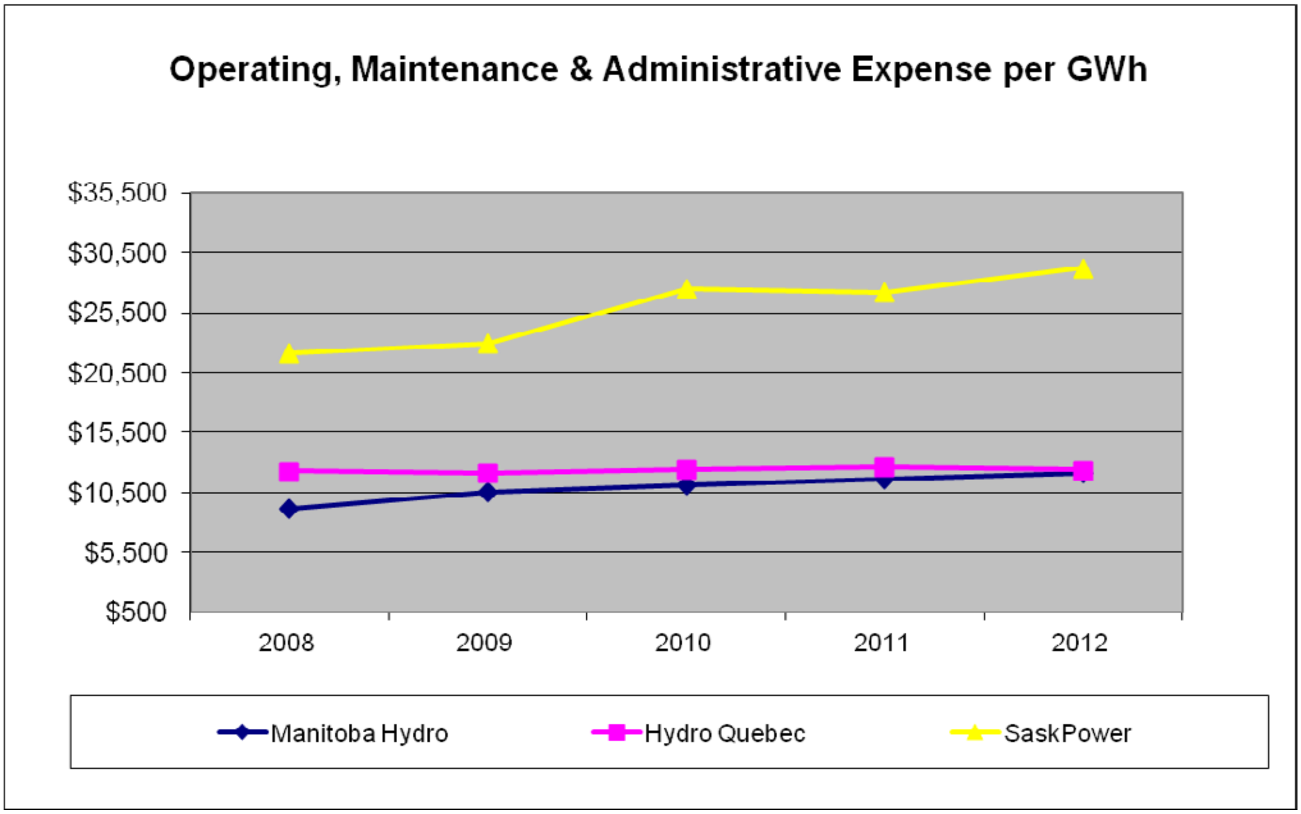
As indicated in the response to PUB/MH I-75:

- 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.
- 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. A comparison to BC Hydro has not been provided.

The Hydro Quebec and SaskPower information comes from their 2011 Annual Reports.

	2008	2009	2010	2011	2012
Manitoba Hydro OM&A	$ 323	$ 364	$ 378	$ 397	$ 403
Hydro Quebec OM&A	2,556	2,502	2,527	2,579	2,571
SaskPower OM&A	416	427	495	513	575
Manitoba Hydro Customers	521,599	527,472	532,359	537,299	542,681
Hydro Quebec Customers	3,868,972	3,913,444	3,960,332	4,011,789	4,060,195
SaskPower Customers	451,713	460,006	467,329	473,007	481,985
Manitoba Hydro GWh	35,354	34,528	33,961	34,102	33,235
Hydro Quebec GWh	208,156	206,603	203,181	203,842	207,693
SaskPower GWh	18,774	18,601	17,989	18,862	19,675
OM&A per Customer					
Manitoba Hydro	$ 619	$ 691	$ 709	$ 739	$ 743
Hydro Quebec	661	639	638	643	633
SaskPower	921	928	1,059	1,085	1,193
OM&A per GWh					
Manitoba Hydro	$ 9,128	$ 10,550	$ 11,117	$ 11,640	$ 12,135
Hydro Quebec	12,279	12,110	12,437	12,652	12,379
SaskPower	22,158	22,956	27,517	27,198	29,225




Operating, Maintenance & Administrative Expense per GWh
$35,500
$30,500
$25,500
$20,500
$15,500
$10,500
$5,500
$500
2008
2009
2010
2011
2012
Manitoba Hydro
Hydro Quebec
SaskPower

PUB/MH II-6

Reference: PUB/MH I-9 (b)/ PUB/MPI I-75

The question requested the comparison with electric utilities in Canada including BC, Saskatchewan, Ontario and Quebec.

b) With respect to Saskatchewan's conversion to IFRS in 2011, please indicate how Sask Power accounts for depreciation, ALS or ELG?

ANSWER:

Following their conversion to IFRS, SaskPower continues to account for depreciation using the Average Service Life method.

PUB/MH II-6

Reference: PUB/MH I-9 (b)/ PUB/MPI I-75

The question requested the comparison with electric utilities in Canada including BC, Saskatchewan, Ontario and Quebec.

c) Please provide a comparison with Saskatchewan assuming the end state of capitalization of overheads was applied in 2010 rather than as indicated in 2013/14.

ANSWER:

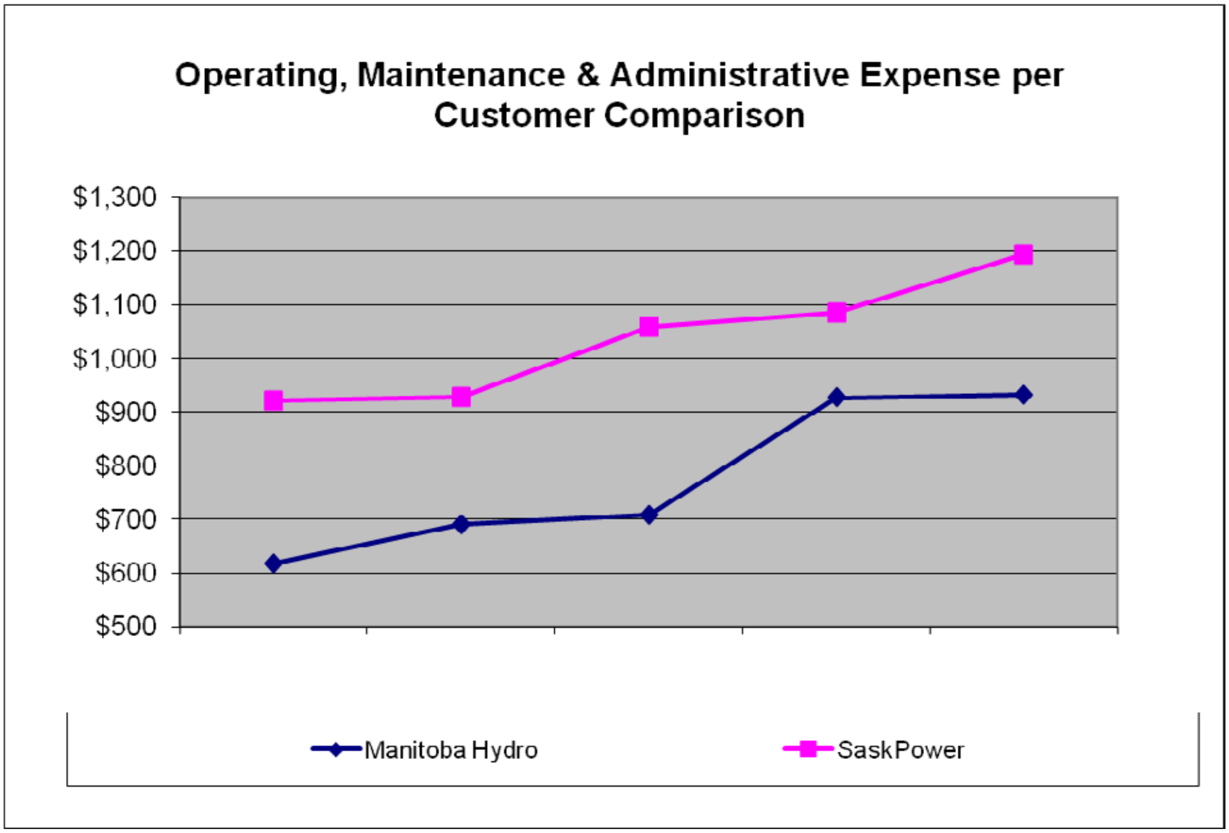
As noted in response to PUB/MH II-6(a), Manitoba Hydro's fiscal years 2011 and 2012 are no longer directly comparable to SaskPower due to SaskPower's implementation to IFRS in fiscal 2011, retroactively applied to 2010. The conversion to IFRS includes various adjustments and Manitoba Hydro is unable to ascertain all of the appropriate adjustments that are required to ensure comparability with SaskPower.

For illustrative purposes only, Manitoba Hydro's OM&A for 2010/11 and 2011/12 has been adjusted (at a high level) to reflect implemented and proposed accounting changes out to 2013/14 discounted back to 2010/11 and 2011/12, which include (as identified in Appendix 5.6, section 4.0, page 5):

- Capitalized cost changes
- Rate regulated accounts changes
- Pension and benefits changes
- Reclassifications changes

Please see the following table and chart.

OM&A		2008		2009		2010		2011		2012
Manitoba Hydro	$	323	$	364	$	378	$	498	$	506
SaskPower		416		427		495		513		575
Customers										
Manitoba Hydro		521,599		527,472		532,359		537,299		542,681
SaskPower		451,713		460,006		467,329		473,007		481,985
OM&A Per Customer										
Manitoba Hydro	$	619	$	691	$	709	$	927	$	933
SaskPower		921		928		1,059		1,085		1,193



PUB/MH II-7

Reference: PUB/MH I-10 (a)/ PUB/MH I-99

a) Please update the schedule of consulting and mitigation costs to include all the years in the requested time frame.

ANSWER:

Please see the table below for consulting and mitigation costs for Major New Generation & Transmission projects from 2003/04 to the end of the first quarter for 2012/13.

(in thousands of dollars)

Project	Fiscal Year										Totals 2004 to Q1 2013
	2004	2005	2006	2007	2008	2009	2010	2011	2012	Q1 2013	
Wuskwatim - Generation	**10 623**	**7 784**	**7 124**	**3 830**	**2 440**	**16 019**	**12 658**	**8 163**	**2 699**	**1 241**	**72 581**
Consultants	10 623	7 784	7 124	2 830	2 135	11 337	12 517	8 014	2 527	1 234	66 125
Mitigation				1 000	305	4 682	141	149	172	6	6 455
Wuskwatim - Transmission	**-**	**2 427**	**686**	**1 063**	**10 955**	**23 834**	**15 903**	**3 834**	**4 353**	**1 172**	**64 227**
Consultants		2 427	686	1 063	10 928	23 708	15 633	3 474	3 866	287	62 073
Mitigation					27	126	270	360	487	885	2 155
Herblet Lake-The Pas 230 kV Transmission	**-**	**-**	**-**	**7**	**1 176**	**3 757**	**2 156**	**651**	**786**	**41**	**8 575**
Consultants				7	1 176	3 757	2 156	651	786	41	8 575
Keeyask - Generation	**6 185**	**7 309**	**6 332**	**8 644**	**9 514**	**17 689**	**16 366**	**3 443**	**3 857**	**4 077**	**83 416**
Consultants	6 185	7 309	6 332	8 644	9 514	11 803	11 731	2 340	2 329	3 991	70 178
Mitigation						5 886	4 635	1 103	1 528	86	13 238
Conawapa - Generation	**2 237**	**4 096**	**8 167**	**12 585**	**11 748**	**12 591**	**11 474**	**5 238**	**2 869**	**950**	**71 955**
Consultants	2 237	4 096	8 167	12 585	11 748	12 591	6 674	5 238	2 869	950	67 155
Mitigation							4 000				4 000
Kelsey Improvements & Upgrades	**37**	**132**	**389**	**216**	**150**	**260**	**435**	**401**	**58**	**48**	**2 126**
Consultants	37	132	389	216	150	260	435	401	58	48	2 126
Kettle Improvements & Upgrades	**-**	**-**	**-**	**-**	**-**	**3**	**15**	**256**	**24**	**-**	**298**
Consultants						3	15	256	24		298
Pointe du Bois - Spillway Replacement	**-**	**-**	**-**	**-**	**4 706**	**7 438**	**4 049**	**6 885**	**8 767**	**329**	**32 173**
Consultants					4 706	7 438	4 049	6 885	8 767	329	32 173
Pointe du Bois - Transmission	**-**	**-**	**-**	**0**	**18**	**296**	**452**	**824**	**(617)**	**35**	**1 007**
Consultants				0	18	296	452	824	(617)	35	1 007
Bipole III - Transmission Line	**23**	**511**	**484**	**633**	**344**	**916**	**3 932**	**5 266**	**4 819**	**456**	**17 384**
Consultants	23	511	484	633	344	916	3 932	5 266	4 819	456	17 384
Bipole III - Converter Stations	**-**	**-**	**-**	**-**	**-**	**531**	**3 151**	**3 708**	**5 551**	**1 415**	**14 357**
Consultants						531	3 151	3 708	5 551	1 415	14 357
Bipole III - Collector Lines	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7**	**107**	**5**	**118**
Consultants								7	107	5	118
Riel 230/500 kV Station	**49**	**0**	**-**	**101**	**295**	**563**	**5 219**	**3 424**	**2 540**	**915**	**13 105**
Consultants	49	0		101	295	563	5 219	3 424	2 540	915	13 105
Dorsey - US Border New 500kV Trans Line	**-**	**-**	**-**	**-**	**-**	**-**	**811**	**32**	**-**	**-**	**843**
Consultants							811	32			843
St. Joseph Wind Transmission	**-**	**-**	**-**	**-**	**-**	**-**	**343**	**499**	**15**	**-**	**857**
Consultants							343	499	15		857
Firm Import Upgrades	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**109**	**-**	**-**	**109**
Consultants								109			109
Northern AC Trans System Requirements	**129**	**737**	**277**	**190**	**31**						**1 364**
Consultants	129	737	277	190	31						1 364
Brandon Combustion Turbine	**174**	**262**	**4**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**440**
Consultants	174	262	4								440

PUB/MH II-7

Reference: PUB/MH I-10 (a)/ PUB/MH I-99

b) Please update the analysis to provide the payments made year to date.

ANSWER:

Please see Manitoba Hydro's response PUB/MH II-7(a).

PUB/MH II-7

Reference: PUB/MH I-10 (a)/ PUB/MH I-99

c) Please also update the answer to include a total for each column by category.

ANSWER:

Please see Manitoba Hydro's response PUB/MH II-7(a).

PUB/MH II-7

Reference: PUB/MH I-10 (a)/ PUB/MH I-99

d) Please provide a listing of payments made by MH to external consultants or parties employing external consultants (identified by only A,B,C etc.) by Major project for the years 2010, 2011 and 2012 indicating the nature of the services MH contracted for with the consultant.

ANSWER:

Please see table below listing payments made by Manitoba Hydro to consultants with annual payments exceeding $500,000 for fiscal years 2010, 2011 and 2012 related to major new generation and transmission projects. These costs were incurred for environmental, engineering, legal, accounting and other professional services necessary to meet the project requirements. This list excludes a breakdown by project in order to protect the privacy of the vendors.

(in thousands of dollars)

Major New Gen & Trans Projects Payments to External Consultants	Fiscal Year		
	2010	2011	2012
Consultant 1	3 691	2 247	558
Consultant 2			3 258
Consultant 3	5 584	5 692	5 933
Consultant 4	811		
Consultant 5	8 372	10 430	9 062
Consultant 6	938		
Consultant 7	7 041	6 380	1 117
Consultant 8			750
Consultant 9	602		
Consultant 10	17 113	3 436	5 091
Consultant 11			627
Consultant 12	541	2 053	4 229
Consultant 13	502	534	
Consultant 14	2 502	1 873	2 823
Consultant 15			1 556
Consultant 16	4 821	7 958	4 592
Consultant 17			597
Consultant 18	6 799	4 484	2 501
Consultant 19	1 222	1 301	932

PUB/MH II-7

Reference: PUB/MH I-10 (a)/ PUB/MH I-99

e) Please provide the aggregate of fees paid to each individual consultant on major projects ranked by order of magnitude but omitting the firms names.

ANSWER:

Please see Manitoba Hydro's response PUB/MH II-7(d).

PUB/MH II-7

Reference: PUB/MH I-10 (a)/ PUB/MH I-99

f) Please confirm that MH can provide aggregate fees paid to individual consultants without their consent.

ANSWER:

Manitoba Hydro can only provide aggregate fees paid to individual consultants in situations where such information does not result in disclosure, either directly or indirectly, of an individual's personal financial information.

PUB/MH II-7

Reference: PUB/MH I-10 (a)/ PUB/MH I-99

g) Please file a copy of a standard pro-forma consulting contract used by MH.

ANSWER:

Please see Attachment 1.

CONSULTING SERVICES AGREEMENT

0728/f
Rev 11 12
v1.2

THIS AGREEMENT dated _______________ , 20____.

BETWEEN:

MANITOBA HYDRO

(hereinafter referred to as **"Hydro"**),

- and -

(hereinafter referred to as the **"Consultant"**).

Hydro and Consultant agree as follows:

1. SERVICES

1.1 Consultant shall perform the Services described in Schedule "A", which is attached and forms part of this Agreement.

1.2 Consultant shall:

(a) perform its obligations in a timely manner;
(b) perform its obligations in a good, workmanlike and professional manner;
(c) use due care in the performance of its obligations to ensure that no person is injured or killed, no property is damaged or lost, and no rights are infringed;
(d) provide written reports (in addition to any specified in Schedule "A") with respect to the Services at Hydro's request;
(e) comply with all reasonable instructions and requests made by Hydro concerning the Services and this Agreement;
(f) comply with all applicable federal, provincial, municipal, state, or other laws, by-laws, and regulations; and
(g) comply with Hydro corporate policies and procedures which have been provided by Hydro to Consultant.

2. TERM

2.1 The Services shall be provided commencing on the date of this Agreement and continuing until ___________________________, 20______ (the **"Term"**).

3. PAYMENTS

3.1 Fees and charges for performance of the Services are described in Schedule "A".

3.2 If pre-approved by Hydro, Consultant's reasonable expenses incurred in performance of the Services will be reimbursed, at actual cost.

3.3 Consultant shall provide itemized invoices to Hydro on a monthly basis. Hydro's purchase order number shall be referenced on the face of each invoice. Taxes payable shall be shown as separate line items on each invoice. All invoices shall be satisfactory to Hydro in form and content. Consultant shall deliver to Hydro any supporting documents and receipts requested by Hydro from time to time.

3.4 Hydro shall pay Consultant all undisputed compensation due within 30 days following receipt of an invoice and supporting materials pursuant to Section 3.3 hereof. Amounts shall be calculated and paid in Canadian dollars unless otherwise stated in Schedule "A".

3.5 Consultant may charge interest on overdue accounts, at the annual interest rate of 1.5% above the prime lending rate established by the Royal Bank of Canada, in effect at the time the amount initially became due, calculated and payable monthly. The same applies to the disputed portion of an invoice subsequently found be properly due and payable.

4. INDEPENDENT CONTRACTOR

4.1 Consultant is an independent contractor. This Agreement shall not be deemed to create the relationship of employer and employee, principal and agent, partnership, or joint venture between Hydro and Consultant.

4.2 Consultant is responsible for any deductions or remittances required by law.

4.3 Consultant has no authority to make any representation, enter any commitment, or incur any liability on behalf of Hydro, except with the prior written consent of Hydro.

5. APPROVAL OF PERSONNEL AND NON-ASSIGNMENT

5.1 Consultant shall perform the Services personally or using an employee or sub-consultant listed in Schedule "A". Consultant shall not engage any other employee or sub-consultant in performance of the Services without the prior written consent of Hydro.

5.2 At Hydro's request, Consultant shall cease using an employee or sub-consultant for any reasonable cause including unsatisfactory performance, failure to pass a personnel risk assessment to Hydro's satisfaction, or failure to comply with Hydro policies or procedures.

5.3 Consultant shall not assign or transfer this Agreement or any of its rights or obligations under this Agreement, without the prior written consent of Hydro.

6. OWNERSHIP OF SERVICE PRODUCT

6.1 **"Service Product"** means all deliverables listed in Schedule "A", and all products arising from the Services regardless of form, format, or medium, including, without limitation, information, know-how, drawings, designs, reports, products, processes, documents, research notes, data, photographs, maps, materials, work in progress, and other tangible or intangible property, and all intellectual property rights thereto.

6.2 The Service Product is the exclusive property of Hydro upon creation. Consultant hereby waives any moral rights to Service Product and at Hydro's request shall obtain waivers of moral rights. Consultant shall make no use of the Service Product other than to provide the Services, except with the prior written consent of Hydro.

6.3 At Hydro's request, Consultant shall deliver to Hydro the Service Product and a record of all Service Product.

7. CONFIDENTIALITY

7.1 **"Confidential Information"** means all information concerning Hydro and the Services that is supplied by Hydro or otherwise comes into the possession of Consultant during the course of performance of the Services, regardless of format or medium, and the Service Product. Confidential Information does not include:

(a) information that is generally known to the public through no fault of Consultant;

(b) information that was specifically known to Consultant before disclosure by Hydro and was not subject to a confidentiality obligation;

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(c) information from a source other than Hydro so long as such source was not subject to a confidentiality obligation; and

(d) information that is subpoenaed or ordered to be disclosed by a judicial or regulatory body of competent jurisdiction.

7.2 Consultant may only use Confidential Information for the purpose of providing the Services to Hydro. Consultant shall not use Confidential Information for any other purpose.

7.3 Consultant may share Confidential Information with an employee or sub-consultant who has a need to know for the purpose of the Services. Consultant shall be responsible for any violation of Section 7 hereof by such persons. Consultant shall not disclose Confidential Information to any other person without Hydro's prior written consent.

7.4 At Hydro's request, Consultant shall immediately return Confidential Information to Hydro, or certify in writing that it has been destroyed.

7.5 Consultant acknowledges that any failure to comply with the provisions of Section 7 hereof shall cause irreparable harm to Hydro which cannot be adequately compensated by damages. Accordingly, in addition to any other remedies available to it, Hydro shall be entitled to interlocutory and permanent injunctive relief to restrain any anticipated, present, or continuing breach of Section 7 hereof.

8. PROTECTIONS

8.1 Consultant shall:

(a) secure all of its premises, equipment and storage cabinets used in connection with the Services, against damage and unauthorized access;

(b) safeguard all electronic data used in connection with the Services including its use, access, transfer and storage, against damage and unauthorized access;

(c) immediately notify Hydro of the discovery of any damage or unauthorized access, and any threats or attempts to accomplish the same.

8.2 At Hydro's direction, Consultant and any of its employees or sub-consultants engaged in performance of the Services shall undergo a personnel risk assessment.

8.3 Consultant shall take all measures required by law to protect personal information pursuant to The Freedom of Information and Protection of Privacy Act (Manitoba) and the Personal Information Protection and Electronic Documents Act (Canada). The provisions of Sections 7 and 8 hereof apply to all such personal information, with necessary modification.

8.4 When on Hydro premises, Consultant shall comply with Hydro safety and security policies.

9. LIABILITY AND INDEMNIFICATION

9.1 Consultant shall indemnify and save harmless Hydro, and its directors, officers, and employees, from and against any and all actions, causes, losses, costs, damages, expenses, suits, claims, liabilities, debts, and demands which they may suffer or be put to, arising from Consultant's breach of this Agreement or the negligence or willful misconduct of Consultant.

9.2 Neither party shall have any liability to the other for any indirect, incidental, or consequential damages.

9.3 Nothing in this Agreement shall be construed to relieve any insurer of its obligations to pay claims consistent with the provisions of a valid insurance policy.

10. INSURANCE

10.1 Consultant shall maintain comprehensive general liability insurance in the minimum amount of two million dollars per occurrence, for bodily injury, death, and damage to property including loss of use thereof. The policy shall include coverage for premises property and operations, products and completed operations, blanket contractual liability, cross liability, non-owned automobile liability and occurrence property damage. The policy shall be endorsed to provide Hydro with not less than 30 days written notice in advance of cancellation and to show Hydro as an additional insured.

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10.2 Consultant shall maintain automobile liability insurance in the minimum amount of two million dollars, at its own cost, for licensed vehicles owned or operated by Consultant.

10.3 Upon request, Consultant shall provide certificates of insurance to Hydro.

10.4 Consultant shall pay any assessment or compensation required to be paid pursuant to The Workers Compensation Act (Manitoba). Upon failure to do so, Hydro may pay the assessment or compensation to the Compensation Board and deduct the amount from monies due to Consultant. Hydro may require a declaration from the Compensation Board that assessments or compensation have been paid in full, and may withhold payment to Consultant until the declaration is received.

11. SUSPENSION AND TERMINATION

11.1 Hydro may, for its convenience, delay or suspend Consultant's performance of any or all of the Services, by giving five business days' notice to Consultant.

11.2 Hydro may, for its convenience, terminate this Agreement by giving ten business days' notice to Consultant.

11.3 Consultant shall cease to perform the Services upon receipt of a notice pursuant to Section 11.1 or 11.2 hereof. At Hydro's request, Consultant shall resume performance of the Services as soon as reasonably possible following a delay or suspension.

11.4 Hydro shall compensate Consultant for direct costs and expenses actually incurred by Consultant that are directly attributable to a delay or suspension pursuant to Section 11.1 hereof, but not for lost profit.

11.5 Hydro shall compensate Consultant for direct costs and expenses actually incurred by Consultant that are directly attributable to a termination pursuant to Section 11.3 hereof, for Services performed to the date of termination, and for any reasonable expenses of Consultant necessary for winding down performance of the Services, but not for lost profit.

11.6 Without prejudice to any other of its rights or remedies, Hydro may immediately terminate this Agreement if Consultant is in breach of this Agreement, or if Consultant becomes bankrupt or insolvent.

11.7 The following provisions shall survive the expiry or termination of this Agreement: Sections 5.3; 6; 7; 8; 9; 10.4; 13; and 14 hereof.

12. FORCE MAJEURE

12.1 Neither party shall be in default of this Agreement where the failure to perform an obligation is due wholly to a cause beyond its reasonable control. The party experiencing such a difficulty shall promptly notify the other of its inability to perform its obligation. The parties agree to negotiate in good faith an extension of time for performing the obligation, avenues to resolve the situation and resolution of any financial impacts. Both parties shall mitigate their losses.

13. RECORDS AND AUDITS

13.1 Consultant shall maintain and preserve accurate and complete records in respect of the Services. During the term of this Agreement and for a period of seven years after, upon reasonable notice, Consultant shall make such records available to Hydro, its agents and auditors, for inspection and copying during reasonable business hours.

14. GOVERNING LAW

14.1 This Agreement shall be subject to, interpreted, performed and enforced in accordance with the laws of Manitoba without regard to Manitoba or Canadian law governing conflicts of law, even if one or more of the parties to this Agreement may be resident of or domiciled in any other province or country. The parties hereby irrevocably attorn to the exclusive jurisdiction of the Court of Queen's Bench of Manitoba, Winnipeg.

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15. NOTICES

15.1 Any notice or other communication required or permitted under this Agreement shall be in writing, and shall be delivered personally, by fax or by email as follows:

For Consultant:

Fax: ____________________

Email: ____________________

Attention: ____________________

For Hydro:

Manitoba Hydro
360 Portage Avenue
Winnipeg, Manitoba, R3C 0G8
Attention: ____________________

Fax: ____________________

Email: ____________________

16. GENERAL

16.1 This is the entire agreement between the parties. There are no other undertakings, representations, or promises, express or implied.

16.2 Each party shall, from time to time, take such actions and execute such documents as may be necessary to give effect to this Agreement.

16.3 If any provision in this Agreement is found to be unenforceable at law, it shall be deemed severed from this Agreement and the remaining provisions shall continue in effect.

16.4 No amendment of this Agreement is valid unless it is in writing, signed by both parties.

16.5 No extension of time for performance of the Services is valid unless it is in writing, signed by Hydro.

16.6 No waiver of any provision of this Agreement, or of a breach hereof, is valid unless it is in writing, signed by waiving party. Waiver of a breach is not a waiver of a subsequent breach.

16.7 This Agreement shall enure to the benefit of. and be binding upon, the heirs, executors, administrators, successors and permitted assigns of the parties.

16.8 This Agreement may be signed in counterpart.

Signed on behalf of Consultant:

Per: ____________________
Authorized Signing Officer

Per: ____________________
Authorized Signing Officer

____________________, 20 .
Date

Signed on behalf of Hydro:

Per: ____________________
Authorized Signing Officer

Per: ____________________
Authorized Signing Officer

____________________, 20 .
Date

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Schedule "A"

DESCRIPTION OF THE SCOPE OF THE SERVICES, FEES AND CHARGES

PUB/MH II-8

Reference: PUB/MH I-10 (b)

a) Please update the response and include the years 2003/04 to 2011/12.

ANSWER:

Please see the attached schedules.

4) Joint Generation Development Agreements, Process and Study Costs										**(in thousands of dollars)**
Project	Community	2004	2005	2006	2007	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	2,031	2,567	2,399	2,193	2,367	2,401	2,317	1,472	1,712
	Manitoba Metis Federation	-	-	-	-	-	-	25	-	16
	Nisichawayasihk Cree Nation	-	-	-	-	-	-	-	-	4
	York Factory First Nation	1,482	1,796	1,922	1,877	2,014	2,239	2,377	2,006	2,010
	Cree Nation Partners (TCN/WLFN)	7,323	7,287	7,294	7,016	7,636	7,938	7,669	4,515	4,755
Keeyask - Generation Total		10,835	11,651	11,614	11,086	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	5,119	4,901	7,589	8,402	5,971	869	1,248	1,278	1,228
	Cree Nation Partners (TCN/WLFN)	569	346	287	304	364	-	-	-	-
Wuskwatim - Generation Total		5,688	5,247	7,877	8,706	6,335	869	1,248	1,278	1,228
Conawapa	Fox Lake Cree Nation	-	122	464	938	2,102	1,250	1,049	751	915
	Manitoba Metis Federation	-	-	-	-	-	-	25	-	16
	York Factory First Nation	-	-	-	173	929	1,150	908	575	616
	Shamattawa First Nation	-	-	-	50	100	134	327	355	329
	Cree Nation Partners (TCN/WLFN)	-	169	270	350	827	1,427	1,389	733	555
Conawapa Total		-	291	734	1,510	3,958	3,961	3,699	2,414	2,431
Grand Total		16,523	17,189	20,224	21,302	22,310	17,408	17,582	14,117	14,228

5) Mitigation										**(in thousands of dollars)**
Project	Community	2004	2005	2006	2007	2008	2009	2010	2011	2012
Keeyask	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 Total		-	-	-	-	-	5,886	4,635	1,103	1,528
Wuskwatim - Generation	Nisichawayasihk Cree Nation	-	-	-	1,000	305	4,682	141	149	172
Wuskwatim - Generation Total		-	-	-	1,000	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		-	-	-	1,000	332	10,695	9,847	1,612	2,187

PUB/MH II-8

Reference: PUB/MH I-10 (b)

b) Please explain the basis of the payments made under the Conawapa, Keeyask and Bipole III projects.

ANSWER:

Manitoba Hydro provides funding to a First Nation or Aboriginal group to consult and participate meaningfully in the planning and licensing of planned hydro projects, which is referred to as process and study costs in PUB/MH I-10(b). The mitigation payments are intended to be used to address the anticipated adverse effects of Manitoba Hydro's new developments on the First Nation or Aboriginal group and their members.

PUB/MH II-9

Reference: PUB/MH I-13 (a) & (b)

a) Please refile the analysis in response to question PUB/MH I – 13 (a) based on an efficient CCCT.

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 and more 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	Variable Production Cost For more efficient CCCT US ¢/kWh
3.00	3.7	3.0
7.00	7.7	6.0
12.50	13.2	10.1

PUB/MH II-9

Reference: PUB/MH I-13 (a) & (b)

b) Please confirm and complete the following table:

	Average NG Supply Cost $/GJ)	Efficient CCCT Variable Costs ¢/KWH	Average MH MISO Day-Ahead Export Price (¢/KWH)*	Average MH Off-Peak Opportunity Export Price (¢/KWH)*	Average MH on-Peak opportunity export price (¢/KWH)*
2008/09			**3.4**	**2.9**	**7.2**
2009/10			**2.2**	**1.9**	**3.1**
2010/11			**2.3**	**2.1**	**3.2**
2011/12			**2.1**	**2.3**	**2.9**

[* Source: PUB/MH I-11]

ANSWER:

Partially confirmed - please see following table and notes.

	Henry Hub Natural Monthly Gas Price Range (US$/ MMBTU) [Note 1]	Average Annual Henry Hub Gas Price (US$/ MMBTU) [Note 1]	Range of Efficient CCCT Variable Costs (US$/ MWh) [Note 2]	Efficient CCCT Variable Costs based on Average Annual Gas Price (US$/ MWh) [Note 2]	Physical Day Ahead Opportunity Market Avg Price [Note 3]	Opportunity Exports: On Peak Avg Price [Note 4]	Opportunity Exports: Off Peak Avg Price [Note 5]
2008/09	3.96 to 12.69	7.84	36.7 to 102	65.8	3.4 ¢/kWh	71.78 CAD$/ MWh (7.2 ¢/kWh)	29.37 CAD$/ MWh (2.9 ¢/kWh)
2009/10	2.99 to 5.83	4.09	29.4 to 50.7	37.7	2.2 ¢/kWh	31.14 CAD$/ MWh (3.1 ¢/kWh)	18.74 CAD$/ MWh (1.8 ¢/kWh)
2010/11	3.43 to 4.8	4.15	32.7 to 43	38.1	2.3 ¢/kWh	31.90 CAD$/ MWh (3.2 ¢/kWh)	21.23 CAD$/ MWh (2.1 ¢/kWh)
2011/12	2.17 to 4.54	3.57	23.3 to 41.0	33.8	2.1 ¢/kWh	28.76 CAD$/ MWh (2.9 ¢/kWh)	22.51 CAD$/ MWh (2.3 ¢/kWh)

Note 1: Henry Hub Gulf Coast Monthly Natural Gas Prices are a monthly average of daily spot prices (in US$/MMBTU) from the US DOE EIA. Annual prices are an average of the 12 monthly averages for the fiscal year.

Note 2: Efficient CCCT Variable Costs are in US$/ MWh. Assumptions of a heat rate of 7.500 MMBTU/ MWh and a $7.00/ MWh variable O&M are consistent with the assumptions in the illustrative example provided in Exhibit #MH-16 from the 2010 GRA.

Note 3: Manitoba Hydro was unable to find the requested “Average MH MISO Day-Ahead Export Price” in the responses to PUB/ MH I-11(a), (b) or (c). Instead the Physical Day Ahead Opportunity Market average revenue from Manitoba Hydro’s responses to PUB/MH I-12(a) and (b) was provided.

Note 4: Confirmed data from column 4 of table in the response to PUB/MH I-11(b)

Note 5: Confirmed data from column 5 of table in the response to PUB/MH I-11(b)

The information and assumptions in Exhibit #MH-16 from the 2010 GRA were intended to be illustrative of how prices are formulated in the MISO market on an hourly basis, and should not be extrapolated to an annual basis without consideration of many other pricing factors as discussed in the response to PUB/MH I-18(b).

PUB/MH II-10

Reference: PUB/MH I-16 (b) Export Sales/ Carbon Pricing

a) Please identify the external consultants that MH relies on in defining electricity export price forecasts and indicate which consultant provided MISO region specific forecasts as opposed to broad market forecasts.

ANSWER:

Manitoba Hydro's view of future export prices is commercially sensitive and confidential information. Disclosure of the identities of the consultants who created the individual forecasts upon which Manitoba Hydro's view is based would enable potential purchasers and competitors to purchase export price forecasts from the same group of consultants and facilitate reproduction of the Corporation's long-term contracts pricing methodology. As such, Manitoba Hydro respectfully declines to provide this information. Manitoba Hydro notes that detailed explanations regarding the commercial sensitivity of export price forecasts were provided in the 2010/11, 2011/12 General Rate Application, for example PUB/MH I-156(a) and CAC/MSOS/MH II-41(a) as well as Manitoba Hydro's August 6, 2010 Submission in Response to Intervenor comments regarding redactions to various risk reports

Manitoba Hydro can confirm that the external consultants contracted to provide export market prices do provide MISO region specific forecasts.

PUB/MH II-10

Reference: PUB/MH I-16 (b) Export Sales/ Carbon Pricing

b) Please provide the ICF 2010 GRA Hearing presentation forecast of CO2 pricing forecasts.

ANSWER:

Please see page 17 of Exhibit #MH-55 from the 2010 General Rate Application attached to this response.

ICF Forecasts of U.S. CO_2 Emissions Allowance Prices (2010 $/ton)

Year	Previous	Current
2011	0	0
2012	0	0
2013	0	0
2014	0	0
2015	22	0
2016	24	0
2017	25	0
2018	26	10 - 15

- ICF has also lowered its forecasts of likely CO_2 emission allowance prices due to political developments. This lowers interest in hydro supply all else equal. However, much environmental regulatory uncertainty remains, creating continued interest in low CO_2 options. For example, US EPA regulations on greenhouse gas emissions are still moving forward and regional initiatives are continuing. Also, concern about CO_2 still blocks new coal power plant options; none broke ground in the U.S. during 2009 - 2010. This eliminates an option that has low volatility in costs.

PUB/MH II-10

Reference: PUB/MH I-16 (b) Export Sales/ Carbon Pricing

c) Please provide the ICF presentation made as part of the Transportation and Storage Portfolio Review; Exploring the Future for Natural Gas Supply and Demand For Centra Gas U.S. and Canada Gas Market and Portfolio Option Overview.

ANSWER:

Please see Appendix 41.

<u>PUB/MH II-10</u>

Reference: PUB/MH I-16 (b) Export Sales/ Carbon Pricing

d) Please confirm that the MISO day-ahead and real-time market prices do not currently include any explicit CO2 premiums.

<u>ANSWER</u>:

It is confirmed that as of October 2012, generation in the MISO market footprint, and in turn day ahead and real-time market prices, are not subject to any explicit carbon price premiums.

PUB/MH II-10

Reference: PUB/MH I-16 (b) Export Sales/ Carbon Pricing

e) Please confirm that MH's new and pending NSP/MP/WPS contracts do not call for any additional CO2 premiums on fixed price energy and market priced energy.

ANSWER:

Manitoba Hydro confirms that the energy prices for the signed NSP, MP and WPS contracts are all-in prices and do not provide for any additional premiums associated with CO2. Manitoba Hydro cannot confirm the pricing details for the balance of energy it intends to sell to WPS under the 500 MW Term Sheet.

PUB/MH II-10

Reference: PUB/MH I-16 (b) Export Sales/ Carbon Pricing

f) Please explain whether MH's export prices forecast either includes or doesn't include CO2 premiums.

ANSWER:

As stated in the response to PUB/MH I-156(a) from the 2010 GRA:

> "It is confirmed that export prices that are forecasted by external consultants that comprise the corporate export price forecast include CO2 premiums. Manitoba Hydro's electricity export price forecast is prepared using information from several external price forecast consultants who each have their own electricity price forecast models and assumptions. Information from five external price forecast consultants was used to prepare the Manitoba Hydro electricity export price forecast. Manitoba Hydro's forecast which is based on a consensus of the five consultants is referred to as the Consensus Price Forecast. In preparing their forecasts, the consultants prepare their own internal estimates for a number of pricing factors. These pricing factors include, but are not limited to, thermal fuel forecasts (coal and natural gas), future load growth forecasts, capital costs and required rates of return, generation retirements and additions, power market rules, future legislative regulations including greenhouse gases, SOx, NOx, and mercury and renewable portfolio standard requirements, and characteristics of the existing generation fleet. Hence, any CO2 premium is but one of many pricing factors considered in developing the electricity export price forecast. This forecast contains an Expected forecast scenario, as well as a Low forecast scenario and a High forecast scenario.
>
> The specific details of Manitoba Hydro's electricity export price forecast, including details on specific pricing factors such as the assumptions regarding the timing and price levels of these CO2 premiums, are commercially sensitive information, and therefore are confidential since public release could harm the Corporation in negotiation of contracts for export sales.

> As a general comment, all five of the price forecast consultants forecast some level of CO2 premiums in their Expected forecasts. The specific level of CO2 premium is generally not a constant number, but rather tends to rise over time as legislative regulation is forecast to tighten, and each consultant has their own view as to timing and degree of regulation."

Manitoba Hydro’s current process using independent price forecast consultants to prepare an export price forecast is same as for the 2010 GRA. For more information on the value of carbon with the export price forecast, please see Manitoba Hydro’s response to CAC/MH II-9(a).

PUB/MH II-10

Reference: PUB/MH I-16 (b) Export Sales/ Carbon Pricing

g) Confirm MISO Market does not provide separate prices by fuel choice.

ANSWER:

It is confirmed that MISO day-ahead and real-time markets do not have any mechanism to separate prices by the type of generation or fuel. Bilateral contracts can be used for sale associated products such as generation attributes, renewable energy credits or accredited generation capacity if desired.

PUB/MH II-11

Reference: PUB/MH I-17 (b)- Imported Energy vs. Export Prices

a) Please explain why export prices are expected to increase by 50% over the next 5 years while import prices remain almost unchanged.

ANSWER:

Manitoba Hydro was unable to find data in Attachment 5 of the GRA that would suggest that average prices for imports or Purchased Energy remains almost unchanged over the next five years. However, Manitoba Hydro can provide the following explanation as to why Average Prices for Total Export Sales and Purchased Energy as provided in Attachment 5 may not move together.

Average annual prices implicitly include several complex and inter-related factors. As stated in Manitoba Hydro's response to PUB/MH I-17(b), export sales are primarily undertaken during the prime on-peak hours and import sales are primarily based in the off-peak hours. In general, the economic dispatch order of generating stations will result in higher priced fuels being used to set prices in the high demand periods. Similarly, lower priced fuels will set the market price during low demand periods. The escalation of energy commodity prices may be different for the price setting fuels for the on-peak and off-peak periods, respectively. However, commodity prices alone do not completely explain the relative difference between average annual export and import prices.

Average annual export prices include revenue from long-term firm export sales and market-based export sales from opportunity energy whose duration may range from 1-hour to several months. The energy volumes of each particular sale will affect the average export prices. Energy volumes, which are available for export, will change on an annual basis given changes in available supply and contractual energy demands.

The Purchased Energy category in Attachment 5 of the GRA includes long term wind purchases as well as market-based purchases of import energy. The relative energy volumes of each type of energy purchase will affect the average annual price. The need for energy imports will change as the energy supply and demand changes.

PUB/MH II-11

Reference: PUB/MH I-17 (b)- Imported Energy vs. Export Prices

b) Would MH expect to primarily import off-peak coal-generated electricity?

ANSWER:

As noted in the response to PUB/MH II-10(g), MISO day-ahead and real-time markets do not have any mechanism to separate [or track] prices by the type of generation or fuel. Therefore any Manitoba Hydro imports from the MISO market are purchases of market energy without identification of the specific generator or type of generator.

However, given historical generation patterns, the overall generation mix in MISO and size of the off-peak load in the MISO market, Manitoba Hydro would expect that, as of October 2012, coal generated electricity would be the marginal resource for the majority of off peak imports.

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

a) Please re-file PUB/MH I-18(a) separately indicating the CCCT generation and SCCT generation for 2008 to 2012; also indicate the imports (MH's plus other) that MISO employed.

