PUB/MH II-1

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-3 (b)**

a) Please confirm that there has been no related party transactions in 2009/10 with Keeyask Hydropower Limited Partnership (KHLP)

ANSWER:

Manitoba Hydro and 590345 Manitoba Ltd. (a wholly owned subsidiary of Manitoba Hydro) have invested in partnership units of Keeyask Hydropower Limited Partnership. The total dollar value of these transactions is $8,250.

PUB/MH II-1

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-3 (b)**

b) Please describe how MH will account for the $246.2 million on spending related to the Keeyask project reflected in PUB/MH I-9 and whether all or a portion thereof will be assigned to KHLP.

ANSWER:

It is expected that Manitoba Hydro will continue to capitalize all Keeyask related spending until construction begins on the generating station and/or related facilities. At that point, all capitalized costs related to the generating station will be assigned to the KHLP. Also, please see Manitoba Hydro's response to PUB/MH II-7(b).

PUB/MH II-1

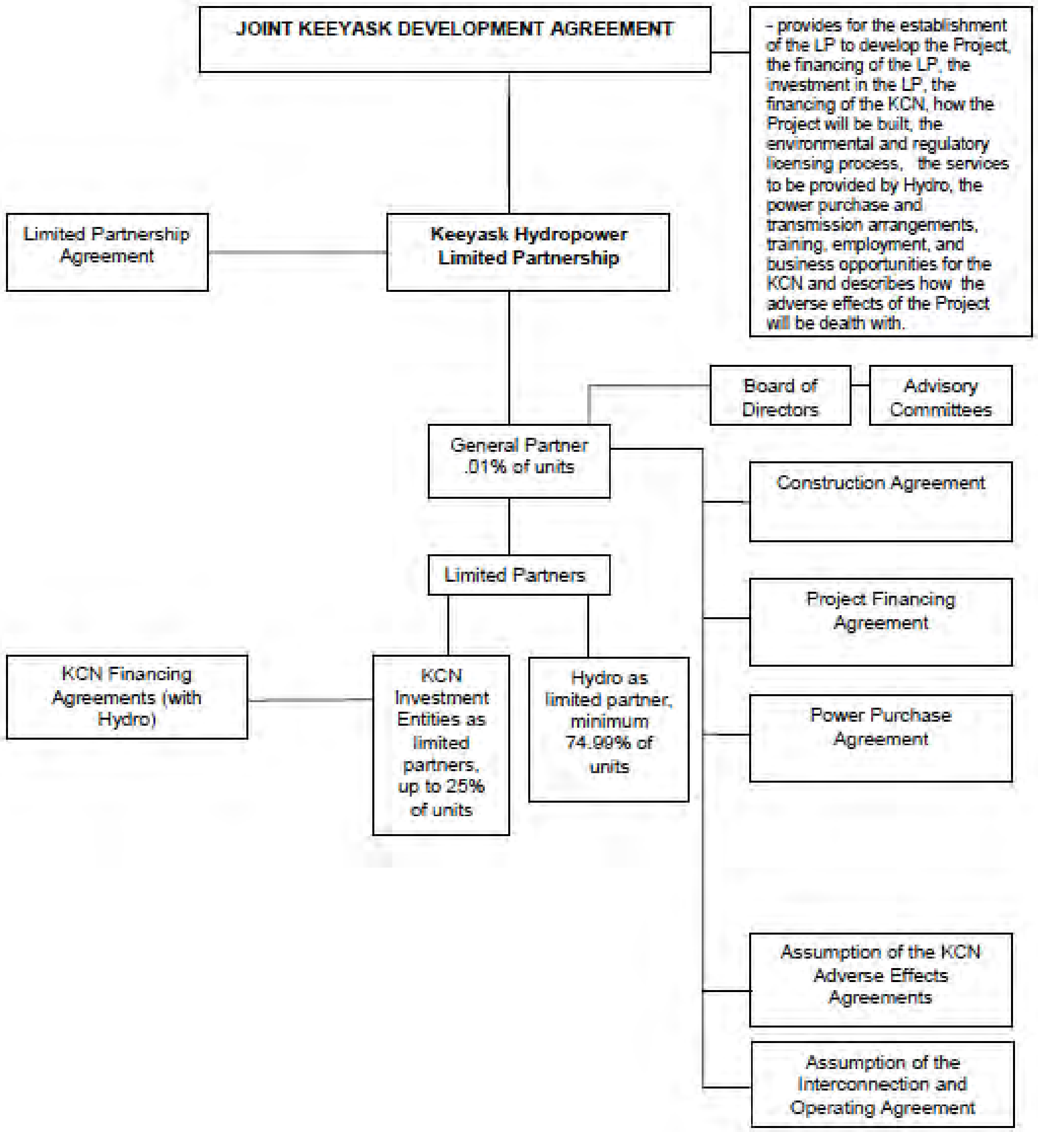
Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-3 (b)**

c) **Please provide a schematic showing the proposed ownership structure by party of the Keeyask project for KHLP.**

ANSWER:

Please see the attached schematic below, which outlines the proposed ownership structure and related agreements.

KEEYASK HYDROPOWER LIMITED PARTNERSHIP (the "LP")



<u>PUB/MH II-1</u>

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-3 (b)**

d) Please file a detailed financial forecast for KHLP if available and indicate to what extent it impacts MH's 2009 20-year outlook.

<u>ANSWER</u>:

A detailed financial forecast for KHLP is not available at this time.

PUB/MH II-1

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-3 (b)**

e) Please indicate when MH plans to prepare financial statements for KHLP.

ANSWER:

Financial statements for KHLP will be provided when available.

PUB/MH II-2

Subject: Tab 3 Corporate Overview
Reference: PUB/MH I-5 (c)

a) Please update the response to include the years 1999/2000 through 2003/04.

ANSWER:

Please see Manitoba Hydro's revised response to PUB/MH I-5(c), which was filed April 23rd, 2010 for the years 2003/04 through 2010/11. Prior year information is not fully comparable due to the acquisition of Centra Gas and Winnipeg Hydro.

PUB/MH II-2

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-5 (c)**

b) Please update the response to include the % of Labour and Benefits Capitalized (based on 75% proportion of Capital Order Activity) and explain the factors that have led to the increase in the proportion of labour and benefits capitalized since 2004/05

ANSWER:

The following chart provides the % of labour and benefits capitalized to total labour & benefits:

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
Labour & Benefits Capitalized	$111,577	$118,297	$127,844	$132,744	$144,254	$153,881	$173,305	$176,280	$179,806
Total Labour and Benefits	$398,449	$423,093	$440,473	$457,233	$477,838	$509,592	$544,952	$556,311	$569,106
% of Lab. & Ben Cap./Total	28%	28%	29%	29%	30%	30%	32%	32%	32%

The increase in percentage of labour and benefits capitalized over the period is related to the expanded capital program, including significant new generation/transmission projects over the same period.

PUB/MH II-2

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-5 (c)**

c) Please explain how requirements under IFRS has impacted the amount of capitalized Labour and Benefits

ANSWER:

The schedule provided in PUB/MH I-5(c) includes labour and benefits that are capitalized as a component of activity charges. Manitoba Hydro has not yet concluded its detailed review of IFRS requirements as it relates to cost capitalization and has included a $15 million general provision for IFRS in its forecast.

PUB/MH II-3

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-8 (c), CAC/MSOS/MH I-9 (g) IFRS**

a) **Please provide a comparison similar to PUB/MH1-8 (c) between IFF09 and IFF08.**

ANSWER:

Please see the following table for a comparison of the OM&A cost per customer for the years 2009 through 2017 (IFF09 to IFF08).

The increase in cost per customer, over the period, is primarily attributable to OM&A cost increases. The change in cost per customer between the two forecasts is primarily attributable to higher OM&A costs as a result of accounting changes and increased business requirements.

	Actual	Forecast - IFF09							
	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only' ($ millions)	360	372	380	403	411	420	428	437	445
# of Customers	527,472	531,804	536,267	540,756	545,215	549,623	553,968	558,286	562,580
OM&A (electric only) per customer (in dollars)	682	699	708	746	755	764	773	782	792

	Forecast - IFF08								
	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only' ($ millions)	349	358	365	379	386	394	402	410	418
# of Customers	525,964	532,391	534,772	539,125	543,453	547,752	552,022	556,265	560,476
OM&A (electric only) per customer (in dollars)	664	673	683	703	711	719	728	737	746

	Change								
	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A (electric only) per customer (in dollars)	18	26	25	43	44	44	44	45	45

PUB/MH II-3

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-8 (c), CAC/MSOS/MH I-9 (g) IFRS**

b) Please separately disclose the impact of the OM&A expense related to accounting changes including proposed changes related to IFRS.

ANSWER:

Please see the following table for a comparison of the OM&A cost per customer for the years 2009 through 2017 with the impact of accounting changes separately disclosed.

(in millions of dollars)	Actual 2009	Forecast - IFF09 2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only'	355	361	369	377	385	394	402	411	419
CICA Accounting Changes:									
Reduction in Stores Overhead Capitalized	5	5	5	5	5	5	5	5	5
Reduction in Intangible Assets Capitalized	-	4	4	4	4	4	4	4	4
Reduction in Administrative & General Overhead Capitalized	-	2	2	2	2	2	2	2	2
IFRS Accounting Changes	-	-	-	15	15	15	15	15	15
Total OM&A expense 'electric only'	360	372	380	403	411	420	428	437	445
# of Customers	527,472	531,804	536,267	540,756	545,215	549,623	553,968	558,286	562,580
OM&A (electric only) per customer (in dollars)	682	699	708	746	755	764	773	782	792

<u>**PUB/MH II-4**</u>

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-9 Consulting Costs**

a) Please provide a breakdown of the $20.7 million in consulting expenses by project forecast to be paid in 2010 for Keeyask Generation.

<u>**ANSWER**</u>**:**

As per PUB/MH I-9, consulting expenses for the Keeyask Generation Station in 2010 totalled $20.8 million as detailed below.

Project	Actual Cost	
Keeyask Generating Station	$	1.2
Keeyask GS Licensing & Planning		19.2
Infrastructure Upgrade - PR 280		0.2
Keeyask GS Infrastructure		0.2
	$	20.8

PUB/MH II-4

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-9 Consulting Costs**

b) Please provide a breakdown of the $16.5 million in 2009 and $9.3 million in 2010 in consulting expense by project for Conawapa Generation.

ANSWER:

The consulting expenses in both years are related to the Conawapa GS Licensing project.

PUB/MH II-4

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-9 Consulting Costs**

c) Please provide a breakdown of the $5.7 million forecast for 2010 in consulting expenses by project for the Bipole III.

ANSWER:

See schedule below (in millions).

Project	Actual Cost
Bipole 3 Licensing & Environmental Assessment	$ 3.0
Bipole 3 Western Route Transmission Line	0.2
Property for Riel Converter Station	0.3
Riel Conversion & 230KV AC Switchyard Site Development	2.0
Northern Converter Station	0.1
Riel Converter Station	0.1
Northern 230KV AC Switchyard	0.1
	$ 5.7

PUB/MH II-5

Subject: Tab 3 Corporate Overview
Reference: PUB/MH I-9

Please describe the current accounting treatment for each of the category amounts and indicate how that accounting treatment may change under IFRS

ANSWER:

The accounting treatment for the following categories (consultants, contractors, interest, labour, materials and other) will not change upon adoption of IFRS. These categories will continue to be capitalized when appropriate to do so. As discussed in the status update report, the amounts of activity and labour overhead capitalized are under review and will be adjusted accordingly. Manitoba Hydro is currently in the process of reviewing how mitigation costs may be affected by IFRS and is thus, not in a position to conclude how such costs may be impacted.

Upon the adoption of the new CICA section 3064, Manitoba Hydro's accounting treatment for planning studies will be to expense these costs as feasibility studies unless there is reasonable assurance that a generation or transmission project will proceed to construction. Once the reasonable assurance criteria are met, Manitoba Hydro will capitalize related costs.

PUB/MH II-6

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-7 (c), 2008 GRA, PUB/MH I-22 (c)**

Please explain the difference between the projected level of funding and trainees for 2007/08 and 2008/09 for the NTI presented at the last GRA with that included in this application. Please indicate whether the current schedule reflects the payments to First Nations partners.

ANSWER:

The Hydro Northern Training and Employment Initiative was originally to end March 31, 2009 but was extended to March 31, 2010 to give the Aboriginal Partners an additional year to utilize the remaining funding. The Aboriginal Partners did not spend their allocated funding as quickly as anticipated, resulting in less funding being disbursed by Manitoba Hydro than forecast.

The funding from Manitoba Hydro represents the funding provided to the Wuskwatim Keeyask Training Consortium that is responsible for administering the Initiative and disbursing funding to the Aboriginal Partners as required. Therefore the amounts presented do not reflect the actual payments to the Aboriginal Partners but only payments made by Manitoba Hydro to the Wuskwatim Keeyask Training Consortium.

The training statistics provided in PUB/MH I-7(c), are the number of training activities (such as programs or courses) started and completed in each year. An individual may have taken more than one training activity in a given year.

The table provided in PUB/MH I-7(c) has been updated below to include the number of trainees per year. The training numbers differ from what was provided in the previous responses. Updated reporting from our Aboriginal Partners has resulted in an increase of the total number of trainees as well as training activities started and completed from prior years.

Fiscal year ending March 31	Manitoba Hydro Funding	Training Activities Started	Training Activities Completed	Number of Trainees
2005	$2,414,560	548	362	434
2006	$2,330,114	1175	700	885
2007	$3,358,282	958	488	680
2008	$2,139,718	1316	618	1010
2009	$2,267,679	882	438	659
2010 *	$2,513,834	446	185	356
2011 Planned**	$600,000	0	0	0
2012 Planned	$0	0	0	0

* Is the actual funding to January 31, 2010 and the actual number of trainees and training activities started and completed to September 30, 2009.
** Holdback funding to be paid after the initiative ends March 31, 2010.

PUB/MH II-7

Subject: Tab 3 Corporate Overview
Reference: Joint Keeyask Development Agreement

a) **Please provide a summary of the details of the Joint Keeyask Development Agreement (JKDA) and Keeyask Adverse Effects Agreements with Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation, and York Factory First Nation. details on the financial and operational commitments. With respect to the JKDA please provide a summary in similar detail with that provided in response to PUB/MH I-4 (c) from the 2008 GRA. Please indicate where the agreement differs materially from that reached in the Wuskwatim development.**

ANSWER:

The Joint Keeyask Development Agreement (JKDA) is available in its entirety on the Manitoba Hydro website at http://www.hydro.mb.ca/projects/keeyask/pdf/JKDA_090529.pdf The Wuskwatim Project Development Agreement (PDA) is also available in its entirety at: http://www.hydro.mb.ca/projects/wuskwatim/pda/Wuskwatim_PDA_ToC.pdf

Manitoba Hydro entered into the Joint Keeyask Development Agreement on May 29, 2009 with the four Keeyask Cree Nations (KCN) or Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation and Fox Lake Cree Nation. The JKDA was preceded by the signing of the Wuskwatim Project Development Agreement between Manitoba Hydro and the Nisichawayasihk Cree Nation (NCN) in June 2006. Both the Joint Keeyask Development Agreement (JKDA) and the Wuskwatim Project Development Agreement (PDA) provide for equity partnership arrangements between Manitoba Hydro and First Nation communities. However, these agreements were negotiated based on the specific projects under consideration and with communities that had differing interests and expectations with respect to the final business arrangements. Many of the differences between these two agreements are the results of these varying circumstances.

The tables below have been developed to address the questions raised. Table 1 summarizes the details of the financial and operational commitments made in the JKDA and, for comparison purposes, the PDA.

Table 2 summarizes the Adverse Effects Agreements reached for the Keeyask Generating Station Project and the Wuskwatim Project. Although these agreements were negotiated concurrent with the partnership arrangements, the need for these agreements and their implementation exists regardless of whether the KCN or NCN ultimately choose to become equity partners in the Keeyask or Wuskwatim developments. These agreements provide mitigation measures, community-based programming and cash compensation to avoid, offset or compensate for anticipated project effects. Unlike past developments, they have been negotiated prior to the start of project construction and are based equally on community and corporate views of potential project effects.

TABLE 1: FINANCIAL & OPERATIONAL COMMITMENTS IN THE JKDA & PDA

DESCRIPTION	KEEYASK JKDA	WUSKWATIM PDA
Nature of Agreement	A partnership between Manitoba Hydro and the four Keeyask Cree Nations (KCN) to build and operate the Keeyask Generating Station. The assets of the Partnership would consist of the Keeyask Generating Station and, to the degree required, a small amount of working capital. The capital cost would include planning studies, engineering and licensing from April 1, 2002 plus the unamortized balance of prior expenditures.	A partnership between Manitoba Hydro and Nisichawayasihk Cree Nation (NCN) to build and operate the Wuskwatim Generating Station. The assets of the Partnership would consist of the Wuskwatim Generating Station and, to the degree required, a small amount of working capital. The capital cost would include planning studies, engineering and licensing from April 1, 2002 plus the unamortized balance of prior expenditures.
Income/Investment Arrangements	The KCN can choose a preferred equity or a common equity option. This selection must be made prior to or at Final Closing and the two options can not be combined (although each community will make its own choice of option).	Common equity option only.
Debt Equity Ratio of Partnership	The Partnership will be financed by 75% debt and 25% equity. During the first 10 years the debt ratio may temporarily rise up to 85% if required to finance cash calls.	The Partnership will be financed by 75% debt and 25% equity. During the first 10 years the debt ratio may temporarily rise up to 85% if required to finance cash calls.

DESCRIPTION	KEEYASK JKDA	WUSKWATIM PDA
Common Equity Option	Limited Partnership option with an interest of up to 25%. Manitoba Hydro, through a holding company as General Partner, would have a 0.01% interest, with Manitoba Hydro as a Limited Partner holding the balance.	Limited Partnership option with an interest of up to 33%. Manitoba Hydro, through a holding company as General Partner, would have a 0.01% interest, with Manitoba Hydro as a Limited Partner holding the balance.
• *Minimum Investment Required by Cree Nations*	The KCN are required to invest a minimum of $12.5 million with a $2.25 million down payment at initial closing (roughly the start of generating station construction).	NCN's minimum investment is $5 million with a $1 million down payment at initial closing (timed to coincide with the start of access road construction).
• *Amount Manitoba Hydro will lend the Cree Nations to Finance Their Investment*	Manitoba Hydro will lend the KCN a maximum amount equal to the difference between $25 million and the amount it takes to acquire a 17.5% common equity ownership in the Keeyask partnership, financed by the KCN's own money and Manitoba Hydro equity loans. If the KCN invest the minimum of $12.5 million, Manitoba Hydro will lend the KCN the difference between $12.5 million and the amount it takes to acquire 8.75% common equity ownership in the Keeyask partnership, financed by the KCN's own money and Manitoba Hydro equity loans. If the KCN invest their own money in an amount between $12.5 million and $25 million, the Hydro loan would be scaled accordingly.	Manitoba Hydro will provide NCN with equity loans of up to 4 times their cash investment to achieve up to 27.5% common equity ownership in the Wuskwatim partnership, financed by NCN's own money and Manitoba Hydro equity loans.

DESCRIPTION	**KEEYASK JKDA**	**WUSKWATIM PDA**
• *Interest Rates on Loans*	The interest rate for project debt - i.e. the financing of the project's capital requirements - is based on Manitoba Hydro's cost of borrowing without markup. Equity loans, cash call loans and dividend loans from Manitoba Hydro to the KCN have a markup of 2% during construction and for all years of operation.	The interest rate for project debt - i.e. the financing of the project's capital requirements - is based on Manitoba Hydro's cost of borrowing without markup. Equity loans, cash call loans and dividend loans from Manitoba Hydro to NCN have a markup of 3% except for the construction period and first 10 years of operations when the equity loan markup is 1%.
• *Period during which Loans are Available*	Equity loans have a term of 50 years. At the end of that term, KCN may utilize a third party lender subject to Manitoba Hydro's right of first refusal.	Equity loans have a term of 50 years. At the end of that term, NCN may utilize a third party lender subject to Manitoba Hydro's right of first refusal.
• *Distributions From Partnership Profits*	Distributions will be payable each year as long as there is enough equity to meet the 25% requirement plus any reserves to cover future costs. No distinction is made between the units purchased by cash and those purchased by loans. KCN will receive 20%-30% of distributions payable on total units, with the balance going to repay the loans. Dividend loans are available based on KCN's own cash investment.	Distributions will be payable each year as long as there is enough equity to meet the 25% requirement plus any reserves to cover future costs. NCN will receive 100% distributions payable on its cash units but will receive distributions from loaned units only after the loans are paid off.
Preferred Equity Option	The preferred equity option would provide a more certain income stream with less downside risk but also less upside potential.	No preferred equity option is currently in place for Wuskwatim.

DESCRIPTION	**KEEYASK JKDA**	**WUSKWATIM PDA**
• *Minimum Investment Required by Cree Nations*	Same minimum investment as for the Common Equity Option. The KCN are required to invest a minimum of $12.5 million with a $2.25 million down payment at initial closing.	N/A
• *Maximum Cree Nations Investment*	Under the preferred option, each of the KCN can only invest up to a maximum of their applicable share of 2.5% of project equity.	N/A
• *Amount Manitoba Hydro will lend the Cree Nations to Finance Their Investment*	No loans are available to the KCN for the purchase of preferred equity shares.	N/A
• *Distributions From Partnership Profits*	Distributions will be payable each year based on a Preferred Distribution Formula outlined in the JKDA.	N/A
Final Closing	Final Closing is 6 months after the last generating station unit is in service.	Final Closing is when the first generating station unit is in service.
Charging of Costs to Partnership	Operating and administrative costs will be without markup and charged in a similar manner to Manitoba Hydro's other generating stations. Applicable transmission costs and associated interest will be recovered annually by means of a 50 year "mortgage". Financial accounting will comply with the standards applied by Manitoba Hydro to its operations.	Operating and administrative costs will be without markup and charged in a similar manner to Manitoba Hydro's other generating stations. Applicable transmission costs and associated interest will be recovered annually by means of a 50 year "mortgage". Financial accounting will comply with the standards applied by Manitoba Hydro to its operations.

DESCRIPTION	KEEYASK JKDA	WUSKWATIM PDA
Terms of Cash Flows	Life of the Project; minimum of 67 years, probably 100 years with refurbishments.	Life of the Project; minimum of 67 years, probably 100 years with refurbishments.
Basis of Power Purchase Agreement (PPA) and Transmission-Costing Arrangements	PPA formula and net revenue to KCN and contribution to transmission costs were established on the basis of an economic calibration. The project was evaluated to determine the net benefit to the integrated system using system models and economic projections. Revenues received by the Partnership from the sale of power to Manitoba Hydro would be based on the actual output of the Keeyask Generating Station and be priced in accordance with an agreed methodology which reflects Manitoba Hydro's actual selling price for exports.	PPA formula and net revenue to NCN and contribution to transmission costs were established on the basis of an economic calibration. The project was evaluated to determine the net benefit to the integrated system using system models and economic projections. Revenues received by the Partnership from the sale of power to Manitoba Hydro would be based on the actual output of the Wuskwatim Generating Station and be priced in accordance with an agreed methodology which reflects Manitoba Hydro's actual selling price for exports.
Responsibilities of Aboriginal Communities for Third Party Liabilities	None	None

TABLE 2: KEEYASK & WUSKWATIM ADVERSE EFFECTS AGREEMENTS

Description	Keeyask	Wuskwatim
Nature of Agreements	Separate agreements between individual KCN communities and Manitoba Hydro which seek to address any potential adverse effects of the Keeyask Project on each community. The agreements were negotiated in advance of project development, but there are clauses which take into account unforeseeable circumstances.	An agreement between NCN and and Manitoba Hydro which seeks to address any potential adverse effects of the Wuskwatim Project on the community. The agreement was negotiated in advance of project development, but includes clauses which take into account unforeseeable circumstances.
Offsetting Programs	Annual funding is provided for a series of programs to offset anticipated adverse effects in the areas of resource access and use, environmental stewardship and cultural sustainability. Funding for specific programs and the duration of this funding vary for each community.	N/A
Financial Compensation	Residual compensation is also provided for adverse effects not addressed by offsetting programs. The amount of residual compensation varies by community consistent with the anticipated adverse effects for each community. Compensation for individual trappers who suffer financial losses is dealt with directly by Manitoba Hydro and not included in the agreements.	The agreement provides financial compensation, payable into a Trust, to offset unavoidable adverse effects. Funds earned by the trust on an annual basis are used for community-based programming and projects determined based on the on the outcomes of a formal Community Approval Process. The agreement also provides compensation for individual trappers who suffer financial loss.

<u>PUB/MH II-7</u>

Subject: **Tab 3 Corporate Overview**
Reference: **Joint Keeyask Development Agreement**

b) Please describe the accounting treatment for amounts disbursed under the agreements.

<u>ANSWER</u>:

The accounting treatment for amounts disbursed under the JKDA is consistent with that of the Wuskwatim Power Limited Partnership in accordance with generally accepted accounting principles described in IFF09-1. In general, Manitoba Hydro will purchase the output from the partnership under a power purchase agreement, and will construct, maintain and operate the Keeyask generating station and associated transmission. Manitoba Hydro's projected financial statements consolidate the partnership results, utilizing the non-controlling interest method of accounting for purposes of recording Keeyask Cree Nations' (KCN) share of partnership net income. The partnership's net assets on the consolidated balance sheet are offset by an amount for KCN's non-controlling equity interest in the liability section of Manitoba Hydro's consolidated balance sheet. Manitoba Hydro's income statement reflects all of the revenues and costs related to the Keeyask partnership with KCN's share of the project net income shown as a deduction before net income.

<u>PUB/MH II-8</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

a) Please file a summary of the financial terms of the agreement reached with Pattern Energy as discussed in a Manitoba news release dated March 22, 2010.

<u>ANSWER</u>:

Manitoba Hydro will provide debt financing to a maximum of the lesser of $250 million or 75% of the total capital cost of the project. Pattern Energy will fully fund its $95 million equity commitment prior to any loan advances being made available from Manitoba Hydro. When the project is completed and final capital costs are known, any overpayment of equity will be refunded. Following project completion, the loan is to be repaid mortgage-style through blended interest and principal payments over 20 years. The principal repayments are accelerated by removing $2 million of principal from each of the last six years and spreading this $12 million equally over the first 14 years. A $10 million revolving reserve loan facility is also available to cover cashflow shortfalls. Principal and interest payments due to Manitoba Hydro will be deducted from amounts owed by Manitoba Hydro to the wind farm for the purchase of energy. Full security provisions applicable to a senior lender will apply.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

b) **Please describe the financial due diligence undertaken on Pattern Energy, the Companies credit rating and file any external or internally created credit rating reports on the company.**

ANSWER:

Manitoba Hydro undertook extensive due diligence with the assistance of qualified external legal, engineering and financial market experts. Pattern Energy is privately held so no credit ratings are available. Project financing relies on the strength of the underlying project to secure the debt. Manitoba Hydro is protected by its position as off-taker of the power, its security interest in the assets and the requirement for Pattern to fully fund their $95 million equity commitment before having access to the credit facilities.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

c) Please provide a full description of Pattern Energy, including company history , corporate structure, principles etc.

ANSWER:

Riverstone Holdings LLC purchased the wind development portfolio of Babcock and Brown LP on June 25, 2009 to form Pattern Energy Group LP. Pattern has issued the following description [1]of the company and its principles:

"Pattern is an independent, fully integrated energy company that develops, constructs, owns and operates renewable and transmission energy assets across North America and parts of Latin America. Formerly Babcock & Brown LP's thriving North American energy group, Pattern employs 80 employees, located in four offices (San Francisco, Houston, San Diego and New York), which successfully developed, financed and placed into operation over 2,000 MW of wind power across 11 states. Pattern has a current development pipeline that exceeds 4,000 MW of wind energy and transmission projects in 11 states and 4 countries. Pattern is dedicated to delivering the highest values for our partners and the communities in which we work, while exhibiting a strong commitment to promoting environmental stewardship and corporate responsibility."

[1] *http://www.patternenergy.com/press_releases/2009-0625-PSR-PatternLaunch.pdf*

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

d) Please describe in full the ownership structure of the St. Joseph Wind Farm Development.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH-II-8(c).

<u>PUB/MH II-8</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

e) **Please explain why Manitoba Hydro is lending Pattern Energy up to $260 million for the development. Is there provisions for loan amounts above $260 million.**

<u>ANSWER</u>:

A decision was made to proceed with this unique financing arrangement because the project, which was the lowest cost proposal received during the RFP process, would otherwise not have proceeded in the current difficult climate for financing. Pricing benefits that the developers obtained for the turbines and Federal Eco-Energy funding would have been lost. EcoEnergy funding, worth more than $40 million in this instance, only applies to wind facilities in operation before March 2011. No additional financing is available from Manitoba Hydro in excess of the $250 million construction/term loan or the $10 million reserve loan facilities.

<u>PUB/MH II-8</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

f) **Please file a copy of the financial agreements, purchase power agreement and the construction/term loan with Pattern Energy.**

<u>ANSWER</u>:

These agreements are commercially sensitive and cannot be provided.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

g) **Please provide a summary of the terms related to any funds to be lent to Pattern Energy, including funds disbursement and use, interest rate, repayment terms, debt covenants and security.**

ANSWER:

The principal terms are provided in the response to PUB/MH II-8(a). No dividends can be paid out unless the debt service coverage ratio in the immediately preceding 12 month period exceeds 1.20. Manitoba Hydro has a first charge on both the assets and the shares of St. Joseph Windfarm Inc. Any additional third party debt must be approved by Manitoba Hydro and must not result in the debt ratio exceeding 75% or the projected debt service coverage ratio to fall below 1.20. The interest rates are considered to be commercially sensitive information.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

h) **Please file a schedule representing the disbursements, amortization and repayment of the construction loan with Pattern Energy.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-8(a).

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

i) Please compare the financial structure of the St. Joseph wind farm with that of the St. Leon

ANSWER:

Manitoba Hydro has a power purchase arrangement with the St. Leon wind farm but is not involved in its financial structure. In the case of the St. Joseph wind farm, Manitoba Hydro has a power purchase agreement and will be providing debt financing equal to the lesser of $250 million or 75% of the capital cost of the project. The developer will be equity funding the balance.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

j) Please confirm that the output from the St. Joseph wind farm at 138 MW capacity is expected to be 400 to 500 GWh.

ANSWER:

Manitoba Hydro confirms that the expected capacity factor of the 138 MW St. Joseph wind farm would result in a projected annual energy volume that falls within the 400 to 500 GWh range.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

k) Please confirm that with an estimated capital cost of $345 M, the project revenue requirement (if entirely owned and built by MH) would be in the range of 7 to 8¢/KWh to cover finance, depreciation, and OM&A costs.

ANSWER:

Manitoba Hydro has no experience with owning or operating a wind farm and cannot confirm these estimates.

PUB/MH II-9

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-22/PUB/MH I-1(a) - Tab 4.0/IFF 08-1 Assumptions - Net Export**

Please confirm and update the following tabulation of net export revenues:

	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
Gross Export Revenue ($M)	554	827	592	625	623	415	383	554	583
Fuel & Power Purchase ($M)	(135)	(125)	(226)	(135)	(176)	(103)	(132)	(248)	(250)
Share of Water Rental $M	(30)	(49)	(27)	(39)	(34)	(32)	(30)	(30)	(30)
Net Export Revenue $M	389	653	338	451	413	280	221	276	303
	GW.h	GW.h	GW.h	GW.h	GW.h	GW.h	GW.h	GW.h	GW.h
Gross Export Sales	10,430	14,347	9,907	11,735	10,576	7,901	6,867	7,191	7,654
Export Transmission Losses	751	1,219	855	986	893	995	687	719	765
Energy Purchases	(2,030)	(739)	(2,249)	(830)	(1,033)	(1,974)	(2,536)	(2,601)	(2,852)
50%Thermal Generation	(207)	(200)	(261)	(228)	(167)	(240)	(275)	(323)	(305)
Net Exports from Hydraulic Generation	8,944	14,627	8,252	11,673	10,269	6,287	4,743	4,986	5,262
Net Export Sales	8,193	13,408	7,497	10,687	9,376	Actual 9500	4,056	4,267	4,408
	3,193	13,408	7,497	10,687	9,376	5,787	4,056	4,267	4,408
Unit Net Export Sales Revenues ¢/kW.h						Actual 3.0			
	4.8	4.9	4.5	4.2	4.4	4.8	4.5	5.5	6.7

ANSWER:

The concept of estimating a unit value for net export sales from only hydraulic generation is not one that is utilized by Manitoba Hydro. Export sales are derived from the surplus resulting from the overall system supply, which includes energy from hydraulic resources, thermal generation and purchases including wind energy. Any attempt to isolate the export value of a specific resource, such as hydraulic generation, requires the arbitrary allocation of costs, revenues and energy volumes, and the end result may not be an accurate or meaningful representation. Therefore, although it can be confirmed that the set of calculations is mathematically correct, Manitoba Hydro does not believe that it is appropriate to separate export sales into those that are derived from hydraulic generation as is being done in the table for this information request.

Manitoba Hydro can confirm that information from the response to PUB/MH I-22 was used to derive the values for the years 2005 to 2009. Manitoba Hydro is unable to determine the methodology that was use to determine the share of water rentals that is allocated to export sales. The estimate of actual generation and export revenue for 2009/10 has not been publicly released and therefore these values cannot be updated.

For the forecast period for the years 2011 to 2013, it appears that IFF08-1 energy volumes were used together with IFF09-1 revenue and cost information to develop the table in the information request. Manitoba Hydro has updated the period 2011 to 2013 using information that is consistent with the response to PUB/MH II-45(b). The changes and updates are shown in italics in the revised table on the next page. In that response export sales revenue was restated and is different from the operating statement in IFF09-1 because additional factors related to export sales were considered. The net effect of transmission costs and revenues have been incorporated into the export sales category since these are associated with Manitoba Hydro's participation in the export market. In order to determine the share of water rental that is allocated to export sales, the total water rental cost is prorated using the volume of "net exports from hydraulic generation" as a proportion of total hydraulic generation.

The results of the financial calculation reflect a mixture of actual water conditions (which were generally average or better from 2005 to date) and Manitoba Hydro's financial forecast which reflects median flows for 2011 and the average of all flow conditions for 2012 and 2013. In effect it is an apples – oranges comparison which bias the result especially in the last two years.

	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
Gross Export Revenue ($M)	**554**	**827**	**592**	**625**	**623**	**415**	*292*	***517***	***545***
+									
Fuel & Power Purchase ($M)	**(135)**	**(125)**	**(226)**	**(135)**	**(176)**	**(103)**	***(64)***	***(212)***	***(213)***
Share of Water Rental $M	**(30)**	**(49)**	**(27)**	**(39)**	**(34)**	**(32)**	***(23)***	***(21)***	***(22)***
Net Export Revenue $M	**389**	**653**	**338**	**451**	**413**	**280**	*205*	***284***	***310***
	GW.h	**GW.h**	**GW.h**	**GW.h**	**GW.h**	**GW.h**	**GW.h**	**GW.h**	**GW.h**
Gross Export Sales	**10,430**	**14,347**	**9,907**	**11,735**	**10,576**	**7,901**	***7,122***	***7,843***	***8,152***
Export Transmission Losses	**751**	**1,219**	**855**	**986**	**893**	**995**	***724***	***554***	***575***
Energy Purchases	**(2,030)**	**(739)**	**(2,249)**	**(830)**	**(1,033)**	**(1,974)**	***(1,508)***	***(2,616)***	***(2,576)***
50%Thermal Generation	**(207)**	**(200)**	**(261)**	**(228)**	**(167)**	**(240)**	***(80)***	***(216)***	***(219)***
Net Exports from Hydraulic Generation	**8,944**	**14,627**	**8,252**	**11,673**	**10,269**	**6,287**	***6258***	***5565***	***5932***
Net Export Sales	**8,193**	**13,408**	**7,497**	**10,687**	**9,376**	**Actual 9500**	***5534***	***5011***	***5357***
	3,193	**13,408**	**7,497**	**10,687**	**9,376**	**5,787**			
Unit Net Export Sales Revenues ¢/kW.h						**Actual 3.0**			
	4.8	**4.9**	**4.5**	**4.2**	**4.4**	**4.8**	***3.7***	***5.7***	***5.8***

PUB/MH II-10

Subject: Tab 4 Financial Results & Forecast
Reference: Donations/ Sponsorships

Please provide a detailed schedule of donations and sponsorships for the 2008/09 and 2009/10 indicating which donation and sponsorship are non-energy related.

ANSWER:

The following table provides a schedule of [1]donations and sponsorships for 2008/09 (in thousands).

	2008/09
Charitable Donations	$ 2,638
Support for Local Events	855
Educational Grants	224
Other Miscellaneous Donations	767
Total	$ 4,484

The forecast for 2009/10 is $3,702.

[1] All donations and sponsorships are directly or indirectly energy related.

PUB/MH II-11

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I- 18, MIPUG/MH I-13 Foreign Exchange/ Exposure Management Program**

a) Please provide a table of corresponding data points for the Graph to MIPUG/MH I-13.

ANSWER:

Please see the attached table.

PUB/MH II - 11 (a)
Manitoba Hydro
Foreign Exchange Exposure Management Program
Projected US Dollar Cash Flows
(in millions of dollars)

Fiscal Year	Net Export Revenue	Debt Retirement/ SF Investments	Financing Costs	USD Payments	FX Contracts	Net Position
2010	263	(40)	(192)	(70)	35	(5)
2011	221	(42)	(172)	(75)		(69)
2012	344	12	(172)	(75)		109
2013	371	12	(176)	(75)		132
2014	376	(140)	(171)	(75)		(9)
2015	348	(81)	(144)	(75)		47
2016	407	(157)	(144)	(75)		31
2017	395	(109)	(144)	(75)		67
2018	397	(173)	(144)	(75)		4
2019	474	(134)	(135)	(75)		130
2020	550	(164)	(102)	(75)		209
2021	617	(198)	(92)	(75)		252
2022	623	(249)	(59)	(75)		239
2023	365	(146)	(13)	(75)		130

PUB/MH II-11

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I- 18, MIPUG/MH I-13 Foreign Exchange/ Exposure Management Program**

b) Please provide a narrative to the Graph to explain how the natural hedge maintained between U.S. Export Revenues (Hedging Item) and US denominated Debt (Hedged Item) protects the Corporation from CAD$:USD$ exchange fluctuations and is an effective hedging relationship.

ANSWER:

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

PUB/MH II-11

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I- 18, MIPUG/MH I-13 Foreign Exchange/ Exposure Management Program

c) Please discuss how the Corporation determined that there was an effective hedging relationship between U.S. denominated debt and US export revenues in accordance with IFRS and discuss the extent there may exist any mismatches between the timing of debt payments and export revenue receipts and the financial impact of such a mismatch in 2008/09 and 2009/10.

ANSWER:

The Foreign Exchange Exposure Management Program establishes a natural hedge between the USD cash inflows from USD export revenues and USD cash outflows (from USD interest & principal payments and USD purchases), such that changes in foreign exchange (FX) rates will be offset on the income statement to the extent that period cash flows are in balance.

The FX Exposure Management Program includes a long term strategy with the objective to maintain a balance between overall US cash inflows and outflows within a range of ± 20% over the time horizon of the program. The existing time horizon of the program extends to the maturity of the longest dated US debt issue in 2023.

As the net long positions become larger in the medium and long term with the in-service of new major generation or the maturity of existing US long term debt, new US long term debt/ interest payments may be secured to structurally rebalance the net position in accordance with Manitoba Hydro's Foreign Exchange Exposure Management Program.

To the extent that a mismatch of USD cash inflows and cash outflows exists over a short period of time, FX forward contracts, USD financing, or investments can be used to bridge the short term timing differences between the months. FX forward contracts are transactions in which counterparties agree to exchange a specified amount of different currencies at some future date, with the exchange rate being set at the time the contract is executed. The user is protected from adverse movements in future FX rates, but also does not benefit from favorable movements. As at March 31, 2010, there were no outstanding FX contract purchases (2009 - $58 million). For the year ended March 31, 2010 FX gains of $7 million were reclassified from other comprehensive income into net income.

To manage a short or long USD position, the Corporation may also elect to purchase or sell USD to meet corporate cash requirements. During 2008/09, Manitoba Hydro sold $65 million to CAD due to a net long position, thereby enabling the Corporation to apply these funds towards current Canadian cash requirements. During 2009/10, Manitoba Hydro purchased USD $4 million in order to meet a net short position.

Accounting cash flow hedges have been established between the US long term debt obligations and anticipated US export revenues, and the Corporation measures the effectiveness of the accounting hedge relationships on a quarterly basis. Accordingly, foreign exchange translation gains and losses on US long term debt balances in effective cash flow hedge relationships are recognized in Other Comprehensive Income (OCI) until future hedged US export revenues are realized, at which time the respective Accumulated OCI balances are also recognized in net income. Accounting fair value hedges have been established between the US Sinking Fund Investments and an equivalent amount of US long term debt obligations. Offsetting foreign exchange gains/ losses on monthly revaluation of these fair value hedge items are recognized in net income.

Manitoba Hydro's current accounting hedges are not expected to be significantly impacted by the transition to IFRS as IAS 39, Financial Instruments: Recognition and Measurement is very similar to Canadian GAAP.

PUB/MH II-11

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I- 18, MIPUG/MH I-13 Foreign Exchange/ Exposure Management Program**

d) **Please provide a schedule indicating the monthly foreign exchange gains or losses in 2009/10 and the impact on the unrealized exchange gains or losses on AOCI**

ANSWER:

As indicated in the following schedule, the Accumulated Other Comprehensive Income (AOCI) balance as at March 31, 2009 was in a loss position of $169 million. As the total OCI during the 2009/10 year was a gain of $454 million, the AOCI balance as at March 31, 2010 was in a gain position of $285 million.

AOCI balance as at March 31, 2009

									(168,951,529)

Realized foreign exchange losses (gains) on debt in cash flow hedges

Realized export revenues in cash flow hedge x (previous month end FX rate - historical FX rate of CO94)

April 2009	6,000,000	x	(	1.26020	-	1.01336	)	1,481,031	
May 2009	6,000,000	x	(	1.19400	-	1.01336	)	1,083,831	
June 2009	6,000,000	x	(	1.09610	-	1.01336	)	496,431	
July 2009	6,000,000	x	(	1.16250	-	1.01336	)	894,831	
August 2009	6,000,000	x	(	1.07900	-	1.01336	)	393,831	
September 2009	6,000,000	x	(	1.09670	-	1.01336	)	500,031	
October 2009	6,000,000	x	(	1.07220	-	1.01336	)	353,031	
November 2009	6,000,000	x	(	1.07740	-	1.01336	)	384,231	
December 2009	6,000,000	x	(	1.05740	-	1.01336	)	264,231	
January 2010	6,000,000	x	(	1.04660	-	1.01336	)	199,431	
February 2010	6,000,000	x	(	1.06500	-	1.01336	)	309,831	
March 2010	6,000,000	x	(	1.05260	-	1.01336	)	235,431	
								$ 6,596,172	6,596,172

Unrealized foreign exchange gains (losses) on debt in cash flow hedges

Month end balances of US debt in cash flow hedge x (previous month FX rate - closing month FX rate)

April 2009	1,879,000,000	x	(	1.26020	-	1.19400	)	124,389,800	
May 2009	1,873,000,000	x	(	1.19400	-	1.09610	)	183,366,700	
June 2009	1,867,000,000	x	(	1.09610	-	1.16250	)	(123,968,800)	
July 2009	1,861,000,000	x	(	1.16250	-	1.07900	)	155,393,500	
August 2009	1,855,000,000	x	(	1.07900	-	1.09670	)	(32,833,500)	
September 2009	1,849,000,000	x	(	1.09670	-	1.07220	)	45,300,500	
October 2009	1,843,000,000	x	(	1.07220	-	1.07740	)	(9,583,600)	
November 2009	1,837,000,000	x	(	1.07740	-	1.05740	)	36,740,000	
December 2009	1,831,000,000	x	(	1.05740	-	1.04660	)	19,774,800	
January 2010	1,825,000,000	x	(	1.04660	-	1.06500	)	(33,580,000)	
February 2010	1,819,000,000	x	(	1.06500	-	1.05260	)	22,555,600	
March 2010	1,813,000,000	x	(	1.05260	-	1.01560	)	67,081,000	
								$ 454,636,000	454,636,000

Foreign exchange losses (gain) on FX forward contracts	(6,976,276)
Unrealized fair value gain on US sinking fund investments	94,192
AOCI balance as at March 31, 2010	285,398,559

PUB/MH II-11

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I- 18, MIPUG/MH I-13 Foreign Exchange/ Exposure Management Program**

e) **Please indicate the amount of foreign exchange gains or losses realized in income (transferred from AOCI) in 2009/09, 2009/10 and forecast to be realized for 2010/11 through 2023 based on the current anticipated timing of export revenue realization.**

ANSWER:

Please see the attached schedule.

PUB/MH II - 11 (e)
MANITOBA HYDRO
Foreign Exchange Gains or Losses Realized/ Forecast to be Realized in Income
In $millions CAD

	2008/09 Actual	2009/10 Actual	2010/11 Forecast	2011/12 Forecast	2012/13 Forecast	2013/14 Forecast	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast
Realized/ Forecast to be Realized Foreign Exchange (Gains) Losses	($11.359)	$6.596	($6.088)	($0.011)	($0.095)	($9.257)	($4.205)	($6.275)	($2.601)	($2.882)	($1.010)	($0.772)	($0.915)	($1.409)	($1.350)

PUB/MH II-11

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I- 18, MIPUG/MH I-13 Foreign Exchange/ Exposure Management Program**

f) **Please discuss and illustrate the impact on the Corporations profits related to CAD$:USD$ foreign exchange fluctuations versus that currently forecast in IFF09-1 and the implications of the Canadian dollar remaining at parity with USD on export revenue and profits for 2010/11 and 2011/12 through 2019/20 .**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-49.

PUB/MH II-12

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-22; PUB/MH I-31; PUB/MH I-23(a)/Tab 4.0 -Export Prices

Please reconcile/explain and update MH's Canadian extra-provincial revenues - sale data filed as follows:

Year	Tab 4.0 Canadian Revenue ($M)	PUB/MH I-22 Canadian Sales (GWh)	PUB/MH I-23a Average Unit Price (¢/KWh)	PUB/MH I-23a Calculated Revenue
2004/05	78.3	1,580	4.35	$70 M
2005/06	172.9	1,424	7.72	$110 M
2006/07	85.4	373	6.72	$25 M
2007/08	110.1	482	8.08	$39 M
2008/09	131.4	417	11.19	$47 M
2009/10	87.0	?	?	
2010/11	68.5	?	?	
2011/12	49.6	?	?	

ANSWER:

The Canadian Revenue from Tab 4.0 includes revenue from Merchant transactions.

The Canadian Sales GWh from PUB/MH I-22 do not include the Merchant transactions, these numbers represents the exports that flowed from the Manitoba Hydro grid.

Merchant transactions are excluded from the calculation of the average price.

The simple calculation of GWh x Average price will not result in the Revenue numbers reported due to the fact that Merchant transactions are not included in the average price calculation.

PUB/MH II-13

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-22; PUB/MH I-31; PUB/MH I-23(a)/Tab 4.0

Please reconcile/explain and update MH's Canadian extra-provincial revenues - sale data filed as follows:

Year	PUB/MH I-22		Tab 4		PUB/MH I-23(a)	
	Power Purchases (GWh)	Thermal Generation (GWh)	Power Purchase Costs ($M)	Fuel Costs ($M)	U.S. Import Price	CDN Import Price
2004/05	2,030	414	135		4.46	6.94
2005/06	739	401	125		3.94	2.91
2006/07	2,249	522	226		5.23	4.47
2007/08	830	457	116	19	4.61	4.95
2008/09	1,033	335	158	18	4.56	5.06
2009/10	1,974	240	90	12		
2010/11	2,536	215	119	13		
2011/12	2,601	323	202	46		

ANSWER:

Power Purchase costs include energy charges as well as various Market charges and transmission costs. The average import prices reported on PUB/MH I-23(a) are calculated from the energy charges divided by the energy purchased.

<u>PUB/MH II-14</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-24 Payments to Province**

a) Please confirm that MH's payments to the province totaled:

F2005	**$228 M**	**(15% of Gross Revenue)**
F2006	**$215 M**	**(11% of Gross Revenue)**
F2007	**$221 M**	**(13% of Gross Revenue)**
F2008	**$247 M**	**(14% of Gross Revenue)**
F2009	**$239 M**	**(13% of Gross Revenue)**
F2010 Forecast	**$230 M**	**(14% of Gross Revenue)**
F2015 Forecast	**$275 M**	**(14% of Gross Revenue)**
F2020 Forecast	**$380 M**	**(13% of Gross Revenue)**

<u>ANSWER</u>:

Payments to the Province exclude municipal GILT and business taxes. The revised table is as follows.

F2005	$228 M	(15% of Gross Revenue)
F2006	$235 M	(13% of Gross Revenue)
F2007	$221 M	(14% of Gross Revenue)
F2008	$237 M	(14% of Gross Revenue)
F2009	$239 M	(14% of Gross Revenue)
F2010 Forecast	$240 M	(15% of Gross Revenue)
F2015 Forecast	$275 M	(13% of Gross Revenue)
F2020 Forecast	$380 M	(13% of Gross Revenue)

PUB/MH II-14

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-24 Payments to Province**

b) Are the $2 M (F2010) and $8 M (F2011) provincial mitigation of settlement obligations related to a specific project (e.g., Wuskwatim G.S.)? Explain.

ANSWER:

The provincial mitigation settlement obligations relate to both the Lake Winnipeg Regulation (LWR) control structure and the Churchill River Diversion (CRD) control structure. The LWR and CRD support all Nelson River northern generating stations.

PUB/MH II-14

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-24 Payments to Province**

c) Does MH anticipate any new or further provincial mitigation/settlement obligations to result from Bipole III/Keeyask/Conawapa? Explain.

ANSWER:

Manitoba Hydro does not anticipate that there will be any further mitigation / settlement obligations for the Province of Manitoba to address. Manitoba Hydro and its current and/or potential partners will assume all mitigation responsibilities associated with these projects.

PUB/MH II-14

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-24 Payments to Province**

d) **Please define any past, current and/or future ongoing financial obligations of MH with respect to winter roads/all-weather road upgrades and maintenance/wharfs/ferry services. Explain.**

ANSWER:

Remedial road works ($4.2M) and dock system ($0.5M) had been implemented for the Churchill River Diversion and the Lake Winnipeg Regulation projects prior to 1979. Due to direct impacts of the post-Project water regime on community infrastructure, Manitoba Hydro has contractual obligations to maintain 4 causeways ($4.2M spent since 1997) in Nelson House and the CR30 road ($2.3M spent since 1997) in Churchill. In addition, provisions have been made for the operation and maintenance ($0.3M annual) of the infrastructure works and on-going programming.

PUB/MH II-15

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-11 (g) Wind Dependable Energy

Please provide a table of corresponding data points including the monthly maximum and minimum recorded in each year to date.

ANSWER:

The monthly factors corresponding to the graph in PUB/MH I-11(g) is provided in the table below.

Apr	1.10
May	1.03
Jun	0.93
Jul	0.83
Aug	0.87
Sep	0.97
Oct	1.00
Nov	1.08
Dec	1.07
Jan	1.03
Feb	1.03
Mar	1.07

As noted in the response to PUB/MH I-86(d), Manitoba Hydro does not own the St. Leon wind farm or its monthly performance data. St. Leon wind farm monthly performance data is deemed confidential information under the power purchase agreement with St. Leon Wind Energy LP as it is of commercial value to wind developers. Therefore, Manitoba Hydro cannot provide specific recorded maximum and minimum data.

PUB/MH II-16

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-25(a); PUB/MH I-24 (b) - Sinking Fund/Debt/Interest Payments**

a) **Please provide an alternative sinking fund continuity analysis based on an exchange rate by unity out to 2030.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-49.

PUB/MH II-16

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-25(a); PUB/MH I-24 (b) - Sinking Fund/Debt/Interest Payments**

b) Please provide a parallel impact analysis out to 2030 of MH's long-term and short term debt with an exchange rate of unity.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-49.

PUB/MH II-16

Subject: **Tab 4 Financial Results & Forecast**

Reference: **PUB/MH I-25(a); PUB/MH I-24 (b) - Sinking Fund/Debt/Interest Payments**

c) Please provide an alternative analysis out to 2030 of MH's operating activities (revenue stream/interest payments) and finance expenditures with an exchange rate of unity.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-49.

PUB/MH II-17

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-30 (a) Energy Sales**

Please provide the respective GWh and average price per KWh for each of the Opportunity Bilateral, Opportunity Spot Market and Merchant trading revenue associated with the reported revenue.

ANSWER:

Please see the attached table.

	Opportunity Bilateral Revenue (CDN$)	Opportunity Bilateral GWh	Opportunity Bilateral Average Price (MWh)	Opportunity Spot Market Revenue (CDN$)	Opportunity Spot Market GWh	Opportunity Spot Market Average Price (MWh)	Merchant Trading Revenue (CDN$)	Merchant Trading GWh	Merchant Trading Average Price (MWh)
1999/00	150,636,616	5,396	27.92				0		
2000/01	216,927,371	5,801	37.39				0		
2001/02	280,792,868	6,022	46.63				0		
2002/03	124,165,676	2,911	42.66	12,951,734	280	46.23	0		
2003/04	38,565,560	545	69.86	14,093,815	190	74.37	473,904	11	44.43
2004/05	184,290,257	3,335	52.10	65,505,054	1,463	44.78	10,518,118	316	33.32
2005/06	235,727,552	3,567	66.08	274,657,114	6,735	40.78	62,926,861	919	68.49
2006/07	242,547,027	4,035	60.11	52,666,604	2,215	23.78	60,134,040	1,206	49.88
2007/08	92,169,622	1,974	66.86	235,657,264	5,840	40.35	71,548,902	1,262	56.69
2008/09	100,092,362	1,758	73.39	186,560,892	4,730	38.80	85,958,504	1,598	53.80

PUB/MH II-18

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-32 (c) OM&A**

a) Please explain the underlying factors, which have led to major increases in Administration from fiscal 2008/09 through 2011/12 in President & CEO, Corporate Planning & Strategic Analysis, Finance & Administration, Power Supply, Customer Service & distribution.

ANSWER:

President & CEO Administration – The increase from fiscal 2008/09 through 2011/12 is mainly due to corporate contingency included in the forecast years, addition of two new Vice-president positions as well as positions transferred from another business unit.

Corporate Planning & Strategic Analysis Administration – The increase from fiscal 2008/09 through 2011/12 is due to the establishment of a new business unit and the associated costs including the addition of a Division Manager and senior administrative support.

Finance & Administration – The increase from fiscal 2008/09 through 2011/12 is due to a new Corporate Services Division Manager position, filling a vacant Vice-President Assistant position and higher consulting costs to address new initiatives.

Power Supply Administration – The increase from fiscal 2008/09 through 2011/12 is primarily due to increased trainee levels to address existing staff shortages and future anticipated attrition levels.

Customer Service & Distribution Administration – The increase from fiscal 2008/09 through 2011/12 is due to the establishment of a new business unit and the associated costs including the addition of a Division Manager, Vice President Assistant and senior administrative support as well as positions transferred from other divisions.

See Table below for an illustration of the underlying factors leading to the major increases:

(in '000s)	**President &CEO Administration**	**Corporate Planning & Strategic Analysis Administration**	**Finance & Administration**	**Power Supply Administration**	**Customer Service & Distribution Administration**
Fiscal 08/09 O&A costs (actuals)	**$9,901**	**$380**	**$1,901**	**$14,952**	**$163**
Salaries & Benefits due to Administrative EFT increases	865	443	267	180	890
Trainees				3,706	
Corporate Donations	(605)				
Consulting		96	344		
Contingency	2,187				
Other	68	155	102	110	232
Fiscal 2011/12 O&A costs (forecast)	**$12,416**	**$1,074**	**$2,614**	**$18,948**	**$1,285**
Net Increase	**$2,515**	**$694**	**$713**	**$3,996**	**$1,122**

PUB/MH II-18

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-32 (c) OM&A**

b) Please explain the increase in Corporate Relations Administration from 2005 to 2009 and what factors have led to a decrease forecast in 2009/10.

ANSWER:

The increase from fiscal 2005 to 2009 is due to the establishment of a new business unit and the associated costs including the addition of a Division Manager, Vice President Assistant and administrative support.

The decrease in 2009/10 is mainly due to the transfer of four manager positions to the Corporate Planning and Strategic Analysis and Finance and Administration business units.

PUB/MH II-18

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-32 (c) OM&A**

c) Please explain the reason for forecast increases in Corporate Planning & Strategic Analysis for the years 2008/09 through 2011/12.

ANSWER:

The primary reason for the forecast increases in Corporate Planning & Strategic Analysis is the additional equivalent full-time (EFT) positions as well as the transfer of two positions and responsibilities from the Corporate Relations business unit. These new positions are required as a result of the establishment of the new Business Unit which includes a Corporate Strategic Review function. Positions include a Division Manager, Department Managers, Administrative Officers, Business Analysts and Secretaries.

<u>PUB/MH II-18</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-32 (c) OM&A**

d) Please comment on the increases in Corporate Risk Management since 2004/05

<u>ANSWER</u>:

Costs have increased in the Corporate Risk Management area primarily due to increased staffing levels required for the department's expanded role. Specifically;

- The addition of a Senior Business Analyst for the Export Power Middle Office; and
- The transfer of the Corporate Credit Risk Management function from Treasury.

<u>PUB/MH II-18</u>

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-32 (c) OM&A

e) Please indicate the extent of the increases forecasted relates to IFRS adjustments.

<u>ANSWER</u>:

Manitoba Hydro has not yet concluded its detailed review of IFRS requirements as it pertains to forecasted operating, maintenance and administrative (OM&A) costs and thus, has included a $15 million general provision for IFRS in its forecast. Other than the aforementioned provision, the OM&A cost increases as per the response to PUB/MH I-32(c) do not include any amounts for IFRS.

PUB/MH II-19

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-152/CAC/MSOS/MH I-13(c)Non-Dependable Energy Sales/Prices**

a) **Please confirm that MH achieved the following volumes/average prices for dependable and non-dependable (opportunity) energy sales.**

Year	Dependable		Non-Dependable	
	GWh	¢/KWh	GWh	¢/KWh
2000/01	6,352	3.50	5,801	3.74
2001/02	6,277	5.13	6,022	4.66
2002/03	6,544	5.13	3,191	4.30
2003/04	6,231	4.74	735	7.10
2004/05	5,633	5.14	4,798	5.00
2005/06	4,044	5.92	10,303	4.95
2006/07	3,654	6.00	6,250	4.72
2007/08	3,921	5.32	7,814	5.20
2008/09	4,087	5.71	6,489	4.72
2009/10	2,613	5.64	6,554	2.22

ANSWER:

Please see updated table in CAC/MSOS/MH I-13(d).

The Dependable Sales value for 2000/01 has been updated to 4.06 ¢/KWh to reflect the correct revenues as opposed to 3.5¢/KWh. In addition the calculated price for Non-Dependable for 2007/08 should be 4.20 not 5.20.

Manitoba Hydro can confirm all the other values are correct.

PUB/MH II-19

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-152/CAC/MSOS/MH I-13(c)Non-Dependable Energy Sales/Prices**

b) Please confirm that in 2000/01 and 2003/04, MH achieved higher unit revenues for opportunity sales than for dependable energy (contract) sales.

ANSWER:

In 2003/04 Manitoba Hydro achieved an average price of $71/MWh for opportunity sales which exceeded the average price for dependable sales of $47.4/MWh. However, this was achieved on a volume of 735 GWh which was only 12% of the dependable volume and represents Manitoba Hydro "cherry picking" hourly sales opportunities due to poor water conditions and reduced hydraulic generation. The dependable sales product is almost entirely 5x16. For a comparable product in the opportunity market, the sale price was $60.64 CDN.

In 2000/01 the average unit revenue from opportunity sales was 3.74¢/kWh compared to 4.06¢/kWh for dependable sales.

PUB/MH II-19

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-152/CAC/MSOS/MH I-13(c)Non-Dependable Energy Sales/Prices**

c) Please confirm that in 8 of the last 10 years, dependable (contract) sales achieved higher prices than the non-dependable opportunity sales.

ANSWER:

In 9 of the last 10 years, dependable sales achieved higher average prices than the non-dependable opportunity sales.

<u>PUB/MH II-20</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-31 - Exchange Rate Revenue Impacts**

a) **Please confirm that MH U.S. export revenues included exchange rate revenue as follows:**

Year	U.S. Exchange Rate Revenue	U.S. Average Exchange Rate
1999/00	$56 M	1.17
2000/01	$58 M	1.17
2001/02	$170 M	1.57
2002/03	$125 M	1.54
2003/04	$80 M	1.35
2004/05	$113 M	1.27
2005/06	$116 M	1.19
2006/07	$41 M	1.14
2007/08	$32 M	1.03
2008/09	$63 M	1.13
2009/10 (Forecast)	$36 M	1.12
2010/11 (Forecast)	$38 M	1.07
2011/12 (Forecast)	$41 M	1.09

<u>ANSWER</u>:

U.S. extra-provincial revenues were translated at the Bank of Canada month-end noon rate. The following table outlines an approximation of the average effective exchange rate revenue included in MH U.S. export revenues.

Year	A U.S. Revenue in USD	B U.S. Average Exchange Rate	C U.S. Revenue in CDN (A x B)	D Difference (C - A)
1999/00	242,343	1.17	283,541	41,198
2000/01	312,074	1.17	365,844	53,770
2001/02	325,724	1.57	510,247	184,523
2002/03	254,560	1.54	393,168	138,608
2003/04	217,368	1.35	293,251	75,883
2004/05	362,164	1.27	461,107	98,943
2005/06	537,903	1.19	639,728	101,825
2006/07	432,814	1.14	491,330	58,516
2007/08	482,512	1.03	494,864	12,352
2008/09	427,771	1.13	485,306	57,535
2009/10 (Forecast)	291,297	1.11	323,340	32,043
2010/11 (Forecast)	276,449	1.07	295,800	19,351
2011/12 (Forecast)	462,915	1.09	504,577	41,662
2012/13 (Forecast)	495,484	1.07	530,168	34,684
2013/14 (Forecast)	503,523	1.11	558,910	55,387
2014/15 (Forecast)	476,071	1.12	533,200	57,129
2015/16 (Forecast)	570,552	1.13	644,724	74,172
2016/17 (Forecast)	589,132	1.14	671,611	82,479
2017/18 (Forecast)	599,298	1.14	683,200	83,902
2018/19 (Forecast)	746,511	1.14	851,023	104,512
2019/20 (Forecast)	924,997	1.14	1,054,497	129,500
2020/21 (Forecast)	1,016,650	1.14	1,158,981	142,331
2021/22 (Forecast)	1,035,804	1.14	1,180,816	145,012
2022/23 (Forecast)	1,180,878	1.14	1,346,201	165,323
2023/24 (Forecast)	1,481,536	1.15	1,703,766	222,230
2024/25 (Forecast)	1,619,838	1.15	1,862,814	242,976
2025/26 (Forecast)	1,583,698	1.15	1,821,253	237,555
2026/27 (Forecast)	1,575,836	1.15	1,812,211	236,375
2027/28 (Forecast)	1,596,690	1.15	1,836,193	239,503
2028/29 (Forecast)	1,614,232	1.15	1,856,367	242,135

PUB/MH II-20

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-31 - Exchange Rate Revenue Impacts**

b) Please provide a 2010 to 2029 tabulation of the exchange rate U.S. export revenue (relative to unity) included in IFF 09-1 20 Year forecasts.

ANSWER:

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

<u>PUB/MH II-21</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **Export Contracts-NEB reporting**

a) **Please describe in detail the current reporting requirements to the NEB as it relates to exported and imported power.**

<u>ANSWER</u>:

Please see Appendix 53 – the National Energy Board Export and Import Reporting Regulations (SOR/95-563).

PUB/MH II-21

Subject: **Tab 4 Financial Results & Forecast**
Reference: **Export Contracts-NEB reporting**

b) Confirm that the current level and detail of reporting will continue in the future.

ANSWER:

Manitoba Hydro is unaware of any pending changes to the reporting requirements to the NEB.

PUB/MH II-21

Subject: **Tab 4 Financial Results & Forecast**
Reference: **Export Contracts-NEB reporting**

c) **Please provide a glossary of terms describing each type of export transaction and those reported to the NEB.**

ANSWER:

Please see Appendix 54 – the National Energy Board Electricity Regulations (SOR/97-130), Section 2 Interpretation.

PUB/MH II-22

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-30 (b)

Please re-file the schedule and separately display the General Service Revenue from Energy Intensive Rate for 2010/11 and 2011/12.

ANSWER:

Manitoba Hydro is unable to relate the Reference provided above to the Energy Intensive Rate.

Revenues related to the Energy Intensive Rate for 2010/11 and 2011/12 can be found in Manitoba Hydro's response to CAC/MSOS/MH II-32(b).

PUB/MH II-23

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-32 (c),CAC/MSOS/MH I-19 (b)**

Please re-file the schedule incorporating 2004/05 & 2005/06 and include columns, which include the Compounded Annual Growth Rate for the years 2004/05 to 2008/09 and 2008/09 to 2011/12.

ANSWER:

Please see the following schedule for the requested information.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(000's)

	2004/05 Actual	**2005/06 Actual**	**2006/07 Actual**	**2007/08 Actual**	**2008/09 Actual**	**Fiscal 2004/05-2008/09 Compounded Annual Growth**	**2009/10 Forecast**	**2010/11 Forecast**	**2011/12 Forecast**	**Fiscal 2008/09-2011/12 Compounded Growtl % Inc/(Dec)**
Labour										
Wages, Salaries	$ 320,808	$ 332,257	$ 344,701	$ 359,249	$ 380,031	4.3	$ 411,832	$ 415,215	$ 424,765	3.8
Overtime	33,842	38,032	38,896	41,781	45,890	7.9	47,248	48,061	49,166	2.3
Employee Benefits	68,442	70,184	73,636	76,807	83,671	5.2	85,872	93,035	95,175	4.4
Subtotal - Labour and Benefits	**423,093**	**440,473**	**457,233**	**477,838**	**509,592**	4.8	**544,952**	**556,311**	**569,106**	3.8
EFTs (Straight Time + Overtime)	5,885	5,999	6,007	6,090	6,312	1.8	6,648	6,704	6,704	2.0
Labour & Benefits per EFT	**72**	**73**	**76**	**78**	**81**	2.9	**82**	**83**	**85**	1.7
Employee Safety & Training	5,275	3,686	3,487	3,646	4,145	(5.8)	4,357	4,747	4,856	5.4
Travel	23,534	26,212	27,729	28,331	31,671	7.7	31,960	32,963	33,721	2.1
Motor Vehicle	17,726	19,380	19,731	22,423	24,125	8.0	22,967	23,114	23,646	(0.7)
Materials & Tools	23,893	26,046	25,414	27,824	29,338	5.3	25,762	26,178	26,780	(3.0)
Consulting & Professional Fees	7,269	7,229	8,498	7,503	9,137	5.9	10,593	10,904	11,155	6.9
Construction & Maintenance Services	13,345	13,700	13,711	15,938	18,000	7.8	21,489	21,785	22,286	7.4
Building & Property Services	21,031	22,973	24,697	25,740	28,685	8.1	20,506	20,671	21,146	(9.7)
Equipment Maintenance & Rentals	9,546	10,720	11,606	11,719	13,028	8.1	13,794	13,858	14,177	2.9
Consumer Services	4,203	4,301	4,316	4,651	5,230	5.6	5,572	5,683	5,814	3.6
Computer Services	3,959	4,293	2,622	1,131	858	(31.8)	682	696	712	(6.0)
Collection Costs	5,161	6,790	7,218	5,256	5,019	(0.7)	4,430	4,542	4,646	(2.5)
Customer & Public Relations	5,223	5,585	6,493	6,665	6,355	5.0	5,870	6,014	6,152	(1.1)
Sponsored Memberships	1,149	1,012	1,187	1,192	1,464	6.3	1,242	1,267	1,296	(4.0)
Office & Administration	15,447	15,902	14,939	14,427	14,538	(1.5)	15,326	15,703	15,857	2.9
Communication Systems	1,844	1,447	1,866	1,353	1,449	(5.8)	1,572	1,603	1,640	4.2
Research & Development Costs	3,685	2,874	3,251	2,979	3,059	(4.6)	4,029	4,110	4,205	11.2
Miscellaneous Expense	2,470	2,811	2,422	3,292	901	(22.3)	1,066	1,087	1,112	7.3
Contingency Planning	-	-	-	-	-		3,994	3,361	2,491	
Operating Expense Recovery	(18,105)	(19,205)	(20,570)	(23,314)	(21,519)	4.4	(16,462)	(16,497)	(16,670)	(8.2)
Total Costs	569,749	596,229	615,849	638,594	685,075	4.7	723,701	738,099	754,129	3.3
Capital Order Activities	(157,730)	(170,458)	(176,992)	(192,338)	(205,175)	6.8	(231,073)	(235,040)	(239,741)	5.3
CICA Accounting Changes*	-	-	-	-	5,000		7,000	7,000	7,000	11.9
Provision for IFRS	-	-	-	-	-		-	-	15,000	
Capitalized Overhead	(58,174)	(62,028)	(61,887)	(67,289)	(66,198)	3.3	(67,964)	(69,021)	(70,447)	2.1
Operating and Administration Charged to Centra	(55,232)	(53,085)	(53,505)	(56,270)	(59,042)	1.7	(60,160)	(61,343)	(62,570)	2.0
OM&A Attributable to Electric Operations	**$ 298,613**	**$ 310,658**	**$ 323,465**	**$ 322,697**	**$ 359,660**	4.8	**$ 371,504**	**$ 379,695**	**$ 403,370**	3.9

* Other CICA Accounting Changes totalling $4 million (beginning in 2009/10) are embedded within the Total Costs

PUB/MH II-24

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-33 Average Salary per EFT

a) Please update the table to incorporate two columns; (1) average Manitoba CPI and (2) compound annual growth rate for the years 2007/08 through forecast 2011/12.

ANSWER:

Please see the following tables which includes Manitoba CPI and compounded annual growth for the years 2007/08 through forecast 2011/12.

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY BUSINESS UNIT **(000's)**

	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast	Compounded Annual Growth %
President & CEO	$ 83.097	$ 86.377	$ 86.843	$ 86.568	$ 88.559	1.6
Corporate Relations	63.417	62.454	62.968	63.438	64.897	0.6
Corporate Planning & Strategic Analysis	83.763	82.711	87.730	100.745	103.062	5.3
Finance & Administration	65.988	67.423	69.143	69.319	70.913	1.8
Power Supply	64.877	66.014	68.120	67.991	69.555	1.8
Transmission	64.717	66.084	66.265	65.606	67.115	0.9
Customer Services & Distribution	56.094	57.220	59.503	59.734	61.108	2.2
Customer Care & Marketing	56.994	58.383	61.168	61.297	62.707	2.4
Corporate Accruals & Adjustments (Subsidiary)	85.384	85.433	80.017	81.577	83.453	(0.6)
Business Unit Total	**62.309**	**63.646**	**65.442**	**65.528**	**67.035**	**1.8**
Manitoba CPI	1.9%	2.2%	0.4%	1.4%	2.0%	
Manitoba CPI (07/08 base year) Cumulative Growth	**100.0%**	**102.2%**	**102.6%**	**104.0%**	**106.1%**	**1.5**

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY DIVISION (000's)

	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast	Compounded Annual Growth %
President & CEO						
General Counsel	$ 78.551	$ 85.035	$ 85.659	$ 85.739	$ 87.711	2.8
Public Affairs	59.978	60.337	62.195	62.309	63.742	1.5
Research & Development	77.842	83.868	83.558	83.750	85.676	2.4
Administration	114.786	118.753	114.399	111.927	114.501	(0.1)
	$ 83.097	**$ 86.377**	**$ 86.843**	**$ 86.568**	**$ 88.559**	1.6
Corporate Relations						
Aboriginal Relations	$ 57.607	$ 56.628	$ 59.734	$ 60.119	$ 61.502	1.6
Administration	110.320	110.598	109.520	112.438	115.024	1.0
	$ 63.417	**$ 62.454**	**$ 62.968**	**$ 63.438**	**$ 64.897**	0.6
Corporate Planning & Strategic Analysis						
Corporate Strategic Review	$ 81.922	$ 82.301	$ 75.640	$ 86.756	$ 88.751	2.0
Corporate Planning & Development	84.883	82.194	94.351	116.307	118.982	8.8
Administration	82.947	85.432	99.250	122.215	125.026	10.8
	$ 83.763	**$ 82.711**	**$ 87.730**	**$ 100.745**	**$ 103.062**	5.3
Finance & Administration						
Information Technology Services	$ 70.187	$ 72.140	$ 74.552	$ 74.719	$ 76.437	2.2
Treasury	66.653	69.826	70.462	70.683	72.309	2.1
Corporate Risk Management	95.747	97.363	88.064	88.623	90.661	(1.4)
Gas Supply	75.492	76.106	76.494	77.340	79.119	1.2
Rates & Regulatory Affairs	75.235	74.565	77.977	78.150	79.948	1.5
Corporate Controller	71.090	73.897	73.823	73.835	75.533	1.5
Human Resources	68.500	68.705	71.111	71.289	72.929	1.6
Corporate Safety & Health	75.747	78.402	80.192	80.356	82.204	2.1
Corporate Services	53.817	54.904	57.131	57.313	58.632	2.2
Administration	122.533	127.082	126.166	126.744	129.659	1.4
	$ 65.988	**$ 67.423**	**$ 69.143**	**$ 69.319**	**$ 70.913**	1.8
Power Supply						
Power Planning	$ 76.909	$ 79.466	$ 81.546	$ 81.879	$ 83.763	2.2
Power Projects Development	76.052	78.495	77.005	77.387	79.167	1.0
HVDC	64.093	66.145	68.629	68.968	70.554	2.4
Generation North	63.428	64.789	67.027	67.272	68.819	2.1
Generation South	62.236	64.079	67.132	67.339	68.888	2.6
Power Sales & Operations	78.069	80.735	82.324	82.667	84.568	2.0
Engineering Services	71.429	72.525	74.590	74.787	76.508	1.7
New Generation Construction	69.967	69.180	72.206	72.653	74.324	1.5
Administration	49.656	49.326	48.683	47.988	49.092	(0.3)
	$ 64.877	**$ 66.014**	**$ 68.120**	**$ 67.991**	**$ 69.555**	1.8

Transmission											
Transmission System Operations	$	70.473	$	73.140	$	72.892	$	72.918	$	74.595	1.4
Transmission Planning & Design		71.606		73.838		74.900		73.930		75.630	1.4
Transmission Construction & Line Maintenance		60.948		62.665		64.728		64.516		66.000	2.0
Apparatus Maintenance		58.809		59.074		56.946		56.791		58.097	(0.3)
Administration		64.445		61.098		68.908		56.234		57.527	(2.8)
	$	**64.717**	**$**	**66.084**	**$**	**66.265**	**$**	**65.606**	**$**	**67.115**	0.9
Customer Services & Distribution											
Customer Service Operations - Winnipeg & North	$	58.109	$	59.137	$	60.745	$	60.975	$	62.377	1.8
Customer Service Operations - South		54.930		56.263		59.376		59.530		60.900	2.6
Distribution Planning & Design		66.946		69.585		71.402		71.771		73.422	2.3
Distribution Construction		49.923		50.134		51.312		51.583		52.770	1.4
Administration		-		-		118.900		119.484		122.232	
	$	**56.094**	**$**	**57.220**	**$**	**59.503**	**$**	**59.734**	**$**	**61.108**	2.2
Customer Care & Marketing											
Industrial & Commercial Solutions	$	78.806	$	82.082	$	84.588	$	84.621	$	86.567	2.4
Consumer Marketing & Sales		53.042		53.373		55.763		55.955		57.241	1.9
Business Support Services		53.528		54.814		56.973		57.105		58.419	2.2
Administration		67.875		70.173		73.273		72.772		74.445	2.3
	$	**56.994**	**$**	**58.383**	**$**	**61.168**	**$**	**61.297**	**$**	**62.707**	2.4
Corporate Accruals & Adjustments											
Corporate Accruals & Adjustments (Subsidiary)	$	85.384	$	85.433	$	80.017	$	81.577	$	83.453	(0.6)
	$	**85.384**	**$**	**85.433**	**$**	**80.017**	**$**	**81.577**	**$**	**83.453**	(0.6)
Total	**$**	**62.309**	**$**	**63.646**	**$**	**65.442**	**$**	**65.528**	**$**	**67.035**	1.8
Manitoba CPI		1.9%		2.2%		0.4%		1.4%		2.0%	
Manitoba CPI (07/08 base year) Cumulative Growth		**100.0%**		**102.2%**		**102.6%**		**104.0%**		**106.1%**	**1.5**

PUB/MH II-24

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-33 Average Salary per EFT**

b) Please explain the major escalation in both Corporate Planning & Development and Administration from 2007/08 through 2011/12 at contrast with the moderate change in Corporate Strategic Review over the same five-year period.

ANSWER:

PUB/MH I-33(c) provided a breakdown of the average salary per EFT by division within the Corporate Planning and Strategic Analysis Business Unit. While the escalation in average salary per EFT at the Business Unit level is correct, a misallocation of the dollars in the 2009/10 budget occurred at the divisional level that resulted in an overstatement of the average salary per EFT for Corporate Planning and Development and Administration divisions.

The average salary per EFT for the Corporate Planning and Strategic Analysis Business Unit, and the year-to-year, change is shown below for each year from 2007/08 to 2011/12.

	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
Corporate Planning & Strategic Analysis	$ 83.763	$ 82.711	$ 87.730	$ 100.745	$ 103.062
Year to Year % Change		-1.3%	6.1%	14.8%	2.3%

The increase in 2010/11 over 2009/10 is due to the newly created Business Unit being filled using the top-down approach of hiring the senior management positions first. As these managers hire additional staff, the average salary per EFT will be reduced.

<u>PUB/MH II-24</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-33 Average Salary per EFT**

c) Please describe the initiatives being undertaken in Corporate Strategic Review and Corporate Planning & Development

<u>ANSWER</u>:

New major initiatives recently undertaken by the Corporate Planning and Strategic Analysis (CPSA) Business Unit include negotiation of the St Joseph wind farm financing arrangements and establishment of an internal task force to review the potential utility impacts of electric vehicles. An initiative has also been undertaken to strengthen and streamline the Environmental Management System, maintaining ISO 14001 standards through integration of three EMS registrations into a single corporate wide registration. CPSA is also involved in a wide range of projects initiated internally or by other Business Units, and in the monitoring of strategic developments in other utilities.

PUB/MH II-24

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-33 Average Salary per EFT**

d) Please explain the decrease over the five years in Finance & Administration – Corporate Risk Management.