ANSWER:

As far as Manitoba Hydro is aware, MISO does not publish data that details natural gas generation by technology (i.e. SCCT or CCCT).

The chart below provides the table originally filed in PUB/MH I-18(a) with additional columns to indicate the annual total imports into the MISO region, along with the share of the total attributed to Manitoba Hydro.

	Coal	Gas, Oil/Gas	Hydro	Nuclear	Oil	Wind	Imports into MISO Region (Total)	Manitoba Hydro Physical Exports to the US
*Year to July 2012	182	33	3	37	3	19		4.4
2011	436	32	5	78	2	29	40.3	9.3
2010	490	25	4	93	2	24	28.0	9.1
2009	453	15	2	82	1	16	26.3	9.2
2008	463	22	2	69	0	4	27.2	9.9

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

b) Include in the refilled table a line item for MH's contribution.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-12(a).

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

c) Please provide an update of 2010 GRA Exhibit #MH-28 separately indicating the 2007 to date new CCCT and new peaking natural gas generation that have been added into the MISO Market.

ANSWER:

Manitoba Hydro does not have available a more detailed analysis of the chart that was included in 2010 GRA Exhibit #MH-28 which provides the gas technology type (combustion turbine vs combined cycle).

Manitoba Hydro can provide the following list of natural gas plants commissioned in the 2010-2012 period in the MISO region. This list is based on publically available data sources and may not be complete:

Commissioned Natural Gas Facilities in MISO - 2010-2012

Year	Facility	Capacity (MW)	Technology Type
2010	Culbertson Peaking	91	SCCT
2011	Marsh Utilities M1	60	SCCT
2012	Fremont Energy Center	716	CCCT
2012	Deer Creek Station	300	CCCT
	Total	**1,168**	

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

d) Please provide an updated forecast of new CCCT and new peaking natural gas generation that is or may be coming online in MISO by 2016.

ANSWER:

As noted in response to PUB/MH II-12(c), Manitoba Hydro does not have complete information on potential future plant additions in the MISO region.

Below is a list of planned/proposed natural gas generation facilities for the MISO region, compiled from public information sources that may or may not be complete. The facilities with Not Yet Defined in the 'Year' column indicate these are proposed facilities that have not yet been provided a defined commissioning date.

Planned/Proposed Natural Gas Facilities in MISO

Year	Facility	Capacity (MW)	Technology Type
2013	Pioneer Generating Station	45	SCCT
2013	Lonesome Creek Station	45	SCCT
2013	Fairmont Energy Station	24	SCCT
2017	Marshalltown Generating Station	650	CCCT
Not yet defined	Morton CT Plant (Heskett)	80	SCCT
Not yet defined	Mesaba Gas Plant	540	CCCT

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

e) Please provide a 2007 to 2016 listing of new CCCT and new peaking generation that has or may come online in Saskatchewan by 2016.

ANSWER:

The following information was compiled from publicly available sources, and may or may not include all future /planned stations.

Saskatchewan Natural Gas Plants 2007-2016

Name	Commissioning Date	Capacity (MW)	Type
North Battleford Energy Centre	2013	260	Natural gas - CCCT
Spy Hill Power Plant	2011	86	Natural gas -SCCT
Ermine Power Station	2010	92	Natural gas - SCCT
Yellowhead Power Station	2010	138	Natural gas - SCCT

References:

North Battleford Energy Centre – http://www.marketwire.com/press-release/North-Battleford-Energy-Centre-Project-Breaks-Ground-at-Official-Ceremonies-TSX-NPI.UN-1275693.htm

Spy Hill Power Plant – http://www.northlandpower.ca/WhatWeDo/PrerevenueProjects/Project.aspx?projectID=27#m=2

Ermine & Yellowhead Power Stations – http://www.saskpower.com/about_us/generation_transmission_distribution/natural_gas_stations.shtml

PUB/MH II-12

Reference: PUB/MH I-18 (a) – MISO Energy Supply Resources

f) Please indicate on a ¢/kWh basis the above new CCCT (not SCCT) generation revenue requirements.

ANSWER:

Manitoba Hydro is not aware of SaskPower's revenue requirements related to new CCCT generation.

PUB/MH II-13

Reference: PUB/MH I-18 (b)

Please identify and explain which energy resources that can supply the MISO day-ahead market at less than 1¢/kWh (as indicated by MH's SEP (summer) prices in each of the last 4 years.

ANSWER:

Generators that can offer into the MISO market at less than $10/MWh include wind and hydro which have zero incremental fuel costs.

During the off peak hours when load is lowest, it is possible that the market price at the MH Commercial Pricing Node (MHEB CPN) could be less than $10/MWh. This low pricing can be due to a combination of low variable cost generating units setting the marginal energy price, transmission congestion/ limitations, and unit commitment considerations.

The MHEB CPN price is generally depressed from the market's marginal energy price (the price set by the marginal generator in MISO) due to the cost of transmission losses and transmission congestion, which are typically negative components of the MHEB CPN market price. These transmission related price deflators can result in MHEB CPN prices that do not resemble generator costs especially during off peak hours, when loads are light, wind generation tends to be the highest, and other generation (such as coal-fired generation) stays on-line because of commitment considerations. Under these circumstances the transmission system becomes congested resulting in relatively low prices at the MH Commercial Pricing Node.

With reference to SEP pricing, there are conditions when SEP prices are not indicative of market prices. In a system spill situation, Manitoba Hydro maximizes its generation and exports as much power as possible, subject to tie-line constraints. Any incremental SEP sales under these conditions result in reduced spill therefore SEP energy is priced at MH's marginal cost of hydro generation (production cost and water rentals), which is less than 1 cent/kWh.

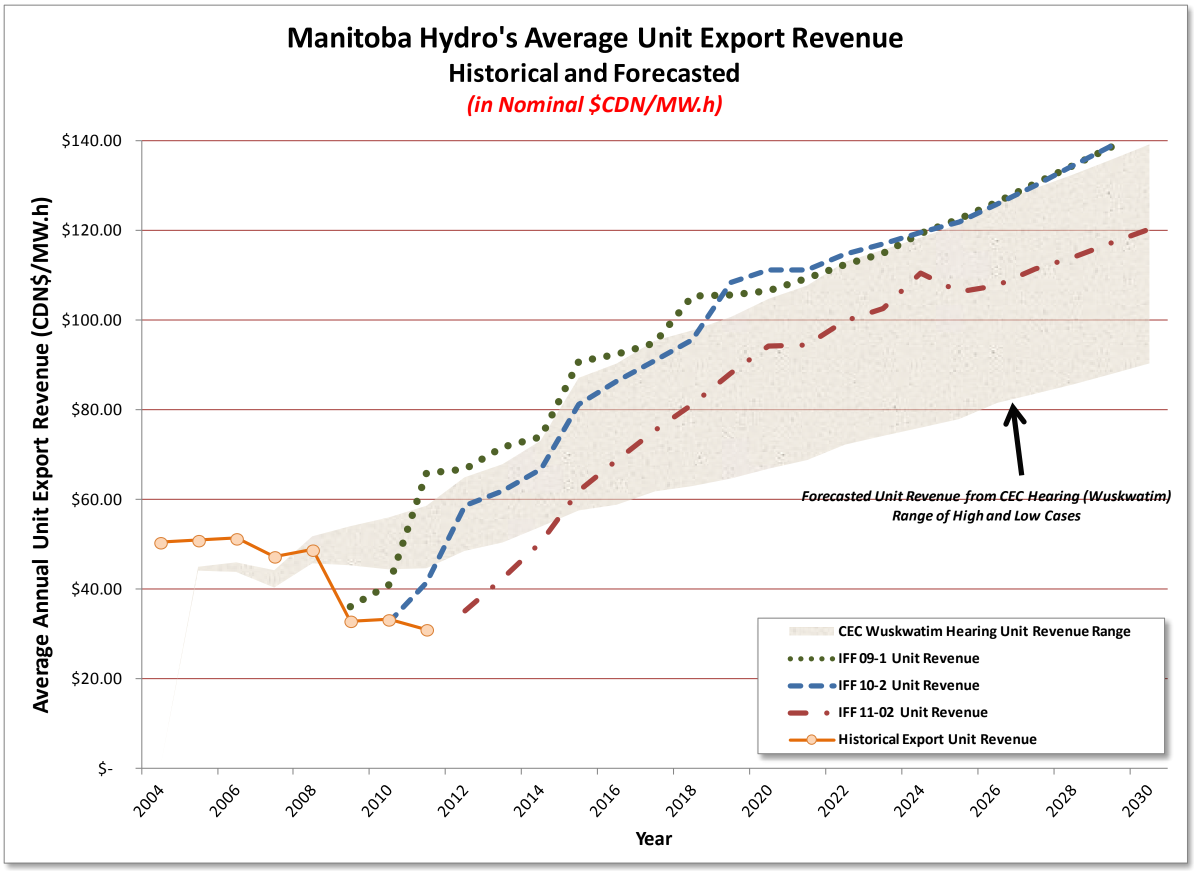
This condition is explained in pp. 10-12, Appendix 13.2 of the 2010-11 GRA Application and in further detail in Manitoba Hydro's response to CAC/MSOS/MH I-187(d) (revised) in the 2010-11 GRA. In these circumstances, SEP pricing is not related to the MISO energy market price as implied by this question.

PUB/MH II-14

Reference: PUB/MH I-19 (a) MH's Average Unit Export Revenue

a) Please re-file PUB/MH I-19(a) using CDN$ values consistent with the 09/10/11 IFF Revenue Assumptions;

ANSWER:



The above chart applies actual historical exchange rates for the years 2004-2011. Post-2011 exchange rates applied are consistent with assumptions used for IFF11-2.

PUB/MH II-14

Reference: PUB/MH I-19 (a) MH's Average Unit Export Revenue

b) Please also include in the table in (a) the CDN$ values for the Wuskwatim CEC Hearing high and low scenario forecast.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-14(a).

PUB/MH II-15

Reference: **PUB/MH I-19 (b) (2013 Response for Additional Information Attachment 5)**

Preamble: **The 2008/09 power resource plan [pages 4 and 5] provides the cost data for a 400 MW CCCT producing 3100 GW hours of dependable energy. It indicates $471 million capital cost and 5.5 ¢/K WH operating cost with $8 /MM BTU gas. PUB/MH I-13(a) and Exhibit MH#-16 (2010 GRA) provides the variable (marginal) costs and natural gas supply cost of an "efficient" CCCT natural gas generation plant.**

a) **Has MH studied other alternatives such as using a CCCT for peak periods? Please file any feasibility analysis of such an alternative.**

ANSWER:

Manitoba Hydro has not studied an alternative where a CCCT is used solely for peak periods. Manitoba Hydro has evaluated proposed plans for new generation which includes thermal resource options such as CCCTs to serve peak load and system energy requirements. A review of matters related to Manitoba Hydro's plans for new generation will take place in the context of A Needs For and Alternatives To (NFAT) hearing, which is expected to commence in 2013. Therefore, Manitoba Hydro respectively declines to file information on the feasibility of CCCT generation alternatives.

PUB/MH II-15

Reference: **PUB/MH I-19 (b) (2013 Response for Additional Information Attachment 5)**

Preamble: **The 2008/09 power resource plan [pages 4 and 5] provides the cost data for a 400 MW CCCT producing 3100 GW hours of dependable energy. It indicates $471 million capital cost and 5.5 ¢/K WH operating cost with $8 /MM BTU gas. PUB/MH I-13(a) and Exhibit MH#-16 (2010 GRA) provides the variable (marginal) costs and natural gas supply cost of an "efficient" CCCT natural gas generation plant.**

b) Please define in the absence of CO2 price adders, the natural gas prices that would result in efficient CCCT generation costs equal to the average export revenue rates in attachment 5.

ANSWER:

As noted in the response to PUB/MH I-19(b) "Manitoba Hydro does not have available to it the requested information and is therefore unable to provide the requested data."

In order to respond to this question Manitoba Hydro would need a methodology to capture all CCCT generation costs and cost interrelationships over all hours in a year. In addition, there are other costs not discussed in the illustrative examples cited, including start up costs, reduced operational efficiencies when load following and allocation of fixed cost (capacity charges), that need to be considered. There are multiple relationships between the various pricing factors that impact export prices that need to be considered and that it would be unrealistic to think that these complex relationships can be modeled assuming a direct correlation between the two identified factors (CO2 adders and gas prices) with no corresponding impact to other factors.

The results of the requested back calculation cannot be used to draw meaningful conclusions. The illustrative example developed for Exhibit #MH-16 in the 2010 GRA and cited in PUB/MH I-13(a) was developed to illustrate how a power market operator such as MISO dispatches generation to meet hourly loads and calculates the market price on an hourly basis. Hence the example is only representative of the short run marginal costs which in the MISO market are updated every five minutes and then used to determine hourly market price. The various market pricing factors vary on a seasonal, weekly, daily and in the case of load- an hourly basis. These market pricing factors need to be considered over the range of their variation of the course of an entire year, as do additional costs included from starting thermal generation and reduced operational efficiencies when load following. In addition, allocation of fixed costs (such as the $471 million capital cost cited in the preamble to this question) through a capacity charge also needs to be considered.

Manitoba Hydro currently captures all of these costs through its export price forecast / internal production costing processes. To capture all costs could require the development of several export price forecasts using a range of natural gas prices, “in the absence of CO2 price adders”, all based on some sort of “CCCT natural gas generation plant” in the market. Then internal production costing analysis could be used to determine which of the natural gas prices / export price forecasts produces “the average export revenue rates in attachment 5”.

Such an undertaking to develop additional price forecast and additional production costing analysis represents a significant and costly effort for which Manitoba Hydro would not have a use and therefore no such analysis has been completed.

PUB/MH II-15

Reference: **PUB/MH I-19 (b) (2013 Response for Additional Information Attachment 5)**

Preamble: **The 2008/09 power resource plan [pages 4 and 5] provides the cost data for a 400 MW CCCT producing 3100 GW hours of dependable energy. It indicates $471 million capital cost and 5.5 ¢/K WH operating cost with $8 /MM BTU gas. PUB/MH I-13(a) and Exhibit MH#-16 (2010 GRA) provides the variable (marginal) costs and natural gas supply cost of an "efficient" CCCT natural gas generation plant.**

c) **Please calculate the approximate Natural Gas price that would result in an efficient CCCT generation price equal to average annual export price levels in attachment 5**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-15(b).

PUB/MH II-16

Reference: PUB/MH I-19 (c) – Specific Transmission Upgrades Required for Attachment 5 Volume & Prices

a) Please indicate the minimum new transmission interconnection needed to meet firm and opportunity sales during the twenty-year timeline.

ANSWER:

No new transmission is planned until the 2020 timeframe in conjunction with Manitoba Hydro's proposed new generation. Matters related to Manitoba Hydro's proposed plans for new generation and a new interconnection will 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 respectively declines to provide the above requested information.

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

PUB/MH II-17

Reference: PUB/MH I-22 (c)

a) Please update the schedule to include the years 2004/05 to 2032

ANSWER:

Please refer to the following table, which has been updated to include 2003/04 to 2006/07.

	For the year ended March 31	Actuals									Forecast					
		2004	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
1	**Cash Flow from Operations**	(156.0)	406.0	712.0	421.0	599.0	653.0	528.0	550.0	518.0	434.2	438.6	444.2	446.9	518.9	574.2
2	**Base Capital Spending**	373.0	337.0	283.0	376.0	363.0	359.0	414.0	450.0	472.0	417.4	411.5	394.4	387.3	363.8	372.4
3	**Excess Cash Flow after Base Capital Spending (1-2)**	(529.0)	69.0	429.0	45.0	236.0	294.0	114.0	100.0	46.0	16.8	27.1	49.8	59.6	155.0	201.8
4	**Capital Coverage Ratio (1/2)**	(0.42)	1.20	2.52	1.12	1.65	1.82	1.28	1.22	1.10	1.04	1.07	1.13	1.15	1.43	1.54
5	**Major New Generation & Transmission**	72.5	160.9	183.5	283.4	477.4	543.5	679.0	657.5	567.8	656.1	762.6	1 060.0	1 223.4	1 566.9	1 610.5
6	**Cash Flow required to Finance MNG&T**	72.5	91.9	-	238.4	241.4	249.5	565.0	557.5	521.8	639.4	735.5	1 010.1	1 163.8	1 411.9	1 408.7

	For the year ended March 31	Forecast														
		2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
1	**Cash Flow from Operations**	563.7	499.2	580.4	514.1	716.6	832.0	920.9	1 065.5	1 175.2	1 192.2	1 294.5	1 388.2	1 501.2	1 597.8	1 748.2
2	**Base Capital Spending**	380.4	387.6	396.4	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)**	183.3	111.6	184.0	154.3	330.7	401.7	458.5	542.8	676.6	677.6	791.5	852.4	933.7	1 119.2	1 164.6
4	**Capital Coverage Ratio (1/2)**	1.48	1.29	1.46	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**	1 953.0	1 177.1	1 412.0	1 445.8	1 306.0	1 071.8	933.3	1 050.2	385.6	224.1	323.8	460.0	374.9	390.2	225.5
6	**Cash Flow required to Finance MNG&T**	1 769.7	1 065.5	1 228.0	1 291.5	975.3	670.1	474.7	507.4	-	-	-	-	-	-	-

PUB/MH II-17

Reference: PUB/MH I-22 (c)

b) Please describe the process used in allocating excess cash flow and demonstrate how the excess cash flow after base capital spending has been allocated to Major G & T projects for each of the years 2004/05 to 2032.

ANSWER:

PUB/MH I-22(c) was prepared as requested for illustrative purposes only. Manitoba Hydro does not allocate excess cash flow to Major New Generation and Transmission on a specific project basis.

PUB/MH II-17

Reference: PUB/MH I-22 (c)

c) Please indicate the amounts of Wuskwatim costs that have been covered by excess cash flow prior to fiscal 2008 and in each of the years 2008 to 2012.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-17(b) which indicates that Manitoba Hydro does not allocate internally generated funds to specific Major New Generation and Transmission projects as a matter of practice.

However, Manitoba Hydro has provided a notional calculation of the internally generated funds attributable to the Wuskwatim Generation Station which is further discussed in the response to PUB/MH II-50(b).

PUB/MH II-17

Reference: PUB/MH I-22 (c)

d) Please indicate separately the amounts of excess cash flow that will flow to Bipole III, Keeyask GS. and Conawapa G.S. prior to fiscal 2008 and for each of the distinct years in the forecast from 2011/12 until in-service.

ANSWER:

Please see Manitoba Hydro’s response to PUB/MH II-17(b).

PUB/MH II-18

Reference: PUB/MH I-23 (a)

a) Please refile the analysis reflecting that rate regulated accounting will continue for rate setting purposes and the election to defer implementation of IFRS until 2014/15.

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 2014/15 until the end of the forecast period and that IFRS will be implemented in 2014/15.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
PUB-MH II-18(a) - MH11-2 with Rate Regulated Accounting Allowed and 1 yr IFRS Deferral
(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	460	507	513	522	543	552	570	586	596
Finance Expense	385	440	449	502	535	568	637	760	800	1 143	1 105
Depreciation and Amortization	353	401	415	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	94	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	1 697	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	81	58	120	153	112	11	64	(62)	110
* 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%	22%	18%	17%	16%	15%	14%	14%	13%	12%
Interest Coverage	1.12	1.03	1.13	1.08	1.15	1.16	1.11	1.01	1.05	0.96	1.08
Capital Coverage	1.04	1.07	1.20	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 II-18(a) - MH11-2 with Rate Regulated Accounting Allowed and 1 yr IFRS Deferral
(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	594	700	735	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 II-18(a) - MH11-2 with Rate Regulated Accounting Allowed and 1 yr IFRS Deferral
(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	15 795	16 521	17 446	18 029	21 452	21 940	25 557	28 311	28 673
Accumulated Depreciation	(4 917)	(5 266)	(5 627)	(5 934)	(6 294)	(6 661)	(7 087)	(7 562)	(8 051)	(8 606)	(9 188)
Net Plant in Service	8 878	9 947	10 168	10 587	11 152	11 368	14 364	14 378	17 506	19 705	19 485
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	1 693	1 375	1 562	1 743	1 989	1 791	1 954	2 208	2 093
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	15 414	16 342	18 088	19 861	22 016	22 914	24 296	25 770	26 788
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	1 386	1 514	1 565	1 723	2 017	1 416	1 779	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	2 491	2 516	2 636	2 789	2 901	2 913	2 977	2 915	3 025
Accumulated Other Comprehensive Income	335	302	287	(206)	(257)	(276)	(303)	(318)	(334)	(353)	(375)
	13 648	14 426	15 414	16 342	18 088	19 861	22 016	22 914	24 296	25 770	26 788

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
PUB-MH II-18(a) - MH11-2 with Rate Regulated Accounting Allowed and 1 yr IFRS Deferral
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
ASSETS										
Plant in Service	29 081	29 646	34 059	38 134	39 394	40 024	40 593	41 123	43 143	43 859
Accumulated Depreciation	(9 775)	(10 366)	(10 992)	(11 685)	(12 430)	(13 183)	(13 949)	(14 724)	(15 532)	(16 361)
Net Plant in Service	19 306	19 280	23 066	26 449	26 964	26 841	26 645	26 399	27 612	27 499
Construction in Progress	6 099	6 969	4 170	1 022	545	786	1 259	1 722	618	758
Current and Other Assets	2 207	2 283	2 530	2 522	3 128	3 540	3 815	4 060	4 630	5 299
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
	27 848	28 760	29 988	30 205	30 840	31 364	31 909	32 369	33 044	33 739
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	3 238	3 531	3 938	4 393	4 812	5 324	5 919	6 618	7 354	8 244
Accumulated Other Comprehensive Income	(388)	(388)	(388)	(387)	(387)	(387)	(387)	(387)	(387)	(387)
	27 848	28 760	29 988	30 205	30 840	31 364	31 909	32 369	33 044	33 739

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
PUB-MH II-18(a) - MH11-2 with Rate Regulated Accounting Allowed and 1 yr IFRS Deferral
(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)	(813)	(897)	(917)	(945)	(991)	(1 021)	(1 060)	(1 078)	(1 100)
Interest Paid	(406)	(466)	(472)	(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	519	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)	(1 556)	(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)	(1 783)	(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)	(83)	(61)	9	(22)	161
Cash at End of Year	(50)	(86)	(147)	(130)	(58)	(83)	(61)	9	(22)	161	382

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
PUB-MH II-18(a) - MH11-2 with Rate Regulated Accounting Allowed and 1 yr IFRS Deferral
(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	(164)	(5)	120	342	150	54	238	266	372
Cash at Beginning of Year	382	418	255	249	369	711	861	915	1 154	1 419
Cash at End of Year	418	255	249	369	711	861	915	1 154	1 419	1 791

PUB/MH II-19

Reference: First Quarter Report

The quarterly report states "the rate increases will also provide sufficient revenues for the Corporation to meet its ongoing costs of operations".

What level of annual rate increases will be required to maintain a minimum 25% equity throughout the forecast period?

ANSWER:

The following scenario provides the minimum rate changes required to maintain a 25% equity throughout the forecast period.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
MAINTAIN 75:25 DEBT TO EQUITY 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	939	471	438	420	585	517	568	734	580
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	2,612	2,188	2,237	2,269	2,483	2,450	2,578	2,976	2,933
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	438	451	461	474	523	623	644	966	907
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	1,695	1,757	1,805	1,856	1,983	2,160	2,234	2,642	2,631
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	916	430	430	411	498	288	341	331	292
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	65.18%	-21.17%	-1.99%	-1.32%	8.94%	-3.74%	2.23%	8.00%	-7.60%
Cumulative Percent Increase	0.00%	4.50%	72.62%	36.07%	33.36%	31.59%	43.36%	37.99%	41.07%	52.35%	40.77%
Financial Ratios											
Equity	26%	24%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Interest Coverage	1.12	1.03	2.49	1.64	1.58	1.49	1.54	1.29	1.31	1.26	1.24
Capital Coverage	1.04	1.07	3.26	2.09	2.26	2.21	2.46	1.99	2.15	2.49	2.32

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
MAINTAIN 75:25 DEBT TO EQUITY 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*	494	459	447	284	360	379	435	421	461	417
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
	2,885	2,885	3,069	3,211	3,427	3,486	3,558	3,569	3,650	3,636
EXPENSES										
Operating and Administrative	634	646	669	676	688	700	713	727	741	755
Finance Expense	879	870	970	1,211	1,387	1,384	1,378	1,366	1,421	1,369
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
	2,639	2,681	2,830	3,158	3,424	3,463	3,496	3,522	3,637	3,635
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	235	192	228	42	(9)	11	49	34	(1)	(13)
* Additional General Consumers Revenue										
Percent Increase	-4.60%	-2.12%	-0.94%	-8.63%	3.96%	0.76%	2.61%	-0.98%	1.70%	-2.39%
Cumulative Percent Increase	34.30%	31.45%	30.21%	18.97%	23.68%	24.62%	27.87%	26.62%	28.78%	25.70%
Financial Ratios										
Equity	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Interest Coverage	1.19	1.15	1.17	1.03	0.99	1.01	1.03	1.02	1.00	0.99
Capital Coverage	1.97	1.79	1.71	1.54	1.50	1.60	1.60	1.50	1.83	1.48

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
MAINTAIN 75:25 DEBT TO EQUITY 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	1,364	1,559	1,736	1,987	1,765	1,973	2,223	2,080
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	16,084	17,847	19,627	21,800	22,687	24,126	25,608	26,609
LIABILITIES AND EQUITY											
Long-Term Debt	9,253	9,469	10,109	10,961	12,179	13,450	14,815	16,107	16,869	17,979	19,223
Current and Other Liabilities	1,351	1,917	1,359	1,496	1,653	1,759	2,086	1,399	1,741	1,788	1,265
Contributions in Aid of Construction	317	328	341	348	355	365	376	386	396	407	418
Retained Earnings	2,391	2,411	3,051	3,480	3,910	4,321	4,819	5,107	5,448	5,779	6,070
Accumulated Other Comprehensive Income	335	302	(79)	(201)	(250)	(268)	(296)	(311)	(327)	(345)	(368)
	13,648	14,426	14,780	16,084	17,847	19,627	21,800	22,687	24,126	25,608	26,609

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
MAINTAIN 75:25 DEBT TO EQUITY 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	2,008	2,383	2,446	2,420	2,790	3,101	3,231	3,213	3,449	3,822
Goodwill and Intangible Assets	91	89	88	86	85	83	82	81	81	80
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	27,491	28,708	29,757	29,963	30,371	30,798	31,203	31,403	31,746	32,146
LIABILITIES AND EQUITY										
Long-Term Debt	20,026	21,029	21,382	21,985	22,386	22,727	22,879	23,180	23,369	22,941
Current and Other Liabilities	1,111	1,121	1,578	1,128	1,131	1,195	1,387	1,238	1,381	2,208
Contributions in Aid of Construction	429	440	451	463	475	487	499	512	525	538
Retained Earnings	6,306	6,498	6,726	6,768	6,759	6,770	6,819	6,853	6,852	6,838
Accumulated Other Comprehensive Income	(381)	(381)	(380)	(380)	(380)	(380)	(380)	(380)	(380)	(380)
	27,491	28,708	29,757	29,963	30,371	30,798	31,203	31,403	31,746	32,146

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
MAINTAIN 75:25 DEBT TO EQUITY 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	2,612	2,188	2,237	2,269	2,483	2,450	2,578	2,976	2,933
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)	(467)	(469)	(490)	(505)	(569)	(674)	(681)	(1,015)	(948)
Interest Received	26	28	27	20	27	34	41	43	39	36	35
	434	439	1,286	809	822	822	937	771	851	895	896
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	811	900	830	1,005	1,590	1,800	2,190	1,600	1,390	1,790	1,390
Sinking Fund Withdrawals	23	129	395	105	15	-	-	424	159	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	403	926	1,287	1,385	1,653	1,171	1,235	1,441	1,381
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)	(116)	(192)	(153)	(231)	(192)	(219)	(288)	(346)
Other	(19)	(20)	(20)	(21)	(19)	(46)	(36)	(30)	(30)	(34)	(40)
	(1,280)	(1,363)	(1,709)	(1,752)	(2,146)	(2,184)	(2,603)	(1,789)	(2,069)	(2,179)	(2,083)
Net Increase (Decrease) in Cash	(116)	(36)	(20)	(17)	(37)	24	(13)	154	18	157	194
Cash at Beginning of Year	66	(50)	(86)	(106)	(124)	(160)	(137)	(150)	4	22	179
Cash at End of Year	(50)	(86)	(106)	(124)	(160)	(137)	(150)	4	22	179	373

ELECTRIC OPERATIONS (MH11-2)
PROJECTED CASH FLOW STATEMENT
MAINTAIN 75:25 DEBT TO EQUITY 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	2,885	2,885	3,069	3,211	3,427	3,486	3,558	3,569	3,650	3,636
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	(901)	(877)	(988)	(1,240)	(1,418)	(1,425)	(1,430)	(1,421)	(1,456)	(1,439)
Interest Received	20	21	29	33	36	46	56	59	66	77
	850	827	895	770	774	803	855	850	876	865
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	780	990	790	590	390	400	390	390	370	590
Sinking Fund Withdrawals	159	-	-	317	-	-	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	984	784	449	382	393	383	414	266	371
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)	(213)	(229)	(248)	(246)	(259)	(273)	(286)	(289)	(304)
Other	(29)	(30)	(27)	(28)	(30)	(28)	(29)	(29)	(29)	(30)
	(1,757)	(1,643)	(1,835)	(1,167)	(1,023)	(1,121)	(1,305)	(1,268)	(1,194)	(1,148)
Net Increase (Decrease) in Cash	(134)	168	(156)	52	133	74	(67)	(5)	(52)	88
Cash at Beginning of Year	373	238	406	251	303	436	510	444	439	387
Cash at End of Year	238	406	251	303	436	510	444	439	387	475

PUB/MH II-20

Reference: First Quarter Report

a) The decrease of 11.1% in generation and delivery of electricity for the first quarter is mostly due to the reduction of energy sold in the export market from 3.2 billion kilowatt hours to 2.3 billion kilowatt hours. Please elaborate on the factors behind this reduction and whether the Corporation expects a continuation of this trend through the next three quarters and over the next three to five years.

ANSWER:

The year-over-year reduction in generation is the result of unfavorable water conditions. Water flows in the first quarter of 2012/13 were below average, mainly due to below average precipitation since September 2011, resulting in below average snowmelt and rainfall runoff.

During the first quarter, flows on the Winnipeg River were well below average and water was conserved in storage in Lake Winnipeg. This resulted in reduced hydraulic generation and less energy available for export.

Since then precipitation across the watersheds has improved with above average inflows from June to August leading to above average hydraulic generation and increased export volumes in the second quarter.

Manitoba Hydro has no reason to believe that the dry spring of 2012 is an indicator of future water flows over the next three to five years.

PUB/MH II-21

Reference: First Quarter Report, PUB/MH I-45

Please explain how the Corporation determines whether expenditures such as those for upgrading Kelsey or DSM would be considered maintenance and expensed versus a betterment and capitalized.

ANSWER:

Canadian GAAP defines property, plant and equipment as identifiable tangible assets that meet the following criteria:

a) are held for use in the production or supply of goods and services;
b) have been acquired, constructed or developed with the intention of being used on a continuing basis; and
c) are not intended for sale in the ordinary course of business.

Manitoba Hydro capitalizes the cost of betterments to property, plant and equipment. Under CGAAP section 3061.26 "the cost incurred to enhance the service potential of an item of property, plant and equipment is a betterment. Service potential may be enhanced when there is an increase in the previously assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved. The cost incurred in the maintenance of the service potential of an item of property, plant and equipment is a repair, not a betterment. If a cost has the attributes of both a repair and a betterment, the portion considered to be a betterment is included in the cost of the asset."

Maintenance related expenditures do not result in the extension of an asset's service left or enhance the service potential of the asset and as such are expensed in the period in which incurred. In the case of the Kelsey Upgrade project significant components such as turbine runners, transformers and exciters were replaced thereby extending the life of the generating station.

Demand Side Management (DSM) expenditures do not meet the criteria for capitalization as either a tangible or intangible asset and as a result are deferred as a rate-regulated asset under Canadian GAAP. The costs are amortized on a straight line basis over a period of 10 years.

PUB/MH II-22

Reference: 2012 Annual Report

The life of certain assets are being extended and depreciated and amortized over periods of as much as 125 years.

a) To what extent does the Corporation consider the risk of obsolescence from new sources of energy that could evolve within such a long period of time?

ANSWER:

During a depreciation study, the potential for obsolescence is discussed, and where warranted adjustments to asset lives are made to reflect the impacts of changing technology. For the 2010 Depreciation Study, adjustments to asset lives were made in areas where technological change is occurring at a rapid rate, such as in the case for Distribution Meters and Communication assets, where mechanical devices are being phased out and replaced with electronic equipment.

For hydraulic generating assets, the ongoing operating cost is relatively low as compared to other generation technologies currently available, and the cost to decommission an existing generating station is very high. At the time of the depreciation study, no new generation technologies were identified that had the potential to make the existing stations obsolete, and thus justify the expense of decommissioning them. As such, no specific provision for obsolescence has been made in establishing the useful life of generating stations.

A high level review of depreciation rates is performed annually to ensure that the depreciation rates are reasonable, and an in-depth review is undertaken with each depreciation study. The potential for obsolescence will be considered as part of the year end review of depreciation rates, and in future depreciation studies. Depreciation rates will be adjusted when and if a new technology is identified that poses a risk of obsolescence to existing assets.

PUB/MH II-22

Reference: 2012 Annual Report

The life of certain assets are being extended and depreciated and amortized over periods of as much as 125 years.

b) What if any considerations of this risk have the Corporation taken in establishing the useful life of its generating station assets?

ANSWER:

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

PUB/MH II-23

Reference: 2012 Annual Report

a) Why would Manitoba Hydro proceed first with the Keeyask generating station at an estimated cost of $8,058,000 per MW ($5.6 billion ÷695 MW) rather than Conawapa at an estimated cost of $5,253,000 per MW ($7.8 billion divided by 1495 MW)?

ANSWER:

Manitoba Hydro notes that Government confirmed, by letter dated January 13, 2011 (a copy of which was filed in the 2010/11, 2011/12 General Rate Application as Exhibit MH-162) its intention to assign responsibility to an independent body for carrying out an Needs For and Alternatives To (NFAT) assessment of major new hydro generation projects. Manitoba Hydro expects that the NFAT process will commence in 2013.

As such, Manitoba Hydro respectfully declines to provide a response to this question at this time.

PUB/MH II-23

Reference: 2012 Annual Report

b) Wuskwatim cost $8,500,000 per MW ($1.7 billion ÷200 MW) please explain why this project was put in place in advance of the other projects when future projects are expected to cost less per MW (per above calculations)?

ANSWER:

As stated in Manitoba Hydro's "Submission To The Manitoba Clean Environment Commission: Need For And Alternatives To The Wuskwatim Project" Volume 1, Wuskwatim was preferred to other options such as Keeyask (Gull), Conawapa and Notigi, for number of reasons, as follows:

- "in part, because they cannot be built as early as 2009…"
- "Proceeding with Wuskwatim does not preclude future development of Gull, Conawapa or Notigi. Should conditions be sufficiently favourable, Wuskwatim could be developed first followed by any or all of the others at later dates."
- "Based on current information, Gull yields a slightly lower rate of return than Wuskwatim and the risks associated with it are considered to be higher, mainly because of its larger size. Similarly, based on current information, Conawapa has nearly as high a rate of return as Wuskwatim but entails more risk because it is many times larger."
- "While Notigi would be smaller than Wuskwatim, Wuskwatim is substantially more economic than Notigi and at this time is judged by Manitoba Hydro to be more ready for development."

In addition the following information is included in the Clean Environment Commission's "Summary Of Public Hearing, Wuskwatim Generation And Transmission Projects", dated October 2004:

- "The Commission has concluded that the Projects represent a viable economic alternative and an in-service date of 2010 should be pursued."

- "The Commission is satisfied that the Projects should proceed prior to Conawapa, Gull/Keeyask and Notigi and notes that none of the Participants challenged the sequencing of hydroelectric generation."

PUB/MH II-24

Reference: 2012 Annual Report

Preamble: Page 55 of the last annual report states "These plans (major construction projects) will involve the investment of approximately $18 billion over the next 10 years which will generate significant returns for Manitobans over the ensuing decades."

a) What is the estimated return on investment (internal rate of return) on each of the proposed investments on a dollar basis and on a yield percentage basis? Please indicate assumptions behind these calculations.

ANSWER:

Manitoba Hydro respectfully declines to provide a response to this question at this time. Review of matters related to Manitoba Hydro's Preferred Development Plan will take place in the context of a Needs For and Alternatives To (NFAT) hearing.

PUB/MH II-25

Reference: Annual Report P. 23 St. Leon Wind Farm

a) Please summarize the terms of the new purchase power agreement with Algonquin Power related to the St. Leon Wind Farm expansion.

ANSWER:

Under the 2011 Power Purchase Agreement, Algonquin Power agreed to expand the existing wind farm at St. Leon by ten turbines with a total capacity of 16.5 MW. Manitoba Hydro agreed to accept and pay for all the energy, capacity and environmental attributes that the wind farm produces over a 25 year term.

Expansion of the St. Leon Wind Farm was initially built with expansion in mind, and did not incur any additional Manitoba Hydro transmission costs.

PUB/MH II-25

Reference: Annual Report P. 23 St. Leon Wind Farm

b) Please provide details of any financing arrangements for the facility expansion.

ANSWER:

Algonquin Power was solely responsible for all financing arrangements for the facility expansion. Those arrangements did not involve Manitoba Hydro.

PUB/MH II-26

Reference: 2012 Annual Report

a) MH proposes building new generation in advance of their requirements for domestic consumption. In this case, does this not make future projects more commercial-like projects, which should require a higher level of equity (40% equity base) with a targeted sales commitments (60%) of capacity immediately after completing the concerned construction project?

ANSWER:

A review of matters related to Manitoba Hydro's proposed plans for new generation will 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 respectively declines to file a response as it relates to investment in new generation requirements.

PUB/MH II-26

Reference: 2012 Annual Report

b) Please discuss the risks faced by MH and how MH plans on mitigating such risk if the USA moved to become self-sufficient in its electricity needs just as it is planning to do with natural gas and oil?

ANSWER:

As a whole, the US is already nearly self sufficient in electricity. According to the US Department of Energy's Energy Information Administration (DOE EIA) Annual Energy Review 2011, the 51 TWh of electricity imports from Canada accounted for about 1.3% of the total 2011 US electricity supply of 3,955 TWh. Hence the US imports electricity from Canada because it is economic to do so in comparison with other supply options, rather than because it has to do so.

Manitoba Hydro's exports have always competed on an economic basis with other alternatives, both in the long term and short term. Manitoba Hydro anticipates that its customers will continue to make such decisions on an economic basis in the future. The trade risks faced by Manitoba Hydro going forward are primarily economic and are manageable through appropriate relationships with government, industry and bilateral contracts.

PUB/MH II-27

Reference: Annual Report, Financial Strength.

Preamble: The annual report states “The debt to equity ratio stands at 74:26, surpassing the target of 75:25”.

Manitoba Hydro has also adopted a strategic plan requiring the maintenance of a 25% equity ratio.

On page 50 of the annual report states as one of its corporate goals “Maintaining the financial strength of the Corporation will ensure that energy rates remain low, stable and predictable. A strong financial structure also assists in protecting the Corporation and its customers from a variety of risks.”

The annual report again in note 17 of page 79 states: "the Corporation monitors its capital structure on the basis of its equity ratio. Manitoba Hydro's current target is to maintain a minimum equity ratio of 25%"

a) What rates would be required to maintain a minimum 25% equity at all times with the anticipated future construction projects based on IFF11-2 and IFF12?

ANSWER:

Please see the response to PUB/MH II-19 for the IFF11-2 scenario. Manitoba Hydro expects that IFF12 will be presented to the MHEB in November 2012. Manitoba Hydro will file IFF12 with the PUB subsequent to the approval by the MHEB.

PUB/MH II-27

Reference: **Annual Report, Financial Strength.**

Preamble: **The annual report states "The debt to equity ratio stands at 74:26, surpassing the target of 75:25".**

Manitoba Hydro has also adopted a strategic plan requiring the maintenance of a 25% equity ratio.

On page 50 of the annual report states as one of its corporate goals "Maintaining the financial strength of the Corporation will ensure that energy rates remain low, stable and predictable. A strong financial structure also assists in protecting the Corporation and its customers from a variety of risks."

The annual report again in note 17 of page 79 states: "the Corporation monitors its capital structure on the basis of its equity ratio. Manitoba Hydro's current target is to maintain a minimum equity ratio of 25%"

b) The potential financial impact of the risks identified on pages 52, 77 and 78 of the annual report exceed Manitoba Hydro's equity, what rates would be required to maintain a higher equity ratio based on a minimum 25% equity on all assets except Wuskwatim, Keeyask and Conawapa where a minimum of 40% equity would be required?

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-26(a).

PUB/MH II-28

Reference: 2012 Annual Report Note 16

Please indicate and discuss the impact on MH's equity when IFRS is adopted, given the current difference between fair value and carrying value of MH's long term debt of approximately $2.3 billion.

ANSWER:

There will be no impact on Manitoba Hydro's equity due to the difference between fair value and carrying value of Manitoba Hydro's long term debt when IFRS is adopted. Under CGAAP, Manitoba Hydro's long term debt is currently classified as "Other Financial Liabilities" and is carried at amortized cost. This basis of accounting will continue under IFRS.

In accordance with IFRS IAS 39.9, the amortized cost of a financial liability is the amount at which the financial liability is measured at initial recognition minus principal repayments, plus or minus the cumulative amortization using the effective interest method. The fair value reported in Note 16 reflects movements in market interest rates and is required for disclosure purposes only.

PUB/MH II-29

Reference: 2012 Annual Report , PUB/MH I-46 (a) (d) & (e)

Note 18 to the Annual Report indicate an accrued benefit liability of $156 million in the pension plan.

a) Please provide the most recent actuarial study for the pension plans

ANSWER:

Please see Appendix 31 for the actuarial valuations prepared at December 31, 2011 for the Manitoba Hydro and Centra Gas pension obligations.

Please note that the $156 million figure quoted in the Information Request, on page 82 of the 2012 Annual Report, relates to the accrued benefit liability with respect to other future employee benefits and not to the pension plan liability. The pension plan accrued benefit obligation with respect to all of Manitoba Hydro's and Centra's pension plans of $1,121 million is reported in the table on page 80 of the 2012 Annual Report.

PUB/MH II-29

Reference: 2012 Annual Report , PUB/MH I-46 (a) (d) & (e)

Note 18 to the Annual Report indicate an accrued benefit liability of $156 million in the pension plan.

b) Is an expected long-term rate of return on plan assets of 7% too optimistic considering a long-term inflation rate of 2%?

ANSWER:

The plan takes a long-term focus with the objective of having sufficient assets to meet future pension obligations. The asset mix for the Manitoba Hydro pension plans emphasizes equities over fixed income which traditionally has enhanced returns.

The expected rate of return is based on the current asset mix and investment strategy and the long-term historical rate of return for the portfolio. While investment experience has been unfavourable in 2 of the last 5 years, the 10 year average historical rate of return is approximately 7%. As economic recovery continues, expectations are that the plan asset return will improve.

It should be noted that upon transition to IFRS, Manitoba Hydro will no longer be using an expected rate of return on plan assets but rather will be applying the discount rate associated with the pension obligation in order to calculate the expected return on plan assets.

PUB/MH II-30

Reference: **2012 Annual Report**

Preamble: **Approximately 1/3 of generated electricity is currently being sold outside the province i.e. 10.3 billion kilowatt hours on a total of 31.1 billion kilowatt hours.**

Manitoba peak load is 4343 MW while capacity is 5878 (5485 MW + 200 MW for Wuskwatim + 116 MW from St. Leon wind farm + 77 MW for improvements on the Kelsey generation station).