ANSWER:

Average costs per EFT have decreased due to the transfer of positions with lower salary levels, along with their functional responsibilities, into this department.

PUB/MH II-25

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-34 (b) & (c) Staff Level Changes**

a) Please provide details on the 10 EFT increases in President & CEO by position forecasts in 2009/10 and explain the increase.

ANSWER:

The following table provides the breakdown of the 10 EFT increase in 2009/10 by position(s):

New Positions Positions required as a result of the establishment of new business units including two new Vice Presidents, as well as positions for increased demand for legal and insurance services	4
Transfers Positions transferred from other Business Units into President and CEO and positions transferred to other Business Units.	2
Filling Vacant Positions in General Counsel (2), Public Affairs (1) and Administration (1)	4
Total Increase	10

PUB/MH II-25

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-34 (b) & (c) Staff Level Changes**

b) **Please provide details on the 15 EFT increase forecast in 2010/11 in Corporate Planning & Strategic Analysis by position and explain the increase.**

ANSWER:

The following table provides a breakdown of the 15 EFT increase in 2010/11 by position:

New Positions	EFT
Management	3
Professional	10
Support	2
Total	15

The increase in EFTs is mainly driven by the establishment of the new Business Unit and Corporate Strategic Review function.

<u>PUB/MH II-25</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-34 (b) & (c) Staff Level Changes**

c) **Please indicate what proportion of the 181 EFT increase in forecast for 2009/10 in Power Supply relates to new generation projects.**

<u>ANSWER</u>:

The increase related to new generation projects is 83 EFTs or 46%.

PUB/MH II-25

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-34 (b) & (c) Staff Level Changes**

d) Please provide details on the 37 EFT increase in 2009/10 in Customer Services & Distribution by position and explain the increase.

ANSWER:

The following table provides the breakdown of the 37 EFT increase in 2009/10 by position(s):

New Positions Positions required as a result of the establishment of a new business unit including a Division Manager, a Division Manager Secretary, an Assistant to the Vice President, and an Executive Secretary, positions required to support the First Nations Collections initiative (3) and trainee positions added to the Powerline Technician Trainee Program (8).	15
Transfers Positions transferred from other Business Units into Customer Service & Distribution and positions transferred to other Business Units.	2
Filling Vacant Positions, including District Workers, District Operators, Safety Officers, and engineering positions.	22
Lower Overtime	(2)
Total Increase	37

PUB/MH II-25

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-34 (b) & (c) Staff Level Changes**

e) **Please provide a schedule, which compares the detail of the actual EFT totaling 6,041 versus budgeted EFT compliment of 6,229 for January 2010 by Business unit.**

ANSWER:

Please see the attached table.

MANITOBA HYDRO
JANUARY 2010 EFTs

	January Budget	January Actual
President & CEO		
General Counsel	29	29
Public Affairs	33	33
Research & Development	2	1
Administration	35	30
	99	**93**
Corporate Relations		
Aboriginal Relations	48	48
Administration	4	4
	52	**52**
Corporate Planning & Strategic Analysis		
Corporate Strategic Review	12	8
Corporate Planning & Development	11	9
Administration	4	4
	26	**21**
Finance & Administration		
Information Technology Services	304	304
Treasury	14	13
Corporate Risk Management	6	4
Gas Supply	19	19
Rates & Regulatory Affairs	21	20
Corporate Controller	118	111
Human Resources	157	151
Corporate Safety & Health	30	26
Corporate Services	337	315
Administration	13	10
	1,018	**973**
Power Supply		
Power Planning	67	64
Power Projects Development	59	50
HVDC	231	219
Generation North	184	184
Generation South	431	431
Power Sales & Operations	87	78
Engineering Services	198	198
New Generation Construction	123	94
Administration	203	203
	1,582	**1,521**
Transmission		
Transmission System Operations	351	339
Transmission Planning & Design	206	192
Transmission Construction & Line Maintenance	256	250
Apparatus Maintenance	408	408
Administration	41	44
	1,262	**1,233**
Customer Services & Distribution		
Customer Service Operations - Winnipeg & North	492	496
Customer Service Operations - South	546	546
Distribution Planning & Design	177	175
Distribution Construction	374	372
Administration	6	5
	1,595	**1,593**
Customer Care & Marketing		
Industrial & Commercial Solutions	60	59
Consumer Marketing & Sales	221	203
Business Support Services	222	209
Administration	56	53
	559	**523**
Corporate Accruals & Adjustments		
Corporate Accruals & Adjustments (Subsiduary)	36	34
	36	**34**
Total	**6,229**	**6,041**

PUB/MH II-26

Subject: Tab 4 Financial Results & Forecast
Reference: CAC/MSOS/MH I-15(b) EFT Vacancy Factor

Please indicate the vacancy factor which has been utilized for 20009/10 through 2011/12 and provide supporting calculations for the factors determination as well as supporting calculations demonstrating the impact of the vacancy factor on the forecast FTE.

ANSWER:

The overall vacancy factor is 6%.

The vacancy factor incorporated in the forecasts for 2009/10 through 2011/12 is calculated at the department level and includes factors related both to delays in hiring and positions being held vacant for cost containment reasons. Calculations are based on historical position data and consider turnover for the upcoming forecast year, expected retirements, time allotment for the hiring process, as well as budgetary constraints.

PUB/MH II-27

Subject: **Tab 4 Financial Results & Forecast**
Reference: **City of Winnipeg Taxes Collected**

a) Please file mock-up customer bills for a typical City of Winnipeg residential customer heated by electricity and commercial customer heated by electricity, describing which taxes are collected and how each tax on the bill is determined.

ANSWER:

Residential Application

The residential tax rate for the City of Winnipeg is 2.5% and the Provincial tax rate is 7.0%. The City of Winnipeg and the Province of Manitoba allow for an exemption from tax on electricity used for heating a residence. Both parties have set the tax exemption at 80%, resulting in a residential City tax of 0.5% and residential Provincial tax of 1.4%.

The attached customer bill for John Doe (Account No. 9999901 7999901) represents the bill for a typical City of Winnipeg residential customer with electric heat.

Commercial Application

The commercial tax rate for the City of Winnipeg is 5.0% and the Provincial tax rate is 7.0%. The City of Winnipeg allows for an exemption from tax on electricity used for heating a commercial service. The City of Winnipeg has set the tax reduction at 80%, resulting in a commercial City tax of 1.0%. There is no tax reduction on the Provincial tax rate.

The attached customer bill for Doe Industries Inc (Account No. 9999991 1999991) represents the bill for a typical City of Winnipeg commercial all-electric customer. The premise for this commercial customer is heated by electricity.

Please note as per Section 443(3) of *The City of Winnipeg Charter*, the rounding rules state that any fraction of a cent is to be computed as a whole cent.

SAMPLE BILL

Customer name Nom de l'abonné	JOHN DOE
Account number N° de compte	**9999901 7999901**
Service location Adresse de service	123 MAPLE RD APT 201 WINNIPEG MB R9N 9A9
Date issued Date d'émission	Apr 13 AVR 2010
Amount due Montant à payer	**$ 25.00**
Due date Date d'échéance	**Apr 29 AVR 2010**
Cycle number N° de cycle	06

Customer service / 24 hour Trouble calls Demandes de renseignements / 24 h sur 24 Dépannage

Winnipeg	480-5900
Outside Winnipeg / Extérieur de Winnipeg	1-888-MBHYDRO (1-888-624-9376)
Deaf access line Ligne pour malentendants	360-6154
E- Mail address Adresse électronique	customerservice@hydro.mb.ca

Visit our website at
www.hydro.mb.ca

Visitez notre site Web
www.hydro.mb.ca/francais

Account summary / Sommaire du compte

Previous charges and credits / Frais et crédits antérieurs

Previous balance / Solde antérieur		$ 47.00
Payment / Paiement	Mar 24 MAR	47.00 CR
Balance forward / Solde reporté		$ 0.00

New charges / Nouveaux frais

Electricity / Électricité	(GST/TPS $ 1.69) **EPP/R.P.É**	$ 25.00

Amount due / Montant à payer $ 25.00

Due date / Date d'échéance Apr 29 AVR 2010

Chargers continue to draw energy even after the device is fully charged. Unplug your cell phone and PDA chargers as soon as they're fully charged.

Les chargeurs continuent de consommer de l'énergie même après le chargement complet des appareils. Débranchez les chargeurs de téléphone cellulaire et d'assistant numérique après le chargement.

Mail Payment to / Envoyez le paiement par la poste à
PO BOX 7900 STN MAIN
WINNIPEG MB R3C 5R1

If mailing, please specify amount paid on return portion of bill and enclose with payment.
Si vous payez par la poste, veuillez inclure le talon de la facture sur lequel le montant payé est indiqué.

Account number/N° de compte
9999901 7999901

Amount due/Montant à payer
$ 25.00

Due date /Date d'échéance
Apr 29 AVR 2010

Payment enclosed/
Paiement ci-joint
$

☐ CH ☐ CA ☐ DR

XGRP
PUBLIC TRUSTEE
FILE #XZ9001
JOHN DOE
199 NEW MAIN ST SUITE 101

WINNIPEG MB R9N 9A9

DIR(A)

00000000 099999017999014 000000000000 0000002500 0000000000 9

Customer name Nom de l'abonné	JOHN DOE
Account number N° de compte	**9999901 7999901**
Service location Adresse de service	123 MAPLE RD APT 201 WINNIPEG MB R9N 9A9
Date issued Date d'émission	Apr 13 AVR 2010

Special messages / Messages particuliers

- **New Equal Payment Plan Instalment**
  One or more of your EPP instalments has been revised to more accurately balance your Instalments billed and Use by the end of the EPP year. Your plan(s) will continue to be reviewed until August when your EPP instalment(s) will be recalculated for the beginning of the next EPP year.

  Nouveau versement du Régime de paiements égaux(RPÉ)
  Nous avons révisé le montant ou les montants de vos versements du RPÉ pour faire correspondre plus exactement les versements facturés et votre consommation jusqu'à la fin de l'année du RPÉ. Votre régime continuera d'être révisé jusqu'au mois d'août alors que votre versement sera recalculé pour le début de la prochaine année du RPÉ.

- The Public Utilities Board has approved new electricity rates. Please see the enclosed insert for details.

  La Régie des services publics a approuvé de nouveaux tarifs d'électricité. Veuillez consulter l'encart ci-joint pour tous les détails.

Electricity - Residential / Électricité - Résidentiel

Meter number / N° de compteur	Service / Pour la période From / Du	To / Au	Days / Jours	Meter readings / Relevés du compteur Previous / Précédent	Present / Nouveau	Multiplier / Multiplicateur	kW.h / kWh	Reading type / Type de relevé
X99995	Mar 08 MAR/10	Apr 08 AVR/10	31	7257	7300	10	430	Estimated Estimatif

Basic Charge / Redevance de base			$ 6.85	
Energy Charge / Frais d'énergie	319.032 kW.h	x $0.06250	19.94	
	110.968	x 0.06380	7.08	
Subtotal / Total partiel			33.87	
	0.50% City Tax / Taxe mun.		0.18	
	1.40% Prov Tax / Taxe prov.		0.48	
	5.00% GST / TPS		1.69	
Electricity charges / Frais d'électricité			**36.22**	
EPP instalment / Versement du R.P.É.				25.00

EPP summary / Sommaire du R.P.É

Equal payment plan year to date / Régime de paiements égaux - cumul annuel à ce jour						
	Meter number / N° de compteur	Beginning of EPP year / Début d'année RPÉ	Instalments billed / Versements facturés	Use / Consommation	Difference / Différence	End of EPP year / Fin d'année RPÉ
Electricity / Électricité	X99995	Sep/SEP	$354.00	$255.28	$98.72 CR	Aug/AOÛ

Consumption history / Histoire de la consommation

Watch this space for consumption comparisons when readings are received. / Surveillez cet espace où figureront des données comparatives de votre consommation quand nous recevrons des relevés de votre compteur.

DUPLICATE BILL

Customer name Nom de l'abonné	DOE INDUSTRIES INC
Account number N° de compte	9999991 1999991
Service location Adresse de service	357 MAPLE AVE WINNIPEG MB R9N 9A9
Date issued Date d'émission	Apr 15 AVR 2010
Amount due Montant à payer	**$ 575.79**
Due date Date d'échéance	**May 03 MAI 2010**
Cycle number N° de cycle	08

Customer service / 24 hour Trouble calls Demandes de renseignements / 24 h sur 24 Dépannage

Winnipeg	480-5900
Outside Winnipeg / Extérieur de Winnipeg	1-888-MBHYDRO (1-888-624-9376)
Deaf access line Ligne pour malentendants	360-6154
E- Mail address Adresse électronique	customerservice@hydro.mb.ca

Visit our website at
www.hydro.mb.ca

Visitez notre site Web
www.hydro.mb.ca/francais

Account summary / Sommaire du compte

Previous charges and credits / Frais et crédits antérieurs

Previous balance / Solde antérieur		$ 592.67
Balance forward / Solde reporté		$ 592.67

New charges / Nouveaux frais

Electricity / Électricité	(GST/TPS $ 25.47)	$ 575.79
Other charges / Autres frais		592.67 CR

Amount due / Montant à payer $ 575.79

Due date / Date d'échéance May 03 MAI 2010

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Mail Payment to / Envoyez le paiement par la poste à
PO BOX 7900 STN MAIN
WINNIPEG MB R3C 5R1

If mailing, please specify amount paid on return portion of bill and enclose with payment.
Si vous payez par la poste, veuillez inclure le talon de la facture sur lequel le montant payé est indiqué.

Account number/N° de compte
9999991 1999991

Amount due/Montant à payer
$ 575.79

Due date /Date d'échéance
May 03 MAI 2010

Payment enclosed/
Paiement ci-joint
$

☐ CH ☐ CA ☐ DR

M532
DOE INDUSTRIES INC
9900 MAPLE ROAD
ROOM #1

BRAMPTON ON R9N 9A9

(A)

Customer name Nom de l'abonné	DOE INDUSTRIES INC
Account number N° de compte	9999991 1999991
Service location Adresse de service	357 MAPLE AVE WINNIPEG MB R9N 9A9
Date issued Date d'émission	Apr 15 AVR 2010

Special messages / Messages particuliers

▶ The Public Utilities Board has approved new electricity rates. Please see the enclosed insert for details.

La Régie des services publics a approuvé de nouveaux tarifs d'électricité. Veuillez consulter l'encart ci-joint pour tous les détails.

Electricity - General service small / Électricité - Serv. gén. faible puiss.

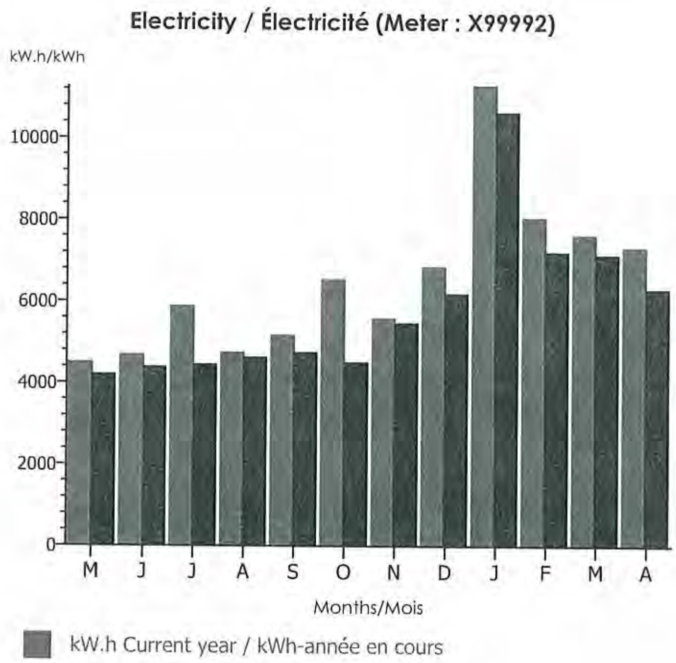
Meter number / N° de compteur	Service / Pour la période From / Du	To / Au	Days / Jours	Meter readings / Relevés du compteur Previous / Précédent	Present / Nouveau	Multiplier / Multiplicateur	kW.h / kWh	Reading type / Type de relevé
X99992	Mar 10 MAR/10	Apr 12 AVR/10	33	5149	5271	60	7,320	Actual Réel

Basic Charge / Redevance de base				$ 10.82	
				6.42	
Energy Charge / Frais d'énergie		4,658.182 kW.h	x $0.06660	310.23	
		2,661.818	x 0.06840	182.07	
Demand / Consommation de pointe					
Measured / Consommation mesurée	.228 x 60	13.680 kV.A			
Subtotal / Total partiel				509.54	
		1.00% City Tax / Taxe mun.		5.11	
		7.00% Prov Tax / Taxe prov.		35.67	
		5.00% GST / TPS		25.47	
Electricity charges / Frais d'électricité					**575.79**

Other charges / Autres frais

Amount Transferred / Montant viré	592.67 CR

Consumption history / Histoire de la consommation



Estimated months / Estimation en
Nov / NOV

Electricity terminology / Terminologie de l'électricité

Balance remaining - This dollar amount reflects your original loan or other term billing less any instalments billed or additional payments on the balance as of the date on the bill; instalments billed but not yet paid are included in your Amount Due. The Balance remaining does not reflect payments made on Interest or future Interest calculations. If you are planning to make a partial or full payment for your loan or other term billing, please contact Manitoba Hydro for current information. / **Solde à payer** - Ce montant comprend le montant de votre prêt initial ou le montant de toute autre facturation à terme diverse moins tout versement facturé ou tout paiement additionnel appliqué au solde jusqu'à la date indiquée sur la facture. Les versements facturés encore impayés sont compris dans le Montant à payer. Le Solde à payer ne comprend pas les paiements appliqués aux intérêts ou aux intérêts à calculer dans l'avenir. Si vous prévoyez payer, en partie ou en entier, votre emprunt ou le montant de toute autre facturation à terme, veuillez communiquer avec Manitoba Hydro pour des renseignements mis à jour.

Basic charge - The fixed charge that pays part of the cost of providing service and does not depend on how much energy is used. It helps pay for such items as the maintenance of meters, the cost of meter reading, billing and record keeping. / **Redevance de base** - Frais fixes qui servent à payer une partie du coût de l'offre d'un service et qui ne dépend pas de la quantité d'énergie consommée. Ils servent à payer les coûts d'éléments tels que l'entretien des compteurs, le relevé des compteurs, la facturation et la tenue de dossiers.

Energy Charge - A breakdown of the costs of your electrical service calculated by multiplying the number of kilowatt-hours by a rate for that block of energy. If Manitoba Hydro provides different rates for different portions of your service, each rate calculation will appear on its own line. / **Frais d'énergie** - Répartition des coûts du service d'électricité calculés en multipliant le nombre de kilowattheures par le tarif correspondant à ce bloc d'énergie. Si Manitoba Hydro propose des tarifs différents pour des portions différentes du service qu'elle vous fournit, le calcul selon chaque tarif paraît sur une ligne séparée.

Kilowatt (kW) - An amount of electrical power equivalent to 1,000 watts (W). / **Kilowatt (kW)** - Unité de mesure de la puissance électrique correspondant à 1 000 watts (W).

Kilowatt-hour (kW.h) - The unit by which electrical energy is measured. For example, 10-100 W light bulbs switched on for one hour would use one kilowatt-hour (1000 W for one hour). / **Kilowattheure (kWh)** - Unité de mesure de l'énergie électrique. Par exemple, dix ampoules de 100 watts chacune, allumées pendant une heure consomment un kWh (1 000 watts pendant une heure).

Multiplier – Each electricity meter records units of consumption. The multiplier is used to convert these units into the actual kW.h consumption used. / **Multiplicateur** - Chaque compteur d'électricité enregistre des unités de consommation. Le multiplicateur sert à convertir ces unités pour indiquer la consommation réelle en kWh.

PUB/MH II-27

Subject: **Tab 4 Financial Results & Forecast**
Reference: **City of Winnipeg Taxes Collected**

b) Please provide a similar bill mock-up of a City of Winnipeg residential customer heated by natural gas and commercial customer heated by natural gas, describing which taxes are collected and how each tax on the bill is determined.

ANSWER:

Residential Application

The residential tax rate for the City of Winnipeg is 2.5% and the Provincial tax rate is 7.0%. The City of Winnipeg and the Province of Manitoba allow for an exemption from tax on natural gas used for space heating.

For Provincial Tax, a residential service that uses natural gas only to heat their house and for no other uses is entitled to a 100% Provincial tax exemption. A customer who has additional gas uses receives an 80% tax reduction resulting in a Provincial tax rate of 1.4%.

For City of Winnipeg Tax, a 100% City tax exemption applies to the heating load. The non heating load is determined by using the natural gas usage during the three summer months of June, July and August where typically no natural gas is used for space heating. The non-heating load is then assumed to occur in each month throughout the year with a 2.5% tax applied to this non heating component.

The attached customer bill for John & Jane Doe (Account No. 9999991 8888881) represents a typical City of Winnipeg residential customer who heats their residence with natural gas. This customer has gas appliances in addition to heating their home with natural gas.

Commercial Application

The commercial tax rate for the City of Winnipeg is 5.0% and the Provincial tax rate is 7.0%. The City of Winnipeg allows for an exemption from tax on natural gas used for space heating. A commercial service that uses natural gas solely to heat their premise is entitled to a 100% City tax exemption. There is no tax reduction on the Provincial tax rate.

The attached customer bill for Market & Deli (Account No. 9999994 1999994) represents a typical City of Winnipeg commercial customer whose premise is heated with natural gas and has no additional gas appliances.

Please note as per Section 443(3) of *The City of Winnipeg Charter*, the rounding rules state that any fraction of a cent is to be computed as a whole cent.

SAMPLE BILL

Customer name Nom de l'abonné	JOHN & JANE DOE
Account number **N° de compte**	**9999991 8888881**
Service location Adresse de service	299 MAPLE RD WINNIPEG MB R9N 9A9
Date issued Date d'émission	Mar 18 MAR 2010
Amount due **Montant à payer**	**$ 215.70**
Due date **Date d'échéance**	**Apr 05 AVR 2010**
Cycle number N° de cycle	11

Customer service / 24 hour Trouble calls
Demandes de renseignements / 24 h sur 24 Dépannage

Winnipeg	480-5900
Outside Winnipeg / Extérieur de Winnipeg	1-888-MBHYDRO (1-888-624-9376)
Deaf access line Ligne pour malentendants	360-6154
E- Mail address Adresse électronique	customerservice@hydro.mb.ca

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Visitez notre site Web
www.hydro.mb.ca/francais

Account summary / Sommaire du compte

Previous charges and credits / Frais et crédits antérieurs

Previous balance / Solde antérieur			$ 223.85
Payment / Paiement	Mar 16 MAR		223.85 CR
Balance forward / Solde reporté			$ 0.00

New charges / Nouveaux frais

Electricity / Électricité	(GST/TPS	$ 2.15)	$ 49.36
Natural gas / Gaz naturel	(GST/TPS	7.67)	164.34
Other charges / Autres frais			2.00

Amount due / Montant à payer $ 215.70

Due date / Date d'échéance Apr 05 AVR 2010

Chargers continue to draw energy even after the device is fully charged. Unplug your cell phone and PDA chargers as soon as they're fully charged.

Les chargeurs continuent de consommer de l'énergie même après le chargement complet des appareils. Débranchez les chargeurs de téléphone cellulaire et d'assistant numérique après le chargement.

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WINNIPEG MB R3C 5R1

If mailing, please specify amount paid on return portion of bill and enclose with payment.
Si vous payez par la poste, veuillez inclure le talon de la facture sur lequel le montant payé est indiqué.

Account number/N° de compte
9999991 8888881

Amount due/Montant à payer
$ 215.70

Due date /Date d'échéance
Apr 05 AVR 2010

Payment enclosed/
Paiement ci-joint
$

☐ CH ☐ CA ☐ DR

JOHN & JANE DOE
299 MAPLE RD

WINNIPEG MB R9N 9A9

T26(A)

00000000 09999991888888815 000000000000 0000021570 0000000000 3

Customer name Nom de l'abonné	JOHN & JANE DOE
Account number N° de compte	9999991 8888881
Service location Adresse de service	299 MAPLE RD WINNIPEG MB R9N 9A9
Date issued Date d'émission	Mar 18 MAR 2010

Electricity - Residential / Électricité - Résidentiel

Meter number / N° de compteur	Service / Pour la période From / Du	To / Au	Days / Jours	Meter readings / Relevés du compteur Previous / Précédent	Present / Nouveau	Multiplier / Multiplicateur	kW.h / kWh	Reading type / Type de relevé
X77772	Feb 12 FÉV/10	Mar 16 MAR/10	32	3776	3834	10	580	Estimated Estimatif

Basic Charge / Redevance de base		$ 6.85	
Energy Charge / Frais d'énergie	580.000 kW.h x $0.06250	36.25	
Subtotal / Total partiel		43.10	
	2.50% City Tax / Taxe mun.	1.09	
	7.00% Prov Tax / Taxe prov.	3.02	
	5.00% GST / TPS	2.15	
Electricity charges / Frais d'électricité			**49.36**

Natural gas - Residential / Gaz naturel - Résidentiel

Meter number / N° de compteur	Service / Pour la période From / Du	To / Au	Days / Jours	Meter readings / Relevés du compteur Previous / Précédent	Present / Nouveau	Usage / Consommation		Base pressure adj/Facteur de rajustement de la pression de base		Metric conversion factor/Facteur de conversion métrique		Cubic metres (m³) / Mètres cubes (m³)	Reading type / Type de relevé
X77773	Feb 12 FÉV/10	Mar 16 MAR/10	32	483	629	146	x	0.98780	x	2.832784	=	408.541	Estimated Estimatif

Basic Charge / Redevance de base					$ 13.00	
Primary Gas (Centra) / Gaz d'inventaire (Centra)	94.0 % x	408.541 m³	x	$0.21480	82.49	
Supplemental Gas / Gaz de réserve	6.0 x	408.541	x	0.15780	3.87	
Transportation to Centra / Transport jusqu'à Centra	100.0 x	408.541	x	0.04290	17.53	
Distribution to Customer / Distribution aux abonnés	100.0 x	408.541	x	0.08960	36.61	
Subtotal / Total partiel					153.50	
	2.50% City Tax Based on Non Heating Load / Taxe mun. fondée sur la charge de non-chauffage				1.03	
	1.40% Prov Tax / Taxe prov.				2.14	
	5.00% GST / TPS				7.67	
Natural gas charges / Frais de gaz naturel						**164.34**

Other charges / Autres frais

Helping Neighbours Pledge / Engagement - Voisins qui aident leurs voisins 2.00

Consumption history / Histoire de la consommation

Watch this space for consumption comparisons when readings are received. / Surveillez cet espace où figureront des données comparatives de votre consommation quand nous recevrons des relevés de votre compteur.

DUPLICATE BILL

Customer name Nom de l'abonné	MARKET & DELI
Account number N° de compte	9999994 1999994
Service location Adresse de service	137 MAPLE BLVD WINNIPEG MB R9N 9A9
Date issued Date d'émission	Apr 20 AVR 2010
Amount due Montant à payer	**$ 1,141.22**
Due date Date d'échéance	**May 06 MAI 2010**
Cycle number N° de cycle	11

Customer service / 24 hour Trouble calls
Demandes de renseignements / 24 h sur 24 Dépannage

Winnipeg	480-5900
Outside Winnipeg / Extérieur de Winnipeg	1-888-MBHYDRO (1-888-624-9376)
Deaf access line Ligne pour malentendants	360-6154
E- Mail address Adresse électronique	customerservice@hydro.mb.ca

Visit our website at
www.hydro.mb.ca

Visitez notre site Web
www.hydro.mb.ca/francais

Account summary / Sommaire du compte

Previous charges and credits / Frais et crédits antérieurs

Previous balance / Solde antérieur		$ 984.47
Payment / Paiement	Apr 13 AVR	984.47 CR
Balance forward / Solde reporté		$ 0.00

New charges / Nouveaux frais

Electricity / Électricité	(GST/TPS $ 32.61)	$ 763.11
Natural gas / Gaz naturel	(GST/TPS 16.88)	378.11

Amount due / Montant à payer $ 1,141.22

Due date / Date d'échéance May 06 MAI 2010

Chargers continue to draw energy even after the device is fully charged. Unplug your cell phone and PDA chargers as soon as they're fully charged.

Les chargeurs continuent de consommer de l'énergie même après le chargement complet des appareils. Débranchez les chargeurs de téléphone cellulaire et d'assistant numérique après le chargement.

Mail Payment to / Envoyez le paiement par la poste à
PO BOX 7900 STN MAIN
WINNIPEG MB R3C 5R1

If mailing, please specify amount paid on return portion of bill and enclose with payment.
Si vous payez par la poste, veuillez inclure le talon de la facture sur lequel le montant payé est indiqué.

Account number/N° de compte **9999994 1999994**	Payment enclosed/ Paiement ci-joint $
Amount due/Montant à payer **$ 1,141.22**	☐ CH ☐ CA ☐ DR
Due date /Date d'échéance **May 06 MAI 2010**	

MARKET & DELI
997 MAPLE BLVD

WINNIPEG MB R9N 9A9

T2(A)

00000000 09999994199999941 000000000000 0000114122 0000000000 9

Customer name Nom de l'abonné	MARKET & DELI
Account number N° de compte	**9999994 1999994**
Service location Adresse de service	137 MAPLE BLVD WINNIPEG MB R9N 9A9
Date issued Date d'émission	Apr 20 AVR 2010

Special messages / Messages particuliers

- The Public Utilities Board has approved new electricity rates. Please see the enclosed insert for details.

  La Régie des services publics a approuvé de nouveaux tarifs d'électricité. Veuillez consulter l'encart ci-joint pour tous les détails.

- **Primary and Supplemental Gas % changes effective April 1, 2010** - Due to a warmer than normal winter, the Primary and Supplemental Gas %'s have been updated to more accurately reflect natural gas consumption.

  Modification des pourcentages que représentent le gaz d'inventaire et le gaz de réserve, à compter du 1er avril 2010 . En raison d'un hiver plus doux que la normale, ces pourcentages ont été mis à jour pour refléter avec plus de précision la consommation du gaz naturel.

Electricity - General service small 3 phase / Électricité - Service général triphasé - petite puissance

Meter number / N° de compteur	Service / Pour la période From / Du	To / Au	Days / Jours	Meter readings / Relevés du compteur Previous / Précédent	Present / Nouveau	Multiplier / Multiplicateur	kW.h / kWh	Reading type / Type de relevé
X99998	Mar 16 MAR/10	Apr 15 AVR/10	30	79677	88981	1	9,304	Estimated Estimatif

Basic Charge / Redevance de base			$ 11.87	
			12.33	
Energy Charge / Frais d'énergie	4,652.000 kW.h	x $0.06660	309.82	
	4,652.000	x 0.06840	318.20	
Subtotal / Total partiel			652.22	
	5.00% City Tax / Taxe mun.		32.63	
	7.00% Prov Tax / Taxe prov.		45.65	
	5.00% GST / TPS		32.61	
Electricity charges / Frais d'électricité				**763.11**

Natural gas - Small Commercial / Gaz naturel - Commercial - petit

Meter number / N° de compteur	Service / Pour la période From / Du	To / Au	Days / Jours	Meter readings / Relevés du compteur Previous / Précédent	Present / Nouveau	Usage / Consommation		Base pressure adj/Facteur de rajustement de la pression de base		Metric conversion factor/Facteur de conversion métrique		Cubic metres (m³) / Mètres cubes (m³)	Reading type / Type de relevé
X99995	Mar 16 MAR/10	Apr 15 AVR/10	30	3034	3370	336	x	0.98780	x	2.832784	=	940.204	Estimated Estimatif

Basic Charge / Redevance de base					$ 13.00	
Primary Gas (Centra) / Gaz d'inventaire (Centra)	94.0 %	x	565.834 m³	x $0.21480	114.25	
Primary Gas (Centra) / Gaz d'inventaire (Centra)	100.0	x	374.370	x 0.21480	80.41	
Supplemental Gas / Gaz de réserve	6.0	x	565.834	x 0.15780	5.36	
Supplemental Gas / Gaz de réserve	0.0	x	374.370	x 0.15780	0.00	
Transportation to Centra / Transport jusqu'à Centra	100.0	x	940.204	x 0.04290	40.33	
Distribution to Customer / Distribution aux abonnés	100.0	x	940.204	x 0.08960	84.24	
Subtotal / Total partiel					337.59	
	7.00% Prov Tax / Taxe prov.				23.64	
	5.00% GST / TPS				16.88	
Natural gas charges / Frais de gaz naturel						**378.11**

Consumption history / Histoire de la consommation

Watch this space for consumption comparisons when readings are received. / Surveillez cet espace où figureront des données comparatives de votre consommation quand nous recevrons des relevés du compteur.

Electricity and natural gas terminology / Terminologie de l'électricité et du gaz naturel

Balance remaining - This dollar amount reflects your original loan or other term billing less any instalments billed or additional payments on the balance as of the date on the bill; instalments billed but not yet paid are included in your Amount Due. The Balance remaining does not reflect payments made on Interest or future Interest calculations. If you are planning to make a partial or full payment for your loan or other term billing, please contact Manitoba Hydro for current information. / **Solde à payer** - Ce montant comprend le montant de votre prêt initial ou le montant de toute autre facturation à terme diverse moins tout versement facturé ou tout paiement additionnel appliqué au solde jusqu'à la date indiquée sur la facture. Les versements facturés encore impayés sont compris dans le Montant à payer. Le Solde à payer ne comprend pas les paiements appliqués aux intérêts ou aux intérêts à calculer dans l'avenir. Si vous prévoyez payer, en partie ou en entier, votre emprunt ou le montant de toute autre facturation à terme, veuillez communiquer avec Manitoba Hydro pour des renseignements mis à jour.

Basic charge - The fixed charge that pays part of the cost of providing service and does not depend on how much energy is used. It helps pay for such items as the maintenance of meters, the cost of meter reading, billing and record keeping. / **Redevance de base** - Frais fixes qui servent à payer une partie du coût de l'offre d'un service et qui ne dépend pas de la quantité d'énergie consommée. Ils servent à payer les coûts d'éléments tels que l'entretien des compteurs, le relevé des compteurs, la facturation et la tenue de dossiers.

Energy Charge - A breakdown of the costs of your electrical service calculated by multiplying the number of kilowatt-hours by a rate for that block of energy. If Manitoba Hydro provides different rates for different portions of your service, each rate calculation will appear on its own line. / **Frais d'énergie** - Répartition des coûts du service d'électricité calculés en multipliant le nombre de kilowattheures par le tarif correspondant à ce bloc d'énergie. Si Manitoba Hydro propose des tarifs différents pour des portions différentes du service qu'elle vous fournit, le calcul selon chaque tarif paraît sur une ligne séparée.

Kilowatt (kW) - An amount of electrical power equivalent to 1,000 watts (W). / **Kilowatt (kW)** - Unité de mesure de la puissance électrique correspondant à 1 000 watts (W).

Kilowatt-hour (kW.h) - The unit by which electrical energy is measured. For example, 10-100 W light bulbs switched on for one hour would use one kilowatt-hour (1000 W for one hour). / **Kilowattheure (kWh)** - Unité de mesure de l'énergie électrique. Par exemple, dix ampoules de 100 watts chacune, allumées pendant une heure consomment un kWh (1 000 watts pendant une heure).

Multiplier – Each electricity meter records units of consumption. The multiplier is used to convert these units into the actual kW.h consumption used. / **Multiplicateur** - Chaque compteur d'électricité enregistre des unités de consommation. Le multiplicateur sert à convertir ces unités pour indiquer la consommation réelle en kWh.

Primary gas - Natural gas received from Western Canada. It can be purchased on an unregulated basis from a natural gas marketer, or from Manitoba Hydro at rates regulated by the Public Utilities Board of Manitoba. The price that Manitoba Hydro pays for its Primary Gas supply is passed directly on to the customer without any markup. During normal weather, this represents approximately 95% of a customer's annual natural gas use. / **Gaz d'inventaire** - Gaz naturel provenant de l'Ouest canadien. Il peut être acheté sur une base non réglementée à un négociant en gaz naturel ou à Manitoba Hydro à un tarif réglementé par la Régie des services publics. Le prix payé par Manitoba Hydro à ses fournisseurs de gaz d'inventaire est celui que paient les abonnés, sans aucune majoration. Lorsque les conditions météorologiques sont normales, le gaz d'inventaire représente environ 95 % de la consommation annuelle de gaz des abonnés.

Supplemental gas - Natural gas that Manitoba Hydro purchases to ensure supply is available when demand is higher than normal. This usually represents approximately 5% of a customer's annual natural gas use, but does fluctuate during warmer or colder than normal years. / **Gaz de réserve** - Gaz naturel acheté par Manitoba Hydro pour veiller à ce que l'offre réponde à la demande lorsque cette dernière est supérieure à la normale. Le gaz de réserve représente habituellement environ 5 % de la consommation annuelle de gaz des abonnés, mais le pourcentage peut varier selon les conditions météorologiques (p. ex., année plus chaude ou froide que la normale).

Transportation to Centra - The cost of transporting natural gas to Manitoba, including pipeline charges and the cost of storage facilities where Manitoba Hydro stores natural gas purchased in the summer for use in the winter. / **Tarif de transport à Centra** - Le tarif correspond au coût de transport du gaz naturel au Manitoba, y compris les frais d'utilisation des gazoducs et les frais afférents aux installations de stockage où Manitoba Hydro entrepose le gaz acheté pendant l'été pour une consommation en hiver.

Distribution to customer charge - The cost of delivering natural gas to a customer's home or business. It includes the cost of pipe and facilities that Manitoba Hydro has installed, the operation and maintenance costs for the distribution system and a small cost component related to unaccounted-for-gas (the Basic Charge recovers a portion of these costs). / **Tarif de distribution aux abonnés** - Il correspond au coût de livraison du gaz naturel à la résidence ou à l'entreprise d'un abonné. Il comprend les frais afférents aux conduites de gaz et aux autres éléments installés par Manitoba Hydro, les frais d'exploitation et d'entretien du réseau de distribution et un élément lié aux frais du gaz non comptabilisé. (La redevance de base permet de recouvrer une partie de ces coûts.)

Metric conversion factor – the number used to convert natural gas consumption from imperial units to metric measurement. / **Facteur de conversion métrique** - Nombre utilisé pour convertir en unités métriques la consommation de gaz naturel indiquée en unités impériales.

Cubic metre (m^3) – the unit by which natural gas volume is measured. / **Mètre cube (m^3)** - Unité de mesure du volume de gaz naturel.

PUB/MH II-27

Subject: **Tab 4 Financial Results & Forecast**
Reference: **City of Winnipeg Taxes Collected**

c) Please provide a similar bill mock-up of a of a Winnipeg based Industrial Customer that utilizes electricity in its manufacturing process and one which uses natural gas as feedstock .

ANSWER:

The commercial tax rate for the City of Winnipeg is 5.0% and the Provincial tax rate is 7.0%.

Industrial customers with greater than 50% of their electric load dedicated to manufacturing are eligible for an 80% Provincial tax reduction. An industrial customer must submit an application to the Provincial Government in order to be considered for the reduced Provincial tax. Once the application is approved, the Province notifies Manitoba Hydro to apply the reduced tax rate of 1.4%.

A commercial service that uses natural gas solely to heat their premise is entitled to a 100% City tax exemption on the heating load. The commercial tax rate of 5.0% applies to the lesser of actual consumption or the base load (non-heating load). Non-heating load is based on the three summer months of June, July and August where typically no energy is used for space heating. The non-heating load is then used to calculate a base load for the customer. There is no tax reduction on the Provincial tax rate for the natural gas service.

The attached customer bill for Doe Industries Ltd (Account No. 9999993 1999993) represents a typical City of Winnipeg Industrial Customer who utilizes electricity in a manufacturing process. Also attached is a representation of the customer's bill for natural gas service which is billed on a different account (Account No. 9999990 1999990). The premise is heated with natural gas and has additional gas appliances.

Manitoba Hydro is not aware of any industrial customers within the City of Winnipeg which use natural gas as feedstock. The attached customer bill for Doe Canada Inc. (Account No. 9999991 1999991) would represent a typical City of Winnipeg Industrial Customer who uses natural gas as feedstock.

Please note as per Section 443(3) of *The City of Winnipeg Charter*, the rounding rules state that any fraction of a cent is to be computed as a whole cent.

DUPLICATE BILL

Customer name / Nom de l'abonné	DOE INDUSTRIES LTD
Account number / Nº de compte	9999993 1999993
Service location / Adresse de service	1350 MAPLE AVE WINNIPEG MB R9N 9A9
Date issued / Date d'émission	Apr 06 AVR 2010
Amount due / Montant à payer	**$ 75,170.41**
Due date / Date d'échéance	**Apr 22 AVR 2010**
Cycle number / Nº de cycle	01

Customer service / 24 hour Trouble calls
Demandes de renseignements / 24 h sur 24 Dépannage

Telephone / Téléphone	474-4698
E- Mail address / Adresse électronique	ICS@hydro.mb.ca

Visit our website at www.hydro.mb.ca

Visitez notre site Web www.hydro.mb.ca/francais

Account summary / Sommaire du compte

Previous charges and credits / Frais et crédits antérieurs

Previous balance / Solde antérieur		$ 70,744.91
Payment / Paiement	Mar 11 MAR	70,744.91 CR
Balance forward / Solde reporté		$ 0.00

New charges / Nouveaux frais

Electricity / Électricité	(GST/TPS $ 3,373.90)	$ 75,170.41

Amount due / Montant à payer $ 75,170.41

Due date / Date d'échéance Apr 22 AVR 2010

Mail Payment to / Envoyez le paiement par la poste à
PO BOX 7900 STN MAIN
WINNIPEG MB R3C 5R1

If mailing, please specify amount paid on return portion of bill and enclose with payment.
Si vous payez par la poste, veuillez inclure le talon de la facture sur lequel le montant payé est indiqué.

Account number/Nº de compte **9999993 1999993**

Amount due/Montant à payer **$ 75,170.41**

Due date /Date d'échéance **Apr 22 AVR 2010**

Payment enclosed/ Paiement ci-joint $

☐ CH ☐ CA ☐ DR

DOE INDUSTRIES LTD
1350 MAPLE AVE

WINNIPEG MB R9N 9A9

83(A)

00000000 099999931999993 7 000000000000 0007517041 0000000000 5

Customer name Nom de l'abonné	DOE INDUSTRIES LTD
Account number N° de compte	9999993 1999993
Service location Adresse de service	1350 MAPLE AVE WINNIPEG MB R9N 9A9
Date issued Date d'émission	Apr 06 AVR 2010

Special messages / Messages particuliers

- The Public Utilities Board has approved new electricity rates. Please see the enclosed insert for details.

  La Régie des services publics a approuvé de nouveaux tarifs d'électricité. Veuillez consulter l'encart ci-joint pour tous les détails.

Electricity - Gen service large 750V - 30KV / Électricité - Serv. gén. grande puiss. 750 v - 30 kV

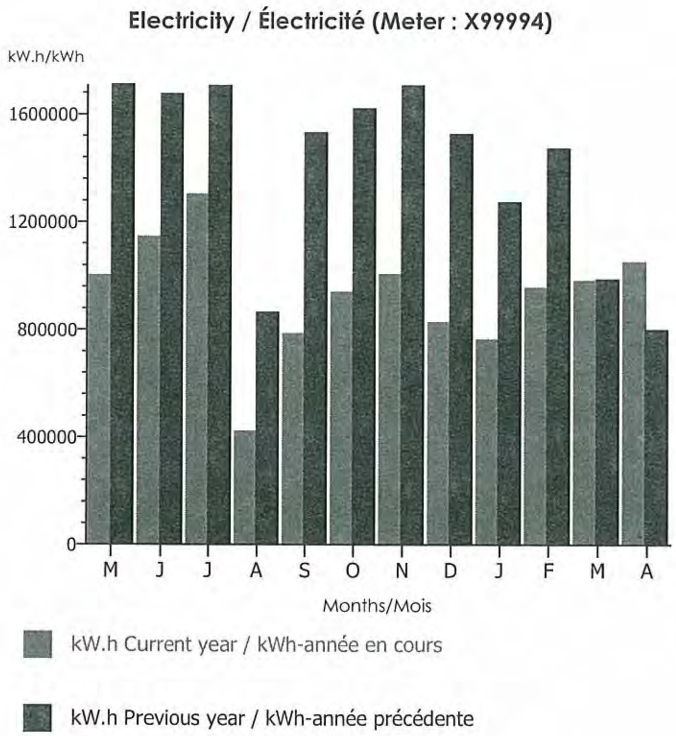
Meter number / N° de compteur	From / Du	To / Au	Power Factor / Facteur de puissance Load Factor / Facteur de charge
X99994	Mar 03 MAR/10	Apr 06 AVR/10	0.920900

Energy / Énergie		1,143,572.000 kW.h		
Energy Charge / Frais d'énergie		1,051,501.000	x $0.02730	$ 28,705.98
		92,071.000	x 0.02880	2,651.64
Demand / Consommation de pointe				
Measured Summer / Mesurée (été)	Mar 16/10 09:30	5,101.736 kV.A		
Measured / Mesurée	Mar 16/10 09:30	5,101.736		
Contract / Contrat	x 25%	2,165.000		
High / Élevée	25% Jun 12/09 15:00	1,385.740		
Billing / Facturation		4,351.481	x $ 7.080	30,808.49
		750.255	x $ 7.080	5,311.81
Subtotal / Total partiel				67,477.92
	5.00% City Tax / Taxe mun.			3,373.90
	1.40% Prov Tax / Taxe prov.			944.69
	5.00% GST / TPS			3,373.90

Electricity charges / Frais d'électricité **75,170.41**

Consumption history / Histoire de la consommation

PUB/MH II-27(c)
Attachment 1
Page 3 of 7



TEST BILL

Customer name / Nom de l'abonné	DOE INDUSTRIES LTD.
Account number / N° de compte	**9999990 1999990**
Service location / Adresse de service	1350 MAPLE AVE MISC MTR 2 WINNIPEG MB R9N 9A9
Date issued / Date d'émission	Apr 05 AVR 2010
Amount due / Montant à payer	**$ 34,717.97**
Due date / Date d'échéance	**Apr 21 AVR 2010**
Cycle number / N° de cycle	21

Customer service / 24 hour Trouble calls
Demandes de renseignements / 24 h sur 24 Dépannage

Telephone / Téléphone	474-4698
E- Mail address / Adresse électronique	ICS@hydro.mb.ca

Visit our website at www.hydro.mb.ca

Visitez notre site Web www.hydro.mb.ca/francais

Account summary / Sommaire du compte

Previous charges and credits / Frais et crédits antérieurs

Previous balance / Solde antérieur		$ 54,276.13
Payment / Paiement	Mar 11 MAR	54,276.13 CR
Balance forward / Solde reporté		$ 0.00

New charges / Nouveaux frais

Natural gas / Gaz naturel	(GST/TPS $ 1,531.42)	$ 34,717.97

Amount due / Montant à payer $ 34,717.97

Due date / Date d'échéance Apr 21 AVR 2010

Mail Payment to / Envoyez le paiement par la poste à
PO BOX 7900 STN MAIN
WINNIPEG MB R3C 5R1

If mailing, please specify amount paid on return portion of bill and enclose with payment.
Si vous payez par la poste, veuillez inclure le talon de la facture sur lequel le montant payé est indiqué.

Account number/N° de compte **9999990 1999990**	Payment enclosed/ Paiement ci-joint $
Amount due/Montant à payer **$ 34,717.97**	☐ CH ☐ CA ☐ DR
Due date /Date d'échéance **Apr 21 AVR 2010**	

DOE INDUSTRIES LTD.
1350 MAPLE AVE

WINNIPEG MB R9N 9A9

83(A)

00000000 09999990199999901 000000000000 0003471797 0000000000 4

Customer name Nom de l'abonné	DOE INDUSTRIES LTD.
Account number **N° de compte**	**9999990 1999990**
Service location Adresse de service	1350 MAPLE AVE MISC MTR 2 WINNIPEG MB R9N 9A9
Date issued Date d'émission	Apr 05 AVR 2010

Natural gas - HVF Sales-Ind / Gaz naturel - Serv ininter vol élevé (ventes)-Ind

Meter number / N° de compteur	From / Du	To / Au	Usage / Consommation		Metric conversion factor/ Facteur de conversion métrique	Cubic metres (m^3)/ Mètres cubes (m^3)	Baseload (m^3)/ Charge de base (m^3)
X99990	Mar 01 MAR/10	Apr 01 AVR/10	3776	x	28.327840	106,965.924	11,340.579

Basic Charge / Redevance de base						$ 1,040.53	
Primary Gas (Centra) / Gaz d'inventaire (Centra)	94.0 %	x	106,965.924 m^3	x	$0.21480	21,597.70	
Supplemental Gas / Gaz de réserve	6.0	x	106,965.924	x	0.15780	1,012.75	
Transportation to Centra / Transport jusqu'à Centra	100.0	x	106,965.924	x	0.01170	1,251.50	
Distribution to Customer / Distribution aux abonnés	100.0	x	106,965.924	x	0.01060	1,133.84	
Demand / Consommation de pointe							
Current / Actuel	Apr 01/10 (241 MCF)		6,827.009 m^3				
Billing / Facturation	Jan 08/10 09:00 (373 MCF)		10,566.284				
Transportation / Transportation			10,566.284	x	0.28050	2,963.84	
Distribution / Distribution			10,566.284	x	0.15410	1,628.26	
Subtotal / Total partiel						30,628.42	
	5.00% City Tax Based on Non Heating Load / Taxe mun. fondée sur la charge de non-chauffage					414.14	
	7.00% Prov Tax / Taxe prov.					2,143.99	
	5.00% GST / TPS					1,531.42	
Natural gas charges / Frais de gaz naturel							**34,717.97**

Consumption history / Histoire de la consommation

	Meter Number / N° de compteur	Use this year/ Consommation - cette année	Days in period/ Nbre de jours	Use per day this year/ Consommation / jour-cette année	Use last year/ Consommation an dernier	Days in period/ Nbre de jours	Use per day last year/ Consommation / jour (an dernier)	Use for the last twelve months / Consommation : 12 derniers mois
Natural gas m^3 / Gas naturel (m^3)	X99990	Apr 106,965.924	31	3,450.51	Apr 121,299.811	31	3,912.90	887,256.277

TEST BILL

Customer name / Nom de l'abonné	DOE CANADA INC.
Account number / N° de compte	9999991 1999991
Service location / Adresse de service	4999 MAPLE ST WINNIPEG MB R9N 9A9
Date issued / Date d'émission	Apr 05 AVR 2010
Amount due / Montant à payer	$ 7,814.25
Due date / Date d'échéance	Apr 21 AVR 2010
Cycle number / N° de cycle	21

Customer service / 24 hour Trouble calls
Demandes de renseignements / 24 h sur 24 Dépannage

Telephone / Téléphone	474-4698
E- Mail address / Adresse électronique	ICS@hydro.mb.ca

Visit our website at
www.hydro.mb.ca

Visitez notre site Web
www.hydro.mb.ca/francais

Account summary / Sommaire du compte

Previous charges and credits / Frais et crédits antérieurs

Previous balance / Solde antérieur		$ 7,760.12
Payment / Paiement	Mar 17 MAR	7,760.12 CR
Balance forward / Solde reporté		$ 0.00

New charges / Nouveaux frais

Natural gas / Gaz naturel	(GST/TPS $ 335.01)	$ 7,814.25

Amount due / Montant à payer $ 7,814.25

Due date / Date d'échéance Apr 21 AVR 2010

Mail Payment to / Envoyez le paiement par la poste à
PO BOX 7900 STN MAIN
WINNIPEG MB R3C 5R1

If mailing, please specify amount paid on return portion of bill and enclose with payment.
Si vous payez par la poste, veuillez inclure le talon de la facture sur lequel le montant payé est indiqué.

Account number/N° de compte 9999991 1999991

Amount due/Montant à payer $ 7,814.25

Due date /Date d'échéance Apr 21 AVR 2010

Payment enclosed/ Paiement ci-joint
$

☐ CH ☐ CA ☐ DR

CMP3
4999 MAPLE-ST CDN
C/O DOE-CDN-WINNIPEG
DOE CANADA INC.
PO BOX 999
COLUMBUS OH 99998-2999
UNITED STATES OF AMERICA

00000000 0999999119999910 000000000000 0000781425 0000000000 7

Customer name / Nom de l'abonné: DOE CANADA INC.

Account number / N° de compte: **9999991 1999991**

Service location / Adresse de service: 4999 MAPLE ST WINNIPEG MB R9N 9A9

Date issued / Date d'émission: Apr 05 AVR 2010

Natural gas - Interruptible T/S-Ind / Gaz naturel - Serv. interruptible (S/T)-Ind

Meter number / N° de compteur	From / Du	To / Au	Usage / Consommation		Metric conversion factor/ Facteur de conversion métrique	Cubic metres (m^3)/ Mètres cubes (m^3)	Baseload (m^3)/ Charge de base (m^3)
X99991	Mar 01 MAR/10	Apr 01 AVR/10	15260	x	28.327840	432,282.838	358,923.175

Basic Charge / Redevance de base				$ 1,028.85	
Distribution to Customer / Distribution aux abonnés	100.0 % x	432,282.838 m³	x $0.00680	2,939.52	
Demand / Consommation de pointe					
Current / Actuel	Apr 01/10 (1025 MCF)	29,036.036 m³			
Billing / Facturation	Jan 06/10 09:00 (1111 MCF)	31,472.230			
Distribution / Distribution		31,472.230	x 0.08680	2,731.79	
Subtotal / Total partiel				6,700.16	
	5.00% City Tax Based on Non Heating Load / Taxe mun. fondée sur la charge de non-chauffage			310.07	
	7.00% Prov Tax / Taxe prov.			469.01	
	5.00% GST / TPS			335.01	
Natural gas charges / Frais de gaz naturel					**7,814.25**

Consumption history / Histoire de la consommation

	Meter Number / N° de compteur	Use this year/ Consommation - cette année	Days in period/ Nbre de jours	Use per day this year/ Consommation / jour-cette année	Use last year/ Consommation an dernier	Days in period/ Nbre de jours	Use per day last year/ Consommation / jour (an dernier)	Use for the last twelve months / Consommation : 12 derniers mois
Natural gas m³ / Gas naturel (m³)	X99991	Apr 432,282.838	31	13,944.61	Apr 475,312.827	31	15,332.67	5,084,337.380

PUB/MH II-28

Subject: **Tab 4 Financial Results & Forecast**
Reference: **Manitoba Hydro Taxes Collected from Customers**

a) What amount in dollars is the City of Winnipeg requesting and does this amount include interest?

ANSWER:

To date, the City of Winnipeg has issued formal assessment notices requesting $8.7 million, of which, $6.2 relates to Manitoba Hydro and $2.5 million to Centra. These dollars relate to the period of August 1, 1999 through to December 31, 2008. These amounts do not include interest.

In the Amended Statement of Claim filed by the City of Winnipeg with the Queen's Bench the period in question has been expanded to include the period from January 1, 1991 to the present. The City did not provide a dollar amount in their Amended Statement of Claim.

<u>PUB/MH II-28</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **Manitoba Hydro Taxes Collected from Customers**

b) To what extent has this contingent liability been included in the forecasts presented in this application.

<u>ANSWER</u>:

No liability with respect to the City of Winnipeg audit has been included in the forecasts.

<u>PUB/MH II-28</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **Manitoba Hydro Taxes Collected from Customers**

c) **To what extent is the City of Winnipeg's claim related to electricity, and which portion is related to natural gas?**

<u>ANSWER</u>:

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

PUB/MH II-28

Subject: **Tab 4 Financial Results & Forecast**
Reference: **Manitoba Hydro Taxes Collected from Customers**

d) **Does any other municipality in Manitoba levy tax on the energy supplied by MH.**

ANSWER:

No other municipality in Manitoba has the legislated ability to levy a tax on energy supplied by Manitoba Hydro.

<u>PUB/MH II-28</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **Manitoba Hydro Taxes Collected from Customers**

e) In calculating the City of Winnipeg tax, how does MH ascertain that a residence is primarily heated by way of electricity or natural gas?

<u>ANSWER</u>:

When a customer contacts Manitoba Hydro to set up a new service, information is gathered at that time to determine the heating energy source. At the time the account is established a service order is issued to have Manitoba Hydro service staff schedule a visit to the residence in order to complete a Heating Information Report.

A Heating Information Report identifies whether the customer's residence is heated by electricity or gas along with information on the type of electric or gas heating equipment installed. Information from the Report is used to confirm the heating information for the service.

Where the customer has gas service Manitoba Hydro also maintains a record of all gas fired equipment installed in the premise. This information is received from the Mechanical and Engineering Branch of Manitoba Labour and Immigration as this is the provincial department that issues the permits necessary for all gas equipment installations in the province.

The information gathered is used to identify whether a residence is heated primarily by electricity or natural gas.

PUB/MH II-28

Subject: **Tab 4 Financial Results & Forecast**
Reference: **Manitoba Hydro Taxes Collected from Customers**

f) If a customer converts from one method of heating to the other, how does Manitoba Hydro identify these situations?

ANSWER:

Manitoba Hydro relies on permit information as well as customer contact to identify situations where customers have changed their primary source of heat.

PUB/MH II-29

Subject: **Tab 4 Financial Results & Forecast**
Reference: **I-36 (a) r , Schedule 4.6.0 Finance Expense**

Please indicate which schedule reflects the correct detail of finance expense.

ANSWER:

The correct detail of finance expense is reflected in both the revised Schedule 4.6.0, as re-filed on February 5, 2010, and the schedule filed with the revised PUB/MH I-36(a), which also has the inclusion of 2003/04 - 2006/07 detail of finance expense.

PUB/MH II-30

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-35 (a) & (b)Finance Expense

a) Reconcile the gross interest cost on short and long term debt per the schedule with gross interest per schedule 4.6.0.

ANSWER:

Please see the attached schedule.

PUB/MH II - 30 (a)

MANITOBA HYDRO
Reconciliation of Gross Interest per PUB/MH I - 35 (a) and Schedule 4.6.0

All in $Millions CAD

	Actual 2008	Actual 2009	Forecast 2010	Forecast 2011	Forecast 2012
Total Gross Interest per PUB/MH I - 35 (a)					
Gross Interest on Long Term Debt	491	470	471	484	534
Gross Interest on Short Term Debt	(1)	(3)	(1)	2	3
Total Gross Interest on Debt	**490**	**467**	**470**	**486**	**537**
Add:					
Other Foreign Exchange Gains/Losses	4	(7)	(1)	-	-
Intercompany Allocation Centra Acquisition	12	12	12	12	12
Amortization and Other	(5)	(4)	(5)	(6)	4
subtotal	**11**	**1**	**6**	**6**	**16**
Total Gross Interest per Pub/MH I - 35 (a) adding back adjustments	**501**	**469**	**476**	**492**	**553**
Total Gross Interest as Filed in Schedule 4.6.0 of Application	**501**	**469**	**476**	**492**	**553**
Difference	**-**	**-**	**-**	**-**	**-**

PUB/MH II-30

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-35 (a) & (b)Finance Expense**

b) Please reconcile the difference in interest allocated to construction on schedule 4.6.0 with the capitalized interest per the schedule.

ANSWER:

Please see the attached schedule.

PUB/MH II - 30 (b)

MANITOBA HYDRO
Reconciliation of Capitalized Interest per PUB/MH I - 35 (a) and Interest Allocated to Construction per Schedule 4.6.0

All in $000's CAD

	Actual 2008	Actual 2009	Forecast 2010	Forecast 2011	Forecast 2012
Total Capitalized Interest per PUB/MH I - 35 (a)	60,015	74,493	91,267	130,789	137,126
Total Interest Allocated to Construction as Filed in Revised Schedule 4.6.0	60,015	74,493	91,267	130,789	137,126
Difference	-	-	-	-	-

A revised Schedule 4.6.0 was filed February 5, 2010. There were no differences between interest allocated to construction on the revised Schedule 4.6.0 and capitalized interest on the schedule in PUB/MH I - 35 (a).

<u>PUB/MH II-30</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-35 (a) & (b)Finance Expense**

c) **Please break out capitalized interest on the schedule to separately disclose Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges**

<u>ANSWER</u>:

Realized foreign exchange (gains) or losses on debt in cash flow hedges are not included in capitalized interest. They are shown on a separate line entitled “FX (Gains) or Losses on SF Contributions”.

PUB/MH II-30

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-35 (a) & (b)Finance Expense

d) Please retile the schedule in thousands of dollars and make adjustments to reconcile with electric finance expense in schedule 4.6.0, please detail each adjustment made.

ANSWER:

Please see the attached schedule.

PUB/MH II - 30 (d)

MANITOBA HYDRO
Reconciliation of Electric Finance Expense per PUB/MH I - 35 (a) and per Schedule 4.6.0

All in $ 000's CAD

	Actual 2008	Actual 2009	Forecast 2010	Forecast 2011	Forecast 2012
Total Electric Finance Expense per PUB/MH I - 35 (a)	**406,280**	**406,603**	**422,793**	**419,243**	**474,354**
Adjustments:					
Centra Acquisition Debt	(15,728)	(15,728)	(16,004)	(16,204)	(16,204)
Interco Allocation Centra Acquisition	12,000	12,000	12,000	12,000	12,000
PGF Acquisition Debt	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)
Amortization of Centra LTD Fair Market Write Up	744	685	624	0	0
subtotal	**(5,484)**	**(5,543)**	**(5,880)**	**(6,704)**	**(6,704)**
Total Electric Finance Expense per PUB/MH I - 35 (a) netting adjustments	**400,796**	**401,060**	**416,913**	**412,539**	**467,650**
Total Finance Expense as Filed in Revised Schedule 4.6.0	**400,796**	**401,060**	**416,913**	**412,539**	**467,650**
Difference	-	-	-	-	-

PUB/MH II-30

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-35 (a) & (b)Finance Expense**

e) **Please explain why a reduction in short and long term interest rates Ordered at the Centra GRA indicates an increase in finance expense in 2010/11 and a decrease in 2011/12. Why is gross interest reduced less than capitalized interest in 2010/11 and the opposite effect in 2011/12.**

ANSWER:

As indicated in response to PUB/MH I-35(b), the reduction in forecasted short and long term interest rates decreased the forecasted gross interest expense.

However, changes in gross interest expense do not directly lead to an equivalent change in total finance expense. As stated in response to CAC/MSOS/MH I-146(d), "varying the debt composition of the total debt portfolio will change the portfolio's weighted average interest rate, thereby affecting the capitalized interest rate. For example, a decreasing portfolio weighted average interest rate will lead to a lower capitalized interest rate. While the gross interest expense will decrease in this example, the amount of offsetting capitalized interest credits will also decrease."

The counterbalancing impact of capitalized interest is affected by time lags and in-service dates. For base capital and new generation & transmission (excluding Wuskwatim), the interest capitalization rate is calculated as 50% of the historical embedded cost of debt (2008/09 actual is used for the 2009/10 rates) and 50% of the actual yield costs on the new long term debt issued in the prior fiscal year (2008/09 debt issues are used for the 2009/10 rates). Therefore, for base capital and new generation & transmission, due to the time lag associated with this methodology, the forecast revision to the interest rates in 2010/11 will affect the interest capitalization rate for 2011/12.

For Wuskwatim, the interest capitalization rate is based on interest rates in effect during the fiscal year. Since there was no change to the short term or long term interest rates for the 2011/12 year in the Board Order, there would be essentially no change to the forecasted Wuskwatim interest allocated to construction for 2011/12. The amount of Wuskwatim's capitalized interest in 2011/12 would also be affected by the timing of the project's in-service date in the 2011/12 fiscal year. Therefore, the interest capitalized on Wuskwatim project capital expenditures is forecasted to reduce by $7.3 million in 2010/11 and only $0.2 million in 2011/12. Consequently, the $7.1 million year over year change associated with the Wuskwatim project affected the overall trends associated with the reduction in forecasted short and long term interest rates for 2009/10 and 2010/11.

<u>PUB/MH II-30</u>

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-35 (a) & (b)Finance Expense

f) Please provide the interest rate differentials in PUB/MH I-46 (h) utilized for determining the impact on finance expense for 2011/12.

<u>ANSWER</u>:

In response to PUB/MH I - 46 (h), Manitoba Hydro utilized the short and long term interest rates approved by the Board in Order 128/09 for 2009/10 and 2010/11.

For 2011/12, the interest rates utilized on existing floating long term debt and forecasted new debt were unchanged.

<u>PUB/MH II-31</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-35 d) Long Term Debt.**

Please provide a separate long-term debt continuity schedule for USD denominated debt for the years 2004 to 2029 including exchange gains and losses and indicate the exchange rate utilized in each year. Please also provide a separate continuity schedule for Canadian dollar denominated long term debt for the years 2004 through 2029.

<u>ANSWER</u>:

Please see the attached schedule.

PUB II-31

MANITOBA HYDRO
CONTINUNITY SCHEDULE
LONG TERM DEBT

Actuals to March 31, 2009
(In $Millions Canadian Dollars)

	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016
Long Term Debt - USD													
Opening Balance - USD	2,631	2,431	2,431	2,432	2,432	2,632	2,386	2,138	1,938	1,938	1,938	1,600	1,600
LTD Issued - USD	-	-	1	-	200	-	-	-	-	-	-	-	-
LTD Retired - USD	(200)	-	-	-	-	(246)	(247)	(200)	-	-	(338)	-	-
Closing Balance Before FX Adjustments - USD	2,431	2,431	2,432	2,432	2,632	2,386	2,138						
Foreign Exchange Adjustments - CAD*	(418)	(245)	(103)	(35)	(301)	565	(478)	21	39	(39)	78	16	16
Closing FX Rate	*1.3105*	*1.2096*	*1.1671*	*1.1529*	*1.0279*	*1.2602*	*1.0600*	*1.0700*	*1.0900*	*1.0700*	*1.1100*	*1.1200*	*1.1300*

Foreign Exchange Adjustments - CAD* includes changes in foreign exchange rates on US dollar denominated debt. Effective 2007/08 for actuals, USD debt issued and retired is recorded at the actual FX rate rather than at the year end FX rate.

	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016
Long Term Debt - CAD													
Opening Balance	3,402	4,204	4,263	4,331	4,424	4,865	5,173	5,851	6,563	7,138	7,557	8,686	9,988
LTD Issued	1,013	300	179	173	778	423	900	800	600	600	1,600	1,400	1,800
LTD Retired	(211)	(241)	(111)	(80)	(311)	(104)	(186)	(90)	(27)	(183)	(473)	(100)	(262)
Premiums/ Discounts and Transaction Costs**	-	-	-	-	(27)	(12)	(36)	2	2	2	2	2	3
Closing Balance	4,204	4,263	4,331	4,424	4,865	5,173	5,851	6,563	7,138	7,557	8,686	9,988	11,529

Premiums/ Discounts and Transaction Costs** Effective 2007/08 with the adoption of Section 3855 Financial Instruments standard, these costs were reclassified to the carrying value of the long term debt issues to which they pertain.

PUB II-31

MANITOBA HYDRO
CONTINUNITY SCHEDULE
LONG TERM DEBT

Actuals to March 31, 2009
(In $Millions Canadian Dollars)

	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029
Long Term Debt - USD													
Opening Balance - USD	1,600	1,600	1,600	1,200	1,050	800	150	-	-	-	-	-	-
LTD Issued - USD	-	-	-	-	-	-	-	-	-	-	-	-	-
LTD Retired - USD	-	-	(400)	(150)	(250)	(650)	(150)	-	-	-	-	-	-
Closing Balance Before FX Adjustments - USD	1,600	1,600	1,200	1,050	800	150	(0)	-	-	-	-	-	-
Foreign Exchange Adjustments - CAD*	16	-	-	-	-	-	-	-	-	-	-	-	-
Closing FX Rate	*1.1400*	*1.1400*	*1.1400*	*1.1400*	*1.1400*	*1.1400*	*1.1400*	*1.1400*	*1.1400*	*1.1400*	*1.1400*	*1.1400*	*1.1400*

Foreign Exchange Adjustments - CAD* includes changes in foreign exchange rates on US dollar denominated debt. Effective 2007/08 for actuals, USD debt issued and retired is recorded at the actual FX rate rather than at the year end FX rate.

	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029
Long Term Debt - CAD													
Opening Balance	11,529	13,131	14,404	15,395	16,248	17,252	17,851	18,653	18,655	18,658	18,360	18,362	18,364
LTD Issued	1,800	1,800	1,400	1,000	1,000	600	800	-	-	-	-	-	-
LTD Retired	(201)	(530)	(413)	(150)	-	(4)	-	-	-	(300)	-	-	(60)
Unamortized Premiums/ Discounts and Transaction Costs**	3	3	3	3	3	3	2	2	2	2	2	2	2
Closing Balance	13,131	14,404	15,395	16,248	17,252	17,851	18,653	18,655	18,658	18,360	18,362	18,364	18,306

Premiums/ Discounts and Transaction Costs** Effective 2007/08 with the adoption of Section 3855 Financial Instruments standard, these costs were reclassified to the carrying value of the long term debt issues to which they pertain.

PUB/MH II-32

Subject: Tab 4 Financial Results & Forecast
Reference: Schedule 4.6.0, PUB/MH I-18- Finance Expense

Please provide a continuity schedule of AOCI for the years 2007/08 through 2011/12 and with respect to the cash flow hedges the detail of the unrealized/ realized foreign exchange gains or losses for the years to be consistent with that reflected in schedule 4.6.0.

ANSWER:

Please see the following table for the requested information.

(000's)

	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
AOCI balance, beginning of year	$ -	$ 304,600	$ (168,953)	$ 191,975	$ 178,262
Adjustment for adoption of new accounting policy	108,306	-	-		
Other comprehensive income (loss)					
Unrealized FX gains (losses) on debt in cash flow hedges	228,946	(438,753)	365,336	(18,111)	(34,964)
Realized FX (gains) losses on debt in cash flow hedges	(52,407)	(11,359)	8,011	4,398	-
Unrealized fair value gains (losses) on U.S. sinking fund investments	19,755	(23,441)	(12,419)	-	-
	196,294	(473,553)	360,928	(13,713)	(34,964)
AOCI balance, end of year	$ 304,600	$ (168,953)	$ 191,975	$ 178,262	$ 143,298

PUB/MH II-33

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-35 (e), CAC/MSOS/MH I-142 (a) Long Term Debt Issues/Maturities**

a) **Please update the schedule of debt maturities in the response to CAC/MSOS/MH I-142 (a) to incorporated forecast debt issues.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-33(b).

<u>PUB/MH II-33</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-35 (e), CAC/MSOS/MH I-142 (a) Long Term Debt Issues/Maturities**

b) Please incorporate additional columns to a) to incorporate issue date and term in years

<u>ANSWER</u>:

Please see the attached schedule.

MANITOBA HYDRO
DEBT MATURITY SCHEDULE
ACTUALS AS AT DECEMBER 31, 2009
AND FORECAST AS AT SEPTEMBER 30, 2009
(IN MILLIONS $)

SHORT TERM DEBT

SERIES	CURRENCY	ISSUE DATE	MATURITY	Term (Yrs)	INTEREST RATE	CANADIAN $	US $	TOTAL CANADIAN (US @ 1.0466)
NO SHORT TERM DEBT DECEMBER 31, 2009						$ -	$ -	$ -
TOTAL SHORT TERM DEBT						**$ -**	**$ -**	**$ -**

LONG TERM DEBT

SERIES	CURRENCY	ISSUE DATE	MATURITY	Term (Yrs)	INTEREST RATE	CANADIAN $	US $	TOTAL CANADIAN (US @ 1.0466)
EM-3	CAD	2/22/2000	2/22/2010	10.0	6.350%	$ 50.0		$ 50.0
EM-4	CAD	2/22/2000	2/22/2010	10.0	6.350%	25.0		25.0
EM-1	CAD	2/22/2000	2/22/2010	10.0	3BA + 0.18375%	66.5		66.5
EM	USD	2/22/2000	2/22/2010	10.0	3LIBOR + 0.0974%		50.0	52.3
EM-6	USD	2/22/2000	2/22/2010	10.0	3LIBOR + 3.7129%		100.0	104.7
EM-5	USD	2/22/2000	2/22/2010	10.0	5.973%		97.1	101.6
FD-2	CAD	4/12/2005	4/12/2010	5.0	3BA + 0.0469%	4.0		4.0
HB10-3FX	CAD	6/15/2007	6/15/2010	3.0	4.600%	84.6		84.6
CO94	USD	2/22/2008	2/22/2011	3.0	6LIBOR -0.155%		200.0	209.3
HB9-FL	CAD	6/15/2006	6/15/2011	5.0	1.000%	10.7		10.7
HB9-5FX	CAD	6/15/2006	6/15/2011	5.0	4.350%	14.9		14.9
HB10-FL	CAD	6/15/2007	6/15/2012	5.0	1.000%	6.8		6.8
HB10-5FX	CAD	6/15/2007	6/15/2012	5.0	4.650%	15.3		15.3
C107	CAD	6/2/2009	9/4/2012	3.3	3BA + 0.40%	100.0		100.0
ER-2	CAD	10/4/2002	12/3/2012	10.2	3BA + 0.192%	50.0		50.0
4I	CAD	9/3/2002	2/11/2013	10.4	9.375%	10.0		10.0
5A	CAD	7/12/2007	6/30/2013	6.0	5.750%	40.0		40.0
5B	CAD	7/12/2007	6/30/2013	6.0	5.750%	4.3		4.3
DE	USD	11/15/2001	7/22/2013	11.7	8.120%		188.4	197.2
C101	CAD	11/21/2008	9/16/2013	4.8	5.744%	200.0		200.0
EZ4	CAD	1/22/2004	12/3/2013	9.9	3BA + 0.0925%	9.5		9.5
EZ3	CAD	1/22/2004	12/3/2013	9.9	6LIBOR - 0.0645%	208.3		208.3
4J	CAD	9/3/2002	1/20/2014	11.4	8.000%	15.0		15.0
EZ-1	USD	12/17/2003	1/21/2014	10.1	5.989%		50.0	52.3
EZ	USD	12/17/2003	1/21/2014	10.1	5.929%		100.0	104.7
FM-4	CAD	9/1/2009	9/1/2014	5.0	3BA + 0.484%	100.0		100.0
4K	CAD	9/3/2002	5/12/2015	12.7	9.125%	12.0		12.0
EY	CAD	10/28/2003	12/3/2015	12.1	5.490%	200.0		200.0
EY2	CAD	10/28/2003	12/3/2015	12.1	3BA + 0.0455%	50.0		50.0
AZ	CAD	1/31/1997	7/17/2016	19.5	3BA + 1.08%	200.6		200.6
ER-1	CAD	10/4/2002	9/3/2017	14.9	7.467%	200.0		200.0
C-011	CAD	9/10/1998	9/22/2017	19.0	7.525%	55.5		55.5
4L	CAD	9/3/2002	11/17/2017	15.2	6.250%	20.0		20.0
BM	CAD	10/10/1997	1/15/2018	20.3	3BA + 3.29%	255.0		255.0
FC-3	CAD	5/22/2008	6/2/2018	10.0	7.169%	200.0		200.0
C097-1	CAD	6/2/2008	6/2/2018	10.0	7.123%	100.0		100.0
C097-2	CAD	6/2/2008	6/2/2018	10.0	7.233%	100.0		100.0
EE	USD	9/15/1998	9/15/2018	20.0	9.500%		200.0	209.3
BU	USD	12/1/1988	12/1/2018	30.0	9.625%		200.0	209.3
3X	CAD	12/30/2002	12/30/2018	16.0	10.000%	5.0		5.0
3V	CAD	12/30/1997	12/30/2018	21.0	10.000%	3.5		3.5

LONG TERM DEBT (CONTINUED)

SERIES	CURRENCY	ISSUE DATE	MATURITY	Term (Yrs)	INTEREST RATE	CANADIAN $	US $	TOTAL CANADIAN (US @ 1.0466)
3W	CAD	12/30/1999	12/30/2018	19.0	10.000%	2.0		2.0
3Y	CAD	12/30/2003	12/30/2018	15.0	10.000%	2.0		2.0
CO77-2	CAD	06/11/2007	02/11/2020	12.7	4.455%	100.0		100.0
CO77-3	CAD	06/11/2007	02/11/2020	12.7	3BA - 0.175%	50.0		50.0
EM-2	USD	02/22/2000	03/15/2020	20.1	9.398%		150.0	157.0
FD	USD	04/12/2005	10/02/2020	15.5	6.766%		203.1	212.5
CO32	USD	10/12/2000	10/02/2020	20.0	6.806%		47.0	49.1
CO	USD	09/15/1991	09/15/2021	30.0	8.875%		300.0	314.0
4A	CAD	12/31/1996	12/31/2021	25.0	9.100%	3.5		3.5
FH-1	USD	12/06/2006	02/01/2022	15.2	6.405%		250.0	261.7
FH-2	USD	12/06/2006	02/01/2022	15.2	6.406%		100.0	104.7
FH-3	USD	12/06/2006	09/16/2022	15.8	6LIBOR + 0.1295%		150.0	157.0
DT	CAD	12/22/1995	12/22/2025	30.0	7.750%	170.0		170.0
DT	CAD	06/22/2004	12/22/2025	21.5	7.750%	130.0		130.0
4M	CAD	09/03/2002	02/02/2029	26.4	5.900%	30.0		30.0
4N	CAD	09/03/2002	02/02/2029	26.4	5.900%	30.0		30.0
C108	CAD	09/01/2009	09/01/2029	20.0	6.150%	100.0		100.0
FM-1	CAD	09/01/2009	09/01/2029	20.0	6.634%	25.0		25.0
FM-2	CAD	09/01/2009	09/01/2029	20.0	6.734%	75.0		75.0
FM-3	CAD	09/01/2009	09/01/2029	20.0	6.689%	50.0		50.0
CL	CAD	03/05/1991	03/05/2031	40.0	10.500%	300.0		300.0
CLW	CAD	03/05/1991	03/05/2031	40.0	10.500%	299.9		299.9
4B	CAD	04/01/2001	04/01/2031	30.0	5.840%	3.5		3.5
4C	CAD	04/01/2001	04/01/2031	30.0	5.840%	1.4		1.4
4Y	CAD	05/01/2001	05/01/2031	30.0	5.650%	4.2		4.2
CO52	CAD	10/29/2002	10/29/2032	30.0	6.300%	30.0		30.0
FD-1	CAD	04/12/2005	04/12/2035	30.0	5.289%	175.0		175.0
EZ2	CAD	01/24/2006	12/03/2035	29.9	4.774%	54.0		54.0
EZ5	CAD	01/24/2006	12/03/2035	29.9	4.774%	46.0		46.0
FA	CAD	07/21/2004	03/05/2037	32.6	4.687%	150.0		150.0
FA-4	CAD	12/13/2006	03/05/2037	30.2	4.505%	50.0		50.0
FJ	CAD	09/12/2007	09/12/2037	30.0	5.104%	250.0		250.0
PB-2	CAD	05/30/2007	03/05/2038	30.8	4.600%	300.0		300.0
C100-1	CAD	11/03/2008	11/01/2038	30.0	4.707%	85.0		85.0
C100-2	CAD	11/03/2008	11/01/2038	30.0	4.637%	100.0		100.0
C099-1	CAD	09/17/2008	12/01/2038	30.2	4.771%	50.0		50.0
C099-2	CAD	09/22/2008	12/01/2038	30.2	4.758%	25.0		25.0
C099-3A	CAD	09/29/2008	12/01/2038	30.2	4.758%	25.0		25.0
C099-3B	CAD	09/29/2008	12/01/2038	30.2	4.770%	15.0		15.0
C102	CAD	01/15/2009	03/01/2039	30.1	4.988%	100.0		100.0
Forecast	CAD	Feb-2010	Feb-2040	30.0	4.600%	200.0		200.0
Forecast	CAD	Mar-2010	Mar-2040	30.0	4.600%	200.0		200.0
FK-2	CAD	06/05/2009	03/05/2040	30.8	4.650%	300.0		300.0
Forecast	CAD	Jun-2010	Jun-2040	30.0	4.650%	200.0		200.0
Forecast	CAD	Aug-2010	Aug-2040	30.0	4.650%	200.0		200.0
Forecast	CAD	Nov-2010	Nov-2040	30.0	4.650%	200.0		200.0
Forecast	CAD	Mar-2011	Mar-2041	30.0	4.650%	200.0		200.0
Forecast	CAD	Sep-2011	Sep-2041	30.0	5.200%	200.0		200.0
Forecast	CAD	Dec-2011	Dec-2041	30.0	5.200%	200.0		200.0
Forecast	CAD	Mar-2012	Mar-2042	30.0	5.200%	200.0		200.0
CO40	CAD	08/20/2002	03/05/2042	39.6	3BA + 0.179%	50.0		50.0
CO68	CAD	06/28/2004	03/05/2044	39.7	4.565%	50.0		50.0
FN	CAD	10/27/2009	03/05/2050	40.4	4.700%	200.0		200.0
4Z	CAD	06/09/2006	06/09/2057	51.0	7.100%	7.0		7.0
C110	CAD	11/23/2009	03/05/2060	50.3	5.200%	125.0		125.0
C109	CAD	11/13/2009	03/05/2063	53.3	4.625%	50.0		50.0
WINNIPEG HYDRO PREMIUM						5.8		5.8
UNAMORTIZED COMMISSIONS, FEES AND EXPENSES						(28.9)		(28.9)
UNAMORTIZED DEBT PREMIUMS AND DISCOUNTS						(26.0)		(26.0)
TOTAL LONG TERM DEBT						**$ 7,781.0**	**$ 2,385.5**	**$ 10,277.6**

PUB/MH II-34

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-36 (a) Finance Expense**

Please provide a breakdown of other Amortization.