Sale agreements:

- **350 MW to Northern States Power – 2015 – 2025**
- **375/325 MW to Xcel Energy- 2015 – 2025**
- **250 MW to Minnesota Power -2020 – 2035**
- **125 MW to Northern States Power – 2021 – 2025**
- **100 MW to Wisconsin Public Service – 2021 – 2027**
- **1,200 MW Subtotal**
- **400 MW potential sales to Wisconsin Public Service (potential)**
- **1,600 MW Grand Total**

a) **Based on the above, is MH therefore building more than the equivalent of Conawapa to supply foreign markets?**

ANSWER:

The sale agreements listed above have various start and end dates and do not all occur over the same period. Please refer to page 5 of Tab 9 for the total winter peak capacity sales.

PUB/MH II-30

Reference: **2012 Annual Report**

Preamble: **Approximately 1/3 of generated electricity is currently being sold outside the province i.e. 10.3 billion kilowatt hours on a total of 31.1 billion kilowatt hours.**

Manitoba peak load is 4343 MW while capacity is 5878 (5485 MW + 200 MW for Wuskwatim + 116 MW from St. Leon wind farm + 77 MW for improvements on the Kelsey generation station).

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- **250 MW to Minnesota Power -2020 – 2035**
- **125 MW to Northern States Power – 2021 – 2025**
- **100 MW to Wisconsin Public Service – 2021 – 2027**
- **1,200 MW Subtotal**
- **400 MW potential sales to Wisconsin Public Service (potential)**
- **1,600 MW Grand Total**

b) **What is the anticipated income from these firm contracts compared to all forecasted operating costs including financing and amortization? If Manitoba Hydro does not want to divulge the terms of each one of these contracts, please provide the total amount of income to be generated from firm energy from all of these contracts combined.**

ANSWER:

Manitoba Hydro considers the income information requested above to be commercially sensitive and confidential as release of this information would harm negotiations between Manitoba Hydro and its export customers. Therefore, Manitoba Hydro respectfully declines to provide this information.

Manitoba Hydro notes that based on IFF11 assumptions, the firm export contracts associated with Manitoba Hydro's Preferred Development Plan (PDP) are expected to generate approximately CAD $9.4 billion of revenues for Manitoba Hydro over their respective terms.

As stated in the response to PUB/MH II-30(a), the sale agreements listed above have various start and end dates and do not all occur over the same period.

In addition, where the above sales agreements are a component of Manitoba Hydro's proposed plans for new generation, the benefits of those sales will be included in the overall evaluation being undertaken in the context of A Needs For and Alternatives To (NFAT) hearing, which process is expected to commence in 2013.

PUB/MH II-31

Reference: 2012 Annual Report

a) Please provide a table indicating the import of electricity from the US and Canada on a year by year basis over the last 10 years including quantity, price and amount spent.

ANSWER:

The table below shows total power purchases (both physical and financial) from 2005/06 to 2011/12, including imports and wind energy. Manitoba Hydro cannot provide disaggregated import information as it would permit the back calculation of wind energy financial amounts which Manitoba Hydro is required to keep confidential.

The dollar amounts include all associated market charges. The average price indicated reflects the average price paid for energy charges only.

	Power Purchases		
	GWh	**$(million)**	**Avg Price in $/MWh**
2005/06	868	31	37.91
2006/07	2249	122	45.81
2007/08	816	35	48.85
2008/09	981	56	48.56
2009/10	1325	32	31.58
2010/11	1132	35	36.71
2011/12	1637	78	47.33

PUB/MH II-31

Reference: 2012 Annual Report

b) Please indicate to what extent MH considers curtailing industrial users (paying a lesser rate) for the purposes of possibly having their electricity consumption curtailed at some point in time in lieu of imports?

ANSWER:

Manitoba Hydro has considered and consulted with large industrial customers on the feasibility and merits of economic load curtailment. Ultimately the Curtailable Rate Program was developed in conjunction with these customers with Terms and Conditions that reflect customer tolerance for a very limited number and duration of curtailments.

It is not feasible to significantly reduce the amount spent on expensive imported energy amounts with curtailable load because customers have a very limited tolerance to the number and duration of curtailments. As a result CRP has been designed for use for reliability events only which occur relatively infrequently.

PUB/MH II-32

Reference: 2012 Annual Report

a) What is the impact on MH's IFF if forecasted growth did not occur over the next 10 years similar to the experience of the last 5 to 7 years?

ANSWER:

Forecasted growth in net firm energy under a low load growth scenario, the 10^{th} percentile of load forecasts, is 1.1% over the first 10 years of the forecast compared to 1.6% in the base forecast. Net firm energy is approximately 1 800 GW.h lower under the low load growth scenario compared to IFF11-2 and delays the requirement for new energy to meet Manitoba demand by 6 years to 2027/28. Due to the long lead time required for hydro resource options, a lower load scenario is not expected to affect the planned in-service date schedule for the resource plan assumed in IFF11-2. The energy not required for Manitoba demand is assumed to be sold in the opportunity export market and the resulting financial impact of a low load scenario is minimal over the 10-year forecast period due to the relatively small difference in domestic customer rates compared to opportunity export prices.

PUB/MH II-33

Reference: Annual Report P. 23 Conawapa Development

Please file a copy of the memorandum of understanding with Fox Lake Cree Nation and indicate if any further agreements have been reached relative to the Conawapa development.

ANSWER:

Review of matters related to the development of the Conawapa 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 respectfully declines to file the Memorandum of Understanding with Fox Lake Cree Nation at this time.

PUB/MH II-34

Reference: Appendix 5.7 P. 6 & 7, 2012 Annual Report.

a) Please confirm that effective April 1, 2013 MH will be increasing the life expectancy for dams, dykes, Weirs and Powerhouses to approximately 120 years with respect to the majority of MH's generation stations. Please provide a listing of the stations impacted, the in-service dates of each station, the proposed new life expectancy and previous life expectancy for each station.

ANSWER:

As disclosed in Note 1 b) and Note 2 to the Consolidated Financial Statements included in the 2012 Annual Report, Manitoba Hydro implemented changes to depreciation rates, component breakdown and average service lives effective April 1, 2011, for the 2011/12 fiscal year. The new depreciation rates were calculated by Gannett Fleming using the ASL procedure for group depreciation with the revised life span dates shown in Schedule 1 to the letter from Gannett Fleming dated January 13, 2012, which is included in Appendix 5.7.

For hydraulic generating stations, the Civil component was broken down into a number of new components, and an average service life was established for each new component as shown in the following table. These average service lives apply to all hydraulic generating stations.

Previous Approved In use until March 31, 2011		**Revised Effective April 1, 2011**	
Civil Components	Average Service Life	Civil Components	Average Service Life
Civil	100	Dams, Dykes & Weirs	125
		Powerhouse	125
		Powerhouse Renovations	25
		Spillway	75
		Water Control Systems	50
		Roads & Site Improvements	50
Composite Weighted Average	100	Composite Weighted Average	104

In addition to the average service life applicable to the depreciable components, each hydraulic generating station has been assigned a life span date. The life span date is used in recognition that there is an overall constraining factor impacting the usefulness of the assets to the Corporation. Except for the Laurie River generating station, the life expectancy of the Powerhouse has been identified as the predominant constraining factor. When the powerhouse itself reaches end of life, all assets contained in the Powerhouse will be retired along with the Powerhouse, regardless of whether the contained items have reached their own end of life. For purposes of establishing a revised life span date, the overall life of a powerhouse is assumed to be 140 years, with exceptions made where conditions at a specific generating station differ from those generally observed.

For the Laurie River, the life expectancy of the turbines and generators has been identified as the predominant constraining factor. It is much less likely that it will be economically feasible to replace the turbines and generators at Laurie River when they reach end of life, as the station produces much less electricity than the other, larger generating stations.

Generating station assets are depreciated over the lesser of the average service life and the remaining years to the life span date.

The following table provides the original in-service date and requested life expectancy information for each hydraulic generating station:

Generating Station	In-Service Date for First Unit	Previous Approved In use until March 31, 2011		Revised Effective April 1, 2011	
		Life Span Date (March 31)	Overall Life Span (Years)	Life Span Date (March 31)	Life Span (Years)
Great Falls	Jan 3, 1923	2052	129	2063	140
Pointe Du Bois	Oct 16, 1911	2015	103	2031	119
Seven Sisters	Jun 3, 1931	2052	120	2072	140
Slave Falls	Sep 1, 1931	2063	131	2072	140
Pine Falls	Dec 12, 1951	2052	100	2092	140
Mcarthur Falls	Nov 26, 1954	2055	100	2095	140
Kelsey	Jun 22, 1960	2062	101	2101	140
Grand Rapids	Sep 1, 1965	2067	101	2091	125
Kettle	Jan 1, 1971	2072	101	2111	140
Laurie River	Sep 18, 1952	2056	103	2032	79
Jenpeg	Jul 1, 1977	2078	100	2118	140
Long Spruce	Oct 1, 1977	2078	100	2118	140
Limestone	Sep 8, 1990	2092	101	2131	140
Wuskwatim	Jan 31, 2012 *			2152	140

* Wuskwatim: Expected in-service date at the time the depreciation study was conducted

Exceptions to the general 140 year life span were made for the following generating stations:

- **Pointe du Bois**: The revised life span date is based on the timing of planned capital work for the Point du Bois Powerhouse Rebuild as included in CEF11-2.
- **Grand Rapids**: The life span has been reduced to reflect differences in the make-up of the concrete used in the construction of the powerhouse, which is deteriorating at a faster rate than at other generating stations.
- **Laurie River**: The revised life span is based on the turbines and generators, and has been established as 2032.

PUB/MH II-34

Reference: Appendix 5.7 P. 6 & 7, 2012 Annual Report.

b) Please provide the supporting rationale for this life expectancy change when none of MH's hydraulic generating stations [excluding Pointe Du Bois] have been in service more than 90 years may have required substantial upgrades.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-82(c).

PUB/MH II-34

Reference: Appendix 5.7 P. 6 & 7, 2012 Annual Report.

c) Please provide a summary of the capital expenditures on upgrades and rehabilitation MH has undertaken on each of its hydraulic generating stations.

ANSWER:

Please refer to the following table for a list of the significant (greater than or equal to $1 million) upgrades and refurbishments made to Dams, Dykes, Weirs and Powerhouses at Manitoba Hydro's hydraulic generating stations. For Pointe du Bois and Slave Falls generating stations, the table includes modifications made since the acquisition of Winnipeg Hydro in 2003:

Component	Year(s)	$ in Millions	Capital Project
Great Falls Generating Station:			
Dams, Dykes & Weirs	1986	8.0	Rehabilitaion - Non-Overflow Dams
	1986	2.7	Rehabilitaion - Dykes
	1986	2.0	Rehabilitaion - Rockfill Dam, East Corewall and Spillway
Powerhouse	1986	4.5	Rehabilitation - Powerhouse
Pointe du Bois:			
Dams, Dykes & Weirs	2004-2005	4.6	East Forebay Wall Anchor
	2006-2008	6.5	Dam Safety Deficiencies
Powerhouse	2005-2010	3.9	Dam Safety Deficiencies
Seven Sisters:			
Dams, Dykes & Weirs	1984	1.9	Rehabilitation - Raising Earth Dykes
	1984	17.8	Rehabilitation - Overflow & Non-Overflow Dams
	2002-2010	2.7	Dam Safety Program
Powerhouse	1997-2000	3.3	Major Concrete Rehabilitaion (Powerhouse)
Slave Falls:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	2005-2010	1.3	Fall Protection Program
Pine Falls:			
Dams, Dykes & Weirs	1998-2011	12.2	Winnipeg River Bank Protection Program
Powerhouse	no significant modifications have been made		

Component	Year(s)	$ in Millions	Capital Project
McArthur Falls:			
Dams, Dykes & Weirs	2005-2011	2.2	Dam Safety Program
Powerhouse	no significant modifications have been made		
Kelsey:			
Dams, Dykes & Weirs	1998-2010	5.4	Dam Safety Upgrades
	2010	1.8	Kelsey Spillway Stability Anchoring
Powerhouse	no significant modifications have been made		
Grand Rapids:			
Dams, Dykes & Weirs	2005-2011	13.5	Dam Safety Program
Powerhouse	no significant modifications have been made		
Kettle:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	2007	2.6	Roof Replacement
Laurie River:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	1995	2.6	Civil Deficencies - Phase 1
	2003-2008	4.7	Civil Deficencies - Phase 2
Jenpeg:			
Dams, Dykes & Weirs	2004-2005	3.8	Kiskitto Ctl.Structure & Dyke 7-2
Powerhouse	2005-2010	1.4	Fall Protection Program
Long Spruce:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	2009	2.9	Roof Replacement
Limestone:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	2009	2.7	Roof Replacement

PUB/MH II-34

Reference: Appendix 5.7 P. 6 & 7, 2012 Annual Report.

d) Please confirm the capital expenditures on rehabilitation and repairs are being depreciated the same rate as the original capital investment.

ANSWER:

Capital expenditures are depreciated over the lesser of the average service life and the years remaining until the life span date. The depreciation rate used for each component is derived by determining the required depreciation expense for the surviving assets of each vintage year, summing those depreciation expense amounts and dividing by the total depreciable base for the component, which results in a single depreciation rate that reflects the varying depreciation periods used for the underlying assets.

PUB/MH II-35

Reference: PUB/MH I-25 (a)

Assuming the preferred capital plan proceeds as currently forecast in IFF11-2

a) Please file copies of MH's public pronouncements and speeches made by MH officials addressing the need for future rate increases to support MH's development plan including the speech made by MH's President to the Winnipeg Chamber of Commerce.

ANSWER:

Please see Appendix 32:

- Attachment 1- Customer Major Accounts Brandon Oct 10 2012
- Attachment 2 - Customer Major Accounts Winnipeg Oct 11 2012
- Attachment 3 - Public Accountability Meeting Thompson Oct 2 2012
- Attachment 4 - Public Accountability Meeting Winnipeg Oct 16 2012
- Attachment 5 - Transmission Distribution Maintenance Management Conference - September 11 2012
- Attachment 6 - Winnipeg Chamber of Commerce - September 19 2012
- Attachment 7 - Winnipeg Chamber of Commerce Speaking Notes - September 19 2012

PUB/MH II-35

Reference: PUB/MH I-25 (a)

Assuming the preferred capital plan proceeds as currently forecast in IFF11-2

b) Please confirm and explain that in the absence of these 3 Major G&T projects MH would not be projecting greater than inflation rate increases out to 2023/24.

ANSWER:

Manitoba Hydro cannot confirm this assertion. The 2011/12 Power Resource Plan indicates that under dependable energy conditions, new generation is required to meet Manitoba load requirements by 2020/21. In the absence of the Keeyask and Conawapa, an alternate source of energy would be required. The evaluation and comparison of alternative resource plans and the associated impacts on customer rates under each plan are expected to be examined in the course of the Need For and Alternatives To hearing process. Bipole III is required for reliability purposes due to the risks associated with a Bipole I and II outage. The Clean Environment Commission has established a process to review the Bipole III project.

As indicated in the response to PUB/MH I-25(a) 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 for 2012/13 and 2013/14.

PUB/MH II-35

Reference: PUB/MH I-25 (a)

Assuming the preferred capital plan proceeds as currently forecast in IFF11-2

c) Please confirm that MH is incurring additional debt and interest charges to fund ongoing expenditures on these major G&T projects in advance of in-service dates.

ANSWER:

Manitoba Hydro can confirm that additional debt and interest charges are being incurred but reiterates that these additional interest charges are capitalized to these projects until in-service. There is no impact to net income or revenue requirement until the projects are placed in-service.

PUB/MH II-35

Reference: PUB/MH I-25 (a)

Assuming the preferred capital plan proceeds as currently forecast in IFF11-2

d) Please confirm that the additional revenue requirements at in-service were previously projected (PUB/MH I-197, PUB Ex#25 (2010 GRA)) to be roughly about:

- **$300 M/yr. for Bipole III**
- **$470 M/yr. for Keeyask G.S.**
- **$700M/yr. for Conawapa G.S.**

ANSWER:

As noted in Manitoba Hydro's response to PUB/MH I-25(a), 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.

PUB/MH II-35

Reference: PUB/MH I-25 (a)

Assuming the preferred capital plan proceeds as currently forecast in IFF11-2

e) Please refile PUB/MH II-90 (b) from the 2011 GRA for Bipole III and provide an update based on current capital cost estimates.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-35(d).

PUB/MH II-35

Reference: PUB/MH I-25 (a)

Assuming the preferred capital plan proceeds as currently forecast in IFF11-2

f) Please provide the same analysis based on IFF11-2 and IFF12 for Wuskwatim, Keeyask and Conawapa.

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH II-35(d) with respect to Keeyask and Conawapa.

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-35

Reference: PUB/MH I-25 (a)

Assuming the preferred capital plan proceeds as currently forecast in IFF11-2

g) Please confirm that a significant (3-5 years) deferral of any one of these projects would allow MH to delay the onset of the ongoing 3.5% rate increase given today's exceptionally good financial status of MH.

ANSWER:

Manitoba Hydro cannot confirm this assertion. Deferral of any one of the three major generation and transmission projects would have no impact on net income, revenue requirement or proposed rate increases until such projects are placed in-service.

As outlined in Tab 2 of the Application, in the absence of the proposed rate increases, Manitoba Hydro is projecting a net loss of $35 million in 2012/13 and a further net loss of $23 million in 2013/14 which is largely attributable to lower prices in the export markets. Please also see the response to PUB/MH I-61(a) which summarizes the need for the rate increases proposed in the current Application.

PUB/MH II-36

Reference: PUB/MH I- 26 (b)

a) Please confirm that MH's new export contracts (with NSP/MP/WPS) in average flow years will consist of approximately 2500 GWh of firm fixed price sales representing approximately 50% of the average output.

ANSWER:

Manitoba Hydro is unclear on what is meant by "average output". Assuming it means "Exportable System Surplus" the average energy volumes associated with Manitoba Hydro's Current Export Contracts (which are shown on page 49 of the 2011/12 Power Resource Plan (Attachment #3)) represent between 41% (2016/17) and 64% (2024/25). Post Conawapa, including Proposed Exports, the ratios vary from 3% (2039/40) to 65% (2034/35).

Manitoba Hydro cannot confirm that all the energy under these contracts is at fixed prices.

PUB/MH II-36

Reference: PUB/MH I- 26 (b)

b) Please confirm that MH's total sales (fixed price and market based price) under MH's new Export Contracts are approximately 50% of the average annual combined output of Keeyask and Conawapa.

ANSWER:

Average annual production from Keeyask and Conawapa is expected to be 4,430 GWh and 7,000 GWh, respectively. As indicated on page 49 of Manitoba Hydro's 2011/12 Power Resource Plan (Attachment #3) Manitoba Hydro's Current and Proposed export contracts represent between 45% (in 2027/28, the first full year of Conawapa production) and 2% (in 2039/40, the last year of the sale agreement to WPS).

PUB/MH II-37

Reference: PUB/MH I-27

a) Given the changes required to IFRS implementation and changes in economic outlook, is it the Corporation's intent to base the rate application on an updated financial forecast based on IFF12? If not, please explain why not.

ANSWER:

The rate increases proposed in the Application are in keeping with Manitoba Hydro's approach to implement regular and modest rate increases to ensure the maintenance of an adequate financial structure. A sufficient level of equity allows the Corporation to withstand the risks and uncertainties inherent in its operations and to address adverse financial consequences outside of its control, and in doing so, promote rate stability and avoid the need for large or sudden rate increases in the future. Accordingly, Manitoba Hydro does not intend to amend its Application to reflect the updated financial forecast in IFF12.

PUB/MH II-38

Reference: PUB/MH I-28 (f)

a) Please update the forecast for finance expense based on more current 2012 vintage external interest rate forecasts.

ANSWER:

As noted in Manitoba Hydro's response to PUB/MH I-28(f), the finance expense forecast based on EO12 will not be available until IFF12 is finalized. Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012.

PUB/MH II-38

Reference: PUB/MH I-28 (f)

b) Please file the response to PUB/MH I-28 (f) when IFF12 is available.

ANSWER:

Manitoba Hydro will file IFF12 with the PUB following approval by the MHEB.

PUB/MH II-39

Reference: PUB/MH I-30 (a) (c) Financial Targets

a) Please update the response to (a) to include IFF12

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-39

Reference: PUB/MH I-30 (a) (c) Financial Targets

b) Please update the response in (c) to include figures for 2012/13 and 2013/14 based on IFF12 (Electric Operations)

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-39

Reference: PUB/MH I-30 (a) (c) Financial Targets

c) Please refile the financial targets in (a) assuming a reduction in capital spending as follows:

2013	**$520 million**
2014	**$760 million**
2015	**$1,200 million**
2016	**$1,600 million**
2017	**$1,800 million**

ANSWER:

Please see Manitoba Hydro's sensitivity analysis on page 16 of IFF11-2 (Appendix 4.2), which provides the one year, five year and nine year impacts of capital expenditure increases of $100 million per year.

PUB/MH II-40

Reference: PUB/MH I-30 (c) PUB/MH I-61 (b) & PUB/MH I-78 (b)

a) Please refile the analysis in PUB/MH I-78 (b) assuming the continuation of rate-regulated accounting based on IFF12, (reflecting the delay in the implementation of IFRS until 2014/15) and the continued use of Average Service Life for depreciation purposes for rate setting. Please provide the electric financial ratios.

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-40

Reference: PUB/MH I-30 (c) PUB/MH I-61 (b) & PUB/MH I-78 (b)

b) Please file another scenario based on (a) excluding the early adoption of IFRS for capitalized overheads on 2012/13 and 2013/14 for rate setting purposes. For further clarity, please reduce OM&A by $27 million in 2012/13 and $63 million for 2013/14 in this scenario.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-40(a).

PUB/MH II-40

Reference: PUB/MH I-30 (c) PUB/MH I-61 (b) & PUB/MH I-78 (b)

c) Please provide a comparison of the impacts on financial results and financial targets for 2012/13 through 2014/15 comparing IFF12 from part (a) with IFF11-2 per the application.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-40(a).

PUB/MH II-41

Reference: PUB/MH I-30 (b) Financial Target Comparisons

Please file an update to the response including IFF12

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-42

Reference: PUB/MH I-32 (a)

Please provide the supporting calculations behind the increase in interest rate risk in year 7 and Year 11 in IFF11-2 over IFF10-2.

ANSWER:

As the interest rate risk in years 7 and 11 are cumulative to that period, the attached schedules provide a breakdown of the impacts to finance expense, depreciation and amortization, and capital and other taxes for each forecast year.

IFF11-2 +1% INTEREST RATE SENSITIVITY COMPARED TO BASE CASE
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Total
New Long-Term Debt Issued:												
IFF11	200	1,000	1,600	1,400	2,000	2,000	2,600	1,800	1,800	2,000	1,800	18,200
Interest +1%	200	1,000	1,600	1,600	2,000	2,000	2,800	2,000	1,800	2,200	2,000	19,200
New Long-Term Debt Interest Rate:												
IFF11	3.75%	3.70%	4.05%	5.40%	5.90%	6.20%	6.40%	6.40%	6.40%	6.40%	6.40%	
Interest +1%	3.75%	4.70%	5.05%	6.40%	6.90%	7.20%	7.40%	7.40%	7.40%	7.40%	7.40%	
Change in Net Finance Expense:												
Gross Interest on New Long-Term Debt	0	3	18	36	58	85	114	145	179	227	243	1,108
Gross Interest on Short-Term Debt	0	1	1	2	0	0	(0)	2	0	(0)	1	7
Gross Interest on Existing Floating Rate Debt	0	10	14	12	11	8	6	4	4	4	4	76
Provincial Guarantee Fee	0	0	0	0	1	1	2	4	5	7	9	29
Interest on Assets Under Construction	0	(21)	(30)	(38)	(49)	(64)	(71)	(68)	(79)	(45)	(55)	(521)
Interest Income	0	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(7)
Total Change in Net Finance Expense	0	(7)	3	11	21	29	51	86	108	191	199	693
Cumulative Change in Net Finance Expense	0	(7)	(4)	8	28	57	108	194	302	494	693	
Depreciation and Amortization	0	0	0	0	1	1	2	3	3	6	6	21
Capital and Other Taxes	0	0	0	0	1	1	1	2	2	1	2	10
Net Income	(0)	7	(4)	(12)	(22)	(31)	(54)	(90)	(113)	(198)	(206)	(724)
Retained Earnings	(0)	7	3	(9)	(30)	(61)	(115)	(205)	(319)	(517)	(724)	

IFF11-2 -1% INTEREST RATE SENSITIVITY COMPARED TO BASE CASE
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**10-Year Total**
New Long-Term Debt Issued:												
IFF11	200	1,000	1,600	1,400	2,000	2,000	2,600	1,800	1,800	2,000	1,800	18,200
Interest -1%	200	1,000	1,600	1,400	1,800	2,000	2,600	1,600	1,400	2,000	1,400	17,000
New Long-Term Debt Interest Rate:												
IFF11	3.75%	3.70%	4.05%	5.40%	5.90%	6.20%	6.40%	6.40%	6.40%	6.40%	6.40%	
Interest -1%	3.75%	2.70%	3.05%	4.40%	4.90%	5.20%	5.40%	5.40%	5.40%	5.40%	5.40%	
Change in Net Finance Expense:												
Gross Interest on New Long-Term Debt	0	(4)	(18)	(35)	(57)	(80)	(104)	(138)	(166)	(208)	(218)	(1,029)
Gross Interest on Short-Term Debt	0	(1)	(1)	(1)	(0)	(1)	(2)	(0)	(1)	(1)	(1)	(10)
Gross Interest on Existing Floating Rate Debt	0	(10)	(14)	(12)	(11)	(8)	(6)	(4)	(4)	(4)	(4)	(76)
Provincial Guarantee Fee	0	0	(0)	(0)	(1)	(1)	(2)	(3)	(5)	(6)	(8)	(27)
Interest on Assets Under Construction	(0)	21	29	37	47	62	68	63	74	42	52	495
Interest Income	0	1	0	0	0	0	1	1	1	1	1	7
Total Change in Net Finance Expense	(0)	6	(4)	(12)	(22)	(27)	(47)	(81)	(100)	(176)	(178)	(641)
Cumulative Change in Net Finance Expense	(0)	6	2	(9)	(32)	(59)	(105)	(187)	(287)	(463)	(641)	
Depreciation and Amortization	0	(0)	(0)	(0)	(1)	(1)	(2)	(3)	(3)	(5)	(6)	(21)
Capital and Other Taxes	0	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(1)	(1)	(9)
Net Income	0	(6)	4	13	23	29	49	86	105	183	185	671
Retained Earnings	0	(6)	(2)	11	34	63	112	198	303	486	671	

IFF10-2 +1% INTEREST RATE SENSITIVITY COMPARED TO BASE CASE
(In Millions of Dollars)

For the year ended March 31	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**10-Year Total**
New Long-Term Debt Issued:												
IFF10-2	600	600	800	1,400	1,600	2,000	1,800	2,400	2,000	1,800	1,600	16,600
Interest +1%	600	600	800	1,600	1,400	2,000	2,000	2,600	2,200	2,000	1,600	17,400
New Long-Term Debt Interest Rate:												
IFF10-2	4.20%	4.35%	5.25%	5.55%	5.90%	6.30%	6.60%	6.60%	6.60%	6.60%	6.60%	
Interest +1%	4.20%	5.35%	6.25%	6.55%	6.90%	7.30%	7.60%	7.60%	7.60%	7.60%	7.60%	
Change in Net Finance Expense:												
Gross Interest on New Long-Term Debt	0	6	10	26	41	60	85	113	146	182	227	896
Gross Interest on Short-Term Debt	0	(0)	2	(1)	1	2	1	0	1	(0)	(0)	5
Gross Interest on Existing Floating Rate Debt	0	12	13	12	10	9	7	6	4	4	4	81
Provincial Guarantee Fee	0	0	0	0	1	1	2	2	4	5	7	22
Interest on Assets Under Construction	0	(23)	(21)	(30)	(37)	(49)	(69)	(76)	(74)	(87)	(54)	(518)
Interest Income	0	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(4)	(4)	(4)	(26)
Total Change in Net Finance Expense	0	(7)	2	6	14	21	25	44	78	100	179	461
Cumulative Change in Net Finance Expense	0	(7)	(5)	1	15	36	60	104	182	282	461	
Depreciation and Amortization	0	0	0	0	1	1	1	2	3	3	6	18
Capital and Other Taxes	0	0	0	0	0	1	1	1	2	2	2	9
Net Income	0	7	(3)	(7)	(15)	(22)	(27)	(47)	(82)	(106)	(187)	(488)
Retained Earnings	0	7	5	(2)	(17)	(39)	(66)	(113)	(195)	(301)	(488)	

IFF10-2 -1% INTEREST RATE SENSITIVITY COMPARED TO BASE CASE
(In Millions of Dollars)

For the year ended March 31	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**10-Year Total**
New Long-Term Debt Issued:												
IFF10-2	600	600	800	1,400	1,600	2,000	1,800	2,400	2,000	1,800	1,600	16,600
Interest -1%	600	600	800	1,400	1,400	2,000	1,600	2,400	1,800	1,600	1,400	15,600
New Long-Term Debt Interest Rate:												
IFF10-2	4.20%	4.35%	5.25%	5.55%	5.90%	6.30%	6.60%	6.60%	6.60%	6.60%	6.60%	
Interest +1%	4.20%	3.35%	4.25%	4.55%	4.90%	5.30%	5.60%	5.60%	5.60%	5.60%	5.60%	
Change in Net Finance Expense:												
Gross Interest on New Long-Term Debt	0	(4)	(11)	(23)	(38)	(59)	(82)	(107)	(137)	(169)	(210)	(842)
Gross Interest on Short-Term Debt	(0)	(1)	(0)	(1)	(2)	(1)	(2)	(2)	(3)	(2)	(2)	(18)
Gross Interest on Existing Floating Rate Debt	0	(12)	(13)	(12)	(10)	(9)	(7)	(6)	(4)	(4)	(4)	(81)
Provincial Guarantee Fee	0	0	(0)	(0)	(1)	(1)	(2)	(3)	(4)	(5)	(7)	(23)
Interest on Assets Under Construction	0	23	21	30	36	48	68	74	72	84	54	509
Interest Income	0	1	1	2	1	2	2	3	3	4	4	23
Total Change in Net Finance Expense	(0)	8	(3)	(5)	(13)	(21)	(23)	(42)	(73)	(93)	(165)	(431)
Cumulative Change in Net Finance Expense	(0)	8	5	0	(13)	(34)	(57)	(99)	(173)	(266)	(431)	
Depreciation and Amortization	0	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(3)	(3)	(6)	(18)
Capital and Other Taxes	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(1)	(9)
Net Income	(0)	(8)	3	6	14	22	25	45	78	99	173	458
Retained Earnings	(0)	(8)	(5)	1	16	38	63	109	186	285	458	

PUB/MH II-43

Reference: PUB/MH I-34 (b) & (d) Equity Financial Targets

"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."

a) Please indicate what the Corporations minimum Debt to Equity target is during major investments in the generation and transmission system.

ANSWER:

At this time, Manitoba Hydro has not changed its debt to equity target.

Please see the response to CAC/MH II-53(a) for a discussion of the financial target review that is being undertaken by Manitoba Hydro.

PUB/MH II-43

Reference: PUB/MH I-34 (b) & (d) Equity Financial Targets

"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."

b) Please explain what actions the Corporation is contemplating or has undertaken to maintain as close to the target as possible given the deterioration in the ratio indicated in the IFF.

ANSWER:

During the period of investment in major generation and transmission, Manitoba Hydro will endeavor to maintain retained earnings and financial ratios at acceptable levels by making annual contributions to retained earnings through a combination of continued cost control and expenditure deferral, maximizing export sales and through regular and reasonable domestic rate increases that properly reflect the risks that the Corporation faces.

PUB/MH II-44

Reference: PUB/MH I-34 (c) & (f) Equity Financial Targets

a) Please file an IFF indicating the required rate increases to maintain 75:25 throughout the forecast period.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-19.

PUB/MH II-44

Reference: PUB/MH I-34 (c) & (f) Equity Financial Targets

b) Please file an IFF scenario indicating the required rate increase to maintain a 75:25 debt to equity ratio maintaining a capital coverage ratio of 1.0 throughout the forecast period.

ANSWER:

Please see the response to PUB/MH II-19. Maintaining a debt to equity ratio of 75:25 and a capital coverage ratio of 1.0 is not possible. In the response to PUB/MH II-19, the capital coverage ratio ranges from a low of 1.04 to a high of 3.26.

Please see Manitoba Hydro’s response to PUB/MH I-23 for an IFF scenario that includes the rate increases necessary to maintain a capital coverage of 1.0 throughout the forecast period.

PUB/MH II-44

Reference: PUB/MH I-34 (c) & (f) Equity Financial Targets

c) File an alternative IFF scenario indicating the required rate increases assuming the following reductions in capital spending in the forecast:

2013	**$520 million**
2014	**$760 million**
2015	**$1,200 million**
2016	**$1,600 million**
2017	**$1,800 million**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-39(c).

PUB/MH II-45

Reference: PUB/MH I-34 (c) & (g) Capital Cost Escalations

a) Please file an alternative IFF scenario assuming a 30% increase in the capital costs of the major projects and detail the impact on debt levels, finance cost based on the current forecast average annual rate increases.

ANSWER:

With respect to the impact on retained earnings and related annual rate impacts associated with an increase of $100 million in capital expenditures, please see the sensitivity analysis shown in table in the Risk Analysis section at page 16 of IFF11-2.

PUB/MH II-45

Reference: PUB/MH I-34 (c) & (g) Capital Cost Escalations

b) Please file an alternative IFF scenario assuming a 30% increase in the capital costs of the major projects as in (a) and detail the impact on debt levels, finance cost and the need for changed average annual rate increases assuming no further degradation in currently forecast financial targets based on IFF11-2 base forecast.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-45(a).

PUB/MH II-45

Reference: PUB/MH I-34 (c) & (g) Capital Cost Escalations

c) Please file an alternative IFF scenario based on (b) assuming the maintenance of the Debt to Equity ratio based on the levels set out in PUB/MH I-34 (c).

ANSWER:

Please see Manitoba Hydro response to PUB/MH II-45(a).

PUB/MH II-46

Reference: PUB/MH I-35 (b)

a) Please provide an update of the charts provided including IFF12.

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-46

Reference: PUB/MH I-35 (b)

b) Please provide table's detailing the data points in the charts.

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-47

Reference: PUB/MH I-36 (e) - Aging Infrastructure

a) Please provide further details quantifying the estimate of $50 million in expenditures by item by year.

ANSWER:

The estimate of $50 million annual expenditure for distribution asset maintenance is an average estimate of the required increase in investment in eight critical asset categories on the distribution system. The required average annual increase in investment can be broken down by the eight critical asset categories as follows:

Cables	43%
Manholes	3%
Duct Lines	7%
Padmount Transformers	0%
Poles	36%
Overhead Conductors	6%
Overhead Transformers	1%
Streetlights	4%

The anticipated increase in maintenance expenditures is presently being refined based on updated asset condition information.

PUB/MH II-47

Reference: PUB/MH I-36 (e) - Aging Infrastructure

b) Please indicate the revenue requirement impacts on each year of the IFF11-2 related to this anticipated expenditure.

ANSWER:

Assuming that the incremental $50 million in expenditures, commencing in 2012/13, is mainly capitalized, the following schedule provides the estimated annual revenue requirement impacts.

Estimated Revenue Requirement Impacts of Incremental $50 Million Capital Expenditures per Year
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Operating and Administrative	-	-	-	-	-	-	-	-	-	-	-
Finance Expense	-	0	2	6	10	16	21	26	32	39	45
Depreciation and Amortization	-	0	2	3	4	6	7	9	10	11	13
Water Rentals and Assessments	-	-	-	-	-	-	-	-	-	-	-
Fuel and Power Purchased	-	-	-	-	-	-	-	-	-	-	-
Capital and Other Taxes	-	0	0	1	1	1	1	2	2	2	2
Revenue Requirement Impacts	-	1	5	10	15	23	29	36	44	52	60
Net Income	-	(1)	(5)	(10)	(15)	(23)	(29)	(36)	(44)	(52)	(60)
Retained Earnings	-	(1)	(5)	(15)	(31)	(53)	(82)	(119)	(163)	(215)	(275)

PUB/MH II-47

Reference: PUB/MH I-36 (e) - Aging Infrastructure

c) Please provide a quarterly breakdown of the Table 2 HVDC – Bipole I & II Availability for the 2005 to 2012 period.

ANSWER:

Please see Tables 1 and 2 below.

Table 1. Bipole I availability by calendar year quarters.

BIPOLE I AVAILABILITY					
Calendar Year	**1st Quarter**	**2nd Quarter**	**3rd Quarter**	**4th Quarter**	**Annual**
2005	98.5	97.5	95.3	93.0	96.1
2006	94.2	96.5	93.7	96.2	95.1
2007	99.1	92.6	95.1	98.2	96.3
2008	99.2	92.3	96.9	98.5	96.7
2009	98.4	96.2	97.9	98.4	97.7
2010	99.6	94.2	96.6	90.5	95.2
2011	99.5	93.0	99.2	93.4	96.3

Table 2. Bipole II availability by calendar year quarters.

BIPOLE II AVAILABILITY					
Calendar Year	**1st Quarter**	**2nd Quarter**	**3rd Quarter**	**4th Quarter**	**Annual**
2005	97.1	98.3	98.6	93.3	96.8
2006	98.8	95.1	98.3	98.0	97.6
2007	99.0	92.0	97.1	98.2	96.6
2008	98.7	96.9	95.4	96.6	96.9
2009	97.3	95.1	97.8	98.5	97.2
2010	98.5	92.4	89.9	97.9	94.7
2011	97.6	95.3	98.5	92.7	96.0

PUB/MH II-47

Reference: PUB/MH I-36 (e) - Aging Infrastructure

d) Please provide an indication of the availability of Bipoles I & II during the 2002/03 and 2003/04-drought period.

ANSWER:

Please see the extended table below

HVDC Energy Availability (%)		
Calendar Year	Bipole I	Bipole II
2004	**93.3**	**96.9**
2003	**93.0**	**94.3**
2002	**97.0**	**78.4**[a]

*The decreased availability was primarily due to two convertor transformers that failed in late 2001.

PUB/MH II-48

Reference: PUB/MH I-38 (a) & (b)/CAC/MH I-39 (b)

a) Please provide an updated table incorporating forecasts for 2012/13 , 2013/14 and 2014/15. In that table to allow for a meaningful comparison revise the EFT per customer to EFT per 10,000 customers. Please also supplement the schedule with each of the measures based on EFT's (ST & OT)

ANSWER:

Please see the following tables for the requested information.

Data Table	Actual								Forecast		
	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EFT (ST & OT)	5,870	5,978	5,988	6,071	6,276	6,429	6,594	6,608	6,842	6,842	6,842
GWh of domestic Supply	22,452	22,622	23,327	23,985	24,285	23,295	23,783	23,499	24,324	24,645	24,935
GWh of total Supply	31,548	37,620	32,132	35,354	34,528	33,961	34,102	33,235	29,379	31,054	31,040
Electric Customers	505,666	509,791	516,861	521,599	527,472	532,359	537,299	542,681	549,150	555,651	562,303
Domestic revenue (in millions)	939	984	1,024	1,075	1,127	1,145	1,200	1,191	1,336	1,399	1,463
Wages & Salaries (in thousands - ST & OT)	353,175	368,827	382,140	399,399	422,432	455,222	472,895	502,737	530,521	541,131	551,954
Benefits (in thousands - ST & OT)	76,628	79,188	82,163	85,865	90,682	97,226	100,601	108,240	123,610	126,082	128,604

Information Requested	Actual								Forecast		
	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EFT (ST & OT)	5,870	5,978	5,988	6,071	6,276	6,429	6,594	6,608	6,842	6,842	6,842
EFT (ST & OT) per 1000 GWh of domestic supply	261.43	264.26	256.69	253.12	258.43	275.98	277.26	281.20	281.29	277.62	274.39
EFT (ST & OT) per 1000 GWh of total supply	186.06	158.91	186.35	171.72	181.77	189.31	193.36	198.83	232.89	220.33	220.43
EFT (ST & OT) per 10,000 domestic customers	116.08	117.27	115.85	116.39	118.98	120.76	122.72	121.77	124.59	123.13	121.68
EFT (ST & OT) per $ millions of domestic revenue	6.25	6.08	5.85	5.65	5.57	5.62	5.49	5.55	5.12	4.89	4.68
Average Salary & Benefits per EFT (ST & OT)	$ 73,224	$ 74,942	$ 77,543	$ 79,931	$ 81,758	$ 85,931	$ 86,972	$ 92,460	$ 95,605	$ 97,517	$ 99,468
Annual Wage Rate Adjustment		2.4%	3.4%	2.9%	2.1%	4.8%	1.5%	6.3%	2.2%	2.0%	2.0%

PUB/MH II-48

Reference: PUB/MH I-38 (a) & (b)/CAC/MH I-39 (b)

b) For each of the years provide Average Salary and Benefits per (ST & OT) EFT.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-48(a).

PUB/MH II-48

Reference: PUB/MH I-38 (a) & (b)/CAC/MH I-39 (b)

c) Please supplement the answer to CAC/MH I-39 (b) to include average benefits the change in wages and benefits and annual percentage increase per EFT. Provide Manitoba CPI in each year.

ANSWER:

As per CAC/MH I-39 (b):

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual Increase
Average W&S/EFT	$63,646	$66,716	$67,736	$72,017	$73,604	$75,076	
Annual Dollar Increase		$3,071	$1,019	$4,281	$1,587	$1,472	$2,286
Annual % Increase		4.8%	1.5%	6.3%	2.2%	2.0%	3.2%

The schedule below includes average benefits. The Manitoba CPI is displayed below the schedule.

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual Increase
Average W&S & Benefits/EFT	$78,568	$82,283	$83,466	$88,741	$92,385	$94,233	
Annual Dollar Increase		$3,715	$1,183	$5,275	$3,644	$1,848	$3,133
Annual % Increase		4.7%	1.4%	6.3%	4.1%	2.0%	3.7%
Manitoba CPI	2.2%	0.6%	1.0%	2.8%	2.0%	2.0%	

PUB/MH II-48

Reference: PUB/MH I-38 (a) & (b)/CAC/MH I-39 (b)

d) Please explain why the annual increase in average salary and benefits in 2011/12 is significantly higher than inflation.

ANSWER:

The annual increase in average salary and benefits in 2011/12 reflects the impact of negotiated contract settlements, merit and payments to align certain classifications within the existing salary structure. Benefit costs also increased due to the impact of the change in the discount rate on pension and other benefits.

PUB/MH II-48

Reference: PUB/MH I-38 (a) & (b)/CAC/MH I-39 (b)

e) Please provide MH's overtime policy.

ANSWER:

Manitoba Hydro's unionized employees are eligible for overtime compensation at the rate of double time for all hours they are directed to work in excess of normal daily or weekly scheduled hours. Employees can choose to bank up to 80 hours of overtime compensation each vacation year to be taken as time off. Management employees are generally expected to work the time necessary to perform their management responsibilities. However, provisions for paid overtime, or time-off in lieu, are made in exceptional circumstances.

PUB/MH II-49

Reference: PUB/MH I-38 (e)

a) For the years 2004/05 through 2014/15 please refile the schedule to include a comparison of the EFT's capitalized with the reported construction EFT's in MH's annual report for the years 2004/05 through 2011/12 actual and that forecast for 2012/13 through 2013/15 .

ANSWER:

The following table has been updated for additional fiscal year information from 2004/05 to 2006/07, as well as construction EFTs as calculated in the annual report.

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual
Labour and Benefits	$423 093	$440 473	$457 233	$477 838	$509 592	$541 307
Labour & Benefits Capitalized						
in dollars	$153 400	$164 900	$171 100	$185 900	$193 500	$207 600
as a percentage of total Labour and Benefits	36%	37%	37%	39%	38%	38%
EFTs (S/T & O/T) capitalized	2 135	2 244	2 247	2 369	2 397	2 479
Construction EFTs (per Annual Report)	1 098	1 154	1 161	1 107	1 266	1 424

	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Labour and Benefits	$571,238	$611,356	$642,542	$655,393
Labour & Benefits Capitalized				
in dollars	$221,200	$246,800	$264,400	$269,700
as a percentage of total Labour and Benefits	39%	40%	41%	41%
EFTs (S/T & O/T) capitalized	2 566	2 678	2 825	2 825
Construction EFTs (per Annual Report)	1 439	1 693	1 531	1 531

Note: The Construction EFTs (per Annual Report) are point-in-time EFTs only (i.e. EFTs at March 31 of the respective years).

PUB/MH II-49

Reference: PUB/MH I-38 (e)

b) Please describe the methodology used for determining the reported EFT's in the annual report.

ANSWER:

The construction EFTs reported in the Annual Report are calculated by taking the total straight-time hours charged to capital for the month of March and dividing this amount by the hours available for one EFT in that month. Please note that construction EFTs reported in the Annual Report do not include overtime EFTs as well as EFTs who provide a support function related to Manitoba Hydro's capital program.

PUB/MH II-50

Reference: PUB/MH I-39 (a), PUB/MH I-134,CAC/MH I-15 (a)

a) Please provide the assumed long term and short term debt supporting calculations for finance expense.

ANSWER:

Please see the following schedule.

WUSKWATIM POWER LIMITED PARTNERSHIP
Summary of Debt Balances and Finance Expense
($Millions)

For the fiscal years ending March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
[1] Project Debt	998	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002
[2] Long Term Debt	0	50	100	100	100	100	100	100	100	100
Short Term Debt	31	21	3	16	(3)	(18)	(33)	(56)	(81)	(115)
Interconnection Credit Facility	296	295	294	292	291	290	288	286	285	283
Sinking Fund Assets	(8)	(18)	(30)	(42)	(54)	(68)	(81)	(96)	(111)	(126)
Effective Interest Rates:										
WPLP Weighted Average GS Debt Rate	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
MH Long Term Debt Rate	4.70%	5.05%	6.40%	6.90%	7.20%	7.40%	7.40%	7.40%	7.40%	7.40%
MH Short Term Debt Rate	2.25%	3.20%	4.80%	5.05%	5.25%	5.30%	5.30%	5.30%	5.30%	5.30%
Weighted Average Transmission Debt Rate	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
MH Sinking Fund Rate	1.60%	2.45%	4.05%	4.30%	4.50%	4.55%	4.55%	4.55%	4.55%	4.55%
[3] Interest on Project Debt	39	53	53	53	53	53	53	53	53	53
[3] Interest on Long Term Debt	9	1	3	7	7	7	7	7	7	7
[3] Interest on Short Term Debt	1	1	1	0	(0)	(1)	(2)	(3)	(4)	(5)
[3] Interest on Interconnection Credit Facility	17	17	17	16	16	16	16	16	16	16
[4] Interest Income	(0)	(0)	(1)	(1)	(2)	(2)	(3)	(4)	(4)	(5)

Notes:

[1] Total outstanding advances for 75% of the total capital requirements up to in-service.

[2] Revolving credit facility for additional capital requirements following in-service.

[3] Interest = Average of prior and current year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

[4] Interest = Prior year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

WUSKWATIM POWER LIMITED PARTNERSHIP
Summary of Debt Balances and Finance Expense
($Millions)

For the fiscal years ending March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
[1] Project Debt	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002
[2] Long Term Debt	100	100	100	100	100	100	100	100	100	100
Short Term Debt	(199)	(176)	(189)	(181)	(184)	(186)	(186)	(185)	(184)	(181)
Interconnection Credit Facility	281	279	277	274	272	269	266	264	260	257
Sinking Fund Assets	(142)	(159)	(176)	(194)	(213)	(233)	(253)	(274)	(296)	(319)
Effective Interest Rates:										
WPLP Weighted Average GS Debt Rate	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%
MH Long Term Debt Rate	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
MH Short Term Debt Rate	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%
Weighted Average Transmission Debt Rate	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
MH Sinking Fund Rate	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%
[3] Interest on Project Debt	53	53	53	53	53	53	53	53	53	53
[3] Interest on Long Term Debt	7	7	7	7	7	7	7	7	7	7
[3] Interest on Short Term Debt	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
[3] Interest on Interconnection Credit Facility	16	16	16	15	15	15	15	15	15	15
[4] Interest Income	(6)	(6)	(7)	(8)	(9)	(9)	(10)	(11)	(12)	(13)

Notes:

[1] Total outstanding advances for 75% of the total capital requirements up to in-service.

[2] Revolving credit facility for additional capital requirements following in-service.

[3] Interest = Average of prior and current year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

[4] Interest = Prior year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

PUB/MH II-50

Reference: PUB/MH I-39 (a), PUB/MH I-134,CAC/MH I-15 (a)

b) Please indicate the total internally generated funds assumed to be used for this project. Provide detailed calculations in support of the estimate.

ANSWER:

Please see the attached schedule.

Manitoba Hydro
Analysis of Wuskwatim Project Sources and Uses of Cash Flows
Based on actuals available to March 31, 2011 and forecast based on IFF11-2

			Total	2012/13	2011/12	2010/11	2009/10	2008/09	2007/08	2006/07	2005/06	2004/05	2003/04 & Prev.
1	Total Capital Expenditures		8,132	1,244	1,114	1,134	1,117	932	869	680	522	520	
2	Less Total Base Capital		(3,659)	(453)	(458)	(477)	(438)	(388)	(391)	(383)	(311)	(361)	
3	**Total MNG&T Capital**	(2 -1)	**4,473**	**791**	**656**	**657**	**679**	**544**	**478**	**297**	**211**	**159**	
4	Total Wuskwatim Capital (Generation & Transmission)		1,672	71	213	326	367	254	207	77	36	36	85
5	% Total Wuskatim Capital/ Total MNG&T Capital	(4 / 3)	37%	9%	32%	50%	54%	47%	43%	26%	17%	23%	
6	Cash Flow from Operations		5,032	537	427	572	589	688	633	443	710	433	
7	Less Total Base Capital		(3,659)	(453)	(458)	(477)	(438)	(388)	(391)	(383)	(311)	(361)	
8	**Total Surplus Cash Flow from Operations for MNG&T Capital**	(6 - 7)	**1,373**	**84**	**(31)**	**95**	**151**	**300**	**242**	**60**	**399**	**72**	
9	Total Surplus Cash Flow from Operations Attributed to Wuskwatim Capital	(5 * 8)	481	8	-	47	82	140	105	16	68	16	-
10	Total Financing Activities Attributed to Wuskwatim Capital		1,191	64	213	279	285	114	102	61	(32)	20	85
11	**Total Wuskwatim Capital** (Generation & Transmission)		**1,672**	**71**	**213**	**326**	**367**	**254**	**207**	**77**	**36**	**36**	**85**
12	**Total IGF Allocated to Wuskwatim/Total Wuskwatim Capital Cost**	**(9 / 10)**	**29%**	**29%**	**30%**	**34%**	**40%**	**50%**	**46%**	**43%**	**54%**	**13%**	**0%**

PUB/MH II-50

Reference: PUB/MH I-39 (a), PUB/MH I-134,CAC/MH I-15 (a)

c) Please provide detail breakdown of current and other assets in WPLP IFF11-2.

ANSWER:

Please see the following schedule.

WUSKWATIM POWER LIMITED PARTNERSHIP
Summary of Current and Other Assets
($Millions)

For the fiscal years ending March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Sinking Fund Investments	0	8	18	30	42	54	68	81	96	111	126
Unamortized Deferred Transmission (incl. interest capitalized)	297	291	285	279	273	267	261	255	249	243	237
Total Current & Other Assets	297	299	303	308	315	321	329	336	345	353	363

WUSKWATIM POWER LIMITED PARTNERSHIP
Summary of Current and Other Assets
($Millions)

For the fiscal years ending March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Sinking Fund Investments	142	159	176	194	213	233	253	274	296	319
Unamortized Deferred Transmission (incl. interest capitalized)	231	225	219	213	207	201	195	189	183	177
Total Current & Other Assets	373	384	395	407	420	433	448	463	479	496

PUB/MH II-50

Reference: PUB/MH I-39 (a), PUB/MH I-134, CAC/MH I-15 (a)

d) Please indicate how the debt for Wuskwatim transmission is being recovered from WPLP.

ANSWER:

The Partnership will repay the total outstanding amount under the interconnection credit facility by making semi-annual blended payments of interest and principal based on an amortization period of fifty years. The liability related to Wuskwatim transmission is reflected in Current & Other Liabilities on the projected balance sheet of WPLP.

PUB/MH II-51

Reference: PUB/MH I-40 (c) JKDA Disbursements

Please indicate the amount of payments to be made under Adverse Effects as well as detail of any amounts contemplated to be paid out under direct negotiated contracts by partner.

ANSWER:

The amount of Adverse Effects payments are documented in the Keeyask Adverse Effects Agreements posted on the Keeyask Hydropower Limited Partnership website:

http://keeyask.com/wp/the-partnership

The KCNs have the opportunity to negotiate up to $203.1 million of direct negotiated contracts related to the Keeyask project. Contract details and allocations are outlined in JKDA Schedule 13-1 on Manitoba Hydro's website:

http://www.hydro.mb.ca/projects/keeyask/pdf/Schedule_13_1_090529.pdf

PUB/MH II-52

Reference: PUB/MH I-42 (a) Capitalized Overheads

"CGAAP handbook section 3061 currently allows for the capitalization of overhead costs directly attributable to the construction or development activity is allowed under CGAAP (as acknowledged by MH's response to PUB/MH I-79). The Corporation has indicated that it has made the changes to be more consistent with IFRS (as indicated in its response to PUB/MH I-44 (a)) and through consultations with other Canadian Utilities."

a) Please confirm that for rate setting purposes CGAAP allows the continued capitalization of overhead costs in 2011/12 and 2012/13 and 2013/14, and that the change proposed in this rate application is to move towards an IFRS standard which is currently to be delayed until 2014/15.

ANSWER:

CGAAP does permit the continued capitalization of certain overhead costs in 2011/12, 2012/13 and 2013/14 where a direct relationship to a capital project can be determined.

As described in the response to PUB/MH I-79(a), historically utilities applying CGAAP utilized a full cost accounting approach whereby common overhead charges such as depreciation on head office buildings were included in the cost of capital items. This interpretation and application of CGAAP was accepted by external auditors as it was consistent across the industry and thus, promoted comparability amongst the financial results of Canadian utilities.

The interpretation and application of CGAAP by utilities has changed over the years such that there has been a reduction in the general and indirect overheads that are being capitalized today as compared to the past.

As indicated in PUB/MH I-79(a), changes to Manitoba Hydro's overhead capitalization practices implemented to date and proposed for 2012/13 recognize industry trends to move away from full cost accounting and are designed to make Manitoba Hydro's practices consistent with those of other Canadian utilities. Manitoba Hydro does not consider these changes as an early adoption of the requirements of IFRS. These changes are fully compliant with Canadian GAAP and have been endorsed by Manitoba Hydro's external auditors.

PUB/MH II-52

Reference: PUB/MH I-42 (a) Capitalized Overheads

"CGAAP handbook section 3061 currently allows for the capitalization of overhead costs directly attributable to the construction or development activity is allowed under CGAAP (as acknowledged by MH's response to PUB/MH I-79). The Corporation has indicated that it has made the changes to be more consistent with IFRS (as indicated in its response to PUB/MH I-44 (a)) and through consultations with other Canadian Utilities."

b) Please provide details of the consultations undertaken and a description of the accounting policies followed by the organizations, which MH consulted. In each case please indicate whether the organization is regulated based on Rate Base or on a Cost of Service Basis and the regulators approval of such changes.

ANSWER:

Manitoba Hydro's consultations with other Canadian utilities as to their overhead capitalization practices involved primarily a review of publicly available information such as utilities financial statements and requests for information from members of the Canadian Electrical Association (CEA) on current and expected capitalization practices. The results of Manitoba Hydro's review were then discussed with its external auditors and its IFRS consultant. The response to PUB/MH I-79(a) describes the proposed changes to Manitoba Hydro's capitalization practices for 2012/13 and 2013/14.

Manitoba Hydro's consultations did not examine the specific regulatory model for each of the utilities studied and thus, Manitoba Hydro is not in a position to specify how each utility is regulated (i.e. Rate Base or Cost of Service model).

Publicly available information (e.g. utility financial statements) was limited with respect to the types of expenditures capitalized in overhead amongst the different utilities. Disclosure of the details supporting overhead capitalization practices is not required for financial reporting purposes and thus, such information is not typically available in the financial statements of a utility.

Manitoba Hydro requested information from CEA members in an effort to identify general and administrative costs that are currently being capitalized under CGAAP and to identify general and administrative costs that utilities are proposing will no longer be capitalized upon transition to IFRS. Please note that CEA requests are conducted on the understanding that responses will not be distributed publicly and thus, Manitoba Hydro is not able to provide the individual responses from each utility. However, a summary of the responses is provided below.

Manitoba Hydro requested information from CEA members as to their capitalization practices under CGAAP and expected practices under IFRS. The requested information focused on expenditures in the following areas:

- Direct wages and supervisory costs for constructing assets (i.e. planning, engineering, constructing)
- Direct and indirect benefits (i.e. vacation, sick time, staff training)
- Departmental administrative Costs (i.e. office and support costs)
- Human resource services (i.e. recruitment, contract negotiations, compensation management)
- Financial services (i.e. management accounting, budgeting, long-term planning)
- Corporate Planning (i.e. Corporate strategic planning)
- Environmental services (i.e. ISO certification)
- Common facilities – office buildings (i.e. depreciation, interest, maintenance)
- Information Technology (IT) costs (i.e. project management, capital reporting)
- Corporate IT systems – HR and Finance Systems (i.e. depreciation and support costs)

The number of responses for the requests varied from 5 – 10 utilities. In some instances, Manitoba Hydro followed up with a verbal discussion with the respondent. A summary of the general results is as follows:

- Direct wages and supervisory costs for constructing assets: All respondents were capitalizing these types of costs. Such costs are expected to eligible for capitalization under IFRS.
- Direct and indirect benefits: All respondents were capitalizing these types of costs where a relationship to capital assets could be made. Where a relationship to a capital asset can be made, such costs are expected to eligible for capitalization under IFRS.
- Departmental administrative costs: The majority of respondents were partially capitalizing such costs under CGAAP as part of an overhead rate. Only where a direct relationship to a capital project can be made will these costs be eligible for capitalization under IFRS.

- Human Resource Services: Many respondents indicated they did not capitalize expenditures for human resource services that were not linked to capital projects under CGAAP and some respondents indicated such costs were included in overhead rates. All respondents indicated they would not be capitalizing such costs upon transition to IFRS. If a direct relationship to a capital project can be made, such costs may be eligible for capitalization under IFRS.
- Financial Services: Some of the respondents did not capitalize costs pertaining to financial services while other utilities indicated they partially capitalized such costs as part of overhead rates. Utilities did not expect to capitalize such costs upon transition to IFRS.
- Corporate Planning: Only one utility partially capitalized such costs under CGAAP. No utilities expected to capitalize such costs upon transition to IFRS.
- Environmental services: No utilities capitalize such costs under CGAAP unless required as part of a specific capital project and no utilities expected to capitalize such costs upon transition to IFRS unless specific to a capital project.
- Common Facilities – office buildings: No respondents capitalized depreciation on common buildings. In general, respondents were not capitalizing charges on common buildings. No utilities expected to capitalize such costs upon transition to IFRS.
- Information Technology (IT) costs: The responses to this area of costs varied where some utilities only capitalized such costs if they were direct to a capital or IT project and some utilities capitalized by including such costs in an overhead rate. Only where a direct relationship to a capital project can be made will these costs be eligible for capitalization under IFRS.
- Corporate IT systems – Depreciation and Support costs: The majority of utilities did not capitalize costs associated with Corporate IT systems under CGAAP. One utility indicated they partially capitalize such costs as part of the overhead rate. Only one utility expected to partially capitalize such costs under IFRS.

Follow up discussions with utilities with respect to their responses further identified that:

- No utilities were capitalizing depreciation or finance charges on common buildings such as head offices;
- Utilities were not capitalizing finance charges on fleet vehicles;
- The majority of utilities were not capitalizing executive costs; and
- The majority of the indirect IT related costs that were capitalized involved support costs for systems involved in the development of capital assets.

Lastly, Manitoba Hydro held discussions with its external auditor and IFRS consultant so as to confirm its understanding of the responses and that Manitoba Hydro's proposed changes would comply with the requirements of CGAAP and the requirements of IFRS upon transition.

PUB/MH II-52

Reference: PUB/MH I-42 (a) Capitalized Overheads

"CGAAP handbook section 3061 currently allows for the capitalization of overhead costs directly attributable to the construction or development activity is allowed under CGAAP (as acknowledged by MH's response to PUB/MH I-79). The Corporation has indicated that it has made the changes to be more consistent with IFRS (as indicated in its response to PUB/MH I-44 (a)) and through consultations with other Canadian Utilities."

c) Please indicate the impact on net income for 2012/13 and 2013/14 assuming for rate setting purposes the proposed changes in capitalization policy is delayed until 2014/15.

ANSWER:

As outlined in the schedule on page 5 of Appendix 5.6, the impact for 2012/13 and 2013/14 of the proposed changes in costs capitalized are an increase in Operating and Administrative expense of $27 million in 2012/13 and $63 million in 2013/14, respectively. The impact of these changes will be a decrease of net income of $27 million in 2012/13 and $63 million in 2013/14, respectively.

As indicated in the response to PUB/MH II-52(a), Manitoba Hydro does not agree with the proposition that the changes proposed for 2012/13 are an early adoption of IFRS and that they can be delayed until the revised implementation of IFRS in 2014/15. The changes proposed for 2013/14 will now be deferred to 2014/15 as a result of the further one-year deferral of the implementation of IFRS and in isolation will result in a decrease in Operating and Administrative expense of $36 million and a corresponding increase in net income in 2013/14. However, there are other impacts of the further one-year deferral of IFRS that will partially offset this increase in net income. Please see the response to PUB/MH II-18(a) for an IFF11-2 scenario that provides the projected net income in 2013/14 for electric operations assuming the deferral of IFRS until 2014/15.

PUB/MH II-52

Reference: PUB/MH I-42 (a) Capitalized Overheads

"CGAAP handbook section 3061 currently allows for the capitalization of overhead costs directly attributable to the construction or development activity is allowed under CGAAP (as acknowledged by MH's response to PUB/MH I-79). The Corporation has indicated that it has made the changes to be more consistent with IFRS (as indicated in its response to PUB/MH I-44 (a)) and through consultations with other Canadian Utilities."

d) Please file the capital coverage ratio including all major G&T capital in its determination.

ANSWER:

Please see the following table, from PUB/MH I-22(c), which has been restated with capital coverage including major G&T.

Please note that schedule has been provided for illustrative purposes only and does not represent Manitoba Hydro's approved financial target for capital coverage.

	For the year ended March 31	Actuals 2008	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
	Capital Coverage Ratio *(Incl MNG&T)* (1/(2+5)	0.71	0.72	0.48	0.50	0.50	0.40	0.37	0.31	0.28	0.27	0.29	0.24	0.32	0.32
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
	Capital Coverage Ratio *(Incl MNG&T)* (1/(2+5)	0.28	0.42	0.55	0.66	0.68	1.33	1.61	1.57	1.39	1.59	1.84	2.16
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 II-53

Reference: PUB/MH I- 44 (a)

a) Please extend the table to include 2004/05 to 2013/14.

ANSWER:

The table below has been extended to the 2006/07 fiscal year. In 2004/05 and 2005/06 a different methodology was employed, which included a common overhead rate and specific electric overhead and gas overhead rates and as such the rates are not directly comparable. It is noted that from 2004/05 through 2006/07 there were no changes in the overall composition of the overhead pools (i.e. no items removed for capitalization purposes). The rates for 2013/14 have not yet been approved.

Overhead Rates
Fiscal Years Ended March 31

	2007	2008	2009	2010	2011	2012	2013
Overhead Rates							
Common	29%	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

PUB/MH II-53

Reference: PUB/MH I- 44 (a)

b) Please describe the need and justification for a tool and procurement overhead rate and explain how such costs were accounted for in prior years.

ANSWER:

The tool and procurement overhead rate includes costs associated with technical design and mapping software, personal computers as well as Purchasing and Accounts Payable functions. Prior to 2012/13, these costs were capitalized either through the common overhead rate or activity charges.

The costs allocated to the tool and procurement rate are deemed eligible for capitalization under IFRS as they are considered 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. In order to simplify the transition to IFRS they were removed from the common overhead rate and activity rates and a separate rate established.

Costs allocated to capital projects through the common overhead rate are considered ineligible for capitalization under IFRS and as a result the 20% overhead rate will be eliminated upon transition.

PUB/MH II-54

Reference: PUB/MH I-45 (d) CWIP

Please provide a summary breakdown with narrative of Other for Wuskwatim, Keeyask, Conawapa and Bipole III.

ANSWER:

The Other category contains costs consisting of: consulting services provided by external vendors, including engineering, management and architecture; general construction and maintenance services provided by external vendors including assembly and installation; unamortized site study costs which were previously deferred and have now been re-allocated to the capital project to construct the asset related to the site study and community participation which are payments to First Nation and other communities as negotiated through formal agreements between Manitoba Hydro and these communities.

Please see below for a breakdown of other for Wuskwatim, Keeyask, Conawapa and Bipole III.

Wuskwatim - Generation	
Construction & Maintenance Services	811.2
Consulting Services	107.5
Site Study Costs	32.1
Adverse Effects Cost	6.5
Insurance	5.4
Professional Fees	4.7
Community Participation	4.3
Manitoba Hydro Electricity Charges	4.3
Transport of people including charters, MV mileage	4.1
Purchases of New Vehicles	1.7
Fuel & Oil	1.3
Other	5.2
	988.3

Wuskwatim - Transmission	
Construction & Maintenance Services	80.4
Consulting Services	67.5
Community Participation	14.7
Transport of people including charters, MV mileage	2.3
Survey & Map Services	1.4
Other	3.0
	169.3

Keeyask	
Consulting Services	178.7
Site Study Costs	53.0
Construction & Maintenance Services	24.8
Community Participation	19.0
Mitigation Settlement	12.1
Transport of people including charters, MV mileage	5.1
Other	2.2
	295.0

Conawapa	
Consulting Services	60.5
Site Study Costs	58.4
Transport of people including charters, MV mileage	5.4
Construction & Maintenance Services	5.4
Community Participation	5.3
Mitigation Settlement	4.9
Accommodations & Other Travel expenses	2.5
Other	1.4
	143.6

Bipole III - Transmission Line	
Consulting Services	21.9
Community Participation	4.3
Transport of people including charters, MV mileage	3.1
Site Study Costs	1.1
Other	2.1
	32.5

Bipole III - Converter Stations	
Construction & Maintenance Services	20.9
Consulting Services	12.0
Site Study Costs	1.0
Other	1.6
	35.5

PUB/MH II-55

Reference: PUB/MH I-52 (b)

Please refile the analysis as requested based on IFF12 , reflecting the deferral of IFRS until 2014/15.

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-56

Reference: PUB/MH I-53, Rate Revenues

a) Please re-file the information to include the 2004/05, 2005/06 and 2006/07 fiscal years.

ANSWER:

Please see the following table for the requested information. Manitoba Hydro notes clarification was obtained from the Public Utilities Board to also include exprovincial revenues in the requested table.

MANITOBA HYDRO
GENERAL CONSUMERS REVENUE (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
Residential - Base Rates	$ 373,737	$ 360,363	$ 381,532	$ 397,742	$ 405,896	$ 401,304	$ 411,995	$ 390,436	$ 423,362	$ 432,192
General Service - Base Rates	534,958	555,836	570,078	581,124	583,448	563,954	571,525	584,748	595,056	607,475
Base Rates	908,694	916,198	951,610	978,865	989,345	965,258	983,520	975,183	1,018,418	1,039,667
2004/05 Approved Rate Increase (5.0% August 1, 2004)	30,260	45,810	47,580	48,943	49,467	48,263	49,176	48,759	50,921	51,983
2005/06 Approved Rate Increase (2.25% April 1, 2005)	-	21,645	22,482	23,126	23,373	22,804	23,236	23,039	24,060	24,562
2006/07 Approved Rate Increase (2.25% March 1, 2007)	-		1,941	23,646	23,899	23,317	23,758	23,557	24,601	25,115
2008/09 Approved Rate Increase (5.0% July 1, 2008)	-	-	-	-	40,728	52,982	53,984	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	30,260	67,455	72,003	95,715	137,468	179,633	216,861	238,827	262,205	267,675
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 General Consumer Revenue	$ 938,954	$ 983,653	$ 1,023,613	$ 1,074,580	$ 1,126,812	$ 1,144,891	$ 1,200,381	$ 1,191,117	$ 1,335,571	$ 1,399,088
Rate increase requested	3.0%	2.5%	2.25%	n/a	2.9%	3.9%	2.9%	2.9%	3.5%	3.5%
Rate increase granted*	5.0%	2.25%	2.25%	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%.

MANITOBA HYDRO
EXTRAPROVINCIAL REVENUE (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
Total Extraprovincial Revenue	$ 553,727	$ 826,766	$ 592,245	$ 624,971	$ 622,646	$ 426,641	$ 398,306	$ 363,044	$ 341,167	$ 362,920

PUB/MH II-56

Reference: PUB/MH I-53, Rate Revenues

b) Below the table please add a companion table which details the cash flow from operations and MH's use of those cash flows to:

1. **Fund operations;**
2. **Fund Base Capital; and**
3. **Fund Major Capital (from internally generated funds from operations).**

ANSWER:

Please see the table below for the requested information.

(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
General Consumer Revenue	$ 938,954	$ 983,653	$ 1,023,613	$ 1,074,580	$ 1,126,812	$ 1,144,891	$ 1,200,381	$ 1,191,117	$ 1,335,571	$ 1,399,088
Extraprovincial Revenue	553,727	826,766	592,245	624,971	622,646	426,641	398,306	363,044	341,167	362,920
Total General Consumer & Extraprovincial Revenue*	$ 1,492,681	$ 1,810,419	$ 1,615,858	$ 1,699,551	$ 1,749,459	$ 1,571,532	$ 1,598,687	$ 1,554,161	$ 1,676,738	$ 1,762,008
Fund Operations	$ 1,086,681	$ 1,098,419	$ 1,194,858	$ 1,100,551	$ 1,096,459	$ 1,043,532	$ 1,048,687	$ 1,036,161	$ 1,238,115	$ 1,317,808
Fund Base Capital	337,000	283,000	376,000	363,000	359,000	414,000	450,000	472,000	411,529	394,370
Fund Major Capital (from internally generated funds from operations)	69,000	429,000	45,000	236,000	294,000	114,000	100,000	46,000	27,094	49,830

* Please note that not all revenue collected in a fiscal year is received as cash, resulting in a receivable. This response has been provided for illustrative purposes only.

PUB/MH II-57

Reference: PUB/MH I-55 IFRS Jurisdictional Comparisons

a) Please file copies or an electronic link to all referenced source materials from the OEB and AUC.

ANSWER:

Please see the following links:'

- OEB report "EB-2008-0408, Report of the Board, Transition to International Financial Reporting Standards"
  http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0408/IFRS_Board_Report_20090728.pdf

- February 24, 2010 letter from the OEB re: Accounting for Overhead Costs Associated with Capital Work
  http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0408/Brdltr_IFRS_OverheadCap_20100224.pdf

- July 8, 2010 Asset Depreciation Study for the Ontario Energy Board (Kinectrics Report)
  http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf

- April 30, 2012 letter from the OEB re: 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
  http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/BoardLtr_IFRS_2013_Cost_of_Service_Application_201.pdf

- July 9, 2012 OEB presentation re: 2013 Cost of Service Orientation Session Setting Rates on MIFRS – Review of Requirements for 2013 Filers
  http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/5.%2520MIFRS_Rates_20120709_v3.ppt

- AUC Rule 026 Regarding Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards
  http://www.auc.ab.ca/acts-regulations-and-auc-rules/rules/Documents/Rule026.pdf

PUB/MH II-57

Reference: PUB/MH I-55 IFRS Jurisdictional Comparisons

b) Please provide MH's understanding of Ontario based electric utilities approach to dealing with the OEB's requirement for utilities, under its jurisdiction, to adopt IFRS overhead capitalization requirements after the date of adoption of IFRS.

ANSWER:

Manitoba Hydro understands that the OEB EB-2008-0408 will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS and that revenue requirement impacts must be specifically and separately quantified.

Manitoba Hydro is not in a position to understand how Ontario based electric utilities will approach the OEB's requirement for utilities to adopt IFRS overhead capitalization requirements after the date of adoption of IFRS. Currently, many of the larger OEB regulated utilities (e.g. Hydro One, Ontario Power Generation, Toronto Hydro) have adopted USGAAP on an interim basis through to 2015 and thus, there is very little experience with comparable Ontario based utilities with respect to the adoption of IFRS. Given that the transition to IFRS for many of the larger Ontario based utilities will not occur until several years into the future, the information for Manitoba Hydro to understand how such utilities will adopt the OEB's IFRS overhead capitalization requirements is not available.

PUB/MH II-57

Reference: PUB/MH I-55 IFRS Jurisdictional Comparisons

c) Please indicate whether OEB regulated utilities have early adopted this accounting change for rate setting purposes similar to what MH proposes in this application.

ANSWER:

As indicated in PUB/MH I-61(a), Manitoba Hydro does not consider changes implemented to the capitalization of overhead costs to date as an early adoption of the requirements of IFRS. Manitoba Hydro's implemented capitalization policies are fully compliant with Canadian GAAP and have been endorsed by Manitoba Hydro's external auditors.

Please see the response to PUB/MH II-57(b) for Manitoba Hydro's understanding of the situation with respect to OEB regulated utilities.

PUB/MH II-57

Reference: PUB/MH I-55 IFRS Jurisdictional Comparisons

d) With respect to the Asset Depreciation Study commissioned by the OEB, please indicate the approach taken in the report is consistent with that taken by MH for comparable major asset groupings, depreciation rates and methodology.

ANSWER:

The Asset Depreciation Study commissioned by the OEB is posted on the OEB's website as the "Kinectrics Report". Manitoba Hydro did not participate in the Kinectrics study, and as such, our understanding is limited to a review of the published study itself.

The Kinectrics Report provides a list of depreciable components and indicates a range of useful lives for each of the identified components. The Kinectrics Report states an assumption that Ontario distributors will continue to use the straight-line remaining service life method of depreciation. The report does not contain any specific guidance with respect to depreciation rates or use of individual asset versus group depreciation procedures such as Average Service Life (ASL) or Equal Life Group (ELG).

The purpose of Manitoba Hydro's depreciation study was to develop depreciation rates applicable specifically to Manitoba Hydro, while the OEB's study was commissioned to determine a generic set of depreciable components and associated useful lives which could be used by Ontario distributors as guidance in the development of depreciation rates applicable to their respective utilities. As stated in the Kinectrics Report:

> "The objective of this Report is to assist electricity distributors in Ontario in determining total service lives for typical electricity distribution system assets that they own. The information contained in the Report is expected to further facilitate transfer of responsibility for determining asset total service lives to distributors as they transition to IFRS."[1]
>
> …..
>
> "The purpose of this Report is to assist utilities in making the transition to IFRS and to assist them with determining appropriate initial service lives for assets most commonly used in the distribution of electricity in Ontario, particularly in situations where they have not conducted their own study. This approach is considered an

[1] KINECTRICS INC, "Asset Depreciation Study for the Ontario Energy Board", Page 3

effective way to minimize the need and cost to Ontario consumers of a myriad of like studies by individual distributors."[2]

…..

"This study will assist distributors with the determination of suitable asset total service lives. Distributors must still evaluate whether the total service lives set out in this Report are completely applicable to their own utility."[2]

Based on a review of the Kinectrics Report, the approach taken in the Kinectrics study appears to be different from that taken in the development of the Manitoba Hydro depreciation study. According to the report, the data used in the Kinectrics study was obtained from a sample of Ontario distributors and from industry related research. The data used in the Manitoba Hydro depreciation study was compiled from Manitoba Hydro's financial records. Manitoba Hydro's average service lives were established by Gannett Fleming based on consideration of the results of statistical analysis of the financial data; industry knowledge and experience; and discussions with Manitoba Hydro operational and engineering staff members regarding past experience and future expectations related to various factors impacting the service life of each component, such as typical levels of retirements prior to end of normally expected life as a result of weather and other environmental events, third party activities and technological changes.

With respect to the identification of individually depreciable components, the Kinectrics Study breaks down each asset category into a much lower level of detail than is used by Manitoba Hydro, for example, segregating cross arms from poles. While these smaller components could form a material portion of the overall asset base for a small utility dedicated to distribution, in the context of Manitoba Hydro's asset base, they are not considered material enough to warrant separate treatment for depreciation purposes. For IFRS, Manitoba Hydro intends to use the Equal Life Group ("ELG") procedure for group depreciation, which specifically considers interim retirement activity, such as the replacement of minor parts, in the development of the depreciation rate for each component.

The average service lives identified in Manitoba Hydro's depreciation study are consistent with those identified in the Kinectrics Report. It appears that the average service lives determined through Manitoba Hydro's depreciation study fall within the range of useful lives indicated in the Kinectrics Report for comparable components.

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[2] KINECTRICS INC, "Asset Depreciation Study for the Ontario Energy Board", Page 1

PUB/MH II-58

Reference: PUB/MH I-59 (c) & (d)

a) Please explain the reasons behind the forecast compound annual cost growth cost increases; in 2011/12 through 2013/14 that are in excess of inflation for:

- **i. President & CEO: General Counsel (6.1%) , Research & Development (14.2%)**
- **ii. Power Supply: Generation North (10.1%), Administration (5.6%)**
- **iii. Transmission: Administration (41.8%)**
- **iv. Customer Service & Distribution: Customer Service South (7.3%) Distribution E&C Winnipeg (187.9%)**
- **v. Customer Care & Marketing: Industrial & Commercial Solutions (45.9%), Consumer Marketing & Sales (9.1%)**

ANSWER:

The explanations for compound annual cost growth cost increases in excess of inflation from 2011/12 through 2013/14 are as follows:

i. President & CEO:

General Counsel (6.1%)
The increase is due to higher insurance costs primarily related to additional premiums for critical sub-transmission and transmission facilities and the addition of provincial sales tax on premiums as per the Provincial Budget.

Research & Development (14.2%)
The increase is primarily due to lower than forecast R&D expenditures in 2011/12, not anticipated to continue in 2012/13.

ii. Power Supply:

Generation North (10.1%)
The increase is primarily due to the in-service of Wuskwatim GS, accounting changes including departmental administrative support costs no longer eligible for capitalization and higher salaries and benefits as a result of wage settlements.

Administration (5.6%)
The increase is primarily due to increased levels of Operating Technician Trainees to address rising attrition for retirement eligibility and trade losses internal and external to Manitoba Hydro, accounting changes including departmental administrative support costs no longer eligible for capitalization and higher salaries and benefits as a result of wage settlements.

iii. **Transmission:**

Administration (41.8%)
The increase is primarily due to increased Engineer-in-Training (EIT) levels to address rising attrition for retirement eligibility and trade losses internal and external to Manitoba Hydro, accounting changes including departmental administrative and support costs no longer eligible for capitalization and the reclassification of Operating Expense Recoveries to Other Revenue and higher salaries and benefits as a result of wage settlements.

iv. **Customer Service & Distribution:**

Customer Service South (7.3%)
The increase is primarily due to accounting changes including departmental administrative and support costs no longer eligible for capitalization and the reclassification of Operating Expense Recoveries to Other Revenue, and higher salaries and benefits due to wage settlements.

Distribution E&C Winnipeg (187.9%)
The increase is primarily due to accounting changes including departmental administrative and support costs no longer eligible for capitalization and higher salaries, overtime and benefits due to wage settlements and increase in staff levels.

v. **Customer Care & Marketing:**

Industrial & Commercial Solutions (45.9%)
The increase is primarily due to accounting changes including departmental administrative and support costs no longer eligible for capitalization and the reclassification of Operating Expense Recoveries to Other Revenue, and increase salaries and benefits due to filling of vacancies.

Consumer Marketing & Sales (9.1%)

The increase is primarily due to accounting changes including departmental administrative and support costs no longer eligible for capitalization and the reclassification of Operating Expense Recoveries to Other Revenue, and increase salaries and benefits due to filling of vacancies.

PUB/MH II-58

Reference: PUB/MH I-59 (c) & (d)

b) Each of the business units other than President & CEO is forecast to increase at compound annual growth rates for 2011/12 through 2013/14 in excess of inflation. Please explain and demonstrate for each business unit where MH has targeted cost containment measures and quantify the estimated cost savings.

ANSWER:

The compounded annual growth rates for 2011/12 through 2013/14 include the impacts of changes in methodology (removal of support costs from activity rates and allocated to programs/projects through the common overhead rate), in-service of the Wuskwatim Generating Station and accounting changes under IFRS. The compounded annual growth rates for the business units adjusted for these changes are as follows:

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
Adjusted for accounting changes and in-service of Wuskwatim GS

(In thousands of $)	**2011/12 Actual**	**2012/13 Forecast**	**2013/14 Forecast**	**Fiscal 2011/12-2013/14 Compounded Annual Growth**
President & CEO	$ 28,328	$ 28,026	$ 28,560	0.4
Corporate Relations	3,025	4,254	4,343	19.8
Finance & Administration	107,443	109,771	111,992	2.1
Power Supply	155,084	157,971	160,969	1.9
Transmission	89,261	91,173	92,997	2.1
Customer Services & Distribution	110,045	111,455	113,638	1.6
Customer Care & Marketing	43,703	45,578	46,490	3.1
Business Unit Total	**$ 536,889**	**$ 548,228**	**$ 558,990**	**2.0**

After considering merit, progression, general wage increases and the impacts of retirements and replacements, the company's wage and salary forecast shows a compounded increase of 3.7% for the same 3 year period. After deducting the allowed general target increase of 2% and considering other factors, the implicit savings is estimated to be approximately 1% per year. These savings are to be achieved through the cost constraint measures as outlined in Appendix 5.6 as well as through productivity improvements throughout the business units.

It is noted that the compounded annual growth of 19.8% in Corporate Relations is a result of an adjustment in 2011/12 for the capitalization of costs associated with the shoreline cleanup program. The forecasts for 2012/13 and 2013/14 reflect normalized operations.

Please also see Manitoba Hydro's response to MIPUG/MH I-9(a) for the compound increase in wages and salaries.

PUB/MH II-59

Reference: PUB/MH I-64 (a)

a) Please explain why Customer Care and Marketing costs have increase by CAGR of 19.4% since 2007/08.

ANSWER:

The Customer Care & Marketing Business Unit costs are projected to increase on an average annual basis of 19.4% over the 2007/08 to the 2013/14 period, primarily due to accounting changes including Rate Regulated (DSM programs), and departmental and administrative support costs no longer eligible for capitalization, as well as the reclassification of Operating Expense Recoveries to Other Revenue.

PUB/MH II-59

Reference: PUB/MH I-64 (a)

b) Please refile the schedule commencing in 2004/05 and reflecting the deferral of IFRS accounting changes until 2014/15.

ANSWER:

The following schedules have been updated to include 2004/05 to 2006/07 actual results and the removal of IFRS accounting changes from 2013/14. The only IFRS changes that were incorporated in the business unit forecasts for 2013/14 is the expensing of Rate Regulated Assets such as DSM and Site Remediation that are no longer eligible for deferral under rate-regulated accounting.

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	2012/13 Forecast	2013/14 Forecast	Average Annual % Inc/(Dec)
President & CEO	$ 20,949	$ 22,123	$ 23,207	$ 22,963	$ 24,230	$ 31,578	$ 28,835	$ 28,328	$ 28,692	$ 29,239	4.2%
Corporate Relations	3,503	5,496	5,220	5,245	5,520	4,697	4,739	3,025	4,491	4,585	6.4%
Finance & Administration	90,619	93,015	99,027	99,521	103,722	108,914	106,528	107,443	114,343	116,656	2.9%
Power Supply	113,433	117,196	123,359	127,610	142,183	147,073	150,120	155,084	177,882	182,951	5.5%
Transmission	77,979	77,810	83,503	83,171	91,088	92,302	90,493	89,261	104,662	106,755	3.7%
Customer Services & Distribution	92,107	96,964	92,091	98,373	103,762	111,068	106,707	110,045	130,355	132,916	4.4%
Customer Care & Marketing	42,359	42,293	42,891	38,472	38,942	42,395	41,446	43,703	52,249	53,295	2.9%
Business Unit Total*	**440,950**	**454,897**	**469,297**	**475,354**	**509,446**	**538,027**	**528,867**	**536,889**	**612,673**	**626,396**	**4.1%**

*Note: Does not include allocations to capital and Centra Gas.

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES 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	Average Annual % Inc/(Dec)
President & CEO	104	101	104	106	107	116	123	127	126	126	2.2%
Corporate Relations	49	62	67	69	75	73	69	69	75	75	5.2%
Finance & Administration	1,038	1,035	1,006	993	1,006	1,010	1,009	983	1,003	1,003	-0.4%
Power Supply	1,345	1,366	1,405	1,470	1,576	1,679	1,796	1,853	1,972	1,972	4.4%
Transmission	1,208	1,220	1,233	1,256	1,298	1,342	1,365	1,354	1,385	1,385	1.5%
Customer Services & Distribution	1,605	1,647	1,616	1,640	1,671	1,678	1,704	1,701	1,731	1,731	0.9%
Customer Care & Marketing	521	547	556	538	543	532	528	521	549	549	0.6%
Total	**5,870**	**5,978**	**5,988**	**6,071**	**6,276**	**6,429**	**6,594**	**6,608**	**6,842**	**6,842**	**1.7%**

PUB/MH II-59

Reference: PUB/MH I-64 (a)

c) Please file an additional scenario as in (b) for rate setting purposes, adjusted to reflect the continued capitalization of incremental overheads MH forecasts on expensing in 2012/13 and 2013/14 that are not allowed when IFRS is in effect in 2014/15.

ANSWER:

The attached schedule reflects the deferral of all IFRS accounting changes from 2013/14 to 2014/15. As discussed in PUB/MH II-59(b), costs in the business units do not reflect the expensing of incremental overheads in 2013/14 and as such the table has been revised to include all cost components that make up total electric OM&A.

As indicated in PUB/MH I-61(a), Manitoba Hydro does not consider changes implemented to the capitalization of overhead costs in 2012/13 and prior as an early adoption of the requirements of IFRS. Manitoba Hydro's implemented capitalization policies are fully compliant with Canadian GAAP and have been endorsed by Manitoba Hydro's external auditors. As such, the following table continues to include these accounting changes.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
Adjusted for deferral of IFRS to 2014/15

(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)
President & CEO	$ 20,949	$ 22,123	$ 23,207	$ 22,963	$ 24,230	$ 31,578	$ 28,835	$ 28,328	$ 28,692	$ 29,239	4.2%
Corporate Relations	3,503	5,496	5,220	5,245	5,520	4,697	4,739	3,025	4,491	4,585	6.4%
Finance & Administration	90,619	93,015	99,027	99,521	103,722	108,914	106,528	107,443	114,343	116,656	2.9%
Power Supply	113,433	117,196	123,359	127,610	142,183	147,073	150,120	155,084	177,882	182,951	5.5%
Transmission	77,979	77,810	83,503	83,171	91,088	92,302	90,493	89,261	104,662	106,755	3.7%
Customer Services & Distribution	92,107	96,964	92,091	98,373	103,762	111,068	106,707	110,045	130,355	132,916	4.4%
Customer Care & Marketing	42,359	42,293	42,891	38,472	38,942	42,395	41,446	43,703	52,249	53,295	2.9%
Business Unit Total	**440,950**	**454,897**	**469,297**	**475,354**	**509,446**	**538,027**	**528,867**	**536,889**	**612,673**	**626,396**	4.1%
Motor Vehicle Chargeout	$ (20,219)	$ (22,089)	$ (22,117)	$ (22,010)	$ (24,266)	$ (24,352)	$ (17,933)	$ (16,843)	(14,371)	(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)	
Operating & Administrative Costs Attributable to Electric Operations	**$ 298,613**	**$ 310,658**	**$ 323,465**	**$ 322,696**	**$ 364,287**	**$ 377,551**	**$ 396,946**	**$ 403,304**	**$ 446,966**	**$ 457,371**	4.9%

PUB/MH II-60

Reference: PUB/MH I-64 (d) & (h)

a) Please update the analysis in (d) to include years 2003/04 through 2013/14, reflecting the delay and implementation of IFRS and provide three tables; a schedule of total corporate costs, cost capitalize by business unit, and the percentage capitalized by business unit in each year.