ANSWER:

Please see the schedule attached.

MANITOBA HYDRO
Breakdown of Other Amortization (PUB/MH II - 34)
(in thousands of dollars)

	2003/2004 ACTUALS	2004/2005 ACTUALS	2005/2006 ACTUALS	2006/2007 ACTUALS	2007/2008 ACTUALS	2008/2009 ACTUALS	2009/2010 FORECAST	2010/2011 FORECAST	2011/2012 FORECAST
AMORTIZATION OF CENTRA LTD WRITE UP ADJ	(1,401)	(1,338)	(1,293)	(1,086)	(744)	(685)	(624)	-	-
MITIGATION BOND AMORTIZATION	2,319	1,615	2,946	7,977	7,911	6,769	8,510	8,413	5,237
INTEREST ON ASSETS	(854)	(1,022)	(1,619)	(2,139)	(2,244)	(2,384)	(2,439)	(2,651)	(2,990)
INTEREST ON INVENTORY	(275)	(208)	(29)	(25)	(32)	(25)	(112)	-	-
NCH PROJECT	805	678	569	-	-	-	-	-	-
INTEREST ON WH OBLIGATION	16,441	16,441	16,441	16,441	16,441	16,441	16,441	16,441	16,441
TOTAL OTHER AMORTIZATION	17,035	16,166	17,015	21,170	21,331	20,116	21,776	22,204	21,008

<u>PUB/MH II-35</u>

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-36 (a), IFRS Status Update Report Page 26

a) Please explain the reasons for the forecasted growth on Intercompany interest receivable in 2010/11 and 2011/12.

<u>ANSWER</u>:

For presentation purposes, interest income from the accrued interest on cash advances to NCN is included in the intercompany interest receivable along with the interest charged to Centra Gas. The growth from 2009/10 to 2010/11 is primarily attributed to new long-term debt issues for Centra Gas and an increase in the interest rate on the loan advanced to NCN. The growth from 2010/11 to 2011/12 is primarily attributed to increasing interest rates.

PUB/MH II-35

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-36 (a), IFRS Status Update Report Page 26**

b) Please describe how the corporation determines how much interest is allocated to construction and to specific construction projects.

ANSWER:

Manitoba Hydro capitalizes all project costs related to asset additions, including engineering, direct labour, materials, contracted services, and interest applied at the average cost of debt. Capital project costs are charged to Construction Work in Progress until the corresponding asset becomes available for use, at which time the transfer to in-service property plant and equipment is made, interest expense allocated to construction ceases and depreciation begins. Manitoba Hydro capitalizes interest on all domestic, major and new generation projects except certain short-term customer service projects with construction durations averaging approximately three months or less.

Interest during construction is calculated by applying the interest capitalization rate to the actual or forecasted month-end work in progress balance of each project, until such project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Interest capitalized calculated by project is then aggregated to form to total interest allocated to construction.

Please see Manitoba Hydro’s response to PUB/MH II-35(c) for an example as to how interest is calculated.

PUB/MH II-35

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-36 (a), IFRS Status Update Report Page 26

c) For the two test years please provide a breakdown of the interest allocated to construction by major project. For illustrative purposes please show supporting calculations for the amount of interest allocated for the construction of the Wuskwatim G.S.

ANSWER:

MANITOBA HYDRO ELECTRIC INC.
2010/11 & 2011/12 General Rate Application

PUB-MH II-35(c)

		(In Millions)
INTEREST ALLOCATED TO CONSTRUCTION	**2011**	**2012**
Wuskwatim	64.39	52.11
Keeyask	27.76	38.34
Conawapa	15.16	20.32
Riel 230/500kV Station	4.53	9.12
Bipole 3 Transmission and Converters	2.65	4.68
Pointe du Bois Modernization	3.20	3.25
Herblet Lake-The Pas 230 kV Transmission	4.42	3.04
Kelsey Re-runnering	1.99	0.84
Kettle Improvements & Upgrades	0.65	0.51
Firm Import/Export Upgrades	0.06	0.28
Base Capital	5.99	4.65
	130.79	**137.13**

The Wuskwatim G.S does not lend itself well for illustrative purposes due to the complex nature of the partnership arrangements. As such, Manitoba Hydro has provided an illustration using the Conawapa GS.

Illustration:

Conawapa

IFF09-1 - Monthly Projection

(In Millions of Dollars)

Date	CWIP Opening Balance	Construction Expenditures	Escalation	Capitalized Interest *	In-service Amount	CWIP Closing Balance
Apr-2010	197.29	3.99	0.02	1.09	0.00	202.39
May-2010	202.39	3.87	0.02	1.15	0.00	207.43
Jun-2010	207.43	4.45	0.03	1.14	0.00	213.05
Jul-2010	213.05	4.26	0.03	1.21	0.00	218.55
Aug-2010	218.55	4.06	0.03	1.25	0.00	223.90
Sep-2010	223.90	4.26	0.04	1.23	0.00	229.43
Oct-2010	229.43	4.06	0.04	1.31	0.00	234.85
Nov-2010	234.85	3.29	0.04	1.30	0.00	239.47
Dec-2010	239.47	3.15	0.04	1.36	0.00	244.03
Jan-2011	244.03	3.01	0.04	1.39	0.00	248.47
Feb-2011	248.47	3.00	0.05	1.28	0.00	252.80
Mar-2011	252.80	3.44	0.06	1.44	0.00	257.74
Total		44.85	0.43	15.16	0.00	

Date	CWIP Opening Balance	Construction Expenditures	Escalation	Capitalized Interest *	In-service Amount	CWIP Closing Balance
Apr-2011	257.74	4.36	0.08	1.47	0.00	263.64
May-2011	263.64	4.58	0.09	1.55	0.00	269.87
Jun-2011	269.87	4.91	0.11	1.54	0.00	276.43
Jul-2011	276.43	4.58	0.11	1.63	0.00	282.75
Aug-2011	282.75	4.75	0.12	1.66	0.00	289.28
Sep-2011	289.28	4.75	0.13	1.65	0.00	295.80
Oct-2011	295.80	4.41	0.13	1.74	0.00	302.09
Nov-2011	302.09	4.75	0.14	1.72	0.00	308.70
Dec-2011	308.70	4.31	0.14	1.82	0.00	314.96
Jan-2012	314.96	3.90	0.13	1.85	0.00	320.85
Feb-2012	320.85	3.90	0.14	1.77	0.00	326.65
Mar-2012	326.65	4.03	0.15	1.92	0.00	332.76
Total		53.23	1.47	20.32	0.00	

* Interest Capitalization Rate for 2011 is 6.71% and 2012 is 6.95%

PUB/MH II-35

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-36 (a), IFRS Status Update Report Page 26**

d) **To what extent has the Corporation identified specific and generally financed capital projects in the determination of an appropriate amount of capitalized carrying costs for the 2010/11 and 2011/12.**

ANSWER:

Manitoba Hydro has not identified any specific financing for individual capital projects for 2010/11 and 2011/12.

PUB/MH II-35

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-36 (a), IFRS Status Update Report Page 26

e) Please indicate the weighted average rate, which is to be applied to capitalize carrying costs on generally financed capital projects.

ANSWER:

CEF09
Interest Capitalization Rate (ICR)

Fiscal Year	Nominal Monthly Rate
2009/10	6.5%
2010/11	6.7%
2011/12	7.0%
2012/13	7.1%
2013/14 and on	7.0%

<u>PUB/MH II-35</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-36 (a), IFRS Status Update Report Page 26**

f) To what extent has the Corporation in 2011/12 included capitalized borrowing costs related to ongoing annual recurring (Non Major G&T) capital additions given IFRS requirements. Please explain.

<u>ANSWER</u>:

Ongoing annual recurring capital projects that are under construction for a significant period of time will continue to be subject to capitalized interest. Based upon a review of IFRS requirements, the types of projects that currently attract interest during construction will continue to do so under IFRS.

The interest capitalization rate used in IFF09 for 2011/12 was 7.20%, resulting in interest capitalized on base capital of approximately $14.2 million. Based on IFRS requirements, a preliminary rate of 7.30% has been calculated for 2011/12 and results in interest capitalized on base capital of approximately $14.4 million.

PUB/MH II-36

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I--38-- Depreciation Rates**

Please indicate how MH determined depreciation rates for Keeyask and Wuskwatim with respect to Civil Works and Turbines and Generators when compared with other existing generating station depreciation rates.

ANSWER:

Manitoba Hydro determined the depreciation rates for Keeyask and Wuskwatim by using the average service life and salvage factor of other existing generating stations. The overall depreciation rates may differ for new stations when compared to existing stations due to other factors that are taken into consideration on existing stations such as changes in service life, early or late retirements, cost of removal and terminal dates.

Plant/Depreciation Category	Original Cost	Salvage to be recovered based on a negative salvage factor of 10%	Total costs to be recovered	Average service life	Depreciation rate
	A	B	C (A+B)	D	C/D
Civil	100.00	10.00	110.00	100	1.10%
Transmssion & Generation	100.00	10.00	110.00	65	1.69%
Accessory Station Equipment	100.00	10.00	110.00	45	2.44%
Other	100.00	10.00	110.00	50	2.20%

PUB/MH II-37 (REVISED)

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-40: New Head Office**

Please provide the 2010 Property and Business Tax assessment when received in May.

ANSWER:

The main Property and Business Tax statements have been received for the 2010 calendar year and they are attached.

With respect to the property tax assessments, nine additional statements have not yet been received from the City of Winnipeg. These statements relate to the areas on the first and second floor of the building that are intended to be leased to third parties and to common areas shared with the lessees. The tax amount relating to these additional areas is estimated to be $260,000.

Of the $260,000 in assessments yet to be received, the majority will be recovered from tenants through the lease agreements. However, Hydro will incur the tax expense relating to those areas not yet leased to others as well as a portion of the common area taxes.

The amount of business tax shown in the attached statement is the total payable by Hydro. Individual business owners who are leasing space in the building are billed directly by the City of Winnipeg for their business taxes.

(FRANÇAIS AU VERSO)

THE CITY OF WINNIPEG 2010 GRANT-IN-LIEU PROPERTY TAX STATEMENT AND DEMAND

STATEMENT DATE: MAY 14, 2010

ROLL NUMBER: 12097557800

Property Address Information :
360 PORTAGE AVE
4985371 MANITOBA LTD

Title No.: 2071733
Mortgage No.:

Part of Lot	Lot	Block	Plan	Parish
	594-597	3	129	1 ST J
	600-603	3	129	1 ST J
	631-633	3	129	1 ST J
	13-14		19168	1 ST J
	A		43247	1 ST J

TAX CALCULATION INFORMATION					MILL RATES		
STATUS CODE	CLASS	PORTION %	ASSESSED VALUE	PORTIONED ASSESSMENT	MUNICIPAL	SCHOOL DIVISION	PROVINCIAL EDUCATION SUPPORT
Grant	Other Property	65.0	130,845,000	85,049,250	15.295	16.451	12.895

Inquiries:
Municipal Taxes 311
or toll free 1-877-311-4974
School Division
(204) 775-0231
Provincial Levy
(204) 945-6910

MUNICIPAL TAXES

CITY OF WINNIPEG MUNICIPAL TAXES	(85,049,250 x 0.015295)	**$1,300,828.28**
Other Charges		
ENCROACHMENT + GST (R121682967)		**480.38**
STREET RENEWAL	Frontage Levy	**3,123.24**
	TOTAL MUNICIPAL TAXES	**$1,304,431.90**

SCHOOL TAXES

Provincial Legislation requires the City of Winnipeg to collect the School Division taxes and Provincial Education Support Levy. These taxes are set by and go directly to the School Divisions and the Province.

WINNIPEG SCHOOL DIVISION	(85,049,250 x 0.016451)	**$1,399,145.21**
PROVINCIAL EDUCATION SUPPORT LEVY	(85,049,250 x 0.012895)	**1,096,710.08**
	TOTAL SCHOOL TAXES	**$2,495,855.29**
	NET PROPERTY TAXES	**$3,800,287.19**
	BALANCE OWING	**$3,800,287.19**

TOTAL TAXES DUE	
Municipal Taxes	$1,304,431.90
School Taxes	2,495,855.29
Total Current Taxes	$3,800,287.19
TOTAL TAXES DUE	**$3,800,287.19**

IMPORTANT MESSAGES - Visit our website at: www.winnipegassessment.com

0 - 210094

RETURN BOTTOM PORTION WITH YOUR PAYMENT

Winnipeg

The City of Winnipeg
Assessment and Taxation Department
510 Main Street
Winnipeg, Manitoba R3B 3M2

DUE DATE: JUNE 30, 2010
A penalty is charged if payment is received or postmarked after June 30, 2010
PLEASE RETAIN YOUR CANCELLED CHEQUE AS NO ADDITIONAL RECEIPT WILL BE ISSUED

ROLL NUMBER/NUMÉRO DU RÔLE	ARREARS/ARRIÉRÉ	TOTAL PAYABLE/MONTANT PAYABLE	AMOUNT PAID/MONTANT PAYÉ
12097557800	**$0.00**	**$3,800,287.19**	

4985371 MANITOBA LTD
C/O PROPERTY MANAGER
PO BOX 815 STN MAIN
WINNIPEG,MB R3C 2P4

R1209755780003800287191209755780O

PAYABLE AT MOST FINANCIAL INSTITUTIONS.
PLEASE MAKE CHEQUE PAYABLE TO:
THE CITY OF WINNIPEG, TAX BRANCH

⑆13373⑈900⑆ 96

Winnipeg

THE CITY OF WINNIPEG - VILLE DE WINNIPEG

STATEMENT AND DEMAND FOR 2010 GRANT-IN-LIEU BUSINESS TAXES
RELEVÉ ET DEMANDE DE SUBVENTION TENANT LIEU DE TAXES - 2010

ROLL NO. / Nº DU RÔLE	STATEMENT DATE / DATE DU RELEVÉ
38290	April 22, 2010

INQUIRIES / RENSEIGNEMENTS
311 or toll free 1-877-311-4974
311 ou (sans frais) le 1-877-311-4974

NAME(S) OF TAXABLE PARTY / NOM(S) DE LA PARTIE IMPOSABLE
MANITOBA HYDRO

PREMISES ASSESSED - STREET NUMBER, ETC. / LOCAUX ÉVALUÉS - Nº DE VOIRIE, ETC.
360 PORTAGE AVE

ANNUAL RENTAL VALUE / VALEUR LOCATIVE ANNUELLE	% RATE / TAUX EN %
12,690,060	6.39

CURRENT YEAR'S TAX (add penalties from June 1, 2010) TAXE DE L'ANNÉE EN COURS (ajoutez pénalités à compter du 1er juin 2010)	810,894.83
SMALL BUSINESS TAX CREDIT CRÉDITS D'IMPÔT POUR PETITES ENTREPRISES	0.00
NET BUSINESS TAX TAXE D'ENTREPRISE NETTE	$810,894.83
BUSINESS IMPROVEMENT ZONE ZONE D'AMÉLIORATION COMMERCIALE	0.00
TOTAL DUE / MONTANT DÛ	**$810,894.83**

IMPORTANT MESSAGES - Visit our website at: www.winnipegassessment.com

MESSAGES IMPORTANTS : Visitez notre site Web à : www.winnipegassessment.com

PLEASE RETAIN YOUR CANCELLED CHEQUE AS NO ADDITIONAL RECEIPT WILL BE ISSUED VEUILLEZ CONSERVER VOTRE CHÈQUE ENCAISSÉ, CAR AUCUN REÇU NE SERA FOURNI

0 - 12304

DUE DATE: MONDAY, MAY 31, 2010
PLEASE DETACH AND RETURN WITH YOUR PAYMENT

ÉCHÉANCE : LUNDI, 31 MAI 2010
VEUILLEZ DÉTACHER ET RETOURNER AVEC VOTRE PAIEMENT

ROLL NUMBER/NUMÉRO DU RÔLE	ARREARS/ARRIÉRÉS	TOTAL PAYABLE/MONTANT PAYABLE	AMOUNT PAID/MONTANT PAYÉ
38290	$0.00	$810,894.83	

MANITOBA HYDRO
C/O PROPERTY DEPT
PO BOX 815
WINNIPEG,MB R3C 2P4

B38290XXXXXX00810894838290XXXXXX

PLEASE PAY:
The City of Winnipeg
Assessment and Taxation Department
510 Main Street
Winnipeg, Manitoba R3B 3M2

FAIRE PARVENIR À :
Ville de Winnipeg
Service de l'évaluation et des taxes
510, rue Main
Winnipeg (MB) R3B 3M2

⑆13373⑈900⑆ 96

<u>PUB/MH II-38</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-42 (b) WPLP IFF**

a) **Please provide the accompanying balance sheet and cash flow statement related to the WPLP forecast.**

<u>ANSWER</u>:

Please see the attached statements.

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
PROJECTED BALANCE SHEET
FORECAST INCLUDED IN MH09-1
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ASSETS											
Plant in Service	-	-	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239	1,239
Accumulated Depreciation	-	-	(6)	(25)	(43)	(62)	(80)	(99)	(117)	(136)	(154)
Net Plant in Service	-	-	1,233	1,214	1,196	1,177	1,159	1,141	1,122	1,104	1,085
Construction in Progress	867	1,131	(12)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Current and Other Assets	267	297	308	309	311	313	315	318	321	325	329
	1,133	1,428	1,529	1,523	1,506	1,490	1,474	1,458	1,443	1,428	1,414
LIABILITIES AND EQUITY											
Long-Term Debt	600	800	920	929	929	929	929	929	929	929	929
Current and Other Liabilities	317	345	306	295	288	279	273	264	256	249	241
Retained Earnings	217	283	303	299	289	282	272	265	257	249	244
	1,133	1,428	1,529	1,523	1,506	1,490	1,474	1,458	1,443	1,428	1,414

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
PROJECTED CASH FLOW STATEMENT
FORECAST INCLUDED IN MH09-1
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OPERATING ACTIVITIES											
Cash Receipts from Customers	-	-	44	104	112	119	129	135	139	144	142
Cash Paid to Suppliers and Employees	-	-	(8)	(11)	(11)	(12)	(12)	(12)	(12)	(12)	(12)
Interest Paid	(21)	(38)	(60)	(69)	(68)	(68)	(67)	(66)	(65)	(65)	(64)
Interest Received	-	-	-	-	-	-	-	-	-	-	-
	(21)	(38)	(24)	24	33	39	51	57	61	67	66
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	400	200	-	-	-	-	-	-	-	-	-
Sinking Fund Withdrawals	-	-	-	-	-	-	-	-	-	-	-
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-	-
Other	89	66	23	2	(1)	(1)	(1)	(1)	(2)	(2)	(2)
	489	266	23	2	(1)	(1)	(1)	(1)	(2)	(2)	(2)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(337)	(226)	(62)	(12)	-	-	(0)	-	-	-	-
Sinking Fund Payment	-	-	-	(9)	(9)	(9)	(9)	(8)	(8)	(8)	(8)
Other	-	-	120	9	(4)	(16)	(21)	(36)	(40)	(45)	(52)
	(337)	(226)	58	(12)	(13)	(25)	(30)	(44)	(48)	(53)	(60)
Net Increase (Decrease) in **Short-Term Debt**	132	2	58	14	18	13	19	11	12	12	4
Short-Term Debt at Beginning of Year	(182)	(50)	(48)	9	23	41	54	74	85	96	108
Short-Term Debt at End of Year	(50)	(48)	9	23	41	54	74	85	96	108	113

<u>PUB/MH II-38</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-42 (b) WPLP IFF**

b) **Please indicate the assumptions used for forecasting revenue and finance expense and provide the supporting calculations based on the agreed methodology.**

<u>ANSWER</u>:

Forecast revenues are calculated in accordance with the terms and conditions of the power purchase agreement utilizing the same underlying assumptions to determine export revenues forecasted in IFF09. Please see the schedule below for additional information regarding Wuskwatim revenues.

The forecasted finance expense is calculated in accordance with the terms and conditions of the project finance agreement. The funds advanced by Manitoba Hydro to the Partnership for project debt are forecasted to bear interest at the short term interest rate plus the guarantee fee until the aggregate principal amount outstanding exceeds $200 million. At this point, $200 million of new long term debt is forecast to be issued (displaces $200 million in short term debt) at the forecast new long term interest rate in effect at the forecast issue date. This provision will apply to all subsequent $200 million incremental debt issues.

The funds advanced by Manitoba Hydro to the Partnership for debt related to the transmission interconnection facilities are forecasted to bear interest at the short term interest rate plus the guarantee fee until the aggregate principal amount outstanding exceeds $40 million. At this point, $40 million of new long term debt is forecast to be issued (displaces $40 million in short term debt) at the forecast new long term interest rate in effect at the forecast issue date. This provision will apply to all subsequent $40 million incremental debt issues.

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST INCLUDED IN MH09-1
(In Millions of Dollars)

For the year ended March 31

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Average Generation (GW.h)	-	-	654	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515
Wuskwatim Revenue	-	-	46	108	116	122	133	139	143	148	147
Marketing Risk Fee	-	-	(1)	(3)	(3)	(4)	(4)	(4)	(4)	(4)	(4)
Wuskwatim Net Revenue	-	-	44	104	112	119	129	135	139	144	142
Average Price ($/MW.h) net of Risk Fee	-	-	67.85	68.95	74.24	78.36	85.32	88.85	91.44	94.88	93.95

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST INCLUDED IN MH09-1
(In Millions of Dollars)

For the year ended March 31

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Finance Expense											
Interest on Long Term Debt	18	36	49	52	52	52	52	52	52	52	52
Interest on Short Term Debt	2	2	2	(1)	(2)	(3)	(3)	(4)	(5)	(5)	(5)
Interest on Interconnection Credit Facility	-	-	9	18	18	18	18	18	18	18	18
Interest Income	-	-	-	-	(1)	(1)	(2)	(2)	(3)	(4)	(4)
Capitalized Interest	(21)	(38)	(34)	-	-	-	(0)	-	-	-	-
	-	-	26	69	68	66	65	64	62	61	60

<u>PUB/MH II-38</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-42 (b) WPLP IFF**

c) Provide a schedule detailing Operating & Administrative Expenses reflected in IFF09-1.

<u>ANSWER</u>:

Please see the attached schedule.

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST INCLUDED IN MH09-1
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Operating and Administrative											
Generating Station O&A	-	-	3	3	3	3	3	3	4	4	4
Transmission Related O&A	-	-	2	2	2	2	2	2	2	2	2
Management Fee	-	-	1	1	1	1	1	1	1	1	1
Insurance Expense	-	-	1	1	1	1	1	1	1	1	1
	-	-	6	6	6	7	7	7	7	7	7

<u>PUB/MH II-38</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-42 (b) WPLP IFF**

d) Please provide details of finance expense utilized in IFF09-1.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-38(b).

PUB/MH II-38

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-42 (b) WPLP IFF**

e) Please indicate the interest rates assumed for loans provided including those to fund equity contributions of NCN.

ANSWER:

Please see the attached schedule.

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST INTEREST RATES INCLUDED IN MH09-1
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Short Term Debt Interest Rate w/ PGF	1.45%	2.40%	4.60%	5.30%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
Long Term Debt Interest Rate w/ PGF	5.60%	5.65%	6.20%	6.70%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
Equity Loan Credit Facility Interest Rate	2.45%	3.40%	7.20%	7.70%	8.10%	8.10%	8.10%	8.10%	8.10%	8.10%	8.10%

PUB/MH II-38

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-42 (b) WPLP IFF**

f) **Please file schedule detailing water rental and assessments charged to WPLP through for 2012 and 2013 in the same level of detail as that provided in response to MIPUG/MH I-8.**

ANSWER:

In Millions of Dollars
For the year ended March 31

	2012	2013
Average Generation (GW.h)	654	1,515
Water Rental Rate ($/MW.h)	3.341	3.341
Water Rentals	2	5
Assessments	-	-
Water Rentals & Assessments	2	5

<u>PUB/MH II-38</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-42 (b) WPLP IFF**

g) **Please indicate to what extent the forecast reflects an additional charge for any facilities that have been advanced to accommodate the Wuskwatim G.S.**

<u>ANSWER</u>:

The WPLP projections do not reflect any additional charges for any facilities that were needed in advance of their originally scheduled in-service date to accommodate the Wuskwatim G.S.

<u>PUB/MH II-39</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-46 (h)**

Please re-file the IFF09-1 schedules for electric operations.

<u>ANSWER</u>:

Please refer to the attached schedules.

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
2010 and 2011 Interest Rates per PUB Order 128/09
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES											
General Consumers											
at approved rates	1,160	1,159	1,177	1,191	1,204	1,229	1,244	1,260	1,272	1,283	1,297
additional *	-	33	69	113	161	212	266	322	381	442	508
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
Other	7	7	8	8	8	8	8	9	9	9	9
	1,581	1,584	1,808	1,895	1,987	2,039	2,219	2,320	2,404	2,628	2,907
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	417	416	463	518	519	536	522	537	579	664	869
Depreciation and Amortization	368	386	407	435	446	466	476	481	500	532	566
Water Rentals and Assessments	120	110	111	113	114	114	115	115	115	115	124
Fuel and Power Purchased	103	132	248	250	260	269	297	341	363	441	419
Capital and Other Taxes	73	76	77	80	85	92	100	109	115	121	124
Corporate Allocation	8	9	9	9	9	9	9	9	9	9	9
	1,460	1,509	1,718	1,817	1,853	1,914	1,955	2,037	2,147	2,360	2,608
Non-controlling Interest	-	-	1	0	(3)	(5)	(9)	(11)	(13)	(15)	(15)
Net Income	121	75	91	79	132	120	255	271	243	253	285
*Additional General Consumers Revenue											
Percent Increase		2.90%	2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase		2.90%	5.88%	9.59%	13.43%	17.40%	21.50%	25.76%	30.16%	34.71%	39.43%

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
2010 and 2011 Interest Rates per PUB Order 128/09
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
ASSETS											
Plant in Service	12,527	13,034	15,070	15,561	15,977	16,686	17,122	17,832	20,296	21,594	24,996
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,009)	(8,513)	(9,051)
Net Plant in Service	7,865	8,015	9,672	9,756	9,761	10,037	10,031	10,292	12,287	13,081	15,945
Construction in Progress	1,947	2,453	1,341	1,818	2,838	3,854	5,532	6,948	6,159	6,446	4,168
Current and Other Assets	2,767	2,733	2,868	2,923	2,662	2,805	3,044	3,281	3,619	3,342	3,761
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,243	13,923	14,538	15,303	16,738	18,648	20,563	22,107	22,911	23,916
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,054	8,769	10,149	11,305	13,123	14,412	15,346	16,429	14,147
Current and Other Liabilities	2,157	1,922	2,110	2,901	2,241	2,425	2,297	2,673	3,051	2,523	5,525
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,258	2,332	2,411	2,542	2,662	2,918	3,188	3,432	3,685	3,969
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,243	13,923	14,538	15,303	16,738	18,648	20,563	22,107	22,911	23,916

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
2010 and 2011 Interest Rates per PUB Order 128/09

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OPERATING ACTIVITIES											
Cash Receipts from Customers	1,581	1,584	1,808	1,895	1,987	2,039	2,219	2,320	2,404	2,628	2,907
Cash Paid to Suppliers and Employees	(646)	(690)	(827)	(845)	(872)	(898)	(946)	(1,010)	(1,059)	(1,156)	(1,168)
Interest Paid	(453)	(427)	(476)	(535)	(544)	(537)	(541)	(560)	(622)	(713)	(902)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	488	519	531	586	608	747	775	759	798	871
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	600	540	1,400	1,400	2,000	1,800	1,800	1,400	1,000
Sinking Fund Withdrawals	262	227	27	103	483	-	3	-	-	456	171
Retirement of Long-Term Debt	(355)	(304)	(27)	(121)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(35)	(10)	19	(10)	(14)	(12)	(13)	(14)	(15)	(26)	(15)
	618	713	619	512	1,020	1,288	1,728	1,585	1,255	961	835
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1,113)	(1,071)	(1,003)	(989)	(1,457)	(1,737)	(2,125)	(2,135)	(1,685)	(1,619)	(1,259)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(107)	(201)	(159)	(242)	(199)	(256)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,243)	(1,190)	(1,117)	(1,122)	(1,648)	(1,875)	(2,355)	(2,334)	(1,954)	(1,846)	(1,542)
Net Increase (Decrease) in Cash	(114)	11	20	(79)	(43)	21	121	26	60	(86)	164
Cash at Beginning of Year	66	(48)	(37)	(17)	(96)	(139)	(118)	2	28	87	1
Cash at End of Year	(48)	(37)	(17)	(96)	(139)	(118)	2	28	87	1	165

PUB/MH II-40

Subject: Tab 4 Financial Results & Forecast

Reference: PUB/MH I-52/CAC/MSOS/MH I-13 (c) Recent Peak Period Export Prices

a) Please confirm that commencing in 2005, MH has achieved total on-peak sales as follows:

	Dependable & Peak Opportunity			Dependable ¢/KWh	Ratio to Dependable
Year	**GWh**	**$M**		**¢/KWh**	**¢/KWh**
2005	**8,529**	**581.4**	**6.82**	**5.92**	**1.14**
2006/07	**6,530**	**398.7**	**6.11**	**6.00**	**1.02**
2007/08	**7,706**	**457.3**	**5.93**	**5.32**	**1.11**
2008/09	**7,220**	**455.0**	**6.30**	**5.71**	**1.10**
2009/10	**5,446**	**227.6**	**4.18**	**5.64**	**0.74**
5-Year					
Average	**7,086**	**423.2**	**5.97**	**5.72**	**1.04**

ANSWER:

The table provided assumes that all Dependable sales are On Peak which is not the case. Please see table below for actual average prices for on-peak sales.

	Average Total On-Peak ($/MWh)	**Average Dependable ($/MWh)**	**Ratio to Dependable**
2005/06	65.72	59.25	1.11
2006/07	61.41	59.67	1.03
2007/08	60.11	52.88	1.14
2008/09	64.56	57.12	1.13
2009/10	41.75	56.38	0.74
5 year average			1.02917

PUB/MH II-40

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-52/CAC/MSOS/MH I-13 (c) Recent Peak Period Export Prices**

b) **Please confirm that in the last five years, MH has achieved average total on-peak sales prices that equate to 75% to 115% of dependable energy contract prices (with the 5-year average being about 105%).**

ANSWER:

In the last 5 years MH has achieved average total on-peak sales prices that range from 74% to 114% of dependable energy contract prices, with the 5 year average being about 103%.

	Average On-Peak (Price/MWh)	**Average Dependable (Price/MWh)**	**Ratio to Dependable**
2005/06	65.72	59.25	1.11
2006/07	61.41	59.67	1.03
2007/08	60.11	52.88	1.14
2008/09	64.56	57.12	1.13
2009/10	41.75	56.38	0.74
5 year average			1.02917

PUB/MH II-41

Subject: Tab 4 Financial Results & Forecast
Reference: 20-Year IFF 09-1/CAC/MSOS/MH I-13(b) & (c)
Forecast Peak Period Export Prices

a) Please confirm that MH's IFF 09-1 export price forecast for 2012/13 is about 7¢/KWh compared to prevailing contract prices of 6¢/KWh (about 1.15 ratio).

ANSWER:

It is confirmed that the average price for all export sales in 2012/13 is forecasted to be about 7¢/KWh compared to prevailing contract prices for dependable sales of about 6¢/KWh.

<u>PUB/MH II-41</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **20-Year IFF 09-1/CAC/MSOS/MH I-13(b) & (c)**
Forecast Peak Period Export Prices

b) **Please confirm that by 2017/18, export prices are forecast to be 10¢/KWh and that within the above context achieving 10¢/KWh would require firm contract prices of:**

Ratio	¢/KWh
1.05	9.5
1.10	9.1
1.15	8.7
1.20	8.3

<u>ANSWER</u>:

It is confirmed that the average price for all export products is forecasted to be about 10¢/kW.h by 2017/18. It is also confirmed that the required contract prices would have to be those provided in the table if the assumed ratios between prices for all export sales and contract export sales were to be used. It should be noted that the ratio between the average price of all export sales and contract sales is expected to change over time as new contracts are negotiated at higher prices relative to those of past years and as the existing lower priced contracts terminate. Because of this increase in contract prices, it is likely that the average prices will be below contract prices and the ratio in the table will be less than 1.00.

<u>PUB/MH II-42</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-200 (c) Periodic 5-Year Drought**

a) **Please confirm that two 5-year droughts of similar to 1987-91 severity did actually occur within a 13-year period; 1929 to 1933 followed by 1936-1941.**

<u>ANSWER</u>:

Manitoba Hydro acknowledges that there were two 5-year droughts in the 13-year period of 1929 to 1941. However, it is not appropriate to characterize the 1929 to 1933 drought period as having similar severity as the 1987 to 1991 drought since its financial consequence is about half of the 1987-91 drought. In addition, Manitoba Hydro has stated in other responses that the frequency of a 5-year drought with severity similar to that of 1987-91 is about once in 50 years. This is the basis for the response to PUB/MH I-200(c) which states that two severe droughts are extremely unlikely to occur in a 20 year period.

PUB/MH II-42

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-200 (c) Periodic 5-Year Drought**

b) Please confirm that in the response to PUB/MH I-200, MH employed roughly equal export prices and import prices (as per IFF 09-1).

ANSWER:

Manitoba Hydro does not have a single price for exports and another single price for imports. Instead of a single price a monthly price structure is developed for exports in which prices decrease as the quantity of export increases. A separate price structure is developed for on-peak and off-peak periods. Similarly a price structure is developed for imports in which the cost increases as the quantity of required import energy in the month increases. Import prices and export prices in any particular time period are closely related. However, exports and imports generally do not occur in the same period and therefore average prices of exports and import in actual application may not be closely related. The degree to which average prices of export and import are similar depends on the specific application and scenario that is analyzed.

In summary, the average prices for exports and imports may appear to be roughly equal for this particular application but the reason for this is not that Manitoba Hydro employed roughly equal prices as input into the analysis. The reason for being similar is that by coincidence the volumes combined with the pricing structures resulted in roughly equal overall average prices.

PUB/MH II-42

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-200 (c) Periodic 5-Year Drought**

c) **Please confirm that the reduction in export revenues would likely be greater (foregone exports would have higher prices than remaining contract obligations).**

ANSWER:

Manitoba Hydro is having difficulty in interpreting the intent of this information request. One interpretation is that the reduction in export revenues can be expected to be greater than what Manitoba Hydro has assumed during extreme drought events. This is likely based on the assumption that opportunity export sales can always be expected to yield higher prices compared to prices associated with long-term contract sales. The consequence of this assumption would be that Manitoba Hydro is underestimating the reduction in export revenues during drought periods, and therefore is underestimating the financial impact of drought.

If the information request has been interpreted correctly, Manitoba Hydro is not in agreement with the conclusion that the reduction in export revenues can be expected to be greater than what is currently being estimated. Firstly, the price of long-term contract sales is not a factor in determining the financial impact of drought because this is a constant revenue source no matter what the water flow conditions. It is the reduced volume and corresponding price of only opportunity export sales that cause a reduction in export revenue during drought events. Consequently, in determining reduced export revenue during drought events, it does not matter whether the opportunity price is higher or lower than the contact sale price. It is the absolute magnitude of the opportunity price that determines the financial impact of drought. The conclusion that Manitoba Hydro is likely underestimating the reduction in export revenues would be correct if it is believed that the forecast of opportunity export prices is too low.

PUB/MH II-42

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-200 (c) Periodic 5-Year Drought**

d) Please confirm that all imports and not just additional imports would likely command higher shortage prices than normal MISO market values.

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-62(g) which discusses shortage pricing in the current market structure and that it may not be as significant a factor in the future compared to what it was in the past. In addition, please refer to the response to PUB/MH I-150(b) which states imports are priced in accordance with a pricing structure that results in higher prices as the volume of required energy increases. By definition, shortage pricing becomes effective whenever Manitoba Hydro requires large quantities of import energy. Therefore, it cannot be confirmed that shortage pricing applies to all imports.

PUB/MH II-43

Subject: Tab 4 Financial Results & Forecast
Reference: PUB/MH I-200 (b) Periodic Low Flow

a) Please confirm that MH "revised" median and periodic low flow scenarios would involve hydraulic generation as follows:

	IFF09-1 (GWh)	Revised IFF09-1 (GWh)	Periodic Droughts (GWh)	Reduction from IFF 09-1
2012	31,200	31,500	29,100	-6.7%
2017	31,800	32,400	30,000	-5.7%
2022	35,000	39,000	32,400	-7.4%
2027	42,000	44,000	38,200	-9.0%

ANSWER:

Manitoba Hydro is not able to confirm that the levels of hydraulic generation in the table are representative of median and periodic low flow scenarios that are referenced in the response to PUB/MH I-200(b). As discussed in the response to PUB/MH I-208(a), the periodic low flow analysis was determined in terms of only financial impact and does not correspond to a specific hydraulic generation level. It appears that the hydraulic generation tabulated in the information request was inferred from the changes in water rental between the average, median and periodic low flow cases. This approach is not valid and produced erroneous results.

It is possible to obtain an approximate estimate of hydraulic energy for the periodic low flow case by observation of the graph in the response to PUB/MH I-208(b) to determine which flow years are closest in representing the revenue for the periodic low flow case. It is found that the representative flow years correspond to annual hydraulic energy production of approximately 25,000 GW.h. This is approximately a 20% reduction from IFF09 and much greater than what was inferred from water rentals.

<u>PUB/MH II-43</u>

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-200 (b) Periodic Low Flow**

b) **Please confirm that the 2003/04 drought represented a 35 to 40% reduction from median flow levels.**

<u>ANSWER</u>:

As indicated in the response to PUB/MH I-81(a), the inflow for 2003/04 is estimated to be 72,000 cfs (cubic feet per second). This is about 64% of the median inflow into the Manitoba Hydro system.

PUB/MH II-43

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-200 (b) Periodic Low Flow**

c) Please provide alternative scenarios which would see a 2003/04 drought in:

- **2012 and 2022**
- **2017 and 2027**

ANSWER:

Manitoba Hydro does not have alternative scenarios which would see a 2003/04 drought in the various years indicated. Such an exercise would require significant new work that cannot be undertaken in the time frame allowed for responses. As an order of magnitude estimate it is observed that the net revenue would be expected to be reduced by nearly $700 million in 2011/12 using the information provided in the response to PUB/MH I-81(a) for 2003/04 flow conditions.

PUB/MH II-44 (REVISED)

Subject: **Tab 5: Integrated Financial Forecast**

Reference: **PUB/MH I-69(a)/20-Year IFF 09-1 Statement of Cash Flow / Interest Costs / Charges**

Please provide several additional columns to the table illustrating the average interest rate employed to define interest paid in the cash flow statement; also show separately the annual provincial debt guarantee fee payment.

ANSWER:

The information referenced in PUB/MH I-69(a) was based on an original graph included in the Debt Management Strategy which illustrated that the Corporation's actual net fixed assets have increased at a much greater pace than the growth in its actual net long term debt since 1974. In response to PUB/MH I-69(a), the graph was provided for the years from 1990 to 2030, and included the level of accumulated capitalized interest for each year. This information was for illustrative purposes only and utilized consolidated data from Manitoba Hydro's financial accounting records.

Manitoba Hydro utilizes accrual accounting, on both an actual and forecast basis, for the determination of its net fixed assets, net long term debt, and capitalized interest. The Corporation fulfils the cash requirements for its interest and provincial debt guarantee fee payments based upon its contractual obligations. The Corporation does not utilize cash basis accounting for the determination of its interest expense nor for determining the Application's revenue requirement.

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-45 (b) Assumptions**

a) **Please provide an expanded table including export transmission losses and all assumptions to 2029.**

ANSWER:

Please see attached table.

Transmission charges are netted to export sales for the purposes of the average price calculation. Merchant sales and purchases are excluded from the calculation.

IFF09 Export Revenue Assumptions

(in GWh)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	33,124	30,525	30,067	30,789	30,989	30,913	30,929	31,078	30,812	30,755	33,518
MH Thermal Generation	152	159	432	437	441	444	497	531	580	591	521
Import Energy (including Wind)	733	1,508	2,616	2,576	2,569	2,608	2,663	2,717	2,794	3,789	3,459
Manitoba Domestic Energy Sales	23,968	24,346	24,728	25,075	25,413	26,030	26,439	26,790	26,743	26,929	27,229
Total Export Sales	9,149	7,122	7,841	8,150	8,020	7,430	7,181	7,082	7,006	7,746	9,598
Export Transmission Losses	891	724	546	577	566	504	469	454	438	461	670
Total Supply	34,009	32,192	33,114	33,802	33,998	33,964	34,089	34,326	34,186	35,136	37,497
Total Demand	34,008	32,192	33,114	33,802	33,998	33,964	34,089	34,326	34,186	35,136	37,497

(in Millions of Dollars)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	$ 111	$ 102	$ 100	$ 103	$ 104	$ 103	$ 103	$ 104	$ 103	$ 103	$ 112
MH Thermal Generation	8	8	41	41	44	45	55	61	70	75	77
Import Energy (including Wind)	36	56	171	172	177	184	195	206	217	289	264
Total Manitoba Domestic Energy Sales	1,160	1,193	1,246	1,305	1,365	1,441	1,510	1,582	1,653	1,725	1,805
Total Export Sales	332	292	517	545	575	549	653	654	665	816	1,013

Average Price ($/MWh)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	$ 3.36	$ 3.35	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	52.79	52.09	95.96	94.72	99.73	102.53	109.86	115.37	120.73	127.24	147.20
Import Energy (including Wind)	49.69	37.12	65.29	66.78	69.08	70.54	73.36	75.75	77.65	76.20	76.21
Total Manitoba Domestic Energy Sales	48.40	48.99	50.39	52.03	53.69	55.36	57.13	59.05	61.80	64.07	66.30
Total Export Sales	36.24	41.02	65.92	66.90	71.73	73.96	90.88	92.33	94.97	105.33	105.58

IFF09 Export Revenue Assumptions

(in GWh)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
MH Hydraulic Generation	34,866	34,976	36,781	40,572	41,767	42,041	41,937	42,015	42,055
MH Thermal Generation	599	645	730	597	597	386	344	348	347
Import Energy (including Wind)	3,359	3,437	3,233	3,178	3,380	3,023	3,025	3,068	3,106
Manitoba Domestic Energy Sales	27,551	27,893	28,363	28,638	28,979	29,379	29,795	30,215	30,600
Total Export Sales	10,516	10,426	11,530	14,541	15,510	14,843	14,331	14,064	13,787
Export Transmission Losses	757	739	851	1,169	1,255	1,228	1,180	1,151	1,122
Total Supply	38,824	39,058	40,744	44,347	45,744	45,450	45,306	45,431	45,509
Total Demand	38,824	39,058	40,744	44,347	45,744	45,450	45,306	45,431	45,509

(in Millions of Dollars)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
MH Hydraulic Generation	$ 116	$ 117	$ 123	$ 136	$ 140	$ 140	$ 140	$ 140	$ 141
MH Thermal Generation	90	100	115	97	102	66	61	64	66
Import Energy (including Wind)	265	278	276	277	304	266	245	270	287
Total Manitoba Domestic Energy Sales	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805
Total Export Sales	1,120	1,140	1,294	1,671	1,852	1,818	1,811	1,835	1,855

Average Price ($/MWh)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
MH Hydraulic Generation	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	150.74	155.41	157.98	163.00	170.49	172.36	177.17	183.42	190.27
Import Energy (including Wind)	78.86	81.00	85.30	87.29	90.06	88.04	81.13	88.03	92.53
Total Manitoba Domestic Energy Sales	65.52	64.72	63.65	63.04	62.29	61.45	60.59	59.75	58.99
Total Export Sales	106.52	109.36	112.25	114.91	119.38	122.51	126.39	130.44	134.52

PUB/MH II-45

Subject: Tab 5: Integrated Financial Forecast
Reference: PUB/MH I-45 (b) Assumptions

b) Please reconcile the answer in part (a) for the energy supply(GWh) and demand (GWh) for each of the years in the 20 year forecast.

ANSWER:

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

PUB/MH II-46

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-45 (f) Merchant Trading Revenues**

a) **Please indentify the merchant trading revenue and volumes (gross and net) that are included in extra-provincial revenue for 2009/10 and 2010/11, and in the balance of the 20 year outlook if any.**

ANSWER:

As explained in CAC/MSOS/MH I-5 (revised), Manitoba Hydro does not forecast gross or net volumes associated with merchant trading. Merchant revenues included in IFF09 for 2009/10 and 2010/11 are as follows:

	System Merchant Sales ($ millions)	System Merchant Purchases ($ millions)	Net ($ millions)
2009/10	31.6	27.2	4.4
2010/11	29.9	26.0	3.8

PUB/MH II-46

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-45 (f) Merchant Trading Revenues**

b) Please explain why there is uncertainty whether merchant trading will continue.

ANSWER:

Manitoba Hydro has no long term merchant transmission reservations beyond 2012. The revenues from merchant activities are dependent on the spreads between the Midwest ISO and the Ontario markets. Should Manitoba Hydro choose to invest in transmission reservations beyond 2012, it will include the expected revenues and costs associated with that decision in its IFF at that time.

PUB/MH II-47

Subject: Tab 5: Integrated Financial Forecast
Reference: PUB/MH I-49

Please provide the assumption with respect to natural gas pricing incorporated in the 20 year forecast and how the assumptions were changed under the low and high price scenarios reflected in Appendix 15.

ANSWER:

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

In general, the low forecast case can be characterized in varying degrees and combinations of pricing factors such as: low economic growth, aggressive energy conservation policies, low growth in energy demand, less stringent U.S. environmental policies, lower natural gas and coal prices relative to those assumed in the expected forecast.

In general, the high forecast case can be characterized in varying degrees and combinations of pricing factors such as: high economic growth and high growth in energy demand, more stringent U.S. environmental policies, increased capital costs due to higher lending rates, and increased natural gas and coal prices relative to those assumed in the expected forecast.

PUB/MH II-48

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-50, Appendix 15**

a) Please provide alternative 20-year electric IFF scenarios for:

- **i. A 5-year drought beginning in 2020 using high export and import prices.**
- **ii. A 5-year drought beginning in 2025 using high export and import prices.**
- **iii. A 7-year drought beginning in 2022 using high export and import prices.**

ANSWER:

Manitoba Hydro has undertaken various drought scenarios. Financial studies were not prepared with impacts to all revenue and cost categories of the operating statement individually. Rather, incremental net export revenues corresponding with the lowest total net export revenues for five and ten consecutive years within all 94 historical flow years on record were applied to base forecast revenues (20 Year Financial Outlook) beginning in 2019/20 (Keeyask post-construction and Conawapa construction stage) and 2025/26 (Keeyask and Conawapa post-construction). Average revenues for all 94 flow conditions are assumed in the periods preceding and following the low flow periods. Each of the flow scenarios has been prepared assuming high export and import prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

The drought alternative requested in question i) is provided in the table below. A 5 year drought beginning in 2026 and a 10 year drought beginning in 2020 are provided as proxies for the requested alternatives in ii) and iii) based on scenarios already available.

Incremental Impact of Drought on Manitoba Hydro Electric Retained Earnings
High Export Prices
Millions of Dollars

Fiscal Year Ending	MH09 Base	5 Year Drought - 2020 to 2024	5 Year Drought - 2026 to 2030	10 Year Drought - 2020 to 2029
2010	**2,183**	-	-	-
2011	**2,261**	-	-	-
2012	**2,331**	-	-	-
2013	**2,403**	-	-	-
2014	**2,528**	-	-	-
2015	**2,641**	-	-	-
2016	**2,889**	-	-	-
2017	**3,153**	-	-	-
2018	**3,388**	-	-	-
2019	**3,632**	-	-	-
2020	**3,908**	(206)	-	(400)
2021	**4,207**	(831)	-	(630)
2022	**4,645**	(2,136)	-	(311)
2023	**5,190**	(3,965)	-	8
2024	**5,922**	(5,974)	-	(620)
2025	**6,713**	(6,393)	-	(892)
2026	**7,623**	(6,831)	(245)	(1,720)
2027	**8,629**	(7,288)	(1,093)	(3,449)
2028	**9,745**	(7,764)	(2,861)	(5,866)
2029	**10,969**	(8,261)	(5,319)	(8,363)
2030	**12,265**	(8,778)	(7,845)	(8,848)
2031	**13,674**	(9,318)	(8,263)	(9,355)
2032	**15,231**	(9,880)	(8,701)	(9,884)
2033	**16,889**	(10,467)	(9,158)	(10,436)
2034	**18,579**	(11,078)	(9,635)	(11,011)
2035	**20,348**	(11,715)	(10,132)	(11,612)
2036	**22,209**	(12,379)	(10,651)	(12,238)
2037	**24,118**	(13,072)	(11,193)	(12,891)
2038	**26,104**	(13,794)	(11,758)	(13,572)
2039	**28,164**	(14,546)	(12,347)	(14,283)
2040	**30,262**	(15,330)	(12,962)	(15,024)
2041	**32,449**	(16,148)	(13,604)	(15,796)
2042	**34,667**	(17,000)	(14,274)	(16,602)

PUB/MH II-48

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-50, Appendix 15**

b) **For each of the above scenarios, provide an in-depth discussion of MH's energy shortfall mitigation efforts.**

ANSWER:

Given that the Manitoba Hydro system is designed for a repeat of the most severe flow sequence on record, it is not expected to have energy shortfalls if the historic 5-year drought event occurs in the years 2020 and 2025, or the 7-year drought occurs in 2022. It will be necessary to import energy and operate the natural gas-fired generation in order to meet firm requirements.

PUB/MH II-48

Subject: Tab 5: Integrated Financial Forecast
Reference: PUB/MH I-50, Appendix 15

c) Please confirm or correct the summaries derived from the tables as drawn from Appendix 15

	2010			2015			2020			2025		
	$M	**GW.h**	**¢/kW.h**	**$M**	**GW.h**	**¢/kW.h**	**$M**	**GW.h**	**¢/kW.h**	**$M**	**GW.h**	**¢/kW.h**
Base												
Domestic Sales	1,160	22,300	5.2	1,441	24,300	5.9	1,805	26,000	6.9	2,110	27,000	7.8
Export Revenue	414	7,901	5.2	590	7,482	7.9	1,093	9,717	11.2	1,940	16,562	11.7
F&PP	103	-	-	268	-	-	418	-	-	492	-	-
Net Export	311	-	-	322	-	-	675	-	-	1,448	-	-
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	**2,183**	2,227		2,921	2,738		4,125	4,059		6,359	6,918	
LT and ST Debt	**9,956**	10,062		13,341	13,887		19,174	19,737		22,017	21,156	
Medium High												
Domestic Sales	1,160	22,300	5.2	1,505	24,300	7.1	1,913	26,000	7.4	-	27,000	-
Export Revenue	414	7,901	5.2	550	?	?	986	?	?	-	-	-
F&PP	103	-	-	293			419					
Net Export	311	-	-	257			567					
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	**2,183**	2,227		-	2,742		-	4,049				
LT and ST Debt	**9,956**	10,062		-	13,832		-	20,150				
Alternative Scenario (No WPS/MP Contracts)												
Domestic Sales	1,160	22,300	5.2	1,441	24,300	5.9	1,805	26,000	6.9	2,110	27,000	7.8
Export Revenue	414	7,901	5.2	593	7,482	7.9	740	?	?	737	?	?
F&PP	103	-	-	269			380			364		
Net Export	311	-	-	324			360			373		
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	**2,183**	2,227		**2,511**	-		**3,544**	-		**6,133**	-	
LT and ST Debt	**9,956**	10,062		**13,017**	-		**16,254**	-		**16,599**	-	
CDN $ Up 10¢												
Domestic Sales	1,160	22,300	5.2	1,441	24,300	5.9	1,805	26,000	6.9	2,110	27,000	7.8
Export Revenue	414	7,901	5.2	536	7,482	7.9	985	9,717	10.1			
F&PP	103	-	-	257			396					
Net Export	311	-	-	279			589					
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	-	2,227		-	2,647		-	3,773				
LT and ST Debt	-	10,062		-	13,754		-	20,034				
CDN $ Down 10¢												
Domestic Sales	1,160	22,300	5.2	1,441	24,300	7.1	1,805	26,000	6.9	2,110	27,000	7.8
Export Revenue	414	7,901	5.2	657	7,482	8.8	1,229	9,717	12.6			
F&PP	103			282			445					
Net Export	311			375			784					
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	-	2,227		-	2,848		-	4,416				
LT and ST Debt	-	10,062		-	13,948		-	19,688				

	2010			2015			2020			2025		
	$M	GW.h	¢/kW.h	$M	GW.h	¢/kW.h	$M	GW.h	¢/kW.h	$M	GW.h	¢/kW.h
Low Export Prices												
Domestic Sales	1,160	22,300	5.2	1,441	24,300	5.9	1,805	26,000	6.9	2,110	27,000	7.8
Export Revenue	414	7,901	5.2	495	7,482	6.6	886	9,717	9.1	1,543	16,562	9.3
F&PP	103			240			353			399		
Net Export	311			255			533			1,144		
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	**2,183**	2,227		-	2,475		-	3,139		-	4,591	
LT and ST Debt	**9,956**	10,062		-	14,108		-	20,756		-	22,029	
High Export Prices												
Domestic Sales	1,160	22,300	5.2	1,441	24,300	5.9	1,805	26,000	6.9	2,110	27,000	7.8
Export Revenue	414	7,901	5.2	769	7,482	10.3	1,451	9,717	14.9	2,490	16,562	15.0
F&PP	103			321			538			618		
Net Export	311			448			913			1,872		
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	**2,183**	2,227		-	3,259		-	5,771		-	10,873	
LT and ST Debt	**9,956**	10,062		-	13,297		-	18,144		-	18,352	
Five Year Drought (2011 to 2015)												
Domestic Sales	1,160	22,300	5.2	1,441	24,300	5.9	1,805	26,000	6.9	2,110	27,000	7.8
Export Revenue	414	7,901	5.2	365	?	?	1,093	9,717	11.2	1,940	16,562	15.0
F&PP	103			382			418			492		
Net Export	311			(17)			675			1,448		
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	**2,183**	2,227		-	748		-	910		-	2,500	
LT and ST Debt	**9,956**	10,062		-	15,840		-	22,983		-	24,767	
1% Higher Interest Rates												
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	**2,183**	2,227		-	2,743		-	3,780				
LT and ST Debt	**9,956**	10,062		-	13,939		-	20,355				
1% Lower Interest Rates												
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	**2,183**	2,227		-	2,733		-	4,313				
LT and ST Debt	**9,956**	10,062		-	13,722		-	19,113				
9.10% Interest Rate by 2013/14												
	Electric	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**		**Electric**	**Consolidated**	
Retained Earnings	**2,183**	2,227		-	2,811		-	3,748		-	23,079	
LT and ST Debt	**9,956**	10,062		-	13,817		-	20,416		-	4,547	

ANSWER:

Manitoba Hydro cannot confirm the information provided in the above tables on the basis that they refer to IFF08 volumes and IFF09 financials to calculate an oversimplified ¢/kWh.

Please refer to Appendix 14 and Appendix 15 for the Domestic Sales, Export Revenue, Fuel & Power Purchased, Retained Earnings, and Long- and Short-Term Debt values for IFF09-1 and corresponding risk scenarios. Please refer to PUB/MH I-45(b) and RCM/TREE/MH II-3(d) for the Export Revenue Energy values and average price calculations.

PUB/MH II-48

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-50, Appendix 15**

d) Please provide detailed narrative on all assumptions utilized in each of the alternative scenarios in Appendix 15.

ANSWER:

The 20 Year Financial Outlook document describes the assumptions within the alternative scenarios. The tables below, expanded from CAC/MSOS/MH I-106(e), illustrate the specific factors that were adjusted in each of the scenarios.

Interest Rates Increase 1 Percent:

	MH Cdn New Short Term Debt Rate*		MH Cdn New Long Term Debt Rate*	
	IFF09-1	IFF09-1 Risk Scenario	IFF09-1	IFF09-1 Risk Scenario
2009/10	0.45%	0.45%	4.60%	4.60%
2010/11	1.40%	2.40%	4.65%	5.65%
2011/12	3.60%	4.60%	5.20%	6.20%
2012/13	4.30%	5.30%	5.70%	6.70%
2017/18	4.45%	5.45%	6.10%	7.10%
2019/20	4.45%	5.45%	6.10%	7.10%
2020/21	4.45%	5.45%	6.10%	7.10%
2021/22	4.45%	5.45%	6.10%	7.10%
2022/23	4.45%	5.45%	6.10%	7.10%
2023/24	4.45%	5.45%	6.10%	7.10%
2024/25	4.45%	5.45%	6.10%	7.10%
2025/26	4.45%	5.45%	6.10%	7.10%
2026/27	4.45%	5.45%	6.10%	7.10%
2027/28	4.45%	5.45%	6.10%	7.10%
2028/29	4.45%	5.45%	6.10%	7.10%

* Excluding Provincial Guarantee Fee of 1.0%

Interest Rates Decrease 1 Percent:

	MH Cdn New Short Term Debt Rate*		MH Cdn New Long Term Debt Rate*	
	IFF09-1	IFF09-1 Risk Scenario	IFF09-1	IFF09-1 Risk Scenario
2009/10	0.45%	0.45%	4.60%	4.60%
2010/11	1.40%	0.40%	4.65%	3.65%
2011/12	3.60%	2.60%	5.20%	4.20%
2012/13	4.30%	3.30%	5.70%	4.70%
2017/18	4.45%	3.45%	6.10%	5.10%
2019/20	4.45%	3.45%	6.10%	5.10%
2020/21	4.45%	3.45%	6.10%	5.10%
2021/22	4.45%	3.45%	6.10%	5.10%
2022/23	4.45%	3.45%	6.10%	5.10%
2023/24	4.45%	3.45%	6.10%	5.10%
2024/25	4.45%	3.45%	6.10%	5.10%
2025/26	4.45%	3.45%	6.10%	5.10%
2026/27	4.45%	3.45%	6.10%	5.10%
2027/28	4.45%	3.45%	6.10%	5.10%
2028/29	4.45%	3.45%	6.10%	5.10%

* Excluding Provincial Guarantee Fee of 1.0%

Canadian Dollar Increases $0.10:

	CDN$/US$ Exchange	
	IFF09-1	IFF09-1 Risk Scenario
2009/10	1.11	1.11
2010/11	1.07	0.97
2011/12	1.09	0.99
2012/13	1.07	0.97
2017/18	1.14	1.04
2019/20	1.14	1.04
2020/21	1.14	1.04
2021/22	1.14	1.04
2022/23	1.14	1.04
2023/24	1.15	1.05
2024/25	1.15	1.05
2025/26	1.15	1.05
2026/27	1.15	1.05
2027/28	1.15	1.05
2028/29	1.15	1.05

Canadian Dollar Decreases $0.10:

	CDN$/US$ Exchange	
	IFF09-1	IFF09-1 Risk Scenario
2009/10	1.11	1.11
2010/11	1.07	1.17
2011/12	1.09	1.19
2012/13	1.07	1.17
2017/18	1.14	1.24
2019/20	1.14	1.24
2020/21	1.14	1.24
2021/22	1.14	1.24
2022/23	1.14	1.24
2023/24	1.15	1.25
2024/25	1.15	1.25
2025/26	1.15	1.25
2026/27	1.15	1.25
2027/28	1.15	1.25
2028/29	1.15	1.25

Low Export Prices:

	Net Export Revenue	
	IFF09-1	IFF09-1 Risk Scenario
2009/10	197	197
2010/11	147	147
2011/12	202	147
2012/13	227	162
2013/14	248	175
2014/15	214	148
2015/16	297	210
2016/17	281	189
2017/18	273	181
2018/19	347	247
2019/20	559	417
2020/21	646	505
2021/22	642	506
2022/23	778	631
2023/24	1158	897
2024/25	1303	1000
2025/26	1343	941
2026/27	1362	949
2027/28	1357	934
2028/29	1358	925

<u>High Export Prices</u>:

	Net Export Revenue	
	IFF09-1	IFF09-1 Risk Scenario
2009/10	197	197
2010/11	147	147
2011/12	202	318
2012/13	227	358
2013/14	248	389
2014/15	214	341
2015/16	297	458
2016/17	281	445
2017/18	273	435
2018/19	347	520
2019/20	559	796
2020/21	646	879
2021/22	642	865
2022/23	778	991
2023/24	1158	1527
2024/25	1303	1727
2025/26	1343	1891
2026/27	1362	1917
2027/28	1357	1915
2028/29	1358	1918

5 Year Drought:

	Net Export Revenue	
	IFF09-1	IFF09-1 Risk Scenario
2009/10	197	197
2010/11	147	147
2011/12	202	-217
2012/13	227	-516
2013/14	248	-1
2014/15	214	-106
2015/16	297	26
2016/17	281	281
2017/18	273	273
2018/19	347	347
2019/20	559	559
2020/21	646	646
2021/22	642	642
2022/23	778	778
2023/24	1158	1158
2024/25	1303	1303
2025/26	1343	1343
2026/27	1362	1362
2027/28	1357	1357
2028/29	1358	1358

Medium High Electric Forecast:

	Net Firm Energy		Net Total Peak (MW)	
	IFF09-1	IFF09-1 Risk Scenario	IFF09-1	IFF09-1 Risk Scenario
2009/10	24080	24080	4333	4333
2010/11	24600	24600	4407	4407
2011/12	25159	26018	4499	4745
2012/13	25599	26572	4570	4846
2013/14	26012	27094	4633	4936
2014/15	26618	27808	4733	5062
2015/16	26973	28264	4789	5140
2016/17	27331	28722	4845	5217
2017/18	27644	29132	4893	5286
2018/19	27923	29506	4942	5354
2019/20	28288	29964	5007	5437
2020/21	28654	30423	5071	5520
2021/22	29021	30881	5136	5602
2022/23	29391	31342	5202	5684
2023/24	29762	31802	5268	5766
2024/25	30136	32263	5334	5847
2025/26	30516	32731	5401	5930
2026/27	30899	33199	5469	6012
2027/28	31285	33671	5537	6095
2028/29	31674	34144	5606	6178

PUB/MH II-49

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-18- Alternative IFF Scenario**

Please provide an alternative IFF 20 year forecast reflecting CAD$ parity with the USD$ over the entire forecast, and discuss the impact from the base case IFF09 20 year forecast.

ANSWER:

Manitoba Hydro establishes a natural hedge between USD cash inflows and outflows such that changes in foreign exchange rates will be offset to the extent that period cash flows are in balance. As the net long positions become larger in the medium and long term with the in-service of new major generation or the maturity of existing US long term debt, new US long term debt/interest payments may be secured to structurally rebalance the net position in accordance with Manitoba Hydro's Exposure Management Program. As the precise timing and volume of this future rebalancing is uncertain, the IFF assumes for long term planning purposes only that all new financings will be in Canadian dollars. As such, IFF scenarios assuming CAD parity with the USD would not produce representative results.

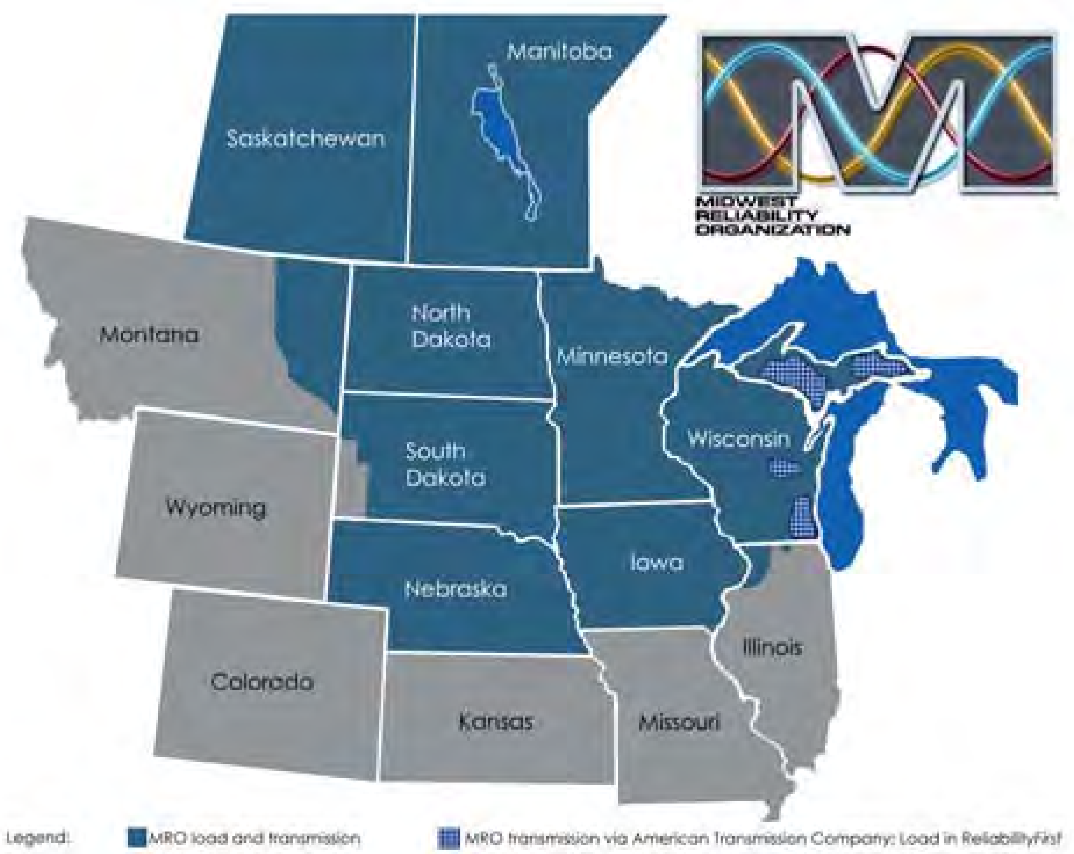
PUB/MH II-50

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-51 (b) & (c) Carbon Adders**

a) **Please provide a full listing of external price forecast consultants/ target market areas the Corporation has relied on in establishing its price forecast.**

ANSWER:

For the 2008 and 2009 price forecast work, Manitoba Hydro requested analysis of the focuses on the MRO (Midwest reliability Organization) region, which is shown in the map below. Several of the consultants run market models for larger regions - as large as the entire eastern interconnect, and only report on the MRO region.



PUB/MH II-50

Subject: Tab 5: Integrated Financial Forecast
Reference: PUB/MH I-51 (b) & (c) Carbon Adders

b) **Please file in confidence with the Board a table indicating the carbon adder assumed by each of the external price forecast consultants in (a) and indicate what carbon adder has been incorporated in the 20 year forecast.**

ANSWER:

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

In addition, each of the electricity price forecast consultants prepares their own carbon price forecast and they incorporate that forecast, as well as their own forecasts of other pricing factors (as discussed in the response to PUB/MH I-156(a)), into their own electricity price forecast. Hence there is not a single carbon price forecast to release, but rather one forecast prepared and utilized by each price forecast consultant for their own work. Also, as noted in the response to PUB/MH I-156(a), "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."

As discussed in the response to CAC/MSOS/MH II-41(a):

> "Manitoba Hydro has a consultant services agreement with each of the electricity export price forecast consultants, and the services agreement has confidentiality requirements that prevent Manitoba Hydro from publically releasing the forecast reports. The electricity export price forecast consultants vigorously protect their reports from becoming public - it would impair their ability to sell similar reports to other clients. For example, one of the reports has wording to the effect that "this report constitutes and contains valuable trade secret information", and that "disclosure of any information contained in this report is prohibited", and further "you will take all necessary precautions to prevent this report from being available to anyone other than employees of your company". "

Hence the confidentiality requirements of the consultant services agreements also prevent Manitoba Hydro from providing the requested electricity price forecast data and reports to anyone outside of Manitoba Hydro.

<u>PUB/MH II-50</u>

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-51 (b) & (c) Carbon Adders**

c) Please provide in confidence with the Board the assumed carbon adder incorporated in the High and Low energy forecast assumptions.

<u>ANSWER</u>:

Please see the response to PUB/MH II-50(b). The carbon adders in the high and low export market price forecasts are protected by confidentiality agreements with the price forecast consultants. As well, the specific details of Manitoba Hydro's electricity export price forecast, including details on specific pricing factors, are commercially sensitive information, and therefore are confidential since public release could harm the Corporation in negotiation of contracts for export sales.

PUB/MH II-51

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-52 (a)**

Conawapa G.S. experienced an increase in base costs due to restating the cost estimate from 2006 to 2008 dollars. Please indicate by Major Generation and Transmission project the year the base costs are currently reflected in the CEF.

ANSWER:

Please see table below.

	Base Costs
Major New Generation & Transmission	
Wuskwatim - Generation	2007
Wuskwatim - Transmission	2008
Herblet Lake - The Pas 230 kV Transmission	2008
Keeyask - Generation	2006
Conawapa - Generation	2006
Kelsey Improvements & Upgrades	2008
Kettle Improvements & Upgrades	2008
Pointe du Bois Improvements & Upgrades	2009
Pointe du Bois - Transmission	2005
Bipole 3	2001
Riel 230/500 kV Station	2008
Firm Import Upgrades	2008
Dorsey - US Border New 500 kV Transmission Line	2008
Brandon Combustion Turbine Pipeline Upgrade	2008

PUB/MH II-52

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (a), (b), (c), (d) Bipole III Costs/Benefits**

a) Please explain the evolution of Bipole III costs and system components:

	December 7, 2007	March 11, 2010	
Transmission Line		$814 M	Line cost
	________	$320 M	int./escalation
Subtotal	$1,081 M	$1,134 M	
Northern Converter		$388 M	base cost
Southern Converter (Riel)		$485 M	base cost
	________	$241 M	int./escalation
Subtotal	$1,166 M	$1,114 M	
Total	$2,247 M	$2,248 M	

ANSWER:

The approved estimate has not been changed since December 2007, except for an apportionment of the estimate into system components.

PUB/MH II-52

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (a), (b), (c), (d) Bipole III Costs/Benefits**

b) Please provide an update to the December 2007 (2007 PUB/MH I-4(f)) net present value cost benefit analysis expanding and updating previous filings to cover:

	West of Lake Winnipegosis	East of Lake Winnipeg	Underwater Lake Winnipeg
Estimated Length	**1,341**	**885 km**	**?**
Total Cost			**?**
Annual Line Loss Costs	**$2,247**	**$1,837 M**	**?**
Annual OM&A Costs	**?**	**?**	**?**
Mitigation Payments	**?**	**?**	**?**

ANSWER:

It should be noted that a net present value cost benefit analysis of Bipole III options was not undertaken in the 2008 GRA. The only component that was analyzed in the responses to 2008 GRA PUB/MH I-4(f) was the difference in losses between West and East options. The table below provides limited additional information and "NA" has been used to indicate where information is not available. The Manitoba Hydro Electric Board decided that a West Side route for Bipole III was the best option to proceed with given that an East Side route was not available. Consequently, Manitoba Hydro has no current information on a hypothetical east-side route.

The research that Manitoba Hydro has done regarding the installation of 500 kV underwater cable in Lake Winnipeg has identified significant risks based on current technology available to construct, install and maintain such a cable system. Extensive study is required before an underground /underwater cable option is proven to be technically feasible and can be installed and operated reliably. The development time for such an unproven technology is expected to be extensive and costly. Given the importance of Bipole III to the reliability of supply in Manitoba, and the risk of significant delay to Bipole III associated with a cable installation, the use of underwater cable for Bipole III is deemed to be unacceptable. Consequently, Manitoba Hydro has no data for the underwater Lake Winnipeg option.

No additional information is available at this time on the total capital costs of Bipole III options since the December, 2007 estimate that was provided in the 2008 GRA. Please note that the table has been revised to show the $2,247M and $1,837M as Total Cost and not as Annual Line Loss Costs.

The absolute magnitude of annual line loss costs for the options is not available. The estimated cost of the difference between line losses for West versus East options was provided in the response to PUB/MH I-4(f) from the 2008 GRA and has increased by approximately 5% since the 2008 estimate due to the increased value of energy.

The OM&A costs for the West option are provided in the table below and include costs for the converters as well as the transmission line. These are consistent with the OM&A costs provided in the response to PUB/MH II-90(b). Mitigation payment estimates are not available.

	West of Lake Winnipegosis	**East of Lake Winnipeg**	**Underwater Lake Winnipeg**
Estimated Length Total Cost	1,341 $2,247 M	885 km $1,837 M	NA NA
Annual Line Loss Costs	NA	NA	NA
Annual OM&A Costs	$13 M/year	NA	NA
Mitigation Payments	NA	NA	NA

<u>PUB/MH II-53</u>

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I – 54 (a) Major G & T CEF 09-1 - Wuskwatim G.S Contracts**

a) **Please confirm that the estimated cost of the Wuskwatim G.S project has remained essentially unchanged since CEF 07-1 (November, 2007).**

<u>ANSWER</u>:

Confirmed.

PUB/MH II-53

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I – 54 (a) Major G & T CEF 09-1 - Wuskwatim G.S Contracts**

b) **Please confirm that the cost plus contract for general civil works has not experienced any substantive additional costs relative to the target cost structure set out in the contract. Explain.**

ANSWER:

Confirmed.

PUB/MH II-54

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I – 56 (a) CEF 04-1 to CEF 09-1 Capital Cost escalation**

In light of the 25% Conawapa G.S & Keeyask G.S capital estimate increases since CEF 06-1, please explain the variable increase for each of:

Wuskwatim G.S	**17%**
Wuskwatim Transmission	**23%**
Herblet/The Pas Transmission	**55%**
Bipole III (West side)	**20%**
Riel Control Station	**55%**

ANSWER:

Wuskwatim G.S. (17% increase)

Project estimate increased to reflect current market conditions for material and labour, predominantly for the General Civil Contract.

Wuskwatim Transmission (23% increase)

Project estimate increased to reflect current market conditions for material and labour for all stations projects, the transmission line construction, and an increase in construction costs for the Wuskwatim Switching Station and Thompson Birchtree Station to reflect switching to external contractors versus using internal construction crews.

Herblet/The Pas Transmission (55% increase)

Project estimate increased to reflect current market conditions for material and labour for the transmission line, along with additional project contingency to reflect a 20 month in-service date deferral to coincide with the Wuskwatim in-service date. The in-service date deferral will not affect Manitoba Hydro's ability to serve load in the area.

Bipole 3 (20% increase)

Project estimate increased to reflect current market conditions for material and labour for the transmission line, along with an increase in line length for the Western route from 1,296 kms to 1,341 kms.

Riel 230/500 kV Station (55% increase)

Project estimate revised to reflect an increase in the station site area by 7.5 hectares, along with increases to reflect current market conditions for apparatus, material and labour. In addition, the site now includes converter facilities, has been reconfigured to accommodate a transfer bus scheme to improve system reliability by including a transfer bus scheme, and now accommodates greater access for major equipment installation from the new spur line.

PUB/MH II-55

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (a) and (b) Bipole Transmission Roles**

Please confirm or revise the following conceptual (post-2025) normal % energy flow plan for generation from or via:

	Bipole I	Bipole II	Bipole III
Keeyask G.S.	100%	Zero	Zero
Kettle G.S.	100%	Zero	Zero
Long Spruce G.S.	Zero	100%	Zero
Limestone G.S.	Zero	%	%
Conawapa G.S.	Zero	Zero	100%

ANSWER:

The lower Nelson River generating stations are in a collector system concept where the power is normally shared between the bipoles in order to minimize transmission losses. The collector system concept allows for the transfer of power between bipoles with outages of either generator units or HVdc transmission facilities so specific generating stations are not always transmitted by a specific bipole or bipoles. In the cases where the power from a generating station flows into a transmission station along with power from another generating station, the electrons from one generating station cannot be distinguished from those of the other generating station.

Generation will tend to utilize the nearest converter station, thus most of Keeyask and Kettle will tend to be transmitted through Bipole I with the surplus going to Bipole II/III, Long Spruce will tend to utilize mostly Bipole II, Limestone will tend to utilize both Bipole II and III, and Conawapa will tend to utilize Bipole III. However, any generation source can utilize any Bipole for transmission. Thus during periods of transmission equipment outages, generation is redistributed among the remaining transmission equipment with the objective of minimizing losses.