ANSWER:

The following schedule has been updated to include the years 2004/05 through 2006/07. As discussed in PUB/MH I-64(d) the figures provided for 2013/14 do not reflect the implementation of IFRS as detailed budgets by business unit/division incorporating the changes will be prepared following approval of IFF12.

MANITOBA HYDRO
COSTS CAPITALIZED 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 [1]
President & CEO	$ 828	$ 886	$ 1,022	$ 841	$ 948	$ 496	$ 331	$ 555	$ 675	$ 689
Corporate Relations	1,663	2,350	3,249	3,449	4,364	4,872	4,934	5,301	4,630	4,723
Finance & Administration	12,734	13,271	9,028	10,559	10,494	10,794	12,482	12,438	12,297	12,543
Power Supply	30,662	31,364	35,709	41,181	45,191	54,629	63,199	74,028	72,093	73,535
Transmission	40,847	44,317	43,789	50,131	53,067	61,254	67,377	72,554	67,637	68,989
Customer Services & Distribution	64,861	69,643	74,739	76,102	80,943	82,373	84,995	92,995	79,432	81,021
Customer Care & Marketing	6,135	8,628	9,456	10,069	10,164	9,879	10,226	10,780	9,299	9,485
	$ 157,730	**$ 170,459**	**$ 176,992**	**$ 192,331**	**$ 205,169**	**$ 224,297**	**$ 243,545**	**$ 268,651**	**$ 246,065**	**$ 250,986**

Table 1 provides a schedule of total corporate costs prior to capitalization. In addition, amounts allocated to Centra Gas have been deducted in order to provide total electric costs before capitalization. Amounts do not include costs such as material and contracted services direct charged to capital projects.

The combined Table 2 and 3 provides the costs capitalized through activity charges by business unit and the percentage of total costs capitalized. Amounts capitalized through overhead have also been provided.

MANITOBA HYDRO
TOTAL COSTS EXCLUDING AMOUNTS CAPITALIZED (Table 1)

(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
President & CEO	$ 21,777	$ 23,009	$ 24,228	$ 23,804	$ 25,178	$ 32,074	$ 29,166	$ 28,883	$ 29,368	$ 29,928
Corporate Relations	5,166	7,846	8,468	8,694	9,884	9,569	9,673	8,326	9,122	9,308
Finance & Administration	103,353	106,286	108,054	110,079	114,215	119,707	119,010	119,882	126,640	131,359
Power Supply	144,095	148,560	159,068	168,790	187,374	201,702	213,319	229,111	249,975	260,566
Transmission	118,826	122,127	127,292	133,302	144,155	153,556	157,871	161,816	172,298	176,254
Customer Services & Distribution	156,967	166,607	166,831	174,475	184,705	193,442	191,701	203,040	209,787	213,936
Customer Care & Marketing	48,495	50,921	52,347	48,540	49,105	52,275	51,672	54,483	61,548	105,408
Business Unit Total (gross of capital activities)	**598,679**	**625,356**	**646,289**	**667,685**	**714,616**	**762,324**	**772,412**	**805,540**	**858,738**	**926,760**
Motor Vehicle Chargeout	(20,219)	(22,089)	(22,117)	(22,010)	(24,266)	(24,352)	(17,933)	(16,843)	(14,371)	(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)
Total Corporate Costs	**569,748**	**596,230**	**615,849**	**638,587**	**690,458**	**722,950**	**748,471**	**787,156**	**829,764**	**897,204**
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)
Total Electric Costs	**$ 514,516**	**$ 543,145**	**$ 562,344**	**$ 582,317**	**$ 630,654**	**$ 661,999**	**$ 687,826**	**$ 725,039**	**$ 762,464**	**$ 828,558**

MANITOBA HYDRO
COSTS CAPITALIZED (Table 2 & 3 combined)
(in thousands of $)

	2004/05 Actual	% of Corp. Costs	2005/06 Actual	% of Corp. Costs	2006/07 Actual	% of Corp. Costs	2007/08 Actual	% of Corp. Costs	2008/09 Actual	% of Corp. Costs	2009/10 Actual	% of Corp. Costs	2010/11 Actual	% of Corp. Costs	2011/12 Actual	% of Corp. Costs	2012/13 Forecast	% of Corp. Costs	2013/14 Forecast	% of Corp. Costs
Total Corporate Costs	$ 569,748		$ 596,230		$ 615,849		$ 638,587		$ 690,458		$ 722,950		$ 748,471		$ 787,156		$ 829,764		$ 897,204	
President & CEO	828	0.1%	886	0.1%	1,022	0.2%	841	0.1%	948	0.1%	496	0.1%	331	0.0%	555	0.1%	675	0.1%	689	0.1%
Corporate Relations	1,663	0.3%	2,350	0.4%	3,249	0.5%	3,449	0.5%	4,364	0.6%	4,872	0.7%	4,934	0.7%	5,301	0.7%	4,630	0.6%	4,723	0.5%
Finance & Administration	12,734	2.2%	13,271	2.2%	9,028	1.5%	10,559	1.7%	10,494	1.5%	10,794	1.5%	12,482	1.7%	12,438	1.6%	12,297	1.5%	12,543	1.4%
Power Supply	30,662	5.4%	31,364	5.3%	35,709	5.8%	41,181	6.4%	45,191	6.5%	54,629	7.6%	63,199	8.4%	74,028	9.4%	72,093	8.7%	73,535	8.2%
Transmission	40,847	7.2%	44,317	7.4%	43,789	7.1%	50,131	7.9%	53,067	7.7%	61,254	8.5%	67,377	9.0%	72,554	9.2%	67,637	8.2%	68,989	7.7%
Customer Services & Distribution	64,861	11.4%	69,643	11.7%	74,739	12.1%	76,102	11.9%	80,943	11.7%	82,373	11.4%	84,995	11.4%	92,995	11.8%	79,432	9.6%	81,021	9.0%
Customer Care & Marketing	6,135	1.1%	8,628	1.4%	9,456	1.5%	10,069	1.6%	10,164	1.5%	9,879	1.4%	10,226	1.4%	10,780	1.4%	9,299	1.1%	9,485	1.1%
Capital Order Activities	$ 157,730		$ 170,459		$ 176,992		$ 192,331		$ 205,169		$ 224,297		$ 243,545		$ 268,651		$ 246,065		$ 250,986	
Capitalized Overhead	$ 58,174	10.2%	$ 62,028	10.4%	$ 61,887	10.0%	$ 67,289	10.5%	$ 61,198	8.9%	$ 60,151	8.3%	$ 47,336	6.3%	$ 53,084	6.7%	$ 69,434	8.4%	$ 95,898 [1]	10.7%

[1] In 2013/14 capitalized overhead includes the provision for IFRS of $25 075 as per PUB/MH I-59(c).

PUB/MH II-60

Reference: PUB/MH I-64 (d) & (h)

b) Please refile the analysis in (h) reflecting IFF 12 and the delay of implementation of IFR S until 2014/15.

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-61

Reference: PUB/MH I-64 (j) OM&A versus Budget

a) Please explain why wages and salaries have had a compounded annual growth rate of 5.2% and Benefits 12.4% for the years 2009/10 through 2011/12 versus that forecast respectively 2% and 7.3% at the last GRA for the same time frame. Indicate which extent the difference relates to staffing level changes and wage settlements.

ANSWER:

The compounded annual growth rate of 5.2% for wages and salaries reflects the impact of negotiated contract settlements, merit and payments to align certain classifications within the existing salary structure as well as an increase of 178 EFTs over the period 2009/10 through 2011/12. The amount attributable to staffing level changes versus wage settlements is as follows -

Wages & Salaries (compounded growth of 5.2%) *(in millions of dollars)*		
$ attributable to wage settlements		31.8
$ attributable to staffing level changes		12.1
Increase in W&S over 3 years (2009/10 through 2011/12)	$	43.9

The compounded annual growth rate of 12.4% for benefits reflects higher pension costs due to the amortization of investment losses, higher vacation expense due to an increase in the number of days accrued and higher extended health benefit costs due to negotiated coverage enhancements. In addition, the increase in benefit costs reflects the impact of negotiated contract settlements and the effect of the change in the discount rate on pension and other benefits.

PUB/MH II-61

Reference: PUB/MH I-64 (j) OM&A versus Budget

b) On an overall basis total costs actual have increased on a compounded annual growth rate of 4.3% versus 2.2% forecast for the years 2009/10 through 2011/12. Please demonstrate where MH has targeted cost containment measures.

ANSWER:

The increase in total costs for the years 2009/10 through 2011/12 compared to the previous GRA is primarily due to the impact of negotiated contract settlements, merit and payments to align certain classifications within the existing salary structure. Benefit costs also increased as a result of higher pension costs due to the amortization of investment losses and the impact of the change in the discount rate on pension and other benefits. It is noted that after adjusting for the impacts of capitalization and amounts allocated to Centra, the actual OM&A results attributable to Electric operations shows a compounded annual growth rate of 3.4% compared to 3.2% as forecasted in the previous GRA.

As indicated below, the corporation's OM&A expenditures adjusted for accounting changes demonstrates an average annual increase over the same period of 1.61% compared to the average annual increase in Canadian CPI of 2.2% over the same period. These below-inflation increases in OM&A costs have been achieved through the cost constraint measures as outlined in Appendix 5.6 and numerous productivity improvements.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS

(in thousands of $)	**2009/10 Actual**	**2010/11 Actual**	**2011/12 Actual**	**Average Annual Increase**
Electric OM&A (per Annual Report)	$ 379,697	$ 403,067	$ 410,717	
Less: Subsidiaries	2,146	6,121	7,414	
Accounting Changes	11,240	30,910	34,973	
Electric OM&A after adjusting for subsidiaries, accounting changes	$ 366,311	$ 366,036	$ 368,330	
% Increase	4.28%	-0.08%	0.63%	**1.61%**
Canadian CPI	1.40%	3.30%	1.90%	**2.20%**

PUB/MH II-61

Reference: PUB/MH I-64 (j) OM&A versus Budget

c) Please explain the extent that productivity factors were incorporated in the budgets at the last GRA for 2009/10 through 2011/12 and comment on the actual experience for the years.

ANSWER:

Manitoba Hydro's practice is to allow a general escalation increase to OM&A forecasts which is approximately 1% lower than the underlying wage and cost increases that are expected.

As noted in response to PUB/MH II-61(b), Manitoba Hydro has experienced a 1.61% average annual increase (adjusted for accounting changes) in OM&A costs for this period despite significant cost pressures including higher wages & salaries and benefits. Manitoba Hydro's response to CAC/MH I-33(a) discusses some of the productivity improvements contributing to the overall cost savings.

PUB/MH II-62

Reference: PUB/MH I-65 (a) & (b)

a) Please file any internal reports addressing the results of cost containment measures that demonstrate the effectiveness of targeted savings measures.

ANSWER:

The effectiveness of targeted savings measures is through the attainment of necessary business requirements within target/approved budget levels. The formalized management cost control process, as described in Tab 3 of the Application, consists of a number of activities which include;

(i) Developing company, business unit, divisional and department plans;
(ii) Preparation of operating and capital forecasts;
(iii) Monthly, quarterly and annual reporting and variance analysis to ensure that costs incurred and resource allocations are consistent and in line with operating and capital plans.

As such, the management cost control process inherently includes the internal reporting of cost containment measures, which have been summarized in the Application, Appendix 5.6 and various Round 1 and 2 information requests.

PUB/MH II-62

Reference: PUB/MH I-65 (a) & (b)

b) Please indicate whether there have been any further correspondence or directives issued internally since the last GRA related to cost containment measures. If so please file.

ANSWER:

The OM&A targets approved by Executive Committee have assumed a 2% escalation increase net of accounting changes for each business unit, which is significantly lower than the underlying wage and cost increases that are expected. The achievement of cost reductions and productivity improvements are necessary to achieve target.

PUB/MH II-63

Reference: PUB/MH I-66 (a)

Please refile the schedule for the years 2004/05 through 2033 based on IFF12.

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-64

Reference: PUB/MH I-67 (b)

Please provide a comparative schedule 5.6.0 for the two test years based on IFF12 versus IFFII-2.

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

<u>PUB/MH II-65</u>

Reference: PUB/MH I- 70, PUB/MH I-134 WPLP

a) Please provide the supporting calculations behind the determination of finance expense for 2013 and 2014 and the assumed level of debt over the forecast period through 2032.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-50(a).

PUB/MH II-65

Reference: PUB/MH I- 70, PUB/MH I-134 WPLP

b) Please explain and provide supporting calculations of the assumed interest income reducing finance expense commencing in 2015.

ANSWER:

The interest income reflected in WPLP projected financial statements is attributed to interest on sinking fund investments. Sinking fund deposits made by Manitoba Hydro on debt incurred to fund the Wuskwatim project are recovered from WPLP. WPLP recognizes the cumulative sinking fund deposits as sinking fund investments on the WPLP balance sheet and earns interest equivalent to Manitoba Hydro's forecast sinking fund interest rate.

Please see Manitoba Hydro's response to PUB/MH II-50(a) for the sinking fund investment balances and supporting interest income calculation.

PUB/MH II-66

Reference: PUB/MH I-73 (e) Wuskwatim Capital Costs

Please update and extend PUB/MH I-65 from the 2010 GRA to incorporate the changed capital costs of Wuskwatim since the CEC hearing by adding the detailed capital costs based on IFF 10 – 2, IFF 11 – 2 and final actual costs for the project and explain any changes from IFF 09.

ANSWER:

Please see the attached table.

As indicated in the response to CAC/MH I-51(d), the increased costs of the generating station between CEF09 and CEF11-2 reflect increases for general civil and electrical & mechanical system contracts and the first unit in-service deferral of six months from September 2011. Please see the response to MIPUG/MH I- 28(b) for a breakdown of the generating station increase. The transmission cost decreased between CEF09 and CEF11-2 to reflect lower costs for the engineering and procurement contract resulting from fewer options and change orders being exercised along with lower contingency costs for transmission line construction.

	CEC 2009/10 ISD	IFF05-1 2011/12 ISD	IFF06-4 2012/13 ISD	IFF07-1 2011/12 ISD	IFF08-1 2011/12 ISD	IFF09-1 2011/12 ISD	IFF10-2 2011/12 ISD	IFF11-2 2011/12 ISD
				(In millions of dollars)				
Wuskwatim Generating Station								
Costs to previous fiscal year end	$32	$103	$133	$193	$339	$510	$813	$1,098
Planning & licensing costs	71	21	8	0	0	0	0	0
Base dollar construction costs	506	608	697	852	740	623	360	195
Escalation	38	61	51	40	27	14	6	3
Capitalized Interest	109	142	164	151	131	93	61	41
In-service cost	756	935	1,052	1,236	1,237	1,239	1,240	1,337
Wuskwatim Transmission								
Costs to previous fiscal year end	0	19	24	40	97	177	234	266
Planning & licensing costs	0	0	0	0	0	0	0	0
Base dollar construction costs	113	130	165	217	165	104	37	20
Escalation	11	8	8	6	3	0	0	0
Capitalized Interest	21	43	60	57	50	35	19	11
In-service cost	145	200	257	320	315	316	291	297
Interest Capitalized on Manitoba Hydro's Equity Contributions								
Capitalized Interest	0	0	41	39	37	36	34	38
In-service cost	0	0	41	39	37	36	34	38
Total in-service cost	**901**	**1,135**	**1,350**	**1,595**	**1,590**	**1,591**	**1,566**	**1,672**

PUB/MH II-67

Reference: PUB/MH I-79 (a), (c), (e), (f)

a) Please restate the analysis in (c) based on IFF12 reflecting that IFRS related adjustments proposed in 2012/13 and 2013/14 are made in 2014/15 when IFRS is to be implemented.

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-67

Reference: PUB/MH I-79 (a), (c), (e), (f)

b) Please restate the analysis in (e) similar to (a) and assume the continuation of rate regulated accounting in 2014/15 for rate setting purposes.

ANSWER:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

PUB/MH II-67

Reference: PUB/MH I-79 (a), (c), (e), (f)

c) Please indicate how the adjustment to retained earnings will be impacted given the transitional election for PP&E being effective April 1 2013, based on the additional IFRS implementation deferral assuming all IFRS related accounting adjustments are delayed until 2014/15 for rate setting purposes.

ANSWER:

Effectively, 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 would now be effective for April 1, 2013; which is the opening date for the comparative IFRS financial reporting period of 2013/14. Any changes made under Canadian GAAP up to the end of the 2012/13 reporting period will be carried forward in the opening net book value of PP&E assets as of April 1, 2013.

PUB/MH II-68

Reference: PUB/MH I-90 (a) & (b) Approved Capital Project Justifications

Please file all approved CPJ(s) to 2011/12 and to September 2012 for major G&T projects.

ANSWER:

Please see the attached CPJs that recently came into service impacting the 2012/13 and 2013/14 test years:

- Attachment 1 – Herblet Lake – The Pas 230kV Transmission (approved July 2010)
- Attachment 2 – Transmission Requirements for the Wuskwatim Generating Station (approved September 2010)
- Attachment 3 – Wuskwatim Generation Station (approved August 2012)
- Attachment 4 – Wuskwatim Staffhouse (approved August 2012)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Herblet Lake – The Pas 230kV Transmission

Recommendation (This section is required for all Addendums).

Decrease the budget by $18,355,000 relative to CPJ Addendum #05 submitted in October 2008, to reflect a number of estimate and scope revisions as detailed herein. No change to the budgetary ISD of September 2011, which corresponds with first power for the Wuskwatim Generating Station.

Project Scope (This section is be filled out only if there is a change to the scope).

Changes to estimates to incorporate additional scope, result in an increase of $824,000 relative to CPJ Addendum #05, as follows:

1) **Re-termination for 230kV Lines P58C and F27P into Rall's Island Station (increase of $693,000).**
   - This work involves design modifications to existing control panels for 230kV Lines F27P and P58C and physically relocating and extending P58C to an existing bay. The relocation of Line P58C will also include salvaging of one dead-end structure and installation of a new dead-end structure. Line F27P will be physically extended in a northerly direction and connected to a new bay. The extension of F27P will include installation of new towers. This work was added, as System Studies indicated that protection changes are required to maintain reliability criteria at the Rall's Island Station.

2) **Relocation of F27P and P58C Line Wave Traps (increase of $70,000):**
   - The swapping of terminating positions for lines F27P and P58C means that the wave trap characteristics, which are specific to a line, also need to be swapped.

3) **Cormorant Mobile Radio System Repeater Installation (increase of $61,000):**
   - Analysis of the mobile radio coverage in the area along transmission line H75P right-of-way has shown that the coverage is inadequate, and that installing a new repeater in the area of MTS's Cormorant facility would rectify this. Radio coverage is required for the safe operation and maintenance of the transmission line.

Background (This section is be filled out only if there is information relevant to the recommendation).

Changes to estimates for the existing scope net to a reduction of $19,179,000 relative to CPJ Addendum #05, as follows:

a) **P:06862 - Herblet Lake – The Pas Ralls Island 230kV Line (gross estimate decreased by $14,912,000):**
   - A very favourable contract bid was received from Valard Construction for construction of transmission line H75P. This allowed the estimate to be reduced by $8,200,000.
   - A favourable contract bid was received from Interlake Power Line Contractors for clearing of the right-of-way for transmission line H75P. This allowed the estimate to be reduced by $2,484,000.
   - With two of the three construction seasons now completed, there is less need for contingency; therefore its estimate has been reduced by $3,800,000.

Background (This section is be filled out only if there is information relevant to the recommendation).

b) **P:14132 - Herblet Lake Transmission Licensing & Environmental Assessment (gross estimate decreased by $1,318,000):**
- The estimate for the remaining duration of the project has been adjusted to reflect the actual expenditures for environmental monitoring during the first four years. The reductions were to helicopter expenses (down $738,000) and consulting services (down $339,000). Contingency was also reduced (down $253,000) to reflect both the reduction to the base estimate and the project nearing its completion date.

c) **P:06861 - Rall's Island - Term Herblet Lake 230kV T/L (gross estimate increased by $1,343,000):**
- Costs for Civil Construction activities were inadvertently omitted when the Wuskwatim high-level estimate was broken up into its detailed components. These activities include installation of foundations, new ground grid, cable trench and chain link fence,

d) **P:06860 - Herblet Lake - Term Pas 230 kV T/L (gross estimate increased by $410,000):**
- Civil Construction estimates increased by $858,000. The previous estimate was based on a high-level scope of work and assumed summer construction over a six-month period. The revised estimate reflects detailed design drawings and winter construction over an eight-month period.
- Engineering Contract Management estimates decreased by $446,000 due primarily to savings realized under the Engineer & Procure contract with ABB Inc. This contract cost less thanks to fewer options and change orders being exercised, and some actual costs coming in lower than the signed Contract Target Price.

e) **P:06868 - Herblet Lake Transmission Development Fund and P:06863 – Herblet Lake Communications (gross estimate decreased by $27,000):**
- Reductions to the estimate for the transmission line and for licensing and environmental assessment result in $88,000 decrease to the calculation for the Transmission Development fund.
- Minor adjustments were made to the estimate for communications, resulting in an increase of $61,000 to gross cost.

f) **Forecast Escalation and Capitalized Interest (decreased by $4,675,000)**
- The various changes to the gross estimate, along with the revised estimate now reflecting 2010 base dollars rather than 2008 base dollars, result in a reduction of $2,379,000 to forecast escalation.
- Likewise, the various changes to the gross estimate result in a reduction of $2,296,000 to capitalized interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

No change.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Reliability-Load Related	New/Increased Generation Delivery	New Asset Addition	50%	$37,434,269
Reliability-Load Related	Capacity Enhancement	New Asset Addition	50%	$37,434,269
				$74,868,538

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911

Recommended Option	NPV Benefits (Costs)
No change.	

Other Alternatives Considered	NPV Benefits (Costs)

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The estimate for Contingency has been reduced by $4,614,000 to a revised total of $2,436,000. The majority of this Contingency is planned under two projects, as follows:

P:06862 - Herblet Lake – The Pas Ralls Island 230kV Line

Contingency of $1,500,000 remains in the estimate (down from $5,295,000), which is approximately 12% of the base forecast expenditures. This contingency may be required to cover the following:

- Potential claims from Valard Construction for issues related to wet site conditions, steel delivery and line re-routing.
- Uncertainty of construction requirements for southern 2km portion of line H75P. Design is currently underway and as such, a high level estimate has been provided.

P:06861 - Rall's Island - Term Herblet Lake 230kV T/L

Contingency of $669,000 remains in the estimate (unchanged from the previous), which is approximately 20% of the base forecast expenditures. This contingency may be required to cover the following:

- Additional costs for labour related to Electrical Construction and Commissioning activities at Rall's Island Station.
- Costs related to design, materials and construction for re-termination of lines P58C and F27P into Rall's Island Station. This work was identified in the summer 2009 as an increase to scope and high level estimate has been provided. Detailed estimates are expected in by fall 2010.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 11,755	$ 11,755	$ -
2009/10	$ 45,743	$ 34,860	$ (10,883)
2010/11	$ 28,960	$ 22,220	$ (6,740)
2011/12	$ 6,556	$ 6,033	$ (523)
2012/13	$ 209	$ 1	$ (209)
2013/14	$ -	$ -	$ -
Total	$ 93,223	$ 74,869	$ (18,355)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The milestone completion dates for the remaining work are as follows:

- P:06860 - Herblet Lake - Term Pas 230 kV T/L: May 2011
- P:06861 - Rall's Island - Terminate Herblet Lake 230kV Line: August 2011
- P:06862 - Herblet Lake – The Pas Ralls Island 230kV Line: June 2011
- P:06863 - Herblet Lake – The Pas Transmission Communications: July 2011

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Transmission Requirements for the Wuskwatim Generating Station.

Recommendation (This section is required for all Addendums).

Decrease the budget by $13,346,000 relative to CPJ Addendum #03 submitted in July 2007, to reflect a number of estimate and scope revisions as detailed herein. Advance the budgetary ISD from June 2012 to September 2011, to correspond with the change in the plan for first power from the Wuskwatim Generating Station.

Project Scope (This section is be filled out only if there is a change to the scope).

Changes to estimates to incorporate additional scope, result in an increase of $2,127,000 relative to the 2007 CPJ Addendum #03, as follows:

1) **Bio-physical Monitoring Program (P:06859, gross increase of $1,508,000):**
   In 2008 a comprehensive five-year bio-physical monitoring program was developed, following review of the Wuskwatim Transmission Clean Environmental Commission (CEC) proceedings, CEC recommendations, and the Manitoba Environment Act Licence conditions. The development of a monitoring program is also a fulfillment of Manitoba Hydro's commitment made to Manitoba Conservation in June of 2007 as part of the licence condition requirements.

2) **Temporary Bypass for Termination of Transmission Line W76B (part of P:06850, gross increase of $619,000):**
   A temporary bypass was necessary when terminating the new Wuskwatim Switching Station – Thompson Birchtree 230kV Transmission Line, due to a quarry being operated by Power Supply which impeded the installation of structures 4 and 5. This quarry has now been closed such that these structures may be installed and the bypass salvaged.

Background (This section is be filled out only if there is information relevant to the recommendation).

Changes to estimates for the existing scope net to a reduction of $15,473,000 relative to the 2007 CPJ Addendum #03, as follows:

1) **Estimate Decreases (total of $24,248,000)**
   a) **Engineer & Procure Contract with ABB Inc. (part of P:06853 and P:06855-P:06858, gross decrease of $9,361,000):**
   Engineering Contract Management's estimate for this contract was reduced, thanks to fewer options and change orders being exercised, and some actual costs coming in lower than the signed Contract Target Price. (The ABB Inc. contract costs were reduced by another $639,000 under the Herblet Lake – The Pas 230kV Transmission complex, for a total reduction of $10,000,000).

   b) **Wuskwatim Switching Station - Herblet Lake 230kV Transmission Line (P:06852, gross decrease of $7,641,000):**
   Construction of transmission lines W73H and W74H has now been completed, with only surveys and clean-up work remaining. As such, contingency costs related to risk were reduced.

Background (This section is be filled out only if there is information relevant to the recommendation).

c) **Wuskwatim Transmission Development Fund (P:06867, gross decrease of $1,582,000):**
This Fund is treated as a capital cost up until the year of in-service, at which point it becomes an operating cost. When the official in-service for Wuskwatim Generation changed from June 2012 (= fiscal 2013) to September 2011 (= fiscal 2012), one year's worth of Transmission Development Fund was no longer a capital cost, and hence this project estimate was reduced. The Fund also decreased in proportion to the cost reductions seen elsewhere in the complex, and the reduction to the Consumer Price Index on which the Fund's calculations are based.

d) **Forecast Escalation (decrease of $5,664,000)**
The various changes to the gross estimate, along with the revised estimate now reflecting 2010 base dollars rather than 2007 base dollars, result in a reduction to forecast escalation.

2) **Estimate Increases (total of $8,775,000):**

a) **Thompson-Birchtree – Establish New Station & SVC (part of P:06853, gross increase of $2,633,000):**
Civil Construction costs increased by $1,962,000 due primarily to additional requirements for foundation piles and costs incurred for winter construction. The additional piles were identified by ABB Inc. as part of their civil design, while the winter construction was required following delays to the provision of those civil design drawings by ABB Inc. The civil construction work that was slated to be completed in the summer of 2009 was shifted to winter 2009/10 in order to maintain the overall project schedule. Also, there were higher costs for work by crews from Electrical Construction and Interlake North Construction ($274,000), Commissioning ($256,000) and Apparatus Maintenance ($203,000), on installation and testing of equipment.

b) **Wuskwatim Generating Station – Wuskwatim Switching Station Transmission Line (P:06865, gross increase of $2,241,000):**
The estimate submitted with the 2007 CPJA reflected a high-level conceptual design, and a cost based on the length of line multiplied by the historical unit costing that was in place at the time. The revised estimate is based on the final design and current market conditions for construction labour, material, fuel, etc., as well as the unit cost premium associated with short line lengths.

c) **K24W Sectionalization at Thompson-Birchtree Station (P:15047, gross increase of $1,000,000):**
The cost of this work was inadvertently missed in the 2007 CPJA.

d) **12.47 kV Feeders from Thompson Birchtree and Wuskwatim Switching Stations (P:14704 & P:14705, gross increase of $992,000):**
The cost for these feeders was inadvertently omitted from the 2007 CPJA.

e) **Addition of Northern AC Cross Trip Schemes at Kelsey Station and Birchtree Station (part of P:06853 and P:06857, gross increase of $664,000):**
The addition of the Wuskwatim facilities will significantly increase the power transfer capability of the Northern AC System. In order to meet NERC, MAPP, and Manitoba Hydro planning standards, and to facilitate the higher flows, it was determined that the fully redundant Northern AC Cross Trip (NACXT) scheme requires upgrades.

f) Smaller changes to various other projects or project components, total an increase of $1,245,000.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

The existing 230-kV transmission system in Northern Manitoba does not have sufficient capacity to accommodate the additional output of the Wuskwatim Generating Station. The justification for the proposed transmission additions is to increase the ability of the transmission system to carry the full output of Wuskwatim to load anywhere in Manitoba.

The facilities help to achieve our corporate strategic goal of expanding the export power market. The facilities will have a high degree of impact on export sales revenue.

Capital Investment Categorization (in thousands of dollars):

By Driver:	Percentage	Amount
Reliability-Import/Export Related	100%	$246,955

By Category:	Percentage	Amount
New/Increased Generation	100%	$246,955

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911 For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV (= PV of BENEFITS - PV of COSTS)
No change.	

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The estimate for Contingency has been reduced to a revised total of $3,708,000. The majority of this Contingency is planned under four projects, as follows:

<u>Wuskwatim New 230kV Switching Station (P:06855)</u>
Contingency of $890,000 or approximately 8% of the base forecast expenditures, to cover:

- Potentials costs associated with SCADA Design and materials related to implementing a device that may be used to interface between SCC and the Gateway device at the Wuskwatim Switching Station.
- Various risks such as market conditions, site conditions, weather, etc. in association with the remaining activities including Design, Construction, Commissioning, Project Management, materials, etc.

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Thompson-Birchtree New Station & SVC (P:06853)

Contingency of $820,000 or approximately 8% of the base forecast expenditures, to cover:

- Potentials costs associated with SCADA Design and materials related to implementing a device that may be used to interface between SCC and the Gateway device at Thompson Birchtree Station.
- Various risks such as market conditions, site conditions, weather, etc. in association with the remaining activities including Design, Construction, Commissioning, Project Management, materials, etc.

Wuskwatim Transmission Communications (P:06866)

Contingency of $603,000 or approximately 33% of the base forecast expenditures, to cover:

- Communication work that may be required related to the Northern AC Cross Trip Scheme at Kelsey Station and Thompson Birchtree Station.
- Various risks such as market conditions, site conditions, weather, etc. in association with the remaining activities including Design, Construction, Commissioning, Project Management, materials, etc.

Wuskwatim Generation Station – Wuskwatim Switching Station 230kV Transmission Line (P:06865)

Contingency of $540,000 or approximately 21% of the base forecast expenditures, to cover various risks such as market conditions, site conditions, weather, etc. in association with the remaining activities including Design, Construction, Commissioning, Project Management, materials, etc.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 36,921	$ 36,921	$ -
2007/08	$ 83,677	$ 54,253	$ (29,424)
2008/09	$ 96,883	$ 72,061	$ (24,822)
2009/10	$ 22,586	$ 45,828	$ 23,242
2010/11	$ 14,187	$ 23,618	$ 9,431
2011/12	$ 6,045	$ 14,273	$ 8,228
2012/13	$ -	$ -	$ -
Total	$ 260,300	$ 246,955	$ (13,346)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name
Wuskwatim Generating Station

Recommendation
That the overall budget be further increased by $44 million for a revised total budget of $1,418 million, reflecting costs to completion.

Project Scope
The staffhouse was transferred to a new CPJ.

Background
Current market conditions, contract prices received and accumulated interest have resulted in the following increases: - Supply & Install of Electrical and Mechanical Systems ($15M) - Other miscellaneous contract increases/decreases ($4M) - Interest ($30M) These increases are offsest by the removal of the preliminary staffhouse budget ($5M).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
EC Minute 893.09 provides the authority for these project activities which in part state that "the 2001 Power Resource Plan", PP&O Report No. 01-5 was reviewed and the Committee approved that the Corporation do the following. "C) Continue to protect early in-service date for Wuskwatim" The project complies with the following Corporate Strategic Goals: CSG 2 - Provide customers with exceptional value CSG 3 - Be a leader in strengthening working relationships with aboriginal peoples. CSG 4 - Improve Corporate financial strength CSG 5 - Maximise export power net revenues

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV (= PV of BENEFITS - PV of COSTS)**
No change.	

Other Alternatives Considered	**NPV (= PV of BENEFITS - PV of COSTS)**

Risk Analysis

Construction activity over the next couple of months is critical with respect to maintaining the in-service dates on the remaining units.

Total Budget

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 1,122,355	$ 1,122,355	$ -
2011/12	$ 200,909	$ 173,734	$ (27,175)
2012/13	$ 65,634	$ 122,204	$ 56,570
2013/14	$ 5,765	$ 245	$ (5,520)
EC Adjustment CEF11	$ (20,000)		
Total	$ 1,374,663	$ 1,418,539	$ 43,876

Proposed Schedule

Construction commenced in July 2006. The current unit in service dates are June 22/2012 (unit 1), August 27/2012 (unit 3) and October 30/2012 (unit 2).

Related Projects

Transmission requirements for the Wuskwatim Generating Station
Wuskwatim Staffhouse

Reference Documents

No change.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Wuskwatim - Staffhouse

Recommendation

Construct a 60 person staffhouse, along with related infrastructure, at Wuskwatim Generating Station to meet the requirements to operate and maintain the station.

Project Scope

Staffhouse Engineering/Construction – 60 Person	$20.2M
Sewer & Water Modifications	$ 3.2M
Project Management	$ 2.3M
Electrical Power Supply Modifications	$ 0.8M
Furniture	$ 0.4M
Communications	$ 0.4M
Parking Lot & Landscaping	$ 0.2M
Recreation Centre Renovate Existing	$ 0.2M
Interest	$ 1.3M
Escalation	$ 1.0M
Total	$30.0M

Background

The original staffing plan for Wuskwatim included staff working a normal 9-day work cycle and commuting to the station from Thompson, Manitoba. The original plan also included a provision for occasional (emergency) overnight stays for a few individuals. Due to issues attracting staff and partnership concerns, Generation North changed the staffing plan to a rotational 8 and 6 facility similar to Kelsey Generating Station. The rotational staffing plan is expected to assist in attracting and retaining staff and to alleviate some of the concerns expressed by the partner aboriginal community.

There are currently no suitable buildings on site that can be utilized as a staffhouse. The concept design for the staffhouse, with regards to layout and room sizes, is similar to the staffhouse at Kelsey Generating Station. The staffhouse will consist of six supervisory and 54 regular, fully-furnished suites; all with private washrooms. The staffhouse will also be equipped with a commercial kitchen, dining area, laundry facilities and reception area.

The existing recreation center will be attached to the staffhouse with a corridor and will include a few minor renovations to open up the offices on the main floor and remove the phone/computer booths on the second floor.

With the construction of the staffhouse, the following infrastructure must be modified for long term usage, as current infrastructure was only installed for temporary use during construction of the Wuskwatim Generating Station.

Background

- Water Treatment Plant
- Sewer and Water Distribution
- Communications
- Construction Power Station

The existing water treatment plant is sized to accommodate 600 people and will require a downsized system designed to accommodate the staffhouse and supporting infrastructure.

The existing sewer and water distribution system requires additional distribution and heat trace repairs, to service the staffhouse and maintain circulation to prevent freezing, as well as reducing the size of the forcemain. The existing lift station will have to be relocated as it is settling and requires constant maintenance/repairs.

The existing communications infrastructure will require additional installations, upgrades and or modifications to provide satellite TV, data, internet, and phone services at the staffhouse.

The existing construction power station has settlement concerns and requires the addition of vertical oil containment.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

Wuskwatim Generating Station's operational philosophy is for a fully staffed facility requiring a Staffhouse sufficient to accommodate the staffing plan.

The project supports or links with the following Corporate goals:
- Attract, develop and retain a highly skilled and motivated workforce that reflects the demographics of Manitoba
- Strengthen working relationships with Aboriginal peoples
- Be recognized as an outstanding corporate citizen and a supporter of economic development in Manitoba

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	**For current corporate rates see G911** 5.75%	**For clarification on hurdle rates, contact the Economic Analysis Department**

Recommended Option	NPV Benefits/(Costs)
To construct a 60 person staffhouse.	

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)

Risk Analysis

A lack of competition with the bidding process could result in escalated costs.

Availability of skilled labour could impact schedule/costs.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year		Proposed Budget
Prev. Actuals	$	72
2012/13	$	1,725
2013/14	$	12,016
2014/15	$	16,223
2015/16+	$	-
Total	$	30,036

Proposed Schedule

Feb 2013 - complete architectural design/drawings
May 2013 – start staffhouse construction
Dec 2014 – staffhouse completion

Related Projects

Wuskwatim Generating Station

Reference Documents

The following documents support or provide background on this recommendation:

Calnitsky Concept design Submission – July 3, 2012

Calnitsky Design Proposal – July 26, 2012

GWH Construction Management Services Ltd. Estimate – July 24, 2012

AECOM Report/Estimate – July 25, 2012

PUB/MH II-69

Reference: PUB/MH I-93 (a) & (b)

Please include the Northern Generation Station improvements and upgrade in the table; also provide annual totals for major G&T capital expenditures shown in the table.

ANSWER:

Please see the attached schedule.

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 Spillway							318	398	398
Pointe du Bois Trans.					83	86	86	86	86
Pointe du Bois Rebuild	421	288	692	834	818	818		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
Northern Generating Station Improvements								536	649
TOTAL	1,683	6,766	9,742	10,957	11,954	16,042	17,781	23,617	23,951

PUB/MH II-70

Reference: PUB/MH I-93 (c)

Please file the PUB directives, MH's correspondence related to the directive and the draft terms and conditions for an Asset Condition Assessment Study.

ANSWER:

The directives respecting Asset Condition reporting may be found in PUB Orders 116/08 and 150/08. In Order 116/08 the directive occurs at pages 345-346; other references to the topic occur at pages 88; 101-103. In Order 150/08 the directive occurs at pages 69-70 with other references at pages 24-26. The orders are available at the following links to the PUB website:

http://www.pub.gov.mb.ca/pdf/08hydro/116-08.pdf
http://www.pub.gov.mb.ca/pdf/08hydro/150-08.pdf

Please see Attachment 1 to this response for Manitoba Hydro's correspondence dated April 1, 2010.

As discussed in the response to PUB/MH I-82(b) the development and use of Asset Condition Reporting and Asset Investment Planning is being handled differently in the different business units.

Manitoba Hydro

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pjramage@hydro.mb.ca

April 1, 2010

Mr. G. Gaudreau
THE PUBLIC UTILITIES BOARD
400 - 330 Portage Avenue
WINNIPEG, Manitoba
R3C 0C4

Dear Mr. Gaudreau:

RE: MANITOBA HYDRO - RESPONSE TO DIRECTIVES 6 AND 7, ORDER 150/08

As part of its 2010/11 and 2011/12 General Rate Application, Manitoba Hydro filed information on Directives issued in previous PUB Orders. With respect to Order 150/08 Directives 6 and 7, Manitoba Hydro advised that it intends to address these directives once it has implemented IFRS and would provide a timeline for addressing these directives by April 1, 2010.

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.

In the interim, and until the IFRS implementation is completed, Manitoba Hydro will be reviewing developments pertaining to the application of performance indicators and measures in other energy utilities in Canada. The results of this work will be taken into account in the Corporation's response to the PUB directive in the timeframe outlined above.

Directive 7 of Order 150/08 directed Manitoba Hydro to prepare and file an asset condition report. As noted in Tab 13, page 11 of Manitoba Hydro's current General Rate Application, Manitoba Hydro undertook to consider the extent to which this issue could be addressed as part of Manitoba Hydro's Depreciation Study, and to advise the PUB as to the specific timeline by April 1, 2010. It now appears that the Depreciation Study will be conducted as an integral part of IFRS implementation and Manitoba Hydro will, therefore, be in a better position to inform the PUB of the extent to which its directive has been addressed by April 1, 2012. In addition to the Depreciation study, Manitoba Hydro is also embarking on two asset-related projects: Enterprise Asset Management and Asset Investment Planning. Manitoba Hydro will also provide the PUB with a progress report on these two projects by April 1, 2012.

If you have any questions or concerns with regard to this letter, please contract the writer at (204) 360-3468.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT
Per:

M Murphy

MARLA D. MURPHY
Barrister & Solicitor

MDM/

PUB/MH II-71

Reference: Annual Report DSM

As indicated on page 7 of the annual report in regards to Power Smart programs, MH references its "plan to invest another $446 million over the next 15 years with expectations of producing an additional 1600 GWh and nearly 67,000,000 m^3 in annual savings"

a) Has Manitoba Hydro considered increasing investments in DSM over the next five years or so to offset demand and allow for the delay of the construction of Keeyask and Conawapa?

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.

As such, Manitoba Hydro respectfully declines to respond to this question at this time.

PUB/MH II-71

Reference: Annual Report DSM

As indicated on page 7 of the annual report in regards to Power Smart programs, MH references its "plan to invest another $446 million over the next 15 years with expectations of producing an additional 1600 GWh and nearly 67,000,000 m^3 in annual savings"

b) If financial resources were not a limitation, what level of DSM spending could be achieved over the next five years and what impact would that have on reducing domestic load to defer the need for new generation?

ANSWER:

Manitoba Hydro undertakes a bottom-up approach in determining the energy savings targets and associated budgets to pursue these targets. Economic energy efficient opportunities are identified and subsequently programs are designed to purse those opportunities. All programs are designed to economically achieve energy savings. As stated in Manitoba Hydro's response to GAC/MH I-7(j), no DSM programs have been curtailed or had participation capped due to financial resource limitations.

PUB/MH II-72

Reference: PUB/MH I-105

As in past proceedings, please file the relevant GHG information for Manitoba.