PUB/MH II-56

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH – I – 56 (c) - Project Capital Updates**

a) **Please confirm that MH's CEF's are typically prepared mid-year for the release in November.**

ANSWER:

The CEF includes all capital projects that have been approved by the August to September timeframe. The CEF is subsequently approved by the Manitoba Hydro-Electric Board in the fall in conjunction with the IFF.

PUB/MH II-56

Subject: Tab 6: Capital Expenditures
Reference: PUB/MH – I – 56 (c) - Project Capital Updates

b) Please confirm that the CEF estimate for each major G & T project represents MH's official update and not necessarily the most recent evaluation of that project & project cost.

ANSWER:

The CEF represents projects that are approved at a point in time, in conjunction with the annual IFF process. Manitoba Hydro employs a budgeting process whereby capital projects are reviewed and updated throughout the year as circumstances warrant. Through this process, the most recent evaluations of projects are entered into the current capital forecast and will be incorporated in the next CEF document.

PUB/MH II-56

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH – I – 56 (c) - Project Capital Updates**

c) **In the case of Bipole III, MH's CEF 09-1 indicates a capital requirement of about $2.2B, the same as in CEF 07-1; Does this suggest zero inflation and that MH still believes Bipole III costs will not be more than $2.2B? Explain.**

ANSWER:

The estimate for Bipole III that was incorporated in CEF07-1 did consider cost escalation and therefore continuing to use the same approved forecast does not suggest zero inflation. The ultimate cost of Bipole III may be greater than $2.2 billion, however there are many aspects of the project that are to be decided and it is not yet possible to develop a project cost estimate with the degree of confidence necessary to warrant an update to the CEF.

PUB/MH II-56

Subject: Tab 6: Capital Expenditures
Reference: PUB/MH – I – 56 (c) - Project Capital Updates

d) Please file a detailed breakdown of the $2.2 billion cost estimate for Bipole III and related Riel control station costs.

ANSWER:

A breakdown of the $2.2B cost estimate was provided by Transmission Line & Converter Components, including Northern & Southern (Riel) Converter Station costs as indicated in PUB/MH I-59(a). No further breakdown is currently available.

PUB/MH II-56

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH – I – 56 (c) - Project Capital Updates**

e) **The major new G & T projects slated to be in service between 2015 and 2025 are shown in CEF 09-1 at the following forecast values:**

	$B (Last updated)
Bipole III - HVDC	**2.2 (CEF07-1)**
Riel Control System	**0.6 (CEF08-1)**
500 KV U.S. Link	**0.2 (CEF09-1)**
Keeyask G.S.	**4.7 (CEF 09-1)**
Conawapa G.S.	**6.2 (CEF 09-1)**
Total	**$13.9**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-56(f).

PUB/MH II-56

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH – I – 56 (c) - Project Capital Updates**

f) **Does MH expect these major G & T projects with currently defined in service dates will be brought on-line for $14B in total or does MH currently anticipate significant increases in subsequent updates of individual projects?**

ANSWER:

The approved estimate for the projects is $14 billion dollars. Given the magnitude of and timeframe involved with these projects, cost estimates may change prior to the commencement of construction.

<u>PUB/MH II-57</u>

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I – 56 (d) - 20 yr CEF 09-1**

Please confirm that from 2020 to 2030 (aside from the Conawapa G.S.), MH does not contemplate:

- **Any major upgrades or rehabilitation of hydraulic stations.**
- **Any thermal plants (CCCT's or SCCT's) to support & maximize export sales.**
- **Any additional AC Transmission expansions for domestic or export sales.**

<u>ANSWER</u>:

During the period of 2021 to 2029, the 20 year CEF09-1 includes $299 million related to major upgrades or rehabilitation of hydraulic stations and $345 million related to additional north-south transmission expansion. There is no provision in the forecast for any combustion turbines during the 2021 to 2029 timeframe.

<u>PUB/MH II-58</u>

Subject: **Tab 6: Capital Expenditures**

Reference: **PUB/MH I – 57 (a) - CEF 09-1/CEF 08-1 Scope change for Pointe Du Bois G.S.**

a) Please confirm that the $500M project cost reduction reflects the full cost deletion of the Powerhouse work.

<u>ANSWER</u>:

The projected cost of Pointe du Bois Modernization in CEF08 was $818 million. A decision was made to reduce the scope of the project to a new spillway and new concrete and earth dams. The existing powerhouse will continue to operate indefinitely and will have ongoing activities to maintain safety and reliability. The amount of $318 million in CEF09 is a preliminary estimate for the spillway replacement project. This estimate is currently being reviewed and may be revised for the upcoming capital expenditure forecast (CEF). The cost for the ongoing activities to maintain safety and reliability at the powerhouse are not part of this project and are not included in this estimate.

PUB/MH II-58

Subject: **Tab 6: Capital Expenditures**

Reference: **PUB/MH I – 57 (a) - CEF 09-1/CEF 08-1 Scope change for Pointe Du Bois G.S.**

b) **Please provide any supporting analysis that had been prepared to support the decision to change the scope of the project to eliminate the powerhouse.**

ANSWER:

Manitoba Hydro undertook a review of the project and determined that the objective to improve safety at the plant could be achieved most economically with a spillway replacement and ongoing maintenance of the existing powerhouse. The estimate for the spillway replacement project is currently being updated to reflect more detailed design information and updated industry cost parameters.

PUB/MH II-58

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I – 57 (a) - CEF 09-1/CEF 08-1 Scope change for Pointe Du Bois G.S.**

c) **Please elaborate on the ongoing activities and annual maintenance cost to maintain the safety and reliability of the existing powerhouse.**

ANSWER:

The maintenance budget for the Pointe du Bois station in 2010 is approximately $5.9 million. Ongoing monitoring activities will continue to be carried out at the powerhouse to ensure safe operation. This monitoring will further define the future work to be undertaken and the annual maintenance expenses to be incurred.

PUB/MH II-59

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-56 Capital Forecast Reclassifications Allocations, Rationale for Revised Categorization of Domestic Items**

a) Please explain the rational for the reclassification of distribution with customer service from transmission and identify specific line items that classification had changed from that used in CEF08-1.

ANSWER:

Capital projects including major and domestic items were reclassified as a result of the corporate reorganization as indicated in Tab 3. Projects were realigned in accordance with the responsibilities depicted in the new organization structure.

Please see the following table which identifies the classification changes.

Project Description	Total Project Costs	CEF09 - Business Unit	CEF08 - Business Unit
Perimeter South Station Distribution Supply Centre Installation	2.4	Customer Service & Distribution	Transmission & Distribution
Defective RINJ Cable Replacement	8.7	Customer Service & Distribution	Transmission & Distribution
Brereton Lake Station Area	9.0	Customer Service & Distribution	Transmission & Distribution
Stony Mountain New 115 - 12 kV Station	5.0	Customer Service & Distribution	Transmission & Distribution
Rover Substation Replace 4 kV Switchgear	12.7	Customer Service & Distribution	Transmission & Distribution
Martin New Outdoor Station	28.2	Customer Service & Distribution	Transmission & Distribution
Frobisher Station Upgrade	14.4	Customer Service & Distribution	Transmission & Distribution
Burrows New 66 kV/ 12 kV Station	28.6	Customer Service & Distribution	Transmission & Distribution
Winnipeg Central District Oil Switch Project	7.1	Customer Service & Distribution	Transmission & Distribution
William New 66 kV/ 12 kV Station	10.3	Customer Service & Distribution	Transmission & Distribution
Waverley West Sub Division Supply - Stage 1	6.5	Customer Service & Distribution	Transmission & Distribution
St. James 24 kV System Refurbishment	65.9	Customer Service & Distribution	Transmission & Distribution
Shoal Lake New 33 - 12.47 kV DSC	3.6	Customer Service & Distribution	Transmission & Distribution
York Station	4.0	Customer Service & Distribution	Transmission & Distribution
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	Customer Service & Distribution	Transmission & Distribution
Winkler Market Feeder M25-13 Conversion	2.9	Customer Service & Distribution	Transmission & Distribution
Neepawa North Feeder NN12-2 & Line 57 Rebuild	1.9	Customer Service & Distribution	Transmission & Distribution
Gas SCADA Replacement	4.6	Customer Service & Distribution	Transmission & Distribution
Fleet	13.0	Finance & Administration	Transmission & Distribution
Automatic Meter Reading - Electric	30.9	Customer Care & Marketing	Customer Service & Marketing
Winnipeg Distribution Infrastructure Requirements	14.9	Customer Service & Distribution	Customer Service & Marketing
Winnipeg Central District Underground Network Asbestos Removal	3.0	Customer Service & Distribution	Customer Service & Marketing

PUB/MH II-59

Subject: **Tab 6: Capital Expenditures**

Reference: **PUB/MH I-56 Capital Forecast Reclassifications Allocations, Rationale for Revised Categorization of Domestic Items**

b) Please identify the specific assets & functional costs actually added to Transmission & the Distribution component of Customer Services & Distribution.

ANSWER:

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

PUB/MH II-59

Subject: **Tab 6: Capital Expenditures**

Reference: **PUB/MH I-56 Capital Forecast Reclassifications Allocations, Rationale for Revised Categorization of Domestic Items**

c) Please define the specific benefits being realized due to the change.

ANSWER:

The adjustments to the classifications have been made in order to align the reporting of capital expenditures with the organizational responsibilities which have been adjusted. This provides clear accountability for each of the capital programs.

PUB/MH II-59

Subject: **Tab 6: Capital Expenditures**

Reference: **PUB/MH I-56 Capital Forecast Reclassifications Allocations, Rationale for Revised Categorization of Domestic Items**

d) Please provide a breakdown by year of the Customer Service Domestic and Distribution Domestic.

ANSWER:

The following table provides the breakdown requested.

	2010	2011	2012	2013	2014	2015-2020
Electric:						
Customer Service - provides for new or replacement customer service extensions to commercial and residential customers, and for minor additions or modifications to the distribution system.	58.0	58.8	60.0	61.2	62.4	401.6
Distribution - provides for additions and modifications to the sub-transmission and distribution system including sub stations. Significant work includes system enhancements to support new customers, municipal and highway changes, street and sentinel lighting, load growth, operational enhancements and safety; improvements to aging infrastructure; and rural sub-transmission and distribution system pole and conductor replacements.	57.9	58.7	59.9	61.1	62.3	401.0
Total Electric Domestic	115.9	117.5	119.9	122.3	124.7	802.6
Gas:						
Customer Service - costs associated with the addition of new customers. Includes distribution mains, residential and commercial services, regulators and associated installation costs.	4.4	4.4	4.5	4.6	4.7	30.2
Distribution - provides for upgrades to transmission and distribution facilities. Upgrade costs for transmission and distribution mains, service line upgrades and retirements, measuring and regulating station upgrades, cathodic protection, and code violation and load increase.	16.4	16.8	17.1	17.5	17.8	114.8
Total Gas Domestic	20.7	21.2	21.7	22.1	22.5	145.0

PUB/MH II-59

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-56 Capital Forecast Reclassifications Allocations, Rationale for Revised Categorization of Domestic Items**

e) Please provide a description of Domestic Items – Customer Service & Marketing utilized in CEF08-1.

ANSWER:

The CEF08-1 CS&M domestic capital provides for new or replacement customer service extensions to commercial and residential customers, and for minor additions or modifications to the distribution system. It includes customer driven District Work Orders and Service Requests; System Improvement programs such as Integrated Pole Maintenance, Rotten Pole Maintenance, Street Lighting, Ground Rod Additions and Meter Replacement; as well as Field Maintenance Tools and Equipment. Typical capital components covered by these programs include transformers, poles, meters, street light standards and cables.

PUB/MH II-59

Subject: **Tab 6: Capital Expenditures**

Reference: **PUB/MH I-56 Capital Forecast Reclassifications Allocations, Rationale for Revised Categorization of Domestic Items**

f) Please indicate how the Capital Increase Provision is determined and provide supporting calculations if formula based.

ANSWER:

The capital increase provision is based on CEF08 base capital annual values, which were escalated at 2% per year beginning in 2016, to ensure a reasonable level of base capital target is maintained in the later years of the CEF where individual future projects may not be known. No changes were made to the capital increase provision for CEF09.

Please see the following attachment which demonstrates that through the use of the capital increase provision, total base capital has been adjusted to show 2% increases each year commencing in 2016.

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF08)

(in millions of dollars)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ELECTRIC										
Major New Generation & Transmission	679.1	583.6	422.9	450.2	785.6	1,472.9	1,865.2	1,777.6	1,376.7	1,516.9
New Head Office	-	-	-	-	-	-	-	-	-	-
Corporate Relations	5.3	5.5	-	-	-	-	-	-	-	-
Base Capital	516.8	496.7	427.8	367.7	373.8	354.3	298.3	278.2	293.2	286.2
Capital Increase Provision	-	-	-	-	-	-	63.1	90.4	82.8	97.3
Revised Base Capital	516.8	496.7	427.8	367.7	373.8	354.3	361.4	368.6	376.0	383.5
Year over year increase							2%	2%	2%	2%
ELECTRIC CAPITAL SUBTOTAL	**1,201.2**	**1,085.8**	**850.7**	**817.9**	**1,159.4**	**1,827.2**	**2,226.6**	**2,146.2**	**1,752.7**	**1,900.4**

<u>PUB/MH II-60</u>

Subject: Tab 6: Capital Expenditures
Reference: PUB/MH I-58

Please provide a schedule demonstrating and explaining the $381.2 million increase in interest costs related to the Keeyask project, including interest rate assumptions utilized.

<u>ANSWER</u>:

Manitoba Hydro's response to PUB/MH I-58 incorrectly identified a $381.2 million interest increase related to the Keeyask project. The increase in the interest forecast was $205.5 million. The difference of $175.7 million relates to higher Licensing costs ($106.3 million) and higher escalation ($69.4 million).

The interest increase relates mainly to increases to the base estimates for the generating station, infrastructure and licensing costs.

PUB/MH II-61

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (c) and (d) Export Delivery**

Please provide a conceptual (post-2025) normal % energy flow plan for exports from/to:

	U.S.	Ontario	Saskatchewan
Dorsey	%	%	%
Riel	%	%	%
Others (specify)	%	%	%

ANSWER:

Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations. Currently, approximately 70% of Manitoba Hydro's hydroelectric generation originates from northern generating plants and flows through the HVdc system terminating at the Dorsey Converter Station. With the construction of Bipole III and under the development plan where Conawapa and Keeyask are constructed, approximately 80% of Manitoba Hydro's hydroelectric generation would originate from the northern generating stations, and flow through the HVdc system terminating at Dorsey and Riel.

The HVdc generation is converted into AC power and interconnected with other AC generation sources at the Dorsey and Riel switchyards. This AC power is utilized for both domestic load requirements and export opportunities. The Dorsey and Riel complexes include major AC substations which connect the AC generating stations as well as form the originating location of high voltage transmission lines that serve both southern Manitoba domestic customers and export customers through interconnections to the U.S. These extraprovincial interconnections provide significant reliability support to domestic customers during contingency events. Connections to Ontario are through the Whiteshell switchyard, while Saskatchewan connections are through Reston, Ralls Island, Border and Roblin South switchyards.

The power from any generating station can be utilized to serve exports to any of Manitoba Hydro's customers. Exports cannot be traced back to a single source.

PUB/MH II-62

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (d) Export Delivery**

Please confirm that U.S. exports coming from Bipoles I and II would pass through the Dorsey Station and U.S. exports coming from Bipole III would be served directly from the Riel Station. Explain.

ANSWER:

Please refer to the response to PUB/MH II-61 in which information is provided relating to HVdc power flow and how it is related to exports. This response indicates that the Manitoba Hydro system is an integrated system and it is not possible to determine the origin of power that is exported to the U.S. Bipole I & II transmission lines will normally terminate at Dorsey, and Bipole III lines will terminate at Riel, however, both converter stations would be capable of providing power to either domestic or export lines.

Both the Dorsey Converter Station and the Riel Converter Station include major switchyard components which integrate the power from various resources (both DC and AC) and serve various loads.

PUB/MH II-63

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (a)/20-Year IFF 08-1 Assumptions Rationale for West Side Bipole III**

a) **Please confirm that despite higher costs and longer time frames for approvals and construction, MH sees a pressing need to proceed with a West Side Bipole III location.**

ANSWER:

The existing Bipole I and Bipole II, which carry about 75% of Manitoba Hydro's generation, are vulnerable to catastrophic weather related events. Due to the enormous negative consequences to the Province from a catastrophic failure of the existing bipoles, Manitoba Hydro has recommended Bipole III for reliability in order to be able to continue to serve Manitoba load if a catastrophic event results in the loss of Bipoles I & II. To minimize the exposure to this risk, Bipole III should be placed in service as soon as possible. The expected in-service date is the fall of 2017.

It should be noted that while the longer west side route has a higher cost, it is unknown as to whether the environmental assessment process for a west side route will require more time than an east side route. The time required for government environmental approvals is independent of the route, and is not determined by Manitoba Hydro.

PUB/MH II-63

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (a)/20-Year IFF 08-1 Assumptions Rationale for West Side Bipole III**

b) **Please confirm that an East Side Bipole III would not necessarily preclude a heritage park designation for lands east of Lake Winnipeg.**

ANSWER:

Manitoba Hydro has no involvement with heritage park designations and therefore is in no position to comment on what would preclude a heritage park designation.

PUB/MH II-63

Subject: **Tab 6: Capital Expenditures**

Reference: **PUB/MH I-59 (a)/20-Year IFF 08-1 Assumptions Rationale for West Side Bipole III**

c) **Please confirm that the pending NSP contract extension, the WPS term sheet, and the MP term sheet are not conditional on avoiding the East Side as a Bipole III routing.**

ANSWER:

Confirmed.

PUB/MH II-63

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (a)/20-Year IFF 08-1 Assumptions Rationale for West Side Bipole III**

d) **Please confirm that none of the above pending contracts provides an explicit environmental premium for energy or capacity.**

ANSWER:

Although there is no "explicit" environmental premium, the contracts' terms do consider the value associated with the renewable aspects of Manitoba Hydro's facilities.

PUB/MH II-63

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-59 (a)/20-Year IFF 08-1 Assumptions Rationale for West Side Bipole III**

e) **Please confirm that MH's export strategy contemplates at least 50% of annual U.S. energy sales will be achieved through opportunity sales in the MISO market on solely a price competitive basis, and that MH forecasts the opportunity sales prices to be higher on average than the pending long-term contract prices.**

ANSWER:

Manitoba Hydro confirms that at least 50% of the annual U.S. energy sales will be achieved through price competitive opportunity sales in the MISO market.

As per Manitoba Hydro's response to PUB/MH I-48(d), on-peak opportunity prices are not typically higher than prices associated with new contract sales.

PUB/MH II-64

Subject: Tab 6: Capital Expenditures
Reference: PUB/MH I-66 Capital Target Adjustment

Please explain how the general provision was determined. Provide supporting calculations.

ANSWER:

In the course of preparing of CEF09, Manitoba Hydro established direction that the overall capital spending should not vary substantially from the amount approved in CEF08. An analysis of previous years' capital expenditure performance indicated that due to various circumstances, including resource capabilities, project constraints, and active project prioritization, the achieved levels of capital expenditures on an annual aggregate basis was consistently lower than the sum of all individual projects.

By considering historical capital performance factors, capital expenditure trends, and current capital demands, annual capital targets were proposed that met the corporate direction for capital spending levels and were deemed to be realistic given prevailing resourcing, capabilities and project constraints. The annual targets were reviewed and accepted for CEF09.

Subsequent to the establishment of the targets and the approval of the specific projects included in CEF09, the target adjustment was calculated as the difference between the capital targets as determined above and the total of all approved individual project spending.

PUB/MH II-65

Subject: Tab 6: Capital Expenditures
Reference: PUB/MH I-67 (a),(b)& (c)

a) Please populate the following chart of all mitigation expenditures by community.

Manitoba Hydro's Expenditures to Date (NFA & Non-NFA						
By Project/ Community	MH's Annual Operating Expense ($M)	MH Funded Capital Expenditures ($M)	MH Capital Contribution to Water & Sewer ($M)	MH's Compensation for Water Regime Deviations ($M)	MH's Funding for NFA & Other Negotiations ($M)	Provincial Obligation Paid by MH ($M)
CRD & LWR (NFA) Communities						
CRD & LWR (Non-NFA) Communities						
Other						

ANSWER:

Please see attached table, which has been modified for clarity, and note the following:

- Column 2 represents pre-determined compensation expenses as identified within adverse effects agreements.
- Column 6 represents the net present value for NFA Claim 138 for Potable Water at March 2004, for the five communities impacted by the CRD and LWR.
- Column 7 contains both the external party professional fees, along with participation costs associated with adverse effects claims and issues.

Manitoba Hydro's Expenditures to Date (NFA & Non-NFA) - in millions							
	Operating Expenses		Capital Expenditures				
By Project/ Community	(1) 2008/09 MH's Annual Operating Expense	(2) 2008/09 MH's Compensation for Water Regime Deviations	(3) MH Funded Capital Expenditures	(4) Provincial Obligation Paid by MH	(5) (column 3 + 4) Total Capital Expenditures	(6) (incl in column 5) MH Capital Contribution to Water & Sewer	(7) (incl in column 5) 2004/05 - 2008/09 MH's Funding for NFA & Other Negotiations
CRD & LWR (NFA)	0.9	0.7	354.4	71.5	426.0	18.6	7.8
CRD & LWR (NON-NFA)	0.3	-	124.3	25.3	149.6	-	2.5
OTHER	0.3	-	87.1	12.3	99.3	-	1.9
TOTAL	**1.5**	**0.7**	**565.8**	**109.1**	**674.9**	**18.6**	**12.2**

PUB/MH II-65

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-67 (a),(b)& (c)**

b) **With respect to the above table, please define the nature and detail break down of significant Generation and Transmission project and/or program mitigation expenditures on:**

- **Operating Costs**
- **Capital Costs**
- **Negotiation Costs**
- **Compensation Payments**

ANSWER:

The amounts provided in the referenced table relate to mitigation commitments and disbursements for communities affected by Lake Winnipeg Regulation, the Churchill River Diversion and the Grand Rapids generating station. The major Generation projects that these relate to are those that currently exist on the Nelson River and at Grand Rapids.

Operating costs relating to generating and transmission facilities are charged to expense in the current period.

Capital costs to construct the generating and transmission facilities are capitalized when the facility or component is placed into service.

The referenced table details the negotiation, mitigation, and compensation payments by community. Mitigation and compensation costs are capitalized as a cost component of these generating facilities and amortized over the life of their civil structures. The costs of administering the settled agreements and to provide compensation for water regime deviations (also detailed in the referenced table) are expensed in the period incurred.

PUB/MH II-65

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-67 (a),(b)& (c)**

c) Specifically please provide a detailed identification of the above costs (Actual & Forecast) for:

- **Wuskwatim G.S. & Transmission**
- **Keeyask G.S.**
- **Bipole III**
- **Conawapa G.S.**
- **Grand Rapids G.S.**

ANSWER:

The table referenced in PUB/MH II-65(a) excludes both actual and forecasted mitigation expenditures related to the Wuskwatim, Keeyask and Conawapa generating stations, as well as Bipole III as these facilities are not yet in-service.

For Wuskwatim G.S. and Keeyask G.S., all negotiation and related costs have been or will be charged to the respective projects and will be capitalized when the related facilities are placed into service.

For Bipole III and Conawapa G.S., negotiations are not yet concluded but will be charged to the respective projects and capitalized when the related facilities are placed into service.

Grand Rapids expenditures that have been capitalized to date include, but are not limited to, obligations such as: the cost of works and measures to alleviate the interference with the exercise of traditions, customs and practices integral to the cultural identity of the First Nation, the costs associated with personal property loss and damage, and loss of commercial income related to adversely affected commercial fishers and trappers, and monetary compensation paid to families who relocated from Grand Rapids as a result of the construction of the Project.

PUB/MH II-65

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-67 (a),(b)& (c)**

d) **Please describe the process involved in accounting for the $675 million in mitigation cost obligations. To what extent has this obligation been paid out and to what extent does it represent future amounts to be paid out.**

ANSWER:

The $675 million shown in the financial statements represents amounts that have been capitalized, including the present value of settled claims and the disbursements of unsettled claims.

The mitigation liability of $120 million at March 31, 2009, represents the estimated present value of mitigation amounts not yet paid out as of that date.

PUB/MH II-65

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-67 (a),(b)& (c)**

e) Please describe how the mitigation costs are recovered in consumer rates and indicate the extent such costs are in current and forecast customer rates for 2010/11 and 2011/12.

ANSWER:

Mitigation interest, operating and amortization expense is included with Generation costs allocated to both the domestic and export customers in the PCOSS. Mitigation costs represented 3.8% of the total revenue requirement for domestic consumers in PCOSS10, which represents the best estimate of the extent such costs are included in current rates, as well as forecast rates for 2010/11 and 2011/12.

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

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-67 (a),(b)& (c)**

f) Please indicate the rate impact related to mitigation costs in 2025 when all the major capital G&T projects currently identified in CEF09 are on line.

<u>ANSWER</u>:

Mitigation costs are an integral cost component of the respective projects and reflected in Manitoba Hydro's financial forecasts. There will be no incremental rate impacts beyond those included in the financial forecasts.

PUB/MH II-65

Subject: **Tab 6: Capital Expenditures**
Reference: **PUB/MH I-67 (a),(b)& (c)**

g) Please provide a detail breakdown of mitigation capital spending by project reflected in response to 67 (b) and incorporate the expenditures forecast through 2011/12.

ANSWER:

Please see the following table for expenditures incurred or settlements reached to mitigate the impacts of capital projects for 2004/05 through 2011/12.

Mitigation Capital Spending **(in millions)**

	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast	2012 Forecast
CRD & LWR (NFA)	26.7	14.9	13.7	26.7	20.1	11.8	4.7	2.5
CRD & LWR (Non-NFA)	0.6	2.6	3.3	1.4	0.6	3.8	6.6	1.4
Grand Rapids	4.1	10.2	0.1	8.4	1.0	10.4	7.6	0.1
Winnipeg River	0.1	0.2	0.2	0.3	0.3	9.6	0.1	0.1
	$ 31.5	**$ 27.9**	**$ 17.3**	**$ 36.8**	**$ 21.9**	**$ 35.6**	**$ 19.0**	**$ 4.0**

Notes:
CRD - Churchill River Diversion
LWR - Lake Winnipeg Regulation
NFA - Northern Flood Agreement

PUB/MH II-66

Subject: Tab 6: Capital Expenditures
Reference: PUB/MH I-69

Please re-file the graph and corresponding data points for electric operations only.

ANSWER:

The original graph was provided in the Debt Management Strategy to illustrate that the Corporation's actual net fixed assets have increased at a much greater pace than the growth in its actual net long term debt since 1974. In response to PUB/MH I - 69 (a), the graph was provided for the years from 1990 to 2030, and included the level of accumulated capitalized interest for each year.

The vast majority of Manitoba Hydro's net fixed assets and net long term debt are the result of electric operations, therefore the elimination of the non-electric activities would not appreciably affect the illustrative intent of the graph.

PUB/MH II-67

Subject: Tab 7 Load Forecast & Load Research
Reference: PUB/MH I – 70 (c) Unit Consumption Growth

a) Please discuss the specific factors, which has led MH to assume that average use growth is to grow by 9% over the next 20 years versus 18% over the last 10 years.

ANSWER:

Manitoba Hydro's response to PUB/MH I-70(c) was provided in the context of using the actual historic consumption in order to match Appendix 7.1 Table 6 (Page 18) as referenced in PUB/MH I-70(c).

To compare forecast growth rates with historic growth rates, it is more appropriate to compare using weather-adjusted historical usage as opposed to actual use. Using weather adjusted historical data, the tables provided in Manitoba Hydro's response to PUB/MH I-70(c) become:

	Total Basic		
	Custs	**GW.h**	**Ave Use**
1998/99	404478	5591	13823
2008/09	437262	6675	15265
growth	32784	1084	1443
% growth	8%	19%	10%

	Total Basic		
	Custs	**GW.h**	**Ave Use**
2009/10	441474	6754	15299
2029/30	516978	8636	16704
growth	75504	1882	1405
% growth	17%	28%	9%

Now we are comparing a 9% future growth over 20 years to a 10% historical weather adjusted growth over the last 10 years.

Manitoba Hydro uses a Residential End Use Model to forecast the Residential Sector, which takes into many factors including forecast of customer growth, appliance saturations (vintaging of appliances using appliance ages along with death and replacement rates), and new appliance average annual consumption. Using this updated data, the forecast predicts a 9% growth rate in average use over the next 20 years.

PUB/MH II-67

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I – 70 (c) Unit Consumption Growth**

b) **Please explain & quantify the various factors that led to an 18% increase in unit residential consumption from 1998/99 to 2008/09 with specific reference: to:**

- **Water Heating (load increases)**
- **Electronics (load increases)**
- **DSM Impacts (load decreases)**
- **Others**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-67(a). Of the 10% increase in average use, the change has been attributed as follows:

– increase in number of electric heat customers (2.5%),
– conversions to electric water heating (3.5%),
– increase in the saturation of computers (2.5%),
– DSM reduced load (-2.5%), and
– all other use changes (4%).

PUB/MH II-67

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I – 70 (c) Unit Consumption Growth**

c) **Please explain & quantify these same factors going forward from 2009/10 to 2029/30**

ANSWER:

The 9% growth is attributed to:

- an increase in number of electric heat customers (2.5%),
- conversions to electric water heating (4%),
- increase in computers (0.5%), and
- all other uses (2%).

Reductions for incentive-based DSM are not included in Manitoba Hydro's electric load forecast.

PUB/MH II-68

Subject: **Tab 7 Load Forecast & Load Research**

Reference: **PUB/MH I – 70 (d) Primary Factors in Increased Unit Consumption for Standard Residential**

a) **Please provide a historical profile (1998/99 to 2009/10) quantifying the number of meters and total electrical consumption of:**

- **Natural Gas Water Heating Residences**
- **Electricity Water Heating Residences**

ANSWER:

The following table estimates the number of gas and electric water heaters for Standard Residential Basic customers and the total usage of the residences they belong to:

Water Heaters in Residential Basic Standard

	Natural Gas Water Heaters	Total GW.h Gas WH Residences	Electric Water Heaters	Total GW.h Elec WH Residences
1998/99	203,425	1,798	31,918	416
1999/00	201,656	1,784	42,092	553
2000/01	200,249	1,759	51,806	683
2001/02	197,744	1,736	60,899	809
2002/03	197,802	1,777	70,283	954
2003/04	196,049	1,815	72,943	1,012
2004/05	194,310	1,833	75,681	1,065
2005/06	192,763	1,830	78,720	1,114
2006/07	191,212	1,817	81,559	1,156
2007/08	189,279	1,834	84,548	1,215
2008/09	187,668	1,821	87,597	1,262
2009/10	184,236	1,779	92,657	1,335

<u>PUB/MH II-68</u>

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I – 70 (d) Primary Factors in Increased Unit Consumption for Standard Residential**

b) **Please quantify & explain the specific other factors that contributed to the increased unit consumption.**

<u>ANSWER</u>:

The 13.4% growth for Standard Residential Basic average use between 1998/99 and 2006/07 is attributed to:

- Conversions to electric water heating contributed 5%;
- Increases in the saturation of computers contributed 3.5%;
- Increases in the saturation of central air units contributed 1.5%;
- DSM reduced load by 0.6%; and
- Other factors contributes 4%.

<u>PUB/MH II-69</u>

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I – 70 (e) Standard Residential Load Growth Primarily Relates to Conversion of Water Heating to Electric**

a) **Please provide a detailed analysis of the basic standard residential consumption increase from 1998/99 to 2008/09 when the number of meters increased by 12,484 (from 287 368 to 299 852) and electricity use grew by 634 GWh (from 2609 GWh to 3243 GWh) of which about 500 GWh appears to relate to increased unit consumption**

<u>ANSWER</u>:

On a weather adjusted basis, residential standard used 2,661 GW.h in 1998/99 and 3,229 GW.h in 2008/09. During this period, the weather adjusted growth was 568 GW.h and the average use increased from 9,260 kW.h to 10,768 kW.h.

This increase in average use is only partially due to increased unit consumption. Computers and miscellaneous uses grew by about 700 kW.h per customer and contributed about 210 GW.h of growth. The remainder of the growth was primarily due to over 47,000 additional electric water heaters being added during those years which contributed about 170 GW.h of growth and the increase of 12,484 customers that added 150 GW.h.

PUB/MH II-69

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I – 70 (e) Standard Residential Load Growth Primarily Relates to Conversion of Water Heating to Electric**

b) **Assuming an electricity demand of 3500 KWh/yr for electric water heating, please indicate how many Standard residences would have to convert to electric water heating to result in a 500 (plus) GWh load increase from 1998/99 to 2008/09**

ANSWER:

A 500 GW.h increase would require 142,857 water heaters at 3,500 kW.h per water heater. Please see Manitoba Hydro's response to PUB/MH II-69(a) for a more detailed explanation of what factors contributed to the load growth.

PUB/MH II-69

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I – 70 (e) Standard Residential Load Growth Primarily Relates to Conversion of Water Heating to Electric**

c) **Please indicate the level of DSM savings from 1998/99 to 2008/09 that MH attributes to:**

- **Basic Standard Customers**
- **Basic All-electric Customers**

ANSWER:

DSM energy savings at generation from 1998/99 to 2008/09 for basic standard customers was 55 GW.h and for all electric customers was 52 GW.h.

PUB/MH II-70

Subject: Tab 7 Load Forecast & Load Research

Reference: PUB/MH I – 71 (c) & (d) - [PUB/MH I – 72 a)][Table 9 – 2009/10 Load Forecast (Page 18)]

a) Please confirm the following table:

	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Chemicals	1841	1847	1865	1929	1870	1870	1970
Petroleum	849	899	879	944	1027	1093	1156
Primary Metals	2237	2248	2300	2237	2014	2236	2353
Pulp/Paper	763	742	764	674	765	715	720
Mining	5	4	4	4	0	0	0
Food/Beverage	182	176	188	202	204	205	205
College	70	71	75	75	76	77	78
Other	0	0	0	0	0	0	0

ANSWER:

Confirmed.

PUB/MH II-70

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I – 71 (c) & (d) - [PUB/MH I – 72 a)][Table 9 – 2009/10 Load Forecast (Page 18)]**

b) **Please confirm that the MH's top consumers have experienced essentially zero growth from 2005/06 to 2009/10 compared to an 1130 GWh increase from 2001/02 to 2005/06.**

ANSWER:

Confirmed.

PUB/MH II-70

Subject: **Tab 7 Load Forecast & Load Research**

Reference: **PUB/MH I – 71 (c) & (d) - [PUB/MH I – 72 a)][Table 9 – 2009/10 Load Forecast (Page 18)]**

c) **Please confirm that MH's top consumers forecast growth from 2009/10 to 2013/14 is 839 GWh, from 2013/14 to 2017/18 being 591 GWh and from 2021/22 being 327 GWh**

ANSWER:

Confirmed. For clarification, the forecast from 2017/18 to 2021/22 is 327 GW.h.

<u>PUB/MH II-70</u>

Subject: **Tab 7 Load Forecast & Load Research**

Reference: **PUB/MH I – 71 (c) & (d) - [PUB/MH I – 72 a)][Table 9 – 2009/10 Load Forecast (Page 18)]**

d) Please confirm that MH's forecast for the petroleum industry is expected to show a substantial consumption increase Jan/Feb/Mar 2010. Explain/reconcile petroleum industry & pipeline transport industry growth data

<u>ANSWER</u>:

When the forecast was prepared in May 2009, the petroleum industry top consumers were forecast to use 1093 GW.h in 2009/10 as indicated in Manitoba Hydro's response to PUB/MH II-70(a). During the first 10 months of 2009/10, the petroleum industry has only used 765 GW.h as provided in Manitoba Hydro's response to PUB/MH I-72(a).

Manitoba Hydro does not expect that the difference will be made up during the last two months of the year as some of the forecast increase in usage did not transpire as forecast.

PUB/MH II-70

Subject: **Tab 7 Load Forecast & Load Research**

Reference: **PUB/MH I – 71 (c) & (d) - [PUB/MH I – 72 a)][Table 9 – 2009/10 Load Forecast (Page 18)]**

e) **Please confirm that the pulp/paper sector experienced a 90 GWh drop in electricity consumption from 2007/08 to 2008/09 and expects a future drop of about 300 GWh from 2008/09 to 2009/10. Please explain & reconcile the 765 GWh forecast for 2009/10 with the 10-month actual sector total of 305 GWh. Also, confirm that there is a strong possibility that this sector may consume less than 400 GWh/yr in the future**

ANSWER:

Confirmed – the statements are correct. Certain customers within this sector have experienced business slow downs during 2009/10 which resulted in a large reduction in electricity consumption in the 10 month actual data. In May 2009 when the forecast was completed, these major problems were seen as possible but were not expected. This new information will be reflected into the 2010 forecast. There is a strong possibility that this sector may consume less than 400 GW.h/yr in the future.

PUB/MH II-70

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I – 71 (c) & (d) - [PUB/MH I – 72 a)][Table 9 – 2009/10 Load Forecast (Page 18)]**

f) **Please confirm/explain that MH's overall top consumer consumption level could be significantly lower than forecast if the impact of the economic downturn extends for several years beyond 2009/10.**

ANSWER:

An extended and significant downturn in the global economy could severely affect certain industries and specific customers causing suspension of operations or closures. This would lower the forecast by amounts that could be considered significant.

PUB/MH II-71

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **CEC Wuskwatim Filings/2009/10 Load Forecast**

a) Please file the applicable (circa 2002/03) load forecast employed in defining domestic revenues for the CEC Wuskwatim Hearing process.

ANSWER:

Please see Appendix 55 - Manitoba Hydro's 2002 Load Forecast.

PUB/MH II-71

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **CEC Wuskwatim Filings/2009/10 Load Forecast**

b) Please provide a comparison tabulation of (circa 2002/03) general services sales forecasts with actual results to date.

ANSWER:

The following table provides Manitoba Hydro's 2002 General Service forecast. The forecast for General Service did not include the areas serviced by Winnipeg Hydro as Winnipeg Hydro was a separate utility at the time. The table also provides an adjusted comparison to actual usage for General Service

	2002 General Service Forecast (GW.h)	General Service Actual (GW.h)	Winnipeg Hydro Service Area Actual (GW.h)	General Service less Winnipeg Hydro Actual (GW.h)
2002/03	10,749	12,796	1,808	10,988
2003/04	10,901	12,923	1,787	11,136
2004/05	11,075	13,274	1,763	11,511
2005/06	11,274	13,577	1,772	11,805
2006/07	11,481	13,870	1,804	12,066
2007/08	11,679	14,123	1,766	12,357
2008/09	11,872	14,154	1,803	12,351
2009/10	12,061	13,485	1,825	11,660

PUB/MH II-71

Subject: Tab 7 Load Forecast & Load Research
Reference: CEC Wuskwatim Filings/2009/10 Load Forecast

c) Please provide a comparison tabulation of (circa 2002/03) general service sales forecasts with the 2009/10 forecast (table 9).

ANSWER:

The following table provides Manitoba Hydro's 2002 General Service forecast and a comparison to the 2009 General Service forecast, with the latter being adjusted for the Winnipeg Hydro service area. Manitoba Hydro's 2002 General Service forecast did not include the areas serviced by Winnipeg Hydro as Winnipeg Hydro was a separate utility at the time. An estimated value of 1,800 GW.h is used as a forecast for the two Manitoba Hydro districts that make up the old service area of Winnipeg Hydro that are neither growing nor shrinking in load over the last 10 years.

	2002 General Service Forecast (GW.h)	2009 General Service Forecast (GW.h)	Winnipeg Hydro Service Area Forecast (GW.h)	General Service less Winnipeg Hydro Forecast (GW.h)
2009/10	12,061	14,056	1,800	12,256
2010/11	12,277	14,412	1,800	12,612
2011/12	12,505	14,831	1,800	13,031
2012/13	12,718	15,136	1,800	13,336
2013/14	12,921	15,400	1,800	13,600
2014/15	13,090	15,848	1,800	14,048
2015/16	13,256	16,067	1,800	14,267
2016/17	13,422	16,287	1,800	14,487
2017/18	13,589	16,468	1,800	14,668
2018/19	13,758	16,617	1,800	14,817
2019/20	13,927	16,840	1,800	15,040
2020/21	14,099	17,064	1,800	15,264
2021/22	14,271	17,288	1,800	15,488
2022/23	14,447	17,513	1,800	15,713

PUB/MH II-71

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **CEC Wuskwatim Filings/2009/10 Load Forecast**

d) Please confirm that for the CEC Wuskwatim Hearing MH prepared a 32 yr forecast of domestic load on a consistent basis with current load forecasts.

ANSWER:

Manitoba Hydro's methodology that was used for forecasting in 2002 was generally similar to how the forecasts are developed today, and the forecast prepared then is consistent with current forecasts. The major difference between the forecasts is that the Winnipeg Hydro service area was not included in the General Service forecast in 2002.

PUB/MH II-71

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **CEC Wuskwatim Filings/2009/10 Load Forecast**

e) Please explain MH's annual load forecast adjustment process and indicate the timing and/or frequency of in-depth re-assessment of the longer-term sales prospects for both residential & general service customer classes.

ANSWER:

Manitoba Hydro does an annual re-assessment of electricity sales every year during April after the last fiscal year's actual usage becomes known. The actual usage is weather adjusted and this data is used as a starting point for developing a revised forecast. In addition to the actual usage data, updated information on economic factors and our customer base is incorporated into the revised forecast. The updated forecast is then reviewed internally and approved by Manitoba Hydro's Executive Committee usually during late May or June.

PUB/MH II-72

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I-73 (a), (b), and (c) General Service Load Growth**

a) Please confirm the 2009/10 forecast general service load transition from:

13,828 GWh in 2006/07 and 2007/08	**0**	
14,100 GWh in 2008/09	**+272**	**over 2 years**
14,016 GWh in 2009/10 and 2010/11	**+198**	**over 3 years**
14,798 GWh in 2011/12	**+970**	**over the past 5 years**
16,270 GWh in 2016/17	**+1,472**	**over the next 5 years**
17,272 GWh in 2021/22	**+998**	**over the next 5 years**
18,408 GWh in 2026/27	**+1,136**	**over the next 5 years**

ANSWER:

The 2008/09 number should be 14,114 GW.h. This changes the “over 2 years” number from +272 to +286. The other numbers are correct.

The historical numbers shown here are actuals and are not weather adjusted.

<u>PUB/MH II-72</u>

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I-73 (a), (b), and (c) General Service Load Growth**

b) Please confirm that MH's GS load projections from 2006/07 to 2026/27 reflect an average annual increase of 250 GWh.

<u>ANSWER</u>:

The General Service Basic load is growing from 13,828 GW.h in 2006/07 to 18,408 in 2026/27. That is a difference of 4,580 GW.h over 20 years, which is an average annual increase of 229 GW.h.

PUB/MH II-72

Subject: **Tab 7 Load Forecast & Load Research**
Reference: **PUB/MH I-73 (a), (b), and (c) General Service Load Growth**

c) **Please confirm that actual GS load for 2010/11 will be less than 14,000 GWh based on industrial slow downs and that the 2011/12 forecast at 14,798 GWh is unlikely to be achieved.**

ANSWER:

The actual figure for General Service Basic for 2010/11 was 13,446 GW.h. It is now unlikely that 14,798 GW.h will be achieved in 2011/12.

PUB/MH II-73

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-76 (b) - Watershed Runoff History**

a) Please provide the seasonal unit runoff (inches) for the April-July period and for the August-October period on an annual basis for the 1978 to 2009 time frame as follows:

Monthly Flows For	**Time Period Accumulated**
• **Burntwood River at Thompson**	**÷ Drainage Area**
• **Saskatchewan River at The Pas**	**÷ Drainage Area**
• **Red River at Lockport**	**÷ Drainage Area**
• **Winnipeg River at Pine Falls**	**÷ Drainage Area**
• **Nelson River at Kettle G.S.**	**÷ Drainage Area**

ANSWER:

Manitoba Hydro respectfully declines to provide a response to this question as it requires a complex and time-consuming calculation that is not related to Manitoba Hydro's Rate Application. As requested, the seasonal runoff values would have little meaning because the effects of upstream storage and diversions would not have been accounted for.

<u>PUB/MH II-73</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-76 (b) - Watershed Runoff History**

b) **For both April-July and August-September annual time frames, please also calculate the annual (1978-2009) seasonal unit runoff (inches) from local drainage not covered by the flows from the four major tributaries to the Nelson River but included in the Nelson River flows at Kettle G.S**

<u>ANSWER</u>:

Manitoba Hydro respectfully declines to provide a response to this question as it requires a complex and time-consuming calculation that is not related to Manitoba Hydro's Rate Application. As requested, the seasonal runoff values would have little meaning because the effects of upstream storage and diversions would not have been accounted for.

<u>PUB/MH II-74</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-77(a), (b), (c), (d) - System Energy Storage Depletion**

Please provide a detailed explanation of MH's actual energy operational parameters and constraints (e.g., rule curve) used to determine surplus energy available for export in:

a) April-May period.
b) June-September period.
c) October-March period.

<u>ANSWER</u>:

As explained in PUB/MH I-77, with respect to rule curve, Manitoba Hydro plans its operations to ensure useable storage levels are, at minimum, sufficient to supply firm domestic and export load under the most severe single year historic drought of record inflow condition. This useable energy storage requirement is effectively a rule curve level.

Manitoba Hydro plans its operations to export surplus energy (i.e. energy in excess of the reserve requirement) in the highest valued periods to the extent possible subject to constraints and operational parameters. Of the periods listed in this information request, higher export prices generally occur in the June-September period. To account for uncertainty in key parameters such as future inflows and Manitoba Load, Manitoba Hydro uses conservative assumptions prior to committing to sell this surplus energy under contract.

As explained in PUB/MH I-91, in addition to inflows, the constraints and operational parameters that impact the operations planning process include, but are not limited to:

a. license, legal and citizenship obligations to all stakeholders affected by Manitoba Hydro's operations;
b. public safety, energy security and environmental stewardship considerations which all involve the use of professional judgment and experience; and
c. current storage levels, near term weather forecasts, equipment maintenance schedules, domestic load forecasts, ice conditions, availability of extraprovincial tie-line capacity and short term market trends and needs.

<u>PUB/MH II-75</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-77(d)/January 2008 PUB/MH I-30 Historic Inflows**

a) Please provide an updated version of MH's historic Lake Winnipeg inflow table.

<u>ANSWER</u>:

Manitoba Hydro derives the inflows into the system using publically available measurements of water levels and streamflows together with supplementary information that is collected by the Corporation. The extended record of unregulated inflows defines the characteristics of the water resource available to Manitoba Hydro in the future. This information is considered to be proprietary to Manitoba Hydro and commercially sensitive information, and is therefore confidential since public release could harm the Corporation in its participation in the export market. Consequently, an updated version of Manitoba Hydro's historic Lake Winnipeg inflow table is not being provided.

PUB/MH II-75

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-77(d)/January 2008 PUB/MH I-30 Historic Inflows**

b) Please provide a tabular (1978-2009) comparison of these inflows with annual recorded flows as available:

Lower Nelson River	Burntwood River at Thompson	Upper Nelson River	Three Major Lake Winnipeg Tributaries	Total Calculated Lake Winnipeg Inflows

ANSWER:

As stated in the response to PUB/MH II-75(a) the record of inflows into the Manitoba Hydro system is not being provided because it is considered proprietary to Manitoba Hydro and commercially sensitive information and therefore is confidential. Consequently, a comparison with recorded flows is not being provided.

PUB/MH II-75

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-77(d)/January 2008 PUB/MH I-30 Historic Inflows**

c) Please describe MH's calculation process for defining Lake Winnipeg inflows and include sample calculations for typical low, medium and high flow years.

ANSWER:

Lake Winnipeg total inflow equals the sum of the following components:

- Winnipeg River at Pine Falls
- Red River at Lockport
- Grand Rapids outflow
- Lake Winnipeg eastern tributary inflows (i.e., Bloodvien River, Poplar River, Pigeon River)
- Fairford River
- Local ungauged inflow component including evaporation losses and direct precipitation

This calculation is the same for all flow conditions. Please refer to PUB/MH II-88 for a detailed description of calculating the local unguaged inflow and the use of a mass balance equation that can be used to determine inflow available for outflow.

PUB/MH II-76

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-77(a), (b), (c), (d) Actual Energy Operations**

Please define on a monthly basis for the 2002-03 and 2003/04 years, MH's decision process based on the then available specific data on:

- **Actual accumulated winter snow pack (inches).**
- **Actual accumulated spring and summer rainfall (inches).**
- **Lake Winnipeg partial inflows (cfs/GWh).**
- **Lake Winnipeg water levels.**
- **System energy-in-storage (GWh).**
- **Total hydraulic generation (GWh).**
- **Total imports and thermal generation (GWh).**
- **Total exports (GWh).**

ANSWER:

Manitoba Hydro's rationale for managing the 2003/04 drought was tested during the 2004 PUB rate hearing. Please refer to the transcripts of that hearing for the details. In addition, Manitoba Hydro had its operations reviewed by an independent consultant as requested by the PUB.

The Manitoba Hydro 2002-2004 Drought Risk Management Review was filed with the PUB on May 3, 2005 and re-filed as Appendix 43 of the 2008 GRA. The document can be found at:
http://www.hydro.mb.ca/regulatory_affairs/electric/gra_08_09/information_requests/Appendix_43-Report_on_2002-2004_Drought.pdf

The review addresses Manitoba Hydro's energy portfolio management activities as they pertained to the drought experienced by Manitoba Hydro from 2002-2004. In both reviews, Manitoba Hydro's actions were deemed to be prudent and in the best interests of the Manitoba rate payer.

Please also refer to explanations of Manitoba Hydro’s operations planning decision process provided in PUB/MH I-91 and PUB/MH I-163. Manitoba Hydro respectfully declines to provide a more detailed response to this question.

PUB/MH II-77

Subject: Tab 8: Energy Supply
Reference: PUB/MH I-82(a), (b), (c), (d), (e)
Energy in Storage

Please provide a tabulation of the major components of energy-in-storage determination:

	Effective Range (Feet) of Operation (Minimum to Maximum)	Effective Storage (GWh months/foot)
Lake Winnipeg	711 ft to 715 ft	
Cedar Lake	830 ft to 842 ft	
Lake of the Woods	1056.25 ft to 1161.25 ft	
South Indian Lake	843 ft to 847.50 ft	
Lake Manitoba	Not regulated by MH	
Lake Winnipegosis	Not regulated by MH	

ANSWER:

Due to the complexity of the hydraulics at the outlet of Lake Winnipeg and the relative magnitude of the inflows to Lake Winnipeg, there is no one value for effective storage for Lake Winnipeg and/or any of the upstream reservoirs. Similarly, for Southern Indian Lake, the amount of effective storage is a complex function of inflows and water levels at Notigi. The effective use of storage in these reservoirs is only determined through appropriate modeling of the hydraulic system for specific system conditions.

Lake Winnipegosis and Lake Manitoba are not regulated by Manitoba Hydro and therefore do not provide Manitoba Hydro with effective storage, i.e. storage that can be expended for hydroelectric purposes.

<u>PUB/MH II-78</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-86 Wind Dependable Energy**

Please confirm that MH's dependable energy supply from wind will be 484 GWh lower (after 2012/13) than shown in the 2008/09 Power Resource Plan.

<u>ANSWER</u>:

Please refer to the response to CAC/MSOS/MH II-84(b) which described the reduction in dependable energy for the St. Joseph wind farm when the size of the project is reduced from 300 MW to 138 MW. This response indicates that the updated estimate for wind energy in the dependable energy supply/demand tables will be 750 GW.h after consideration is given to avoided losses that are inherent in the load forecast. The dependable energy for wind energy in the 2008 power resource plan was 1229 GW.h, Consequently, the reduction in the dependable energy supply from wind generation will be 479 GW.h relative to the 2008 power resource plan.

<u>PUB/MH II-79</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-86(b), (c), (d), (f) - 2008/09 Power Resource Plan Dependable Energy Reduction**

a) Please provide the statistical background data that MH relied on in concluding that St. Leon annual output of 320 GWh (35% of 104 MW x 8,760) is equivalent to the lowest annual output that would be historically anticipated.

<u>ANSWER</u>:

As explained in the response to PUB/MH I-86(b), the power resource plan assumes a 39% average annual capacity factor and an 85% dependable energy factor for the St. Leon wind farm which is assumed to have a nominal rating of 100 MW. The basis for the 85% dependable energy factor is explained in the response to CAC/MSOS/MH II-59(a). In addition to the previous factors, the 320 GW.h estimate is an effective output since the actual wind farm generation is increased by 10% in order to be consistent with other generation resources that may be farther from the load centre and to recognize that transmission losses are inherently included in the load forecast.

PUB/MH II-79

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-86(b), (c), (d), (f) - 2008/09 Power Resource Plan Dependable Energy Reduction**

b) Please quantify and explain, on a seasonal basis, the relationship between St. Leon/St. Joseph turbine height wind speeds and multi-decades of recorded wind speeds at the Winnipeg Airport .

ANSWER:

Manitoba Hydro has not analyzed the Winnipeg Airport wind speed data and is not in a position to comment on the relationship, if any, with the St. Leon or St. Joseph wind speed data. Winnipeg Airport data is typically recorded at 10 metres and cannot reasonably be used to determine turbine elevation wind speeds at St. Leon or St. Joseph, or vice versa. The relationship between any two sites is a statistical one that may be useful as an indicator of overall long term (20 to 25 year) performance provided that sufficient statistical correlation can be demonstrated. Seasonal performance is determined at a specific site and it is determined as close to the height intended as is practical.

PUB/MH II-79

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-86(b), (c), (d), (f) - 2008/09 Power Resource Plan Dependable Energy Reduction**

c) Please indicate whether the 2006-2009 years of operation at 40% average annual capacity reflected lower quartile/median/upper quartile relative to Winnipeg Airport recorded data.

ANSWER:

Manitoba Hydro has not analyzed the Winnipeg Airport wind speed data and is not in a position to comment on the relationship, if any, with the St. Leon or St. Joseph wind speed data.

PUB/MH II-80

Subject: Tab 8: Energy Supply
Reference: PUB/MH I-86 (d) - 2008/09 Power Resource Plan – Wind Reliability

a) Please provide (in confidence if necessary) a monthly history of MH's purchases of energy (GWh) from the St. Leon wind farm (July 1, 2006 to June 30, 2009).

ANSWER:

St. Leon wind farm monthly performance data has been designated as Confidential Information under the Confidentiality Agreement with St. Leon Wind Energy LP as it may be of commercial value to wind developers. Therefore Manitoba Hydro cannot provide the requested data on monthly wind purchases since this can be used to infer the characteristics of the wind resource.

PUB/MH II-80

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-86 (d) - 2008/09 Power Resource Plan – Wind Reliability**

b) Please confirm that the St. Leon wind farm has experienced significant cold weather supply outages (how many days?) and high wind speed outages (how many days?).

ANSWER:

Manitoba Hydro does not own the St. Leon wind farm or its performance data. St. Leon wind farm performance data is deemed confidential information under the power purchase agreement with St. Leon Wind Energy LP as it is of commercial value to wind developers.

As noted in the response to PUB/MH I-86(d), as a general comment, Manitoba Hydro can confirm that the actual performance data from St. Leon over the three year period from July 1, 2006 to June 30 2009 has exceeded a 40% average annual capacity factor, calculated using an installed capacity of 104 MW [63 units x 1.65 MW per unit]. Note that this is actual performance and is net of all effects from maintenance and weather related outages. To the knowledge of Manitoba Hydro, the St. Leon wind farm has not experienced significant cold weather supply outages or high wind speed outages.

PUB/MH II-81

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-87 (a) Dependable DSM Resources**

Please provide a listing and quantification (GWh/MW) of the major DSM resources MH can call on in support of dependable energy and capacity with a breakdown into winter and summer 5x16/2x16/7x8 energy/capacity.

ANSWER:

Manitoba Hydro's DSM Program provides multiple programs tailored to different customer groups, including residential, commercial, industrial, as well as load management and customer self-generation components. Total savings through DSM by 2024/25 are expected to be 269 MW (winter), 199 MW (summer) and 1159 GW.h at generation, as included in the power resource plans. These savings are summarized as follows:

DSM Programs 2009/10 to 2024/25			
Residential	**Summer (MW)**	**Winter (MW)**	**Annual Energy (GW.h)**
New Home	0.3	4.2	23.6
Home Insulation	0.0	12.5	25.6
Water & Energy Saver	2.4	4.2	25.6
Lower Income Energy Efficiency	0.0	2.9	11.0
Residential HE Furnace & Boiler	0.2	0.2	1.6
EE Light Fixtures	0.1	0.2	0.8
Residential CFL	0.0	0.0	0.0
Fridge Recycling	0.7	0.3	3.9
Appliance Program	0.8	0.7	4.0
Power Smart Loan	0.0	5.4	10.2
EcoEnergy	0.0	0.0	0.0
Earth Power	0.2	4.5	16.2
Solar Water Heater	0.1	0.0	0.3
Total @ meter	*4.8*	*5.1*	*121.8*
Total @ Generation	**5.5**	**40.0**	**138.9**

DSM Programs 2009/10 to 2024/25			
Residential	**Summer (MW)**	**Winter (MW)**	**Annual Energy (GW.h)**
Power Smart Commercial Programs			
Lighting	70.5	75.9	294.3
Custom Measures	1.0	1.3	8.7
Windows	0.4	6.5	16.0
HVAC	1.5	0.0	18.4
Parking Lot Controller	0.0	0.0	10.4
City of Wpg Power Smart	0.0	0.0	0.0
Rinse & Save	0.0	0.0	0.0
Refrigeration	5.7	6.3	56.1
Insulation	4.8	15.2	30.7
Earth Power	0.8	6.8	16.3
New Construction	8.7	5.9	30.6
Building Optimization	2.7	5.3	16.0
Internal Retro Fit	2.9	7.1	20.1
Agricultural Heat Pad	0.7	0.7	7.2
Power Smart Energy Manager	0.1	0.2	3.9
Kitchen Appliances	1.1	1.1	3.4
Clothes Washers	1.9	1.9	2.5
Network Energy Management	2.0	2.0	12.7
Power Smart Shops	1.4	1.2	9.9
CO2 Sensors	0.0	0.0	1.1
Total @ Meter	*106.2*	*137.4*	*558.3*
Total @ Generation	**121.1**	**156.6**	**636.5**
Industrial Incentive Based Programs			
Performance Optimization	37.1	37.1	245.1
Emergency Preparedness	28.5	28.5	28.5
Total @ meter	*65.6*	*65.6*	*273.6*
Total @ Generation	**72.2**	**72.2**	**301.0**

DSM Programs 2009/10 to 2024/25			
Residential	**Summer (MW)**	**Winter (MW)**	**Annual Energy (GW.h)**
Customer Self-Generation			
Bioenergy Optimization	0.0	0.0	74.8
Total @ Generation	0.0	0.0	82.3
Total Savings @ meter	*176.6*	*238.1*	*1028.5*
Total Savings @ Generation	**198.7**	**268.8**	**1158.6**

Savings included in Codes and Standards are expected to save 149.2 MW (winter), 100.2 MW (summer), and 784.6 GW.h by 2024/25, and are included in the Manitoba Load Forecast.

The capacity savings from the Curtailable Rates Program is not included in power resource plans since they may not be in place in the long term. The capacity savings from Bioenergy Optimization are not included in power resource plans since they may not be available during the time of the system peak. The capacities of these programs can be expected to be included in operating schedules since there is more knowledge about their availability in the operations timeframe.

These programs cover a wide group of customer classes, and savings are generally spread evenly throughout the day. Much of the program is based on reduced heating requirements. Therefore, the savings are assumed to vary seasonally, but to be constant throughout the various 5x16, 2x16 and 7x8 export time periods.

<u>PUB/MH II-82</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-87 (d) - 2008/09 Power Resource Plan Dependable Energy**

Please confirm that MH's dependable energy over the next eight years will be reduced by:

- **150 GWh (no Pointe du Bois upgrade).**
- **485 GWh (162 MW less wind).**

<u>ANSWER</u>:

The 150 GW.h of dependable energy from Pointe du Bois upgrade was not expected to be available until 2016/17 under assumptions in the 2008/09 power resource plan. The dependable energy in the next power resource plan will be reduced by 60 GW.h in 2016/17 and 150 GW.h in subsequent years.

Please refer to the response to CAC/MSOS/MH II-84(b) which describes the reduction in dependable energy for the St. Joseph wind farm when the size of the project is reduced from 300 MW to 138 MW. This response indicates that the updated estimate for wind energy in the dependable energy supply/demand tables will be 750 GW.h after consideration is given to avoided losses that are inherent in the load forecast. The dependable energy for wind energy in the 2008/09 power resource plan is 1229 GW.h, Consequently, the reduction in the dependable energy supply from a 162 MW reduction in wind generation will be 479 GW.h relative to the 2008/09 power resource plan.

PUB/MH II-83

Subject: **Tab 8: Energy Supply**

Reference: **PUB/MH I-88 (b) - 2008/09 Power Resource Plan Dependable Energy Reduction**

a) Please explain MH's rationale for making firm export contract commitments, which appear to rely on non-firm (opportunity) imports in order to fulfill a portion of the dependable supply obligations.

ANSWER:

Manitoba Hydro's long term supply plan includes imports as part of its dependable energy supply. These imports may already be covered by contracts and if not, there is an expectation that any amount not contracted for will be contracted for at an appropriate time. Manitoba Hydro's recent experience with extending the NSP sale agreements is an example of this practice.

PUB/MH II-83

Subject: **Tab 8: Energy Supply**

Reference: **PUB/MH I-88 (b) - 2008/09 Power Resource Plan Dependable Energy Reduction**

b) **Please confirm that in looking to augment domestic energy generation in drought years, MH is likely to be faced with high "locked in" import prices for energy requirements of 2,000 to 3,000 GWh (or more if thermal generation is uneconomic).**

ANSWER:

Manitoba Hydro does not expect to be faced with high "locked in" import prices for energy requirements of 2,000 to 3,000 GWh as the majority of this energy could be acquired during off-peak hours when marginal prices are set by efficient thermal units and low marginal cost renewable facilities (i.e. wind).

PUB/MH II-84

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-88(a), (c) - Dependable Imports**

a) Please explain how contracted (scheduled) imports can be considered dependable energy and yet allow MH to not purchase this energy under mean or better flow conditions.

ANSWER:

The contracted import energy is considered dependable as there is a commitment to deliver the energy to Manitoba Hydro when required by Manitoba Hydro. Through the agreement, the counterparty is obligated to make available a portion of their generation facilities when required by Manitoba Hydro. In mean or better flow conditions, the energy is not required by Manitoba Hydro and the contract does not require Manitoba Hydro to purchase it.

PUB/MH II-84

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-88(a), (c) - Dependable Imports**

b) Please explain how and when in a given (below mean) year, does MH determine the need to lock in the price and accept or decline delivery.

ANSWER:

Manitoba Hydro's need for imports is constantly being forecast through its supply planning process. The need will vary depending upon current and projected water conditions and firm load requirements. Manitoba Hydro has the option of meeting these import needs from the spot market, from the forward market or by exercising its contractual rights under long term contracts.

None of Manitoba Hydro's long term import contracts are at fixed prices with take or pay obligations. Given that and the flexible nature of Manitoba Hydro's hydraulic system, it is usually more financially advantageous to make hourly energy purchases than it is to lock into fixed blocks of purchased energy at fixed prices in the forward market.

However, there are times such as in extreme drought conditions, when it may be prudent to buy down an export obligation in advance which would require Manitoba Hydro to negotiate an offsetting block purchase at a fixed price.

In addition, there may be market conditions such as during severe drought when Manitoba Hydro may be exposed to significant price risk. In this case, Manitoba Hydro may deem it prudent to fix the price of some portion of its power purchases in order to hedge against this risk.

PUB/MH II-84

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-88(a), (c) - Dependable Imports**

c) Please explain why and at what price the counter party would guarantee supply to MH (if MH can decline delivery).

ANSWER:

The energy supply is available because through the agreement, the counterparty has reserved a portion of their dependable energy supply for Manitoba Hydro's use. Through other contractual provisions, the price for the energy may be set, capped or otherwise priced at market at the time of delivery.

PUB/MH II-84

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-88(a), (c) - Dependable Imports**

d) Does MH have the sole discretion under these contracts on selecting peak or off-peak delivery.

ANSWER:

Energy deliveries may be made in either off or on peak periods. Manitoba Hydro would generally schedule in off peak periods for price reasons but transmission limitations may require that deliveries occur in on peak hours as well. However, the energy made available under these contracts is energy that is surplus to the requirements of the supplying utility. If, in particular hours the supplying utility does not have a surplus, Manitoba Hydro may have to shift its energy purchases to other hours when a surplus is available.

PUB/MH II-85

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-80 (c) - Minimum Lake Winnipeg Levels**

a) **Please provide the increased 2003/04 hydraulic generation for Lake Winnipeg drawn down to:**

- **711.5.**
- **711.0.**

ANSWER:

As Manitoba Hydro was maintaining storages to protect against continued drought in 2004/05 any additional storage withdrawals from Lake Winnipeg would have been offset by storage increases in other reservoirs. As a result, there would not have been a net increase in hydraulic generation had Lake Winnipeg been drawn down any further than it actually was.

<u>PUB/MH II-85</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-80 (c) - Minimum Lake Winnipeg Levels**

b) Please indicate the 2003/04 Lake Winnipeg partial inflow/energy (cfs/GWh) and the 2003/04 Burntwood River inflow/energy (cfs/GWh).

<u>ANSWER</u>:

Manitoba Hydro does not understand the term "partial inflow/energy (cfs/GWh)." This is not a term generally used by Manitoba Hydro.

Please refer to PUB/MH II-133(b) for the general proportions of energy from flows by major basin.

PUB/MH II-86

Subject: Tab 8: Energy Supply
Reference: PUB/MH I-83 (c) - Energy Supply/Hydraulic Generation

Please provide a graphical illustration of the annual energy-in-storage and annual energy inflow relationship.

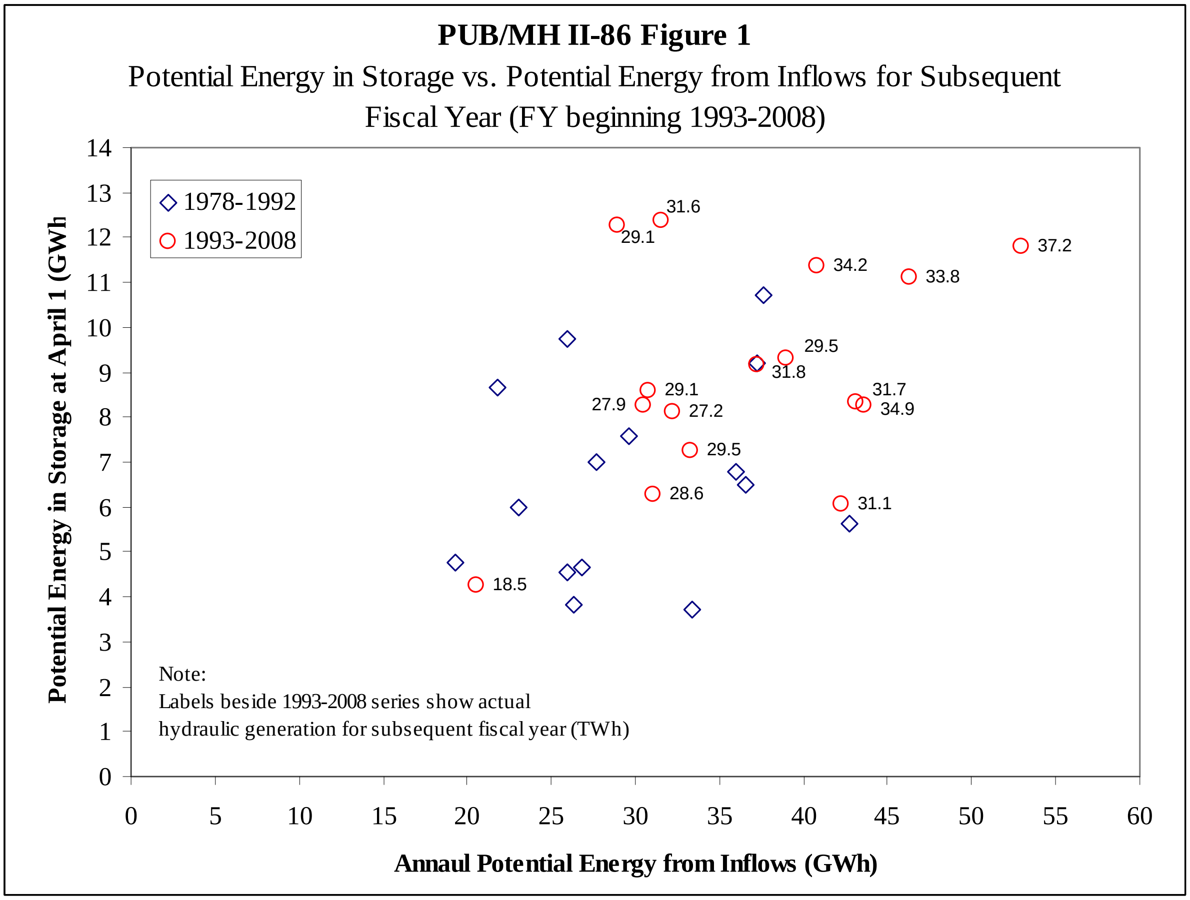
Energy in Storage at April 1 (GWh) (Y Axis)

- **33,000 (GWh) Hydraulic Generation**
- **29,000 (GWh) Hydraulic Generation**
- **25,000 (GWh)Hydraulic Generation**

Energy Inflow For Year GWh (X axis)

ANSWER:

Please refer to Figure 1 below. Note that actual hydraulic generation was provided for post-Limestone years. There is no well defined relationship between potential energy in storage on April 1 and the subsequent annual (fiscal year) energy from inflow. In general, higher energy in storage on April 1 combined with higher energy in inflows result in higher actual hydraulic generation, although the relationship is not obvious due to the many other factors impacting hydraulic generation operations including but not limited to: timing of inflows within the year, ice conditions, generation and HVdc outages, available export transmission capability, etc.


PUB/MH II-86 Figure 1
Potential Energy in Storage vs. Potential Energy from Inflows for Subsequent Fiscal Year (FY beginning 1993-2008)
1978-1992
1993-2008
Potential Energy in Storage at April 1 (GWh
Annaul Potential Energy from Inflows (GWh)
31.6
29.1
37.2
34.2
33.8
29.5
31.8
29.1
27.9
27.2
31.7
34.9
29.5
28.6
31.1
18.5
Note:
Labels beside 1993-2008 series show actual hydraulic generation for subsequent fiscal year (TWh)

PUB/MH II-87

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-84 (b) & (c) Legal Supply Obligation**

a) **Please explain how (what GWh supply level) MH determines that a supply contract can be voided on the basis of "Extreme Drought."**

ANSWER:

There is no specified "GWh supply level" that is relevant to the decision. To the extent that Manitoba Hydro is unable to supply its higher priority loads it has the right to curtail the export obligation, including for events of force majeure such as extreme drought.

Force majeure conditions are contemplated under the contract and are not a basis for defaulting on or "voiding" the contract.

PUB/MH II-87

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-84 (b) & (c) Legal Supply Obligation**

b) Please explain how the counter-party would know that MH's obligation was no longer valid.

ANSWER:

There are notification provisions within agreements which require Manitoba Hydro to notify the counter party that a force majeure event is in effect.

PUB/MH II-88

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-77 (d)**

Please fully described and detail the standard methodology of calculating inflows for available outflow and how such a methodology implicitly recognizes summer reductions of energy storage due to net evaporation losses.

ANSWER:

Manitoba Hydro monitors and measures outflows and the major inflows into its reservoirs. The reservoir elevations are continuously monitored as well. Reservoir storage quantity is a function of reservoir elevation where storage is calculated based on the reservoir area and shoreline topography.

A mass balance calculation using reservoir water level, outflow and measured inflow data is used to calculate the portion of the reservoir inflow that is not measured, called local inflow. The local inflow consists of ungauged reservoir inflow (i.e. not measured) as well as direct precipitation on the reservoir and is net of evaporation losses.

The simple mass balance formula for local inflow during a given period of time is as follows:

$$LI = (S_{t = n+1} - S_{t = n}) / \Delta t + O - GI$$

Where

LI	is local inflow during a period (*e.g.* a day)
$S_{t = n+1}$	is the storage quantity of the reservoir at Time n (calculated using elevation-storage function)
$S_{t = n}$	is the storage quantity of the reservoir at Time n
Δt	is the duration of the period between Time n Time $n + 1$
GI	is the gauged or measured inflow during the period n to $n + 1$
O	is the measured outflow during the period

The local (LI) in the above calculation includes the net effect of direct precipitation and evaporation from the reservoir.

PUB/MH II-89

Subject: Tab 8: Energy Supply
Reference: PUB/MH I-79 (b)

Please explain and illustrate by specific examples how spring flow conditions in its various watersheds are utilized in the determination of available outflow.

ANSWER:

Reservoir storage and inflow conditions are evaluated on a weekly basis by monitoring reservoir levels, gauged tributary flows, controlled outflows, and calculated local inflows in the Manitoba Hydro system. During the spring, flood and runoff forecasts issued by Water Stewardship are incorporated into the water supply forecast. Reservoir outflows are scheduled recognizing both expected and worst case water supply forecasts, load demands in Manitoba, export obligations, market prices in the export market and many other factors. Under a worst case analysis, if reservoir releases need to be constrained to maintain supply security for Manitoba load, this release schedule governs.

PUB/MH II-90

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-60 Bipole III, 2007/12/07 PUB/MH I-4 (f)**

a) Please confirm that Bipole III costs have evolved as follows:

	East Side	**West Side**	**Potential West Side**	**Updated Alternative**
Line Length	**885 km**	**1,341 km**	**1,375 km**	**1,670 km**
Line Cost	**$671 M**	**$1,081 M**	**$1,108 M**	**$1,352 M**
Cost/km	**$0.76/M**	**$0.81/km**	**$0.81/M**	**$0.81/M**
Capital Cost Increment	**0**	**$410 M**	**$437 M**	**$681 M**
Converter Costs - Unchanged at $1,166 M				
Line Losses 40-Year PV - $181 M				

ANSWER:

The costs for the East side and the West side above are consistent with Manitoba Hydro estimates. Manitoba Hydro has not identified a Potential West Side and an Updated Alternative or provided costs for such options and is therefore unable to confirm the data contained in the table.

<u>PUB/MH II-90</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-60 Bipole III, 2007/12/07 PUB/MH I-4 (f)**

b) **Please provide the anticipated annual interest/depreciation/OM&A costs associated with Bipole III after in-service.**

<u>ANSWER</u>:

Please see the attached schedule.

BIPOLE III
COMPONENTS INCLUDED IN 20 YEAR OUTLOOK
(In Millions of Dollars)

For the year ended March 31

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Operating and Administrative	-	-	-	-	-	-	-	-	13	13	13
Finance Expense	-	-	-	-	-	-	-	-	2	158	153
Depreciation and Amortization	-	-	-	-	-	-	-	-	19	46	46

BIPOLE III
COMPONENTS INCLUDED IN 20 YEAR OUTLOOK
(In Millions of Dollars)

For the year ended March 31

	2021	2022	2023	2024	2025	2026	2027	2028	2029
Operating and Administrative	13	14	14	14	14	15	15	15	16
Finance Expense	149	145	140	136	132	129	125	122	118
Depreciation and Amortization	46	46	46	46	46	46	46	46	46

<u>PUB/MH II-90</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-60 Bipole III, 2007/12/07 PUB/MH I-4 (f)**

c) Please confirm that Bipole III is typically expected to function at the 2,000 MW level and after 2024, transmit about 1,200 GWh of energy/month on average or up to about 1,500 GWh/month (maximum).

<u>ANSWER</u>:

Bipole III is to be rated to allow a 2000 MW power level leaving the northern converter.

Theoretically, in a 31 day month, up to 1,488 GW.h of energy (before consideration of losses) could be transmitted with 2,000 MW of transfer capability, assuming continuous loading to the maximum transfer capability for the entire period. Such continuous loading to the maximum transfer capability is not the normal operating practice, does not allow for following the Manitoba load shape and does not allow for any maintenance work.

The energy transmitted per month on average is estimated to be about 1000 GW.h after 2024 with Keeyask and Conawapa in service.

PUB/MH II-90

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-60 Bipole III, 2007/12/07 PUB/MH I-4 (f)**

d) **Please confirm that the East Side alternative would have had similar loads, but in the event of Bipole I and II failure could operate at a 3,000 MW level and transmit up to about 2,200 GWh of energy/month.**

ANSWER:

The East Side Bipole III alternative would have had converters rated at 2,000 MW which is the same as the West Side Bipole III. However, in the event of an Interlake corridor loss, the East Side Bipole III alternative would be technically capable of paralleling operation at a 3,000 MW level - a capability the West Side Bipole III will not have.

Paralleling is the ability to place more than one set of converters on a single transmission line, greatly increasing the capacity of the line. The East Side Bipole III alternative is technically capable of being used for paralleling because its length is similar to that of the existing Bipole I and II lines. The West Side Bipole III can not have paralleling capability for technical reasons, and the new Bipole III converters will be specifically designed to work with the western routed line. Consequently, with an Interlake corridor loss, the transmission capacity for the West Side Bipole III is equal to that of the Bipole III converters or 2000 MW.

If in the event of loss of the Interlake corridor due to failure of Bipole I and II transmission lines, an East Side Bipole III paralleled with Bipole I and II converters could transfer up about 3000 MW of power south, assuming the necessary converter equipment would be available.

Theoretically, in a 31 day month, up to about 2,230 GWh of energy (before consideration of losses) could be transmitted with 3,000 MW of transfer capability, assuming continuous loading to the maximum transfer capability for the entire period. Such continuous loading to the maximum transfer capability is not the normal operating practice, does not allow for following the Manitoba load shape and does not allow for any maintenance work. The paralleling mode would only be used for minimum periods during unusual operating situations when the only other alternative would be to shed load.