ANSWER:

Table A14-14: 1990-2010 GHG Emission Summary for Manitoba from page 63 of Part 3 from the National Inventory Report 1990-2010 below provides the most current overview of major sources of GHG emissions in Manitoba. The complete National Inventory Report 1990-2010 is obtainable at the following website:

http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/6598.php

Table A14–14 1990-2010 GHG Emission Summary for Manitoba

Greenhouse Gas Categories		1990	2000	2005	2006	2007	2008	2009	2010
	kt CO_2 equivalent								
TOTAL		**18 300**	**21 000**	**20 600**	**20 700**	**21 300**	**21 200**	**19 800**	**19 800**
ENERGY		12 300	13 300	12 900	12 400	13 100	12 800	11 900	11 600
a.	Stationary Combustion Sources	4 770	5 510	4 760	4 380	4 860	5 010	4 550	3 990
	Electricity and Heat Generation	497	1 030	541	412	486	436	198	89.4
	Fossil Fuel Production and Refining	3.8	0.96	0.46	2.5	0.46	0.46	0.31	0.31
	Mining & Oil and Gas Extraction	75.6	29.2	115	295	323	316	265	175
	Manufacturing Industries	1 060	1 280	1 420	1 290	1 410	1 470	1 420	1 290
	Construction	63.1	61.7	84.9	90.9	102	98.4	76.2	106
	Commercial & Institutional	1 400	1 670	1 450	1 290	1 410	1 500	1 380	1 230
	Residential	1 600	1 400	1 100	950	1 100	1 100	1 100	1 000
	Agriculture & Forestry	42.3	62.7	45.0	46.7	55.1	60.4	113	79.2
b.	Transport[1]	7 140	7 240	7 570	7 450	7 660	7 130	6 700	6 980
	Civil Aviation (Domestic Aviation)	480	550	570	550	570	530	460	450
	Road Transportation	3 750	4 410	4 670	4 940	5 180	4 840	4 860	5 160
	Light-Duty Gasoline Vehicles	1 610	1 310	1 140	1 220	1 240	1 080	1 080	1 150
	Light-Duty Gasoline Trucks	847	1 480	1 630	1 750	1 770	1 540	1 540	1 650
	Heavy-Duty Gasoline Vehicles	341	212	229	248	254	224	227	246
	Motorcycles	7.08	4.40	8.21	8.92	9.14	8.01	8.13	8.81
	Light-Duty Diesel Vehicles	14.5	10.6	11.0	12.1	12.8	12.7	13.5	15.2
	Light-Duty Diesel Trucks	40.1	90.1	100	109	112	108	110	119
	Heavy-Duty Diesel Vehicles	828	1 260	1 540	1 570	1 770	1 860	1 870	1 960
	Propane & Natural Gas Vehicles	61	36	14	15	18	20	17	13
	Railways	600	300	300	200	200	200	500	600
	Navigation (Domestic Marine)	0.02	-	-	-	0.32	-	5.9	-
	Other Transportation	2 300	2 000	2 100	1 700	1 700	1 500	860	750
	Off-Road Gasoline	460	440	370	330	380	310	320	440
	Off-Road Diesel	1 000	720	1 100	850	870	970	430	290
	Pipelines	841	822	596	535	426	244	102	17.8
c.	Fugitive Sources[2]	386	512	557	610	626	623	617	651
	Coal Mining	-	-	-	-	-	-	-	-
	Oil and Natural Gas	386	512	557	610	626	623	617	651
INDUSTRIAL PROCESSES[3]		293	289	369	353	358	367	403	642
a.	Mineral Products	210	79	69	64	63	63	56	67
	Cement Production	140	-	-	-	-	-	-	-
	Lime Production	58	69	59	54	53	51	46	55
	Mineral Products Use	11	11	10	10	11	12	10	12
b.	Chemical Industry	20	44	54	50	51	53	52	47
	Nitric Acid Production	20.1	44.2	53.7	50.2	50.6	53.3	51.9	47.1
	Adipic Acid Production	-	-	-	-	-	-	-	-
	Petrochemical Production[4]	-	-	-	-	-	-	-	-
c.	Metal Production	-	-	-	-	-	-	-	-
	Iron and Steel Production	-	-	-	-	-	-	-	-
	Aluminum Production	-	-	-	-	-	-	-	-
	SF_6 Used in Magnesium Smelters and Casters	-	-	-	-	-	-	-	-
d.	Production and Consumption of Halocarbons and SF_6[5]	4.5	120	200	190	200	200	230	260
e.	Other & Undifferentiated Production[6]	55	42	45	46	40	46	64	270
SOLVENT & OTHER PRODUCT USE		7.1	17	14	12	12	12	9.4	8.8
AGRICULTURE		5 100	6 700	6 500	7 100	7 000	7 200	6 700	6 600
a.	Enteric Fermentation	1 300	1 800	2 200	2 200	2 000	2 000	1 900	1 800
b.	Manure Management	380	570	700	700	660	630	610	610
c.	Agriculture Soils	3 300	4 200	3 600	4 100	4 200	4 500	4 100	4 200
	Direct Sources	1 800	2 200	1 700	2 000	2 100	2 300	2 100	2 200
	Pasture, Range and Paddock Manure	310	460	550	550	510	510	470	450
	Indirect Sources	1 000	2 000	1 000	2 000	2 000	2 000	2 000	2 000
d.	Field Burning of Agricultural Residues	130	75	12	19	16	21	19	14
WASTE		590	760	830	840	850	870	880	890
a.	Solid Waste Disposal on Land	560	720	790	800	820	830	840	850
b.	Wastewater Handling	32	36	37	37	38	38	38	39
c.	Waste Incineration	-	-	-	-	-	-	-	-

Notes:
1. Emissions from Fuel Ethanol are reported within the gasoline transportation sub-categories.
2. Fugitive emissions from refineries are only reported at the national level.
3. Emissions associated with the consumption of PFCs and SF_6 (except for electric utilities) are only reported at the national level.
4. The category Petrochemical Production includes CH_4 and N_2O emissions coming from production of silicon/calcium carbides; of carbon black; of ethylene; of methanol; of ethylene dichloride; and of styrene. CO_2 emissions from this category are in Other & Undifferentiated Production.
5. Only SF_6 emissions from electrical equipment are included. SF_6 emission estimates for semi-conductor manufacturing are only available at national level.
6. Emissions coming from ammonia production are included in the category Other & Undifferentiated Production at provincial levels.

- Indicates no emissions

0.0 Indicates emissions truncated due to rounding

Note that 2003 to 2009 historical estimates have been revised on the basis of updated energy data provided by Statistics Canada.

PUB/MH II-73

Reference: PUB/MH I-107 (b) Marginal Cost

Please indicate the marginal cost (incremental costs) employed in each of the years since 2008 in evaluating DSM initiatives.

ANSWER:

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

PUB/MH II-74

Reference: PUB/MH I-108 (a) & (b)

a) Please provide a chart illustrating the various elements listed in PUB/MH I-108 (a) over the next 20 years.

b) Please provide the net present value analysis of each of the DSM measures using ten-year, 20-year and 30-year benefit time frames.

ANSWER:

The analysis presented within PUB/MH I-108(a) and (b) is based upon a 30 year timeframe.

When assessing the cost effectiveness of an energy efficient measure or a Power Smart Program, Manitoba Hydro assesses its investment based upon the anticipated economic benefits across the life of the energy efficient measure for the proposed program duration. This analysis is undertaken using a 30 year period as it is an appropriate time frame to allow for the incorporation of the full benefits associated with measures with longer expected useful lives. Many of the measures pursued under the Power Smart Plan have 20 year or longer expected measure lives (e.g. insulation, heating systems, lighting, etc.). Arbitrarily ending the timeline of the benefits at 10 years or 20 years will result in the premature truncation of the benefits and would not appropriately reflect the justification behind the utility's investment in the program. For example, a program with measures being installed in year seven will only recognize three years of benefits but will be compared to the full incremental cost of the measure that would incurred in year seven if the analysis is truncated at 10 years. Also, most programs incur marketing and administration costs in the early years of the program to support the future customer engagement and resulting energy benefits. Truncating the analysis period would result in a misrepresentation of the full benefits of the energy efficient measures and of the program overall.

As stated in Manitoba Hydro's response to GAC/MH I-9(i), Manitoba Hydro undertakes a bottom-up approach in determining the energy savings targets and associated budgets required to pursue these targets. As such, undertaking the above analyses would require substantive effort to adjust, rerun and recompile the cost effective analyses for each program as presented in PUB/MH I-108(a) for a 10 year and a 20 year time frame. Accordingly, Manitoba Hydro respectfully declines to undertake this analysis.

PUB/MH II-75

Reference: PUB/MH I-112 Fuel Switching- Economic Impact Assumptions

a) Please provide the 20-year forecast of electricity marginal cost (¢/kWh) employed by MH in the Fuel Switching Report.

ANSWER:

The levelized marginal cost used for the analyses in the Fuel Switching Report is 7.33 cents per kWh.

PUB/MH II-75

Reference: PUB/MH I-112 Fuel Switching- Economic Impact Assumptions

b) Please provide a graphical comparison of (a) with MH's IFF11-2, 20-year average electricity export price assumptions.

ANSWER:

As noted in its response to PUB/MH II-75(a), Manitoba Hydro is unable to provide 20-year forecast of electricity marginal cost data as it is commercially sensitive. Accordingly, Manitoba Hydro is unable to provide the graphical comparison requested.

PUB/MH II-75

Reference: PUB/MH I-112 Fuel Switching- Economic Impact Assumptions

c) Please provide MH's latest forecast of annual natural gas supply prices going out to 2030.

ANSWER:

The forecast of natural gas prices is an integral part of Manitoba Hydro's electricity price forecast in the export market. As such, a specific forecast of natural gas prices is considered to be commercially sensitive.

PUB/MH II-76

Reference: PUB/MH I-112 Economic Impact – Space Heating

a) Please provide a 20 year tabular illustration of MH's utility impact calculations for electric space and water heating of a residential home showing:

i. Annual revenue rates (¢/kWh) in each year
ii. Increased annual residential revenue ($/yr.)
iii. Foregone export revenue prices (¢/kWh)
iv. Foregone export revenue ($/yr.)
v. Natural gas price progression ($/GJ)
vi. Natural gas utility revenue losses ($/yr.)
vii. Net utility revenue gain (loss) in $/yr.
viii. 20 year NPV $ of net utility revenue

ANSWER:

i. The following presents the energy component of electricity rates in constant 2012 dollars as used in the economic analyses presented in the Fuel Switching Report filed as Appendix 26.

Fiscal Year Beginning	Annual Residential Electricity Rate – Energy Charge Only ($/kW.h – 2012 dollars)
2012	$0.06872
2013	$0.06975
2014	$0.07079
2015	$0.07185
2016	$0.07293
2017	$0.07403
2018	$0.07514
2019	$0.07626
2020	$0.07741
2021	$0.07857
2022	$0.07975
2023	$0.08094
2024	$0.08216

Fiscal Year Beginning	Annual Residential Electricity Rate – Energy Charge Only ($/kW.h – 2012 dollars)
2025	$0.08339
2026	$0.08464
2027	$0.08591
2028	$0.08720
2029	$0.08851
2030	$0.08983
2031	$0.09118

Please note the above differs from the electricity rates presented in Manitoba Hydro's response to PUB/MH II-83(a) as those values include the basic monthly charge and are presented in nominal dollars.

ii. Estimated annual residential electricity revenue associated with residential space heating (20 years) and water heating (10 years) is shown in the table below.

Fiscal Year	Estimated Annual Electricity Revenue (2012 dollars)	
	Residential Space Heating	Residential Water Heating
2012	$1,126	$240
2013	$1,143	$243
2014	$1,160	$247
2015	$1,178	$251
2016	$1,195	$254
2017	$1,213	$258
2018	$1,232	$262
2019	$1,250	$266
2020	$1,269	$270
2021	$1,288	$274
2022	$1,307	
2023	$1,327	
2024	$1,347	
2025	$1,367	
2026	$1,387	
2027	$1,408	

Fiscal Year	Estimated Annual Electricity Revenue (2012 dollars)	
	Residential Space Heating	Residential Water Heating
2028	$1,429	
2029	$1,451	
2030	$1,472	
2031	$1,495	

iii. The levelized marginal cost used for the analyses in the Fuel Switching Report is 7.33 cents per kWh. Manitoba Hydro is unable to provide the marginal cost values for each year as this information is commercially sensitive and therefore confidential.

iv. Please see Section 4.1.3 on page 25 of the Fuel Switching Report filed as Appendix 26.

v. Please see Manitoba Hydro's response to PUB/MH II-75(c).

vi. Please see Manitoba Hydro's response to PUB/MH II 76(b).

vii. Please see Manitoba Hydro's response to PUB/MH II 76(b).

viii. Please see Manitoba Hydro's response to PUB/MH II 76(b).

PUB/MH II-76

Reference: PUB/MH I-112 Economic Impact – Space Heating

b) Please provide a 20 year tabular illustration of MH's customer impact calculations showing:

- **Annual electricity billing revenue increases ($/yr.)**
- **Annual natural gas billing revenue decreases ($/yr.)**
- **Annual net customer billing increase (decrease) $/yr.**

ANSWER:

The following table provides the present value customer bill increase (decrease) for customers choosing electric space and water heating relative to natural gas over the life of the equipment. Annual bill amounts cannot be provided as Manitoba Hydro's natural gas price forecast is considered to be commercially sensitive and therefore confidential.

	PV Customer Bill Increase (Decrease) (2012 Dollars)		
	Space Heating	Water Heating	Geothermal
Electricity	$16,335	$1,894	$6,533
Natural Gas	($9,319)	($1,267)	($9,319)
Net Change	$7,016	$627	($2,786)

<u>PUB/MH II-76</u>

Reference: PUB/MH I-112 Economic Impact – Space Heating

c) Please provide the information as (a) and (b) for geothermal space and water heating.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-76(b).

PUB/MH II-77

Reference: Fuel Switching

Please discuss the merits of encouraging current users of electricity for space heating to move to natural gas given the forecasted natural gas glut anticipated for the next decades?

ANSWER:

There is considerable uncertainty with regards to the expected future differentials in fuel costs (e.g. during the 2000 to 2008 period, there was general industry consensus that natural gas prices would remain high and continue to be volatile). In addition, there is considerable uncertainty in terms of whether the market will continue to experience a oversupply of natural gas as a number of market factors can impact this condition, including the export of domestic natural gas overseas, increased demand in North America (e.g. electricity generation), and environmental considerations which could impact production.

The merits, if any, of customers switching their space heating fuel from electricity to natural gas are customer specific. The most obvious consideration is economics, which would take into account the age of the existing furnace, the cost of a replacement furnace, the heating load, the expected future differentials in fuel costs and the expected duration which a customer could expect to realize benefits from fuel switching (e.g. when a customer may consider moving).

Manitoba Hydro recognizes there may be merits for some customers to select natural gas for space heating. The Corporation is taking a more aggressive approach to informing customers of the factors impacting their decisions related to space and water heating. By being informed, Manitoba Hydro expects customers to make decisions that best suits their unique circumstances.

PUB/MH II-78

Reference: 2.2 Residential Space/Water Heating Market Trends

Please provide detailed calculations to illustrate the customer break-even point between natural gas heating costs of operation and electric heat cost of operation and defining the following:

	Primary Gas Cost ($/GJ)	**Residential Electricity Rate (¢/kWh)**	**Export Electricity Market Price (¢/kWh)**
2010/11			
2015/16			
2020/21			
2025/26			

ANSWER:

As shown on page 15 of the report "Economic, Load and Environmental Impacts of Fuel Switching" submitted as Appendix 26, the bundled natural gas rate would need to increase to $0.65/m3 (excluding the basic monthly charge) or $0.55/m3 (including the basic monthly charge) in order for the cost of using a natural gas furnace to equal the current cost of using electricity for space heating.

PUB/MH II-79

Reference: 3.3 Page 20 Environmental (GHG) Impact Assumptions

a) With respect to U.S.-MISO region CO2 emissions, please confirm that:

- **Natural gas CCCT generation is currently competitive with coal generation for both base load and opportunity sales.**
- **MH exports are currently only achieving 1 to 3¢/kWh for MISO Market opportunity sales of clean energy.**
- **MISO coal-generated energy is competitive with CCCT natural gas generation at about 3¢/kWh when natural gas supply prices are $4-5/GJ.**
- **MH opportunity export prices may at times achieve 6 ¢/kWh when natural gas prices are $6-8/GJ.**

ANSWER:

Not confirmed.

As of October 2012, Henry Hub natural gas prices are approximately twice that of Powder River Basin coal on an energy equivalent basis. Even once fuel transportation costs and the lower efficiencies of the steam cycle in a coal plant in comparison with a combined cycle natural gas plant are considered, Powder River Basin coal generation can generally be produced at a lower cost than CCCT generation in Manitoba Hydro's market region.

At times Manitoba Hydro's exports of opportunity energy into the MISO energy market achieves prices in the range of 1 to 3¢/kWh, but during other times prices can be higher. As previously noted in the response to PUB/MH I-132(b) "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." In addition, as noted in the response to PUB/MH II-10(g) "Bilateral contracts can be used for sale associated products such as generation attributes, renewable energy credits or accredited generation capacity if desired."

Natural gas supply prices in the $4-5/GJ will result in MISO market prices higher than 3¢/kWh.

Day ahead and real time MISO market prices do at times exceed 6 ¢/kWh when natural gas prices are $6-8/GJ, and also do at times exceed 6 ¢/kWh when natural gas prices are less than the $6-8/GJ range as noted in the response PUB/MH I-132(b).

PUB/MH II-79

Reference: 3.3 Page 20 Environmental (GHG) Impact Assumptions

b) Please confirm that in the absence of CO2 energy pricing that:

- **MH opportunity exports will typically not displace coal generation if market prices are above 3 ¢/kWh.**
- **MH opportunity exports will typically displace natural gas generation when natural gas supply prices are in excess of $6/GJ**

ANSWER:

Manitoba Hydro cannot confirm either statement outlined above. As explained in the response to PUB/MH I-18(b), there are numerous dynamic market factors that determine the marginal fuel/generator, and in turn the MISO market price at any time, with natural gas price being only one of the inputs.

For example, in the summer of 2008 (June-August) natural gas prices peaked at $13.31/MMBtu (Henry Hub spot price, July 2, 2008). During this period coal was the major fuel on the margin, setting the MISO market price 80.8% of the time while MISO power prices exceeded 10¢/kWh in June and July.

PUB/MH II-80

Reference: Fuel Switching Study 3.2.2. Page 18 Excluded Considerations/Marginal Cost

a) Please provide a graphical and tabular 20 year domestic load at generation for MH's:

- **2011 load forecast.**
- **2011 load forecast reduced to reflect smelter closure circa 2015/16.**
- **2011 load forecast (reduced by smelter closures) and firm export contract commitments at generation.**
- **2011 load forecast (reduced by smelter closures) plus firm export contract commitments and fuel switching loads growing by:**
  - **100 GWh in 2015/16**
  - **200 GWh in 2020/21**
  - **300 GWh in 2025/26**
  - **400 GWH in 2030/31**

ANSWER:

As stated in Manitoba Hydro's response to PUB/MH I-118(b):

"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."

For this reason, the following table includes the 2011 load forecast (which accounts for smelter closures), current and proposed long-term export contracts and specified fuel switching loads.

Fiscal Year	2011/12 Load Forecast	2011/12 Power Resource Plan Current & Proposed Export Contracts	2011/12 Load Forecast plus Export Contracts	Fuel Switching amounts specified in question	Total
2011/12	24615	3493	28108		28108
2012/13	25173	3202	28375		28375
2013/14	25930	3156	29086		29086
2014/15	26284	3156	29440		29440
2015/16	26406	1806	28212	100	28312
2016/17	26794	1642	28436	100	28536
2017/18	27205	1642	28847	100	28947
2018/19	27481	1642	29123	100	29223
2019/20	27966	1642	29608	100	29708
2020/21	28462	2694	31156	200	31356
2021/22	28887	3325	32212	200	32412
2022/23	29311	3410	32721	200	32921
2023/24	29733	3410	33143	200	33343
2024/25	30153	3410	33563	200	33763
2025/26	30570	3639	34209	300	34509
2026/27	30984	3933	34917	300	35217
2027/28	31396	3933	35329	300	35629
2028/29	31801	3933	35734	300	36034
2029/30	32208	3933	36141	300	36441
2030/31	32608	3933	36541	400	36941

PUB/MH II-80

Reference: Fuel Switching Study 3.2.2. Page 18 Excluded Considerations/Marginal Cost

b) For each of the above scenarios, please indicate/explain the latest domestic load only in-service date for:

- Keeyask G.S.
- Conawapa G.S.

ANSWER:

Based on the 2011/12 power resource plan new generation resources are required to meet existing obligations in 2020/21.

PUB/MH II-80

Reference: Fuel Switching Study 3.2.2. Page 18 Excluded Considerations/Marginal Cost

c) For each of the above scenarios, please indicate/discuss:

- **Scope of new transmission infrastructure needs.**
- **Scope of new distribution infrastructure needs.**

ANSWER:

The above noted reference discusses the assumptions that were used in the development of the Fuel Switching Report. While it is recognized that the current transmission and distribution infrastructure would not have sufficient capacity available to serve a large scale shift of heating load to electricity from natural gas, no analysis of the incremental cost has been undertaken at this time.

PUB/MH II-81

Reference: PUB/MH I-113 (a) GSL > 100 and GSL 30-100 Forecasts

a) As MH does not separately forecast peak/shoulder/off-peak energy usage for GSL > 100 KV or GSL 30-100 KV, please provide the 10 year total usage (in MW and GWh) forecast for each of these sub-classes.

ANSWER:

The following table provides the total GWh and MVA forecasts for the Large 30-100 kV and Large >100 kV sub-classes (based on the 2011 Electric Load Forecast).

	Large 30-100 kV		**Large >100 kV**	
	GWH	MVA	GWH	MVA
2011/12	1,049	2,119	4,719	8,229
2012/13	1,067	2,146	4,929	8,618
2013/14	1,219	2,546	5,085	8,917
2014/15	1,243	2,598	5,093	8,919
2015/16	1,292	2,716	4,883	8,565
2016/17	1,366	2,896	4,874	8,552
2017/18	1,399	2,972	4,935	8,644
2018/19	1,366	2,883	4,940	8,624
2019/20	1,414	2,999	5,050	8,803
2020/21	1,470	3,134	5,162	8,988

PUB/MH II-81

Reference: PUB/MH I-113 (a) GSL > 100 and GSL 30-100 Forecasts

b) Please provide the sub-class load factors for GSL > 100 and GSL 30-100 over the last 6 years and for the forecast for the next 10 years.

ANSWER:

The table below provides the average annual load factors (actual and forecast) for the Large 30-100 kV and Large >100 kV subclasses.

	Load Factor	
	Lrg30-100	**Lrg >100**
2006/07	65%	83%
2007/08	65%	82%
2008/09	67%	80%
2009/10	62%	75%
2010/11	63%	79%
2011/12	61%	80%
2011/12	68%	79%
2012/13	68%	78%
2013/14	66%	78%
2014/15	66%	78%
2015/16	65%	78%
2016/17	65%	78%
2017/18	64%	78%
2018/19	65%	78%
2019/20	65%	79%
2020/21	64%	79%

PUB/MH II-82

Reference: PUB/MH I-114 (b) SEP Option 1 – Time of Use Profiles

In the absence of actual SEP Option I user profiles, please provide hypothetic examples of customers that would achieve significant benefits from a TOU-SEP Option 1.

ANSWER:

Customers that may achieve significant benefits from Option 1 of the Surplus Energy Program under current rates would generally have characteristics that include:

1) Significant existing unused production capacity that could be utilized at lower Surplus Energy Program rates to attract additional short-term sales for the products and/or services that could be produced if this capacity was utilized. To achieve this objective, energy costs would generally have to represent a significant share of total input costs and Surplus Energy Program rates would have to continue to provide for reasonable long-term margins relative to firm energy supplies in order to maintain a competitive market position.

2) The ability to provide an alternate fuel-source (back-up) or a willingness to cease operation of the specified Surplus Energy Load in the event of an interruption. The alternative energy source (i.e. backup) would generally need to be reasonably priced over the long term in the event that such interruptions are sustained for longer durations. In many instances, the capital investment to provide for an alternate fuel-source or higher energy costs for alternative energy supplies would negate the potential rate benefits available under Option 1 of the Surplus Energy Program.

3) A willingness to accept the risk of long-term price uncertainty and interruptible nature of energy (both inherent to the Surplus Energy Program), and a willingness to invest the capital required for additional infrastructure and back-up to utilize Option 1 of the Surplus Energy Program.

PUB/MH II-83

Reference: PUB/MH I-115 (c) Future Electric Heat Customer Bills

a) Please provide the IFF11-2 assumptions unit residential revenues for 2010/11, 2020/21 and 2030/31; and assuming MH does not increase basic charges, indicate the unit energy charge for those years.

ANSWER:

The unit residential revenues used in preparation of IFF11-2 are derived below. Please note however that the IFF is based on nominal dollars, therefore the rates depicted in this response are also based on nominal dollars and will not correspond to the rates shown in response to PUB/MH II-76 a) which is based on constant dollars.

Note also that IFF11-2 does not include 2010/11 revenues, however the Residential data has been provided below as it forms the basis for the following years in the IFF. The 2010/11 revenues are based on April 1, 2010 rates whereas the revenues for 2020/21 and 2030/31 are based on April 1, 2011 rates.

2010/11	Basic Charge:	5,350,583 customer bills @ $6.85 =	$ 36,651,494
	> 200 Amp Chg:	37,928 customer bills @ $6.85 =	$ 259,807
	1st Block kWh:	3,619,725,789 kWh @ $0.0638 =	$230,938,505
	Balance of kWh:	3,332,363,328 kWh @ $0.0657 =	$218,936,271
			$486,786,077
	IFF11-02 GCR at approved April 1, 2011 Rates:		
2020/21	Basic Charge:	6,030,564 customer bills @ $6.85 =	$ 41,309,363
	> 200 Amp Chg:	42,748 customer bills @ $6.85 =	$ 292,824
	Energy Charge:	8,161,771,982 kWh @ $0.0662 =	$540,309,305
			$581,911,492
2030/31	Basic Charge:	6,661,704 customer bills @ $6.85 =	$ 45,632,672
	> 200 Amp Chg:	47,222 customer bills @ $6.85 =	$ 323,471
	Energy Charge:	9,388,894,399 kWh @ $0.0662 =	$621,544,809
			$667,500,952

IFF11-2 proposes rate increases of 3.57% for 2012/13, 3.5% increases each year from 2013/14 through to 2023/24, and 2.0% increases thereafter. In determining what the Residential energy rate will be for 2020/21 and 2030/31, several factors need to be taken into account, such as:

- The annual growth in customers;
- The annual growth in energy (kWh);
- The rate design to be employed (i.e. a single energy charge or an inverted rate); and,
- The application of future rate increases either across-the-board or class differentiated.

To obtain an overall class increase of 3.5% with no change to the Basic Monthly Charge requires that the energy charge increase by approximately 3.7%. (In future years where the overall class increase is expected to be 2.0%, no change in the Basic Monthly Charge would result in an energy charge increase of 2.1%). Assuming that the Residential revenue increases for the next twenty years at the same percentage as total General Consumers' Revenue, that there is no increase to the Basic Monthly Charge and the remaining revenue is collected through a single energy charge, the energy rates for 2020/21 and 2030/31 would be $0.0930 and $0.1198 respectively.

PUB/MH II-83

Reference: PUB/MH I-115 (c) Future Electric Heat Customer Bills

b) Using the rates in (a), please provide the average annual residential electricity bill for all electric customers and for standard (or basic) non-electric heat customers for each of the years in (a).

ANSWER:

Based on the average use figures provided in Table 6 (Page 15) of the 2011 Electric Load Forecast (Appendix 8.1 of the filing), the average annual residential electricity bill for electric and non-electric customers is calculated as follows. Please note that the rates depicted in this response are reflective of IFF11-2 which is based on nominal dollars, therefore they will not correspond to the rates shown in response to PUB/MH II-76 a) which is based on constant dollars.

2020/21:

Electric space heat customers:

Annual average use = 25,616 x $0.0930	= $2,382.28
Annual Basic Charge = 12 months x $6.85	= $82.20
Total Annual Bill	= $2,464.48

Non-electric space heat customers:

Annual average use = 10,424 x $0.0930	= $ 969.43
Annual Basic Charge = 12 months x $6.85	= $82.20
Total Annual Bill	= $1,051.63

2030/31:

Electric space heat customers:

Annual average use = 25,830 x $0.1198	= $3,094.43
Annual Basic Charge = 12 months x $6.85	= $82.20
Total Annual Bill	= $3,176.63

Non-electric space heat customers:

Annual average use = 10,928 x $0.1198	= $1,309.17
Annual Basic Charge = 12 months x $6.85	= $82.20
Total Annual Bill	= $1,391.37

PUB/MH II-83

Reference: PUB/MH I-115 (c) Future Electric Heat Customer Bills

c) Using the latest ICF natural gas price forecasts; provide a typical natural gas (Centra) space and water heating bill for each of the years in (a).

ANSWER:

Please see the attachments to this response for the Typical Home & Water Heating Cost comparison charts for each quarter in fiscal 2010/11, based on the natural gas rates that were in effect at that time.

ICF provides forecast information to Manitoba Hydro, and the forecast of natural gas prices is an integral part of Manitoba Hydro’s electricity price forecast in the export market. As such, a specific forecast of natural gas prices is considered to be commercially sensitive and therefore Manitoba Hydro respectfully declines to provide this information.

Typical Home & Water Heating Costs

Average Single Family Residence at Rates in Effect on April 1, 2010

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:
$0.3473 /cubic metre

Electricity:
$0.0657/kilowatt-hour

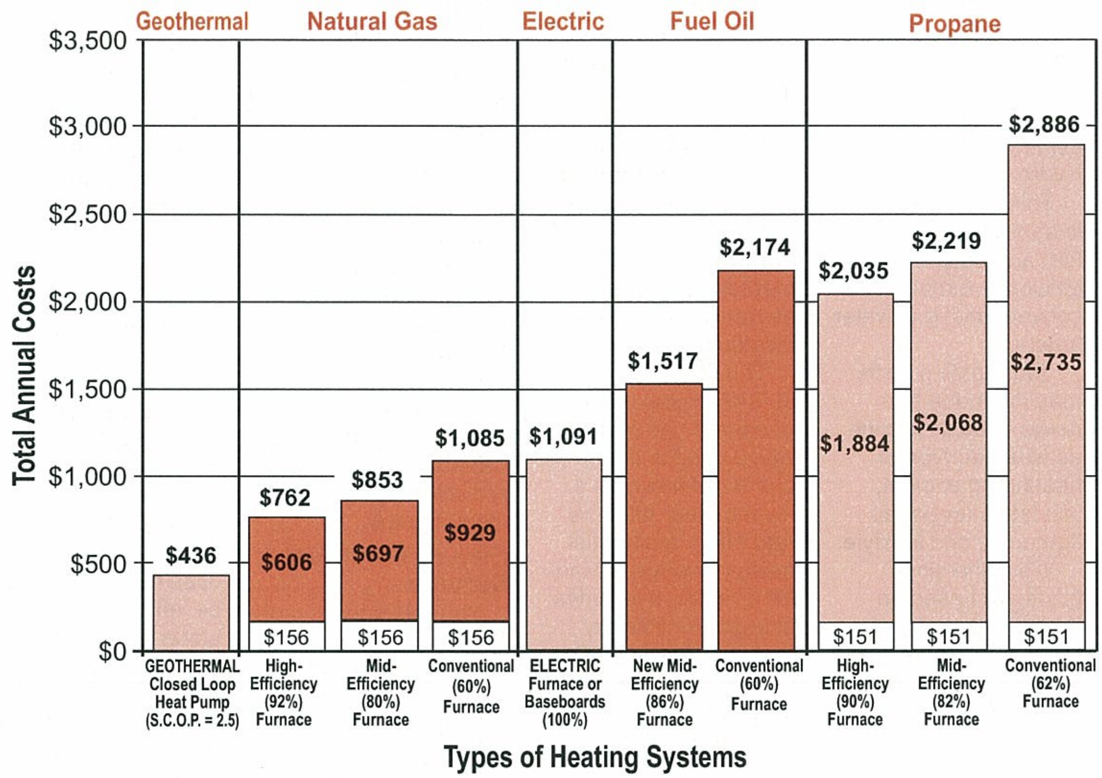
Fuel Oil:
$0.840/litre

Propane:
$0.724/litre

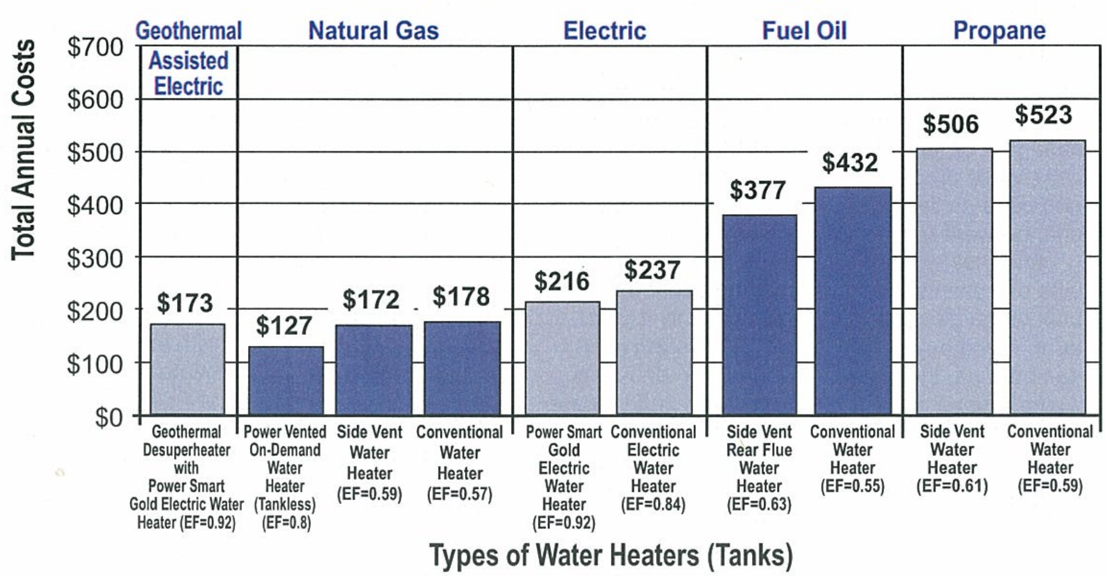
Basic Monthly Charge for Natural Gas is $13, for an Annual Charge of:
$156

Annual Tank Rental Charge for Propane is:
$151

Typical Annual SPACE HEATING COSTS



Typical Annual WATER HEATING COSTS
(2.4 people/household average)



Manitoba Hydro
POWER SMART

Typical Home & Water Heating Costs

Average Single Family Residence at Rates in Effect on April 1, 2010

Weighing 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 range of factors, such as weather, type of heating equipment, insulation levels, air tightness, and lifestyle.

Water-heating costs are based on the typical usage of the average Manitoba household size 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 April 1, 2010.

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 you burn. If you buy your gas from us, the price we charge you for Primary Gas is the same price we pay for the gas in the marketplace. There is no markup. Our Primary Gas rate is currently $0.2148/cubic metre.

If you buy Primary Gas from a broker at a negotiated rate, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges.

The figure of $0.3473/cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate that a residential customer pays to Manitoba Hydro. It includes charges for Primary and Supplemental Gas, as well as for transportation and distribution of the gas.

Manitoba Hydro POWER SMART

Key Points to Consider If You are Thinking of Converting

If you decide to convert your system, consider these points:

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.

If you are still serious about switching to another system after reading this, be sure to get quotations from at least three reputable heating contractors before you make your final decision.

Conventional Furnaces No Longer Manufactured

The home heating chart includes conventional natural gas, fuel oil, and propane furnaces.

Note that since 1992, conventional furnaces were no longer manufactured in Canada, although they are still in operation in many homes.

Size of 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.

If your home needs more than this, you may have to increase the size of your electrical service. This may involve changing your electrical panel or installing an additional one. An electrician should perform an electrical code calculation to advise whether your existing service is adequate to serve the size of furnace or baseboards required to heat your house.

Other Gas Appliances

If you have other gas appliances, such as a range, clothes dryer, fireplace, or swimming pool heater, the cost of switching to an all-electric system may be prohibitive.

Venting

If you are thinking of switching to a high-efficiency natural gas furnace, note that such a furnace does not need a chimney because it is side-wall vented.

You may also have a standard natural gas water heater, in which case the heater can be left on the chimney alone if the chimney meets the requirements of the Natural Gas Installation Code. Your heating contractor can confirm this.

Once the water heater is isolated on the old chimney, if flue gases condense in the chimney, or if back-drafting or other venting problems occur, it may be necessary to modify your venting system.

If costly modifications are required, the simplest solution may be to replace your old natural gas water heater with a side-wall vented version or with an electric water heater, either standard or Power Smart Gold.

Reduced Chimney Ventilation

Converting to electric heat, or to a high-efficiency or mid-efficiency furnace, eliminates or minimizes the uncontrolled ventilation provided by the chimney.

With a conventional furnace, warm moist air continuously exits the house through the chimney. This draws replacement cold dry air into the house through cracks in walls and around windows and doors.

Reducing or eliminating this chimney ventilation will save energy but could also increase humidity levels, reduce air quality, and change the way that air leaks into and out of your home.

Impacts of these changes could include frozen doors and locks, increased condensation/icing on interior surfaces of well-sealed windows, and frost build-up between the panes of poorly sealed windows.

These impacts may be minimized or eliminated by installing:

- improved weather-stripping and caulking on doors and windows
- seasonal window insulator kits (clear poly over inside windows and frames)
- central, washroom, and/or kitchen exhaust fans
- a fresh-air intake into the furnace cold-air return duct
- a heat recovery ventilator (HRV)
- new triple-pane windows.

Typical Home & Water Heating Costs

Average Single Family Residence at Rates in Effect on April 1, 2010

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.

For further details, call for a copy of our brochure on "Carbon Monoxide Safety—Because your family comes first!"

What's 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 roughly 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.

Technical Details

NOTES FOR THE HOME & WATER HEATING COST 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/day that are heated up an average temperature rise of 50˚C.
- The Geothermal Assisted Electric option is based on Manitoba Hydro's field monitoring of nine homes with geothermal heating and desuperheaters where 80% of the average water heating load was provided by the electric heating elements of the water tank and 20% by the desuperheater.
- The cost of heating with propane includes a propane tank rental or lease charge of $151/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 heating with natural gas includes a basic monthly charge of $13 ($156 a year).
- The efficiency of heating systems is given in terms of their "seasonal" efficiency, for maximum accuracy. In the case of furnaces, for example, seasonal efficiency 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.
- S.C.O.P. = 2.5 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.

  S.C.O.P. is defined as the total heat in Btu's produced by the system during the heating season, divided by the total energy in Btu's consumed by the system.

  S.C.O.P.s of geothermal heat pumps typically range from 2.0 to 3.0. For reference, the S.C.O.P. of an electric baseboard heater is 1.

  The higher the S.C.O.P., the more efficient your heat pump and the lower your heating costs. Home heating costs with a geothermal closed loop heat pump with an S.C.O.P. of 2.0 would be $545/year; with an S.C.O.P. of 2.5, $436/year (as in the chart); and with an S.C.O.P. of 3.0, $364/year.
- 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 $0.2148/cubic metre. Primary Gas currently comprises 100% of the gas supplied (Supplemental Gas is 0%.)
- ALL TAXES HAVE BEEN EXCLUDED FROM COSTS.

ENERGY RATES—In Effect on April 1, 2010

	Commodity Charge	Heating Value	
Natural Gas	$0.3473 /cubic metre	35,310	Btu/cubic metre
Electricity	$0.0657/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel Oil	$0.840/litre	36,500	Btu/litre
Propane	$0.724/litre	24,200	Btu/litre

Manitoba Hydro
POWER SMART

Typical home & water heating costs

Average Single Family Residence at Rates in Effect on May 1, 2010

1

Wondering about your energy options for heating...?

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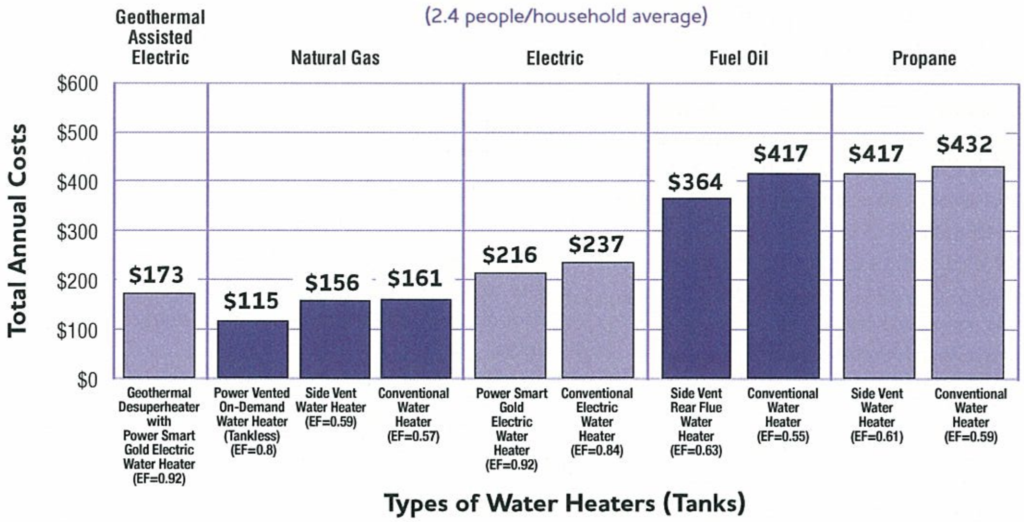
Energy Rates

Natural Gas: **$0.3140**/cubic metre
Electricity: **$0.0657**/kilowatt-hour
Fuel Oil: **$0.812**/litre
Propane: **$0.597**/litre

Basic Monthly Charge for Natural Gas is **$14**, for an Annual Charge of: **$168**

Annual Tank Rental Charge for Propane is: **$151**

Typical Annual
WATER HEATING COSTS
(2.4 people/household average)



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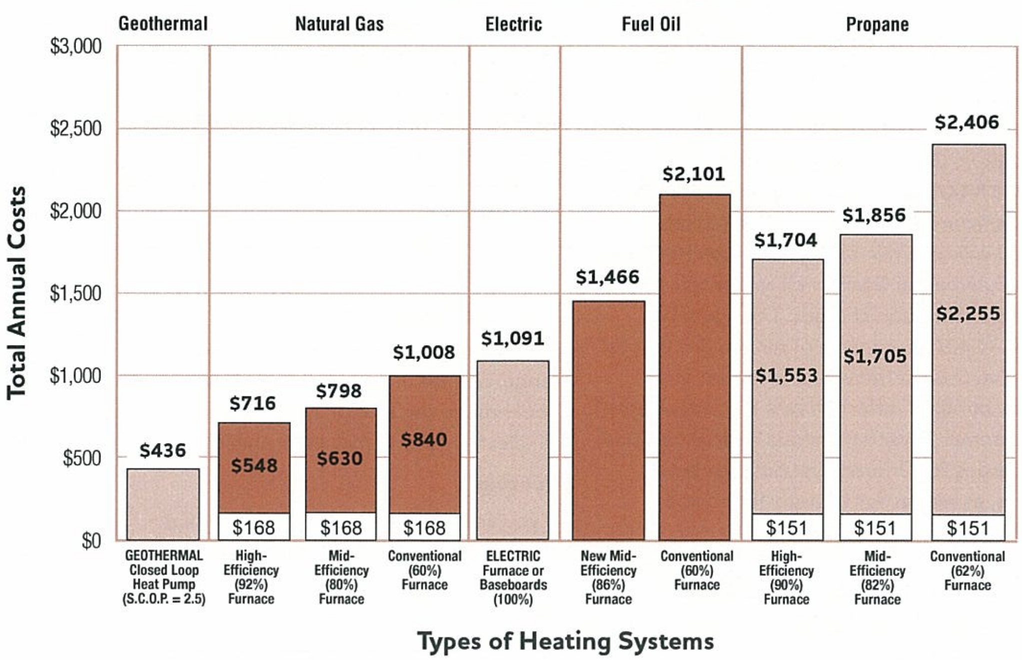

Manitoba Hydro
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Typical home & water heating costs

Average Single Family Residence at Rates in Effect on May 1, 2010

2

Weighing your options

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Key points to consider if you are thinking of converting

If you decide to convert your system, consider these points:

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- new triple-pane windows.

Manitoba Hydro
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Typical home & water heating costs

Average Single Family Residence at Rates in Effect on May 1, 2010

3

Carbon Monoxide Safety

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What's the Payback?

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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 roughly what you can expect to save each year, at current energy rates.

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  S.C.O.P. is defined as the total heat in Btu's produced by the system during the heating season, divided by the total energy in Btu's consumed by the system.

  S.C.O.P.s of geothermal heat pumps typically range from 2.0 to 3.0. For reference, the S.C.O.P. of an electric baseboard heater is 1.

  The higher the S.C.O.P., the more efficient your heat pump and the lower your heating costs. Home heating costs with a geothermal closed loop heat pump with an S.C.O.P. of 2.0 would be $545/year; with an S.C.O.P. of 2.5, $436/year (as in the chart); and with an S.C.O.P. of 3.0, $364/year.
- 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 $0.1844/cubic metre. Primary Gas currently comprises 100% of the gas supplied (Supplemental Gas is 0%.)
- ALL TAXES HAVE BEEN EXCLUDED FROM COSTS.