PUB/MH II-91

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-14 (f) HVDC Functional Usage**

a) **Please confirm or amend (and explain) the following estimates of typical or average functional usage of the HVDC system.**

Bipoles I and II						
Serve G.S.@	**MW**	**Dependable (GWh)**	**Median (GWh)**	**Maximum (GWh)**	**Maximum HVDC Output**	
Kettle	**1,220**	**4,750**	**7,010**	**8,960**	**|- Bipole I**	**13,300 GWh**
Long Spruce	**1,010**	**3,890**	**5,970**	**7,830**	**|**	
Limestone	**1,340**	**5,140**	**7,500**	**9,900**	**|- Bipole II**	**13,400 GWh**
Totals	**3,570**	**13,780**	**20,480**	**26,690**		**26,700 GWh**

After Bipole III						
Serve G.S. @	**MW**	**Dependable (GWh)**	**Median (GWh)**	**Maximum (GWh)**	**Maximum HVDC Output**	
Keeyask	**600**	**2,880**	**4,480**	**4,740**	**|- Bipole I**	**13,700 GWh**
Kettle	**1,220**	**4,750**	**7,010**	**8,960**		
Long Spruce	**1,010**	**3,890**	**5,970**	**7,830**	**|- Bipole II**	**13,700 GWh**
Limestone	**1,340**	**5,140**	**7,500**	**9,900**	**|**	
Conawapa	**1,300**	**4,600**	**7,050**	**9,760**	**|- Bipole III**	**13,800 GWh**
Totals	**5,270**	**21,260**	**32,010**	**41,190**		**41,200 GWh**

ANSWER:

The capacity and energy available from Limestone will be reduced when Conawapa is constructed, as Conawapa forebay will raise the water level at Limestone tailrace. Normally the reduction at Limestone is reflected in the capacity of Conawapa as “Net Addition”.

The maximum energy capability of the Bipoles is estimated assuming that 500 MW is reserved as spare transmission, shared between the available bipoles. The maximum energy transfer capability of the Bipoles is calculated by adjusting the Bipoles for the prorated share of the 500 MW reserve, and fully loading the adjusted Bipoles for all hours of the year.

The capacities quoted reflect maximum capability in January, without reserves.

The capability of generating stations that was used in preparing the 2009/10 power resource plan is as follows:

Generating Station.	MW	Dependable (GWh)	Median (GWh)	Maximum (GWh)	Maximum HVDC Output		
Kettle	1,220	5,180	7,130	8,770	Bipole I	14,150 GWh	1,854 MW
Long Spruce	1,007	4,240	6,080	7,665	Bipole II	15,250 GWh	2,000 MW
Limestone	1,335	5,610	7,630	9,695			
Totals	3,562	15,030	20,840	26,130		29,400 GWh	3,854 MW

Generating Station	MW	Dependable (GWh)	Median (GWh)	Maximum (GWh)	Maximum HVDC Output		
Keeyask	630	2,900	4,360	5,260	Bipole I	14,900 GWh	1,854 MW
Kettle	1,220	5,180	7,130	8,770	Bipole II	16,000 GWh	2,000 MW
Long Spruce	1,007	4,240	6,080	7,665	Bipole III	16,000 GWh	2,000 MW
Limestone	1,335	5,610	7,630	9,695			
Conawapa*	1,300	4,550	7,820	10,740			
Totals	5,492	22,480	33,020	42,130		46,900 GWh	5,854 MW

*Conawapa values are the “net addition”. Conawapa Generation is adjusted to reflect the losses at Limestone.

PUB/MH II-92

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-98 (d)**

a) **Please elaborate on what is meant by mandatory GHG systems and the impact of such a system on MH?**

ANSWER:

A mandatory GHG system would be a government regulated system to reduce GHG emissions. If such mandatory systems are put in place in both Canada and the US, it is expected that the cost of fossil fuelled generation would increase. This would increase the cost of Manitoba Hydro's thermal generation. It is also expected that market prices for electricity would increase in Manitoba Hydro's export markets. This would result in increasing the value of hydropower generation.

PUB/MH II-92

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-98 (d)

b) Please discuss the future of the CCX in light of the view that CFI's are ineligible under a mandatory GHG system.

ANSWER:

The CCX's voluntary GHG emission reduction system was established for companies desiring to demonstrate early action through formally reporting GHG emissions and committing to GHG emission reductions. Most participants and the exchange itself would likely prefer that any mandatory system would reward this early action by recognizing the CFI units. However, even in the absence of this, members may still see benefits in continuing to participate until such time as a mandatory system is in place. The CCX as an exchange has interests beyond it voluntary program and presumably will continue to position itself as a trading exchange for other environmental commodities and derivatives (including any future units that may be defined under a mandatory GHG program).

PUB/MH II-92

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-98 (d)

c) Please indicate the cost of MH's participation in the CCX for 2009/10 and 2010/11.

ANSWER:

Manitoba Hydro's annual fee for participation in the CCX in 2009 and 2010 was $20,000 per year.

PUB/MH II-93

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-100 (b)

Please confirm the displacement factor used to determine the GHG savings from the energy savings as the tables reflect a range of displacement factors from 968 to 1234 tonnes CO2/GWh. These factors do not correspond with the factor listed in PUB/MH I-122 (a) of 750 tonnes CO2/GWh.

ANSWER:

The energy savings shown in PUB/MH I-100(b) are the planned savings for efficiency efforts excluding energy savings from codes and standards as measured at the customer meter. The following table shows the planned energy savings as measured at the point of generation.

GW.h SAVINGS

Class/Sub-Class	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Residential	86	180	262	279	295	255	212	175	178	178
GS Small (Non-Demand)	22	45	62	77	90	100	110	120	131	141
GS Small (Demand)	19	42	58	73	86	97	109	122	135	147
GS Medium	41	72	97	124	147	165	169	189	207	226
GS Large <30 kV	28	43	57	76	92	105	103	115	126	137
GS Large 30-100 kV	5	8	10	13	15	17	15	17	18	19
GS Large >100 kV	42	50	60	78	93	104	80	88	94	101
Total	**244**	**440**	**606**	**719**	**818**	**842**	**798**	**826**	**890**	**949**

To determine the GHG reductions by customer class, the GW.h savings at the point of generation is first multiplied by 0.9 to adjust for the southern bus and then it is multiplied by 750 tonnes of CO2e per GW.h.

The breakdown of GHG savings into customer class shown in PUB/MH I-100(b) was incorrect as it allocated the total GHG savings including those from codes and standards into customer class based on the GW.h distribution at the customer meter shown in PUB/MH I-100(b).

The following table outlines the GHG savings by customer class excluding those achieved through codes and standards.

GHG SAVINGS (thousands of tonnes)

Class/Sub-Class	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Residential	58	122	177	188	199	172	143	118	120	120
GS Small (Non-Demand)	15	30	42	52	61	67	74	81	88	95
GS Small (Demand)	13	28	39	49	58	66	74	82	91	99
GS Medium	28	49	65	84	99	112	114	128	140	152
GS Large <30 kV	19	29	39	51	62	71	70	78	85	93
GS Large 30-100 kV	4	5	7	9	10	11	10	11	12	13
GS Large >100 kV	28	34	40	52	63	70	54	59	64	68
Total	**164**	**297**	**409**	**485**	**552**	**569**	**539**	**557**	**601**	**640**

PUB/MH II-94

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-100 (b) , PUB/MH I-107a) DSM Savings**

Please explain why the Residential DSM GWh, MW, and GHG savings are expected to peak in 2014/15 and decline thereafter. To what extent are these changes related to anticipated federal lighting efficiency regulation to take effect in 2012.

ANSWER:

The Residential DSM GWh, MW and GHG savings are expected to peak in 2013/14 and decline thereafter. Energy savings are no longer claimable as a result of the federal lighting efficiency regulation coming into effect.

PUB/MH II-95

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-103 (b) Codes and Standards.**

Please indicate the technologies being tracked under Codes and Standards and the level of savings associated with each technology. For the technology providing the largest savings please provide the calculations for the determination of the Electric Demand Savings and Average Winter Demand Savings for 2007/08 and 2008/09.

ANSWER:

The following tables provide the technologies tracked under Codes and Standards and the energy savings associated with each technology. The Codes and Standards energy savings for ovens and freezers are negative values which was due to an inappropriate calculation of energy savings. The analysis compared the per unit energy savings between the energy consumption of a smaller inefficient model and a larger but more efficient model. These energy savings will be revised and updated in the 2009/10 Power Smart Annual Review.

Energy Savings (GW.h)	07/08	08/09
Appliances:		
Ovens	-0.2	-0.2
Dishwashers	3.4	3.5
Clothes Washers	3.6	3.8
Clothes Dryers	0.9	0.9
Refrigerators	16.2	17.1
Freezers	-0.7	-0.8
New Homes	1.3	1.5
T12 Lighting	0.3	0.3
Total Energy Savings	**24.8**	**26.1**

Demand Savings (MW) - Winter On-Peak	07/08	08/09
Appliances:		
Ovens	0.0	0.0
Dishwashers	0.8	0.9
Clothes Washers	0.9	0.9
Clothes Dryers	0.2	0.2
Refrigerators	4.0	4.2
Freezers	-0.2	-0.2
New Homes	0.5	0.5
T12 Lighting	0.1	0.1
Total Demand Savings	**6.2**	**6.5**

The following calculations outline the energy and demand savings associated with refrigerators for 2007/08 and 2008/09.

2007/08 Energy and Demand Savings Calculations

Average kW.h Consumption

Appliance	**1991 Average**	**2007 Average**	**New Appliance Sales Estimates**
Refrigerators	970.49	449.36	31,149

Energy Savings: = (kW.h 1991 - kW.h 2007) x sales
= (970.49 - 449.36) x 31,149
= 16,232,577.34 kW.h

Demand Savings: kW avg 2007 = (kWh 1991 - kWh 2007) / [(%winter on peak + %winter off peak) x 8,760]
= (970.49 - 449.36)/[(0.267 + 0.185) x 8,760]
= 0.1316 kW

= kW avg 2007 / [(winter AM Load Factor + winter PM Load Factor)/2] x sales
= 0.1316/[(1.09 + 0.98)/2] x 31,149
= 3,961.00 kW

2008/09 Energy and Demand Savings Calculations

Average kW.h Consumption

Appliance	**1991 Average**	**2007 Average***	**New Appliance Sales Estimates**
Refrigerators	970.49	449.36	32,752

Energy Savings: = (kW.h 1991 - kW.h 2008) x sales
= (970.49 - 449.36) x 32,752
= 17,067,938.99 kW.h

Demand Savings: kW avg 2008 = (kWh 1991 - kWh 2008) / [(%winter on peak + %winter off peak) x 8,760]
= (970.49 - 449.36)/[(0.267 + 0.185) x 8,760]
= 0.1316 kW

= kW avg 2008 / [(winter AM Load Factor + winter PM Load Factor)/2] x sales
= 0.1316/[(1.09 + 0.98)/2] x 32,752
= 4,164.84 kW

*Consumption averages are assumed to stay fairly constant and thus are not updated every year.
Note: numbers may not be exact due to rounding.

PUB/MH II-96

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-107 (a)**

Please describe the pending federal lighting efficiency regulations and their impact on the Corporations lighting DSM programs and recorded DSM savings.

ANSWER:

Amendment 10 to the Energy Efficiency Regulations was published on December 24, 2008. The amendment outlines Minimum Energy Performance Standards (MEPS) for general service lamps and applies to products manufactured as follows:

- 75 to 100 watt equivalent lamps, effective January 1, 2012
- 40 to 60 watt equivalent lamps, effective December 31, 2012

The following table compares the forecast energy savings (GW.h) resulting from the Residential Compact Fluorescent Lighting (CFL) Program and based on the 2008 and the 2009 Power Smart Plans.

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
2008 Plan	12.6	22.0	28.0	31.4	34.3	22.9	13.6	7.5	4.1	1.2	0.0	0.0	0.0	0.0	0.0
2009 Plan	44.4	90.2	130.6	130.6	130.6	86.3	40.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

The 2009 Power Smart Plan took the upcoming regulation into account when forecasting energy savings. While the length of time that the energy savings are claimed is reduced as a result of the regulation, the total energy savings are significantly higher in the 2009 Plan as a result of changes to the program design. It was anticipated that more CFLs will be rebated through an instant rebate strategy which was included in the 2009 program design versus the mail-in rebate strategy included in the 2008 program design.

Projected savings also extend two years past the effective dates for the MEPS to reflect continuing energy savings from units purchased prior to the effective date and to provide a short lag time for remaining retailer inventories of incandescent lamps within the Province to be sold and the life of purchased lights.

The following table compares the energy savings (GW.h) resulting from the Energy Efficient Light Fixtures Program and based on the 2008 and the 2009 Power Smart Plans.

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
2008 Plan	1.9	4.0	6.2	6.5	6.8	7.2	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
2009 Plan	0.6	1.5	3.1	3.1	3.1	3.1	3.1	3.1	2.6	2.0	0.9	0.9	0.9	0.9	0.9

The Energy Efficient Light Fixtures program promotes many types of fixtures including products that will be impacted by the MEPS. Again, the energy savings in the 2009 Power Smart Plan were revised to take into account the MEPS for general service lamps. In addition, the energy savings period for CFL light fixture products was lowered from 20 years (the life of the light fixture) to 8 years, when it was estimated that inefficient light bulbs would no longer be sold and replacement bulbs for the fixture could only be energy efficient products. These changes resulted in a significant decrease in forecast energy savings that would achieved through CFL light fixtures.

Energy savings resulting from the MEPS were not included in any of Manitoba Hydro's previous Power Smart Plans, however an estimate of the codes and standards energy savings resulting from these regulations is being estimated and these energy savings will be included in the 2010 Power Smart Plan as energy savings achieved through codes and standards.

<u>PUB/MH II-97</u>

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-108 (a)**

a) **Please explain why the Total Resource Cost (TRC) for the Internal Retrofit program decreased in 2009, as the response to PUB/MH I-108 states that incentives for the Downtown Office increased, but customer incentive costs do not factor into the TRC test.**

<u>ANSWER</u>:

The incremental cost of energy efficient measures is included within the TRC calculation and therefore any changes in this cost will impact on the TRC metric. Incentives provided to customers do not factor into the TRC calculation.

For the 2008 Power Smart Plan, the incremental product costs and the amounts paid as incentives were incorrect. The 2009 Power Smart Plan includes the correct values.

PUB/MH II-97

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-108 (a)**

b) Regarding the Internal Retrofit measure, please explain why MH increased incentives for its own Downtown Office Project.

ANSWER:

Total incentives paid towards the Downtown Office Project did not increase from the 2008 to the 2009 Power Smart Plan. Please see Manitoba Hydro's response to PUB/MH II-97(a).

PUB/MH II-97

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-108 (a)

c) Please compare the energy consumption of MH's office space for the previous 3 years with that of 2009/10.

ANSWER:

The sample listing below includes energy consumption for major Manitoba Hydro office buildings for the past 3 years compared with 2009/10. Buildings leased and occupied by multiple tenants, multi-use facilities that include attached garages, workshops and/or warehouses, and buildings where consumption data is not available, have not been included in the analysis.

Location	Electric (kWh)				Gas (m^3)			
	2009/10	2008/09	2007/08	2006/07	2009/10	2008/09	2007/08	2006/07
Winnipeg								
1315 Notre Dame	2,783,035	2,792,103	2,703,873	2,721,443				
% change compared to '09/10		0.3%	-3%	-2%				
2160 McPhillips	308,760	329,160	321,240	321,840				
% change compared to '09/10		7%	4%	4%				
450 Pandora	266,880	305,200	307,200	240,080	4,894	4,530	5,434	4,278
% change compared to '09/10		14%	15%	-10%		-7%	11%	-13%
375 Dawson Rd.	491,980	541,100	557,200	510,760				
% change compared to '09/10		10%	13%	4%				
35 Sutherland	1,671,840	1,718,880	1,775,040	1,710,720	258,540	354,570	426,150	602,650
% change compared to '09/10		3%	6%	2%		37%	65%	133%
400 Dovercourt	697,200	701,040	767,280	784,080	52,322	39,029	37,596	30,519
% change compared to '09/10		1%	10%	12%		-25%	-28%	-42%
820 Taylor Ave.	8,875,200	9,400,500	9,655,500	9,328,800				
% change compared to '09/10		6%	9%	5%				

Brandon								
235 10th Street	891,360	1,101,960	1,042,400	945,360				
% change compared to '09/10		24%	17%	6%				

Selkirk								
177 Main St.	1,019,020	1,048,310	888,780	775,910				
% change compared to '09/10		3%	-13%	-24%				

Thompson								
16 Station Rd.	313,728	336,048	347,328	270,768				
% change compared to '09/10		7%	11%	-14%				

PUB/MH II-98

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-110 (c) DSM LIEEP**

Please provide a comparison of the actual participation for 2009/10 with the forecasted participation for electric homes and explain any differences.

ANSWER:

The forecast and actual participation for 2009/10 is provided in the following table.

Category	Forecasted Participation 2009-10				Actual Participation 2009-10			
	Gas	Electric	Other	Total	Gas	Electric	Other	Total
Homeowner	1,128	608	119	1,855	357	23	3	383
Tenant	513	196	55	764	233	96	-	329
Total	1,641	804	174	2,619	590	119	3	712

The actual participation was lower than forecast due to varying factors including the underestimate of time required to establish the infrastructure (e.g. agreements with contractors, internal processes, etc.) required to implement the program and the underestimate of time required to deal with competing demands placed on staff dedicated to the lower income program.

PUB/MH II-99

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-110 (d)**

Please explain why there is a significant difference between the average per home spent for Manitoba Housing Authority units between the BUILD and BEEP

ANSWER:

The first pilot for the Lower Income Energy Efficiency Program was undertaken with BUILD. The administration associated with the start up of this program was much larger with BUILD than it was with BEEP due to various start up issues associated with establishing processes. When the BEEP pilot was launched, many of the learnings from the initial pilot involving BUILD had taken place and the program was modified to reflect efficiencies and effectiveness.

PUB/MH II-100

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-110 (f), PUB/MH I-218**

a) **Please elaborate on the options being assessed for allowing private landlords to participate in the LIEEP , and file a summary of the assessment.**

ANSWER:

Progress in assessing options for allowing private landlords to participate in the LIEEP has been delayed due to competing priorities placed on staff working on the lower income program. As such, an assessment of the options is currently not available.

In development of the program, several considerations need to be addressed, including:

a. Ensuring that the resulting up-grades do not result in increased rents for the tenants;
b. Ensuring that low income tenants benefit from the investment both in the short and long term;
c. Ensuring that the tenant is not at risk of eviction upon completion of the up-grades; and
d. Ensuring that the low income tenants benefit from the up-grade and that there is some requirement of repayment should the landlord sell the residence upon completion of the retro-fit or within a reasonable period thereafter. In addition, conditions will need to be put in place should the residence "turn-over" result in a non-low income family or individual becoming the tenant.

PUB/MH II-100

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-110 (f), PUB/MH I-218**

b) **It appears that the landlord program is to be launched in the summer of 2010. If so, please provide details of the landlord program when available.**

ANSWER:

Details of the landlord program will be provided when they become available.

PUB/MH II-101

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-110 (d) LIEEP Funding**

Please confirm whether there are any Power Smart funds set-aside exclusively for the LIEEP. If not, does the LIEEP leverage funding from existing Power Smart programs and combine this with other funding, for example from the AEF? Please confirm all the sources of funding that the LIEEP leverages (AEF, Natural Gas Furnace Replacement Program, Power Smart, etc.)

ANSWER:

Manitoba Hydro leverages funding from existing Power Smart Programs, the Affordable Energy Fund and PUB-directed funding for furnace replacements. Specific funds have been allocated within the Affordable Energy Fund and through Power Smart based on projected participation in the Lower Income program. In addition, Manitoba Hydro also leverages funding through the ecoENERGY program where customers have qualified for the rebates, subject to the cancellation provisions of this program.

The community program delivered by BUILD and BEEP leverages funding from Manitoba Hydro's LIEEP program as well as provincial government funding.

PUB/MH II-102

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-110 (e)**

Please file a representative example of a Community Energy Efficiency Business Plan.

ANSWER:

Each community Energy Efficiency Business Plan is unique to the organization and hence there is no pre-established template. The Business Plans for those community groups participating in the program are the property of the community group and as such, Manitoba Hydro does not have a representative example of a Community Energy Efficiency Business Plan which could be filed.

PUB/MH II-103

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-111 (a)**

With respect to LIEEP electric households Please provide an updated table including all households where spending had been incurred including Island Lake participation when available

ANSWER:

LIEEP Electric Spending			
Category	**2005-06**		
	PS	**Bill 11**	**Total**
Community	$ -	$ -	$ -
Individual	$ -	$ -	$ -
First Nations	$ 5,000	$ -	$ 5,000
Total 2005-06	**$ 5,000**	**$ -**	**$ 5,000**
Category	**2006-07**		
	PS	**Bill 11**	**Total**
Community	$ 38,453	$ 61,067	$ 99,520
Individual	$ 58,523	$ -	$ 58,523
First Nations	$ 12,897	$ 161,622	$ 174,519
Total 2006-07	**$ 109,873**	**$ 222,690**	**$ 332,563**
Category	**2007-08**		
	PS	**Bill 11**	**Total**
Community	$ 158,947	$ 177,922	$ 336,869
Individual	$ 62,705	$ 7,811	$ 70,516
First Nations	$ 2,107	$ (18,217)	$ (16,110)
Total 2007-08	**$ 223,758**	**$ 167,517**	**$ 391,275**

Category	2008-09		
	PS	**Bill 11**	**Total**
Community	$ 110,231	$ 148,379	$ 258,610
Individual	$ 93,345	$ 245,790	$ 339,134
First Nations	$ 5,834	$ 35,289	$ 41,124
Total 2008-09	**$ 209,410**	**$ 429,458**	**$ 638,868**
Category	**2009-10**		
	PS	**Bill 11**	**Total**
Community	$ 20,337	$ 57,094	$ 77,431
Individual	$ 51,827	$ 199,038	$ 250,865
First Nations	$ 38,840	$ 174,859	$ 213,699
Total 2009-10	**$ 111,004**	**$ 430,992**	**$ 541,996**
Category	**TOTAL SPENDING FROM 2005-06 TO 2009-10**		
	PS	**Bill 11**	**Total**
Community	$ 327,968	$ 444,462	$ 772,430
Individual	$ 266,400	$ 452,639	$ 719,039
First Nations	$ 64,678	$ 353,555	$ 418,232
Grand Total All	**$ 659,045**	**$ 1,250,656**	**$ 1,909,702**

Notes:

1. Cost includes all work undertaken during the fiscal year. Participants noted below are only those that have all LIEEP program recommendations completed and a "post-retrofit E" ecoENERGY evaluations performed. In many homes some upgrades were performed, but not all work was completed.
2. The negative amount shown for 2007/08 is due to costs being reconciled related to recorded costs in the previous year being too high.

The following table provides the participation for electric heated homes in the Lower Income Energy Efficiency Program. Participation is defined as those homes that have completed all the LIEEP program recommendations and completed an ecoENERGY E evaluation (or comparable verification).

Category	Participants for Electric Heated Homes				
	2006-07 Total	2007-08 Total	2008-09 Total	2009-10 Total	2006-07 to 2008-09 TOTAL
Community	27	84	95	93	**206**
Individual	0	0	2	18	**2**
First Nations[1]	0	0	0	30	**0**
Grand Total All	**27**	**84**	**97**	**141**	**208**

NOTES:

1. There were 101 homes retrofitted in Island Lake however these homes haven't been recorded yet as the verification has not been undertaken yet.

PUB/MH II-104

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-111 (b)

a) **Please provide a comparison of the actual 2009/10 spending with the forecasted 2009/10 spending for Electric LIEEP by measure and explain major differences.**

ANSWER:

The following table provides the 2009/10 spending and a comparison to the 2009/10 budget. The variance is primarily due to the over estimate on participation. The budget amount for Basic Energy Efficiency Items was also corrected. In Manitoba Hydro's response to PUB/MH I-111(b), the amount of $14,148 was incorrectly entered into the table as the amount is $13,208.

LIEEP Actual Spend vs Budget - Electric				
SPENDING BY MEASURE	**ELECTRIC BUDGET**	**ELECTRIC ACTUAL SPEND**		**VARIANCE ACTUAL VS BUDGET**
		2009/10		
Participation	**803**	**141**		**662**
Power Smart				
Basic Energy Efficiency Items & Draft Proofing	$ 13,208	$ 3,378		$ 9,830
Insulation - Attic	$ 222,694	$ 37,090		$ 185,604
Insulation - Basement/Crawl	$ 99,713	$ 16,181		$ 83,532
Insulation - Wall	$ 143,898	$ 2,594		$ 141,304
Fridges/Furnace& Boiler	$ -	$ -		$ -
Total Incentives	**$ 479,512**	**$ 59,242**		$ 420,270
Total Administration	**$ 170,453**	**$ 51,762**		$ 118,691
				$ -
Total Power Smart Electric	**$ 649,965**	**$ 111,004**		**$ 538,961**

SPENDING BY MEASURE	ELECTRIC BUDGET	ELECTRIC ACTUAL SPEND		
Participation	**803**	**141**		**662**
AEF				
Basic Energy Efficiency Items & Draft Proofing	$ 187,158	$ 7,830		$ 179,329
Insulation - Attic	$ 153,544	$ 3,367		$ 150,177
Insulation - Basement/Crawl	$ 1,322,788	$ 86,947		$ 1,235,841
Insulation - Wall	$ 192,482	$ 3,795		$ 188,688
Fridges	$ 467,611	$ -		$ 467,611
Total Incentives	**$ 2,323,584**	**$ 101,938**		$ 2,221,645
Total Administration	$ 892,272	$ 329,054		$ 563,218
Total AEF Electric	**$ 3,215,856**	**$ 430,992**		**$ 2,784,864**
	$ -			**$ -**
Grand Total PS and AEF Electric	**$ 3,865,821**	**$ 541,996**		**$ 3,323,824**

PUB/MH II-104

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-111 (b)

b) Please provide a detailed breakdown, including overheads, of the forecasted administration costs for the LIEEP for 2009/10, 2010/11 and 2011/12 that are funded by Power Smart and by the AEF.

ANSWER:

Forecast Budget

Spending by Measure	**Electric Costs**	**Electric Costs**	**Electric Costs**
	2009/10	**20010/11**	**Total**
Power Smart			
Administration:			
ecoENERGY Audit	$ 80,300	$ 96,300	**$ 176,600**
Labour	$ 57,700	$ 52,200	**$ 109,900**
Overhead	$ 15,600	$ 14,100	**$ 29,700**
Other *	$ 16,900	$ 15,200	**$ 32,100**
Total Administration	**$ 170,500**	**$ 177,800**	**$ 348,300**
AEF			
Administration:			
ecoENERGY Audit	$ 185,300	$ 209,200	**$ 394,500**
Labour	$ 238,100	$ 219,500	**$ 457,600**
Overhead	$ 64,400	$ 59,300	**$ 123,700**
Other *	$ 404,500	$ 404,300	**$ 808,800**
Total Administration	**$ 892,300**	**$ 892,300**	**$ 1,784,600**

* includes contingency, outreach & support costs, marketing and training

<u>PUB/MH II-104</u>

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-111 (b)

c) Please explain why basements and crawlspaces comprise 80% of the insulation funding from the AEF, yet basements and crawlspaces only comprise 22% of the insulation funding from Power Smart.

<u>ANSWER</u>:

Funding provided through Power Smart is based on what funding would be provided through existing programs and programs which all customers have access. The funding provided through the Affordable Energy Fund is incremental to this amount and was determined through the design process for the Lower Income Energy Efficiency program.

PUB/MH II-105

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-112 (a) & (b) Low Income Households**

a) **Please provide tables based on the new demographic information which indicates the number of qualified households (LICO) by household size and rural and urban community by size.**

ANSWER:

The following table provides the estimated number of LICO customers.

LICO						
		Urban				
	Rural	**Less than 30,000**	**Between 30,000 - 99,999**	**Between 100,000 - 499,999**	**500,000 + over**	**Total**
1 person	11,424	3,148	982	0	21,058	36,612
2	2,776	2,155	808	0	15,444	21,183
3	1,179	78	348	0	4,622	6,227
4	976	387	268	0	4,338	5,969
5	908	224	40	0	1,712	2,884
6	256	0	0	0	465	721
7 or more	1,047	0	0	0	295	1,342
Total	18,566	5,992	2,446	0	47,934	74,938

PUB/MH II-105

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-112 (a) & (b) Low Income Households

b) Please provide a similar table in (a) for LICO 125%.

ANSWER:

The following table provides the estimated number of LICO-125 customers.

LICO-125						
	Rural	Urban				Total
		Less than 30,000	Between 30,000 - 99,999	Between 100,000 - 499,999	500,000 + over	
1 person	11,424	4,904	1,295	0	25,738	43,361
2	8,743	3,932	1,974	0	22,392	37,041
3	1,556	671	348	0	7,914	10,489
4	1,450	927	346	0	5,256	7,979
5	1,041	329	98	0	2,485	3,953
6	541	0	143	0	754	1,438
7 or more	1,047	0	0	0	476	1,523
Total	25,802	10,763	4,204	0	65,015	105,784

PUB/MH II-106

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-113 (a) AEF

a) **Please provide a detailed breakdown by initiative (similar to the response to PUB/MH 111(b)) of the forecast $8.5 Million spending in 2009/10 and $9.0 million in 2010/11 on the Lower Income Program from the AEF including administrative, energy audits and other (for both natural gas and electric operations)**

ANSWER:

Forecast Budget

Spending by Measure	Electric Costs	Electric Costs	Electric Costs
	2009/10	20010/11	Total
AEF			
Incentives:			
Basic Energy Efficiency Items & Draft Proofing	$ 187,200	$ 208,800	$ 396,000
Insulation - Attic	$ 153,500	$ 173,600	$ 327,100
Insulation - Basement/Crawl	$ 1,322,800	$ 1,515,600	$ 2,838,400
Insulation - Wall	$ 192,500	$ 210,400	$ 402,900
Fridges	$ 467,600	$ 494,100	$ 961,700
Total Incentives	**$ 2,323,600**	**$ 2,602,500**	**$ 4,926,100**
Administration:			
ecoENERGY Audit	$ 185,300	$ 209,200	$ 394,500
Labour	$ 238,100	$ 219,500	$ 457,600
Overhead	$ 64,400	$ 59,300	$ 123,700
Other*	$ 404,500	$ 404,300	$ 808,800
Total Administration	**$ 892,300**	**$ 892,300**	**$ 1,784,600**
Total AEF	**$ 3,215,900**	**$ 3,494,800**	**$ 6,710,700**

Forecast Budget

Spending by Measure	Gas Costs	Gas Costs	Gas Costs
	2009/10	**20010/11**	**Total**
AEF			
Incentives:			
Basic Energy Efficiency Items & Draft Proofing	$ 309,500	$ 320,000	$ 629,500
Insulation - Attic	$ 285,800	$ 294,300	$ 580,100
Insulation - Basement/Crawl	$ 2,515,000	$ 2,568,900	$ 5,083,900
Insulation - Wall	$ 338,600	$ 356,600	$ 695,200
Fridges	$ -	$ -	$ -
Total Incentives	**$ 3,449,000**	**$ 3,539,800**	**$ 6,988,800**
Administration:			
ecoENERGY Audit	$ 229,400	$ 316,200	$ 545,600
Labour	$ 294,800	$ 341,800	$ 636,600
Overhead	$ 79,700	$ 92,400	$ 172,100
Other *	$ 629,200	$ 625,700	$ 1,254,900
Total Administration	**$ 1,233,100**	**$ 1,376,100**	**$ 2,609,200**
Total AEF	**$ 4,682,100**	**$ 4,915,900**	**$ 9,598,000**

Forecasted Budget

Spending by Measure	Other Fuels Costs	Other Fuels Costs	Other Fuels Costs
	2009/10	**20010/11**	**Total**
AEF			
Basic Energy Efficiency Items & Draft Proofing	$ 30,000	$ 29,800	$ 59,800
Insulation - Attic	$ 78,400	$ 75,600	$ 154,000
Insulation - Basement/Crawl	$ 288,200	$ 281,000	$ 569,200
Insulation - Wall	$ 66,700	$ 65,600	$ 132,300
Fridges	$ -	$ -	$ -
Total Incentives	**$ 463,100**	**$ 452,000**	**$ 915,100**
			$ -
Administration:			$ -
ecoENERGY Audit	$ 53,600	$ 52,400	$ 106,000
Labour	$ 49,600	$ 48,500	$ 98,100
Overhead	$ 13,400	$ 13,100	$ 26,500
Other *	$ 72,400	$ 67,600	$ 140,000
Total Administration	$ 189,000	$ 181,600	$ 370,600
Total AEF	**$ 652,100**	**$ 633,600**	**$ 1,285,700**

Total Forecast Budget

Spending by Measure	TOTAL	TOTAL	TOTAL
	2009/10	**20010/11**	**Total**
AEF			
Basic Energy Efficiency Items & Draft Proofing	$ 526,700	$ 558,600	$ 1,085,300
Insulation - Attic	$ 517,700	$ 543,500	$ 1,061,200
Insulation - Basement/Crawl	$ 4,126,000	$ 4,365,500	$ 8,491,500
Insulation - Wall	$ 597,800	$ 632,600	$ 1,230,400
Fridges	$ 467,600	$ 494,100	$ 961,700
Total Incentives	**$ 6,235,700**	**$ 6,594,300**	**$ 12,830,000**
	$ -	$ -	$ -
Administration:	$ -	$ -	$ -
ecoENERGY Audit	$ 468,300	$ 577,800	$ 1,046,100
Labour	$ 582,500	$ 609,800	$ 1,192,300
Overhead	$ 157,500	$ 164,800	$ 322,300
Other*	$ 1,106,000	$ 1,097,600	$ 2,203,600
Total Administration	$ 2,314,300	$ 2,450,000	$ 4,764,300
Total AEF	**$ 8,550,000**	**$ 9,044,300**	**$ 17,594,300**

* includes contingency, outreach & support costs, marketing and training

PUB/MH II-106

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-113 (a) AEF**

b) Please provide the actual to date spending on the lower income program for 2009/10 including the number of energy audits funded.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-107 for AEF spending on the lower income program. The total number of audits that were completed during 2009/10 was approximately 1780, which includes both D and E audits.

PUB/MH II-106

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-113 (a) AEF**

c) Please elaborate on what is envisioned for the Community Energy Development spending in 2010/11 thorough 2014/15.

ANSWER:

Manitoba Hydro is exploring the potential for pursuing community wind projects.

PUB/MH II-107

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-113 (c) AEF

Please provide an updated schedule incorporating actual spending for 2009/10.

ANSWER:

	Actual Expenditures				Total Spent	Total Planned	Percent Spent
Initiative	2006/07	2007/08	2008/09	2009/10	to 2009/10	to 2024/25	to Date
Lower Income Program	0.3	0.2	0.9	1.7	3.0	19.0	16%
Geothermal Support	0.6	0.3	0.1	0.1	1.1	6.0	18%
Community Support and Outreach	0.0	0.0	0.0	0.1	0.2	0.8	22%
Special Projects							
Residential ecoEnergy Audits	0.0	0.1	0.2	0.1	0.4	0.5	71%
Solar Water Heaters	0.0	0.0	0.1	0.1	0.2	0.3	68%
Residential Loan	0.0	0.0	0.0	0.1	0.1	1.2	11%
ANNUAL EXPENDITURES	0.9	0.6	1.4	2.2	5.0	27.8	18%

PUB/MH II-108

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-116**

Please explain why there are energy and demand savings for the City of Winnipeg Power Smart program shown in PUB/MH I-116 (b) but not in PUB/MH I-116 (a). If the response is related to the expected product life of traffic lights, as explained in the 2009 Power Smart Plan on page 64, then please explain why there are no other energy or demand savings related to other energy efficiency projects undertaken for the City of Winnipeg.

ANSWER:

There are no energy and demand savings for the City of Winnipeg Power Smart program shown in PUB/MH I-116(a) because energy savings do not persist to 2023/24. The only forecasted projects within the Plan are traffic and pedestrian signal retrofits. The expected product life of traffic signals is 12 years and the City of Winnipeg Power Smart program ends in 2011/12. With the Power Smart Agreement (PSA) ending soon, there is limited potential for new projects. All other energy efficient projects undertaken by the City of Winnipeg will be through Manitoba Hydro's other Power Smart programs with the energy savings claimed as part of those programs.

<u>PUB/MH II-109</u>

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-118**

a) **Please confirm whether the sum of the revenue gain, avoided infrastructure benefits, and unit non-energy benefits is greater than or equal to the levelized utility cost for RIMs greater than or equal to one.**

<u>ANSWER</u>:

Confirmed.

PUB/MH II-109

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-118**

b) If (a) is confirmed, please explain why the revenue gain is less than the levelized utility cost for the following programs if the RIM for these programs all exceed 1.0:

LIEEP
EE Light Fixtures
Residential CFL Program
Fridge Recycling Program
Residential Appliance Program
Commercial Custom Measures Program
Commercial Windows Program
Commercial HVAC Chiller Program
Commercial New Construction Program
Network Energy Management Program
Emergency Preparedness Program

ANSWER:

The revenue gain is less than the levelized utility cost for the above programs because the benefits related to the avoided cost of new infrastructure are not included in the calculation. When the infrastructure benefits are added to the revenue gain the total benefits exceed the levelized utility cost for each program which is consistent with these programs having a RIM exceeding 1.

PUB/MH II-110

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-122 and Appendix 7.1 Table 6

a) **Please reconcile the negative 4-year growth in average consumption shown in PUB/MH I-122 (e) with the 1.3% increase in average consumption shown in Table 6 in Appendix 7.1. Please confirm the other growth rates shown in this IR.**

ANSWER:

The 1.3% referred to in the question could not be identified in Table 6 of Appendix 7.1. In Table 6, the Basic All-Electric average use during 2004/05 is 26,053 kWh and this average use grows to 26,231 kWh during 2008/09. That is a growth of 0.7% over this four year period. The growth of -1.7% provided in Manitoba Hydro's response to PUB/MH I-122(e) is based on weather adjusted usage as opposed to actual usage which is provided in Table 6 of Appendix 7.1.

The other growth rates provided in Manitoba Hydro's response to PUB/MH I-122(e) are also correct and the information is based on weather adjusted average use.

The variation in the answer due to weather-adjusting and not weather-adjusting exemplifies why caution needs to be exercised when comparing short term growth rates among various regions when the data is based on actual usage as compared to weather adjusted usage.

PUB/MH II-110

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-122 and Appendix 7.1 Table 6**

b) Please provide the annual residential average consumption for Saskatchewan and BC back to 1998/99.

ANSWER:

The following table provides the average residential consumption in Saskatchewan and BC.

	Sask	BC
1998	7,664	10,079
1999	7,799	10,141
2000	7,807	10,443
2001	7,923	10,300
2002	8,100	10,649
2003	8,208	10,415
2004	8,048	10,701
2005	8,065	10,654
2006	8,030	10,759
2007	8,229	10,811
2008	8,278	11,191

PUB/MH II-110

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-122 and Appendix 7.1 Table 6**

c) **Please estimate the number of electric hot water tanks that have been added since 2003/04 in Manitoba, separately identified by retrofits of gas hot water tanks and new construction hot water tanks. Please also estimate the impact on average consumption of Basic Standard electric customers.**

ANSWER:

Province wide, since 2003/04, approximately 45,300 private-use electric water tanks have been installed. This does not include common shared tanks, such as those found in apartment dwellings. Of these, 18,000 were natural gas water tanks retrofits to electric water tanks, 17,500 were electric tank installations in newly constructed dwellings, and 9,800 were old electric water tanks replaced with new electric water tanks. For standard heat customers (i.e. those customers not using electricity for space heat), there were about 9,000 newly constructed, natural gas heat dwellings installing an electric water tank.

These 27,000 electric water tanks, each averaging 3,630 kW.h, produce an impact of about 98 GW.h annually. Across the total of 302,000 Residential Basic Standard customers in 2009/10, the average impact is about 325 kW.h/year per customer.

PUB/MH II-110

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-122 and Appendix 7.1 Table 6**

d) Please estimate the number of natural gas hot water tanks in use each year back to 1998/99 or as far back as possible.

ANSWER:

The following table estimates the number of natural gas hot water tanks used by Manitoba Hydro residential customers.

1993/94	187,697
1994/95	188,861
1995/96	189,774
1996/97	190,842
1997/98	192,166
1998/99	193,340
1999/00	194,510
2000/01	195,545
2001/02	196,772
2002/03	197,802
2003/04	194,964
2004/05	192,326
2005/06	189,691
2006/07	187,218
2007/08	184,711
2008/09	182,476
2009/10	179,864

PUB/MH II-110

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-122 and Appendix 7.1 Table 6**

e) Please estimate the increase in Basic Standard average consumption if every consumer in this category that uses a gas hot water tank converted to an electric hot water tank.

ANSWER:

If the 179,864 natural gas water tanks converted to an electric water tank at 3,631 kW.h per year, the impact would be about 650 GW.h.

PUB/MH II-110

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-122 and Appendix 7.1 Table 6**

f) Please estimate the typical annual consumption for an electric hot water tank

ANSWER:

The average annual consumption for an electric hot water tank in 2009/10 is estimated to be 3,631 kW.h.

<u>PUB/MH II-111</u>

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-124**

a) Please confirm the period for on-peak hours each week (e.g. 5 days, 16 hours per day) and that the off-peak period covers the balance of the hours for each week.

<u>ANSWER</u>:

Confirmed.

PUB/MH II-111

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-124**

b) Please explain why the on-peak and off-peak energy savings show little or no seasonality.

ANSWER:

The on-peak and off-peak energy savings distribution is created by a blend of technologies included in the Power Smart Plan. More than half of the programs in the Plan include technologies that provide non-seasonal energy savings. These programs that provide non-seasonal energy savings represent over 80% of the portfolio energy savings.

The programs that provide energy savings with seasonal variations include insulation, windows, geothermal, chillers, residential and commercial new construction, parking lot controllers and residential lighting. The savings from these programs represent less than 20% of the total portfolio energy savings.

The result of this blend of technologies is an overall energy distribution with little seasonality.

PUB/MH II-112

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-129(a); Appendix 9.1 Pages 138 and 139 of 317**

a) **If Agricultural Heat Pads are used for heating purposes, intuitively the heating load is higher in the winter than in the summer. Please explain why the energy savings for these Pads are higher in the summer than in the winter.**

ANSWER:

Heat pads are used for providing zone heating in piglet crates, as they require a warmer temperature than the sows. Heat pads are not used for general heating purposes, as barns have their own heating and cooling systems which help moderate general room temperature.

Energy savings for heat pads are greater in the summer because of reduced run hours versus the winter. This is accomplished as the heat pads are equipped with a thermostat which ensures the crates achieve a set temperature of approximately 35ºC. This temperature is achieved mainly through the heat output of the heat pad, however can also be impacted by the surrounding room temperature. In the summer months, warm air will infiltrate the barns when outside doors are opened, thus allowing the crates to achieve a temperature of 35ºC with fewer run hours of the heat pads than in the winter.

PUB/MH II-112

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-129(a); Appendix 9.1 Pages 138 and 139 of 317**

b) Please explain why the winter capacity savings are approximately three times as great as the summer capacity savings for the Residential CFL program

ANSWER:

Based the Residential End Use Model prepared by Manitoba Hydro's Load Forecast Department, 61.8% of lighting is used during winter months and 38.2% is used during summer months. Demand savings are higher during winter months when the sun rises later in the morning and sets earlier in the evening, reducing the amount of natural light available and increasing the need for artificial lighting.

PUB/MH II-113

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-121; Appendix 9.1 Pages 138 to 140, 259 to 261 of 317, Appendix 9.2 Page 63 of 166**

a) **Please demonstrate how the total minimum commitment payments totaling $3.2 million was determined (provide details) and reconcile with the annual commitment under the agreement and actual energy savings realized by the City since the inception of the program.**

ANSWER:

The following table outlines how the value of each year's commitment payments to the City of Winnipeg are determined. The commitment payment for each year, with the exception of 2002/03, is equal to $800,000 less the energy savings achieved through the project year and less any adjustments to previous years' savings (where prior commitment payments did not reflect all savings realized).

Commitment Payment Breakdown					
Year	**Original Savings Claim**	**Savings Adjustments (savings from previous years)[1]**	**Total Savings After Adjustments**	**Annual Commitment**	**Commitment Payment**
2002/03	$607	$0	$607	$1,600,000	$1,599,393
2003/04	$52,301	$12,874	$65,175	$800,000	$734,825
2004/05	$140,137	$4,289	$144,426	$800,000	$655,574
2005/06	$631,523	$22,716	$654,239	$800,000	$145,761
2006/07	$771,905	$0	$771,905	$800,000	$28,095
2007/08	$758,259	$3,638	$761,897	$800,000	$38,103
2008/09	$874,858	-$81	$874,777	$800,000	TBD[2]
Total	**$3,229,590**	**$43,436**	**$3,273,026**	**$6,400,000**	**$3,201,751**

The values presented in PUB/MH I-121(b) differ from those presented in the table above as PUB/MH I-121(b) provided the savings realized in the year that they actually occurred while

[1] Savings Adjustments are presented in the program year in which they were finalized. These amounts reflect energy savings that occurred in prior years but are included in the current program year for determining the amount to be paid to the City of Winnipeg in that year.
[2] Given that savings are now higher than the commitment savings, City of Winnipeg is required to remit $74,777 to Manitoba Hydro. This payment has not yet been finalized.

the table above provides the original savings for each year plus any savings adjustments from previous years that are made in that year. These are the total annual savings used to determine the annual commitment payment.

Since filing Manitoba Hydro's response to PUB/MH I-121(b), additional savings adjustments have been made. The following table provides the most updated annual savings and adjustments.

Savings Realized by Project Year			
Year	**Annual Savings**	**Adjustments as of August 2009**	**Total**
2002/03	$13,529	$25	$13,554
2003/04	$55,921	$7,627	$63,548
2004/05	$140,147	$15,410	$155,557
2005/06	$626,229	$5,419	$631,648
2006/07	$770,906	$3,420	$774,326
2007/08	$757,792	$1,054	$758,846
2008/09	$874,859	$0	$874,859
Total	**$3,239,383**	**$32,955**	**$3,272,338**

PUB/MH I-121(a) stated that Manitoba Hydro has invested $10.6 million on the City of Winnipeg Power Smart Agreement. Exhibit 5.2 B on page 101 of Appendix 9.2 reports that $10.5 million has been expended on the City of Winnipeg Power Smart Agreement to the end of 2007/08. When combined with spending in 2008/09 and 2009/10, the program has spent $10.6 million to date.

The historical utility cost tables provided in the appendices of Appendix 9.1 and Appendix 9.2 do not include commitment payments and program administration and management fees and thus do not accurately reflect the expenditures of the City of Winnipeg Power Smart Agreement. The 2010 Power Smart Plan and the 2009/10 Power Smart Annual Review will reflect these additional costs.

PUB/MH II-113

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-121; Appendix 9.1 Pages 138 to 140, 259 to 261 of 317, Appendix 9.2 Page 63 of 166**

b) Please confirm whether MH's minimum commitment payments to the City of Winnipeg factor into the cost effectiveness tests (TRC, RIM, LUC).

ANSWER:

The minimum commitment payments are not factored into the cost effectiveness tests. These tests look strictly at the economics of each project and thus do not include commitment payments.

PUB/MH II-113

Subject: Tab 9: Demand Side Management

Reference: PUB/MH I-121; Appendix 9.1 Pages 138 to 140, 259 to 261 of 317, Appendix 9.2 Page 63 of 166

c) **Please provide the supporting calculations for the LUC of .011/kW.h related to the City of Winnipeg program.**

ANSWER:

	PV Utility Costs (dollars)	PV kW.h @ Generation	cents/kW.h @ Generation
	(A)	*(B)*	*(C) = (A) / (B)*
City of Winnipeg Power Smart Agreement	$ 72,567.52	6,566,394	$ 0.011

PUB/MH II-113

Subject: **Tab 9: Demand Side Management**

Reference: **PUB/MH I-121; Appendix 9.1 Pages 138 to 140, 259 to 261 of 317, Appendix 9.2 Page 63 of 166**

d) Please demonstrate how the forecasted cost savings in part (b) for 2009/10, 2010/11, and 2011/12 are determined considering the annual energy savings for these three years are forecasted at 0.2, 0.5, and 0.7 GWh and the demand savings are forecasted at 0.1, 0.1, and 0.2 MW, respectively as shown in Appendix A of the 2009 Power Smart Plan.

ANSWER:

Forecasted annual energy savings in Appendix A of the 2009 Power Smart Plan for 2009/10, 2010/11 and 2011/12 includes energy savings from new projects starting in 2009/10. These energy savings are incremental from the energy savings total presented for the 2008/09 project year.

The forecasted energy savings are based on traffic and pedestrian signal retrofits anticipated for the remainder of the agreement. The energy savings per signal vary depending on colour, size and type with an average annual savings of 244 kW.h, 70 W and $21 per signal. The following table provides the total forecast cumulative energy savings in each year based on traffic signals installed from 2009/10 to 2011/12.

Year	Project Type	Number (signals)	GW.h	MW	Energy Savings
2009/10	Traffic Signals	943	0.2	0.1	$20,000
2010/11	Traffic Signals	1,886	0.5	0.1	$40,000
2011/12	Traffic Signals	2,829	0.7	0.2	$60,000

The forecast cost savings in Manitoba Hydro's response to PUB/MH I-121 b) for 2009/10, 2010/11 and 2011/12 are estimated using historical achieved energy saving values and estimated savings associated with new projects by the end of the agreement in 2011/12.

Variances in savings forecasts against those achieved are due to rate changes, weather variability, performance fluctuations and the addition of new projects.

PUB/MH II-114

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-114 , PUB/MH I-131 (a)**

a) **If a Fridge Recycling Program has not been launched, please explain why there are 15,250 fridges forecasted to be replaced in each of 2009, 2010, and 2011, as stated in PUB/MH I-108 (c) and forecasted energy and capacity savings in Appendix A.1 to A.3. and program costs in appendix A. 4.**

ANSWER:

The data regarding participation, energy savings, capacity savings and program costs provided in Manitoba Hydro's response to PUB/MH I-131 is based on the 2009 Power Smart Plan which was developed in early 2009. At that time, Power Smart staff expected that the Fridge Recycling Program would be launched in mid 2009.

PUB/MH II-114

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-114, PUB/MH I-131 (a)**

b) Please explain why the program has been delayed.

ANSWER:

The delay in launching a program is a result of issues associated with disposal of the units to be collected under the Program and the cost associated with the disposable of the fridges in an environmentally responsible manner. Manitoba Hydro has conducted research into recycling options and is currently assessing alternatives for proceeding with a fridge recycling program.

<u>PUB/MH II-114</u>

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-114 , PUB/MH I-131 (a)**

c) Please indicate the timeline related to the introduction and duration of the planned Fridge Recycling Program.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-114(b). At this point, Manitoba Hydro has not resolved all the issues associated with this program; however, the Corporation is working towards launching a program in late 2010.

PUB/MH II-114

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-114 , PUB/MH I-131 (a)**

d) Please indicate whether there is a LIEEP component of the program, if so provide details.

ANSWER:

Manitoba Hydro is assessing options for including a lower income component to the program. Details cannot be provided as the program design has not been finalized nor approved internally.

<u>PUB/MH II-114</u>

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-114, PUB/MH I-131 (a)**

e) **Please file any studies undertaken either externally or internally on behalf of MH related to a fridge-recycling program, including program concept if available.**

<u>ANSWER</u>:

There have been no internal or external studies undertaken related to a fridge recycling program. Market research has been conducted by Power Smart staff in the form of contacting other utilities in North America and major recycling companies in order to gain information regarding lessons learned with respect to the logistics of program delivery and the issues associated with the recycling of the fridge units.

PUB/MH II-115

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-129

Please confirm whether MH's efficiency programs attach value to summer on peak demand savings. Please give a relative percentage value of summer on-peak demand savings to winter onpeak demand savings.

ANSWER:

Manitoba Hydro's efficiency programs attach a value to summer on-peak demand savings. The table below outlines the relative percentage of summer on-peak savings to winter on-peak savings.

2007/08 Actual Savings	Average Winter on-peak (MW)	Summer on-peak (MW)	Relative Percentage Summer to Winter On-Peak
RESIDENTIAL			
Home Insulation	2.80	0.00	0%
Compact Fluorescent Lighting	1.54	0.70	45%
Appliances	0.52	0.59	113%
New Homes	0.29	0.14	48%
Energy Efficient Light Fixtures	0.17	0.07	41%
Low Income	0.12	0.01	8%
Seasonal LED Lighting	0.05	0.00	0%
COMMERCIAL			
Commercial Lighting	2.91	4.08	140%
Commercial Geothermal	1.25	0.11	9%
Building Envelope	0.70	0.47	67%
Commercial Refrigeration	0.70	0.42	60%
Agricultural Heat Pads	0.47	0.60	128%
Internal Retrofit	0.17	0.15	88%
Custom	0.17	0.23	135%
City of Winnipeg Agreement	0.16	0.15	94%
HVAC	0.00	0.13	0%
INDUSTRIAL			
Performance Optimization	3.07	2.86	93%
CUSTOMER SELF-GENERATION PROGRAMS			
Customer Load Displacement Pilot	14.30	13.60	95%
RATE/LOAD MANAGEMENT PROGRAMS			
Curtailable Rates	180.62	183.86	102%

Note: Figures may not add due to rounding.

PUB/MH II-116

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-130**

For each of the programs listed in PUB/MH I-130(a), please provide the calculations for determining the energy and demand savings.

ANSWER:

Energy savings calculations for each technology are shown below. There are no demand savings for these technologies.

i. Seasonal LED Lighting

	A	B	C	D	E
	Total rebated sales	Free rider sales	Free driver sales	Total program driven sales (A - B + C)	Average per sale savings (kWh)
	21,846	9,612	22,375	34,609	29.41
Total savings (D x E)	1,017,962.82 kWh				
Persistence factor	0.94				
Savings x persistence factor	956,885.05 kWh				
Total savings	**956,885.05** kWh				

Note: numbers may not add due to rounding.

ii. Parking Lot Controllers

A Sector	B Number of circuits		C Average winter savings per circuit (kWh)		D Savings by sector (kWh) (B x C)	
Office	4,475	x	181.44	=	811,944.00	
Multi-Residential	3,182	x	343.73	=	1,093,742.50	
Comm./Ind	1,659	x	544.32	=	903,026.88	
					2,808,713.38	
Less: Free riders (office sector)	25	x	181.44	=	4,536.00	kWh
Savings net of free riders					2,804,177.38	kWh
Persistence factor	0.9					
Savings x persistence factor					**2,523,759.64**	**kWh**
Total winter savings					**2,523,759.64**	**kWh**

Note: numbers may not add due to rounding.

iii. Commercial Custom Measures

The Custom Measures Program is available for new and emerging technologies for which Manitoba Hydro does not have current data estimates for savings. All energy savings figures are site and project specific. As such, each project must submit a detailed feasibility study conducted by a professional engineer or architect which outlines savings estimates for the technologies to be installed at a specific site. The feasibility study is then reviewed by Manitoba Hydro program engineers for accuracy, and once all parties are in agreement concerning projected savings, implementation may begin.

iv. Spray Valves

	A	B	C
	Total program driven sales	Average winter savings (kWh)	Average summer savings (kWh)
	118	4,500	4,500

Total winter savings (A x B)	531,000	kWh
Total summer savings (A x C)	531,000	kWh
Annual savings (winter + summer)	1,062,000	kWh
# spray valves deemed free riders	3	
Winter savings associated with free rider valves	15,166	kWh
Summer savings associated with free rider valves	15,166	kWh
Annual savings associated with free riders*	30,332	kWh
Annual savings less free rider savings	1,031,668	kWh
Persistence factor	0.95	
Annual savings x persistence factor	980,084.60	kWh
Total annual savings	**980,084.60**	kWh

NOTES: Annual program savings were determined based on average per spray valve energy savings. Annual free rider savings is based on each individual spray valve (not the average), thus the average of the free rider savings is slightly different from the average annual savings.

Numbers may not add due to rounding.

PUB/MH II-117

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-132

a) For each DSM measure shown in the table in PUB/MH I-132(a), please give the unit export price per kWh that reconciles with the TRC and RIM given in the 2009 Power Smart Plan, assuming that 75% of the marginal benefits are related to export sales.

ANSWER:

	Estimated Export Revenue Marginal Benefit (75% of marginal benefits) (a)	*PV of Energy Saved @ Gen (kW.h) (b)*	*Unit Export Price per kW.h (c) = (a) / (b)*
RESIDENTIAL			
New Home	$20,599,363	295,615,532	$0.0697
Home Insulation	$33,104,742	343,077,994	$0.0965
Water and Energy Saver	$16,349,367	283,586,906	$0.0577
Lower Income	$14,865,625	213,886,387	$0.0695
HE Furnace & Boiler	$773,606	9,526,204	$0.0812
EE Light Fixtures	$1,487,467	26,086,831	$0.0570
Residential CFL	$38,145,224	627,476,240	$0.0608
Fridge Recycling	$18,395,821	387,605,783	$0.0475
Appliances	$2,875,865	48,027,994	$0.0599
COMMERCIAL			
Lighting	$260,550,155	3,488,418,075	$0.0747
Custom Measures	$5,026,594	83,999,761	$0.0598
Windows	$14,164,919	157,555,226	$0.0899
HVAC - Chiller	$5,907,530	173,096,889	$0.0341
Parking Lot Controller	$5,907,314	109,875,846	$0.0538
City of Winnipeg Agreement	$481,689	6,566,394	$0.0734
Rinse & Save	$592,420	12,044,790	$0.0492
Refrigeration	$28,573,806	486,802,139	$0.0587
Insulation	$31,522,551	301,643,229	$0.1045
Earth Power	$16,431,548	175,206,593	$0.0938
New Construction	$23,438,500	335,927,288	$0.0698
Building Optimization	$11,165,965	136,823,103	$0.0816
Internal Retrofit	$23,458,265	309,398,949	$0.0758
Agricultural Heat Pad	$5,342,961	98,139,001	$0.0544
Power Smart Energy Manager	$6,088,322	150,886,092	$0.0404
Kitchen Appliances	$2,913,411	34,460,247	$0.0845
Clothes Washers	$2,697,673	19,589,824	$0.1377
Network Energy Management	$8,229,796	149,354,594	$0.0551
Power Smart Shops	$6,030,266	103,463,120	$0.0583
CO2 Sensors	$340,365	8,766,464	$0.0388
INDUSTRIAL			
Performance Optimization	$109,658,859	1,869,852,327	$0.0586
Emergency Preparedness	$37,921,897	273,600,739	$0.1386
Customer Self Generation			
Bioenergy Optimization	$70,033,345	1,229,772,822	$0.0569

PUB/MH II-117

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-132**

b) Please explain why some of the calculated unit export prices in (a) are higher than the proxy for the export sale price of $0.055/kWh as articulated in the Energy Intensive Industry Rate proceeding.

ANSWER:

The assumption that 75% of the marginal benefits are related to export sales is a proxy only and caution needs to be exercised with using this data. The unit export prices calculated in PUB/MH II-117(a) are high level estimates with variations depending on such factors as demand savings, energy savings, timing of savings, etc.

The export price of $0.055/kWh as referenced in the Energy Intensive Industry Rate proceeding was derived from an average of export prices in 2006/07 and 2007/08 which are lower than export prices that are forecast in the future. The marginal cost is related to export prices levelized over the next 30 years. Export prices over the next 30 years are expected to be higher than those of the past due to many factors including the higher cost of natural gas and the consideration of greenhouse gas emissions.

PUB/MH II-117

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-132**

c) Please give MH's forecast unit export prices and avoided infrastructure unit costs that underlie the calculation of the marginal benefits. If they differ from those calculated in part (a), please explain why.

ANSWER:

Please refer to the response to RCM/TREE/MH II-4(b) for a general description of the methodology for determining the marginal costs for the generation, transmission and distribution components that are utilized in evaluations of DSM options. The series of responses for RCM/TREE/MH II-4(b) provide the values of each component levelized over a 30 year period.

The specific details of Manitoba Hydro's forecast of unit export prices cannot be provided since this is commercially sensitive information, and therefore is confidential since public release could harm the Corporation in participation in the export market and in negotiation of contracts for export sales.

It would be expected that the unit export prices calculated in PUB/MH II-117(a) would be different than Manitoba Hydro's forecast of unit export prices since the assumption that 75% of the marginal cost is related to export prices is a proxy and there are other factors that influence Manitoba Hydro's marginal cost.

PUB/MH II-117

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-132**

d) **For the DSM measures that do not have additional non-energy benefits, please calculate the required unit export price for each measure to obtain a TRC of unity, assuming the same level of avoided costs in the marginal benefits.**

ANSWER:

	Required unit export price per kWh to obain a TRC of Unity
RESIDENTIAL	
New Home	$0.0367
Home Insulation	$0.0219
Water and Energy Saver	$0.0099
Lower Income	$0.0412
HE Furnace & Boiler	$0.1056
EE Light Fixtures	$0.0309
Residential CFL	$0.0040
Fridge Recycling	$0.0299
Appliances	$0.0476
COMMERCIAL	
Lighting	$0.0300
Custom Measures	$0.0238
Windows	$0.0384
HVAC - Chiller	$0.0198
Parking Lot Controller	$0.0146
City of Winnipeg Agreement	$0.0089
Rinse & Save	$0.0018
Refrigeration	$0.0101
Insulation	$0.0331
Earth Power	$0.0353
New Construction	$0.0469
Building Optimization	$0.0162
Internal Retrofit	$0.0667
Agricultural Heat Pad	$0.0004
Power Smart Energy Manager	$0.0130
Kitchen Appliances	$0.0440
Clothes Washers	$0.0995
Network Energy Management	$0.0159
Power Smart Shops	$0.0361
CO2 Sensors	$0.0079
INDUSTRIAL	
Performance Optimization	$0.0156
Emergency Preparedness	$0.0583
Customer Self Generation	
Bioenergy Optimization	$0.0348

	Required unit export price per kWh to obain a TRC of Unity
RESIDENTIAL	
New Home	$0.0367
Home Insulation	$0.0219
HE Furnace & Boiler	$0.1056
EE Light Fixtures	$0.0309
Residential CFL	$0.0040
Fridge Recycling	$0.0299
COMMERCIAL	
Lighting	$0.0300
Custom Measures	$0.0238
Windows	$0.0384
HVAC - Chiller	$0.0198
Parking Lot Controller	$0.0146
City of Winnipeg Agreement	$0.0089
Refrigeration	$0.0101
Insulation	$0.0331
Earth Power	$0.0353
New Construction	$0.0469
Building Optimization	$0.0162
Internal Retrofit	$0.0667
Agricultural Heat Pad	$0.0004
Power Smart Energy Manager	$0.0130
Network Energy Management	$0.0159
CO2 Sensors	$0.0079
INDUSTRIAL	
Performance Optimization	$0.0156
Emergency Preparedness	$0.0583
Customer Self Generation	
Bioenergy Optimization	$0.0348

PUB/MH II-117

Subject: Tab 9: Demand Side Management
Reference: PUB/MH I-132

e) For each DSM measure, please calculate the required unit export price for each measure to obtain a RIM of unity, assuming the same split where 75% of the marginal benefits are related to export sales.

ANSWER:

	Required unit export price per kWh to obain a RIM of Unity
RESIDENTIAL	
New Home	$0.0495
Home Insulation	$0.0616
Water and Energy Saver	$0.0533
Lower Income	$0.0487
HE Furnace & Boiler	$0.0437
EE Light Fixtures	$0.0777
Residential CFL	$0.0468
Fridge Recycling	$0.0610
Appliances	$0.0479
COMMERCIAL	
Lighting	$0.0536
Custom Measures	$0.0489
Windows	$0.0739
HVAC - Chiller	$0.0313
Parking Lot Controller	$0.0317
City of Winnipeg Agreement	$0.0492
Rinse & Save	$0.0362
Refrigeration	$0.0424
Insulation	$0.0644
Earth Power	$0.0574
New Construction	$0.0638
Building Optimization	$0.0491
Internal Retrofit	$0.0163
Agricultural Heat Pad	$0.0301
Power Smart Energy Manager	$0.0268
Kitchen Appliances	$0.0640
Clothes Washers	$0.0864
Network Energy Management	$0.0496
Power Smart Shops	$0.0584
CO2 Sensors	$0.0270
INDUSTRIAL	
Performance Optimization	$0.0426
Emergency Preparedness	$0.1267
Customer Self Generation	
Bioenergy Optimization	$0.0408

PUB/MH II-117

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-132**

f) Please confirm whether the marginal benefits arising from avoided expenditures on infrastructure are calculated by netting avoided local transmission and distribution infrastructure against infrastructure expenditures necessary to support additional export transmission. Also, please confirm whether additional transmission infrastructure necessary to deliver electricity from northern generation to the Winnipeg area is included in the calculation of marginal benefits.

ANSWER:

The determination of marginal costs for transmission and distribution does not include the costs of additional transmission infrastructure for export purposes. The expenditures that are considered in the determination of marginal transmission costs are those that are driven by transmission requirements to meet domestic load.

The additional transmission infrastructure necessary to deliver electricity from northern generation to the load centre (e.g. BiPole III) is required for reliability and is not included in the calculation of marginal benefits.

PUB/MH II-117

Subject: **Tab 9: Demand Side Management**
Reference: **PUB/MH I-132**

g) **Please confirm whether demand savings benefits are fully captured in the avoided infrastructure benefits.**

ANSWER:

The transmission and distribution components of marginal cost are related entirely to demand savings since these facilities are designed for peak loads. A reduction in design load will allow for the deferral of the in-service date for these facilities and result in benefits due to avoided infrastructure costs.

The benefit of demand savings is not limited to only savings from deferral of transmission and distribution infrastructure. The generation component of marginal cost also derives benefits from demand savings by reducing production cost of system operation by increasing the value of exports and reducing the cost of imports. Therefore, the benefit of demand savings is derived from both avoided infrastructure costs and reduced cost of system operation.

PUB/MH II-118

Subject: Tab 9: Demand Side Management

Reference: PUB/MH I-138- DSM Cost Effectiveness Measures- Inputs

Please provide the data inputs for the 2008 Power Smart Plan.

ANSWER:

	Marginal Benefits		Program Admin Costs		Incremental Product Cost	Revenue Loss	Incentives		Energy Saved
	INPUT i & ii		INPUT iii		INPUT iv	INPUT v	INPUT vi		INPUT vii
	PV of Marginal Benefit	PV of Non-Energy (Water) Benefits	PV of Utility Program Admin Costs	PV of AEF Program Admin Costs	PV of Incremental Product Costs	PV of Revenue Loss	PV of Utility Incentives	PV of AEF Incentives	PV of Energy Saved @ Gen (kW.h)
RESIDENTIAL									
New Home	$23,522,604	$0	$1,756,943	$0	$12,228,556	$16,440,513	$808,631	$0	274,904,698
Home Insulation	$54,487,923	$0	$4,078,603	$0	$9,733,626	$26,779,252	$6,603,276	$0	454,710,239
Water and Energy Saver	$11,764,838	$0	$758,751	$0	$494,301	$10,252,718	$744,108	$0	181,592,767
Lower Income	$7,300,297	$0	$225,192	$0	$1,803,911	$3,713,583	$677,170	$0	64,432,925
Lower Income with AEF	$10,197,140	$0	$225,192	$2,936,405	$4,263,764	$5,558,341	$677,170	$5,569,705	97,286,511
EE Light Fixtures	$9,066,891	$0	$1,969,927	$0	$1,205,572	$6,342,385	$861,248	$0	111,277,324
Residential CFL	$16,331,981	$0	$1,923,863	$0	$1,102,271	$11,569,712	$705,609	$0	217,412,279
Residential SLED Program	$1,541,936	$0	$391,496	$0	$0	$1,388,341	$90,768	$0	24,549,213
Appliances	$5,645,069	$0	$969,850	$0	$3,996,818	$3,952,254	$1,209,825	$0	70,195,534
COMMERCIAL									
Lighting	$288,712,048	$0	$16,544,731	$0	$70,315,352	$157,385,600	$36,473,330	$0	3,023,060,689
Custom Measures	$4,910,295	$0	$781,640	$0	$2,480,133	$2,479,087	$1,297,970	$0	73,433,844
Windows	$20,691,244	$0	$2,359,380	$0	$3,359,425	$9,656,116	$1,906,089	$0	184,802,985
HVAC - Chiller	$11,504,574	$0	$48,591	$0	$3,515,779	$8,425,121	$2,318,830	$0	162,005,356
Parking Lot Controller	$29,566,983	$0	$327,884	$0	$8,739,472	$17,846,395	$1,678,947	$0	493,111,732
City of Winnipeg Agreement	$3,606,337	$0	$58,624	$0	$189,987	$2,163,477	$131,364	$0	34,532,735
Rinse & Save	$516,203	$0	$15,589	$0	$15,473	$448,405	$16,647	$0	11,267,707
Refrigeration	$15,783,367	$0	$2,205,170	$0	$1,631,906	$10,358,988	$806,921	$0	208,710,455
Insulation	$32,565,070	$0	$3,226,258	$0	$12,304,138	$19,365,657	$4,322,867	$0	466,994,025
Earth Power	$29,988,215	$0	$1,729,316	$0	$8,790,347	$13,226,138	$2,615,909	$0	226,931,747
New Construction	$40,653,913	$0	$2,194,240	$0	$24,138,859	$23,284,933	$12,276,151	$0	477,945,089
Building Optimization	$34,430,255	$0	$906,348	$0	$6,282,983	$16,509,981	$3,156,856	$0	321,790,617
Internal Retrofit	$33,488,294	$0	$10,314,062	$0	$190,185	$0	$0	$0	360,222,200
Agricultural Heat Pad	$17,512,143	$0	$101,595	$0	$1,848,290	$9,400,725	$452,792	$0	241,657,769
Power Smart Energy Manager	$19,509,448	$0	$1,243,098	$0	$7,048,813	$10,036,708	$223,826	$0	338,376,329
Kitchen Appliances	$2,058,131	$0	$109,176	$0	$1,015,601	$1,067,071	$492,214	$0	18,376,886
Clothes Washers	$3,082,839	$0	$200,298	$0	$2,043,698	$1,400,598	$365,553	$0	16,589,483
Network Energy Management	$21,759,255	$0	$196,654	$0	$7,373,067	$17,424,117	$1,950,547	$0	329,342,093
Power Smart Shops	$6,479,553	$0	$938,751	$0	$3,027,800	$4,720,927	$677,367	$0	84,476,078
INDUSTRIAL									
Performance Optimization	$147,428,323	$0	$9,720,967	$0	$33,917,798	$79,799,532	$13,496,933	$0	2,033,524,258
Emergency Preparedness									
CUSTOMER SELF GERNERATION									
Bioenergy Optimization	$69,091,801	$0	$2,605,949	$0	$40,327,965	$38,250,391	$10,589,884	$0	1,034,240,208

PUB/MH II-119

Subject: **Tab 10: Proposed Rates and Customer Impacts**
Reference: **PUB/MH I-128- Basic Monthly Charge**

a) **Please add to the table in PUB/MH I-128 a residential customer count in the consumption increments shown in the table.**

ANSWER:

The customer counts shown in the last column of the following table are based on 2008/09 Bill Frequency data which provides the total number of bills generated for each consumption level throughout the year. To derive at the customer counts shown, the bill counts were divided by 12, assuming that each customer receives one bill per month.

RESIDENTIAL 200 AMP & LESS

KW.h	April 1, 2009 $/MONTH	April 1, 2010 $/MONTH	DIFF. $/MONTH	% Chg.	Cust Count
0	$6.85	$5.85	($1.00)	-14.60%	54
10	$7.48	$6.49	($0.99)	-13.24%	2,060
20	$8.10	$7.12	($0.98)	-12.10%	1,474
40	$9.35	$8.40	($0.95)	-10.16%	2,726
60	$10.60	$9.67	($0.93)	-8.77%	2,819
75	$11.54	$10.63	($0.91)	-7.89%	3,005
80	$11.85	$10.95	($0.90)	-7.59%	57
100	$13.10	$12.22	($0.88)	-6.72%	3,517
125	$14.66	$13.81	($0.85)	-5.80%	5,787
150	$16.23	$15.41	($0.82)	-5.05%	4,303
175	$17.79	$17.00	($0.79)	-4.44%	5,208
185	$18.41	$17.63	($0.78)	-4.24%	2,335
200	$19.35	$18.59	($0.76)	-3.93%	3,989
250	$22.48	$21.78	($0.70)	-3.11%	12,596
300	$25.60	$24.96	($0.64)	-2.50%	13,410
350	$28.73	$28.15	($0.58)	-2.02%	13,891
375	$30.29	$29.74	($0.55)	-1.82%	6,387

KW.h	April 1, 2009 $/MONTH	April 1, 2010 $/MONTH	DIFF. $/MONTH	% Chg.	Cust Count
400	$31.85	$31.33	($0.52)	-1.63%	7,938
500	$38.10	$37.70	($0.40)	-1.05%	29,689
600	$44.35	$44.07	($0.28)	-0.63%	29,797
700	$50.60	$50.44	($0.16)	-0.32%	28,504
750	$53.73	$53.63	($0.10)	-0.19%	13,523
835	$59.04	$59.04	$0.00	0.00%	25,122
900	$63.10	$63.18	$0.08	0.13%	11,517
1000	$69.40	$69.93	$0.53	0.76%	20,912
1100	$75.70	$76.68	$0.98	1.29%	18,251
1200	$82.00	$83.43	$1.43	1.74%	15,758
1300	$88.30	$90.18	$1.88	2.13%	13,541
1400	$94.60	$96.93	$2.33	2.46%	11,610
1500	$100.90	$103.68	$2.78	2.76%	10,178
1750	$116.65	$120.56	$3.91	3.35%	23,767
2000	$132.40	$137.43	$5.03	3.80%	11,140
2500	$163.90	$171.18	$7.28	4.44%	20,676
3000	$195.40	$204.93	$9.53	4.88%	14,207
4000	$258.40	$272.43	$14.03	5.43%	18,708
5000	$321.40	$339.93	$18.53	5.77%	10,980

PUB/MH II-119

Subject: **Tab 10: Proposed Rates and Customer Impacts**
Reference: **PUB/MH I-128- Basic Monthly Charge**

b) Please provide the number of residential customers that will experience a bill reduction and the number that will experience a bill increase based on the proposed residential rates in Appendix 10.3.

ANSWER:

One cannot answer this question with respect to number of customers; it can only be answered in regards to number of bills. Every customer receives on average 12 hydro bills per year. Based on the proposed rates in Appendix 10.3 and depending on a customer's monthly kWh usage, some bills will reflect a reduction while other bills will reflect an increase. Therefore a customer can experience both increases and decreases throughout the year.

The response to PUB/MH II-119(a) shows the number of customers (i.e. number of bills divided by 12) for each consumption level. Customers consuming less than 835 kW.h per month will, on average over the course of a year, receive a bill reduction whereas those consuming more than 835 kW.h a month will see a bill increase. Cumulatively, approximately 5,033,000 Residential bills (excluding seasonal and diesel) are issued in a given year, of which approximately 52% of them are for less than or equal to 835 kW.h.

<u>PUB/MH II-120</u>

Subject: Tab 10: Proposed Rates and Customer Impacts
Reference: PUB/MH I-133- Basic Monthly Charge

a) **Please provide data supporting MH's position that low-income consumers are also low volume consumers. If the type of space heating (gas or electric) influences this position, please elaborate.**

<u>ANSWER</u>:

Manitoba Hydro indicated that those customers with lower energy use due to the size of their home would immediately benefit from the elimination/reduction of the basic monthly charge. For those customers whose energy bills which are higher and fall within the inverted tail block, they can access the Lower Income Energy Efficiency Program to reduce their consumption. For consumption, see Manitoba Hydro's response to CAC/MSOS/MH I-1(b).

<u>PUB/MH II-120</u>

Subject: **Tab 10: Proposed Rates and Customer Impacts**
Reference: **PUB/MH I-133- Basic Monthly Charge**

b) Please explain why eliminating income screening is desired or necessary in the context of MH's rate design.

<u>ANSWER</u>:

Manitoba Hydro proposes to reduce the basic monthly charge for all consumers. As such, there would be no need to screen customers to determine eligibility based on income. This eliminates the difficulty associated with establishing and monitoring income screening for low income customers. Should a reduction in the basic monthly charge be based on predetermined criteria such an income level, an administrative process would need to be established to screen applicants. A more complicated process would also be required to monitor those customers who qualify to determine continued eligibility on an ongoing and continuous basis as a customer's incomes can change weekly or monthly and can have seasonal considerations. Other complicating factors involve consideration for a customer's asset worth and how this should impact eligibility.

PUB/MH II-121

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-136(a), PCOSS-10 Methodology Used - Thermal Generation Output**

a) **Please confirm that the Brandon Coal (Unit #5) will only have a limited (emergency) role after 2009/10 and that the natural gas thermal generation will not normally be employed on a significant basis.**

ANSWER:

It is confirmed that operation of Brandon Unit 5 has been limited to support emergency operations by the Climate Change and Emissions Reductions Act commencing January 1, 2010. Please refer to the response to PUB/MH I-85 for more information regarding operational restrictions.

It is also confirmed that natural gas-fired thermal generation will not normally be employed by Manitoba Hydro on a significant basis in most flow conditions. In extremely low flow conditions there is expected to be a requirement for energy in addition to the energy provided by Manitoba Hydro's hydraulic resources, but even under these conditions it is expected that it will be more economic to import energy if it is available in sufficient quantities.

PUB/MH II-121

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-138 - IFF 08-1 Export Revenue Assumptions Ongoing Import Requirements**

b) **As such, why would PCOSS-10 need to employ any thermal fuels/generation output in a median flow situation?**

ANSWER:

PCOSS-10 is based on estimates of system operation for the year 2009/10 that were prepared in 2008/09 prior to implementation of the restricted operation of Brandon Unit #5. The estimate of generation for 2009/10 was based on a forecast of median inflow conditions, and this level of hydraulic energy supply did not require thermal generation from natural gas-fired units at Brandon or Selkirk. However, this forecast included thermal generation from the coal-fired Brandon Unit #5 since the year 2009/10 was prior to implementation of the restricted operation of this unit and it was economic to generate this energy for export purposes.

<u>PUB/MH II-122</u>

Subject: **Tab 11: Cost of Service Study**

Reference: **PUB/MH I-138 - IFF 08-1 Export Revenue Assumptions Ongoing Import Requirements**

a) **Please confirm that MH's 20-year IFF 08-1 assumptions included energy shortfalls (Domestic +Exports + Export Losses- Hydraulic Generation-Imports-Thermal Generation) which could result in combined total imports as follows:**

	Energy Shortfalls (GWh)	Imports and Thermal Generation (GWh)	Combined Total Imports (GWh)
2010/11	**686**	**3,136**	**3,822**
2015/16	**734**	**3,766**	**4,400**
2020/21	**1,395**	**4,384**	**5,779**
2025/26	**1,726**	**3,667**	**5,393**

<u>ANSWER</u>:

The values in the table are derived from a Manitoba Hydro submission from the 2008 GRA process - PUB/MH I-3 (Feb 20, 2009). The values provided in PUB/MH I-3 represent the expected condition which corresponds to the consequences corresponding to the 94 possible inflow conditions. Consequently, the import and thermal generation represents the average amount of non-hydro energy that is expected to be used, including both high usage periods (droughts) and low usage periods (floods). The sum of all supply sources is balanced against all demands which include forecast loads and export sales. Therefore, there is neither a surplus nor a deficit in any given year. It is incorrect to use the transmission losses from PUB/MH I-3 in the supply/demand balance since these losses have already been accounted for in the determination of energy surpluses.

It is noted that the energy shortfalls in the information request are equal to the transmission losses plus a second factor after 2017/18. This second factor that creates the perceived shortfall is the saving in HVDC losses due to Bipole III being in-service after 2017. These savings in losses should be added to the supply side of the equation in order to obtain a balance between supply and demand. In conclusion, there are no energy shortfalls in Manitoba Hydro's 20-year IFF08-1 once correct consideration has been given to the treatment of transmission losses.

PUB/MH II-122

Subject: **Tab 11: Cost of Service Study**

Reference: **PUB/MH I-138 - IFF 08-1 Export Revenue Assumptions Ongoing Import Requirements**

b) Please confirm (or otherwise explain) that MH could be employing at least 3,000 GWh of imports during the forecast period as long as normal (or below) market import energy prices prevail.

ANSWER:

Manitoba Hydro will import energy when it is economic to do so. The main factor that will affect the quantity of imports is water supply conditions. Purchase quantities could vary from nothing under the highest of flows to 10,000 GWh under the lowest of flows. On average purchases of between 1,000 and 2,000 GWh are included in the IFF. Please refer to the response to PUB/MH II-178(b) for a clarification of why the quantity of expected annual imports in IFF09 are significantly less than 3,000 GWh after wind energy purchases are considered.

Under high flows, Manitoba Hydro is not energy short and needs no additional energy from imports. Under low flows imports will be maximized to avoid operating Manitoba Hydro’s own more expensive generation. Next to its own hydraulic generation, imported energy is the most economic supply because Manitoba Hydro’s gas-fired generation is very inefficient and significantly more expensive than energy purchased from the market. In addition, Manitoba Hydro’s coal-fired generation is under restricted operation and can only be operated under emergencies as defined under the *Climate Change and Emissions Reductions Act*. As a result market price is not a factor as market priced energy will generally be less expensive compared to alternatives in Manitoba.

<u>PUB/MH II-123</u>

Subject: **Tab 11: Cost of Service Study**

Reference: **PUB/MH I-139 (a) Amended Schedule B-2 - PCOSS-10 Methodology Used (Page 9)**

a) **Please confirm that PCOSS-10 is based on an export revenue of $546 million, export sales of 7,901 GWh and an average unit revenue of 6.9¢/KWh for 2009/10 (as also forecast in IFF 08-1).**

<u>ANSWER</u>:

Manitoba Hydro can confirm that PCOSS-10 is based on an export revenue figure of $546 million and export sales of 7,901 GWh (which underlie forecast in IFF08-1). However, the 6.9¢/kWh figure is not representative of average unit revenue because the revenue figure includes other revenues (e.g., merchant sales) that are not attributable to the 7,901 GWh export volume.

PUB/MH II-123

Subject: **Tab 11: Cost of Service Study**

Reference: **PUB/MH I-139 (a) Amended Schedule B-2 - PCOSS-10 Methodology Used (Page 9)**

b) Please confirm (or revise) that MH's January 15, 2010 financial update forecasts indicates:

Date	Export Revenues	IFF 08-1 Volume	Calculated Unit Revenue
2009/10	$414.5 M	7,901 GWh	5.25¢/KWh
2010/11	$383.5 M	6,867 GWh	5.55¢/KWh
2011/12	$554.2 M	7,191 GWh	7.70¢/KWh

ANSWER:

Manitoba Hydro cannot confirm the information provided in the above table on the basis that it refers to IFF08 volumes and IFF09 financials to calculate an oversimplified ¢/KWh.

Please see Manitoba Hydro's response to PUB/MH I-45(b) for the appropriate average price calculations.

PUB/MH II-123

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-139 (a) Amended Schedule B-2 - PCOSS-10 Methodology Used (Page 9)**

c) **Please explain why PCOSS-10 employs average export price levels that are about 50% higher than prices realized to date.**

ANSWER:

The average unit price used in IFF08 and PCOSS10 exceeds the average unit price realized to date for fiscal 2009/10 primarily due to the timing of the preparation of IFF08. As discussed in Manitoba Hydro's response to CAC/MSOS/MH I-7, the export price analysis underlying IFF08 was completed in the spring 2008 before the financial crisis and subsequent global recession became apparent. The export price outlook underlying IFF09 reflects these conditions and anticipates prices for 2009/10 and 2010/11 significantly below those in IFF08.

A secondary factor is the higher than forecast volume of lower priced opportunity sales in the first three quarters of 2009/10 due to favourable water conditions, which results in a lower average unit price.

Manitoba Hydro continues to believe that it is appropriate to include Export Revenues in the PCOSS consistent with those used in the IFF, rather than based on the most recent actual export prices. If the most recent actual export prices were used as the basis for the IFF in the current year, the rate increase requirements would be increased relative to using Manitoba Hydro's forecast. The rapid and unforeseen change in market and economic conditions is atypical, and does not provide a justification for a departure from using the approved forecast of export prices.

Finally actual prices are, in some measure, a reflection of actual water flows. Since the PCOSS is based on median flows, it is incorrect to apply average unit prices from a year of above average or below average flows, and the resulting mix of Dependable and Opportunity sales, against sales volumes under median flow conditions.

PUB/MH II-123

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-139 (a) Amended Schedule B-2 - PCOSS-10 Methodology Used (Page 9)**

d) Please provide an alternative PCOSS-10 (Schedules B1, B2 & B3) that values the 7,901 GWh of energy @ 5.55¢/KWh to define export revenue.

ANSWER:

The cited average unit revenues of 6.9¢/kWh for PCOSS10 and the forecast 5.55¢/kWh for 2010/11 cannot be confirmed as discussed in Manitoba Hydro's responses to PUB/MH II-123(a) and (b).

To be responsive to the question, Manitoba Hydro has done a high level adjustment to the PCOSS by reducing total export revenue by twenty percent (5.55¢/kWh ÷ 6.9¢/kWh = 80%). This adjustment requires simplifying assumptions about merchant transactions and other items included in total export revenue that are not attributable to the 7,901 GWh export volume, but Manitoba Hydro believes this treatment is consistent with the context of the question.

Due to the correlation between export and import prices, the total cost of power purchases in the PCOSS has also been reduced by twenty percent. The export sales and power purchases volume included in the PCOSS have not been adjusted.

The results of the revised PCOSS10 are as follows:

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2010
Revenue Cost Coverage Analysis

S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	534,755	486,651	91.0%	26,975	513,626	96.0%
General Service - Small Non Demand	110,676	111,651	100.9%	5,417	117,068	105.8%
General Service - Small Demand	117,320	115,256	98.2%	5,711	120,966	103.1%
General Service - Medium	164,483	158,991	96.7%	8,071	167,062	101.6%
General Service - Large 0 - 30kV	77,905	67,889	87.1%	3,817	71,706	92.0%
General Service - Large 30-100kV*	43,638	44,588	102.2%	2,196	46,784	107.2%
General Service - Large >100kV*	183,758	192,906	105.0%	9,187	202,093	110.0%
*Includes Curtailment Customers						
SEP	1,509	1,315	87.1%	-	1,315	87.1%
Area & Roadway Lighting	19,664	19,837	100.9%	325	20,162	102.5%
Total General Consumers	1,253,708	1,199,084	95.6%	61,698	1,260,781	100.6%
Diesel	12,369	4,665	37.7%	631	5,296	42.8%
Export	374,568	436,897	116.6%	(62,329)	374,568	100.0%
Total System	1,640,646	1,640,646	100.0%	-	1,640,646	100.0%

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2010
Customer, Demand, Energy Cost Analysis

SUMMARY

	C U S T O M E R			D E M A N D				E N E R G Y			
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential	115,719	466,759	20.66	194,904	0%	n/a	n/a	197,157	6,811,218	5.76	**
GS Small - Non Demand	21,968	52,716	34.73	37,496	0%	n/a	n/a	45,796	1,478,206	5.63	**
GS Small - Demand	7,086	11,260	52.44	44,516	38%	2,203	7.73	60,007	1,983,393	4.41	
General Service - Medium	5,719	1,859	256.37	61,683	100%	7,008	8.80	89,010	3,032,155	2.94	
General Service - Large <30kV	2,884	259	n/a	27,005	100%	3,452	8.66 *	44,199	1,533,322	2.88	
General Service - Large 30-100kV	1,810	30	n/a	9,966	100%	2,455	4.80 *	29,666	1,151,746	2.58	
General Service - Large >100kV	2,098	14	n/a	29,232	100%	9,476	3.31 *	143,241	5,626,174	2.55	
SEP	352	25	1,174.24	241	0%	n/a	n/a	916	22,550	5.13	**
Area & Roadway Lighting	14,715	153,710	7.98	2,374	0%	n/a	n/a	2,250	99,432	4.65	**
Total General Consumers	172,352	686,631		407,417		24,594		612,242	21,738,196		
Diesel	258	732	29.43	388	0%	n/a	n/a	11,092	12,820	89.55	**
Export	n/a	n/a	n/a	49,564	0%	n/a	n/a	325,003	7,901,000	4.74	***
Total System	172,610	687,363		457,369		24,594		948,338	29,652,016		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2010
Functional Breakdown

S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	507,781	197,157	38.8%	46,569	9.2%	39,013	7.7%	57,554	11.3%	167,488	33.0%
General Service - Small Non Demand	105,259	45,796	43.5%	10,773	10.2%	7,047	6.7%	14,371	13.7%	27,273	25.9%
General Service - Small Demand	111,609	60,007	53.8%	13,235	11.9%	8,227	7.4%	3,179	2.8%	26,961	24.2%
General Service - Medium	156,412	89,010	56.9%	19,985	12.8%	10,967	7.0%	4,750	3.0%	31,700	20.3%
General Service - Large <30kV	74,088	44,199	59.7%	9,824	13.3%	5,129	6.9%	2,660	3.6%	12,276	16.6%
General Service - Large 30-100kV	41,442	29,666	71.6%	6,347	15.3%	3,619	8.7%	1,762	4.3%	49	0.1%
General Service - Large >100kV	174,571	143,241	82.1%	29,232	16.7%	0	0.0%	2,075	1.2%	23	0.0%
SEP	1,509	916	60.7%	241	16.0%	0	0.0%	337	22.3%	16	1.0%
Area & Roadway Lighting	19,339	2,332	12.1%	391	2.0%	544	2.8%	579	3.0%	15,493	80.1%
Total General Consumers	1,192,011	612,324	51.4%	136,597	11.5%	74,545	6.3%	87,266	7.3%	281,278	23.6%
Diesel	11,738	11,092	94.5%	0	0.0%	0	0.0%	0	0.0%	646	5.5%
Export	374,568	325,003	86.8%	49,564	13.2%	0	0.0%	0	0.0%	0	0.0%
Total System	1,578,317	948,419	60.1%	186,162	11.8%	74,545	4.7%	87,266	5.5%	281,924	17.9%

PUB/MH II-124

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS 09 - Table E-1 Functional Usage of Transmission**

a) **Please confirm that MH's mean hydraulic generation in 2009/10 consists of: GWh MW**

- **AC transmitted 8,600 1,400**
- **DC transmitted 20,500 4,700**

ANSWER:

Please note, the reference to PCOSS 09 is incorrect as there was no PCOSS 09 study.

The hydraulic generation values (GWh) provided below were used in PCOSS 10 and are based on median flow conditions as forecast in Fall 2008 for 2009/10.

Table 1.Projected Hydraulic Generation for FY 09/10.

Manitoba Hydro Transmission	Generation (GWh)[1, 2]	Net Capability (MW)[3]
AC	9,381	1,550
DC	21,794	3,468

Notes:

1. As projected in Fall 2008 for median flow conditions in 2009/10.
2. At generation (i.e. - not net of transmission and distribution losses).
3. As reported in Manitoba Hydro Annual Report for FY ended March 31, 2009.

PUB/MH II-124

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS 09 - Table E-1 Functional Usage of Transmission**

b) Please confirm that in the absence of imports or thermal generation, MH would in mean years be able to supply:

- **Domestic load - 24,000 GWh:**
  - **8,600 GWh (AC)**
  - **15,400 GWh (DC)**
- **Exports - 5,000 GWh (DC)**

ANSWER:

Manitoba Hydro cannot confirm the numbers assumed or the validity of the premise.

In the absence of imports and thermal generation, Manitoba Hydro would have developed a different generating system in order to meet Manitoba Hydro's dependable load requirements with different average annual energy production and exports.

<u>PUB/MH II-124</u>

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS 09 - Table E-1 Functional Usage of Transmission**

c) Please provide an analysis of MH's interest/depreciation/OM&A costs for generation facilities broken down as follows:

- **AC transmitted power resources (Winnipeg River/Grand Rapids/Upper Nelson River).**
- **DC transmitted power (Lower Nelson River including CRD and LWR).**

<u>ANSWER</u>:

Please note that generation costs and forecast energy output are consistent with PCOSS10 filed as part of this GRA, and not PCOSS09 as referenced in the question. Also as noted in Manitoba Hydro's response to PUB/MH I-143(b) all power transmitted through the HVdc transmission system is injected into the MH AC Transmission System at Dorsey station.

Costs assigned to the Lower Nelson GS include:

- All LWR costs, and the bulk of CRD costs, excluding a share assigned to Upper Nelson GS based on forecast energy output of all Nelson River plants,
- HVDC facilities costs which are functionalized as Generation in the PCOSS, ie all HVDC excluding Dorsey convertor station.

PCOSS10 Generating Station Costs ($ million)

	Interest	**Deprec.**	**OM&A**	**PCOSS10 Generation Costs**	**2009/10 Forecast Generation GWh**	**Average Unit Cost ($/MWh)**
Lower Nelson GS	218.2	82.9	164.1	465.3	22,430	$20.7
Other Hydraulic GS	111.6	37.1	101.6	250.2	8,745	$28.6

PUB/MH II-124

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS 09 - Table E-1 Functional Usage of Transmission**

d) Please indicate the average unit cost of power generation:

- **AC transmitted resources.**
- **DC transmitted resources.**

ANSWER:

Please see Manitoba Hydro’s response to PUB/MH II-124(c).

PUB/MH II-125

Subject: Tab 11: Cost of Service Study
Reference: PUB/MH I-139 (c) Export Revenue 2009/10

Please provide an update to the answer to incorporate the actual export volumes (GWh) and average unit prices for the 2009/10 fiscal year.

ANSWER:

Fiscal year	EXPORTS	
2009/10	GWh	Avg Price
Dependable	3,258	57.02
Opportunity	7,722	22.77

PUB/MH II-126

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-141b) - PCOSS-10, PCOSS-08 Directly Assigned Costs**

a) **Please confirm that directly assigned G&T costs in PCOSS-08 represent 100% of the total cost of these elements. If not, explain.**

ANSWER:

In PCOSS08 the Export class was directly assigned the total cost related to Uniform Rates, DSM, Trading Desk, MAPP/MISO/NEB, and Purchased Power. Fuel costs related to the operation of the thermal plants were directly assigned to the Export class. The remaining operating and maintenance costs as well as interest and deprecation expense associated with Thermal Generation was included in the Generation pool, to be shared by all classes of customer, including exports.

<u>PUB/MH II-126</u>

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-141b) - PCOSS-10, PCOSS-08 Directly Assigned Costs**

b) Please provide a tabulation of annual export sales transactions and import/purchase transactions over the last eight years to illustrate the relative activities of MH's Trading Arm.

<u>ANSWER</u>:

The following table includes all Manitoba Hydro's sales and purchase activities, including Merchant transactions.

	SALES		**PURCHASE**	
	GWh	**Revenue (000's)**	**GWh**	**Cost (000's)**
2002/03	9,736	476,339	3,223	126,004
2003/04	6,976	348,136	9,627	506,147
2004/05	10,790	539,672	2,277	100,664
2005/06	15,360	641,156	1,780	83,415
2006/07	12,265	573,763	3,455	178,728
2007/08	12,348	609,199	2,098	95,043
2008/09	11,720	601,118	2,579	133,208
2009/10	11,635	402,215	2,095	54,751

PUB/MH II-127

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-143(a) AC/DC Electricity Sources**

a) **Please clarify that in MH's view, electricity (electrons) serving customers in northern Manitoba could come from the Lower Nelson plants and could incur transmission losses on the HVDC system going south and again on the AC system going north.**

ANSWER:

The generation from Kettle, Long Spruce and Limestone Generating Stations which is connected to the HVDC system can flow south only via the HVDC system. The result is that the HVDC system operates independently from the AC transmission system in northern Manitoba and northern generation that is connected only to the HVDC system cannot be used to meet northern loads directly.

Normally, the generation that is connected to AC transmission in northern Manitoba is sufficient to serve northern loads. Under some uncommon operating conditions, resulting from equipment outages, it is possible that the northern system could "import" a limited amount of its energy requirements from the southern system. This energy supply would flow north on the AC transmission system and could be sourced from a blend of power sources including southern system generation, northern generation delivered to the south via the HVDC system, thermal generation and imports.

PUB/MH II-127

Subject: Tab 11: Cost of Service Study
Reference: PUB/MH I-143 (a) AC/DC Electricity Sources

b) Please confirm that, in general, electricity flow from the AC generation does not have to pass through the Dorsey Station in order to serve customers in some parts of Manitoba.

ANSWER:

In general, all Manitoba Hydro customers are served from the power grid which receives injections of power from sources at various locations, and power flows to a destination along the path of least impedance according to the laws of physics. In addition to being a terminus for HVDC power, the Dorsey complex contains a 230 kV AC station which serves to distribute power transmitted from the north via HVDC transmission as well as distribute power flows from other generating stations that are connected directly to the AC transmission network. Consequently, under normal operating conditions some of the power injected at locations that are physically far removed from the Dorsey complex may flow through the Dorsey AC station location due to the laws of physics. However, in general it can be concluded that customers in some parts of Manitoba can be served with power that does not flow through Dorsey.

PUB/MH II-127

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-143 (a) AC/DC Electricity Sources**

c) **Please confirm that a complete shutdown of the Dorsey Station would not necessarily preclude the continuation of AC-generated supply to some parts of Manitoba. Explain.**

ANSWER:

A complete shutdown of the Dorsey Station would not be considered part of normal operations for Manitoba Hydro. If the entire HVDC transmission was taken out of service in an orderly manner, only a portion of the Manitoba load could still be served using generation sources not connected to the HVDC transmission system (including thermal generation and imports). It should be noted that, in the special situation of a complete shutdown of the HVDC supply into Dorsey Station, the electrical service to the portion of customers still receiving power supply would be of much lower reliability compared to normal operations.

<u>PUB/MH II-127</u>

Subject: Tab 11: Cost of Service Study
Reference: PUB/MH I-143 (a) AC/DC Electricity Sources

d) Please confirm that a complete shutdown of the Dorsey Station would essentially preclude substantial exports into the U.S. If not, explain.

<u>ANSWER</u>:

It is confirmed that under a condition where the Bipoles I and II High Voltage Direct Current transmission systems into Dorsey C.S. were shutdown, Manitoba Hydro would not be able to make exports sales. In this situation it would be necessary to import as much as possible. Even with imports, it is likely that a significant part of the Manitoba load would not be served under such a catastrophic event.

PUB/MH II-127

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-143 (a) AC/DC Electricity Sources**

e) **Please confirm that while MH's AC transmission system is structured to isolate failure areas, it is set up to allow electricity movements along the path of least resistance which may be the shortest travel path.**

ANSWER:

Manitoba Hydro's AC transmission system consists of a network of 230 kV, 138 kV and 115 kV AC transmission lines, which connect generation (both AC generating plants and the DC generation at Dorsey) to transformer stations which reduce the voltage to subtransmission and distribution levels at which most of the load is supplied.

The AC power flows from generation to load through this network via the path(s) of least impedance, which may or may not be the shortest physical path(s). In an interconnected AC transmission network, there are generally multiple paths from the generation source to the load, and a portion of the power flow may flow through each path. Having multiple pathways provides redundancy or reliability for the service to the load. If one transmission element is lost, the power flow will be redistributed amongst the remaining transmission elements by the laws of physics relating to power flow.

PUB/MH II-128

Subject: **Tab 11: Cost of Service Study**
Reference: **22009 Annual Report and 2007/02/03, PUB/MH 28**

a) **Please confirm (or revise) the unit net and gross export revenues shown in the following table:**

Year	**MH's Actual Net Metered**		**Net Unit Export Revenue**	**Gross Unit Export Revenues**
	Export Sales	**Export Revenue Minus F&PP**		
2009/10	**?**	**?**	**?**	**3.2 (est.)**
2008/09	**9,589**	**447**	**4.66**	**5.33**
2007/08	**10,590**	**491**	**4.64**	**5.89**
2006/07	**8,217**	**366**	**4.45**	**5.05**
2005/06	**13,706**	**702**	**5.12**	**5.11**
2004/05	**8,213**	**419**	**5.10**	**5.32**
2003/04	**(2,578)**	**(?)**	**?**	**6.27**
2002/03	**6,378**	**312**	**4.89**	**4.93**
2001/02	**10,911**	**517**	**4.73**	**4.62**
2000/01	**11,247**	**432**	**3.46**	**3.6**
1999/00	**9,906**	**343**	**3.46**	**3.5**

ANSWER:

The table provided in the question is using the Net Metered Interchange as it includes non Manitoba Hydro transactions as the export sales volume. This is an incorrect assumption. In addition the full amount of fuel and power purchase has been deducted which includes diesel and other costs not related to extraprovincial sales. Due to these incorrect assumptions the numbers representing Net Unit Export Revenue and Gross Unit Export Revenues are not correct.

Please see the following table for a revised analysis.

	1999/00 Actual	2000/01 Actual	2001/02 Actual	2002/03 Actual	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual
Extraprovincial Revenue	376	480	588	463	351	554	827	592	625	623
Total Fuel and Power Purchased for Extraprovincial Power Sales	32	46	70	149	567	133	122	223	132	172
NET EXPORT REVENUE	344	434	518	314	(216)	421	705	369	493	451
Sales GWh	10,911	12,154	12,298	9,736	6,976	10,790	15,360	12,265	12,348	11,720
Net Unit Export Revenue (¢/KWh)	**3.15**	**3.57**	**4.21**	**3.22**	**(3.09)**	**3.90**	**4.59**	**3.01**	**3.99**	**3.84**
Gross Unit Export Revenue (¢/KWh)	**3.45**	**3.95**	**4.78**	**4.76**	**5.03**	**5.13**	**5.38**	**4.83**	**5.06**	**5.31**

<u>PUB/MH II-128</u>

Subject: **Tab 11: Cost of Service Study**
Reference: **22009 Annual Report and 2007/02/03, PUB/MH 28**

b) **Please confirm that since 2001 and excluding 2003/04, MH's net and gross unit export revenues have generally been in the 4.50 to 5.50¢/KWh range despite export volume variations of up to 7,000 GWh (net exports ranging from 6,378 GWh to 13,706 GWh).**

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-128(a).

Subject: **Tab 11: Cost of Service Study**
Reference: **22009 Annual Report and 2007/02/03, PUB/MH 28**

c) **Please confirm that the above data does not support the assumption of 6.9¢/KWh median year average unit export prices employed in PCOSS-10 which is significantly higher than those averages experienced in the last five years.**

ANSWER:

Please see Manitoba Hydro’s response to PUB/MH II-123(a).

<u>PUB/MH II-129</u>

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS-10, Schedule D-2, Schedule B-2 Export Energy Weighting**

a) Please confirm that PCOSS-10 (Schedule D-2) anticipates export sales approximately as follows:

- **From hydraulic generation:**

• **Dependable 5x16 peak**	**2,600 GWh**
• **Non-dependable 5x16 peak**	**400 GWh**
• **Off-peak 2x16**	**1,100 GWh**
• **Off-peak 7x8**	**1,300 GWh**

- **From thermal generation:**

• **Peak**	**500 GWh**

- **From imports:**

• **Peak 5x16**	**500 GWh**
• **Off-peak**	**<u>1,000 GWh</u>**
	7,900 GWh

Restating this as market:

Total:

• **5x16 (firm)**	**2,600 GWh**
• **5x16 (opportunity)**	**1,900 GWh**
• **2x16**	**1,500 GWh**
• **7x8**	**<u>1,900 GWh</u>**
	7,900 GWh

ANSWER:

Not confirmed. Manitoba Hydro is unable to verify the allocation of export energy as described above.

PUB/MH II-129

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS-10, Schedule D-2, Schedule B-2 Export Energy Weighting**

b) Please confirm that contracted 5x16 firm energy would achieve 5.5 to 6.0¢/KWh; 5x8 overnight opportunity sales might at best achieve about 3.0¢/KWh; and 2x16 weekend opportunity sales might achieve about 4.0¢/KWh; therefore, 5x16 opportunity sales would have earned 11¢/KWh to bring total export revenue to $546 million.

ANSWER:

The detailed pricing assumptions used in forecasting export revenues are considered to be Trade Secret and Confidential and cannot be provided. However included in the export revenue forecast of $546 million were a total of $76.8 million of non-energy related revenues from merchant sales, ancillary services, transmission service credits and revenues. These revenues need to be excluded from any back calculation to determine average 5x16 opportunity sales.

PUB/MH II-129

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS-10, Schedule D-2, Schedule B-2 Export Energy Weighting**

c) Please confirm that to achieve a $546 million export revenue, about 7,000 GWh of export sales would have to achieve peak prices averaging 7.5¢/KWh.

ANSWER:

Manitoba Hydro cannot confirm the 7.5 cents/kWh value as the $546 million in export revenue includes other revenues such as merchant sales, demand charges and transmission credits. In addition, the export volume in PCOSS-10 was 7901 GWh.

Please see Manitoba Hydro's response to PUB/MH II-123(a)

PUB/MH II-129

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS-10, Schedule D-2, Schedule B-2 Export Energy Weighting**

d) **To ensure consistent treatment of generation energy cost allocations to export, please provide an alternative scenario which revises Schedule D-2 and Schedules B1/B2/B3 to reflect 90% of MH's median year exports occurring in the 5x16 period and zero exports occurring in the off-peak (7x8) period.**

ANSWER:

Manitoba Hydro believes that the current apportionment of Export sales to time periods in Schedule D2 provides a fair allocation of generation costs, while employing objective and verifiable data. Use of historical sales as the basis of apportionment is not constrained by issues of commercial sensitivity that would accompany using forecast sales as the basis, or the subjectivity of other methods of estimating the apportionment. Manitoba Hydro endorses neither the concept, nor the relative percentages set out in the question. Nevertheless, the results are modeled as described and shown below.

As discussed in Manitoba Hydro's response to PUB/MH II-130(c) the definition of Time-of-Use periods in the Surplus Energy Program (SEP) do not correspond with 5x16 and 7x8 sales. As the SEP prices provide the basis of the weightings in Schedule D2, the following assumptions have been made to accommodate the sales as indicated in the question into the periods used in Schedule D2:

- The 90% of Export sales indicated to occur in the 5x16 period are assumed to occur half in the Peak period (45% of total sales), and half in the Shoulder period (45% of total sales).
- With no sales indicated to occur in the Off-Peak period the remaining 10% is assumed to occur in the Shoulder period, bringing the total Export sales in the Shoulder period to 55% of sales.
- The Peak and Shoulder energy are then each distributed between the seasons in Schedule D2 in the same proportion as included in the unrevised schedule.

The revised Schedule D2 including increased Export sales presumed to occur in the Peak and Shoulder periods, and the resulting Schedules B1/B2/B3 are as follows:

2010 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report

Energy (MW.h) Weighted by Marginal Cost (Hydraulic for Domestic and Export Classes)

	2009/10 Forecast		Spring Peak	Spring Shoulder	Spring Off Peak	Summer Peak	Summer Shoulder	Summer Off Peak	Fall Peak	Fall Shoulder	Fall Off Peak	Winter Peak	Winter Shoulder	Winter Off Peak	Total	Weighted Energy/1000
Residential	7,831,948,530	Residential	252,136,339	479,694,560	307,643,591	485,872,434	908,179,538	460,964,880	332,979,991	604,043,107	377,993,173	888,009,681	1,627,361,716	1,107,069,520	7,831,948,530	19,536,101
Res FRWH	19,891,874	Residential FRWH	804,167	1,529,944	981,202	1,736,716	3,246,223	1,647,686	839,482	1,522,864	952,966	1,625,440	2,978,772	2,026,413	19,891,874	48,423
Res Seasonal	83,957,616	Residential Seasonal	3,854,883	7,333,995	4,703,527	9,320,219	17,421,100	8,842,431	3,062,230	5,555,045	3,476,191	4,997,938	9,159,194	6,230,861	83,957,616	201,202
GS Small Non Demand	1,699,975,517	GS Small Non-Demand	63,169,675	113,139,517	65,546,470	146,108,969	213,161,587	119,242,216	74,882,670	129,202,012	77,800,874	178,737,740	315,750,229	203,233,558	1,699,975,517	4,247,235
GSS FRWH	6,304,394	GS Small Non-Demand FRWH	274,438	491,530	284,764	641,661	936,133	523,671	279,126	481,602	290,004	538,339	951,007	612,118	6,304,394	15,525
GSS Seasonal	5,382,794	GS Small Non-Demand Seasonal	303,111	542,885	314,516	869,542	1,268,594	709,649	168,356	290,480	174,917	189,759	335,220	215,765	5,382,794	12,839
GS Small Demand	2,281,353,953	GS Small Demand	83,696,379	146,991,056	89,302,491	178,266,239	291,346,879	169,911,019	102,245,928	175,932,915	109,787,832	237,144,144	419,771,724	276,957,347	2,281,353,953	5,655,564
GS Medium	3,476,648,890	GS Medium	134,938,050	236,401,141	144,503,448	299,209,167	488,425,641	290,457,394	151,794,756	261,316,524	161,893,687	335,856,518	588,768,733	383,083,834	3,476,648,890	8,566,269
GS Large <30KV	1,743,068,864	GS Large 750-30kV	72,793,420	121,835,898	79,369,038	158,098,820	250,217,035	163,029,274	77,257,665	127,092,422	84,510,777	160,622,548	267,725,792	180,516,176	1,743,068,864	4,256,626
GS Large 30-100kV	1,030,440,052	GS Large 30-100kV	36,014,278	70,371,417	54,785,569	72,849,372	137,393,514	107,295,480	40,343,284	76,440,296	60,481,821	85,437,291	162,800,908	126,226,822	1,030,440,052	2,437,875
GS Large 30-100kV Curtail	242,666,448	GS Large 30-100kV Curtailable	8,832,789	17,502,414	13,231,349	17,677,043	34,343,935	26,157,653	9,245,286	18,009,863	13,671,209	18,916,414	36,979,088	28,099,404	242,666,448	572,157
GS Large > 100kV	3,136,017,512	GS Large > 100kV	120,097,255	230,388,001	179,079,534	218,539,949	408,120,391	319,486,835	123,161,343	233,179,627	181,811,562	256,720,419	487,396,415	378,036,182	3,136,017,512	7,412,217
GS Large > 100kV Curtail	2,991,082,697	GS >100kV Curtailable	108,157,981	211,855,092	162,298,696	217,935,677	427,598,356	329,943,486	112,870,159	218,683,496	167,898,520	232,764,416	453,985,199	347,091,620	2,991,082,697	7,042,243
Streetlights	115,848,424	Street Lights	-	4,402,240	10,831,828	463,394	8,225,238	21,721,579	3,359,604	6,603,360	13,206,720	7,877,693	13,264,645	25,892,123	115,848,424	232,378
Total	24,664,587,563	Totals	885,072,765	1,642,479,689	1,112,876,023	1,807,589,201	3,189,884,162	2,019,933,252	1,032,489,881	1,858,353,614	1,253,950,253	2,409,438,340	4,387,228,642	3,065,291,741	24,664,587,563	60,236,653
Exports	6,424,000,000	**Exports**	**581,458,760**	**693,423,168**		**1,276,609,009**	**1,544,664,305**		**384,968,895**	**488,679,466**		**647,763,337**	**806,433,061**		**6,424,000,000**	**18,255,682**
		Weighting Factor	2.712	2.344	1.380	3.435	2.484	1.000	2.793	2.305	1.440	3.845	2.652	2.096		

Energy (MW.h) Weighted by Marginal Cost (Thermal for Domestic Classes)

Thermal Generation	2009/10 Forecast		Spring Peak	Spring Shoulder	Spring Off Peak	Summer Peak	Summer Shoulder	Summer Off Peak	Fall Peak	Fall Shoulder	Fall Off Peak	Winter Peak	Winter Shoulder	Winter Off Peak	Total	Weighted Energy/1000
Residential	50,171,034	Residential	1,615,172	3,072,897	1,970,748	3,112,472	5,817,748	2,952,916	2,133,052	3,869,467	2,421,404	5,688,541	10,424,790	7,091,827	50,171,034	125,147
Res FRWH	127,426	Residential FRWH	5,151	9,801	6,286	11,125	20,795	10,555	5,378	9,755	6,105	10,412	19,082	12,981	127,426	310
Res Seasonal	537,828	Residential Seasonal	24,694	46,981	30,131	59,705	111,599	56,644	19,616	35,585	22,268	32,017	58,673	39,915	537,828	1,289
GS Small Non Demand	10,889,950	GS Small Non-Demand	404,661	724,766	419,887	935,966	1,365,501	763,859	479,694	827,661	498,388	1,144,984	2,022,679	1,301,903	10,889,950	27,208
GSS FRWH	40,386	GS Small Non-Demand FRWH	1,758	3,149	1,824	4,110	5,997	3,355	1,788	3,085	1,858	3,449	6,092	3,921	40,386	99
GSS Seasonal	34,482	GS Small Non-Demand Seasonal	1,942	3,478	2,015	5,570	8,127	4,546	1,078	1,861	1,121	1,216	2,147	1,382	34,482	82
GS Small Demand	14,614,229	GS Small Demand	536,154	941,617	572,067	1,141,964	1,866,352	1,088,441	654,982	1,127,017	703,295	1,519,132	2,689,035	1,774,174	14,614,229	36,229
GS Medium	22,271,223	GS Medium	864,406	1,514,373	925,681	1,916,718	3,128,828	1,860,654	972,389	1,673,979	1,037,082	2,151,478	3,771,620	2,454,014	22,271,223	54,875
GS Large <30KV	11,166,004	GS Large 750-30kV	466,311	780,474	508,434	1,012,772	1,602,877	1,044,357	494,908	814,147	541,371	1,028,939	1,715,037	1,156,377	11,166,004	27,268
GS Large 30-100kV	6,600,943	GS Large 30-100kV	230,705	450,795	350,953	466,669	880,135	687,329	258,437	489,672	387,443	547,307	1,042,894	808,602	6,600,943	15,617
GS Large 30-100kV Curtail	1,554,508	GS Large 30-100kV Curtailable	56,582	112,120	84,759	113,238	220,005	167,564	59,225	115,370	87,577	121,178	236,886	180,003	1,554,508	3,665
GS Large > 100kV	20,089,157	GS Large > 100kV	769,336	1,475,853	1,147,174	1,399,955	2,614,397	2,046,615	788,965	1,493,736	1,164,675	1,644,537	3,122,235	2,421,679	20,089,157	47,482
GS Large > 100kV Curtail	19,160,712	GS >100kV Curtailable	692,854	1,357,132	1,039,677	1,396,084	2,739,172	2,113,600	723,040	1,400,875	1,075,549	1,491,076	2,908,204	2,223,450	19,160,712	45,112
Streetlights	742,119	Street Lights	-	28,201	69,388	2,968	52,690	139,147	21,521	42,301	84,602	50,464	84,973	165,864	742,119	1,489
Thermal Generation	158,000,000	Totals	5,669,728	10,521,635	7,129,023	11,579,318	20,434,224	12,939,582	6,614,074	11,904,512	8,032,737	15,434,730	28,104,347	19,636,091	158,000,000	385,873
Exports	-	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Weighting Factor	2.712	2.344	1.380	3.435	2.484	1.000	2.793	2.305	1.440	3.845	2.652	2.096		

Definition of Periods

Spring (April 1 to May 31)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Summer (June 1 to Sept 30)
Peak = 12:00 noon to 8:00 pm weekdays
Shoulder = 7:00 am to 12:00 noon weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Fall (Oct 1 to Nov 30)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Winter (December 1 to March 31)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2010
Revenue Cost Coverage Analysis

S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	555,366	486,651	87.6%	46,888	533,539	96.1%
General Service - Small Non Demand	114,702	111,651	97.3%	9,392	121,044	105.5%
General Service - Small Demand	121,690	115,256	94.7%	9,910	125,166	102.9%
General Service - Medium	170,446	158,991	93.3%	13,993	172,984	101.5%
General Service - Large 0 - 30kV	80,657	67,889	84.2%	6,611	74,500	92.4%
General Service - Large 30-100kV*	45,018	44,588	99.0%	3,789	48,377	107.5%
General Service - Large >100kV*	189,454	192,906	101.8%	15,828	208,734	110.2%
*Includes Curtailment Customers						
SEP	1,513	1,315	86.9%	-	1,315	86.9%
Area & Roadway Lighting	20,432	19,837	97.1%	566	20,402	99.9%
Total General Consumers	1,299,279	1,199,084	92.3%	106,977	1,306,061	100.5%
Diesel	12,516	4,665	37.3%	1,069	5,734	45.8%
Export	438,075	546,121	124.7%	(108,046)	438,075	100.0%
Total System	1,749,870	1,749,870	100.0%	-	1,749,870	100.0%

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2010
Customer, Demand, Energy Cost Analysis

SUMMARY

	C U S T O M E R			D E M A N D				E N E R G Y			
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential	115,744	466,759	20.66	197,813	0%	n/a	n/a	194,920	6,811,218	5.77	**
GS Small - Non Demand	21,774	52,716	34.42	38,064	0%	n/a	n/a	45,472	1,478,206	5.65	**
GS Small - Demand	7,049	11,260	52.17	45,192	38%	2,203	7.85	59,538	1,983,393	4.41	
General Service - Medium	5,602	1,859	251.11	62,628	100%	7,008	8.94	88,224	3,032,155	2.91	
General Service - Large <30kV	2,813	259	n/a	27,427	100%	3,452	8.76 *	43,806	1,533,322	2.86	
General Service - Large 30-100kV	1,764	30	n/a	10,133	100%	2,455	4.85 *	29,333	1,151,746	2.55	
General Service - Large >100kV	2,043	14	n/a	29,772	100%	9,476	3.36 *	141,811	5,626,174	2.52	
SEP	356	25	1,187.66	242	0%	n/a	n/a	915	22,550	5.13	**
Area & Roadway Lighting	15,238	153,710	8.26	2,408	0%	n/a	n/a	2,221	99,432	4.66	**
Total General Consumers	172,382	686,631		413,679		24,594		606,241	21,738,196		
Diesel	254	732	28.96	381	0%	n/a	n/a	10,811	12,820	87.31	**
Export	n/a	n/a	n/a	52,345	0%	n/a	n/a	385,730	7,901,000	5.54	***
Total System	172,637	687,363		466,405		24,594		1,002,782	29,652,016		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2010
Functional Breakdown

S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	508,478	194,920	38.3%	47,428	9.3%	39,548	7.8%	56,032	11.0%	170,550	33.5%
General Service - Small Non Demand	105,310	45,472	43.2%	10,972	10.4%	7,143	6.8%	13,987	13.3%	27,735	26.3%
General Service - Small Demand	111,779	59,538	53.3%	13,479	12.1%	8,340	7.5%	3,094	2.8%	27,328	24.4%
General Service - Medium	156,453	88,224	56.4%	20,354	13.0%	11,117	7.1%	4,624	3.0%	32,135	20.5%
General Service - Large <30kV	74,046	43,806	59.2%	10,005	13.5%	5,199	7.0%	2,589	3.5%	12,447	16.8%
General Service - Large 30-100kV	41,230	29,333	71.1%	6,465	15.7%	3,668	8.9%	1,715	4.2%	49	0.1%
General Service - Large >100kV	173,626	141,811	81.7%	29,772	17.1%	0	0.0%	2,019	1.2%	24	0.0%
SEP	1,513	915	60.5%	242	16.0%	0	0.0%	340	22.5%	16	1.1%
Area & Roadway Lighting	19,867	2,360	11.9%	408	2.1%	566	2.8%	578	2.9%	15,953	80.3%
Total General Consumers	1,192,302	606,380	50.9%	139,125	11.7%	75,580	6.3%	84,979	7.1%	286,237	24.0%
Diesel	11,447	10,811	94.4%	0	0.0%	0	0.0%	0	0.0%	636	5.6%
Export	438,075	385,730	88.1%	52,345	11.9%	0	0.0%	0	0.0%	0	0.0%
Total System	1,641,823	1,002,922	61.1%	191,470	11.7%	75,580	4.6%	84,979	5.2%	286,873	17.5%

PUB/MH II-130

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-145 Summer Overnight Sales**

a) **Please confirm that in PCOSS 10, MH anticipates export sales of 7,900 GWh, which involve 995 GWh of transmission losses for a total generation requirement of 8,900 GWh in addition to the domestic generation requirement of 24,900 (overall total 33,800 GWh).**

ANSWER:

PCOSS10 includes export sales of 7,901 GWh with associated transmission losses of 814 GWh for a total generation requirement of 8,715 GWh. The overall total is 33,635 GWh, including domestic generation requirement of 24,920 GWh.

PUB/MH II-130

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-145 Summer Overnight Sales**

b) Please define MH's annual surplus energy generation capability (GWh) for export during:

- **5x16 periods (summer and winter).**
- **2x16 weekend periods (summer and winter).**
- **7x8 overnight periods (summer and winter).**

ANSWER:

The following table illustrates Manitoba Hydro's surplus generation capability assuming 2010/11 Manitoba load conditions and system capability and 2005/06 river flow conditions. This flow year represents the maximum flow condition which demonstrates the current surplus capability of the system.

Period	Surplus Energy Generation Capability (GWh) for Export		
	Summer	Winter	Annual
5x16 weekday	4,300	2,900	7,200
2x16 weekend	2,000	1,200	3,200
7x8 overnight	3,100	1,700	4,800

PUB/MH II-130

Subject: **Tab 11: Cost of Service Study**
Reference: **PUB/MH I-145 Summer Overnight Sales**

c) Please quantify (using SEP price weighting) the relative economics of:

- **Weekend (2x16) summer sales with winter 2x16 and 7x8 sales.**
- **Overnight 7x8 summer sales with winter 2x16 and 7x8 sales.**

ANSWER:

The Surplus Energy Program offers a price per kW.h for three Time-of-Use periods on a weekly basis; that is, one for each of the peak, shoulder, and off-peak periods. The prices for the sales as requested have been taken from the relevant SEP periods as follows:

Period per IR	SEP Period	SEP Period Definition
Summer 2x16	Shoulder*	All hours except Peak, every day from: 07:01 hours - 23:00 hours, May 1 to Oct 31
Winter 2x16	Shoulder*	All hours except Peak, every day from:07:01 hours - 23:00 hours, Nov 1 to Apr 30
Winter 7x8	Off-Peak	All night time hours from 23:01 hours - 07:00 hours, Nov 1 to Apr 30
Summer 7x8	Off-Peak	All night time hours from 23:01 hours - 07:00 hours, May 1 to Oct 31
*Shoulder period limited to Saturday, Sunday and Statutory Holidays only for this Information Request		

The average prices are based on the inflation adjusted daily SEP prices for the period of April 1, 2000 to March 31, 2008. This is consistent with the data used to determine the "12 Period Weighted Energy" allocator in PCOSS10. The comparison of the average prices of sales in the requested periods using these SEP price weightings are as follows:

	Average Price (2008 $/MWh)	Price Relative to Summer 2x16
Summer 2x16	39.44	100%
Winter 2x16	46.21	117%
Winter 7x8	42.51	108%

	Average Price (2008 $/MWh)	Price Relative to Summer 7x8
Summer 7x8	23.40	100%
Winter 2x16	46.21	198%
Winter 7x8	42.51	182%

A comparison of period prices is insufficient information to make conclusions on the relative economics of these sales, as it does not take into consideration the availability of water or market conditions which influence the ability to change timing of export or SEP sales.

PUB/MH II-131

Subject: **Tab 11: Cost of Service Study**
Reference: **2009/10 Load Forecast, 2008/09 Power Resource Plan Transmission Reliability**

a) **Please confirm that a major outage on both Bipoles I and II would in 2009/10 reduce MH generation capacity as follows:**

AC-transmission Hydro	**1,423 MW**
Thermal	**535 MW**
Contracted Imports	**550 MW**
Total Capacity	**2,508 MW**
Peak Domestic Winter Load	**4,515 MW**
Peak Export Contract Demand	**693 MW**
Total Demand	**5,208 MW**
Shortfall*	**2,708 MW**
Possible Additional Imports	**1,075 MW**
Cutback Required	**1,733 MW**

ANSWER:

The estimates that are provided in the information request can only be confirmed in general as they are based on a single possible set of assumptions of generating capability, domestic load, export commitments and import capability. In addition, it is noted that the peak load is from the 2008 power resource plan and does not include the effect of DSM savings and also does not include the requirement for reserve capacity. Please see the response to PUB/MH I-143(d) which provides a similar summary of capacity shortfalls based on Manitoba Hydro's current assumptions of capacity supply and demand based on the operations perspective. Manitoba Hydro would not be required to deliver on its export capacity commitments should there be a loss of Bipole I and II, and the last column of the response to PUB/MH I-143(d) provides the capacity shortfall without export sales.

PUB/MH II-131

Subject:	**Tab 11: Cost of Service Study**
Reference:	**2009/10 Load Forecast, 2008/09 Power Resource Plan Transmission Reliability**

b) Please confirm that 2022/23 with Bipole III in place, the generation capacity (without Bipole I and II) would be:

AC-transmission Hydro	**1,423 MW**
Thermal	**535 MW**
Contracted Imports	**385 MW**
Bipole III	**2,000 MW**
Total Capacity	**4,343 MW**
Possible Additional Imports (no new tie-line)	**640 MW**
	4,683 MW
Peak Domestic Winter Load	**5,363 MW**
Peak Contract Demand	**1,375 MW**
Total Demand	**6,738 M**
Shortfall *	**2,145 MW**

ANSWER:

Manitoba Hydro does not accept the capacity shortfall presented in the information request as being representative of the 2022/23 situation.

Please see the response to PUB/MH I-143(e) which provides a similar summary of capacity shortfalls based on Manitoba Hydro's current assumptions of capacity supply and demand based on the operations perspective for the year 2023/24. Manitoba Hydro would not be required to deliver on its export capacity commitments should there be a loss of Bipole I and II, and the response to PUB/MH I-143(e) indicates that there is no capacity shortfall without export sales. This is based on a total of 1950 MW of import capability which includes the additional import capacity associated with a new interconnection.

PUB/MH II-132

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS 09/ Tab 11/ Appendix 11: HVDC Costs**

a) Please provide an alternative PCOSS-10 analysis allocating all HVDC (transmission and converter) costs to the domestic class and the export class on an annual energy consumption basis with exports being net of:

- **• Imports.**
- **• 50% of thermal generation.**

ANSWER:

The following scenario includes the allocation of all HVDC costs to the domestic and export classes on the basis of unweighted annual energy consumption, rather than on the basis of 2CP Seasonal Demand (Dorsey Convertor Station) and Marginal Weighted Energy (all other HVDC) as done in PCOSS10.

The energy used for the Export class is net of all imports, and 66% of total thermal generation rather than the 50% requested. This minor variation was made to be consistent with the energy associated with the costs of Brandon Unit 5 that have been directly assigned to the Export class.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2010
Revenue Cost Coverage Analysis

S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	560,962	486,651	86.8%	55,875	542,525	96.7%
General Service - Small Non Demand	115,627	111,651	96.6%	11,173	122,824	106.2%
General Service - Small Demand	123,382	115,256	93.4%	11,861	127,117	103.0%
General Service - Medium	173,137	158,991	91.8%	16,777	175,768	101.5%
General Service - Large 0 - 30kV	82,111	67,889	82.7%	7,945	75,834	92.4%
General Service - Large 30-100kV*	46,474	44,588	95.9%	4,616	49,204	105.9%
General Service - Large >100kV*	196,982	192,906	97.9%	19,430	212,336	107.8%
*Includes Curtailment Customers						
SEP	1,513	1,315	86.9%	-	1,315	86.9%
Area & Roadway Lighting	20,674	19,837	95.9%	692	20,528	99.3%
Total General Consumers	1,320,862	1,199,084	90.8%	128,368	1,327,451	100.5%
Diesel	12,516	4,665	37.3%	1,261	5,926	47.4%
Export	416,492	546,121	131.1%	(129,629)	416,492	100.0%
Total System	1,749,870	1,749,870	100.0%	-	1,749,870	100.0%

PUB/MH II-132

Subject: **Tab 11: Cost of Service Study**
Reference: **PCOSS 09/ Tab 11/ Appendix 11: HVDC Costs**

b) Please confirm that exports (including transmission losses) typically equate to 25- 40% of annual hydraulic generation.

ANSWER:

It is confirmed that exports have been in the range of 25 to 40% of hydraulic generation. With ongoing load growth it is expected that future exports will be in the lower end of the range at about 25% of hydraulic generation under expected flow conditions.

<u>PUB/MH II-133</u>

Subject: **Tab 12: Corporate Risk Management**

Reference: **Tab 12, Section 12.3, Pages 2/3/ICF Report (10.3 Page 122), 2008 PUB/MH 30 (b) - Low Generation Outputs**

a) **Please confirm that in the last 31 years, MH's total hydraulic generation was less than 25,000 GWh in 8 of those years.**

<u>ANSWER</u>:

Total hydraulic generation was less than 25,000 GWh in 14 of the past 31 fiscal years (1979/80 through 2008/09).

PUB/MH II-133

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Section 12.3, Pages 2/3/ICF Report (10.3 Page 122), 2008 PUB/MH 30 (b) - Low Generation Outputs**

b) **Please confirm on an order of magnitude basis, MH annual hydraulic generation in low flow years roughly reflected watershed contributions as follows:**

	Total (GWh)	Burntwood River Flows (GWh)	Saskatchewan River Flows (GWh)	Winnipeg River/Red River Local Inflows (GWh)
F1981	24,100	5,500	4,000	14,600
F1982	22,200	5,500	5,000	11,700
F1988	21,000	5,500	3,500	12,000
F1989	19,700	5,500	2,000	12,200
F1990	23,500	5,200	3,000	14,700
F1991	24,200	5,100	5,500	13,600
F1992	24,700	5,000	4,500	15,200
F2004	18,500	4,000	3,300	12,200

ANSWER:

Manitoba Hydro cannot confirm the values provided in the above table.

PUB/MH II-133

Subject: **Tab 12: Corporate Risk Management**

Reference: **Tab 12, Section 12.3, Pages 2/3/ICF Report (10.3 Page 122), 2008 PUB/MH 30 (b) - Low Generation Outputs**

c) Please confirm that the minimum annual watershed contributions in those 31 years were approximately as follows:

• **Burntwood River**	**3,300 GWh**	**(in F2004)**
• **Saskatchewan River**	**2,000 GWh**	**(in F1989)**
• **Winnipeg River/Red River Local Inflow**	**11,700 GWh**	**(in F1982)**
Subtotal	**17,000 GWh**	

(Aggregate of minimums)

ANSWER:

Manitoba Hydro cannot confirm these numbers.

PUB/MH II-134

Subject: **Tab 12: Corporate Risk Management**

Reference: **Tab 12, Section 12.3, Pages 2/3, ICF Report, 2008 PUB/MH 30(b) Minimum Hydraulic Output**

a) Please confirm on an order of magnitude basis that the minimum annual hydraulic generation contributions for the Winnipeg River/Red River/local inflow watersheds on a sub-watershed could have been:

- **Winnipeg River sub-watershed 6,500 GWh (F2004)**
- **Red River sub-watershed 500 GWh (F1978)**
- **Local inflow sub-watersheds* 1,500 GWh (F2005)**

(*including net inputs or withdrawals of storage and evaporation losses)

ANSWER:

Manitoba Hydro cannot confirm these numbers.

PUB/MH II-134

Subject: **Tab 12: Corporate Risk Management**

Reference: **Tab 12, Section 12.3, Pages 2/3, ICF Report, 2008 PUB/MH 30(b) Minimum Hydraulic Output**

b) Please discuss and advise on how the foregoing minimums are/are not representative of the full 95 years of recorded flows when adjusted to current hydraulic system.

ANSWER:

Manitoba Hydro cannot confirm the values in II-134(a). Therefore Manitoba Hydro cannot provide a response to this question.

PUB/MH II-134

Subject: **Tab 12: Corporate Risk Management**

Reference: **Tab 12, Section 12.3, Pages 2/3, ICF Report, 2008 PUB/MH 30(b) Minimum Hydraulic Output**

c) Please quantify the total import (no thermal) requirements (MW and GWh) that would be involved in meeting 2012/13 and 2017/18 domestic load and committed export contracts if hydraulic generation were:

- **17,000 GWh**
- **13,800 GWh**

ANSWER:

The values that are summarized on the next page are based on the supply/demand Table 1a from the 2009/10 power resource plan that is referenced in the response to CAC/MSOS/MH I-35(a). The information summarized below is derived by reducing the total hydraulic generation to the levels specified in the information request. It should be noted that the quantities in the information request are below the 21,000 GWh level to which the Manitoba Hydro system is planned and designed. Supply-side resources other than hydraulic generation such as wind power purchase, transmission upgrades, supply side improvements and demand side management programs are consistent with the 2009/10 power resource plan estimates.

The import requirement for the specified levels of reduced hydraulic generation is provided with and without the consideration of thermal generation. The MW rating of the import requirements is shown assuming an equal loading over every hour of the year.

<u>2012/13</u>

Firm Load

MB Load	25763 GW.h	
Committed Export	3279 GW.h	
Total	29042 GW.h	

Supply

Limited Hydraulic supply	**17000 GW.h**	
Thermal supply	4118 GW.h	
Other Supply	1860 GW.h	
<u>Required Import</u>	**<u>6064 GW.h</u>**	**<u>(692 MW average)</u>**
Total	29042 GW.h	

<u>Total Import with no Thermal 10182 GW.h (1162 MW average)</u>

<u>2012/13</u>

Firm Load

MB Load	25763 GW.h	
Committed Export	3279 GW.h	
Total	29042 GW.h	

Supply

Limited Hydraulic supply	**13800 GW.h**	
Thermal supply	4118 GW.h	
Other Supply	1860 GW.h	
<u>Required Import</u>	**<u>9264 GW.h</u>**	**<u>(1058 MW average)</u>**
Total	29042 GW.h	

<u>Total Import with no Thermal 13382 GW.h (1528 MW average)</u>

<u>2017/18</u>

Firm Load

MB Load	27808 GW.h
Committed Export	155 GW.h
Total	27963 GW.h

Supply

Limited Hydraulic supply	**17000 GW.h**	
Thermal supply	4118 GW.h	
Other Supply	2537 GW.h	
<u>Required Import</u>	**<u>4308 GW.h</u>**	**<u>(492 MW average)</u>**
Total	27963 GW.h	

<u>Required Import with no Thermal 8426 GW.h (962 MW average)</u>

<u>2017/18</u>

Firm Load

MB Load	27808 GW.h
Committed Export	155 GW.h
Total	27963 GW.h

Supply

Limited Hydraulic supply	**13800 GW.h**	
Thermal supply	4118 GW.h	
Other Supply	2537 GW.h	
<u>Required Import</u>	**<u>7508 GW.h</u>**	**<u>(857 MW average)</u>**
Total	27963 GW.h	

<u>Required Import with no Thermal 11626 GW.h (1327 MW average)</u>

PUB/MH II-134

Subject: **Tab 12: Corporate Risk Management**

Reference: **Tab 12, Section 12.3, Pages 2/3, ICF Report, 2008 PUB/MH 30(b) Minimum Hydraulic Output**

d) **Please provide a similar analysis of total imports (no thermal) requirements (MW and GWh) that would be involved in meeting 2023/24 and 2028/29 domestic load and committed export contracts if hydraulic generation were:**

- **23,000 GWh (adjusted for Keeyask and Conawapa).**
- **18,500 GWh (adjusted for Keeyask and Conawapa).**

ANSWER:

The values that are summarized on the next page are based on the supply/demand Table 1a from the 2009/10 power resource plan that is referenced in the response to CAC/MSOS/MH I-35(a). The information summarized below is derived by reducing the total hydraulic generation to the levels specified in the information request. It should be noted that the quantities in the information request are below the 28250 GWh in 2023/24 and the 27,950 GWh in 2028/29 to which the Manitoba Hydro system is planned and designed. Supply-side resources other than hydraulic generation such as wind power purchase, transmission upgrades, supply side improvements and demand side management programs are consistent with the 2009/10 power resource plan estimates.

The import requirement for the specified levels of reduced hydraulic generation is provided with and without the consideration of thermal generation. The MW rating of the import requirements is shown assuming an equal loading over every hour of the year.

<u>2023/24</u>

Firm Load

MB Load	29927 GW.h
Export	5116 GW.h
Total	35043 GW.h

Supply

Limited Hydraulic supply	**23000 GW.h**	
Thermal supply	3307 GW.h	
Other Supply	2717 GW.h	
<u>Required Import</u>	**<u>6019 GW.h</u>**	**<u>(687 MW average)</u>**
Total	35043 GW.h	

<u>Required Import with no Thermal 9326 GW.h (1065 MW average)</u>

<u>2023/24</u>

Firm Load

MB Load	29927 GW.h
Export	5116 GW.h
Total	35043 GW.h

Supply

Limited Hydraulic supply	**18500 GW.h**	
Thermal supply	3307 GW.h	
Other Supply	2717 GW.h	
<u>Required Import</u>	**<u>10519 GW.h</u>**	**<u>(1201 MW average)</u>**
Total	35043 GW.h	

<u>Required Import with no Thermal 13826 GW.h (1578 MW average)</u>

2028/29

Firm Load

MB Load	31838 GW.h
Export	3589 GW.h
Total	35427 GW.h

Supply

Limited Hydraulic supply	**23000 GW.h**	
Thermal supply	3307 GW.h	
Other Supply	2636 GW.h	
Required Imports	**6484 GW.h**	**(740 MW average)**
Total	35427 GW.h	

Required Import with no Thermal 9791 GW.h (1118 MW average)

2028/29

Firm Load

MB Load	31838 GW.h
Export	3589 GW.h
Total	35427 GW.h

Supply

Limited Hydraulic supply 18500 GW.h

Thermal supply 3307 GW.h Other Supply

2636 GW.h

Required Import 10984 GW.h (1254 MW average)

Total 35427 GW.h

Required Import with no Thermal 14291 GW.h (1631 MW average)

<u>PUB/MH II-135</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.3, Page 2/3, ICF Report Maximum Imports**

a) Please quantify MH's five highest to date actual annual physical imports (GWh).

<u>ANSWER</u>:

During the period 1990/1990 through 2009/10 the five highest annual physical imports were:

Fiscal Year	Physical Imports (GWh)
1990/91	1,507
1999/00	1,941
2002/03	3,043
2003/04	7,073
2006/07	1,416

<u>PUB/MH II-135</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.3, Page 2/3, ICF Report Maximum Imports**

b) Please identify the years in the historical flow record in which MH would require imports in excess of MH's current total import capability (e.g., about 10,000 GWh).

<u>ANSWER</u>:

The Manitoba Hydro system is planned on the basis of dependable flow conditions which correspond to the lowest flows on record over the last 100 years. The required quantity of import capability that is used in planning the system is below the maximum import capability of the interconnections. The supply/demand tables in the power resource plan provide an indication of planned import requirements. Table 1a is a supply/demand table that can be found in the 2009/10 power resource plan that is referenced in the response to CAC/MSOS/MH I-35(a). This table indicates that Manitoba Hydro would not be required to import more than 2800 GW.h of energy annually in the period to 2019/20 in order to meet forecasted load requirements. This would correspond to about 700 MW of import capability in the off-peak hours, which is less than Manitoba Hydro's maximum import capability. Given the above information that the dependable is the lowest flow condition, there are no flow years that require imports in excess of the current total import capability.

PUB/MH II-136

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Sections 12.1 and 12.2, Pages 1/2/3 Drought Operations**

a) Please indicate when the Corporation anticipates completing the "Drought Preparedness Plan" referred to in the ICF report and when will it be provided to the Board.

ANSWER:

Manitoba Hydro intends to produce the Drought Preparedness Plan by April 1, 2011.

Despite the fact that a formal Drought Preparedness Plan hasn't been produced, Manitoba Hydro continually plans its operations regardless of the current water conditions. The operations planning process considers a range of possible future water conditions over the spectrum from worst one-year drought on record to very high inflows.

PUB/MH II-136

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Sections 12.1 and 12.2, Pages 1/2/3 Drought Operations**

b) What parameters does MH employ to predict an impending drought? List and explain.

ANSWER:

Droughts are not predictable and Manitoba Hydro does not rely on its predictive ability in protecting Manitoba Hydro from the risk of drought. Instead of operating based on predictive ability, Manitoba Hydro plans its operations considering the full range of possible future water supply conditions. Sufficient storage reserves are maintained such that firm demand and exports can be supplied during the most severe single-year drought of record. Relating specifically to water supply, Manitoba Hydro's operations planning process considers the following parameters:

a. historical record of inflow conditions – used to establish the severity of dry conditions that are possible in the future;
b. current usable energy in reservoir storage;
c. existing inflow conditions – tributary flows into the Churchill and Nelson River basins;
d. accumulated snowpack conditions – extreme snowpack conditions (high or low) correlate to spring runoff; and
e. accumulated rainfall - recent rainfall information is used qualitatively to monitor overall basin conditions.

PUB/MH II-136

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Sections 12.1 and 12.2, Pages 1/2/3 Drought Operations**

c) Would below average October-February Winnipeg River/Red River/local Lake Winnipeg watershed precipitation preclude additional firm contracts for the upcoming summer? If not, explain.

ANSWER:

Not necessarily. As discussed in part (b) of this question there are other factors to consider in evaluating Manitoba Hydro’s energy surplus, most notably current energy in storage, current inflows and possible future inflows.

Please also refer to responses provided for PUB/MH I-77 and PUB/MH II-74. Also, as explained in PUB/MH I-90, the Winnipeg River, Red River [and local Lake Winnipeg] basins only make up a portion of the larger Nelson-Churchill River Basin that supplies Manitoba Hydro’s hydraulic generation stations.

PUB/MH II-136

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Sections 12.1 and 12.2, Pages 1/2/3 Drought Operations**

d) Would below average October-April Winnipeg River/Red River/local Lake Winnipeg watershed precipitation preclude off-peak overnight and/or weekend energy sales? Explain.

ANSWER:

Not necessarily. Please refer to the response provided for part (c) of this information request.

PUB/MH II-136

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Sections 12.1 and 12.2, Pages 1/2/3 Drought Operations**

e) **Would below average system energy-in-storage in April, May, or June result in the immediate curtailment of off-peak opportunity sales? Explain on a monthly basis.**

ANSWER:

Manitoba Hydro interprets the phrase "curtailment of off-peak opportunity sales" to mean reduced off-peak sales (as opposed to a curtailment of a contracted sale).

As a part of Manitoba Hydro's operations planning process, Manitoba Hydro may operate its system so as to reduce off-peak sales in the event energy in reservoir storage is below average, if such an operation is needed to maintain required useable energy in reservoir storage and/or the operation is economic. Such an operating decision would consider other parameters in addition to energy in reservoir storage. PUB/MH I-91 explains the operations decision process.

The above explanation applies to April, May and June.

<u>PUB/MH II-136</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Sections 12.1 and 12.2, Pages 1/2/3 Drought Operations**

f) **Would below average May-September precipitation in the Winnipeg River/Red River/local Lake Winnipeg watersheds result in curtailment of peak as well as offpeak opportunity sales? Explain on a monthly basis.**

<u>ANSWER</u>:

Not necessarily. Below average May-September precipitation in these basins would result in below average inflows occurring in these basins. Well below average inflows over the May-September period will result in reduced off-peak exports and possibly increased off-peak imports. Depending on the snowmelt runoff from the prior spring, precipitation and storage conditions in other basins, on-peak sales may be reduced in order to preserve reserve storage for the following year. This activity would typically occur after off-peak imports have been exhausted. If dry conditions persist over the course of the May-September period, conservation operations would increase in intensity (*i.e.*, first reduced off-peak exports, then increased off-peak imports, then reduced on-peak exports).

PUB/MH II-136

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Sections 12.1 and 12.2, Pages 1/2/3 Drought Operations**

g) What specific actions would MH undertake if October energy-in-storage fell below average? Explain.

ANSWER:

The response to this question is dependent on numerous factors including, but not limited to what is the useable energy in storage (*i.e.*, how much below average), inflow conditions, forecast Manitoba load, export contract commitments, thermal generation availability, import capability, etc.

If energy in storage is below average in October but not well below average, Manitoba Hydro may still be exporting power in the off-peak period depending on inflow conditions.

Regardless of the water supply condition, Manitoba hydro will operate in accordance with the System Operations Priorities as provided in the response to PUB/MH I-147(a)(ii), where Priority 1 is to maintain firm energy supply. Depending on the severity of the water supply conditions, including current storage and inflows, Manitoba Hydro continuously evaluates the need to, and merit of, taking the following actions:

- decreased off-peak exports;
- increased off-peak imports;
- financial settlement of existing on-peak export contracts;
- hedging to mitigate price risk for imports and/or gas costs;
- increased on-peak imports;
- operation of gas-fired generation; and
- operation of coal-fired generation (as permitted under *The Climate Change and Emissions Reductions Act*).

Some or all of the above actions could be invoked at any point in the year if deemed necessary to protect firm energy supply.

PUB/MH II-137

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Section 12.1, Page 1 New G&T Cost Impacts**

a) Please confirm and discuss that MH's proposed new G&T projects represent a very substantial business risk in today's electricity market with respect to:

- **New contract prices and volumes.**
- **Uncertain opportunity export market (volume and prices).**
- **Higher Canadian $**
- **Domestic load decline (or growth).**
- **Project cost escalation/higher interest rates.**
- **Environmental uncertainties.**
- **FN equity positions.**

ANSWER:

There is some degree of risk inherent in any future energy decision. Manitoba Hydro has analyzed the business environment and risks and developed a plan to meet the future energy needs of the province while utilizing the export market to provide a stream of net revenue that reduces the revenue required from Manitoba consumers, resulting in lower rates. The risks in Manitoba Hydro's development plans are manageable and the types of risk are not new. Manitoba Hydro has successfully managed similar such risks in the past when its system grew from about 1500 MW of generation in 1969 to over 5300 MW of generation with the completion of Limestone G.S. in 1992.

PUB/MH II-137

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Section 12.1, Page 1 New G&T Cost Impacts**

b) Please confirm that a continuation of the current and possible near future natural gas prices of $5-7/GJ has the potential to drastically reduce MH's 20-year IFF 09-1 export revenues.

ANSWER:

It appears that the assumption is being made in this information request that a continuation of current natural gas prices of $5-7/GJ can be expected to drastically reduce export prices that Manitoba Hydro can achieve in the export market. Manitoba Hydro's forecast for electricity prices is driven by many factors including increased natural gas prices and the impact of CO2 emissions. Therefore, Manitoba Hydro does not confirm that a continuation of current natural gas prices of $5-7/GJ with no consideration for limiting CO2 emissions has the potential to drastically reduce its 20-year IFF 09-1 export revenues. Some reduction in revenues would be expected under this assumption but it would not likely be drastic.

PUB/MH II-137

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12, Section 12.1, Page 1 New G&T Cost Impacts**

c) Please confirm and discuss that in the absence of marked increases in current natural gas prices and/or significant CO2 emissions pricing, the domestic consumer rates would have to be dramatically higher than indicated in 20-year IFF 09-1.

ANSWER:

The response to PUB/MH II-137(b) indicates that Manitoba Hydro's forecast for electricity prices is driven by many factors including natural gas prices and the impact of CO2 emissions. In the absence of increases in natural gas prices and CO2 emissions pricing it is likely that there would be the requirement for higher domestic rates. This, however, points to the importance of long-term firm contracts. The case of low export prices in Appendix 15 can be considered to be a proxy for the scenario described in this information request.

PUB/MH II-138

Subject: **Tab 12: Corporate Risk Management**
Reference: **PUB/MH I-148a) and (b) -Diversity Sales and Purchases**

a) Please complete the following table:

	Diversity Sales	NEB Average Seasonal Opportunity Sale Price	Diversity Purchases
Summer 2002	**219 GWh @ ? ¢/KWh**	**? ¢/KWh**	**168 GWh @ ? ¢/KWh**
Winter 2002-03	**0**	**? ¢/KWh**	**353 GWh @ ? ¢/KWh**
Summer 2003	**400 GWh @ ? ¢/KWh**	**? ¢/KWh**	**0**
Winter 2003-04	**0**	**? ¢/KWh**	**28 GWh @ ? ¢/KWh**
Summer 2006	**320 GWh @ ? ¢/KWh**	**? ¢/KWh**	**0**
Winter 2006/07	**0**	**? ¢/KWh**	**21 GWh @ ? ¢/KWh**

ANSWER:

The NEB average seasonal opportunity sales price is derived from the data submitted to the National Energy Board for energy exported as Interruptible Sales. The Summer season includes months May to October and Winter includes months November to April. See updated table below

	Diversity Sales	NEB Average Seasonal Opportunity Sale Price	Diversity Purchases
Summer 2002	219 GWh @ 4 ¢/KWh	4 ¢/KWh	168 GWh @ 2¢/KWh
Winter 2002-03	0	5 ¢/KWh	353 GWh @ 3 ¢/KWh
Summer 2003	400 GWh @ 5 ¢/KWh	6 ¢/KWh	0
Winter 2003-04	0	8 ¢/KWh	28 GWh @ 4¢/KWh
Summer 2006	320 GWh @ 4¢/KWh	5 ¢/KWh	0
Winter 2006-07	0	8 ¢/KWh	21 GWh @ 10 ¢/KWh

PUB/MH II-138

Subject: **Tab 12: Corporate Risk Management**
Reference: **PUB/MH I-148a) and (b) -Diversity Sales and Purchases**

b) Please explain the economic and other benefits MH derived in these years.

ANSWER:

During the three fiscal years referenced in PUB/MH II-138(a), Manitoba Hydro realized a price for seasonal diversity exports that was approximately CAD $12.13 per MWh greater than the price for seasonal diversity purchases. Therefore Manitoba Hydro realized a net incremental revenue benefit of approximately $8.8 million when this differential is multiplied by the 728,454 MWh's that were purchased during the three year timeframe.

The fixed energy prices contained in the seasonal diversity contracts provide price certainty for a portion of Manitoba Hydro's export revenues. This revenue certainty assists the Corporation in maintaining stable domestic electricity prices for Manitoba customers.

The fundamental rationale for the seasonal diversity contracts when negotiated was and continues to be a seasonal capacity swap and a call on dependable energy under adverse water conditions. In order to facilitate the capacity swap, additional firm transmission facilities were put in place between Manitoba Hydro, Great River Energy and Northern States Power through an upgrade of the US interconnections in the early 1990's. The increased transmission capacity provided for and continues to provide ongoing reliability and economic benefits to Manitoba.

The seasonal diversity contracts provide Manitoba Hydro with the ability to import more energy than it is committed to export. The net import capability of the seasonal diversity contracts enables Manitoba Hydro to avoid building costly new generation facilities to provide energy during periods of low water flows.

PUB/MH II-138

Subject: **Tab 12: Corporate Risk Management**
Reference: **PUB/MH I-148a) and (b) -Diversity Sales and Purchases**

c) **Please discuss how the above price scenario would differ in average and/or above average flow years.**

ANSWER:

The economic benefits described in part b) are a result of contract provisions that allow Manitoba Hydro to take advantage of seasonal market price differences which do not vary as a result of flow conditions in Manitoba.

PUB/MH II-139

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.3, Export Markets (Pages 4 and 5) Market Prices**

a) Please define on a quantitative basis the impacts on the 20-year IFF 09-1 export revenues of:

- **An extended period (5 years) of current natural gas prices of $5/GJ.**
- **An extended period (5 years) of reduced U.S. demand as in the current economic downturn.**
- **An extended period (5 years) of reduced U.S. demand during unusually cool summers.**
- **An extended period (5 years) of increased domestic demand in unusually cold winters.**

ANSWER:

Manitoba Hydro is unable to provide information for this request in the timeframe that is available. Each of the cases described would require significant work in defining the particular sensitivity case, undertaking an analysis and finally providing a response.

PUB/MH II-139

Subject: Tab 12: Corporate Risk Management
Reference: Tab 12.3, Export Markets (Pages 4 and 5) Market Prices

b) Does MH see the above scenarios as potentially coincident or as independent risks? Explain.

ANSWER:

The scenario of an extended period (5 years) of current natural gas prices of $5/GJ and the scenario of an extended period (5 years) of reduced U.S. demand as in the current economic downturn could be potentially coincident since an economic downturn could reduce the demand for natural gas and thus depress price. Manitoba Hydro would consider weather events to be independent of economic events.

The case of low export prices and the case of high export prices provided in Appendix 15 can be considered to be proxies for any number of events or combinations of events which result in increasing or decreasing revenues over an extended period of time.

PUB/MH II-139

Subject: Tab 12: Corporate Risk Management
Reference: Tab 12.3, Export Markets (Pages 4 and 5) Market Prices

c) **Will the mandated renewable energy targets (and subsidies) in the northern MISO states result in higher and more frequent market surpluses and consequently lower demand for MH's exports? Explain.**

ANSWER:

As noted in the response to PUB/MH I-156(c):

> "Wind power, while complementary to hydro in some ways, could be viewed as competition in the renewable energy market. Wind power in the Midwest is an intermittent resource that has slightly higher average output in the off-peak hours in comparison with on-peak hours. As an intermittent resource, wind power is not a dispatchable resource and has limited capacity value, making hydro a superior choice in those areas. In order to operate the power system reliably, most of the resources on the grid must be dispatchable and purchasers cannot rely solely on intermittent resources such as wind power. To the extent that wind power is mandated through state renewable portfolio mandates, wind power is expected to have a slight suppression effect on power market prices, primarily in the off-peak hours when loads are lower and wind output tends to be higher. The increasing development of wind power and other renewable sources of power are considered by the price forecast consultants in preparing their price forecasts."

The wind construction boom in the US appears to have peaked for now. On April 29, 2010 the American Wind Energy Association announced that the U.S. wind industry installed 539 megawatts (MW) in the first quarter of 2010, the lowest first quarter figure since 2007. In comparison, in all of 2009, the U.S. wind energy industry installed over 10,000 MW of new wind power generating capacity. Wind generation currently represents about 5% of the installed generation capacity in the MISO market footprint.

PUB/MH II-140

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.4, Financial Risks, Page 7 Future Revenue Requirements**

a) **Please provide a tabular illustration of the following revenue/cost components that define the full 20-year IFF 09-1 (2009/10 → 2029/30).**

Revenue requirements (GWh/¢/KWh/$ M):

- **Domestic (distribution).**
- **Domestic (G&T).**
- **Exports (net of fuel and power purchases).**
- **Fuel and power purchases.**

ANSWER:

Domestic revenue requirements cannot be broken out further than already shown in the table, as details on operating and capital costs by distribution, generation and transmission are not defined in the IFF period. The same % breakdown as the PCOSS cannot be applied going forward as Manitoba Hydro does not functionalize cost data beyond the study year.

Please refer to the average price table provided in response to PUB/MH-I 45(b).

PUB/MH II-140

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.4, Financial Risks, Page 7 Future Revenue Requirements**

b) Please provide the same tabular illustration as in (a), but without the WPS and MP contract commitments (e.g., Alternative Scenario with respect to the 2008/09 Power Resource Plan.

ANSWER:

The same % breakdown as the PCOSS cannot be applied going forward as costs are not functionalized beyond the study year.

Please see the average price table attached for the Alternative Development Sequence filed in Appendix 15.

IFF09 Alternate Sequence Export Revenue Assumptions

(in GWh)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	33,124	30,525	30,065	30,786	30,990	30,912	30,927	31,158	30,884	30,791	30,809
MH Thermal Generation	152	159	432	437	440	443	496	516	544	573	483
Import Energy (including Wind)	733	1,508	2,616	2,576	2,568	2,604	2,659	2,685	2,758	2,817	2,889
Manitoba Domestic Energy Sales	23,968	24,346	24,728	25,075	25,413	26,030	26,439	26,790	26,743	26,929	27,229
Total Export Sales	9,149	7,122	7,842	8,158	8,036	7,468	7,216	7,166	7,061	6,866	6,548

(in Millions of Dollars)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	$ 111	$ 102	$ 100	$ 103	$ 104	$ 103	$ 103	$ 104	$ 103	$ 103	$ 103
MH Thermal Generation	8	8	41	41	44	45	54	59	65	70	68
Import Energy (including Wind)	36	56	171	172	177	184	195	203	213	221	233
Total Manitoba Domestic Energy Sales	1,160	1,193	1,246	1,305	1,365	1,441	1,510	1,582	1,653	1,725	1,805
Total Export Sales	332	292	517	546	576	552	655	661	671	673	660

Average Price ($/MWh)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	$ 3.36	$ 3.35	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	52.79	52.09	95.96	94.73	99.73	102.49	109.81	115.07	118.63	122.54	140.21
Import Energy (including Wind)	49.69	37.12	65.29	66.79	69.09	70.57	73.38	75.67	77.19	78.60	80.82
Total Manitoba Domestic Energy Sales	48.40	48.99	50.39	52.03	53.69	55.36	57.13	59.05	61.80	64.07	66.30
Total Export Sales	36.24	41.02	65.90	66.88	71.71	73.92	90.81	92.19	95.06	98.02	100.84

IFF09 Alternate Sequence Export Revenue Assumptions

(in GWh)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
MH Hydraulic Generation	30,852	33,296	36,834	37,623	37,528	37,614	37,688	37,709	37,744	37,788
MH Thermal Generation	542	487	398	387	382	305	305	306	307	308
Import Energy (including Wind)	2,902	2,597	2,289	2,326	2,352	2,165	2,164	2,196	2,220	2,254
Manitoba Domestic Energy Sales	27,551	27,893	28,363	28,638	28,979	29,379	29,795	30,215	30,600	31,016
Total Export Sales	6,347	7,903	10,484	10,943	10,550	10,003	9,691	9,359	9,066	8,761

(in Millions of Dollars)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
MH Hydraulic Generation	$ 103	$ 111	$ 123	$ 126	$ 125	$ 126	$ 126	$ 126	$ 126	$ 126
MH Thermal Generation	79	72	60	61	63	52	54	56	58	61
Import Energy (including Wind)	241	221	201	209	215	193	170	191	204	212
Total Manitoba Domestic Energy Sales	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805
Total Export Sales	655	850	1,115	1,205	1,199	1,166	1,169	1,168	1,170	1,168

Average Price ($/MWh)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
MH Hydraulic Generation	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	145.00	147.66	151.91	158.63	163.82	170.52	176.38	182.80	189.59	197.88
Import Energy (including Wind)	83.03	85.00	87.73	89.91	91.60	88.96	78.58	86.93	92.04	93.89
Total Manitoba Domestic Energy Sales	65.52	64.72	63.65	63.04	62.29	61.45	60.59	59.75	58.99	58.20
Total Export Sales	103.27	107.60	106.35	110.15	113.63	116.60	120.66	124.81	129.00	133.31

PUB/MH II-140

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.4, Financial Risks, Page 7 Future Revenue Requirements**

c) Please provide the same tabular illustration as in (a), but without the NSP extension, WPS, and MP contract commitments; deferring Keeyask and/or Conawapa G.S. until after 2030.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-140(b).