ENERGY RATES — In Effect on May 1, 2010

	Commodity Charge	Heating Value	
Natural Gas	$0.3140/cubic metre	35,310	Btu/cubic metre
Electricity	$0.0657/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel Oil	$0.812/litre	36,500	Btu/litre
Propane	$0.597/litre	24,200	Btu/litre

Manitoba Hydro
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Typical space & water heating costs

Average single family residence at rates in effect August 1, 2010

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.
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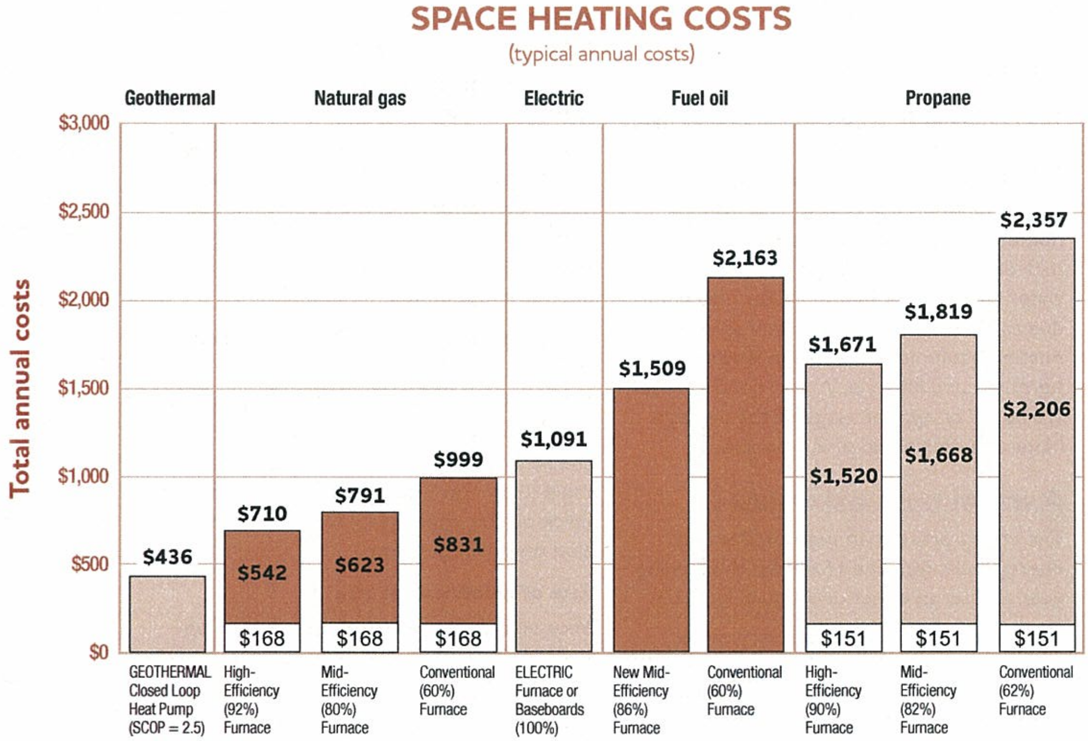


Energy rates

Natural gas:
$0.3106/cubic metre

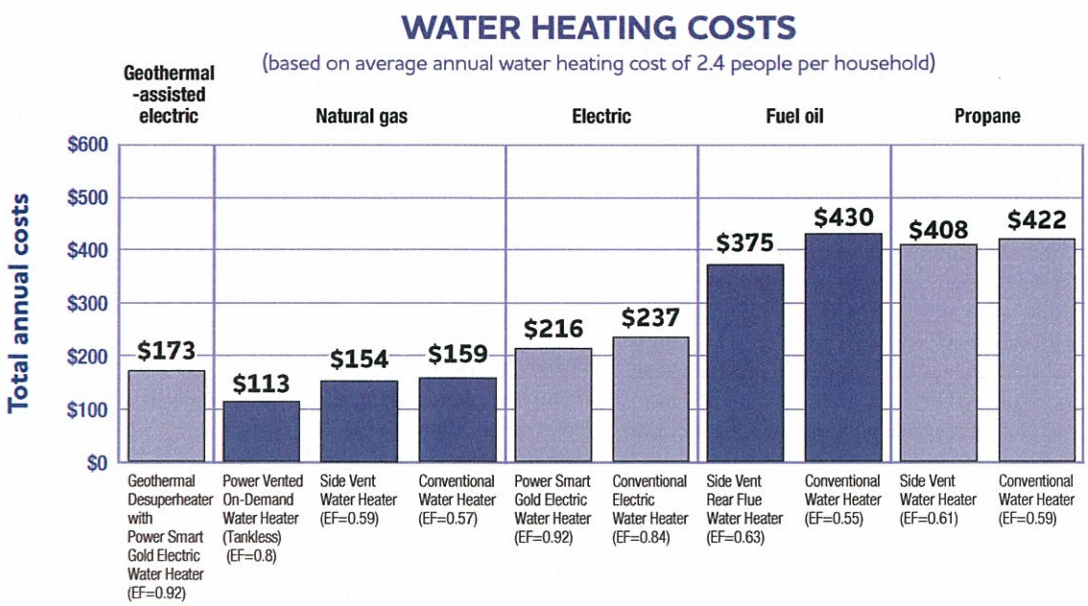
Electricity:
$0.0657/kilowatt-hour

Fuel oil:
$0.836/litre

Propane:
$0.584/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect August 1, 2010

2

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, 2010.

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. If you buy your gas from Manitoba Hydro, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. We do not mark up the cost. Our Primary Gas rate is currently $0.1810 per cubic metre. If you buy Primary Gas from a broker or Manitoba Hydro on a term contract at a fixed rate, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of $0.3106 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate that a residential customer pays to Manitoba Hydro. It includes charges for Primary and supplemental gas, as well as for transportation and distribution of the gas.

Key points if you are thinking of converting

If you decide to convert your system, consider these points:

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 in Canada since 1992, but they have been included because some 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 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 need more than this, so you would have to increase the size of your electrical service. This may involve changing your electrical panel or installing an additional one. An electrician should perform an electrical code calculation to advise whether your existing service is adequate to serve the size of furnace or baseboards 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.

Venting

If you are thinking of switching to a high-efficiency natural gas furnace, note that it will not need a chimney because it is side-wall vented.

You may also have a standard natural gas water heater, in which case the heater can be left on the chimney alone if the chimney meets the requirements of the Natural Gas Installation Code. Your heating contractor can confirm this.

Once the water heater is isolated on the old chimney, if flue gases condense in the chimney, or if back-drafting or other venting problems occur, you may need to modify your venting system.

If costly modifications are required, the simplest solution may be to replace your old natural gas water heater with a side-wall vented style gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency or mid-efficiency furnace will eliminate or minimize the uncontrolled ventilation provided by the chimney.

With a conventional furnace, warm moist air continuously exits the house through the chimney. This draws replacement cold dry air into the house through cracks in walls and around windows and doors.

Reducing or eliminating this chimney ventilation will save energy but may also increase humidity levels, reduce air quality, 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 air pressure could cause frozen doors and locks, increased condensation/icing on interior surfaces of well-sealed windows, and frost build-up between the panes of poorly sealed windows.

You can minimize these effects by installing some combination of the following:

- improved weatherstripping and caulking on doors and windows
- seasonal window insulator kits (clear poly over inside windows and frames)
- a heat recovery ventilator (HRV)
- new triple-pane windows
- 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, 2010

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.

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Divide the estimated cost of switching your system, by the estimated savings.

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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 Geothermal Assisted Electric 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 heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- The efficiency of heating systems is given in terms of their "seasonal" efficiency, for maximum accuracy. In the case of furnaces, for example, seasonal efficiency 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.
- SCOP (Seasonal Co-efficient of Performance) = 2.5 appears in the home heating chart under geothermal closed loop heat pump. It refers to the Seasonal Co-efficient 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 typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0.

  The higher the SCOP rating, the more efficient your heat pump will be in lowering your heating costs. Home heating costs with a geothermal closed loop heat pump with an SCOP of 2.0 would be $545 per year; with an SCOP of 2.5, $436 per year; and with an SCOP of 3.0, $364 per year.
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ENERGY RATES — in effect August 1, 2010

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Manitoba Hydro
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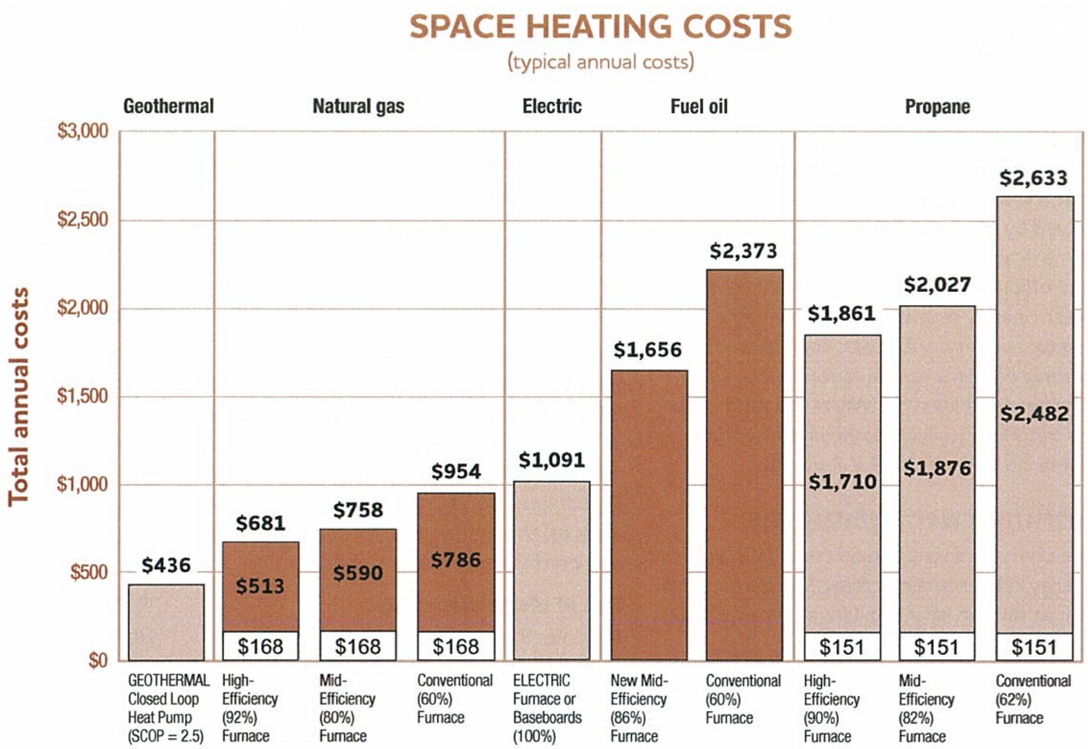

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Natural gas:
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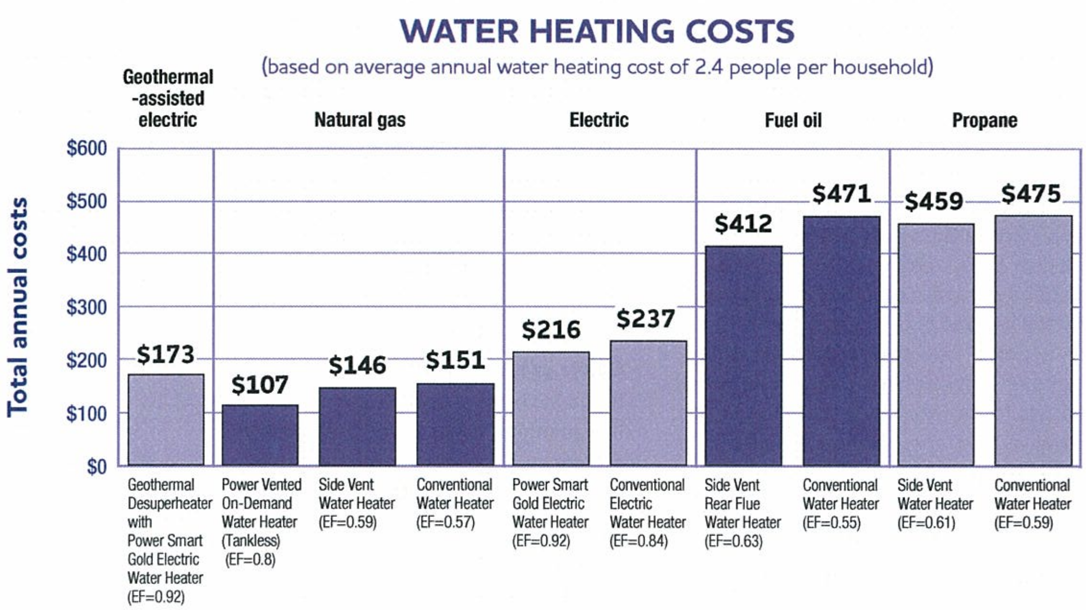

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- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect November 1, 2010

	Commodity charge	Heating value	
Natural gas	$0.2939/cubic metre	35,310	Btu/cubic metre
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Manitoba Hydro
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PUB/MH II-83

Reference: PUB/MH I-115 (c) Future Electric Heat Customer Bills

d) Please indicate the probable difference in utility (MH and Centra) annual billings for each of the years in (a).

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-76(b) for a representation of the estimated bill increase (decrease) for customers choosing electric heating relative to natural gas heating over the life of the equipment.

Annual bill comparisons cannot be provided as Manitoba Hydro's natural gas price forecast is considered to be commercially sensitive and is therefore confidential.

PUB/MH II-84

Reference: PUB/MH I-116 (a) & (b) - Electric Vehicle (PEV Loads

a) Please provide an update of MH electric vehicle load forecasts that have been included in MH's residential load forecasts out to 2030/31 and MH's general load forecasts out to 2030/31.

ANSWER:

Please see Table 17 on page 27 of the 2012 Electric Load Forecast provided as Attachment 1 of the Submission for Interim Rates Effective September 1, 2012 & Response to Request for Additional Information.

PUB/MH II-84

Reference: PUB/MH I-116 (a) & (b) - Electric Vehicle (PEV Loads

b) Please provide MH's views on the most recent survey results (KPMG survey in 2011) which appear to conflict with MH's PEV load forecast of 100 GWh by 2031 and the suggested longer-term 1610 GWh new load scenario (if electric vehicles grow to 70%).

ANSWER:

The above referenced KPMG survey was conducted in 2011, with the report printed in January 2012 and titled "KPMG's Global Automotive Executive Survey 2012". It specifies on page 16 that industry executives in the United States and Western Europe project e-vehicles will account for 6 to 10 percent of new registrations (sales) by 2025. This view was similarly held by industry executives in India and Brazil. Representatives from Japan projected the highest market penetration, anticipating e-car registrations to represent more than 25% of new registrations by 2026.

Manitoba Hydro's 2011 forecast for plug-in electric vehicles (PEVs) is for 42,920 vehicles consuming 110 GW.h by 2030/31. For 2025/26, Manitoba Hydro forecasts that there will be 3,180 new PEVs out of a total of 60,199 vehicles sold in Manitoba. This represents 5.4% of new sales and appears in-line with the findings of the KPMG survey.

The 1610 GW.h sensitivity presented under the 2011 Electric Load Forecast represents the energy impact if market saturation of electric vehicles grows to 70% of new vehicle sales. This is not consistent with the findings of the above referenced KPMG report.

PUB/MH II-84

Reference: PUB/MH I-116 (a) & (b) - Electric Vehicle (PEV Loads

c) Please provide a copy of the KPMG survey report - executive summary and conclusions.

ANSWER:

Please see Appendix 33 for copy of the above requested report.

PUB/MH II-85

Reference: PUB/MH I-118 (b) Industry Growth

a) Please provide the forecast industry sector annual loads (GWh) for 2012/13 to 2017/18 as a tabular extension of the actual individual industry sector annual loads quantified in PUB/MH I-118 (a); also provide annual totals for the 2005/06 to 2017/18 period.

ANSWER:

The table below provides the total actual and forecast GWh for the industry sectors reported in response to PUB/MH I-118(a). As explained in response to PUB/MH I-118(b), Manitoba Hydro cannot provide individual forecast sector data (monthly or annually) as not all customers are forecasted on an individual basis.

Industry Sector Totals

Fiscal Year	GWh
2005/06	5,890
2006/07	5,946
2007/08	6,059
2008/09	6,077
2009/10	5,479
2010/11	5,406
2011/12	5,554
2012/13	5,995
2013/14	6,303
2014/15	6,335
2015/16	6,174
2016/17	6,239
2017/18	6,333

PUB/MH II-85

Reference: PUB/MH I-118 (b) Industry Growth

b) Please calculate the actual annual load reductions by industry sector, assumed in the 2011 load forecast and in IFF11-2 assumptions.

ANSWER:

This response has been prepared based on "actual annual load reductions" as noted in the first part of the request, as forecast load reductions as "assumed in the 2011 load forecast and in IFF11-2 assumptions" are not available by industry sector. The table below provides the actual year-to-year changes in energy usage for each of the industry sectors provided in response to PUB/MH I-118(a). As noted in response to PUB/MH I-118(b), Manitoba Hydro is unable to provide forecast data by industry type as mass market customers are not forecasted individually.

	Annual Load Changes by Industry Sector (MWh)						
	Chemical	Food & Beverage	Mining	Misc.	Petroleum	Primary Metals	Pulp & Paper
2006/07	6,438	11,794	8,192	5,450	49,248	10,519	(35,795)
2007/08	34,093	6,398	7,943	9,782	(19,567)	51,759	22,383
2008/09	90,900	4,482	11,219	2,639	61,823	(62,420)	(90,326)
2009/10	(15,862)	2,595	1,662	(101)	(39,398)	(203,886)	(342,391)
2010/11	76,074	(2,845)	13,228	3,057	(135,420)	120,167	(147,272)
2011/12	13,009	(3,648)	18,490	(178)	87,055	46,811	(14,234)

PUB/MH II-86

Reference: PUB/MH I-134, PUB/MH II-38 (2010 GRA) WPLP

a) Please provide a comparison of the revenue and $/Mwah reflected in IFF09 from PUB/MH II-38 from the 2011 GRA with the updated schedule (PUB/MHI-134 P. 11) based on IFF11-2 for comparable years and comment on the differences.

ANSWER:

Please see the attached schedule for the comparison of average WPLP unit revenues. The change in unit revenues can be entirely attributed to the reduction in forecast export prices since IFF09.

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
PUB/MH I-134 IFF11-2 WPLP Average Unit Revenues:										
WPLP Revenue ($Millions)	57.0	56.6	68.8	90.2	99.3	108.3	117.1	124.3	125.5	133.5
WPLP Average Energy (GW.h)	1,469	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
WPLP Average Unit Revenue ($/MW.h)	38.79	37.29	45.38	59.45	65.49	71.42	77.22	81.95	82.71	87.99
PUB/MH II-38(b) IFF09 WPLP Average Unit Revenues:										
WPLP Revenue ($Millions)	44.4	104.5	112.5	118.7	129.3	134.6	138.6	143.8	142.4	143.3
WPLP Average Energy (GW.h)	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515
WPLP Average Unit Revenue ($/MW.h)	29.28	68.95	74.24	78.36	85.32	88.85	91.44	94.88	93.95	94.58

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PUB/MH I-134 IFF11-2 WPLP Average Unit Revenues:										
WPLP Revenue ($Millions)	138.7	141.2	146.8	143.0	145.8	150.7	154.8	159.3	163.8	168.3
WPLP Average Energy (GW.h)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
WPLP Average Unit Revenue ($/MW.h)	91.40	93.08	96.78	94.28	96.10	99.33	102.04	104.98	107.98	110.97
PUB/MH II-38(b) IFF09 WPLP Average Unit Revenues:										
WPLP Revenue ($Millions)	146.8	148.7	148.4	151.3	160.2	167.4	173.0	178.9	194.5	201.3
WPLP Average Energy (GW.h)	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515
WPLP Average Unit Revenue ($/MW.h)	96.86	98.11	97.91	99.87	105.75	110.50	114.20	118.06	128.37	132.89

PUB/MH II-87

Reference: PUB/MH I-121 (b) Watershed Flows

a) Please provide a table of average monthly flows for the period 2000/01 to 2012/13 for major watersheds as follows:

- **Winnipeg River into Lake Winnipeg**
- **Red River into Lake Winnipeg**
- **Saskatchewan River at Grand Rapids G.S.**
- **Nelson River at Kelsey G.S.**
- **Burntwood River near Thompson.**
- **Nelson River at Kettle G.S.**

ANSWER:

The tables below provide the average monthly flows for the period 2000/01 to 2012/13 for the above listed major watersheds.

	Monthly Average Flow in CMS					
	Winnipeg Rvr. @ Great Falls	Red River @ Lockport	Sask River @ Grand Rapids	Nelson Rvr. @ Kelsey	Burntwood Rvr Near Thomp	Nelson Rvr @ Kettle GS
2000/Apr	814	235	442	2089	980	3161
2000/May	760	185	342	1707	900	3165
2000/Jun	1177	397	289	1521	1134	2842
2000/Jul	1833	775	334	2011	1115	3368
2000/Aug	1472	189	260	2081	1060	3629
2000/Sep	1415	170	205	2261	1089	3552
2000/Oct	994	119	316	2407	1084	3776
2000/Nov	1376	594	416	2393	1106	3637
2000/Dec	1405	179	883	2420	1080	3578
2001/Jan	1145	132	260	2653	1046	3760
2001/Feb	1023	122	390	2671	1016	3991
2001/Mar	1000	146	194	2440	1000	3844

	Monthly Average Flow in CMS					
	Winnipeg Rvr. @ Great Falls	Red River @ Lockport	Sask River @ Grand Rapids	Nelson Rvr. @ Kelsey	Burntwood Rvr Near Thomp	Nelson Rvr @ Kettle GS
2001/Apr	1113	1676	348	2306	883	3507
2001/May	1879	1527	258	2977	928	4367
2001/Jun	2335	569	116	3457	794	4757
2001/Jul	2333	432	133	3755	739	5008
2001/Aug	1804	490	133	2995	739	4428
2001/Sep	1400	124	77	2522	765	3635
2001/Oct	911	88	113	2475	790	3496
2001/Nov	997	125	153	2375	941	3523
2001/Dec	1063	94	172	2304	975	3320
2002/Jan	1030	83	227	2251	975	3563
2002/Feb	1038	67	243	2030	969	3176
2002/Mar	890	69	580	1998	794	2934
2002/Apr	885	190	378	1721	829	2694
2002/May	940	235	372	1770	887	2812
2002/Jun	1648	753	360	1832	990	3192
2002/Jul	2437	911	403	2151	792	3217
2002/Aug	1845	249	391	2427	624	3317
2002/Sep	978	281	256	2407	627	3238
2002/Oct	686	89	383	2345	616	3299
2002/Nov	631	87	349	2162	869	2986
2002/Dec	627	60	285	2232	978	3209
2003/Jan	630	46	630	2130	981	3408
2003/Feb	660	41	894	1902	926	3009
2003/Mar	617	89	568	1780	902	2732
2003/Apr	480	321	299	1604	724	2413
2003/May	388	302	277	1504	592	2310
2003/Jun	327	306	378	1274	617	1917
2003/Jul	287	285	514	1276	615	2047
2003/Aug	301	76	510	1233	600	1757
2003/Sep	273	42	80	861	598	1505
2003/Oct	459	44	46	765	616	1417
2003/Nov	560	31	42	941	794	1558
2003/Dec	732	21	56	1055	869	1853
2004/Jan	827	23	254	1023	835	1853
2004/Feb	886	24	159	1070	819	1845
2004/Mar	848	159	315	1185	686	2064

	Monthly Average Flow in CMS					
	Winnipeg Rvr. @ Great Falls	Red River @ Lockport	Sask River @ Grand Rapids	Nelson Rvr. @ Kelsey	Burntwood Rvr Near Thomp	Nelson Rvr @ Kettle GS
2004/Apr	1073	1317	445	1152	606	1791
2004/May	1340	516	388	1546	545	2220
2004/Jun	2226	838	167	2222	585	2954
2004/Jul	1666	309	387	2708	580	3382
2004/Aug	1032	149	451	2558	570	3413
2004/Sep	1396	222	613	2348	730	3342
2004/Oct	1843	250	521	2481	964	3542
2004/Nov	1719	421	431	2634	1033	3868
2004/Dec	1390	107	828	2520	1010	3603
2005/Jan	1274	86	795	2767	998	4031
2005/Feb	1294	89	682	2967	989	4241
2005/Mar	1308	114	923	2855	982	4063
2005/Apr	1783	1326	434	3083	978	4211
2005/May	1689	576	621	3789	748	5108
2005/Jun	2375	1221	1410	4143	976	5846
2005/Jul	2486	1612	1335	4174	787	6091
2005/Aug	1433	441	767	4314	794	6431
2005/Sep	880	237	1353	4420	882	6554
2005/Oct	738	182	1511	4017	890	6009
2005/Nov	758	173	945	2817	1104	4618
2005/Dec	997	149	1063	2774	1052	4008
2006/Jan	1192	144	1028	2835	1004	4243
2006/Feb	1207	134	1436	2906	988	4238
2006/Mar	1167	163	908	2976	983	4487
2006/Apr	1398	2120	449	3099	1172	4262
2006/May	1304	947	922	3643	974	5107
2006/Jun	990	339	996	3688	976	5233
2006/Jul	565	147	970	3057	1101	4529
2006/Aug	411	95	758	2807	1089	4302
2006/Sep	342	75	303	2048	1091	3423
2006/Oct	326	66	536	1377	1092	2593
2006/Nov	310	63	641	1627	1057	2687
2006/Dec	411	52	665	2196	1004	3285
2007/Jan	538	52	1124	2289	1001	3459
2007/Feb	583	47	1421	2099	998	3204
2007/Mar	567	203	771	1857	990	3059

	Monthly Average Flow in CMS					
	Winnipeg Rvr. @ Great Falls	Red River @ Lockport	Sask River @ Grand Rapids	Nelson Rvr. @ Kelsey	Burntwood Rvr Near Thomp	Nelson Rvr @ Kettle GS
2007/Apr	646	1125	692	1725	1099	2992
2007/May	576	529	775	1885	1314	3590
2007/Jun	1191	854	1286	2313	1124	3665
2007/Jul	1392	603	957	3140	992	4356
2007/Aug	959	148	704	3271	952	4657
2007/Sep	692	78	469	2472	1045	3862
2007/Oct	1001	86	463	2681	1095	3900
2007/Nov	1789	101	590	2986	1105	4346
2007/Dec	1558	64	1063	2628	1063	3693
2008/Jan	1338	55	1064	2849	1035	3998
2008/Feb	1310	51	1198	2736	1005	3983
2008/Mar	1143	66	648	2621	990	3744
2008/Apr	980	420	324	2553	1120	3788
2008/May	1082	269	370	2013	1193	3491
2008/Jun	1798	375	472	2107	1078	3337
2008/Jul	2279	179	660	3404	858	4313
2008/Aug	2252	134	513	4049	701	5246
2008/Sep	1114	140	431	3466	939	4665
2008/Oct	787	276	300	3205	1068	4331
2008/Nov	975	405	342	3095	1041	4276
2008/Dec	1140	157	647	2770	1022	3787
2009/Jan	1120	75	783	2762	1005	3771
2009/Feb	1173	85	827	2555	1013	3776
2009/Mar	1296	435	392	2434	1037	3638
2009/Apr	1519	2400	128	2499	1066	3686
2009/May	2184	1731	276	3445	876	4364
2009/Jun	2487	692	200	4310	791	5454
2009/Jul	2037	547	193	4475	818	6229
2009/Aug	1641	174	223	4362	721	5611
2009/Sep	1655	124	403	4325	627	5211
2009/Oct	1224	161	508	3256	886	4416
2009/Nov	985	233	253	2833	1038	3981
2009/Dec	993	123	761	2633	1063	3659
2010/Jan	1060	99	790	2774	1035	3854
2010/Feb	1081	94	796	2618	1032	3777
2010/Mar	1129	637	557	2446	1043	3607

	Monthly Average Flow in CMS					
	Winnipeg Rvr. @ Great Falls	Red River @ Lockport	Sask River @ Grand Rapids	Nelson Rvr. @ Kelsey	Burntwood Rvr Near Thomp	Nelson Rvr @ Kettle GS
2010/Apr	914	1425	281	2122	1060	3356
2010/May	661	684	152	1549	1007	2598
2010/Jun	1123	895	339	2322	919	3358
2010/Jul	1282	517	1072	3348	816	4035
2010/Aug	1550	371	920	3964	662	4938
2010/Sep	1390	586	704	4313	905	5567
2010/Oct	1296	642	790	4503	918	5666
2010/Nov	1145	614	700	3882	978	5146
2010/Dec	1017	296	785	3126	1014	4267
2011/Jan	1022	208	817	3175	886	4215
2011/Feb	1093	201	709	3409	943	4536
2011/Mar	1104	244	848	3176	1013	4430
2011/Apr	1449	1948	622	2955	1184	4123
2011/May	1838	2181	938	3855	717	4641
2011/Jun	1712	1323	1712	4837	551	5432
2011/Jul	1082	1273	2099	5243	546	5927
2011/Aug	347	858	1721	5450	689	6311
2011/Sep	274	381	815	5421	653	6144
2011/Oct	334	217	809	4253	601	5207
2011/Nov	372	163	690	2882	660	4134
2011/Dec	545	130	785	2875	975	3816
2012/Jan	605	107	726	2785	908	4011
2012/Feb	641	84	539	2419	881	3586
2012/Mar	619	278	505	1932	812	3211
2012/Apr	606	264	717	1773	943	2834
2012/May	614	261	787	1831	924	3072
2012/Jun	927	268	799	1964	1150	3234
2012/Jul	1261	301	1136	2604	1108	3886
2012/Aug	903	134	1247	2772	1040	3993
2012/Sep	681	87	675	2283	1040	3708

PUB/MH II-87

Reference: PUB/MH I-121 (b) Watershed Flows

b) Please provide the tributary drainage area (Sq. KM) for each of the above.

ANSWER:

Approximate drainage areas in square kilometers (km^2):

Winnipeg River into Lake Winnipeg		139,000
Red River into Lake Winnipeg		203,000
Saskatchewan River at Grand Rapids G.S.		347,000
Nelson River at Kelsey G.S.[a]		236,000
(Lake Winnipeg local)	209,000	
(between Lake Winnipeg outlet and Kelsey G.S.)	27,000	
Burntwood River near Thompson[b]		290,000
(upstream of Southern Indian Lake (SIL))	258,000	
(between outlet of SIL and inlet of Split Lake)	32,000	
Nelson River at Kettle G.S.		
(between Split Lake inlet and Kettle G.S.)		9,000

Notes:

(a) Includes the local tributary drainage areas surrounding Lake Winnipeg.

(b) Includes the Churchill River upstream of Missi Falls.

PUB/MH II-87

Reference: PUB/MH I-121 (b) Watershed Flows

c) Please provide the monthly Lake Winnipeg levels within the table in (a).

ANSWER:

The tables below provide the Lake Winnipeg wind eliminated elevation (meters) for the 1st of each month through the period between April 1, 2000 to September 1, 2012.

	1st of the month Elev in M Lake Winnipeg
2000/Apr	217.45
2000/May	217.43
2000/Jun	217.53
2000/Jul	217.68
2000/Aug	217.82
2000/Sep	217.76
2000/Oct	217.70
2000/Nov	217.57
2000/Dec	217.67
2001/Jan	217.68
2001/Feb	217.58
2001/Mar	217.50
2001/Apr	217.43
2001/May	217.62
2001/Jun	217.86
2001/Jul	217.91
2001/Aug	217.88
2001/Sep	217.81
2001/Oct	217.64
2001/Nov	217.45
2001/Dec	217.33
2002/Jan	217.24
2002/Feb	217.17
2002/Mar	217.13

	1st of the month Elev in M Lake Winnipeg
2002/Apr	217.13
2002/May	217.19
2002/Jun	217.24
2002/Jul	217.53
2002/Aug	217.67
2002/Sep	217.63
2002/Oct	217.55
2002/Nov	217.38
2002/Dec	217.29
2003/Jan	217.17
2003/Feb	217.12
2003/Mar	217.12
2003/Apr	217.11
2003/May	217.07
2003/Jun	217.06
2003/Jul	217.07
2003/Aug	217.05
2003/Sep	217.00
2003/Oct	216.97
2003/Nov	216.97
2003/Dec	216.90
2004/Jan	216.91
2004/Feb	216.96
2004/Mar	216.98
2004/Apr	217.06
2004/May	217.33
2004/Jun	217.59
2004/Jul	217.81
2004/Aug	217.85
2004/Sep	217.75
2004/Oct	217.83
2004/Nov	217.81
2004/Dec	217.84
2005/Jan	217.85
2005/Feb	217.82
2005/Mar	217.76

	1st of the month Elev in M Lake Winnipeg
2005/Apr	217.74
2005/May	217.93
2005/Jun	217.95
2005/Jul	218.19
2005/Aug	218.41
2005/Sep	218.21
2005/Oct	217.99
2005/Nov	217.84
2005/Dec	217.79
2006/Jan	217.76
2006/Feb	217.74
2006/Mar	217.74
2006/Apr	217.70
2006/May	217.84
2006/Jun	217.89
2006/Jul	217.84
2006/Aug	217.69
2006/Sep	217.48
2006/Oct	217.33
2006/Nov	217.29
2006/Dec	217.23
2007/Jan	217.13
2007/Feb	217.14
2007/Mar	217.19
2007/Apr	217.20
2007/May	217.33
2007/Jun	217.58
2007/Jul	217.86
2007/Aug	217.90
2007/Sep	217.73
2007/Oct	217.64
2007/Nov	217.56
2007/Dec	217.59
2008/Jan	217.63
2008/Feb	217.64
2008/Mar	217.67

	1st of the month Elev in M Lake Winnipeg
2008/Apr	217.65
2008/May	217.63
2008/Jun	217.69
2008/Jul	217.84
2008/Aug	217.95
2008/Sep	217.84
2008/Oct	217.84
2008/Nov	217.72
2008/Dec	217.63
2009/Jan	217.58
2009/Feb	217.54
2009/Mar	217.55
2009/Apr	217.57
2009/May	217.84
2009/Jun	218.00
2009/Jul	218.04
2009/Aug	218.03
2009/Sep	217.95
2009/Oct	217.79
2009/Nov	217.74
2009/Dec	217.61
2010/Jan	217.56
2010/Feb	217.52
2010/Mar	217.50
2010/Apr	217.51
2010/May	217.64
2010/Jun	217.76
2010/Jul	217.92
2010/Aug	218.03
2010/Sep	218.10
2010/Oct	218.08
2010/Nov	218.03
2010/Dec	217.97
2011/Jan	217.89
2011/Feb	217.83
2011/Mar	217.78

	1st of the month Elev in M Lake Winnipeg
2011/Apr	217.76
2011/May	218.03
2011/Jun	218.34
2011/Jul	218.50
2011/Aug	218.51
2011/Sep	218.33
2011/Oct	217.94
2011/Nov	217.72
2011/Dec	217.61
2012/Jan	217.51
2012/Feb	217.46
2012/Mar	217.39
2012/Apr	217.44
2012/May	217.53
2012/Jun	217.66
2012/Jul	217.80
2012/Aug	217.84
2012/Sep	217.79

PUB/MH II-88

Reference: PUB/MH I-122 Alternative PRP Revenue/Cost Assumptions

Because PRP Alternative Development Plans 1 and 2 are likely to have lower annual revenue requirements, MH is requested to define their average annual rate increase requirements from 2012/13 onward.

a) Please provide the rate increases that flow from the PRP Alternatives 1 and 2.

ANSWER:

Manitoba Hydro notes that Government confirmed, by letter dated January 13, 2011 (a copy of which was filed in the 2010/11, 2011/12 General Rate Application as Exhibit MH- 162) its intention to assign responsibility to an independent body for carrying out an Needs For and Alternatives To (NFAT) assessment of major new hydro generation projects. To date the independent panel has not been announced however Manitoba Hydro expects that the NFAT process will commence in 2013.

As such, Manitoba Hydro respectfully declines to respond to this question at this time.

PUB/MH II-88

Reference: PUB/MH I-122 Alternative PRP Revenue/Cost Assumptions

Because PRP Alternative Development Plans 1 and 2 are likely to have lower annual revenue requirements, MH is requested to define their average annual rate increase requirements from 2012/13 onward.

b) Please provide the IFF revenue and cost assumptions (as per July 2012 Attachment 5 format).

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-88(a).

PUB/MH II-89

Reference: PUB/MH I-125 (a) & (b) New Hydraulic Generation 'Condition' vs. New Supply Obligations

a) Please explain how MH is contractually obligated to build new hydraulic generation but apparently not obligated to supply clean energy under contract.

ANSWER:

Manitoba Hydro intends to but is not obligated under the contracts to construct major new hydraulic generation. If Manitoba Hydro chooses not to build major new hydraulic generation, or new major transmission, the contracts will terminate without penalty.

If Manitoba Hydro does build major new hydraulic generation the new generation will produce more than sufficient dependable energy than required by the contracts. However should conditions occur such as outages on the major transmission system, that interrupt delivery of that energy, Manitoba Hydro has the right to continue to serve the sale with any other available resources including purchased power.

PUB/MH II-89

Reference: PUB/MH I-125 (a) & (b) New Hydraulic Generation 'Condition' vs. New Supply Obligations

b) Please indicate the average annual level of non-hydraulic energy that MH could supply; when NSP/MP/WPS would prefer this to be zero.

ANSWER:

The requested information is commercially sensitive and confidential and cannot be provided. Release of this information would affect ongoing negotiations with other customers.

With regard to the NSP 375/325 Sale Agreement, it is served from existing system resources and will have a lower hydraulic component on average as a result as compared to the other three sale agreements which are served from major new hydraulic generation.

Manitoba Hydro cannot confirm the preferred amounts of non-hydraulic energy for NSP, MP or WPS.

PUB/MH II-90

Reference: PUB/MH I-128 (d) Adverse Water Energy (Summer & Winter)

a) Please explain the process that MH would employ in initiating the adverse water when faced with energy in storage levels below 5,000 GWh (as in 2003/04), very low winter precipitation (and snowpack), very low spring precipitation and a hot dry summer.

ANSWER:

Manitoba Hydro has the right up to September 15 of each contract year to exercise the Adverse Water Provisions in its agreements with Northern States Power. There is no obligation to exercise its rights prior to that date.

Should Manitoba Hydro's forecasts by that date indicate that available hydraulic energy supplies for the upcoming winter season will be insufficient to meet Manitoba Hydro's future requirements and that exercising a portion or all of the Adverse Water Rights is the most economic supply option for the upcoming winter season, Manitoba Hydro will provide notice and will indicate the amount of Adverse Water Right to NSP as required under the agreements.

PUB/MH II-90

Reference: PUB/MH I-128 (d) Adverse Water Energy (Summer & Winter)

b) Please indicate whether the adverse water situation has to be declared on a monthly (?), quarterly or semi-annual; basis.

ANSWER:

Please see the response to part a) of this question.

Manitoba Hydro has additional adverse water rights under other contracts to curtail deliveries of non-firm energy. The timing requirements for exercising these curtailments can be a short as one month.

PUB/MH II-90

Reference: PUB/MH I-128 (d) Adverse Water Energy (Summer & Winter)

c) Please explain the NSP public assertion to Minnesota Public Utility Commission that there would be no summer curtailments.

ANSWER:

Manitoba Hydro did not take participate in NSP's processes before its regulator and cannot confirm the above statement. Further, Manitoba Hydro does not purport to speak for NSP. Manitoba Hydro notes however that its Adverse Water Rights with NSP only apply to the Winter Season, November 1 to April 30, hence this statement is not controversial.

PUB/MH II-91

Reference: PUB/MH I-133 (b) – 7 Year Drought Scenario

a) Given the indicated time problems, please provide by October 31, 2012 the requested 7-year drought scenario starting in 2021/22:

i. Recommended Plan
ii. Alternative Plan 1 (with 250 MW-MP interconnection)
iii. Alternative Plan 2 (CCCT w/o new interconnection)

ANSWER:

As indicated in the response to PUB/MHG I-133(b), 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 of this GRA process.

In addition, Manitoba Hydro considers the drought analysis requested in this information request to be related to proposed plans for new generation. Matters related to Manitoba Hydro's proposed plans for new generation will 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 respectively declines to file a response as it relates to new generation requirements.

Manitoba Hydro's response to MIPUG/MH I-36(a) provides details of the cost of a 7 year drought for the recommended development plan, which for the 2011/12 forecast has a start date for the impact of the drought in year 2013/14. If, for the recommended development plan, analysis of the cost of a 7 year drought commencing in 2014/15 becomes available during this rate application, Manitoba Hydro would file that updated analysis.

PUB/MH II-91

Reference: PUB/MH I-133 (b) – 7 Year Drought Scenario

b) Please comment on the level of drought risk reserve appropriate for the 3 scenarios under the 7-year drought situation.

ANSWER:

Manitoba Hydro does not have a specifically identified "drought risk reserve". Manitoba Hydro has financial targets which take into consideration all major risks faced by Manitoba Hydro including the financial impact of drought.

In addition, Manitoba Hydro considers the drought analysis requested in this information request for Alternative Plan 1 and Alternative Plan 2 to be related to proposed plans for new generation. Matters related to Manitoba Hydro's proposed plans for new generation 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 II-92

Reference: PUB/MH I-133 (d) Drought Management

a) Please confirm that MH does not have a formal drought mitigation plan and does not intend to put one in place.

ANSWER:

As a predominantly hydraulic utility MH plans all of its operations to in effect act as a Drought Plan. It should be recognized however that once a drought has commenced that it cannot be mitigated. They are naturally occurring events, their timing and magnitude cannot be predicted and Manitoba Hydro cannot change the volume of water available at any time including during drought periods. Given those realities, Manitoba Hydro builds new generating plant, maintains the readiness of its existing generation fleet and operates its reservoir storages at all times so that under a repeat of historic worst drought conditions it has or will have adequate energy supplies to meet its firm load obligations without having to declare an energy emergency.

To the extent that the cost of drought can be mitigated Manitoba Hydro does so through its normal operating practices of managing reservoir storages, dispatching its generation fleet and managing its export obligations and market activities in a manner that maximizes net revenue while maintaining a reliable and dependable supply for Manitobans. This practice is continuous, ongoing and is used under all water conditions, not just during droughts.

PUB/MH II-92

Reference: PUB/MH I-133 (d) Drought Management

b) Please confirm that MH does not employ a precipitation-runoff prediction process in order to anticipate a pending drought, but rather employs actual flows and reservoir at specific times in the year to confirm the existence of a drought.

ANSWER:

Manitoba Hydro does not rely on its predictive ability, whether based upon precipitation or stream flow forecasting, to anticipate droughts.

Manitoba Hydro can confirm that its operational planning process relies on measured river flows and reservoir inflows as the basis for its decision making process.

PUB/MH II-92

Reference: PUB/MH I-133 (d) Drought Management

c) Please provide the specific processes and parameters (e.g. in April and September) that MH employs to determine the existence of a drought situation.

ANSWER:

Manitoba Hydro monitors basin wide precipitation (seasonal, last 60 days, last week, daily), river flows, and reservoir inflows throughout the year. This information provides input into Manitoba Hydro's antecedent forecasting procedures which produces water supply forecasts for the balance of the year. These forecasts, as well as forecasts of other key inputs such as water storage levels, reserve targets, committed load, market, and generator and transmission outages are inputs to the HERMES model. Results from the HERMES model include revenue and cost inputs to the IFF.

The existence of a drought can be indicated by:

a) Cumulative and current water supply conditions relative to long term normals, and
b) Net export revenues variance compared to those forecast in the IFF. Significant financial variations associated with below average water conditions are indicative of drought.

Manitoba Hydro reviews current conditions, updates forecasts and prepares operating plan updates on a weekly basis. The Manitoba Hydro executive is provided water supply condition update reports on a weekly basis. The Export Power Risk Management Committee meets quarterly to review current water conditions and updated net export revenue projections for the balance of the year under a range of scenarios. During periods of significant drought the EPRMC reviews the situation more frequently.

For additional information on Manitoba Hydro's antecedent forecasting procedures and the HERMES model please review Chapter 3 of the Manitoba Hydro External Quality Review, "Forecasting Models", dated April 15, 2010.

PUB/MH II-92

Reference: PUB/MH I-133 (d) Drought Management

d) Please confirm that because MH does not attempt to predict drought situations there is only minimal opportunity to mitigate the cost of an imminent drought.

ANSWER:

Not confirmed.

Manitoba Hydro is well-prepared to recognize the onset of drought and to take actions appropriate to address current and potential water supply conditions. As explained in part c) of this question, Manitoba Hydro continually monitors conditions as a normal course of business and responds weekly through appropriate revisions to its operating plans.

However, because precipitation and river flows are mean reverting and because Manitoba Hydro protects against worst case drought conditions, in most circumstances Manitoba Hydro's actions, although justified, are conservative with resultant additional costs or lost opportunity costs. This is because on average water conditions do improve and in some cases, such as in the spring-fall 2010 period, to such an extent that water held back in storage due to concern about low inflows, is subsequently spilled as the result of flood inflows.