PUB/MH II-140

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.4, Financial Risks, Page 7 Future Revenue Requirements**

d) Please provide the same tabular illustration as in (d), but also deferring Bipole III until after 2030.

ANSWER:

Bipole III is required for system reliability and cannot be deferred beyond the currently scheduled in-service date.

<u>PUB/MH II-140</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.4, Financial Risks, Page 7 Future Revenue Requirements**

e) Please confirm that MH's capital forecasts in the above analyses reflect the most recent CEF (identify which project costs have not been updated.

<u>ANSWER</u>:

Manitoba Hydro confirms that the most recent CEF is reflected in PUB/MH II-140 (a).

PUB/MH II-140(b) adjusts the CEF only for Conawapa advancement to 2022, an additional CT in 2034 and Keeyask and the planned interconnection to the US are deleted.

PUB/MH II-141

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.3, Export Markets (Page 4) New Contract Obligations**

a) Please confirm that going forward MH will be contractually committed to providing weekend (2x16) energy at prevailing market prices in the summer months of each year unless a "drought situation" has been previously established. Explain how this "drought situation" would be determined.

ANSWER:

Assuming MP and WPS Agreements are concluded in accordance with the term sheets, Manitoba Hydro will be committed to providing weekend energy year round unless Manitoba Hydro is experiencing adverse water conditions or a force majeure.

Adverse water conditions are when Manitoba Hydro's projections of available water indicate that Manitoba Hydro is or expects to be unable to meet its firm energy commitments from Manitoba Hydro's electrical generation facilities (excluding the importing of energy on-peak by Manitoba Hydro and the operation of Manitoba Hydro gas resources off-peak) in Manitoba.

PUB/MH II-141

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.3, Export Markets (Page 4) New Contract Obligations**

b) Please confirm that MH will be contractually committed to providing weekend (2x16) energy at prevailing market prices in the winter months of each year unless a "drought situation" is declared by a specified date. Explain how this "drought situation" would be determined.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-141(a).

PUB/MH II-141

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.3, Export Markets (Page 4) New Contract Obligations**

c) Please define the probability of significant energy shortfalls due to summer (2x16) and winter (2x16) sales employing the last 30 years and the last 95 years of historic energy supply.

ANSWER:

Manitoba Hydro does not expect any energy shortfalls due to summer (2x16) and winter (2x16) sales. As stated in the response to PUB/MH II-141(a) these sales would not take place during adverse flow conditions when projections of available water indicate that Manitoba Hydro expects to be unable to meet its firm energy commitments from its electrical generation facilities.

PUB/MH II-141

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.3, Export Markets (Page 4) New Contract Obligations**

d) Please estimate the annual magnitude and the aggregate of cost consequences (employing winter peak prices for imports) applying the historic water supply record to 2015/16, 2020/21, and 2025/26 demand situations.

ANSWER:

As stated in the responses to PUB/MH II-141(c), Manitoba Hydro does not expect any energy shortfalls due to summer (2x16) and winter (2x16) sales. Therefore, there is not expected to be any cost consequence from these sales.

PUB/MH II-141

Subject: **Tab 12: Corporate Risk Management**
Reference: **Tab 12.3, Export Markets (Page 4) New Contract Obligations**

e) Please define the potential impacts of summer overnight sales on the frequency of winter energy shortfalls in 2x16 weekend and 5x16 peak period energy supply.

ANSWER:

Manitoba Hydro does not expect any winter energy shortfalls due to summer overnight sales. Summer overnight sales are generally those of lowest value and are undertaken only in situations of high water supply in which there is no available storage capacity to be able to transfer the water to higher value periods such as the winter season when water supply is generally lower and demands are higher. If off-peak (overnight) export sales are not made during such high flow situations, water would have to be spilled with no resulting revenue.

PUB/MH II-142

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report (Pages 95/96) New Contract Obligations**

a) Please confirm that MH will be contractually committed to supplying about 6,200 GWh of peak (5x16 plus 2x16) energy from 2020/21 through 2024/25.

ANSWER:

Subject to not being in adverse water conditions, Manitoba Hydro confirms that it will be committed to supplying approximately 6,200 GWh of on-peak and weekend energy per year during 2020/21 through 2024/25.

<u>**PUB/MH II-142**</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report (Pages 95/96) New Contract Obligations**

b) **Please confirm that under the dependable definition, MH would be required to supply as much as 9,000 GWh (imports and/or thermal generation) to fulfill the contractor obligations to NSP/WPS/MP.**

<u>**ANSWER**</u>**:**

Assuming that;

- Agreement is reached with WPS and MP,
- A major new interconnection is constructed,
- Manitoba Hydro builds Keeyask and Conawapa, and
- Manitoba Hydro exercises its right to increase its sales to NSP by 125 MW,

Manitoba Hydro’s dependable energy obligation then increases by approximately 5,600 GWh which will be more than amply supplied by the additional 7,450 GWh of dependable hydraulic energy from Keeyask and Conawapa.

PUB/MH II-142

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report (Pages 95/96) New Contract Obligations

c) Please confirm that the summer week sales could carry relatively low prices going into a historical drought year, but that MH would be faced with buying the bulk of the drought shorting at higher winter and shortfall prices. Discuss.

ANSWER:

Manitoba Hydro's new sales energy obligations can be met entirely from new dependable hydraulic generation from Keeyask and Conawapa. Therefore, there is no need to purchase energy to serve the sales obligations.

<u>PUB/MH II-142</u>

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report (Pages 95/96) New Contract Obligations

d) Would exclusion of the 2x16 sales void the WPS on MP letters of intent?

<u>ANSWER</u>:

The term sheets with WPS and MP are not binding contracts. The term sheets document mutually beneficial negotiations and the exclusion of any component may result in the renegotiation of the balance of the terms.

<u>PUB/MH II-143</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **PUB/MH I – 211 (b) - Tab 13.4 (3) Maximizing Export Sales w/o WPS & MP Sales**

a) Please provide a tabulation of the 20 yr IFF 09-1 assumed revenue rates for both 5x16 peak and off-peak sales.

<u>ANSWER</u>:

Manitoba Hydro has provided information on the average annual export prices for the 20 year financial outlook in the response to PUB/MH I-209 which included low and high export price scenarios as well as the expected scenario. The breakdown of prices for future expected export sales into 5x16 peak and off-peak components is commercially sensitive information, and therefore is confidential since public release could harm the Corporation in negotiation of contracts for export sales. Consequently, the requested information on prices for 5x16 peak and off-peak sales for the 20 year financial outlook is not being provided.

PUB/MH II-143

Subject: **Tab 12: Corporate Risk Management**
Reference: **PUB/MH I – 211 (b) - Tab 13.4 (3) Maximizing Export Sales w/o WPS & MP Sales**

b) Please provide a tabulation of an alternate 20 yr IFF 09-1 (without WPS & MP contracts) revenue rates for 5x16 peak and off-peak sales.

ANSWER:

Similar to the response to PUB/MH II-143(a), the breakdown of prices for future expected export sales into 5x16 peak and off-peak components is commercially sensitive information, and therefore is confidential since public release could harm the Corporation in negotiation of contracts for export sales. Consequently, the requested information on prices for 5x16 peak and off-peak sales for an alternative development plan is not being provided.

PUB/MH II-143

Subject: **Tab 12: Corporate Risk Management**

Reference: **PUB/MH I – 211 (b) - Tab 13.4 (3) Maximizing Export Sales w/o WPS & MP Sales**

c) **Please confirm that MH would, in the absence of firm contract sales to WPS & MP, be offering an additional 3500 GWh/yr of 5x16 and 700 GWh of 2x16 energy into the MISO Market.**

ANSWER:

Manitoba Hydro is unable to identify the source for the 3500 GWh/yr of 5x16 and 700 GWh of 2x16 energy or the time period for this estimate.

In the absence of firm contract sales to WPS & MP, one of the options for Manitoba Hydro is to undertake the alternative development plan in which the next resource addition is planned to be the Conawapa G.S. in 2021/22 without the early development of the Keeyask G.S. The addition of Conawapa is expected to contribute 4550 GW.h of dependable energy and 7000 GW.h of energy on average over the range of flow conditions. The NSP 375/500 MW firm sale is expected to utilize a portion of the dependable energy from Conawapa up to the year 2025/26. Please refer to the supply/demand Table 2a that can be found in the 2009 Power Resource Plan that is referenced in the response to CAC/MSOS/MH I-35(a). This table provides the surplus dependable energy for export sales in each year that result from the alternative development plan.

PUB/MH II-143

Subject: **Tab 12: Corporate Risk Management**
Reference: **PUB/MH I – 211 (b) - Tab 13.4 (3) Maximizing Export Sales w/o WPS & MP Sales**

d) Would this additional energy command higher or lower revenue rates than defined in MH's IFF 09-1? Explain the change for high/median/low flow situations.

ANSWER:

The energy that is referenced in the response to PUB/MH II-143(c) is dependable energy. The revenue from this energy would be derived from a long-term firm contract at a pre-defined price. The value would not be dependent on high, median or low flow conditions. It is unknown whether the prices for new contracts would be higher or lower than the prices forecasted in IFF09-1.

PUB/MH II-144

Subject: **Tab 13 Board Directives**
Reference: **December 18, 2009 MH Letter to PUB; February 2010 Report/Attachment #1; August 7, 2009 Application**

a) **Please indicate which (if any) of the 53 to 67 eligible customers and 17 to 25 approved customers were previously subject to the winter ratchet for billing demand determination.**

ANSWER:

None of the 53 - 67 eligible customers or 17 - 25 approved customers were subject to the winter ratchet for billing demand during the 24 month period used to determine the baseline for the Billing Demand Deferral program.

PUB/MH II-144

Subject: **Tab 13 Board Directives**
Reference: **December 18, 2009 MH Letter to PUB; February 2010 Report/Attachment #1; August 7, 2009 Application**

b) **Please provide a tabulation of class actual and billable demands/revenues for June to November 2009 assuming:**

- **Actual situation (including demand concessions).**
- **Normal situation (without demand concession).**
- **Normal situation (winter ratchet eliminated).**

ANSWER:

The class actual and billable demand and revenues for the Jun 09 - Nov 09 for those customers participating in the Billing Demand Deferral program were as follows:

Actual Situation (including billing demand deferrals)

Class	Recorded	Billed	Revenue
GS Medium	31,308	26,671	$ 415,350
GS Large 750V-30 kV	114,722	89,188	$ 1,235,968
GS Large 30-100 kV	54,759	45,104	$ 806,076
GS Large >100 kV	621,110	633,642	$ 8,105,594

Normal Situation (without billing demand deferrals)

Class	Recorded	Billed	Revenue
GS Medium	31,308	31,595	$ 456,414
GS Large 750V-30 kV	114,722	114,722	$ 1,407,285
GS Large 30-100 kV	54,759	61,077	$ 902,871
GS Large >100 kV	621,110	815,497	$ 9,087,608

Normal Situation (with winter ratchet eliminated)

Class	Recorded	Billed	Revenue
GS Medium	31,308	31,308	$ 454,018
GS Large 750V-30 kV	114,722	114,722	$ 1,407,285
GS Large 30-100 kV	54,759	54,759	$ 864,585
GS Large >100 kV	621,110	678,488	$ 8,347,763

<u>PUB/MH II-144</u>

Subject: **Tab 13 Board Directives**

Reference: **December 18, 2009 MH Letter to PUB; February 2010 Report/Attachment #1; August 7, 2009 Application**

c) **Please confirm that the elimination of the winter ratchet will not significantly change customer demand billings during the months of December 2009/January/February/March 2010.**

<u>ANSWER</u>:

Confirmed.

<u>PUB/MH II-145</u>

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-165 (a) Pages 3 and 4 of 6, Demand Billing Reductions**

a) **Please confirm that hypothetical elimination of the 70% winter ratchet as of June 1, 2009 would have given 2 GSL >100 KV customers a billing reduction of $723,000 or about 70% of what might have been granted if their demand concession application were fully approved.**

<u>ANSWER</u>:

Hypothetical elimination of the 70 percent winter ratchet as of June 1, 2009 would have given two General Service Large (>100 kV) customers a billing demand reduction of approximately $645,000.

PUB/MH II-145

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-165 (a) Pages 3 and 4 of 6, Demand Billing Reductions**

b) **Please confirm (and quantify) that going forward from December 1, 2009, these two and possibly other customers may see a substantial bill reduction if their monthly demand levels continue at 25% or less of past averages.**

ANSWER:

These two customers would have continued to see similar monthly billing demand reductions as determined in response to PUB/MH II-145(a) if their measured demand levels had remained at the levels recorded during the program period. The amount of these billing demand reductions would have been approximately $220,000 per month.

Other customers would have seen billing demand reductions as well if their measured demand levels had remained at the levels recorded during the program period. The amount of these billing demand reductions would have been approximately $20,000 per month.

PUB/MH II-146

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-181(d) - Recent Demand Billing Rates**

a) **Please confirm that MH has effectively frozen demand charges for the last five to six years.**

ANSWER:

Confirmed.

PUB/MH II-146

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-181(d) - Recent Demand Billing Rates**

b) Please provide a breakdown for each subclass and industry sector of the "foregone revenue from demand charge increases" that the accumulated (from F2004-F2009) rate increases would theoretically have permitted on an across-the-board basis.

ANSWER:

The table included below provides the calculated cumulative demand revenues from 2004/05 to 2008/2009 for all demand-billed rate classes had rate increases been applied equally to the demand and energy portion of the rate. For each year demand revenue at the April 2004 approved kVA rate was compared with demand revenue calculated at an adjusted demand rate which incorporated that year's rate increase, if any. The adjusted Demand rate incorporated the cumulative rate increases for the period August 1, 2004 to March 31, 2009 multiplied by the 2004 Demand rate.

Over the 5 year period $68.9 million in additional revenue would have been collected through increased demand charges. In the absence of these higher demand charges the revenue was collected instead through higher Energy Charges, which as a result, were higher in order to compensate for the static Demand Charges.

It is impossible to provide a breakdown of the information by industry sector as Manitoba Hydro does not provide revenue forecasts by industry type for all customer classes.

	Apr-04 kVa Rate	Adj 09 kVa Rate	Cumulative Increase	2010/11 kVa Rev @ Current	2010/11 kVa Rev @ Revised	Difference
Small	$8.32	$9.59	13.24%	$86,758,847	$94,141,764	$7,382,917
Medium	$8.32	$9.59	13.24%	323,421,688	350,310,283	26,888,596
Lrg <30	$7.09	$8.17	13.24%	125,189,620	135,843,363	10,653,742
Lrg 30-100	$6.05	$6.97	13.24%	53,793,795	58,424,453	4,630,657
Lrg >100	$5.40	$6.23	13.24%	228,111,721	247,453,697	19,341,976
				$817,275,671	$886,173,560	$68,897,889

PUB/MH II-146

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-181(d) - Recent Demand Billing Rates**

c) **Please provide a class-specific breakdown of the favorable impact (benefit) of foregone demand rate increases on 2009/10 actual billings for approved demand concession customers.**

ANSWER:

The table below provides a breakdown of the foregone demand rate increases from 2004 to 2009 on 2009/10 actual billings for approved demand concession customer. The concession amounts processed in 2009 are also shown, comparing the concession revenue at the 2009 demand rate versus the adjusted demand rate as calculated in response to PUB/MH II-146(b).

	2009/10 Billings (excl Concessions)			Concessions Only		
Sub-Class	**kVA Rev @ 2004 Rate**	**kVA Rev @ Adj Rate**	**Diff in Revenue**	**Conc. kVA @ 2009 Rate**	**Conc. kVA @ Adj Rate**	**Diff in Revenue**
Medium	$535,784	$638,888	$104,104	$41,065	$48,696	$7,632
Lrg <30	1,619,090	1,925,367	306,277	171,316	215,251	43,935
Lrg 30-100	715,837	849,399	133,561	96,794	114,684	17,889
Lrg >100	7,543,726	8,966,991	1,423,265	982,014	1,167,505	185,491
			$1,964,208			$254,948

PUB/MH II-147

Subject: Tab 13 Board Directives
Reference: PUB/MH I-184, PUB/MH I-190

a) **Please provide the customer numbers and unit consumption by class for each of the four diesel communities for 1992 to 2009 and forecast for the two test years.**

ANSWER:

Brochet

Fiscal Year	Residential Customers	Res Ave. use kW.h/yr	GS Customers	GS Ave. use kW.h/yr
1992/93	86	7191	35	17827
1993/94	92	7469	36	19958
1994/95	97	9682	36	18551
1995/96	97	12086	31	24323
1996/97	103	10576	33	22019
1997/98	104	11250	31	23789
1998/99	113	11123	36	21436
1999/00	116	12923	36	21630
2000/01	115	12407	37	19653
2001/02	114	13266	39	21783
2002/03	122	12168	40	19029
2003/04	114	13030	41	18797
2004/05	114	13641	41	25487
2005/06	117	13476	42	25257
2006/07	124	12968	41	27311
2007/08	122	13363	43	21924
2008/09	121	13910	43	23758
2009/10	120	13404	43	22007
Fcst 2010/11	121	13424	44	24052
Fcst 2011/12	122	13424	45	24052

Lac Brochet

Fiscal Year	Residential Customers	Res Aveuse kW.h/yr	GS Customers	GS Ave. use kW.h/yr
1992/93	95	6051	32	17748
1993/94	100	6455	33	16493
1994/95	106	6583	36	22902
1995/96	111	6940	41	30801
1996/97	120	7213	40	27634
1997/98	118	7702	41	31772
1998/99	123	8027	40	27209
1999/00	139	8081	41	29621
2000/01	132	10261	50	31787
2001/02	134	11313	47	31923
2002/03	134	12759	49	23602
2003/04	133	13707	48	27897
2004/05	134	12788	45	27021
2005/06	138	13208	49	25740
2006/07	139	13933	49	26001
2007/08	138	13171	50	24706
2008/09	137	13280	51	26175
2009/10	138	13590	52	30208
Fcst 2010/11	139	13436	53	29870
Fcst 2011/12	140	13792	54	30660

Tadoule Lake

Fiscal Year	Residential Customers	Res Ave. use kW.h/yr	GS Customers	GS Ave. use kW.h/yr
1992/93	81	3508	19	10476
1993/94	82	4066	23	10756
1994/95	87	3966	26	12813
1995/96	98	4695	31	17331
1996/97	101	5293	30	20078
1997/98	99	5377	30	21543
1998/99	95	5961	31	20361
1999/00	112	5859	32	25459
2000/01	111	7072	31	29700
2001/02	107	9554	29	41221
2002/03	109	7766	31	27111
2003/04	107	9003	30	26964
2004/05	107	10268	36	27574
2005/06	114	9792	37	28123
2006/07	119	10060	36	25846
2007/08	115	10016	39	25037
2008/09	113	10636	42	24143
2009/10	110	10583	41	25517
Fcst 2010/11	114	10850	42	26160
Fcst 2011/12	114	11118	43	26810

Shamattawa

Fiscal Year	Residential Customers	Res Ave. use kW.h/yr	GS Customers	GS Ave. use kW.h/yr
1992/93	102	5914	21	38609
1993/94	113	6073	22	38349
1994/95	116	5858	26	36515
1995/96	120	5917	27	33580
1996/97	120	6715	28	38504
1997/98	118	7874	29	38872
1998/99	143	7331	32	35197
1999/00	149	9443	35	36900
2000/01	147	11095	33	49937
2001/02	148	11312	35	52102
2002/03	138	13757	35	47230
2003/04	153	12269	36	45171
2004/05	154	14249	45	37703
2005/06	151	13489	43	40438
2006/07	149	14448	43	43165
2007/08	155	14532	43	44538
2008/09	168	15661	42	46312
2009/10	172	16468	41	47729
Fcst 2010/11	175	17041	42	49390
Fcst 2011/12	178	17614	43	51050

PUB/MH II-147

Subject: Tab 13 Board Directives
Reference: PUB/MH I-184, PUB/MH I-190

b) Please provide the customer numbers and unit consumption by class for each of the North Central communities for 1992 to 2009 and forecast for the two test years.

ANSWER:

Manitoba Hydro does not forecast the load for individual communities that are on the integrated system. The following table provides the history electric use for the seven communities.

Oxford House

Fiscal Year	Residential Cust	Res Aveuse kW.h/yr	GS Cust	GS Aveuse kW.h/yr
1992/93	282	5919	56	32697
1993/94	284	6024	57	31985
1994/95	292	6175	58	30839
1995/96	305	5461	62	30663
1996/97	318	6148	68	32040
1997/98	346	8114	59	53944
1998/99	354	8459	64	55538
1999/00	354	11346	58	92099
2000/01	363	13317	54	105876
2001/02	373	15415	52	156978
2002/03	389	19211	53	84188
2003/04	392	19696	60	111256
2004/05	402	22920	62	128123
2005/06	402	22644	59	122960
2006/07	411	25234	60	133916
2007/08	419	27823	60	144872
2008/09	414	29875	58	149483

God's Lake Narrows

Fiscal Year	Residential Cust	Res Aveuse kW.h/yr	GS Cust	GS Aveuse kW.h/yr
1992/93	208	6314	66	25848
1993/94	218	5954	76	24670
1994/95	224	5891	95	20938
1995/96	227	6028	118	20636
1996/97	234	5809	139	20054
1997/98	297	9573	96	24838
1998/99	313	15454	103	41133
1999/00	317	16435	102	50124
2000/01	313	18731	97	57199
2001/02	312	21325	98	55421
2002/03	320	24950	95	65734
2003/04	326	23580	95	61643
2004/05	326	27074	95	68528
2005/06	326	25924	94	66700
2006/07	330	26703	90	70852
2007/08	334	27482	85	75003
2008/09	333	27439	83	71333

God's River

Fiscal Year	Residential Cust	Res Aveuse kW.h/yr	GS Cust	GS Aveuse kW.h/yr
1992/93	68	6663	30	13082
1993/94	72	7159	31	13738
1994/95	78	6681	31	14238
1995/96	78	6818	33	16187
1996/97	80	7938	36	20667
1997/98	90	11720	33	28121
1998/99	97	23786	32	35650
1999/00	100	28196	36	39378
2000/01	98	30918	36	61764
2001/02	93	31262	36	66258
2002/03	96	34715	36	76515
2003/04	96	32634	37	66260
2004/05	96	36198	37	84919
2005/06	96	35786	38	72151
2006/07	96	36990	36	78633
2007/08	96	38195	35	85115
2008/09	96	39713	35	82668

Red Sucker Lake

Fiscal Year	Residential Cust	Res Aveuse kW.h/yr	GS Cust	GS Aveuse kW.h/yr
1992/93	96	6331	29	17877
1993/94	98	6475	32	19212
1994/95	118	5977	38	18820
1995/96	129	6221	41	24985
1996/97	126	6600	42	24932
1997/98	127	6750	42	24328
1998/99	149	7117	30	26569
1999/00	165	12257	31	28943
2000/01	175	15275	34	32068
2001/02	181	17524	32	37723
2002/03	180	18582	32	46889
2003/04	179	19759	32	61415
2004/05	179	21779	28	95387
2005/06	181	21924	29	83793
2006/07	150	28763	30	81402
2007/08	119	35603	32	79010
2008/09	168	25354	32	79952

St. Theresa Point

Fiscal Year	Residential Cust	Res Aveuse kW.h/yr	GS Cust	GS Aveuse kW.h/yr
1992/93	325	6490	66	22895
1993/94	332	6744	71	23841
1994/95	346	6448	77	24694
1995/96	361	7030	75	27661
1996/97	371	7044	74	27970
1997/98	382	7191	76	29089
1998/99	399	7261	81	27059
1999/00	442	8426	72	52891
2000/01	455	10141	78	61571
2001/02	459	11949	81	62686
2002/03	462	15815	79	65637
2003/04	469	16383	83	63916
2004/05	462	22152	82	70269
2005/06	476	21080	83	61870
2006/07	491	22950	83	67716
2007/08	505	24820	83	73563
2008/09	520	26060	84	71840

Garden Hill

Fiscal Year	Residential Cust	Res Aveuse kW.h/yr	GS Cust	GS Aveuse kW.h/yr
1992/93	380	6513	99	21966
1993/94	393	6434	106	24446
1994/95	431	6271	109	26142
1995/96	428	6468	108	28108
1996/97	458	6438	111	27457
1997/98	457	6697	119	29007
1998/99	450	7167	128	29452
1999/00	489	8774	113	42554
2000/01	527	10626	123	62916
2001/02	550	12245	116	84453
2002/03	547	15872	105	107496
2003/04	529	15881	105	104701
2004/05	517	18194	108	108111
2005/06	526	19187	109	96925
2006/07	515	20355	82	131253
2007/08	503	21523	55	165581
2008/09	536	24080	57	154223

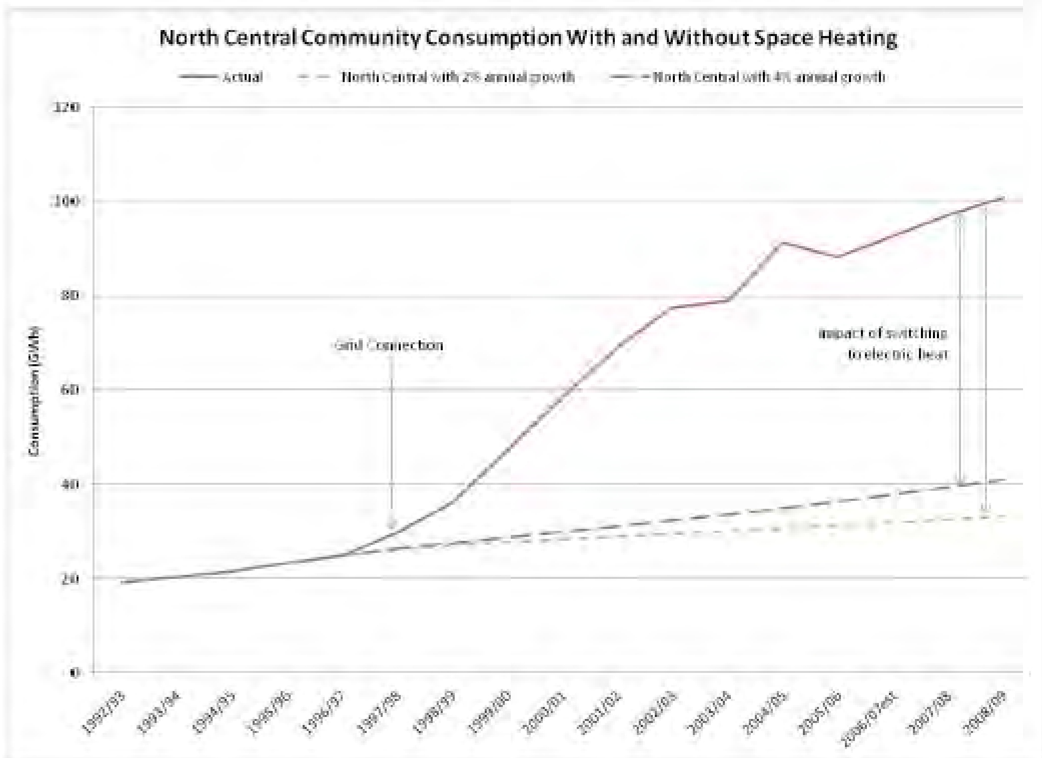
Wasagamack

Fiscal Year	Residential Cust	Res Aveuse kW.h/yr	GS Cust	GS Aveuse kW.h/yr
1992/93	127	6591	18	55467
1993/94	139	7116	20	55757
1994/95	157	6417	22	54769
1995/96	163	7320	26	46987
1996/97	171	7190	31	38134
1997/98	174	7515	37	38769
1998/99	184	7619	36	44051
1999/00	195	8991	32	49041
2000/01	221	10615	34	57368
2001/02	233	11784	41	77322
2002/03	229	14201	41	106617
2003/04	224	14816	40	97204
2004/05	223	18776	37	111658
2005/06	236	17636	41	99243
2006/07	230	19681	43	95478
2007/08	224	21725	45	91714
2008/09	226	22855	44	97848

PUB/MH II-147

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-184, PUB/MH I-190**

c) **Plotted below is the annual consumption of the North Central communities from PUB/MH I-184(a). Please confirm that conversion to space heating added at least 100% to the projected annual consumption, assuming population growth between 2 and 4%.**



ANSWER:

Confirmed. Conversion to space heating added at least 100% to the annual consumption.

<u>PUB/MH II-147</u>

Subject: Tab 13 Board Directives
Reference: PUB/MH I-184, PUB/MH I-190

d) Please comment on whether MH expects similar consumption growth of 2.5 to 3 times current consumption if 200A service is introduced to the four diesel communities.

<u>ANSWER</u>:

When the North Central communities switched from 15 amp service to 200 amp, their usage grew approximately by four times.

When the four diesel communities were converted from 15 amp service to 60 amp during the 1990's, their consumption approximately doubled their average use. Moving from 60 amp to 200 amp would probably result in another doubling of the average use.

<u>PUB/MH II-147</u>

Subject: Tab 13 Board Directives
Reference: PUB/MH I-184, PUB/MH I-190

e) **Please also comment on whether MH expects a proliferation of supplemental electric space heating with the introduction of grid rates even if residential electric services remain limited to 60A.**

<u>ANSWER</u>:

The usage of the communities doubled when their service was enhanced to 60 amp. Lower electricity rates should encourage customers to use more electricity. The extent to which this may occur is difficult to forecast with service limited to 60 A.

PUB/MH II-147

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-184, PUB/MH I-190**

f) Please confirm that the majority of residential customers in the four diesel communities use electricity for hot water heating.

ANSWER:

Confirmed, the majority of residential homes use electric hot water tanks.

PUB/MH II-147

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-184, PUB/MH I-190**

g) Please give MH's understanding of whether the majority of homes and businesses in the North Central communities have switched to electric heat through the use of baseboard heaters or with forced air-type furnaces.

ANSWER:

The majority of customers in the North Central communities have switched to electric heat.

PUB/MH II-148

Subject: Tab 13 Board Directives
Reference: PCOSS 09-1 February 2010 Report Attachment #1

Please provide a tabulation of demand charge revenues and PCOSS 09-1 allocated demand or non-energy costs:

	Actual Demand (MVA)	**Billed Demand (MVA)**	**Demand Revenue ($/KVA)**	**Pre-Credit Allocated Non-Energy Costs ($/KVA)**
GSS-D				
GSM				
GSL <30				
GSL 30-100				
GSL >100				

ANSWER:

The following includes actual and billed demand for fiscal year 2009/10, and Demand charges effective April 1, 2009. Demand costs are taken from PCOSS10 as filed in this proceeding; not PCOSS09 as cited in the reference.

	Actual Demand (MVA)	**Billed Demand (MVA)**	**April 1, 2009 Demand Charge ($/KVA)**	**PCOSS10 Demand Costs Before Net Export Revenue Allocation ($/KVA)**
GSS-D	5,901	2,247	8.34	8.58
GSM	7,832	7,057	8.35	9.77
GSL <30	3,619	3,727	7.08	9.58*
GSL 30-100	2,035	2,071	6.06	5.30*
GSL >100	7,962	8,237	5.40	3.67*

* Includes recovery of Customer costs.

PUB/MH II-149

Subject: **Tab 13 Board Directives**
Reference: **February 2010 Report Attachment #1**

Please provide a breakdown of GSM and GSL total deferral amounts (in Attachment #1) by the following industry types:

- **Chemical**
- **Petroleum transport**
- **Primary metals**
- **Pulp and paper**
- **Institutional**
- **Commercial**

ANSWER:

Total deferral amounts referenced in Attachment 1 by industry types

Industry Type	Deferral Amount
Chemical	$ 0
Petroleum Transport	$ 0
Primary Metals	$ 578,292
Pulp and Paper	$ 540,323
Institutional	$ 0
Commercial	$ 0
Mining	$ 117,492
Miscellaneous Industrial	$ 52,518
Warehouse	$ 2,563

PUB/MH II-150

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-176 Rate Regulated Accounting; PUB/MH I-16**

a) Please clarify on what is meant by rate regulated accounting would likely prevail and indicate what if any accounting adjustments were made to IFF09-1 and the 20-year Outlook.

ANSWER:

At the time of the preparation of IFF09-1 and the 20 year financial outlook, Manitoba Hydro assumed that some form of rate regulated accounting would prevail based on the recent release of the IASB exposure draft for rate regulated activities.

While Manitoba Hydro didn’t make any specific adjustments with respect to rate regulated accounting, IFF09-1 includes a $15 million general provision for IFRS for potential changes such as accounting for property, plant and equipment, regulatory accounting, employee benefits and the first-time adoption of IFRS (IFRS1).

PUB/MH II-150

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-176 Rate Regulated Accounting; PUB/MH I-16**

b) Please provide a continuity schedule of retained earnings in IFF09 separately indicating each adjustment to retained earnings made related to compliance with new GAAP and IFRS and specifically identify the transitional adjusting entries made related to rate –regulated assets and liabilities and indicate whether such adjustments would be necessary if the Exposure Draft as drafted is adopted. Explain.

ANSWER:

Please see the attached table below. Please note that IFF09-1 did not include any transitional adjusting entries related to rate-regulated assets and liabilities as it was assumed that a standard for rate regulated assets and liabilities would be approved by the IASB in time for Manitoba Hydro's conversion to IFRS.

ELECTRIC OPERATIONS (MH09-1)

Detailed impacts to retained earnings for changes in GAAP and conversion to IFRS

(in millions of dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Cumulative
GAAP Adjustments:												
Intangible Asset Adjustments												
Demand Side Management (DSM)	(5.0)											
Planning Studies	(18.0)											
IT Application Development	(3.0)											
Annual Reduction in DSM capitalized	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	
Annual Reduction in Planning Studies capitalized	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	
Annual Reduction in IT application capitalized	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	
Annual Reduction in Stores Overhead Capitalized	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	
Annual Reduction in General Admin & Overhead Capitalized	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	
Reduction in annual amortization*	4.0	5.0	5.0	6.0	6.0	7.0	7.0	7.0	7.0	7.0	8.0	
Total	**(33.0)**	**(6.0)**	**(6.0)**	**(5.0)**	**(5.0)**	**(4.0)**	**(4.0)**	**(4.0)**	**(4.0)**	**(4.0)**	**(3.0)**	**(78.0)**
IFRS Adjustments:												
Adjust pension balance for transition to fair value method			(13.0)									
Adjust benefits for recognition of unvested liabilities			(4.0)									
Annual reduction in indirect OH capitalized			(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	
Reduction in annual amortization*			-	-	1.0	2.0	2.0	3.0	4.0	4.0	5.0	
Total	**-**	**-**	**(32.0)**	**(15.0)**	**(14.0)**	**(13.0)**	**(13.0)**	**(12.0)**	**(11.0)**	**(11.0)**	**(10.0)**	**(131.0)**
TOTAL ANNUAL IMPACT TO RETAINED EARNINGS	**(33.0)**	**(6.0)**	**(38.0)**	**(20.0)**	**(19.0)**	**(17.0)**	**(17.0)**	**(16.0)**	**(15.0)**	**(15.0)**	**(13.0)**	**(209.0)**

**** Represents the annual reduction in amortization resulting from write downs to opening deferred balances and reductions in future amounts capitalized***

PUB/MH II-150

Subject: **Tab 13 Board Directives**

Reference: **PUB/MH I-176 Rate Regulated Accounting; PUB/MH I-16**

c) Please file PUB/MH I (c) dated February 20, 2009 as a document to this proceeding and indicate whether any of the adjustments to retained earnings reflected in the document are currently incorporated in IFF09. Please identify adjustments related to rate-regulated assets and liabilities.

ANSWER:

Please see the attachment for PUB/MH I(c) dated February 20, 2009.

The following table summarizes the IFF08 and IFF09 adjustments:

IFF08	IFF09
Includes a write-down to retained earnings of $50 million for 2009/10 for ineligible research and promotion charges re: CICA Intangible Assets Standard changes.	Includes a write-down to retained earnings of $26 million for 2009/10 for ineligible research and promotion charges re: CICA Intangible Assets Standard changes.
Includes a write-down to retained earnings of $59 million for 2011/12 for rate regulated assets - assuming IFRS would not have a standard for rate regulated accounting.	Assumes IFRS would have a standard for rate regulated accounting and therefore does not have an adjustment for rate regulated assets.
Includes a $10 million annual charge for ineligible research, promotion and indirect overhead charges not considered eligible for capitalization.	Includes an $11 million annual charge for ineligible research, promotion and indirect overhead charges not considered eligible for capitalization.
Includes a $15 million annual charge for reductions in capitalized overhead and general administrative expenditures.	Includes a $15 million annual charge for reductions in capitalized overhead and general administrative expenditures.
Includes reductions in annual amortization expense for reductions in capitalized expenditures and for retained earnings adjustments for ineligible research and promotion charges and rate regulated items.	Includes reductions in annual amortization expense for reductions in capitalized expenditures and for retained earnings adjustments for ineligible research and promotion charges and rate regulated items.

PUB/MH-1

Reference: IFRS Appendix 4.2, IFF08-1

Section 2.2 of IFF08-1 states that for the years 2011/12 and on, IFF 08 - 1 includes provision for the more certain aspects of the conversion to IFRS in the amount of $25 million less offsets due to the corresponding reductions in depreciation and amortization expense.

c) Please provide a detailed schedule, by year, of the IFRS changes incorporated into IFF08-1.

ANSWER:

Please see the following schedule. Due to the preliminary nature of the IFRS provisions, the individual impacts to operating and administrative and depreciation expenses were netted together and included in the depreciation expense line item in IFF08-1.

IMPACTS OF IFRS PROVISIONS ON CONSOLIDATED PROJECTED OPERATING STATEMENT
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES											
General Consumers Revenue	0	0	0	0	0	0	0	0	0	0	0
Extraprovincial	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
EXPENSES											
Finance Expense	0	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(2)
Operating & Administrative	0	0	0	0	0	0	0	0	(0)	0	0
Depreciation & Amortization[1]	0	6	6	17	15	14	14	13	13	13	12
Water Rentals & Assessments	0	0	0	0	0	0	0	0	0	0	0
Fuel & Power Purchased	0	0	0	0	0	0	0	0	0	0	0
Capital & Other Taxes	0	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Cost of Gas Sold	0	0	0	0	0	0	0	0	0	0	0
	0	6	5	16	14	13	12	12	11	11	9
Noncontrolling Interest	0	0	0	0	0	0	0	0	0	0	0
Net Income	0	(6)	(5)	(16)	(14)	(13)	(12)	(12)	(11)	(11)	(9)
Retain Earnings	0	(56)	(61)	(136)	(150)	(163)	(175)	(187)	(197)	(208)	(217)

[1] Depreciation & Amortization:

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reclass projected intangible and IFRS expenditures from deferred to period costs	0	10	10	25	25	25	25	25	25	25	25
Depreciation reductions for:											
Reclassed projected costs from deferred to O&A	0	(0)	(0)	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)
Retained earnings writeoff for CICA intangible assets	0	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Retained earnings writeoff for IFRS rate regulated assets	0	0	0	(3)	(5)	(5)	(5)	(5)	(5)	(5)	(4)
	0	6	6	17	15	14	14	13	13	13	12

PUB/MH II-150

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-176 Rate Regulated Accounting; PUB/MH I-16**

d) **Please provide a similar schedule to (c) reflecting the adjustments for IFRS incorporated in IFF09-1.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-150(b) for a similar schedule reflecting the adjustments for IFRS incorporated in IFF09-1.

<u>**PUB/MH II-151**</u>

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-179 (a) & (h)**

a) **Please file Exhibit # 20 dated June 22, 2009 from the 2009/10 and 2010/11 Centra GRA and provide an update and reconciliation with the analysis provided at this hearing.**

<u>ANSWER</u>:

Please see the following attachment for a copy of Exhibit #20 from the 2009/10 & 2010/11 Centra GRA.

Please see the attached tables.

444 St. Mary Costs

(in thousands of $)	
Annual Rent	$1,064
Common Area Maintenance	724
Operations	36
Property & Business Tax	235
Annual Cost	**$2,060**
Square footage	78,642
Cost per square foot	**$26**
Cost per square foot (Exhibit #20 2009/10 Gas GRA)	**$29**

The costs presented in Exhibit 20, from the 2009/10 Gas GRA, were based upon Centra's estimate of entering into a new lease. Also, the square footage provided in this response was understated.

The costs presented in PUB/MH I-179(a) are based on the last full year of costs incurred by Manitoba Hydro to lease 444 St. Mary.

360 Portage Projected Costs - 2010/11

(in thousands of $)	
Operating & Maintenance	$3,201
Property & Business Tax	4,862
Depreciation	3,093
Interest	15,990
Projected Annual Cost	**$27,147**
Square footage	697,609
Cost per square foot	**$39**
Cost per square foot (Exhibit #20 2009/10 Gas GRA)	**$44**

The costs presented in Exhibit 20, from the 2009/10 Gas GRA, where based on the annualized amounts for 360 Portage. The principal and interest amount represented the annualized payments of a $278 million building over 60 years, which inherently includes depreciation and amortization.

The costs presented in PUB/MH I-178(a) are based on the expected costs for the 2010/11 fiscal year.

CENTRA GAS MANITOBA INC.

2009/10 & 2010/11 GENERAL RATE APPLICATION

UNDERTAKING PROVIDED BY: V. WARDEN

UNDERTAKING NO. 14 - TRANSCRIPT PAGE NO. 838:

Please provide a breakdown of the projected 2010 cost per square foot for 444 St. Mary Avenue and 360 Portage Avenue.

Below is a table containing the projected 2010 cost per square foot breakdown for 444 St. Mary Avenue and the annual projected cost for 360 Portage Avenue. Please note that the projected annual costs for 360 Portage Avenue are preliminary.

444 St. Mary Projected Costs	
Rent @ $12 / sq ft	$850,000
Common Area Maintenance @ $12 / sq ft	850,000
Parking	300,000
Electric Utility	50,000
Other Operating & Maintenance	50,000
Projected Annual Cost for 2010	**$2,100,000**
Square footage	72,688
Cost per square foot	**$29**

360 Portage Projected Costs	
Operating & Maintenance	$3,950,000
Property & Business Tax	6,700,000
Principal & Interest	20,000,000
Projected Annual Cost (annualized)	**$30,650,000**
Square footage	697,609
Cost per square foot	**$44**

PUB/MH II-151

Subject: Tab 13 Board Directives
Reference: PUB/MH I-179 (a) & (h)

b) It appears that the square footage used in the analysis provided in exhibit #20 differs from that reported for 444 St. Mary on PUB/Centra I -179 (a). Please re-file the table including the leased square footage[on which base lease rent is determined] of each leased property and the cost per square foot based on total lease facility savings.

ANSWER:

Please see the following tables.

Location	Total lease facility savings (in thousands of $)	Total Square footage	Cost per Square foot
1080 WAVERLEY	$ 65	2,000	$ 33
1090 WAVERLEY	591	21,867	27
1100 WAVERLEY	540	49,697	11
1120 WAVERLEY	240	19,594	12
1140 WAVERLEY	468	32,051	15
1146 WAVERLEY	552	35,697	15
1150 WAVERLEY B & C	357	17,350	21
1461 CHEVRIER	166	10,000	17
1565 WILLSON PLACE/ 900 Waverley	931	48,075	19
1664 SEEL AVE*	23	N/A	N/A
185 KING STREET	324	18,715	17
444 ST. MARY	2,060	78,642	26
693 TAYLOR	319	13,873	23
756 PEMBINA HIGHWAY**	10	N/A	N/A
Total	**$ 6,645**	**347,561**	**$ 19**

*1664 Seel was a parking lot associated with the Apache Mall (1100,1120,1140,1146 & 1150 Waverley)

** 756 Pembina was a parking lot associated with 693 Taylor.

PUB/MH II-151

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-179 (a) & (h)**

c) Please provide a description of the renovation and the associated cost undertaken at 820 Taylor and describe the future use of the facility.

ANSWER:

Renovations at 820 Taylor included:

- Construction of new offices and cubicle space to suit incoming occupants.
- Installation of new and used system furniture (redeployed from leased facilities).
- New cable plant (power and network) in select areas.
- Cosmetic improvements (carpet, paint and ceiling tile) in select areas.

Costs for this work were $1.299 M in 2009/2010 with $265,000 planned for renovations to be completed in 2010/2011.

820 Taylor will be used as an administrative office for the Customer Service & Distribution and Transmission Business Units.

PUB/MH II-152

Subject: **Tab 13 Board Directives**
Reference: **IFRS Mitigation Cost**

a) At the 2008 GRA MH identified that the capitalization of mitigation costs may be affected by IFRS and that there may need to be a more direct correlation to a specific capital project than is currently used.

ANSWER:

Manitoba Hydro is currently in the process of reviewing how mitigation costs may be affected by IFRS and is thus, not in a position to conclude how such costs may be impacted.

<u>PUB/MH II-152</u>

Subject: Tab 13 Board Directives
Reference: IFRS Mitigation Cost

b) **Please explain how IFRS will impact how mitigation costs are accounted for and implications on any transitional adjustments to retained earnings and ongoing operating expenses.**

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-152(a).

<u>PUB/MH II-153</u>

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32 IFRS Status Update Report**

Please file a copy of the detailed gap analysis between MH's policies and IFRS.

<u>ANSWER</u>:

The gap analysis referred to on page 3 of the IFRS Status Update Report is not one discreet document but rather the product of all analysis performed to date. The IFRS Status Update Report summarizes the main issues that have resulted from this analysis.

PUB/MH II-154

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32 IFRS Status Update Report**

"Although several preliminary accounting choices have been made by MH, until the IASB makes a decision as to the future of rate regulated accounting, a number of final decisions on policy choices cannot be made."

a) Please provide a table which summarizes the preliminary accounting policies which have been adopted and identify which policy choices are awaiting final determination of rate-regulated accounting including the options being considered if rate-regulated accounting per the ED (as drafted) is allowed and if the ED is rejected.

ANSWER:

The following table represents the preliminary accounting policy choices that have been adopted to date.

Topic	Accounting Policy Choice	Influenced by Rate-Regulated Accounting
Planning Studies	Where reasonable assurance exists that a project will proceed to construction, study expenditures will be capitalized into Construction Work in Progress. Studies for non-committed generation and transmission and emerging energies will be expensed as incurred.	Not Likely
IT Application Development	Expenditures for computer system application development will be recognized as intangible assets. Research, feasibility, and planning related expenditures for computer system application development will be expensed as incurred.	Not Likely

Topic	Accounting Policy Choice	Influenced by Rate-Regulated Accounting
Existing Rate Regulated Assets	Maintain existing policies	Yes
Electric DSM*	Electric DSM program expenditures will be reclassified to rate regulated assets and will continue to be deferred and amortized over a 10 year period.	Yes

**** Demand Side Management (DSM)* –** Subsequent to the IFRS Status Update Report, Manitoba Hydro concluded that electric DSM program costs do not qualify as intangible assets and therefore Manitoba Hydro has reclassified these costs as regulatory assets. However, Manitoba Hydro will expense research and general promotional expenses as incurred.

The other accounting policy choices that may be influenced by rate regulated accounting pertain mainly to amounts eligible for capitalization and to depreciation practices. Manitoba Hydro has not yet concluded its position on these policy options and will provide an update once those policy choices have been selected.

Should the IASB not approve a standard for rate regulated accounting, Manitoba Hydro will reassess those items currently classified as rate regulated items against the IFRS framework to determine if they can continue to be deferred and amortized. Those that do not meet the definition of an asset or liability under the IFRS framework will be recognized in income.

PUB/MH II-154

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32 IFRS Status Update Report**

> **"Although several preliminary accounting choices have been made by MH, until the IASB makes a decision as to the future of rate regulated accounting, a number of final decisions on policy choices cannot be made."**

b) **For each of the policy choices please indicate the potential financial implications on MH's electric and natural gas operations.**

ANSWER:

The potential financial implications for the items quantified to date have been summarized in sections 4.2.3 and 4.4 of the IFRS Status Update Report and are summarized in the response to PUB/MH II-154 (c).

<u>PUB/MH II-154</u>

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32 IFRS Status Update Report**

> **"Although several preliminary accounting choices have been made by MH, until the IASB makes a decision as to the future of rate regulated accounting, a number of final decisions on policy choices cannot be made."**

c) Please reconcile the impact of IFRS reflected in IFF09-1 page 12 with that described in the IFRS Status Update Report Page 5

<u>ANSWER</u>:

The following table reconciles the accounting policy changes presented in the IFRS Status Update Report and IFF-09-01.

(In millions of dollars)

	IFF09			**IFRS Status Update - Feb 28/10**		
	2009/10	**2010/11**	**2011/12**	**2009/10**	**2010/11**	**2011/12**
Interest & Facilities Overhead on Stores	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0
Executive Costs from Overhead Pool	2.0	2.0	2.0	2.0	2.0	2.0
Property Taxes on Facilities	-	-	-	2.0	2.0	2.0
Interest on Common Assets	-	-	-	-	12.0	12.0
General & Administrative Departmental costs	-	-	-	-	5.0	5.0
General Provision	-	-	15.0	-	-	-
Subtotal Capitalized Overhead	**$7.0**	**$7.0**	**$22.0**	**$9.0**	**$26.0**	**$26.0**
Intangible Assets	4.0	4.0	4.0	12.0		
Total	**$11.0**	**$11.0**	**$26.0**	**$21.0**		

With respect to intangible assets, IFF09-1 assumed that certain planning studies and demand side management costs would be classified as intangible assets resulting in an additional $4 million annual charge to operating expense. The IFRS Status Update Report reflected a more comprehensive review of intangible assets and concluded that planning studies were not eligible as intangible assets and that there were additional research and promotional costs relating to DSM that were ineligible. The estimate flowing from this analysis was that $12 million of 2009/10 costs that had previously been eligible for deferral would have to be expensed.

PUB/MH II-154

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32 IFRS Status Update Report**

> **"Although several preliminary accounting choices have been made by MH, until the IASB makes a decision as to the future of rate regulated accounting, a number of final decisions on policy choices cannot be made."**

d) Please provide a summary table of the impact on the forecast impact of transitional adjustments to retained earnings for each of the six identified topics, reflecting updated work since the Status Update Report.

ANSWER:

As an update to the Status Update Report, the following table provides the proposed retained earnings adjustments to be made for Planning Studies, IT Application Development and Demand Side Management programs. These amounts are retrospective to April 1, 2008 as required by the new CICA Section 3064. No further retained earnings adjustments have been identified at this time.

($ millions)	**Proposed Adjustments**
Ineligible Electric DSM	$5
Ineligible Gas DSM	1
Ineligible Planning Studies	25
Ineligible IT Application Development	5
Total	**$36**

<u>PUB/MH II-155</u>

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32 IFRS Status Update Page 24 - Componentization**

a) Please provide copies of any reports or presentations prepared by Gannett Fleming Inc. related to the IFRS conversion project.

<u>ANSWER</u>:

Manitoba Hydro has not received any reports or presentations from Gannett Fleming Inc. with respect to the IFRS Conversion Project.

<u>PUB/MH II-155</u>

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32 IFRS Status Update Page 24 - Componentization**

b) Please provide an estimate of the impact on depreciation expense for the 2010/11 and 2011/12 test years due to the componentization of assets.

<u>ANSWER</u>:

The impact on depreciation expense for the 2010/11 and 2011/12 test years due to the componentization of assets will be determined in conjunction with the depreciation study which is scheduled to be completed in the Fall of 2010.

<u>PUB/MH II-155</u>

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32 IFRS Status Update Page 24 - Componentization**

c) Please indicate the detail of non-physical assets identified including a description of the groupings and the proposed depreciation period. Please indicate how such groupings depreciation differs from the assets to which they relate.

<u>ANSWER</u>:

Manitoba Hydro is in the process of determining IFRS compliant component groupings.

<u>PUB/MH II-155</u>

Subject: **Tab 13 Board Directives**

Reference: **Appendix 32 IFRS Status Update Page 24 - Componentization**

d) Please provide a listing of componentization groupings and the proposed depreciation rates for those groupings including identifying which plant assets represent new groupings.

<u>ANSWER</u>:

Manitoba Hydro is in the process of determining IFRS compliant component groupings. Depreciation rates will be determined through the depreciation study which is scheduled to be completed in the Fall of 2010.

PUB/MH II-156

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32 IFRS Status Update Report Pages 25 & 26- Disposal of Assets**

a) **Please indicate what the impact will be (on what year) for the planned retirements on each asset for which the Corporations have already recorded an Asset Retirement Obligation.**

ANSWER:

At this time, Manitoba Hydro does not anticipate any significant impacts of IFRS on AROs that are already recorded in its financial statements.

PUB/MH II-156

Subject: **Tab 13 Board Directives**

Reference: **Appendix 32 IFRS Status Update Report Pages 25 & 26- Disposal of Assets**

b) Please indicate the amount of ARO's related to each identified assets,

ANSWER:

The following table provides the ARO liabilities at March 31, 2009.

	(thousands)
HVDC AC Filter PCB Capacitors Replacement	$ 6,692
Pointe du Bois Generating Station Decommissioning	12,363
Thermal Decommissioning	18,374
	$ 37,429

PUB/MH II-156

Subject: **Tab 13 Board Directives**

Reference: **Appendix 32 IFRS Status Update Report Pages 25 & 26- Disposal of Assets**

c) Please advise whether the Corporation has identified any further legal or constructive obligations exists, if so please provide details.

ANSWER:

No further legal or constructive obligations have been identified at this point in time.

PUB/MH II-157

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-97 (b), IFRS Status Update Report Page 23- Planning Studies**

a) **Please reconcile the $25.2 million in transfer to retained earnings reflected in the schedule with the potential impact $20 million set out in the IFRS Status Update Report.**

ANSWER:

The difference primarily represents unamortized expenditures pertaining to the study of the Notigi generating station. At the time of preparing the IFRS Status Update Report; these expenditures were being reviewed for possible reclassification to construction work in process. Subsequently Manitoba Hydro decided to expense the unamortized expenditures for Notigi until there is reasonable assurance that it will proceed to construction. Once the reasonable assurance criteria are met Manitoba Hydro will capitalize Notigi's future costs.

PUB/MH II-157

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-97 (b), IFRS Status Update Report Page 23- Planning Studies**

b) **Given that the approved regulatory practice has been to amortize planning studies, please indicate how the accounting for that internally generated intangible assets would change if the current proposed IASB Exposure Draft (ED), Rate-regulated Activities is adopted as drafted**

ANSWER:

Prior to the 2009/10 fiscal year and the issue of the new CICA standard 3064 for Intangible Assets, planning study expenditures were deferred and amortized over a period of 15 years. This accounting treatment was in accordance with Canadian GAAP at the time and as such, planning studies were not recognized as a regulatory asset. As identified in the Status Update Report, planning studies for next generation and transmission and for the study of emerging energies do not meet the new CICA section 3064 requirements for recognition as an intangible asset. Thus, such expenditures must now be expensed as incurred unless there is reasonable assurance that construction of the related project will proceed, in which case the expenditures are recognized as part of a tangible asset. If the proposed IASB ED for Rate-regulated activities is adopted as drafted, Manitoba Hydro proposes to maintain the accounting treatment that has been adopted in accordance with section 3064.

PUB/MH II-157

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-97 (b), IFRS Status Update Report Page 23- Planning Studies**

c) Please provide a detail of the unamortized balance of $25.2 million in planning studies by project , and indicate whether any of the projects meet the criteria for capitalization; reasonable assurance that a commitment to construction will be made.

ANSWER:

Planning Studies Unamortized Balance		**($000's)**
Project		
Next Generation and Transmission Studies	$	10,013
Wind Studies		5,959
Emerging Energy Studies		3,493
Supply Side Management Studies		2,208
Feasibility Studies		1,396
Environmental Studies		1,421
Other Studies		681
	$	**25,171**

None of the unamortized balance meets the criteria for capitalization and as a result, the unamortized planning studies balance was written-off to retained earnings.

PUB/MH II-157

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-97 (b), IFRS Status Update Report Page 23- Planning Studies**

d) Please provide a detail of the planning study expenditures that are to be made in 2009/10, 2010/11 and 2011/12 which are to be classified as next generation and transmission studies and emerging energy studies. With respect to next generation and transmission studies please indicate the proposed accounting treatment.

ANSWER:

Projected Planning Study Expenditures **($000's)**

Project	**2009/10**	**2010/11**	**2011/12**
Next Generation and Transmission Studies	$ 4,570	$ 7,266	$ 1,860
Emerging Energy Studies	166	-	-
Wind Studies	268	-	-
Supply Side Management Studies	360	367	47
Environmental Studies	327	333	-
	$ 5,692	**$ 7,967**	**$ 1,906**

All planning study costs are expensed in the year they are incurred. Next generation and transmission studies are capitalized where reasonable assurance exists with respect to the construction of the associated project. None of the expenditures in the above table are considered eligible for capitalization at this time.

<u>PUB/MH II-157</u>

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-97 (b), IFRS Status Update Report Page 23- Planning Studies**

e) Please provide a detail of the planning studies, which were written off against retained earnings.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-157(c) for the details pertaining to planning studies that were written off against retained earnings.

PUB/MH II-157

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-97 (b), IFRS Status Update Report Page 23- Planning Studies**

f) **Please discuss whether the proposed treatment of DSM promotion expenditures and planning studies which have historically been allowed to be recovered in rates may change if rate regulated accounting is allowed as currently drafted in the exposure draft.**

ANSWER:

With respect to DSM please see the response in PUB/MH II-154(a) and for planning studies please see the response in PUB/MH II-157(b).

PUB/MH II-157

Subject: Tab 13 Board Directives

Reference: PUB/MH I-97 (b), IFRS Status Update Report Page 23- Planning Studies

g) With respect to planning studies, please indicate the amounts incurred related to planning studies for Wuskwatim G.S., Keeyask G.S. , Conawapa G.S. and Bipole III and explain how the planning study expenditures related to each of these projects are being accounted for under the new standard.

ANSWER:

	Unamortized Balance transferred to CWIP (in thousands of $)
Wuskwatim G.S.	32,121
Keeyask G.S.	52,773
Conawapa G.S.	36,927
Bipole III	3,249

The above planning study costs are being accounted for as construction work in progress under the category property, plant and equipment.

<u>PUB/MH II-157</u>

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-97 (b), IFRS Status Update Report Page 23- Planning Studies**

h) **Describe when the Corporation determines that planning studies will be capitalized?**

<u>ANSWER</u>:

Planning studies will be capitalized when there is reasonable assurance that a project will proceed to construction. The condition for reasonable assurance is met upon the date of entering into process agreements and/or similar arrangements with impacted communities, date of application to commence the environmental licensing or regulatory process, the date of a commitment to commence capital construction or such other date as specifically approved by the Executive Committee.

<u>PUB/MH II-158</u>

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Pages 26 Capitalization of Borrowing Costs**

a) **Indicate to what extent the Corporation capitalizes borrowing costs related to its ongoing annual capital maintenance program [not major Generation & Transmission]**

<u>ANSWER</u>:

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

PUB/MH II-158

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Pages 26 Capitalization of Borrowing Costs**

b) **Please indicate how the Corporation has defined " substantial period of time" in applying capitalized borrowing costs to ongoing capital maintenance programs and whether any capital costs currently incurred would not attract interest under IFRS criteria.**

ANSWER:

Manitoba Hydro is in the process of reviewing a "substantial period of time" as it relates to IFRS and Manitoba Hydro's capitalization policies. At this time, no major changes are anticipated with respect to which assets will attract or will not attract interest upon conversion to IFRS.

PUB/MH II-159

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Pages 28 Capitalized OH**

a) **For each of the indicated impacts on operations for 2008/09 and 2009/10, please break down the impact between electric and natural gas operations.**

ANSWER:

Please see the table below:

Reduction to Capitalized Overheads in fiscal 2008/09:
(In millions of dollars)

	Electric	**Natural Gas**	**Total**
Interest and Facilities Overhead on Stores	$4.8	$0.2	$5.0

Estimated Reduction to Capitalized Overheads in fiscal 2009/10:
(In millions of dollars)

	Electric	**Natural Gas**	**Total**
Executive Costs from the Overhead Pool	$1.9	$0.1	$2.0
Property Taxes on Facilities	$1.9	$0.1	$2.0
Total Increase to Operating Costs	**$3.8**	**$0.2**	**$4.0**

Estimated Reduction to Capitalized Overheads in fiscal 2010/11:
(In millions of dollars)

Item	**Electric**	**Natural Gas**	**Consolidated**
Interest on Common Assets	$11.5	$0.5	$12.0
General and Administrative Departmental Costs	$4.8	$0.2	$5.0
Total Estimated Increase to Operating Costs	**$16.3**	**$0.7**	**$17.0**

PUB/MH II-159

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Pages 28 Capitalized OH**

b) Please provide a table indicating the cumulative impact by each change in accounting policy on 2010/11 and 2011/12 and indicate to which extent such changes are currently reflected in IFF09-1

ANSWER:

Please see the following table for the change in accounting policy for 2010/11 and 2011/12 for both the IFRS Status Update and IFF09.

(In millions of dollars)

	IFF09		**IFRS Status Update**	
	2010/11	**2011/12**	**2010/11**	**2011/12**
Interest & Facilities Overhead on Stores	$5.0	$5.0	$5.0	$5.0
Executive Costs from Overhead Pool	2.0	2.0	2.0	2.0
Property Taxes on Facilities	-	-	2.0	2.0
Interest on Common Assets	-	-	12.0	12.0
General & Administrative Departmental costs	-	-	5.0	5.0
IFRS	-	15.0	-	-
Total	**$7.0**	**$22.0**	**$26.0**	**$26.0**

<u>PUB/MH II-159</u>

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Pages 28 Capitalized OH**

c) Please indicate whether the corporation through its review of overhead capitalization methodology has identified any additional costs not eligible for capitalization under IFRS. If so, please provide details.

<u>ANSWER</u>:

As was indicted in the status update report, Manitoba Hydro is in the process of reviewing its overhead capitalization methodology which may identify additional costs not eligible for capitalization under IFRS.

PUB/MH II-159

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Pages 28 Capitalized OH**

d) **Please provide an update on the Corporation's intention to introduce business methodology changes to facilitate the direct charging of costs in accordance with IFRS. Please indicate the proposed costs of system changes and indicate how this will impact MH's operating costs.**

ANSWER:

As noted in response to PUB/MH II-159(c), Manitoba Hydro is in the process of reviewing its overhead capitalization methodology which may identify additional costs not eligible for capitalization under IFRS. Based on the results of that review, Manitoba Hydro may introduce business methodology changes to facilitate the direct charging of such costs in accordance with IFRS.

PUB/MH II-160

Subject: Tab 13 Board Directives
Reference: App. 32 IFRS Status Update Report Page 30 Pensions

a) Please file a copy of all reports and presentations made by Ellement & Ellement related to IFRS conversion project.

ANSWER:

Manitoba Hydro has recently received draft reports from Ellement & Ellement and will provide the results once reviewed and finalized.

PUB/MH II-160

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Page 30 Pensions**

b) Please provide MH's detailed assessment of the policy options including recording actuarial gains and losses immediately to OCI or continuing using the corridor calculation. Please indicate the implications of each on MH's operations.

ANSWER:

Manitoba Hydro has not yet completed its detailed assessment of pension policy options.

<u>PUB/MH II-160</u>

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Page 30 Pensions**

c) **With respect to past service costs, please provide the amount of past service costs existing in unamortized plan amendment balances and the transitional impact of such an adjustment on retained earnings.**

<u>ANSWER</u>:

The only unamortized pension plan amendment balances relate to the Centra Gas curtailed pension plans which will result in a transitional impact of approximately $2 million to Retained Earnings. As a result, there will be no amortization of these costs which will result in an annual reduction in pension expense for each of fiscal 2010/11 and 2011/12 of approximately $0.5 million.

<u>PUB/MH II-160</u>

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Page 30 Pensions**

d) **Please indicate the impact on 2010/11 and 2011/12 related to the change in accounting for past service costs.**

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-160(c).

PUB/MH II-160

Subject: Tab 13 Board Directives
Reference: App. 32 IFRS Status Update Report Page 30 Pensions

e) With respect to transitional requirements, please indicate if known the transitional adjustment to retained earnings of the first option; re-measurement of pension plan balances as if IFRS had been always applied.

ANSWER:

Manitoba Hydro is still in the process of analyzing the transitional adjustments associated with the option of re-measuring pension plan balances as if IFRS had always been applied.

<u>PUB/MH II-160</u>

Subject: **Tab 13 Board Directives**
Reference: **App. 32 IFRS Status Update Report Page 30 Pensions**

f) **Please indicate the current balance of actuarial gains and losses under option 2 and discuss what impact such an option would have on future pension expenses in 2011/12.**

<u>ANSWER</u>:

Under this option, unamortized actuarial net losses of approximately $212 million would be adjusted to retained earnings upon the transition to IFRS and would not be recognized in future pension expense.

PUB/MH II-161

Subject: **Tab 13 Board Directives**
Reference: **App. 32: IFRS Status Update Report Page 31- Employee Benefits**

a) Please provide the amount of past service balances, unvested obligations and the forecasted adjustment to retained earnings on transition to IFRS.

ANSWER:

The March 31, 2010 past service balance pertaining to the Retirement Health Spending obligation is approximately $8 million. This balance would be adjusted to opening retained earnings upon transition to IFRS.

With respect to unvested obligations, Manitoba Hydro is currently in the process of working with its actuary to determine unvested obligations for severance and sick leave benefits.

PUB/MH II-161

Subject: **Tab 13 Board Directives**
Reference: **App. 32: IFRS Status Update Report Page 31- Employee Benefits**

b) Please indicates the impact of the change in accounting for employee benefits will impact 2010/11 and 2011/12 operating results.

ANSWER:

Please also see Manitoba Hydro's response to PUB/MH II-161(a)

Retiree Health Spending (RHSA):
IFRS (IAS 19) requires past service costs that are vested to be expensed as incurred. This requirement will impact the accounting for the RHSA as it pertains to unamortized plan improvements for vested/retired employees. For fiscal 2010/11 and 2011/12, there will be an annual reduction in the expense for this account of approximately $1 million.

Sick Leave and Severance Benefits:
Unvested obligations related to sick leave and severance benefits must be recognized under IAS 19. Once recognized, these unvested obligations will be deferred and amortized over the average vesting period for the respective benefit. As of the date of this response, Manitoba Hydro is assessing the unvested obligations associated with these benefits, as well as the average vesting period and thus, the annual income impacts of amortizing these balances is not known at this time.

PUB/MH II-162

Subject: **Tab 13 Board Directives**
Reference: **App. 32: IFRS Status Update Report , Page 31 Fin. Instruments**

Please elaborate on the IASB project to replace IFRS in 2013, and discuss the implications to MH of applying these new requirements as part of its 2011 transition.

ANSWER:

The reference to an IASB project to replace IFRS refers to the replacement of current guidance set out in IAS 39, Financial Instruments: Recognition and Measurement. The first phase of the IASB project was completed in November 2009 with the issuance of IFRS 9, a standard that applies only to financial assets within the scope of IAS 39. The standard is effective for annual periods on or after January 1, 2013 and earlier application is permitted. Financial liabilities and hedge accounting will be addressed separately, later this year or early in 2011. For now, financial liabilities, including derivative liabilities, will remain within the scope of IAS 39.

Under IFRS 9, current classification categories for financial assets are limited to two measurement categories: amortized cost or fair value. Financial assets are initially recorded at fair value and subsequently measured at amortized cost or fair value. The classification of financial assets into one of these two categories is based on the entity's business model for managing financial assets, and contractual cash flow characteristics of the financial asset. The held to maturity, available-for-sale, and loans and receivables categories currently used in classification will be eliminated with the adoption of this new standard.

If IFRS 9 is adopted at the 2011 transition, Manitoba Hydro's financial assets such as customer loans and accounts receivable would continue to be classified at amortized cost. U.S. sinking funds would be reclassified from the current available-for-sale category to amortized cost with foreign exchange gains and losses continued to be recorded in net income, offset by the foreign exchange gains and losses on the associated long term debt. Under the amortized cost classification, fair value changes in interest rates are no longer recognized.

Once the remaining phases of the IASB project are completed, Manitoba Hydro will be able to fully assess the implications of applying the new requirements in 2013 or earlier.

<u>PUB/MH II-163</u>

Subject: **Tab 13 Board Directives**
Reference: **App. 32: IFRS Status Update Report , Page 32- Commodity Contracts**

Please elaborate on the "own use" exemption and provide specific examples where commodity contracts entered into by MH may not meet the exemption. Please provide the estimated financial impact related to the contracts that do not meet the exemption.

<u>ANSWER</u>:

In order for a contract to be considered as "own-use" it must be entered into without any requirement to be net settled and continue to be held in accordance with the entity's expected purchase, sale or usage requirements. Under IFRS, a contract can be net settled if it includes terms that requires or permits either party to settle it net in cash or by another financial instrument e.g. commodity contract; or if there is a practice of settling similar contracts net in cash; or if the entity has a practice of taking delivery of the underlying commodity and selling it within a short period for the purpose of generating a profit. Commodity contracts that do not qualify for the "own use" exemption would be within the scope of IAS 39 and are considered derivatives. These contract terms would be measured at fair value with changes in fair value recorded in net income.

With respect to export sales contracts, the majority of contracts are entered into with the intent to settle with physical delivery of power. The contract terms do not permit either party to settle net in cash. Contracts for Differences (CFD's) in use at Manitoba Hydro, have been identified as derivative contracts that do not meet the requirements for the "own purchase/own sales use" exemption. The purpose of these CFD contracts is to manage price risk that results from the volatility of market prices by agreeing to a fixed price with the counterparty. In the case of CFD's, Manitoba Hydro and its counterparty agrees to exchange in cash, the difference between the contractually agreed fixed price and the variable market price. Although the CFD is supported by physical energy, it is net settled in cash and represents a financial contract that is separate and distinct from the physical supply contract. CFD's have been classified as derivatives with the requirement to record changes in fair value to net income. At the end of this 2009/2010 fiscal period, an approximate fair value gain of $810,000 was recorded in net income for open CFD's at March 31, 2010.

PUB/MH II-164

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32: IFRS Status Update Report Page 33- Leases**

Please provide an update of the Corporation's review of its Lease agreements and report whether any changes are required under IFRS. These indicate the financial implications to MH if any.

ANSWER:

Manitoba Hydro is still in the process of reviewing its agreements to determine if any changes are required under IFRS.

PUB/MH II-165

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32: IFRS Status Update Report Page 34 – Customer Contributions**

Please describe how the corporations accounting policies have been impacted due to changes in recording of customer contributions under IFRS.

ANSWER:

Manitoba Hydro is currently assessing the IFRS requirements for customer contributions in order to determine the impact on its existing accounting policies.

PUB/MH II-166

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32: IFRS Status Update Report Page 39**

Please elaborate on the Corporation's review of its costing methodologies and other related policies and practices and indicate what specific changes Corporation anticipates making in 2010/11.

ANSWER:

For 2010/11, Manitoba Hydro has or anticipates making the following changes:

1. Reducing the overhead capitalization rate to eliminate:

   - the capitalization of those administrative and general cost components which cannot be directly linked to capital projects or programs
   - the capitalization of property and business taxes
   - the capitalization of interest on common assets

2. Adjusting the interest during construction rate to be both IFRS and GAAP compliant.

3. Removing the interest on vehicles and tools from activity rate calculations

4. Analyzing activity charges to assess which components may not be IFRS compliant and developing system processes to capture these amounts so that any necessary adjustments to amounts capitalized can be made for comparative year reporting.

5. Developing alternative allocation methods to subsidiaries for those shared cost components which have been removed from overhead and activity rate calculations.

6. Adjusting capital processes, structures and depreciation rates to conform to changing requirements relating to componentization, salvage values, and retirements.

7. Assessing the impact of changes on cost allocation information for rate design calculations and adjusting allocations as necessary.

8. Modifications to accounting instructions, policies and practices as required to reflect.

9. Assess what further changes are necessary and implement such changes to timecarding, allocations, and other accounting policies and processes for fiscal 2011/12.

PUB/MH II-167

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32: IFRS Status Update Report Page 42**

a) Given the assessment, that it is unlikely to expect a final standard for rate regulated assets in time for the 2011 adoption of IFRS, what is the Corporation's intention relative to the continued recognition of rate regulated accounting practices. Has the Corporations sought guidance from the IASB on its course of action if the standards are not ready when MH adopts IFRS.

ANSWER:

The Corporation's intention with respect to the continued recognition of rate regulated accounting practices will depend on the outcome of future IASB decisions on this topic. To date, the IASB has only provided relief for first time adopters of IFRS with respect to allowing rate regulated entities the option to carry forward the net book value of their property plant and equipment and intangible asset balances upon transition. At this time, it is uncertain whether or not further guidance from the IASB with respect to rate regulated accounting will be provided prior to Canada's transition to IFRS.

Manitoba Hydro has participated in the development of a joint letter from the Canadian Electrical Association requesting interim guidance from the IASB on this matter. The letter from the CEA requests that the IASB allow for additional transitional relief upon the first time adoption of IFRS by Canadian rate regulated entities. Please see the attached letter from the CEA to the IASB.

Canadian Electricity Association | Association canadienne de l'électricité

April 28, 2010

Mr. Michael Stewart
Director of Implementation Activities
International Accounting Standards Board
30 Cannon Street
London, EC4M 6XH
United Kingdom
Email: mstewart@iasb.org

Subject: Accounting for Rate-Regulated Activities

Dear Mr. Stewart:

The **Canadian Electricity Association (**CEA) is the leading voice for the electricity sector in Canada. CEA members represent approximately 90 percent of all generation, transmission, distribution and marketing of electricity in Canada, as well as leading manufacturers and suppliers to the industry. The CEA's Accounting and Finance Committee includes more than 25 representatives from some of the largest member organizations having rate-regulated activities. T**he CEA provided comments to the** International Accounting Standards Board (**IASB) on its July 2009 Exposure Draft (ED) on rate-regulated activities** jointly with the **Canadian Energy Pipeline Association (CEPA) and the Canadian Gas Association (CGA). We appreciate the opportunity to now** provide input to the staff of the IASB as the Board re-deliberates its proposals based on comments received on the ED.

The CEA and its members are well aware and appreciative of the extensive work being done by the IASB and its staff on the Rate-regulated Activities project, including the recently approved IFRS 1 deemed cost exemption. We understand that the current activities of the Board and staff on this project are necessary for the IASB to fulfill its required due process. In addition, we are cognizant of the many other high priority projects underway at the IASB that also require time and resources, especially those projects being undertaken jointly with the Financial Accounting Standards Board as part of the Memorandum of Understanding. At the same time, as you know, some urgency attaches to the Rate-regulated Activities project from the perspective of countries, including Canada, that are preparing to adopt International Financial Reporting Standards (IFRSs) for the first time in the near future. Canadian publically accountable entities are adopting IFRSs effective January 1, 2011, which means we are already in the 2010 transition year.

The IASB currently expects to complete its Rate-regulated Activities project after January 1, 2011. As a result, significant uncertainty surrounds the accounting for rate-regulated activities after that date and before the issuance of a final standard. Early resolution of this uncertainty is important to the quality of the transition to IFRSs by CEA members with rate-regulated activities and entities in other countries adopting IFRSs at the same time (an example is India, where rate-regulated activities are prevalent). The IASB staff identified this issue in Agenda Paper 7 for the Board meeting of February 2010. Should the Board continue with its project and this issue remains unresolved, we believe there is significant risk of diversity in practice after January 1, 2011. Another undesirable consequence could be that large accounting firms and their clients, rather than the IASB, are interpreting and essentially setting accounting standards in certain circumstances.

The CEA's members have given considerable thought to this issue. To resolve it, we propose that the IASB staff consider recommending to the Board that it approve transitional relief in the form of a limited-time exemption for inclusion in IFRS 1. The exemption would be available to rate-regulated entities adopting IFRSs for the first time that meet the scope requirements set out in the recently approved IFRS 1 deemed cost exemption for this sector. The effect of the exemption would be to permit such entities to continue accounting for their rate-regulated activities in a manner consistent with the principles underlying US GAAP in this area, modified as noted below. We propose that the transitional relief become effective upon first time adoption of IFRS, and remain effective until a final standard is available. Following are our suggestions for how such transitional guidance might be achieved:

1) **Entities should recognize regulatory assets and regulatory liabilities in accordance with paragraphs 8- 11, inclusive, of the July 2009 ED.**
   As stated in the July 2009 ED, entities within scope would apply all existing IFRSs first before accounting for the effects of rate regulation. For example, IAS 16 *Property, Plant and Equipment* would be applied to account for the de-recognition of an item of property, plant and equipment (PP&E) prior to accounting for the effects of rate regulation to defer any associated gain or loss.

   The July 2009 ED proposed that regulatory assets and liabilities be measured at their expected present value. We recommend that this requirement be omitted from any transitional guidance issued and, instead, be considered in the development of the final standard.

2) **All regulatory assets and liabilities that are recognized on the statement of financial position should be separately identified as such, and not embedded within other asset or liability balances.**

   For example, if the allowance for funds used during construction (AFUDC) capitalized for rate-setting purposes includes an amount related to the cost of equity, any amount in excess of what would otherwise be permitted to be capitalized in accordance with IAS 23 *Borrowing Costs* would be recognized as a separate regulatory asset and not embedded in the PP&E balance. In North America, other examples of regulatory assets and liabilities that would be separately identified include those resulting from an entity's use of "group" depreciation practices, as specified by the regulator for rate-setting purposes.

   Aggregation of individual regulatory assets or liabilities on the face of the financial statements would be acceptable provided additional note disclosure is provided.

3) **Disclosure should be as proposed in the IASB's July 2009 ED to provide users of the financial statements with a full understanding of the effects of regulation on an entity's financial results.**

The CEA and its members believe that these proposals, if adopted by the IASB, would provide entities preparing to adopt IFRSs for the first time the degree of certainty they require in the temporary absence of a final standard on rate-regulated activities. They would also help address the diversity in practice that might otherwise result. Lastly, the proposals ensure adherence to all existing IFRSs, as well as transparent presentation and robust disclosure of the effects of rate-regulation. As a result, the financial statements of first-time adopters using the proposed exemption would be comparable to entities already reporting in accordance with IFRSs that do not recognize regulatory assets and regulatory liabilities, and to North American competitors that follow US GAAP.