PUB/MH II-92

Reference: PUB/MH I-133 (d) Drought Management

e) Please undertake and provide a detailed operational analysis of both MH's defined 5-Year and 7-Year droughts commencing in 2014/15.

ANSWER:

As indicated in Manitoba Hydro's response to PUB/MH I-133(a), Manitoba Hydro has not completed a five year drought impact calculation for a drought beginning in 2014/15. 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).

Please see Manitoba Hydro's response to MIPUG/MH I-36(a) for details of the cost of a seven year drought, which for the 2011/12 forecast has a start date for the impact of the drought in year 2013/14.

PUB/MH II-93

Reference: PUB/MH I-134 (a) WPLP Agreement

a) Please provide a 2012/13 to 2032/33 tabulation of:
i. Average MH export revenue rates (as per Attachment 5/July/12 GRA)
ii. Average MH import /purchase rates (as per Attachment 5/July/12 GRA)
iii. WPLP (IFF11-2) average revenue rates as calculated from forecast revenues (p.2 of 12) and average generation (p.11 of 12)

ANSWER:

Please see the attached schedule.

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(i) Attachment 5 - July 2012 Average Unit Export Sales:										
Total Export Sales ($Millions)	254.8	302.9	350.8	424.3	456.9	484.8	506.6	562.6	771.7	863.4
Firm & Opportunity Export Sales (GW.h)	7,252	7,126	6,956	6,859	6,643	6,434	6,243	6,383	8,184	8,955
Average Unit Export Sales ($/MW.h)	35.14	42.50	50.44	61.85	68.78	75.34	81.14	88.14	94.29	96.42
(ii) Attachment 5 - July 2012 Average Unit Purchases:										
Purchased Energy ($Millions)	120.0	108.5	120.5	125.6	133.7	143.1	151.2	168.0	171.3	170.7
Purchased Energy (GW.h)	3,497	2,259	2,350	2,328	2,371	2,449	2,495	2,751	2,738	2,612
Average Unit Purchases	34.33	48.03	51.26	53.93	56.37	58.43	60.59	61.06	62.58	65.36
(iii) PUB/MH I-134 WPLP Average Unit Revenues:										
WPLP Revenue ($Millions)	57.0	56.6	68.8	90.2	99.3	108.3	117.1	124.3	125.5	133.5
WPLP Average Energy (GW.h)	1,469	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
WPLP Average Unit Revenue ($/MW.h)	38.79	37.29	45.38	59.45	65.49	71.42	77.22	81.95	82.71	87.99

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
(i) Attachment 5 - July 2012 Average Unit Export Sales:										
Total Export Sales ($Millions)	880.0	894.6	1,071.2	1,353.9	1,470.8	1,487.8	1,482.2	1,486.2	1,505.6	1,513.9
Firm & Opportunity Export Sales (GW.h)	8,819	8,726	9,682	12,732	13,667	13,354	12,994	12,680	12,519	12,282
Average Unit Export Sales ($/MW.h)	99.78	102.52	110.63	106.34	107.62	111.41	114.06	117.21	120.27	123.27
(ii) Attachment 5 - July 2012 Average Unit Purchases:										
Purchased Energy ($Millions)	179.7	207.0	188.5	190.6	208.7	222.6	233.0	244.9	253.9	264.9
Purchased Energy (GW.h)	2,647	3,045	2,712	2,675	2,850	2,965	3,031	3,104	3,139	3,190
Average Unit Purchases	67.89	67.97	69.50	71.28	73.21	75.08	76.87	78.89	80.89	83.03
(iii) PUB/MH I-134 WPLP Average Unit Revenues:										
WPLP Revenue ($Millions)	138.7	141.2	146.8	143.0	145.8	150.7	154.8	159.3	163.8	168.3
WPLP Average Energy (GW.h)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
WPLP Average Unit Revenue ($/MW.h)	91.40	93.08	96.78	94.28	96.10	99.33	102.04	104.98	107.98	110.97

PUB/MH II-93

Reference: PUB/MH I-134 (a) WPLP Agreement

b) Please provide the process and calculations to support generation station and transmission expense items as follows:

i. Operating and administrative
ii. Finance (with applicable debt)
iii. Depreciation and amortization (defining service life of each major component)
iv. Water rentals

ANSWER:

i. Please see the attached schedule for a breakdown of projected WPLP operating, administrative and maintenance expenses.

ii. Please see the response to PUB/MH II-50(a) for projected WPLP debt balances and the supporting calculations of finance expense.

iii. Please see the attached for the projected WPLP asset continuity schedule as well as the corresponding depreciation and amortization.

iv. Projected WPLP water rentals are equal to the average Wuskwatim energy (1 517 GW.h) multiplied by the Provincial water rental rate ($3.341/MW.h) which totals $5.1 million.

WUSKWATIM OPERATING, MAINTENANCE & ADMINSTRATION
($Millions)

For the Fiscal Years Ending	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Generating Station Operating, Maintenance & Administrative:										
Wages & Salaries	2.7	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3
Other Operating & Administrative	2.2	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.4	2.5
Generating Station Maintenance	2.2	2.4	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.8
Environmental Monitoring	1.6	1.4	1.6	1.5	1.6	1.4	1.0	1.0	1.1	1.0
Total Generating Station OM&A	8.8	8.8	9.1	9.1	9.4	9.3	9.1	9.2	9.4	9.6
Transmission Operating, Maintenance & Administrative:										
Transmission Line Maintenance	0.2	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.5	0.5
Communications	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Station Maintenance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Transmission OM&A	0.3	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.7	0.7
Development Fund	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Corporate Adjustment for In-service Deferral	(1.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Wuskwatim Operating, Maintenance & Administration	7.8	9.6	10.0	10.1	10.5	10.5	10.3	10.4	10.7	10.9

WUSKWATIM OPERATING, MAINTENANCE & ADMINSTRATION
($Millions)

For the Fiscal Years Ending	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Generating Station Operating, Maintenance & Administrative:										
Wages & Salaries	3.4	3.4	3.5	3.6	3.7	3.7	3.8	3.9	4.0	4.1
Other Operating & Administrative	2.5	2.6	2.7	2.7	2.7	2.8	2.4	2.4	2.5	2.5
Generating Station Maintenance	2.8	2.9	3.0	3.0	3.1	3.1	3.2	3.3	3.3	3.4
Environmental Monitoring	1.1	1.1	1.1	1.1	1.1	0.3	0.3	0.3	0.3	0.3
Total Generating Station OM&A	9.8	10.0	10.2	10.4	10.6	10.0	9.7	9.9	10.1	10.3
Transmission Operating, Maintenance & Administrative:										
Transmission Line Maintenance	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Communications	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Station Maintenance	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Total Transmission OM&A	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Development Fund	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Corporate Adjustment for In-service Deferral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Wuskwatim Operating, Maintenance & Administration	11.1	11.3	11.5	11.7	11.9	11.3	11.1	11.3	11.5	11.7

WUSKWATIM DEPRECIATION & AMORTIZATION
($Millions)

For the Fiscal Years Ending	**Composite Rate**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Generating Station:												
Opening Balance		0.0	445.5	1,336.5	1,336.5	1,336.5	1,336.5	1,336.7	1,336.7	1,336.7	1,336.7	1,336.7
Additions		445.5	891.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.2
Closing Balance		445.5	1,336.5	1,336.5	1,336.5	1,336.5	1,336.7	1,336.7	1,336.7	1,336.7	1,336.7	1,336.9
Generating Station Depreciation	1.41%	0.5	16.7	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Transmission Additions		297.4										
Transmission Depreciation	2.02%	0.5	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Total Depreciation		1.0	22.7	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8

WUSKWATIM DEPRECIATION & AMORTIZATION
($Millions)

For the Fiscal Years Ending	**Composite Rate**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Generating Station:											
Opening Balance		1,336.9	1,340.0	1,340.0	1,340.0	1,340.0	1,340.2	1,340.2	1,340.2	1,340.2	1,340.2
Additions		3.1	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.3
Closing Balance		1,340.0	1,340.0	1,340.0	1,340.0	1,340.2	1,340.2	1,340.2	1,340.2	1,340.2	1,340.5
Generating Station Depreciation	1.41%	18.8	18.9	18.9	18.9	18.9	18.9	18.9	18.9	18.9	18.9
Transmission Additions											
Transmission Depreciation	2.02%	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Total Depreciation		24.8	24.9	24.9	24.9	24.9	24.9	24.9	24.9	24.9	24.9

PUB/MH II-94

Reference: PUB/MH I-135 Keeyask Agreement

a) Please provide the information requested in PUB/MH I-135 a), b) & c), d) as an overall clarification to the potential losses flowing from the Keeyask Agreement.

ANSWER:

As noted in Manitoba Hydro's response to PUB/MH I-25(a), 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 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.

PUB/MH II-94

Reference: PUB/MH I-135 Keeyask Agreement

b) Please correlate the Keeyask partnership revenue stream with average export revenue rates in IFFII-2 revenue assumptions (Attachment 5/July/12 GRA).

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-94(a).

PUB/MH II-95

Reference: PUB/MH I-136 (a) Quarterly Reports

Please provide the tabulation requested in PUB/MH I-136(a) of quarterly and annual energy supply components; the quarterly reports only cover three quarters in each year and may or may not reconcile with MH's Annual Report.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-105(a).

PUB/MH II-96

Reference: PUB/MH I-137 (b) Wind Energy Availability

a) Please provide the percent of annual wind energy that was available in 2009/10, 2010/11, 2011/12 and 2012/13 during:

a. Summer (6) months – peak
b. Summer (6) months – off-pea
c. Winter (6) months – peak
d. Winter (6) months – off-peak

ANSWER:

Manitoba Hydro is unable to provide wind farm specific production information as it is commercially sensitive and confidential. Therefore all wind generation data prior to April 2011, when only one wind farm was in production cannot be provided.

For the seasons commencing in April 2011, the percent of wind energy available was:

a.	On peak	Apr 2011 – Sep 2011	47%
b.	Off peak	Apr 2011 – Sep 2011	53%
c.	On peak	Oct 2011 – Mar 2012	45%
d.	Off peak	Oct 2011 – Mar 2012	55%

PUB/MH II-96

Reference: PUB/MH I-137 (b) Wind Energy Availability

b) Please identify the time periods in 2009/10, 2010/11, 2011/12 and 2012/13 when MH was unavoidably spilling energy at hydraulic generating stations while employing available wind energy.

ANSWER:

The table below summarizes the approximate time periods when MH was spilling while purchasing available wind energy.

Fiscal Year	Spill Period[a]
2009/10	May 14 – Nov 18
2010/11	Jul 24 – Dec 21 Jan 25 – Mar 31
2011/12	Apr 1 – Nov 19 Dec 27 – Jan 03
2012/13	Aug 5 – Sep 17

Notes:

(a) Comprising periods of both continuous and intermittent spill at Kettle G.S.

These periods include situations when incremental spillage was required as a result of incremental wind generation and when spillage was the result of river flows greater than those needed to operate Manitoba Hydro's generating units at maximum.

In establishing the value of wind energy to Manitoba Hydro, a cost associated with incremental spill associated with incremental wind generation is included in the evaluation.

PUB/MH II-97

Reference: PUB/MH I-137 (d) Wind Storage

a) Please explain the financial transaction that allows MP to store wind energy in MH's reservoir system and subsequently reclaim this for MP use or resale; how is MH compensated?

ANSWER:

The details of Manitoba Hydro's wind storage arrangement with Minnesota Power are trade secret, commercially sensitive and confidential. To the extent that there are any financial impacts on Manitoba Hydro, these have been included in the IFF.

PUB/MH II-97

Reference: PUB/MH I-137 (d) Wind Storage

b) Please explain the energy value/balance when MH is experiencing:

- **i. High flows/full reservoirs**
- **ii. Hydraulic generating capacity constraints during peak periods**
- **iii. Dependable energy shortfalls**

ANSWER:

Please see the response to part (a) of this question.

PUB/MH II-97

Reference: PUB/MH I-137 (d) Wind Storage

c) Does MH anticipate an on-going positive cash flow from this storage process?

ANSWER:

Please see the response to part (a) of this question. The provision of storage services to Minnesota Power was part of the negotiated package which included the 250 MW Power Sales Agreement, and MP's commitment to build a major new interconnection from Canada.

PUB/MH II-98

Reference: PUB/MH I-139 (a), (b), (c), (d)& (e)

a) Please explain why MH is introducing Time-of-Use Rates (TOU) into Surplus Energy Program (SEP) when there is minimal interest.

ANSWER:

Manitoba Hydro is not introducing Time-of-Use rates into the Surplus Energy Program in the 2012/13 & 2013/14 General Rate Application. Time-of-Use differentiated pricing has been part of the Surplus Energy Program since its inception. The adoption of Time-of-Use rates within the Surplus Energy Program is not related to customer interest, but rather used to differentiate energy prices to time-of-use costs for providing such energy during standardized time periods commonly used in power markets.

PUB/MH II-98

Reference: PUB/MH I-139 (a), (b), (c), (d) & (e)

b) Please indicate the number of potential Option #1 customers and maximum load (GWh) that may be shifted to off-peak.

ANSWER:

Option 1 of the Surplus Energy Program provides for weekly time-period specific pricing of surplus, non-firm, interruptible energy, which may or may not be desirable for many large industrial customers for these very reasons. The use of Option 1 to facilitate load shifting was not an intended outcome of the Surplus Energy Program's design.

Analysis of how Option 1 may be used to facilitate load shifting is a complex undertaking that involves factors beyond energy pricing, including a customer's available production capacity, willingness to invest in additional production capacity, investment considerations, risk aversion, market opportunities, etc. Many of these factors are not directly related to energy supply and pricing, yet an analysis of the load shifting potential cannot ignore these aspects. The following provides an overview of some contractual and pricing considerations, which will impact use of Option 1for load shifting.

Based on available analysis, only two customers presently have sufficient back-up to reduce their Reference Demand to the maximum allowed under Option 1 (75 percent threshold). Historic demand and consumption levels for most large industrial customers are relatively uniform across all time-of-use periods. It is unlikely that many customers would jeopardize the firm supply available to them under their Supply Agreements by specifying Reference Demand Levels below their historic consumption levels, as Manitoba Hydro is not obligated to provide energy above the Reference Demand level in the event of an interruption. As a result, most customers would not benefit from a reduction in demand charges under an Option 1 load shifting scenario, reducing some of the benefits available from a potentially lower Surplus Energy Program off-peak rate.

In order to facilitate load-shifting, customers will need to reduce consumption levels during the on-peak and shoulder time periods and provide for equivalent increases in consumption during the off-peak period. Facilitating such a process was not the intention behind the design of the Surplus Energy Program. Given the relative difference in annual hours (on-peak and shoulder periods account for approx 67 percent of annual hours), average reductions in demand levels during the on-peak and shoulder periods would need to be approximately half of the demand increase required in the off-peak period. In some instances, such an off-peak increase will require the customer to obtain additional transmission/distribution supply capacity beyond their presently contracted capacity. Additional supply capacity may be available, but any incremental costs for providing such capacity would be the responsibility of the customer. Most customers would not be interested in investing capital for capacity improvements that do not provide for firm supply.

Using the 75 percent of Total Demand criteria for specifying Reference Demand, customers with a load factor of approximately 80 percent would be limited to an increase in off-peak consumption equal to about 25 percent of their current off-peak period consumption. Present Contract Demand levels would further restrict the amount of energy that many customers could consume in the off-peak period without incurring potential costs for supply capacity enhancements.

While the details of Option 1 terms and conditions have been distributed to industrial customers, no customers have indicated a strong desire to subscribe to significant amounts of Option 1 energy. Any incremental load served under the Surplus Energy Program in the off-peak period will be provided on a cost-recovery basis, ensuring revenue-neutrality for Manitoba Hydro. Given that the design of the program was not intended to facilitate load shifting, and recognizing the many other influencing factors that will contribute to a customer’s decision to use the program for such purpose create significant uncertainty about possible outcomes, Manitoba Hydro is unable to provide an estimate for the maximum load that may be shifted to the off-peak period under the program. Given that this form of SEP pricing has been available since 2000, and no customers have selected Option 1 since that time, a significant load shifting as a result of this program would appear to be unlikely.

PUB/MH II-98

Reference: PUB/MH I-139 (a), (b), (c), (d)& (e)

c) Please explain the benefits and risks to MH of significant uptake of Option #1 off-peak energy.

ANSWER:

The supply of energy under the Surplus Energy Program is revenue neutral for Manitoba Hydro with weekly prices varying in accordance with the cost of obtaining this energy for use by potential Option 1 customers. Energy is priced specific to the periods in which it is provided, based on the costs for providing energy in that period. The off-peak period is treated in the same manner as other time-of-use periods specified under the Surplus Energy Program. Since supply of surplus energy is constrained by contract demand levels specified under a customer's Supply Agreement, Manitoba Hydro does not have an obligation to incur costs for enhancing the supply to a customer in order to accommodate use of surplus energy.

In the event that energy is unavailable, Surplus Energy Program supply to customers would be interrupted as allowed by the terms of the program, mitigating the risk to Manitoba Hydro of maintaining a firm supply.

Significant up-take of off-peak energy under Option 1 by potential Surplus Energy Program customers could be of benefit to Manitoba Hydro in instances of high water flows and constrained transmission interconnections with export markets. Under such circumstances, additional revenue could be derived from additional energy sales to domestic Option 1 customers, which could not otherwise be delivered to export markets.

Some revenue risk does exist if customers choose to convert load presently served under firm supply to the potentially lower-priced non-firm supply offered under the Surplus Energy Program. The prospects of such load conversions are highly speculative under present conditions and would be dependent on customer willingness to accept the risk of an non-firm, interruptible supply. Potential revenue losses of such conversions could potentially be recovered rapidly during periods of drought when non-firm load may be interrupted, reducing the costs of obtaining and supplying energy during droughts.

PUB/MH II-98

Reference: PUB/MH I-139 (a), (b), (c), (d)& (e)

d) Please define and estimate the potential increase in Option #2 peak and off-peak energy from Manitoba Government Mandate on the use of coal in space and water heating.

ANSWER:

At present, it is estimated that potential increase in Option 2 load arising from the Provincial mandate on the use of coal for space and water heating is approximately 2.2 GWh. This increase in Option 2 load arises predominately from rural customers that do not have access to alternative forms of energy such as natural gas or low-cost biomass. Given their alternatives, these customers are willing to accept the inherent risk of a non-firm, interruptible supply.

PUB/MH II-99

Reference: PUB/MH I-141 (a),(b),(c),& (d) Curtailable Rate Program

a) Please explain how the 180 MW of CRP (reduced from 230 MW) is reflected in the 2011/12 PRP incremental industrial DSM going forward; why not negative values?

ANSWER:

The capacity associated with the Curtailable Rates Program is not included as part of the Demand Side Management dependable capacity used in the power resource plan. From the planning perspective Manitoba Hydro does not count on curtailable loads to meet capacity requirements in the long term because there is no assurance that the Curtailable Rates Program will exist one or two decades into the future. An additional reason for not including curtailable capacity in long-term resource planning is that the limitations of CRP may result in it not being available when required during critical peak load demand periods.

PUB/MH II-99

Reference: PUB/MH I-141 (a),(b),(c),& (d) Curtailable Rate Program

b) Please explain why MH sees a reduced value in the CRP.

ANSWER:

The reduced value in the CRP is due to the following reasons:

Greater Certainty in Contingency Reserve Requirements

The CRP Option 'R' Curtailable Load can be used to supply supplemental contingency reserves. As of January 1st, 2010, Manitoba Hydro's supplemental contingency reserve obligation (90 MW) is defined by the MH-MISO Contingency Reserve Sharing Group (CRSG) Agreement with MISO.

Given that this agreement has no sunset date, and that reserve sharing is mutually beneficial, MH is confident that its reserve obligation will not increase in the foreseeable future. Prior to the MH-MISO CRSG, there was greater uncertainty about MH's long-term contingency reserve requirements (beyond a year) because of: the dissolving of the Mid-Continent Area Power Pool (MAPP) Generation Reserve Sharing Pool, movements of some former MAPP GRSP members to other contingency reserve sharing groups, significant changes in the MISO region with the development of the MISO Ancillary Services Market, and a sunset date to the predecessor contingency reserve sharing group. For these reasons, prior to January 1, 2010 there was greater value in having additional Option 'R' reserve in place, should MH's reserve requirement increase significantly.

Please also see Manitoba Hydro's response to MIPUG/MH I-44(h) for reference to the MH-MISO CRSG.

Retirement of the MAPP GRSP

As discussed above and in PUB/MH I-141(a), the MAPP GRSP retired on January 1, 2010. Prior to this Option 'A' and Option 'C' loads could be used to manage Manitoba Hydro's capacity obligations. An imbalance would have subjected Manitoba Hydro to significant financial penalties. With the MAPP GRSP retiring, this benefit from curtailable load ended.

Near-term Capacity Surplus in Export Market

The value of Option ‘A’ Load in the near term is reduced due to less export demand for capacity. Industrial load reductions and reduced load growth projections related to the continued economic downturn have resulted in near-term capacity surplus in MH’s export market regions. As a result, the value of capacity in the near-term has diminished which has added downward pressure on the value of Option ‘A’ load to MH.

Notification Timing Requirements

The value of Option ‘C’ load is less relative to Option ‘R’ and Option ‘A’ due to its longer notification timing requirements. There is greater reliability value to having shorter notification requirements for curtailable load. Option ‘C’ load requires one hour notice vs. Option ‘R’ and Option ‘A’ load which only requires five minute notice.

MH will typically achieve its overall hourly supply and demand balance using the export markets. MH can adjust for *anticipated* deficiencies using the MISO real-time market, where the bid window closes 30 minutes prior to the time of delivery. After this bid window closes, deficiencies must be addressed using reliability measures, such as calling upon uneconomic generation or exercising curtailable load. However, Option ‘C’ load is of limited value because the notification window is longer.

PUB/MH II-100

Reference: PUB/MH I-145 Demand Energy Rebalancing

a) Please expand tables in PUB/MH I-145 to include unit energy and unit demand rates (as requested).

ANSWER:

The energy and demand rates applicable to each fiscal year are provided below as separate tables.

Fiscal 2004/05:

April 1, 2004 – July 31,2004

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:		$0.02120	$0.02010	$0.01975	$0.01975
First 1,090 kWh @	$0.05810				
Next 10,000 kWh @	$0.05550				
Next 8,500 kWh @	$0.03520				
Balance of kWh @	$0.02120				
Demand Charge:					
First 50 kV.A @	No Charge	All kV.A	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.32	$ 8.32	$7.089	$6.051	$5.401

August 1, 2004 - March 31, 2005

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:		$0.02339	$0.02196	$0.02138	$0.02119
First 1,090 kWh @	$0.05860				
Next 10,000 kWh @	$0.03850				
Next 8,500 kWh @	$0.02339				
Balance of kWh @					
Demand Charge:					
First 50 kV.A @	No Charge	All kV.A	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.32	$8.32	$7.089	$6.051	$5.401

Fiscal 2005/06:

April 1, 2005 - March 31, 2006

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:		$0.02444	$0.02284	$0.02215	$0.02187
First 11,090 kWh @	$0.06004				
Next 8,500 kWh @	$0.03936				
Balance of kWh @	$0.02444				
Demand Charge:					
First 50 kV.A @	No Charge	All kV.A	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.32	$8.32	$7.089	$6.051	$5.401

Fiscal 2006/07:

April 1, 2006 - February 28, 2007

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:		$0.02444	$0.02284	$0.02215	$0.02187
First 11,090 kWh @	$0.06004				
Next 8,500 kWh @	$0.03936				
Balance of kWh @	$0.02444				
Demand Charge:					
First 50 kV.A @	No Charge	All kV.A	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.32	$8.32	$7.089	$6.051	$5.401

March 1, 2007 - March 31, 2007

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:		$0.0255	$0.0238	$0.0229	$0.0226
First 11,000 kWh @	$0.0618				
Next 8,500 kWh @	$0.0400				
Balance of kWh @	$0.0255				
Demand Charge:					
First 50 kV.A @	No Charge	All kV.A	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.34	$8.34	$7.08	$6.06	$5.40

Fiscal 2007/08:

April 1, 2007 - March 31, 2008

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:		$0.0255	$0.0238	$0.0229	$0.0226
First 11,000 kWh @	$0.0618				
Next 8,500 kWh @	$0.0400				
Balance of kWh @	$0.0255				
Demand Charge:					
First 50 kV.A @	No Charge	All kV.A	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.34	$8.34	$7.08	$6.06	$5.40

Fiscal 2008/09:

April 1, 2008 - June 30, 2008

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:		$0.0255	$0.0238	$0.0229	$0.0226
First 11,000 kWh @	$0.0618				
Next 8,500 kWh @	$0.0400				
Balance of kWh @	$0.0255				
Demand Charge:					
First 50 kV.A @	No Charge	All kV.A	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.34	$8.34	$7.08	$6.06	$5.40

July 1, 2008 - March 31, 2009

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:			$0.0259	$0.0247	$0.0242
First 11,000 kWh @	$0.0648	$0.0613			
Next 8,500 kWh @	$0.0430	$0.0430			
Balance of kWh @	$0.0273	$0.0273			
Demand Charge:					
First 50 kV.A @	No Charge	No Charge	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.34	$ 8.34	$7.08	$6.06	$5.40

Fiscal 2009/10:

April 1, 2009 - March 31, 2010

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:			$0.0273	$0.0258	$0.0252
First 11,000 kWh @	$0.0666	$0.0642			
Next 8,500 kWh @	$0.0448	$0.0448			
Balance of kWh @	$0.0286	$0.0286			
Demand Charge:					
First 50 kV.A @	No Charge	No Charge	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.34	$8.34	$7.08	$6.06	$5.40

Fiscal 2010/11:

April 1, 2010 - March 31, 2011

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:			$0.0288	$0.0269	$0.0262
First 11,000 kWh @	$0.0684	$0.0684			
Next 8,500 kWh @	$0.0469	$0.0469			
Balance of kWh @	$0.0305	$0.0305			
Demand Charge:					
First 50 kV.A @	No Charge	No Charge	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.34	$8.34	$7.08	$6.06	$5.40

Fiscal 2011/12:

April 1, 2011 - March 31, 2012

	Small	Medium	Large 750-30	Large 30-100	Large >100
Energy Charge:			$0.0297	$0.0277	$0.0269
First 11,000 kWh @	$0.0696	$ 0.0696			
Next 8,500 kWh @	$0.0484	$0.0484			
Balance of kWh @	$0.0315	$0.0315			
Demand Charge:					
First 50 kV.A @	No Charge	No Charge	All kV.A	All kV.A	All kV.A
Balance of kV.A @	$8.34	$ 8.34	$7.08	$6.06	$5.40

PUB/MH II-100

Reference: PUB/MH I-145 Demand Energy Rebalancing

b) Please explain the substantial 2011/12 increase in GSL 30-100KV demand revenues and the substantial 3 year (F09 to F12) decline in GSL > 100KV demand charge.

ANSWER:

The increase in GSL 30-100 kV demand revenue for 2011/12 can be attributed to the addition of six new accounts to this class throughout the fiscal year. As these operations are new businesses that are in the process of commissioning their operations, they tend to operate at lower load factors, which means setting higher demands relative to their energy usage.

With respect to the GSL >100 kV, this sub-class has not grown over the past three years. Both demand and energy use have declined, but the energy decline has been more than offset by the increase in energy rates whereas the rates for demand have remained constant. The decline in demand over the past three years can be attributed to the following factors:

- This subclass is comprised of 13 of the largest electricity users of all Manitoba Hydro customers. They do not all operate in the same manner or at the same load factor. A change in operation or the closure of an operation of one or more customers can have a significant impact on the class energy and demand revenues making year-to-year comparisons difficult.

- Some customers in this subclass have improved their load factor over the years, resulting in lower demand required to utilize the same energy. For example, a customer with a demand of 40 MVA at a 68% LF would use 20 GWh. Improving their load factor to 86% without increasing their energy usage would reduce their demand to 32 MVA.

PUB/MH II-101

Reference: PUB/MH I-149 Inverted Rates Alternative

a) Please provide an outline of the alternative residential rate strategies that MH is considering with respect to customers whose primary heat source (no access to natural gas) is electrical.

ANSWER:

Manitoba Hydro reviews potential residential rate strategies from time to time, including inverted rate strategies. Manitoba Hydro's Residential energy rate proposed for implementation April 1, 2013 is 7.2 cents per kW.h which is 85% of the marginal cost value (8.52 cents per kW.h) in the current Power Smart plan and higher than current short run marginal cost.

Other jurisdictions, such as BC Hydro, have recently introduced inclining block rates to replace the single rate schedule for residential customers with the objective of encouraging conservation by reflecting the legacy cost of energy in the first block and the marginal cost of new energy in the second. Price elasticity for electricity in the residential sector is traditionally low therefore requiring a substantial differential to effect a marginal change.

While not under active consideration by Manitoba Hydro at this time, if it were desired to implement inverted rates to the Residential class and to differentiate application of such rates between customers with electric heat and customers with other sources of space heating, the following alternatives may be considered:

- Seasonal differentiation of first block size such that more energy would be billed at a lower rate during the winter heating months
- Differentiating application of Residential rates between electrically heated customers and those with other space heating fuels.
- Special rates for customers where natural gas is not available.

The main goal of any strategy to re-design electricity rates for the Residential class is to balance the competing objectives of sending an appropriate price signal to encourage efficient choices by customers and mitigating impact of future rate increases on specifically electric heat customers. Revenue neutrality, customer acceptability, administrative cost and burden, gradualism and conformity to Uniform Rate Legislation are other factors to be considered.

1) <u>Seasonal Differentiation of First Block Size</u>

This method increases the size of the first block for the winter months (November through April inclusive) and reduces the block size for the summer months (May through October). For example, the summer season inversion could be set at 500 kWh per month while the winter season could be set at 1000 to 1500 kWh per month.

The advantage of a seasonally differentiated first block size is mitigation of impacts on winter bills for those who have no choice but to use electricity to heat their homes. This method does not distinguish between residential customers who are coded as standard (non-electric) or all-electric and so avoids the administrative difficulties inherent in maintaining a separate classification of residential customers based on their heating fuel.

In terms of customer impacts, the winter bill advantage may be offset, at least in part, by higher summer bills. Further, because the larger winter first block shelters a larger portion of residential energy from the second block price, the second block price may have to be higher in order to capture the same revenue as a rate design which is not seasonally differentiated.

From a billing administration perspective, this is the easiest strategy (other than the status quo or a similar approach) to implement and perhaps the easiest for customers to understand. All residential services would be affected with two rate changes a year. Billing issues through a rate change month would, however, be magnified as customers would look more closely at bills and would therefore be more apt to contact the Customer Contact Centre and/or their district office with inquiries. The major complaint would be unfairness of estimated bills and proration.

A more complex variant would be to add one or two additional seasons with first block size set mid way between the winter and summer rate structure; these would apply during the shoulder months of March, April, May, September, October and November.

2) <u>Different application of Rates for Standard and All-Electric Customers</u>

This method is similar to 1) above except that only those customers coded on the Billing System as all-electric would be eligible for the seasonal block rate. Standard customers would not have any seasonal differentiation. Expanding on this method, monthly block sizes could be based on monthly heating degree days. For example, the monthly block could rise gradually starting in October with each month increasing until the maximum block size is reached in January/ February, decreasing gradually thereafter.

The major advantage of this method is that it will expose a larger number of customers and kWh to the higher second block price, than the method which does not distinguish between standard and all-electric customers. However, differentiating rates solely upon heating source may encourage customers to make less optimal heating fuel choices.

Should this method be considered, new billing/customer codes would need to be created to more accurately identify electrically heated customers. Identifying customers with electric heat has been done, but it is a manual process and is primarily based upon customers self-declaring their heating fuel choice or where available evidence demonstrates the heating fuel source (e.g. permit information). Variable blocks, based on heating degree days, are likely to lead to considerable customer confusion and increased calls to the Contact Centre and district offices, especially with estimated billings. Varying monthly blocks would also complicate adjusted billings for periods greater than one month.

One important factor to note is that this method may be perceived as not conforming to the principles of uniform rates, even though the separate electric versus standard heating rate classes would apply across the province. Customers would be discriminated against based on the type of heating they chose to use to heat their homes. More seriously, there is also the potential for customers to choose electric heating in order to benefit from the better rate, thereby increasing demand on the system, which in turn will result in higher rate increases to all customers.

3) <u>Different Rates Based on Fuel Availability.</u>

Similar to the second method above, this method would apply seasonal blocked rates based on availability of alternate heating fuels. Only those customers who do not have access to gas service would be eligible for a larger seasonal block. Customers in areas served by natural gas either would not get a seasonal block charge or would have a lower block kWh amount per month. This method also has the advantage of exposing a larger number of customers and kWh to the higher second block price, particularly during the winter, than the method which does not distinguish between standard and all-electric customers.

Notwithstanding these advantages, this method is judged to be the least appropriate approach to recognizing electric heat requirements. It is administratively difficult to specifically identify areas served and not served by gas, as boundaries and proximity to natural gas are continually changing. Further, the costs associated with conversion to natural gas heating even in areas where natural gas is available can be a significant burden for customers. Alternatively, one could distinguish between existing and new electrically heated homes within areas served by natural gas, although this could add significantly to administrative complexity. This method would also require legislative change, as it would clearly violate existing uniform rates legislation.

PUB/MH II-101

Reference: PUB/MH I-149 Inverted Rates Alternative

b) Please explain what the major impediments are to implementing a two-tier rate structure for these electrical customers.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-101(a)

PUB/MH II-102

Reference: PUB/MH I-150 (a) Diesel Communities – Supply Option

a) Please indicate and discuss the status of small hydraulic generation alternatives previously under consideration for the remaining diesel communities.

ANSWER:

Small hydraulic generation alternatives were part of the supply options screening studies for each of the communities currently served by diesel generation considered in the report on "Recommendations for Reducing or Eliminating the Use of Diesel Fuel to Supply Power in Off-Grid Communities." Other than updating the cost estimates associated with the hydraulic generation alternatives, no further investigations have been undertaken to date.

PUB/MH II-102

Reference: PUB/MH I-150 (a) Diesel Communities – Supply Option

b) Please confirm that MH is no longer considering the grid extension to Brochet, Lac Brochet and Tadoule Lake.

ANSWER:

Manitoba Hydro continues to explore alternatives to diesel generation. A grid extension to any of the remote diesel communities would require a major capital contribution from a third party or parties, such as government.

PUB/MH II-102

Reference: PUB/MH I-150 (a) Diesel Communities – Supply Option

c) Please indicate the time frame within which MH will be faced with adding new diesel generation in each of the four off grid communities if there is no alternative supply put in place.

ANSWER:

Manitoba Hydro currently forecasts the following time frame to increase generating capacity in the (4) remote communities:

- BROCHET
  - 2016/2017 - Install (1) 1015 kW generator to replace 600 kW generator.

- LAC BROCHET
  - 2013/2014 – Install (1) 635 kW generator to replace 425 kW generator.
  - 2014/2015 – Install (1) 635 kW generator to replace 425 kW generator.
  - 2015/2016 – Install (1) 635 kW generator to replace 425 kW generator.

- SHAMATTAWA
  - 2014/2015 – Install (1) 1500 kW generator.

- TADOULE LAKE
  - No new generation is currently estimated to be required in the next 10 year period.

PUB/MH II-103

Reference: PUB/MH I-150 (d) North-Central Communities GHG Emissions

a) Please provide a hypothetical determination of historical change in annual GHG emissions for the north-central project using the typical residential fuel oil heating and electric heating scenario source.

ANSWER:

The following hypothetical analysis is presented by community and for local (Manitoba) and MISO region and net global impacts. Hypothetical GHG Emissions are calculated for each community assuming the following:

- All residential customers are assumed to be converting from Fuel Oil to Electric space heat. Manitoba Hydro has no data on the number of customers using wood or other heating sources prior to conversion to electric space heat.
- All residential customers are assumed to be converting from a Conventional Fuel Oil heating system using an average of 2,588 liters per year.
- GHG Emissions calculated for fuel oil heating is 7.350 tonnes per year.
- Residential customers are assumed to use an average of 16,605 kWh per year for electric space heat.
- GHG Emission calculated globally for electric heating is 12.454 tonnes per year.

Estimated GHG Emissions -Local (Manitoba)

	Total Tonnes	A Tonnes	B Tonnes	C Tonnes	D Tonnes	E Tonnes	F Tonnes	G Tonnes
1992/93	0	0	0	0	0	0	0	0
1993/94	0	0	0	0	0	0	0	0
1994/95	0	0	0	0	0	0	0	0
1995/96	0	0	0	0	0	0	0	0
1996/97	0	0	0	0	0	0	0	0
1997/98	-353	-44	-191	-118	0	0	0	0
1998/99	-1,330	-191	-742	-397	0	0	0	0
1999/00	-2,176	-470	-875	-500	-331	0	0	0
2000/01	-3,660	-684	-1,088	-573	-500	-353	-265	-198
2001/02	-4,792	-1,000	-1,360	-559	-669	-500	-500	-206
2002/03	-6,755	-1,301	-1,580	-588	-816	-1,044	-1,073	-353
2003/04	-7,901	-1,573	-1,749	-610	-889	-1,264	-1,345	-470
2004/05	-9,614	-1,749	-1,852	-639	-926	-2,065	-1,683	-698
2005/06	-10,885	-2,007	-1,896	-654	-1,066	-2,337	-2,029	-897
2006/07	-11,966	-2,095	-1,992	-676	-1,125	-2,712	-2,337	-1,029
2007/08	-13,281	-2,426	-2,124	-684	-1,132	-3,153	-2,617	-1,147
2008/09	-13,818	-2,514	-2,109	-684	-1,125	-3,271	-2,889	-1,227
2009/10	-14,450	-2,573	-2,109	-698	-1,117	-3,513	-3,183	-1,257
2010/11	-15,104	-2,778	-2,117	-750	-1,191	-3,697	-3,212	-1,360
2011/12	-14,928	-2,734	-2,065	-786	-1,161	-3,660	-3,153	-1,367

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

Estimated GHG Emissions - MISO Region

	Total Tonnes	A Tonnes	B Tonnes	C Tonnes	D Tonnes	E Tonnes	F Tonnes	G Tonnes
1992/93	0	0	0	0	0	0	0	0
1993/94	0	0	0	0	0	0	0	0
1994/95	0	0	0	0	0	0	0	0
1995/96	0	0	0	0	0	0	0	0
1996/97	0	0	0	0	0	0	0	0
1997/98	598	75	324	199	0	0	0	0
1998/99	2,254	324	1,258	673	0	0	0	0
1999/00	3,686	797	1,482	847	560	0	0	0
2000/01	6,202	1,158	1,843	971	847	598	448	336
2001/02	8,120	1,694	2,304	947	1,133	847	847	349
2002/03	11,445	2,204	2,678	996	1,382	1,768	1,818	598
2003/04	13,388	2,665	2,964	1,034	1,507	2,142	2,279	797
2004/05	16,290	2,964	3,138	1,083	1,569	3,500	2,852	1,183
2005/06	18,444	3,400	3,213	1,108	1,806	3,960	3,437	1,519
2006/07	20,275	3,549	3,375	1,146	1,905	4,596	3,960	1,744
2007/08	22,504	4,110	3,599	1,158	1,918	5,343	4,434	1,943
2008/09	23,414	4,259	3,574	1,158	1,905	5,542	4,894	2,080
2009/10	24,485	4,359	3,574	1,183	1,893	5,953	5,393	2,130
2010/11	25,593	4,708	3,587	1,270	2,018	6,264	5,442	2,304
2011/12	25,294	4,633	3,500	1,333	1,968	6,202	5,343	2,316

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

Estimated GHG Emissions - Net Global

	GHG Local Effect Tonnes	GHG MISO Region Effect Tonnes	Net Global Effect Tonnes
1992/93	0	0	0
1993/94	0	0	0
1994/95	0	0	0
1995/96	0	0	0
1996/97	0	0	0
1997/98	-353	598	245
1998/99	-1,330	2,254	924
1999/00	-2,176	3,686	1,511
2000/01	-3,660	6,202	2,542
2001/02	-4,792	8,120	3,328
2002/03	-6,755	11,445	4,691
2003/04	-7,901	13,388	5,487
2004/05	-9,614	16,290	6,676
2005/06	-10,885	18,444	7,559
2006/07	-11,966	20,275	8,309
2007/08	-13,281	22,504	9,223
2008/09	-13,818	23,414	9,596
2009/10	-14,450	24,485	10,034
2010/11	-15,104	25,593	10,489
2011/12	-14,928	25,294	10,366

PUB/MH II-104

Reference: PUB/MH I-151

a) Please elaborate on the administrative obstacles that are delaying the finalization of the interim diesel rates.

ANSWER:

The administrative obstacles that could delay the finalization of the interim diesel rates are:

1. To date, neither Manitoba Hydro nor INAC (now AANDC) have received true copies of the Settlement Agreement and related documents as required under the terms of the agreement nor has provision of alternative documentation in lieu thereof (due to certain documents having been lost) been fully satisfied. Both Manitoba Hydro and AANDC require true copies of the Agreement in order to finalize their respective commitment there under and in Order 134/10 the PUB directed Manitoba Hydro a true copy of the fully executed Settlement Agreement.

2. Order 134/10 directed that Manitoba Hydro's request for finalization of rates be accompanied by the written consents of INAC (now AANDC), MKO, the four First Nation Communities and CAC/MSOS. Draft consents were provided to the parties on December 19, 2011 for review and comment. Manitoba Hydro is not in receipt of any signed consents. Manitoba Hydro's position is that the PUB does not require the consents of these parties in order to finalize interim rates.

As indicated in Manitoba Hydro's response to PUB/MH I-151, if interim rates are not approved as final due to these administrative obstacles, 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 II-104

Reference: PUB/MH I-151

b) Please indicate the Diesel rates that MH proposes, with supporting calculations, if the Board does not approve the interim rates as final.

ANSWER:

Interim rates not being approved as final due to the administrative obstacles outlined in Manitoba Hydro's response to PUB/MH II-104(a) would not result in different rates being proposed by Manitoba Hydro. Manitoba Hydro would expect the interim orders to remain in place and request diesel rates proposed in this Application to also be approved on an interim basis.

The approval of interim rates as final is a condition of finalization of the tentative Settlement Agreement. If this condition is not met, theoretically it could result in the unwinding of the provisions of Settlement Agreement including return of significant capital contributions paid and setting new rates which recover such contributions and any other revenue lost as a result of acting on the tentative Settlement Agreement since 2004. This would result in an astronomical rate for the Diesel customers and is not realistic in the circumstance.

PUB/MH II-105

Reference: PUB/MH I-155(a) Summary of Quarterly Reports

a) Please provide the tabulation requested in PUB/MH I-155 of quarterly and annual energy supply components; the quarterly reports show only the first three quarters of each year and may not reconcile with the annual report values.

ANSWER:

Manitoba Hydro is unable to provide individual or recent wind farm generation data due to confidentiality agreement prohibitions although Manitoba Hydro has inadvertently provided this data in some past quarterly reports.

Manitoba Hydro has received permission to release aggregated wind production data for 2011/12 which is reported below.

	Actual Results (GWh)	Hydraulic Generation	Thermal Generation	Wind Purchases	Imports
2011/12	Q1	8309	19	202	19
	Q2	8770	25	182	12
	Q3	8213	26	271	79
	Q4	7866	8	245	190
	Annual	33158	77	900	300

For the other periods requested, Manitoba Hydro can only provide combined wind and imported data on an aggregated basis as follows.

	Actual Results (GWh)	Hydraulic Generation	Thermal Generation	Imports (incl. Wind)
	Q1 (Ending Jun 30, 2012)	7257	5	342
2011/12	Q1	8309	19	221
	Q2	8770	25	194
	Q3	8213	26	350
	Q4	7866	8	435
	Annual	33158	77	1200
2010/11	Q1	6998	18	218
	Q2	8840	12	91
	Q3	9182	13	136
	Q4	9016	22	155
	Annual	34036	66	600
2009/10	Q1	7973	25	125
	Q2	8630	18	94
	Q3	8866	74	230
	Q4	8349	26	201
	Annual	33818	143	650