The CEA urges you and other IASB staff to consider our proposals when developing recommendations to be presented to the IASB. Should you have any questions or require any additional information about any aspect of our proposals, please contact Mike Olson, Chair of the Accounting & Finance Committee. Mike may be contacted as follows:

Email; mike.olson@fortisalberta.com
Telephone: (403) 514-4309
Fax: (403) 514-5309

Fortis Alberta
320 – 17th Avenue SW
Calgary, Alberta, T2S 2V1

Yours sincerely,

Pierre A. Guimond
President & Chief Executive Officer

PUB/MH II-167

Subject: **Tab 13 Board Directives**
Reference: **Appendix 32: IFRS Status Update Report Page 42**

b) Please provide the Corporations view of utilizing regulatory accounting, prescribed by the Board, if the IASB does not allow the continuation of rate regulated accounts in advance of updated standards.

ANSWER:

If the IASB does not approve the continuation of rate regulated accounting, upon transition to IFRS, Manitoba Hydro will be required to eliminate the effects of rate regulated accounting in their financial records when preparing their annual financial statements. In order to obtain an annual unqualified external audit opinion, the annual financial statements will not be allowed to incorporate any form of rate regulated accounting. If the PUB prescribes rate regulated accounting under these circumstances, it will be adopted for rate setting purposes only.

It should be noted, however, that IFRS will only affect the timing of when a cost is ultimately charged to ratepayers (whether charged directly to operating expense in the year incurred or amortized to operating expense over a number of years through capital). With appropriate planning, rate increases (or decreases) can be adjusted to achieve the same financial results over the long-term and the same rate impacts on customers.

<u>PUB/MH II-168</u>

Subject: Tab 13 Board Directives
Reference: PUB/MH I-200

Please file a copy of the analysis/ study, which provides the impact of the plug-in electric vehicle.

<u>ANSWER</u>:

A copy of the analysis/study which provides the impact of the plug-in electric vehicle is provided in Attachment 1. This document is titled “Discussion: Plug-in Vehicle Adoption in Manitoba”.

Discussion: Plug-in Vehicle Adoption in Manitoba

Predicting reliable future electric transportation adoption scenarios is a difficult process. Electrified vehicle adoption estimates are difficult to develop and forecast and are often the subject of debate as original equipment manufacturers (OEM) R&D and production plans have typically been kept secret[1]. Complicating the normal uncertainties (projected vehicle costs, customer uptake, etc.) in determining how quickly manufacturers will introduce plug-in vehicles, such as Plug-in Hybrid Electric Vehicles (PHEV) and Electric Vehicles (EV), collectively known as Plug-in Electric Vehicles (PEV), is the recent turmoil in global financial markets, which is causing the automobile industry significant financial hardship.

Part of this investigation assesses electrified vehicle penetration scenarios worked out by other institutions. So far, the most plausible (but still exploratory) scenarios were developed by the Electric Power Research Institute (EPRI), of which Manitoba Hydro is an active participant.

In the 2009/10 Load Forecast, Manitoba Hydro incorporated existing estimates of future electric vehicle energy requirements based on the EPRI 30% vehicle market share by 2030 base case model (EPRI 2008 Report 1016853: Impact of Plug-in Electric Vehicle Technology Diffusion on Electricity Infrastructure).

Currently, EPRI has formed an overall opinion that PEV in North America will be introduced at reasonable volumes and ramp up reasonably quickly (tens of thousands up to hundreds of thousands) and then likely ramp up very quickly after that. Aside from PEVs, EPRI does not envision any alternative technology such as hydrogen fuel cell vehicles that would be capable of taking over.

Medium Adoption Scenario

With this view and considering announced OEM production plans and the favourable current and likely future political, environmental and economic environment supporting PEV, the scenarios in this report focus on a 2007 report undertaken by EPRI and the Natural Resources Defence Council (NRDC)[2]. While the focus of the EPRI/NRDC study was not a market projection[3], it served well as a 'bounding scenario' for electrified vehicle penetration, defining three adoption scenarios: low, medium and high.

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[1] This secrecy is changing as recently OEMs including GM, Nissan, BYD, Tesla and others have released information regarding the production plans of their respective plug-in hybrid or all-electric vehicles.
[2] 2007 report titled "Environmental Assessment of Plug-in Hybrid Electric Vehicles"; a comprehensive environmental assessment of electric transportation in the United States.
[3] The joint EPRI/NRDC model was developed to provide a detailed GHG simulation of the electric utility sector and the entire US energy-economy. The three adoption scenarios in it were based on a combination of factors, including (but not limited to) high fuel prices, societal concerns about climate change and energy security, and improvements in the cost and performance of PEV technology.

This Manitoba Hydro adoption study focuses on the EPRI medium penetration scenario (Figure 1) in its approximation of PEV adoption and cumulative PEV growth within Manitoba. This study considers in its findings the replacement of PEVs throughout their normal life spans (14 years).

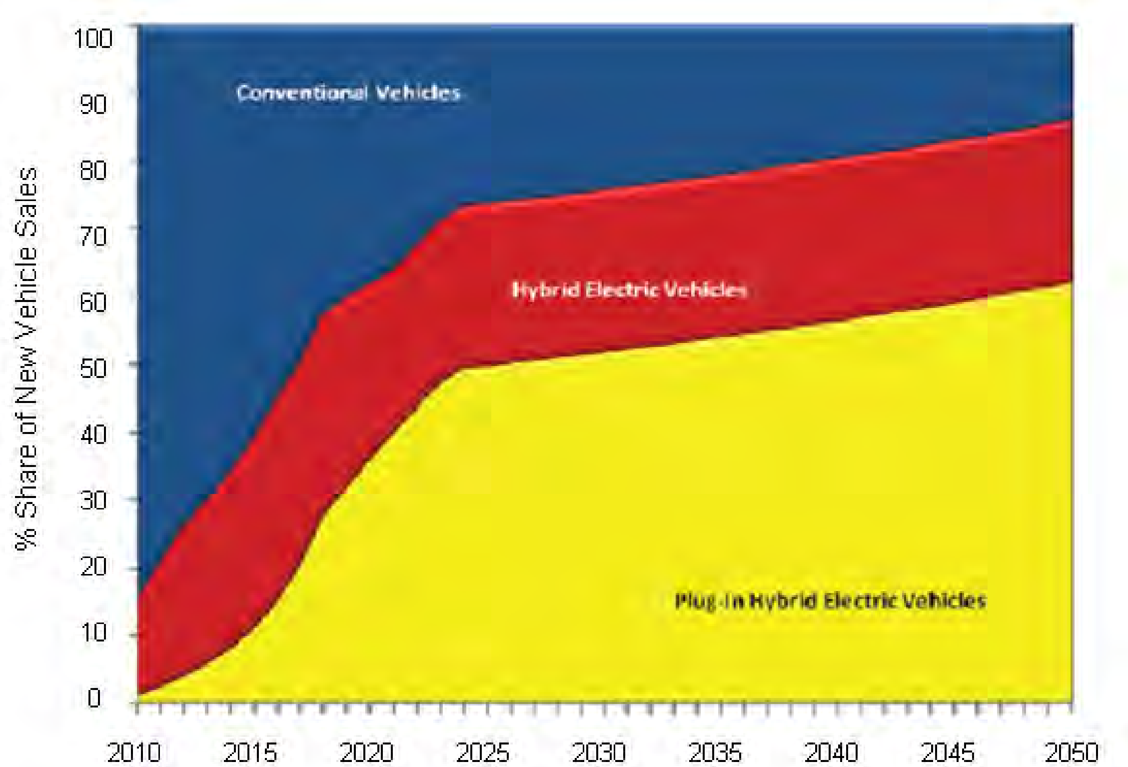


Figure 1: EPRI Medium PEV Penetration Scenario - Assumed New US Vehicle Market Share for Conventional Vehicles (CV), Hybrid Electric Vehicles (HEV), and Plug-In Electric Vehicles (PEV).

The EPRI/NRDC study defining the medium penetration scenario was published shortly after General Motors originally announced (August 2007) a more aggressive initial release of 60,000 - 80,000 Chevrolet Volt PEVs in 2010. In February of 2008, General Motors scaled back its 2010 plans to an initial release of 10,000 vehicles. As such, the medium adoption curves presented by EPRI and used in this report were offset forward by two years (Figure 2). The current global economic situation is not factored in any further than recent manufacturer production announcements, which only carry forward a few years and are subject to change. Significantly, while vehicle manufacturers are scaling back the sizes of their operations in almost every area, they are also demonstrating strong commitments to electric vehicle technology by expanding research and development facilities.

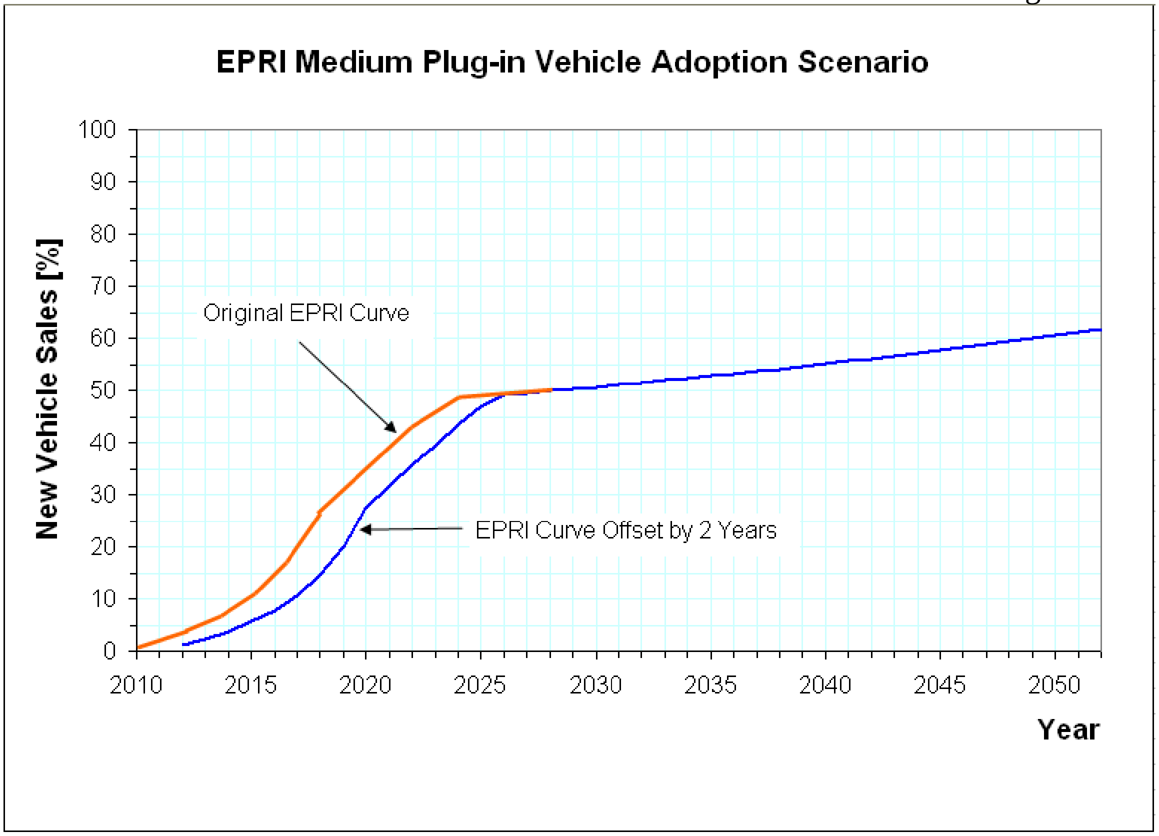


Figure 2: EPRI - US Medium Plug-in Vehicle Adoption Scenario with 2 Year Forward Offset

PEV adoption and energy requirements in Manitoba were based on:

- EPRI medium adoption curve offset by 2 years in Figure 2
- Historical new vehicle sales in Manitoba from 1991 - 2008 Statistics Canada data. Approximately 48,000 new vehicles were sold in Manitoba in 2008.
- The total number of registered vehicles in Manitoba (Approximately 651,000 registered in 2008, extrapolated to be 1,040,000 by 2052[4])

Commuting Distance

A 1990 US national personal transportation survey of vehicle kilometres of daily driving was used as an initial approximation of daily aggregate commuting distances in Manitoba. The exponential curve shown in Figure 3 (below) depicts the percent of PEV mileage driven on electricity for any given net electric range. Assuming a large number of PEVs with 50 km net electric range, approximately 60% of the total distance travelled will be on electricity and 40% will be on petroleum.

[4] Based on Statistics Canada data of total registered vehicles

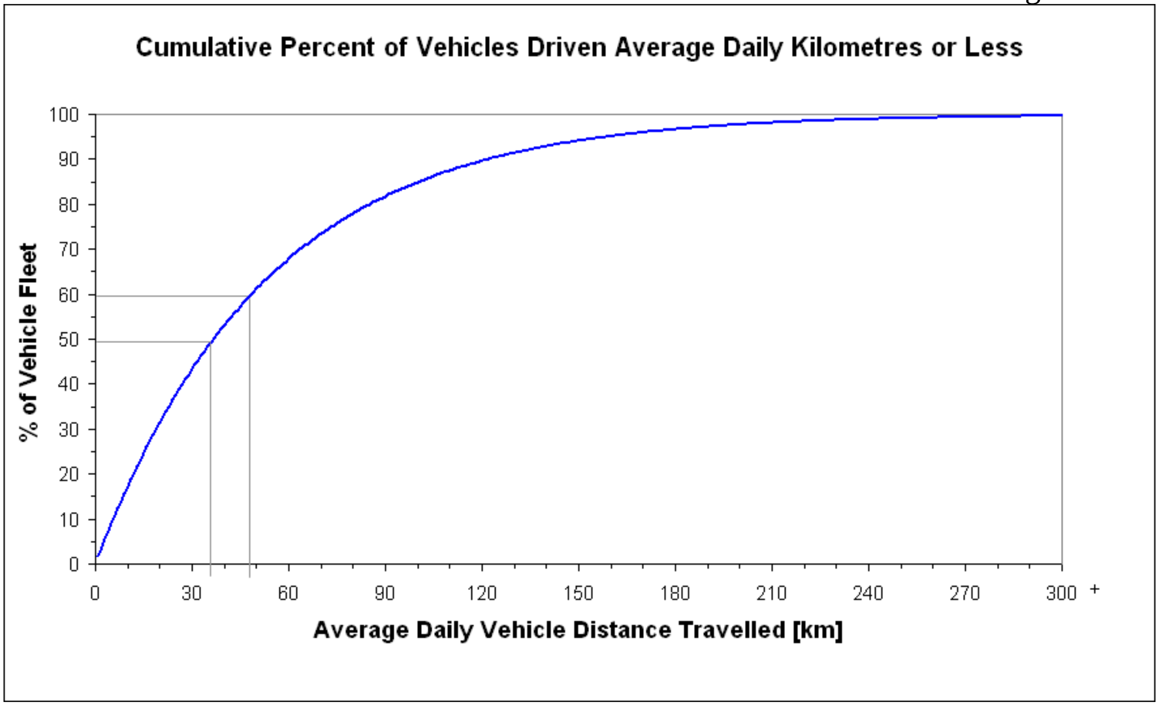


Figure 3: Cumulative Percentage of Vehicles Driven Average Daily Kilometres or Less

A probability distribution function (PDF, see Figure 4 below) is derived from the curve in Figure 3. This PDF describes the likelihood of possible average distances that an average vehicle will travel each day within the range defined (0-300 km). Assuming that the vehicle is a PEV with some all-electric range (50 km in example below), the distribution in Figure 4 illustrates the amount of electricity required for its propulsion versus the amount of petroleum required.

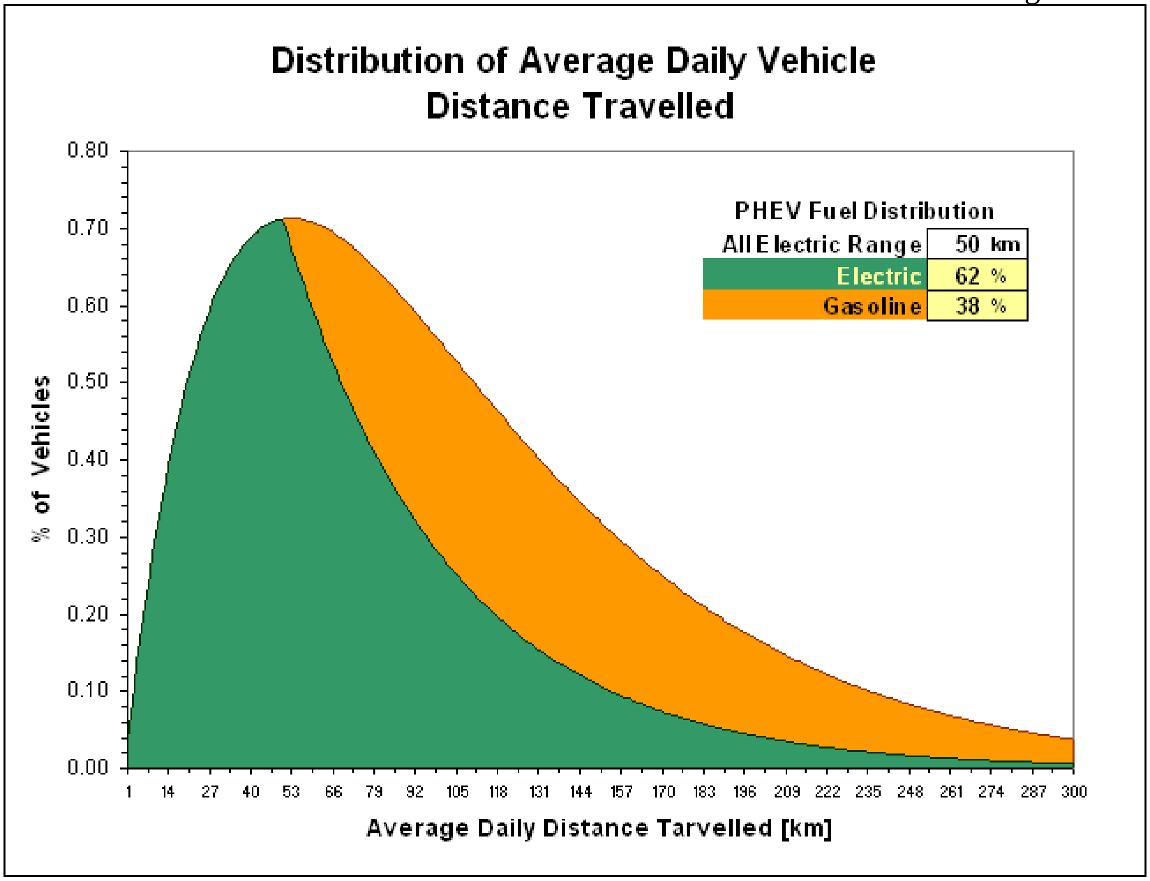


Figure 4: Distribution of Daily Vehicle Average Distance Travelled with Overlaid PEV Fuel Distribution

In Figure 4, the green area under the curve (lower left) represents the average distance travelled on electricity and the tan coloured area under the curve (upper right) depicts the average distance travelled on petroleum for any PEV in the distribution. In the example shown, for a 50 km net-electric range, the ratio of the green area (travel on electricity) to the total area under the curve (green plus tan areas) is approximately 60%.

It is clear in Figure 4, that the total distribution is skewed to the lower end of the driving range, representing more vehicles travelling shorter distances on average. Equally clear, and the primary focus of this analysis, is demonstrating that a PEV with a relatively short battery range can have a very significant effect on reducing petroleum consumption.

Combining the data from Figures 2 and 3 yields a medium penetration percentage of PEVs out of the total number of vehicles in Manitoba over time (Figure 5) and defines a medium adoption rate for the province.

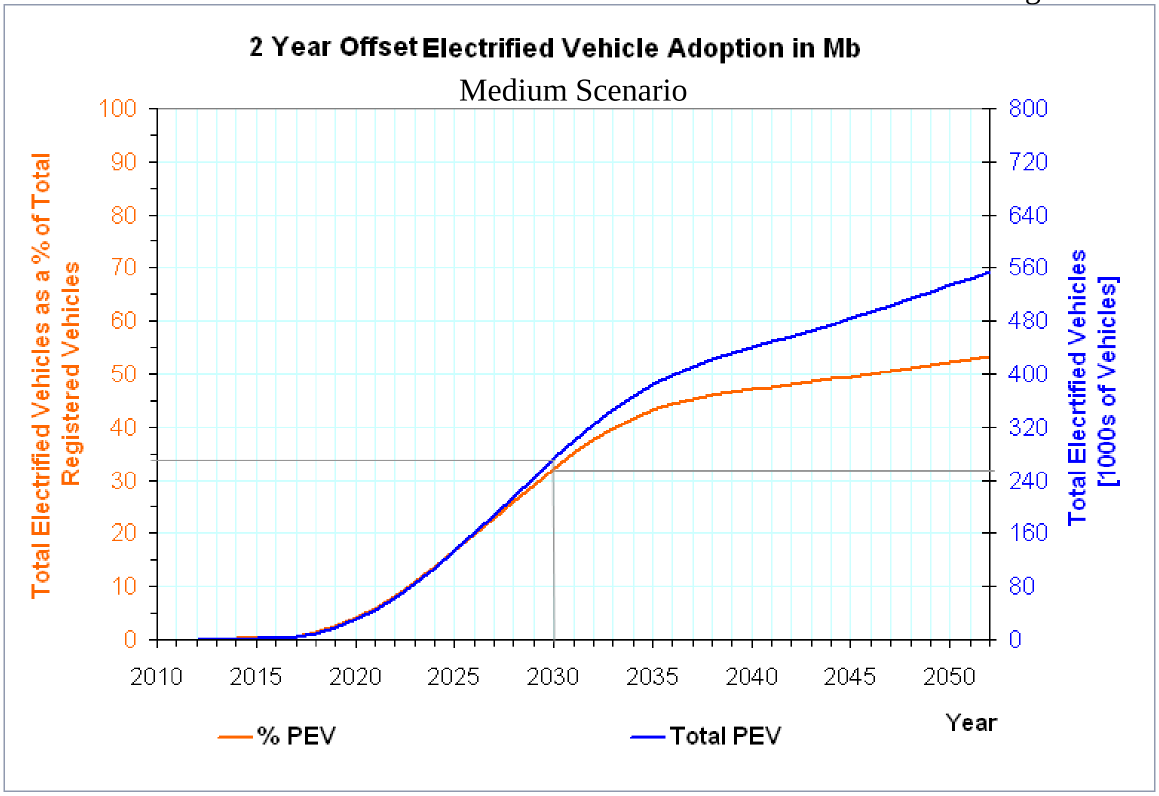


Figure 5: Percentage and Total Penetrations of PEVs in Manitoba (Medium Scenario)

From Figure 5, by 2030, an estimated 32% of registered vehicles in Manitoba (271,000) will be plug-in electric.

Fuel Distribution

Based on the data in Figures 4 and 5, an estimation of the fuel distribution from all vehicles, PEV as well as internal combustion engine (ICE), in Manitoba was achieved by weighting the portion of vehicle km travelled on electricity (Figure 4) with the percentage of PEV on the road as defined by the medium adoption scenario for the province. In Figures 6 and 7 below, the green areas under the curves illustrate that by 2030, for 50 km and 150 km net-electric ranges, 20% and 31%, respectively, of the daily vehicle average distance travelled in Manitoba will be on electricity as opposed to petroleum.

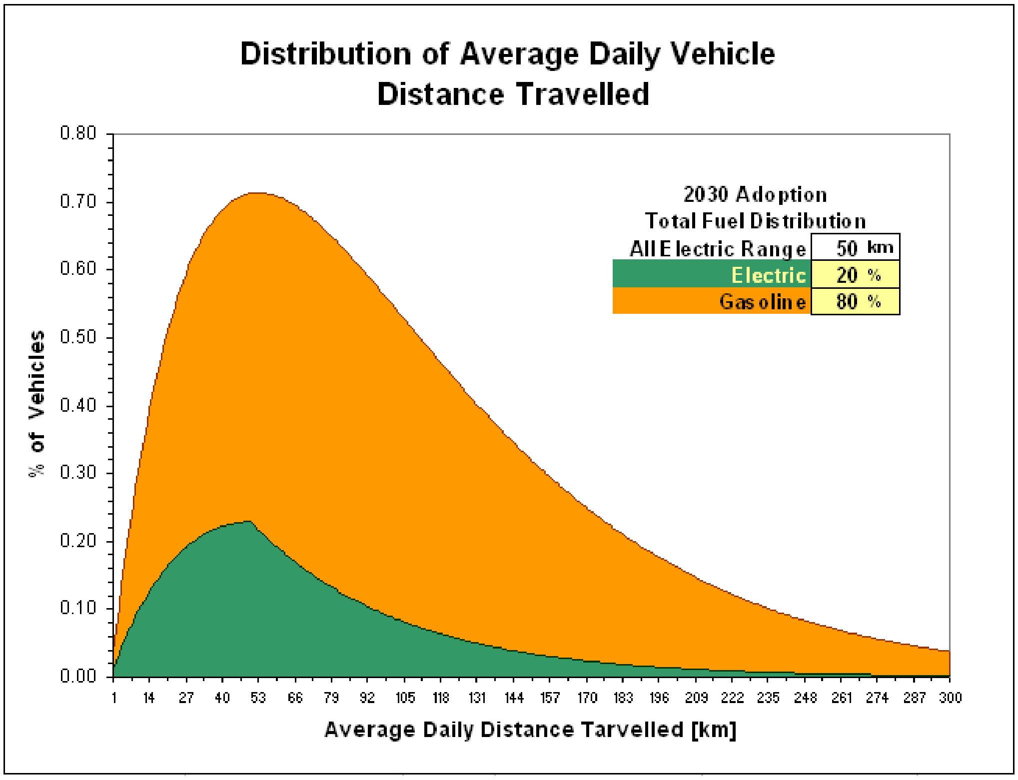


Figure 6: 2030 PDF of Daily Vehicle Average Distance Travelled with 50 km PEV Net-Electric Range (Medium Adoption Scenario for Manitoba)

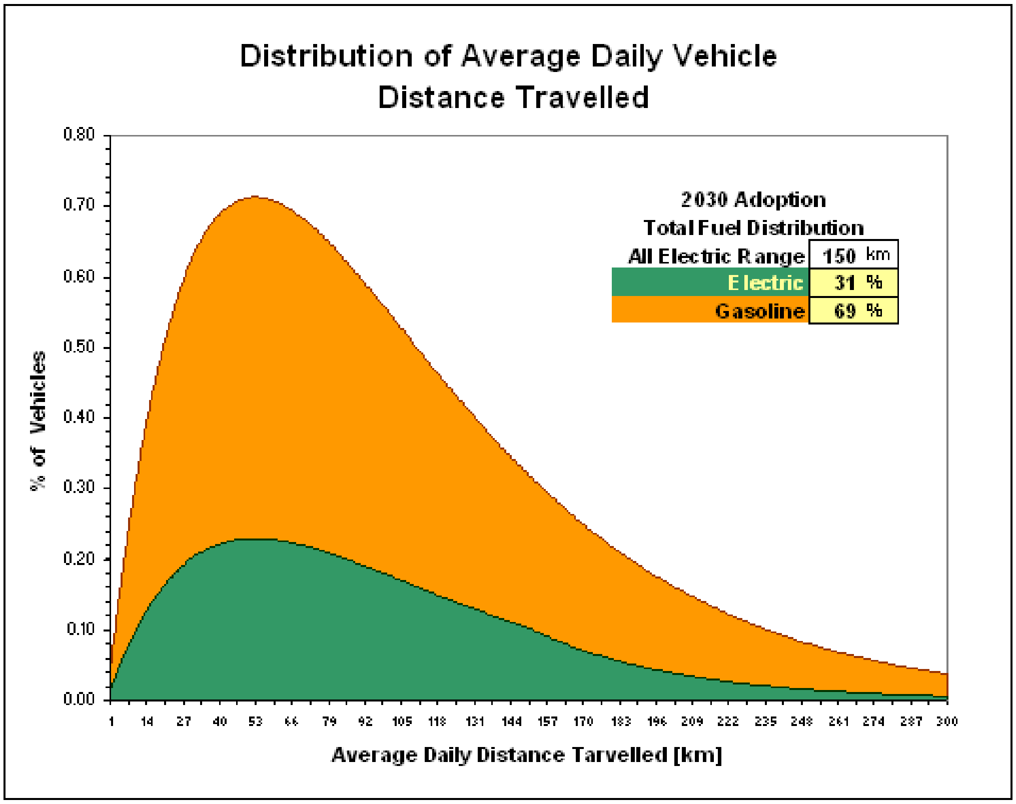


Figure 7: 2030 PDF of Daily Vehicle Average Distance Travelled with 150 km PEV Net-Electric Range (Medium Adoption Scenario for Manitoba)

The majority of all vehicles travel far less than 150 km per day, so if by 2030, PEV vehicles all had a 150 km net-electric range, the percentage of distance travelled by PEVs in 2030 would approach that of the total 2030 PEV medium adoption penetration of 32% (see Figure 5 above).

Annual Energy Requirements

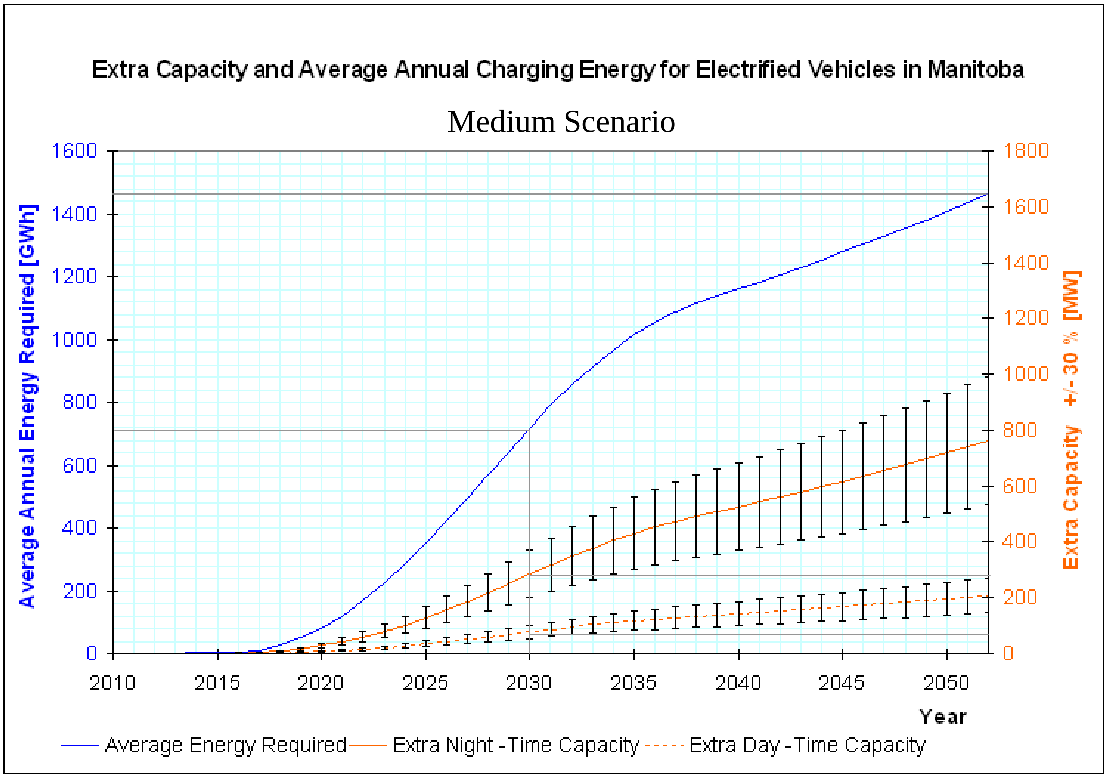


Figure 8: Extra Capacity & Average Annual Energy Required (Medium Scenario)

The estimated annual energy and extra nighttime and daytime system capacity[5] required for medium adoption of PEV in Manitoba is shown above in Figure 8. From Figure 8, the total estimated annual energy required to supply PEV for the medium adoption scenario in Manitoba for the years 2030 and 2052 are as follows:

<u>2030</u>

- 720 GWh (1,970 MWh/day)
- approximately 2.0% of 2030 projected Manitoba total load (including PEVs)
- 10.5% of projected total load growth (6,900 GWh) from 2012 to 2030.

[5] Range markers of +/- 30% were chosen around the nighttime and daytime capacity curves to estimate the present level of uncertainty.

2052

- 1,460 GWh (4,000 MWh/day)
- approximately 3.5% of 2052 projected Manitoba Hydro total load (including PEVs)
- 9.4% of projected domestic load growth (15,500 GWh) from 2012 to 2052.

<u>PUB/MH II-169</u>

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-202 (d) Base Capital Expenditures**

Please explain the relationship between base capital expenditure and net plant in service and why the relative percentage of based capital expenditures to net plant in service is forecasted to drop to below 3% in 2018 substantially below the historical and forecast average spend.

<u>ANSWER</u>:

Given that net Property Plant and Equipment (PPE) is growing to nearly three times in size with new generation and transmission, it would not be expected that the relationship between base capital and net plant in-service would remain constant.

The last two columns in the table below show base capital additions to PPE excluding new generation and transmission additions. By excluding new generation and transmission from the net PPE, it can be seen that existing plant is replaced at or above historical rates. New generation and transmission can be excluded from the net PPE amounts for this calculation because as new assets their expected replacements are not forecasted within this period.

(in Million's)

Fiscal Year	PP&E Major NG&T Net Expenditures	PP&E Base Capital Net Expenditures	PP&E Total Net Expenditures	Net PP&E Plant In-Service	**Percentage of Base Capital Expenditures to Net PP&E Plant in Service**	Net PP&E Plant In-Service (Base Capital Additions)	**Percentage of Base Capital Expenditures to Net PP&E Plant in Service (Base Capital Additions)**
2000	87	223	310	5 710	**3.9%**		
2001	145	191	335	5 803	**3.3%**		
2002	192	237	429	5 886	**4.0%**		
2003	73	358	430	6 590	**5.4%**		
2004	72	382	455	6 778	**5.6%**		
2005	134	369	503	6 917	**5.3%**		
2006	149	347	497	7 014	**5.0%**		
2007	224	422	646	7 094	**5.9%**		
2008	376	459	835	7 283	**6.3%**		
2009	470	423	893	7 646	**5.5%**		
2010	641	380	1 020	7 865	**4.8%**	7 760	**4.9%**
2011	558	433	991	8 015	**5.4%**	7 831	**5.5%**
2012	510	441	951	9 677	**4.6%**	7 949	**5.5%**
2013	549	394	943	9 761	**4.0%**	8 026	**4.9%**
2014	962	456	1 418	9 765	**4.7%**	8 024	**5.7%**
2015	1 317	385	1 702	10 042	**3.8%**	8 027	**4.8%**
2016	1 709	384	2 093	10 035	**3.8%**	8 050	**4.8%**
2017	1 695	409	2 104	10 297	**4.0%**	8 065	**5.1%**
2018	1 278	378	1 656	12 292	**3.1%**	8 061	**4.7%**
2019	1 237	354	1 590	13 085	**2.7%**	8 041	**4.4%**
2020	917	317	1 233	15 950	**2.0%**	8 013	**4.0%**
2021	1 025	387	1 412	16 451	**2.4%**	8 010	**4.8%**
2022	866	460	1 326	16 316	**2.8%**	7 985	**5.8%**
2023	998	507	1 505	19 599	**2.6%**	8 004	**6.3%**
2024	250	541	791	21 998	**2.5%**	8 200	**6.6%**
2025	21	603	624	22 556	**2.7%**	8 398	**7.2%**
2026	15	580	596	22 613	**2.6%**	8 701	**6.7%**
2027	26	598	624	22 441	**2.7%**	8 765	**6.8%**
2028	79	588	668	22 401	**2.6%**	8 918	**6.6%**
2029	57	623	679	22 226	**2.8%**	8 963	**6.9%**

<u>PUB/MH II-170</u>

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-204**

a) Given that Capitalized OM&A is not forecast in the IFF beyond 2011/12 please indicate to what extent the 20 year CEF reflects forecasted capitalized OM&A in the Capital Cost estimates for each of the years 2012/13 through 2028/29.

<u>ANSWER</u>:

Capitalized OM&A is forecast in the IFF beyond 2011/12 as a net amount included in OM&A at the rate of inflation.

In the CEF active projects include expected capitalized OM&A based upon labour hour estimates. Future project estimates are prepared at higher levels which aggregate estimated capitalized OM&A with other cost components.

PUB/MH II-170

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-204**

b) **For finance expense allocated to Construction, please recast the table including the total debt level, total finance expense, the % of finance expense capitalized, capital spending attracting interest, the interest rate for the amounts allocated to projects including the assumed capital balance and interest rate in the following format**

Year	Total Debt	Total Interest / Carrying Cost on Total Debt	Average Interest Rate	Total Capital Spending Attracting Interest	Average Interest Rate on Capitalized Interest	Finance Expense allocated to Construction	% of Total Interest Expense
2004/05							
2028/29							

ANSWER:

Please see the following table based upon pre-IFRS calculations.

In Millions

Year	Net Debt*	Net Interest Expense	Average Interest Rate	Total Capital Spending Attracting Interest**	Average Interest Rate on Capitalized Interest	Finance Expense allocated to Construction	% of Total Interest Expense
2004/05	6,431	468	7.6%	474	8.0%	33	7%
2005/06	6,277	468	8.0%	600	6.6%	34	7%
2006/07	6,479	467	8.2%	872	6.7%	47	9%
2007/08	6,485	401	7.2%	1,232	6.7%	60	13%
2008/09	7,299	401	7.2%	1,447	6.8%	74	16%
2009/10	7,462	417	6.8%	1,947	6.5%	92	18%
2010/11	8,101	413	6.9%	2,458	6.7%	131	24%
2011/12	8,627	468	7.2%	1,341	7.0%	137	23%
2012/13	9,089	525	7.1%	1,818	7.1%	110	17%
2013/14	10,072	527	7.0%	2,838	7.0%	144	21%
2014/15	11,276	544	7.0%	3,854	7.0%	208	28%
2015/16	12,728	529	6.9%	5,532	7.0%	306	37%
2016/17	14,150	545	7.1%	6,948	7.0%	408	43%
2017/18	15,132	587	7.1%	6,159	7.0%	449	43%
2018/19	16,019	674	7.1%	6,446	7.0%	430	39%
2019/20	16,462	878	7.6%	4,168	7.0%	365	29%
2020/21	17,011	958	7.5%	4,523	7.0%	300	24%
2021/22	17,367	851	7.0%	5,453	7.0%	353	29%
2022/23	17,755	890	6.9%	3,111	7.0%	330	27%
2023/24	17,189	1,071	7.0%	877	7.0%	160	13%
2024/25	16,348	1,166	7.1%	270	7.0%	31	3%
2025/26	15,347	1,126	7.3%	119	7.0%	30	3%
2026/27	14,256	1,094	7.5%	207	7.0%	18	2%
2027/28	13,093	1,037	7.7%	205	7.0%	23	2%
2028/29	11,822	980	8.0%	338	7.0%	25	2%

** Represents total long-term debt plus current portion and short term debt less sinking fund assets and Centra Gas debt.*
***Represents Construction in Progress from the Balance Sheet as at March 31.*

PUB/MH II-171

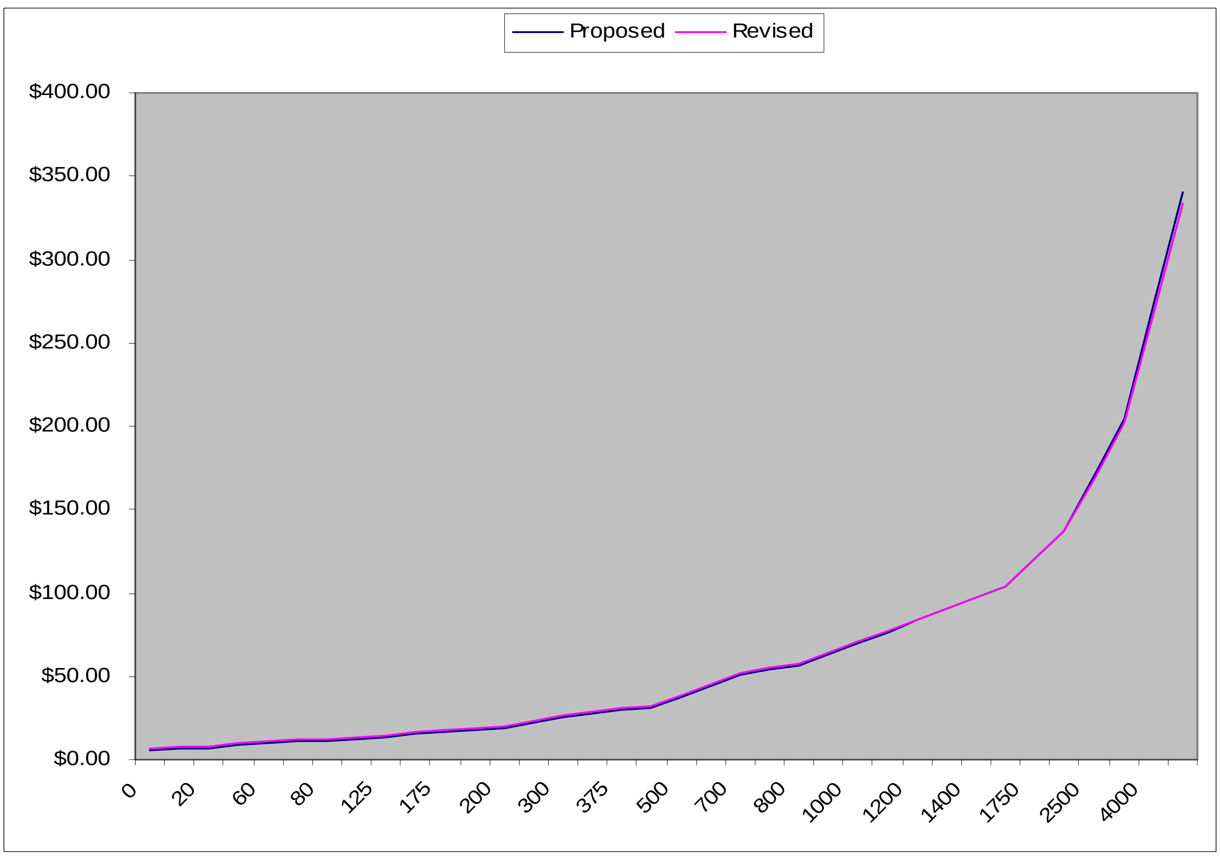
Subject: Tab 13 Board Directives
Reference: PUB/MH I-220

Please provide a comparison graph and tabular which illustrates the billing impacts of MH's proposed BMC reduction on various consumption patterns of customers with the existing rates

ANSWER:

The following graph and table illustrate the billing impacts of Manitoba Hydro's proposed rates (as filed in Appendix 10.3 of the Application) and those interim-approved as per Board Order 33/10.

	Proposed	Interim-Approved
Basic Charge:	$5.85	$6.85
First 900 kW.h @	6.37¢	6.38¢
Balance of kW.h @	6.75¢	6.57¢



KW.h	Proposed $/Month	Interim-Approved $/Month	Difference $/Month
0	$5.85	$6.85	$1.00
10	$6.49	$7.49	$1.00
20	$7.12	$8.13	$1.01
40	$8.40	$9.40	$1.00
60	$9.67	$10.68	$1.01
75	$10.63	$11.64	$1.01
80	$10.95	$11.95	$1.00
100	$12.22	$13.23	$1.01
125	$13.81	$14.83	$1.02
150	$15.41	$16.42	$1.01
175	$17.00	$18.02	$1.02
185	$17.63	$18.65	$1.02
200	$18.59	$19.61	$1.02
250	$21.78	$22.80	$1.02
300	$24.96	$25.99	$1.03
350	$28.15	$29.18	$1.03
375	$29.74	$30.78	$1.04
400	$31.33	$32.37	$1.04
500	$37.70	$38.75	$1.05
600	$44.07	$45.13	$1.06
700	$50.44	$51.51	$1.07
750	$53.63	$54.70	$1.07
800	$56.81	$57.89	$1.08
900	$63.18	$64.27	$1.09
1000	$69.93	$70.84	$0.91
1100	$76.68	$77.41	$0.73
1200	$83.43	$83.98	$0.55
1300	$90.18	$90.55	$0.37
1400	$96.93	$97.12	$0.19
1500	$103.68	$103.69	$0.01
1750	$120.56	$120.12	($0.44)
2000	$137.43	$136.54	($0.89)
2500	$171.18	$169.39	($1.79)
3000	$204.93	$202.24	($2.69)
4000	$272.43	$267.94	($4.49)
5000	$339.93	$333.64	($6.29)

PUB/MH II-172

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2**

a) **Please provide a comprehensive report as defined in 150/08 Directive #2 (and as amended):**

ANSWER:

Manitoba Hydro sponsored a workshop on May 31st, June 1st and June 2nd for the PUB, its advisors and Intervenors to discuss Manitoba Hydro's export activities. The Manitoba Hydro presentations from the workshop for May 31 and June 1 can be found in Appendix 56 which Manitoba Hydro considers fulfillment of Order 150/08 Directive #2.

PUB/MH II-172

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2**

b) Overview of MH's export business strategies, historical revenue/cost performance.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-172(a).

PUB/MH II-172

Subject: Tab 13 Board Directives
Reference: Order 150/08 Directive #2

c) Monthly profiles of MH's U.S. and CDN peak and off-peak energy exports (GWh/¢/KWh) and imports (GWh/¢/KWh) for 1999/00 to 2009/10.

ANSWER:

Please see tables below.

	ON PEAK				OFF PEAK			
	CDN EXPORTS		US EXPORTS		CDN EXPORTS		US EXPORTS	
	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)
Apr-05	78	67.73	579	61.87	71	49.55	416	27.63
May-05	81	58.64	673	59.23	84	37.97	587	20.81
Jun-05	83	72.05	731	63.53	86	37.01	562	24.76
Jul-05	65	84.78	696	66.61	59	53.26	635	38.09
Aug-05	87	106.18	796	60.31	71	54.46	451	23.48
Sep-05	69	118.38	377	72.70	57	55.95	406	25.07
Oct-05	45	96.53	660	68.59	20	51.72	506	23.74
Nov-05	66	66.28	607	61.97	39	43.54	415	23.22
Dec-05	54	86.71	528	72.08	38	59.22	232	58.82
Jan-06	63	64.70	543	59.34	54	46.77	337	56.11
Feb-06	27	53.31	501	59.65	32	41.05	312	50.73
Mar-06	58	53.95	607	53.42	37	36.38	432	21.23
Apr-06	33	53.17	582	53.42	18	33.05	442	23.22
May-06	41	52.84	750	56.35	35	32.99	634	26.08
Jun-06	43	58.00	763	55.16	18	30.33	575	22.81
Jul-06	37	68.41	687	67.54	23	42.13	643	40.23
Aug-06	23	67.46	750	62.32	9	38.93	487	35.99
Sep-06	27	44.83	518	56.06	8	35.71	182	32.87
Oct-06	11	60.83	406	63.39	7	53.96	67	49.31
Nov-06	5	104.45	313	63.44	1	72.54	88	55.13
Dec-06	5	55.85	321	62.95	3	61.40	99	57.29
Jan-07	7	39.95	365	63.69	6	35.75	62	49.25
Feb-07	2	130.95	290	67.17	1	99.39	38	98.30
Mar-07	4	58.11	436	68.06	3	46.29	32	74.79
Apr-07	4	56.23	529	67.15	3	39.16	75	59.34

	ON PEAK				OFF PEAK			
	CDN EXPORTS		US EXPORTS		CDN EXPORTS		US EXPORTS	
	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)
May-07	15	48.67	683	62.69	23	28.08	310	25.86
Jun-07	48	52.63	768	58.58	33	30.00	404	23.92
Jul-07	50	54.03	735	60.28	58	27.81	611	25.94
Aug-07	35	69.09	947	60.21	14	43.89	657	23.14
Sep-07	19	50.70	716	52.06	9	33.66	484	23.36
Oct-07	19	60.88	668	50.58	10	41.88	456	19.56
Nov-07	51	54.86	578	56.59	32	37.41	429	25.66
Dec-07	7	58.09	421	60.33	7	51.94	163	53.25
Jan-08	12	80.67	361	48.50	13	43.45	180	40.63
Feb-08	5	62.05	347	55.48	6	49.08	152	48.91
Mar-08	6	96.52	440	67.01	3	86.60	142	58.43
Apr-08	26	71.15	562	62.76	24	42.03	225	34.87
May-08	22	44.97	701	58.39	21	26.41	236	22.40
Jun-08	16	63.05	726	60.12	12	46.22	197	22.95
Jul-08	13	72.19	826	68.40	13	37.11	530	23.34
Aug-08	15	57.47	809	65.61	13	32.99	621	22.16
Sep-08	30	56.76	657	50.39	32	32.86	545	17.79
Oct-08	40	54.82	626	57.92	24	34.34	459	20.27
Nov-08	31	54.37	484	62.24	20	38.77	377	26.87
Dec-08	8	92.44	315	69.83	2	66.46	88	57.60
Jan-09	9	72.00	296	66.56	9	50.40	54	50.48
Feb-09	10	53.17	317	64.79	12	46.25	62	40.71
Mar-09	8	56.52	358	62.97	7	37.65	91	28.27
Apr-09	19	34.61	497	47.71	13	25.89	289	16.85
May-09	18	37.22	584	39.67	18	24.84	375	14.12

	ON PEAK				OFF PEAK			
	CDN EXPORTS		US EXPORTS		CDN EXPORTS		US EXPORTS	
	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)
Jun-09	27	36.90	620	42.96	20	19.83	324	14.81
Jul-09	40	36.96	669	38.81	30	22.76	508	11.71
Aug-09	35	32.67	693	39.98	25	21.33	522	12.64
Sep-09	27	29.24	558	41.24	16	18.24	467	12.74
Oct-09	36	34.31	683	41.73	16	22.82	538	15.70
Nov-09	41	34.24	541	40.78	39	21.84	429	17.18
Dec-09	24	47.71	337	51.05	19	30.60	75	33.10
Jan-10	24	51.38	333	54.32	19	36.22	166	36.95
Feb-10	8	48.96	349	53.87	13	34.97	91	32.96
Mar-10	16	32.32	605	39.95	14	25.03	174	23.69

	ON PEAK				OFF PEAK			
	CDN IMPORTS		US IMPORTS		CDN IMPORTS		US IMPORTS	
	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)
Apr-05	0	0.00	15	60.28	0	0.00	30	23.22
May-05	0	70.89	17	39.62	0	0.00	68	15.03
Jun-05	1	79.79	49	28.20	0	0.00	82	18.21
Jul-05	0	23.92	23	54.15	1	61.32	30	19.61
Aug-05	0	56.85	55	51.72	0	49.84	31	13.63
Sep-05	0	0.00	31	66.12	0	0.00	28	18.94
Oct-05	1	99.10	25	65.73		0.00	20	13.99
Nov-05	0	13.48	29	70.31	0	0.00	19	35.38
Dec-05	8	112.54	27	91.12	0	0.00	25	56.40
Jan-06	0	97.58	19	62.31	0	0.00	15	30.49
Feb-06	1	43.38	50	59.80	0	0.00	14	33.06
Mar-06	0	0.00	19	62.78	0	0.00	17	24.75
Apr-06	0	17.99	14	52.28	0	0.00	6	19.29
May-06	0	101.78	13	40.14	0	12.34	22	30.24
Jun-06	0	33.16	22	44.24	1	2.68	26	22.31
Jul-06	1	70.34	30	73.90	0	45.05	43	52.31
Aug-06	0	57.13	37	71.32	0	66.09	22	36.36
Sep-06	1	37.00	27	41.68	3	14.82	46	26.50
Oct-06	10	48.12	76	57.59	16	30.13	248	38.44
Nov-06	15	54.77	89	89.51	22	27.76	295	39.84
Dec-06	17	70.28	38	116.34	22	28.01	163	42.36
Jan-07	24	57.73	21	153.43	20	27.18	81	48.31
Feb-07	20	75.86	27	119.27	33	44.18	135	53.38
Mar-07	16	62.27	19	179.05	22	39.99	142	39.18

	ON PEAK				OFF PEAK			
	CDN IMPORTS		US IMPORTS		CDN IMPORTS		US IMPORTS	
	GWh	**Avg Price/MWh (CDN$)**	**GWh**	**Avg Price/MWh (CDN$)**	**GWh**	**Avg Price/MWh (CDN$)**	**GWh**	**Avg Price/MWh (CDN$)**
Apr-07	19	71.66	10	57.05	31	36.39	79	39.92
May-07	4	44.19	8	56.52	1	28.01	32	23.38
Jun-07	1	65.12	15	50.27	1	2.62	7	24.76
Jul-07	3	56.09	4	91.47	2	99.34	5	-25.60
Aug-07	1	7.98	12	84.82	1	-22.95	14	22.71
Sep-07	1	-107.66	5	78.22	1	-0.53	2	27.51
Oct-07	0	11.66	22	72.79	1	-5.00	23	20.05
Nov-07	2	74.94	5	74.31	0	-2.91	11	20.10
Dec-07	9	41.21	3	108.57	8	25.60	20	31.28
Jan-08	13	44.36	8	75.53	6	24.24	14	42.09
Feb-08	6	43.43	15	73.16	3	27.58	12	41.74
Mar-08	9	44.98	7	95.58	6	31.36	11	41.20
Apr-08	6	56.55	6	98.04	3	15.76	0	63.36
May-08	0	0.00	14	52.78	0	0.00	3	22.20
Jun-08	0	0.00	47	60.41	0	0.00	16	22.67
Jul-08	0	0.00	22	79.57	0	0.00	13	24.80
Aug-08	0	68.26	26	93.29	0	13.11	29	26.21
Sep-08	2	59.63	15	41.64	1	26.33	27	25.24
Oct-08	1	46.30	23	62.15	1	24.55	22	22.99
Nov-08	1	60.34	15	69.31	8	44.11	25	24.21
Dec-08	37	57.62	19	67.71	24	37.30	45	30.14
Jan-09	19	55.70	32	56.64	3	37.04	53	32.85
Feb-09	4	48.50	13	49.09	2	34.77	3	26.58
Mar-09	13	31.85	21	56.39	15	20.00	19	14.79
Apr-09	7	23.14	34	53.51	5	1.65	68	25.77

	ON PEAK				OFF PEAK			
	CDN IMPORTS		US IMPORTS		CDN IMPORTS		US IMPORTS	
	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)	GWh	Avg Price/MWh (CDN$)
May-09	4	27.24	34	62.68	5	10.69	17	62.64
Jun-09	7	24.99	18	66.79	7	12.53	22	43.63
Jul-09	4	17.07	24	59.30	2	15.52	27	36.49
Aug-09	3	27.81	36	46.87	3	13.44	40	21.28
Sep-09	1	24.80	13	107.77	2	9.01	32	43.47
Oct-09	3	34.40	17	81.66	3	18.68	54	20.97
Nov-09	2	24.50	36	58.74	17	14.44	96	23.21
Dec-09	12	35.26	40	56.95	27	21.19	80	32.00
Jan-10	6	46.00	38	62.55	31	27.77	56	37.07
Feb-10	2	40.61	27	56.26	9	25.46	30	44.82
Mar-10	1	29.73	36	53.56	8	17.91	22	49.64

<u>PUB/MH II-172</u>

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2**

d) Accompanied by un-redacted (in confidence with the Board only) and redacted copies of current export contracts and a definition of the annual capacity (MW)/energy (GWh) commitments over the contract life.

<u>ANSWER</u>:

Please refer to the response to PUB/MH I-153 where Manitoba Hydro provided selected copies of contracts.

<u>PUB/MH II-172</u>

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2**

e) Accompanied by un-redacted (in confidence with the Board only) and redacted copies of pending contracts (or term sheets) and a definition of the annual capacity (MW)/energy (GWh) commitments over the contract life.

<u>ANSWER</u>:

Manitoba Hydro's term sheets are trade secret and are subject to confidentiality agreements.

<u>PUB/MH II-172</u>

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2**

f) **A quantitative overview of MH's other annual bilateral sales/diversity exchange commitments/MISO market participation/merchant trading.**

<u>ANSWER</u>:

		2009/10	
	GWh	**Revenue (CAD $)**	**Average Price (CAD$/MWh)**
Opportunity Bilateral Sales	2,754	64,742,932	23.51
Diversity Sales	866	21,514,485	24.84
MISO Market Sales	4,605	100,348,103	21.79

The net profit from merchant trading transactions was $ 1,488,271 on 775 GWh.

<u>PUB/MH II-172</u>

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2**

g) A quantitative discussion of MH's transmission constraints on U.S. and CDN export/import ventures.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-172(a).

PUB/MH II-172

Subject: Tab 13 Board Directives
Reference: Order 150/08 Directive #2

h) A quantitative discussion of MH's IFF09-1 assumptions with respect to export/import price forecasts and a sensitivity analysis of upper/lower quartile water flows/ foreign exchange/domestic load growth and natural gas prices.

ANSWER:

The assumptions that are utilized in developing the forecast for export prices in IFF09-1 are commercially sensitive information since public release could harm the Corporation in participation in the export market and in negotiation of contracts for export sales. General information on the derivation of export price forecasts is provided in responses to several information requests such as PUB/MH I-156(a) and PUB/MH I-48(b).

The risk analysis section in IFF09-1 contains a sensitivity analysis to a number of factors. The impact on net export revenues due to high and low water flows in each year is provided on Page 22 of IFF09-1. The table on page 20 summarizes the impact on retained earnings due to each the following factors: a 1% increase or decrease in the foreign exchange rate, low and high export prices, and a medium-high domestic load forecast. A sensitivity analysis to natural gas prices is not undertaken as a separate analysis since this factor would likely be part of the scenario of low or high export prices.

PUB/MH II-173

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2 - Canadian Energy Sales/Trading**

a) **Please provide MH's marketing plan for energy sales and market trading with Ontario/Saskatchewan/Alberta Utilities.**

ANSWER:

Manitoba Hydro's marketing plans are commercially sensitive and confidential, as such Manitoba Hydro declines to provide same.

PUB/MH II-173

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2 - Canadian Energy Sales/Trading**

b) Please provide monthly summary of sales/purchase (2000-2009) history with Ontario, Alberta and Saskatchewan defining:

i. Firm sales and purchases.
ii. Opportunity on-peak sales and purchases.
iii. Opportunity off-peak.

ANSWER:

Below are the tables for the Opportunity On-Peak Sales and Purchases and the Opportunity Off-Peak Sales and Purchases with Ontario, Alberta and Saskatchewan. Manitoba Hydro does not have any firm sales or purchases with these provinces.

Opportunity on-peak sales and purchases with Ontario, Alberta and Saskatchewan

Month	MWh Sales On-Peak	Total Sales Revenue On-Peak	MWh Purchases On-Peak	Total Purchases Costs On-Peak
April,2005	77,546	5,267,312	0	0
May,2005	80,898	4,743,674	253	16,887
June,2005	83,239	5,997,428	767	74,572
July,2005	64,523	5,470,522	18	210
August,2005	86,711	9,206,981	314	26,789
September,2005	68,671	8,129,464	0	0
October,2005	45,106	4,353,880	801	79,364
November,2005	65,526	4,342,819	73	11,524
December,2005	53,994	4,681,640	8,075	891,676
January,2006	62,663	4,054,204	266	24,955
February,2006	27,233	1,451,729	623	34,960
March,2006	58,444	3,153,209	7	368
April,2006	32,823	1,745,194	80	3,645
May,2006	41,303	2,182,630	24	919
June,2006	43,292	2,510,939	418	18,457
July,2006	37,108	2,538,726	1,475	112,906
August,2006	23,352	1,575,427	300	16,344
September,2006	26,746	1,199,034	821	35,978
October,2006	11,219	682,470	9,596	429,672
November,2006	4,902	515,794	14,536	722,679
December,2006	5,063	282,791	16,806	1,043,751
January,2007	7,498	299,509	24,227	1,303,283
February,2007	2,028	265,564	19,649	1,334,379
March,2007	3,666	213,015	15,593	923,064
April,2007	3,542	163,758	18,745	1,173,556
May,2007	14,669	713,918	4,181	197,903
June,2007	48,402	2,547,497	701	31,243
July,2007	50,836	2,713,653	3,432	202,416
August,2007	35,005	2,418,456	719	44,963

Month	MWh Sales On-Peak	Total Sales Revenue On-Peak	MWh Purchases On-Peak	Total Purchases Costs On-Peak
September,2007	18,593	942,598	603	45,175
October,2007	19,327	1,155,992	437	36,268
November,2007	50,828	2,788,322	1,675	127,999
December,2007	6,839	401,476	8,826	656,072
January,2008	12,128	978,369	13,383	633,505
February,2008	5,203	322,842	5,578	356,555
March,2008	6,402	617,895	9,202	608,493
April,2008	25,814	1,836,556	5,544	424,896
May,2008	22,361	1,005,656	0	0
June,2008	15,736	992,164	0	0
July,2008	13,179	951,447	0	0
August,2008	15,118	868,839	302	20,614
September,2008	29,530	1,676,051	1,635	97,503
October,2008	39,766	2,179,882	846	39,171
November,2008	30,983	1,684,600	1,464	88,343
December,2008	7,667	708,747	36,576	2,107,330
January,2009	8,944	643,993	18,600	1,035,979
February,2009	9,898	526,238	4,103	198,999
March,2009	7,535	425,879	13,026	414,902

Opportunity off-peak sales and purchases with Ontario, Alberta and Saskatchewan

Month	MWh Sales Off-Peak	Total Sales Revenue Off-Peak	MWh Purchases Off-Peak	Total Purchases Costs Off-Peak
April,2005	71,100	3,523,087	0	0
May,2005	84,074	3,192,251	0	0
June,2005	86,072	3,185,692	0	0
July,2005	59,389	3,163,336	617	50,737
August,2005	71,308	3,883,304	100	4,984
September,2005	56,931	3,185,356	0	0
October,2005	20,450	1,057,768	3	135
November,2005	38,591	1,680,301	0	0
December,2005	37,641	2,229,141	472	44,891
January,2006	54,093	2,530,097	0	0
February,2006	32,076	1,316,660	5	223
March,2006	37,008	1,346,475	0	0
April,2006	18,383	607,485	6	206
May,2006	35,456	1,169,691	271	38,417
June,2006	17,526	531,641	704	21,823
July,2006	22,679	955,448	275	13,956
August,2006	9,296	361,915	497	37,591
September,2006	8,413	300,412	2,867	48,773
October,2006	7,266	392,060	33,692	1,110,833
November,2006	1,433	99,480	37,644	1,399,846
December,2006	3,262	200,284	22,923	789,507
January,2007	5,667	202,589	19,854	754,922
February,2007	926	92,038	33,128	1,522,958
March,2007	3,329	154,089	22,293	914,241
April,2007	2,625	102,796	31,411	1,178,174
May,2007	22,983	645,299	1,350	42,023
June,2007	32,629	978,717	649	4,325
July,2007	58,462	1,604,666	2,277	48,496
August,2007	13,869	608,678	1,275	47,714

Month	MWh Sales Off-Peak	Total Sales Revenue Off-Peak	MWh Purchases Off-Peak	Total Purchases Costs Off-Peak
September,2007	8,817	296,737	695	24,792
October,2007	10,237	428,693	643	28,169
November,2007	31,694	1,185,757	425	14,425
December,2007	6,672	346,516	7,977	229,024
January,2008	12,798	556,014	6,362	195,794
February,2008	6,358	312,031	3,113	121,014
March,2008	2,813	243,602	6,436	297,088
April,2008	23,914	1,005,012	3,308	37,360
May,2008	20,776	548,671	0	0
June,2008	12,218	564,753	0	0
July,2008	13,432	498,407	0	0
August,2008	13,149	433,756	76	996
September,2008	31,740	1,042,850	966	25,438
October,2008	24,107	827,802	684	16,790
November,2008	19,585	759,321	8,019	357,534
December,2008	2,125	106,124	23,982	894,531
January,2009	8,513	429,078	3,498	129,556
February,2009	12,291	568,438	2,432	84,552
March,2009	7,115	267,871	15,377	307,562

PUB/MH II-173 (REVISED)

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2 - Canadian Energy Sales/Trading**

c) Please provide a monthly status report for 2007/08/09:

i. Firm transmission arrangements within or into Canada.
ii. Non-firm transmission arrangements in or into Canada.

ANSWER:

i) The following table indicates Manitoba Hydro's firm transmission reservations.

Interface	Firm Long Term Transmission Reservations held by Manitoba Hydro			
	2010	**2009**	**2008**	**2007**
ON Export	200 MW	200 MW	200 MW	200 MW
SK Export	0 MW	0 MW	0 MW	0 MW
ON Import	0 MW	0 MW	0 MW	0 MW
SK Import	0 MW	0 MW	0 MW	0 MW
US Import	700 MW	700 MW	850 MW	850 MW

Notes:
1. The US import limit was reduced from 850 MW to 700 MW in April 2009.

ii) Non-firm transmission service is purchased by Manitoba Hydro on an hourly, daily, weekly or monthly basis. Such service is arranged to support opportunity sales and purchases on an as needed basis. Manitoba Hydro does not maintain a record of these short term non firm arrangements.

PUB/MH II-174

Subject: **Tab 13 Board Directives**

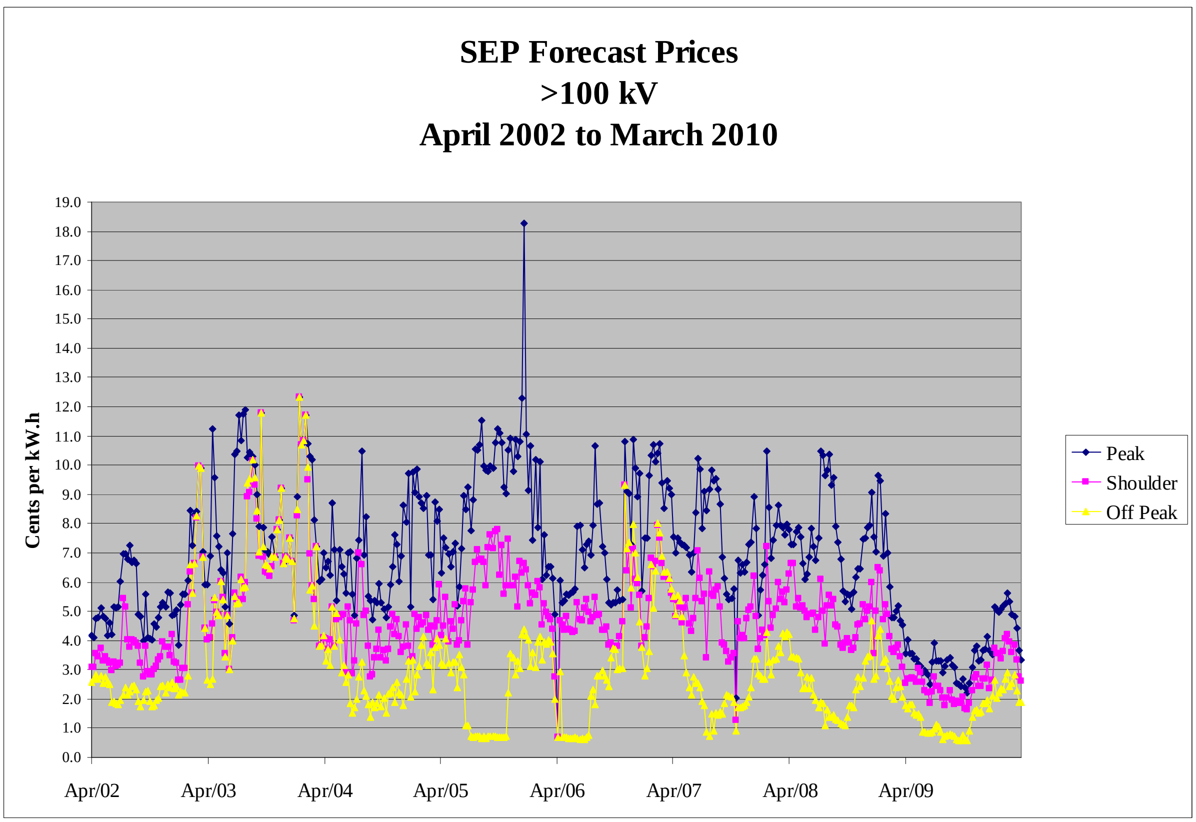
Reference: **Order 150/08 Directive #2 - SEP/NEB/MISO Clearing House Data**

a) **Please provide a report documenting the last 8 years of:**

- **SEP filing (peak/shoulder/off-peak graphs).**
- **NEB monthly filing (summarized by permit number).**
- **MISO monthly clearinghouse peak/off-peak summaries of MH's opportunity export sales and purchase activities (separately defining merchant trading).**

ANSWER:

SEP Forecast Price Graph

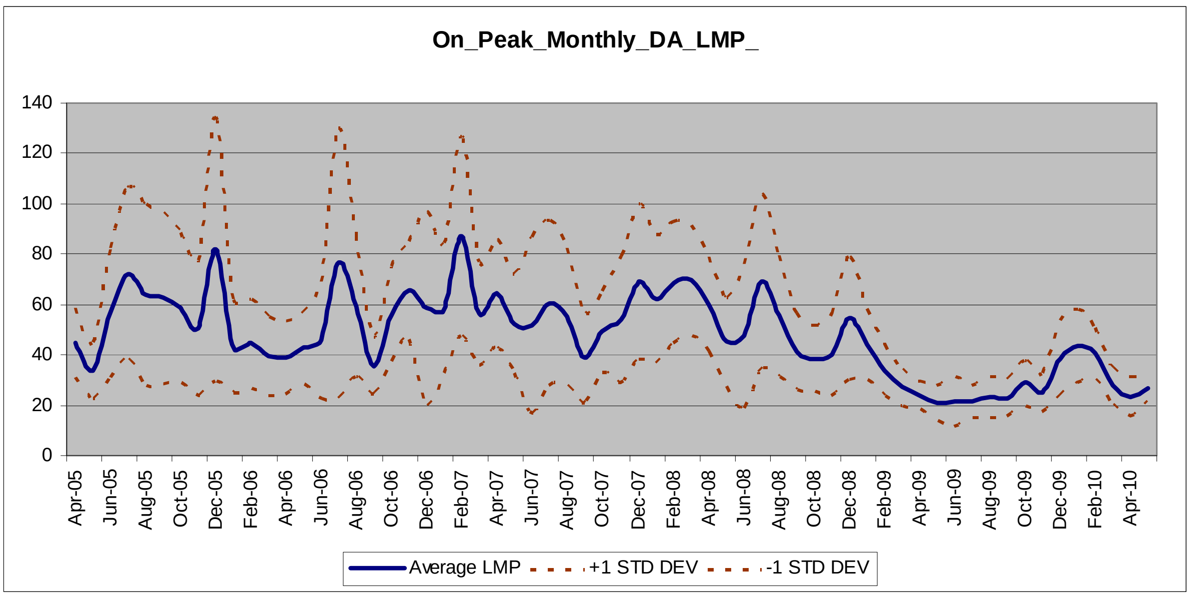


NEB monthly filing by permit number can be found at:
http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/sttstc/lctrctyxprtmprt/lctrctyxprtmprt-eng.html

MISO Monthly Peak/Off-Peak Summaries

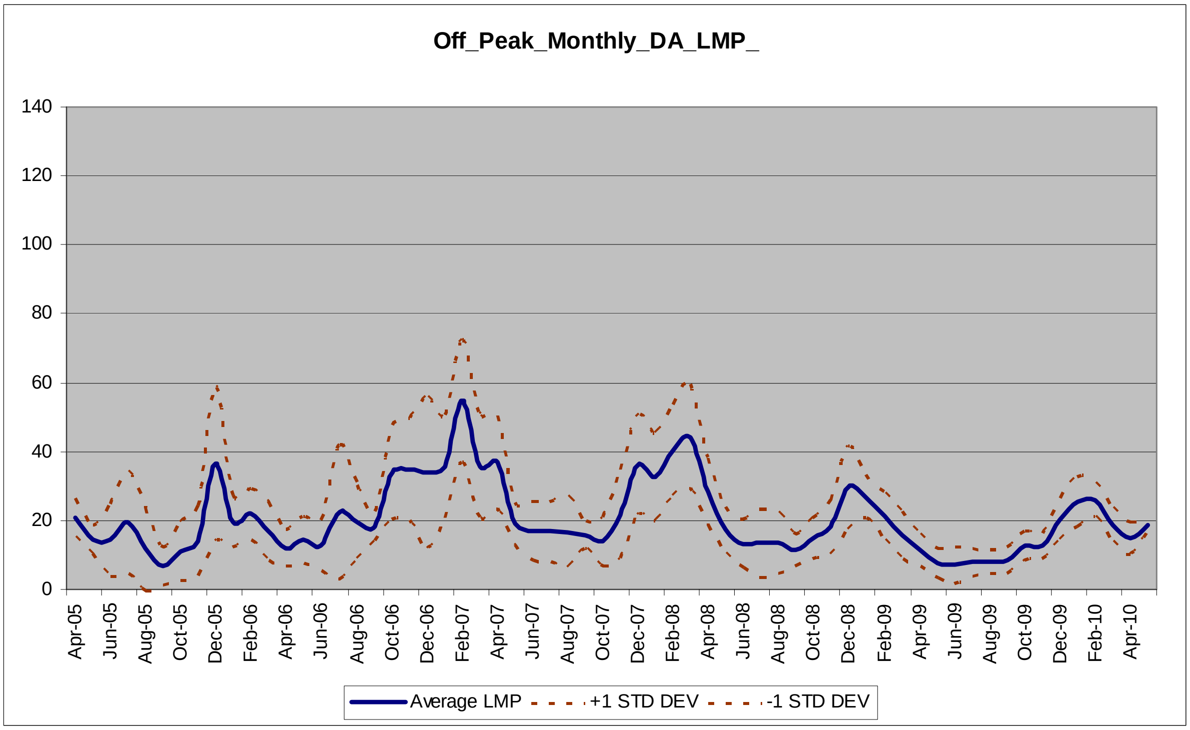
The tables provided for this response summarize the monthly average pricing data for both peak and off-peak periods with the MISO market. Peak hours are from 7:00 am to 10:00 pm each weekday. The first table shows prices for only those hours in the peak period. Off-peak hours include all other hours of the week i.e. Monday to Friday from 10:00 pm to 6:00 am and all day Saturday and Sunday and six US statutory holidays.

The bottom chart shows the probability distributions for on peak and off peak prices. For the on peak hours the most frequent (10% of the time) price is around $60 per MW.h. For the off peak hours the most frequent (18% of the time) price is around $15 per MW.h.

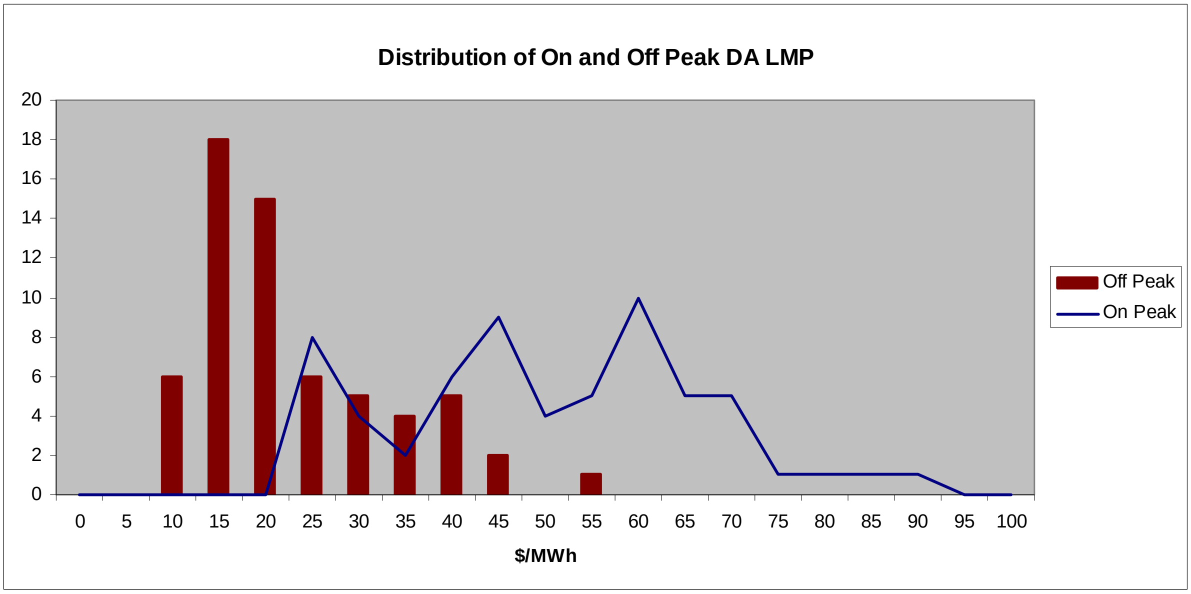


On Peak Monthly DA LMP

Average On	Year						
Month	2005	2006	2007	2008	2009	2010	Grand Total
January		43.25	58.37	62.07	44.19	43.55	50.29
February		44.48	87.07	68.72	33.87	40.47	54.92
March		39.47	56.14	69.58	27.11	27.83	44.03
April	44.69	39.06	64.56	59.92	24.04	23.43	42.62
May	33.65	42.88	52.32	45.18	20.78	26.48	36.88
June	56.68	45.94	51.45	47.40	21.38		44.57
July	72.25	76.52	60.47	68.90	21.43		59.92
August	63.97	59.47	55.12	55.54	23.27		51.47
September	62.47	35.72	39.04	41.29	22.87		40.28
October	58.64	55.90	49.09	38.45	28.88		46.19
November	50.66	65.46	54.13	40.08	24.84		47.03
December	81.77	58.69	68.99	54.58	38.43		60.49
Grand Total	58.31	50.57	58.06	54.31	27.59	32.35	47.95



Off Peak Monthly DA LMP							
Average Off	Year						
Month	2005	2006	2007	2008	2009	2010	Grand Total
January		19.68	35.49	32.78	26.86	25.52	28.07
February		21.92	54.58	40.40	21.28	26.02	32.84
March		16.92	35.66	44.16	15.57	18.82	26.23
April	20.72	12.07	36.90	28.46	11.55	14.92	20.77
May	14.45	14.62	18.96	17.21	7.68	18.77	15.28
June	14.30	12.75	17.14	13.34	7.19		12.94
July	19.45	22.51	16.86	13.37	8.00		16.04
August	11.69	19.53	16.67	13.50	8.09		13.89
September	6.80	18.37	15.83	11.57	8.46		12.20
October	11.08	34.07	13.91	14.90	12.70		17.33
November	13.95	34.93	21.73	18.18	12.60		20.28
December	36.59	33.99	35.98	29.53	20.35		31.29
Grand Total	16.56	21.78	26.64	23.12	13.36	20.81	20.51


Distribution of On and Off Peak DA LMP
20
18
16
14
12
10
8
6
4
2
0
0 5 10 15 20 25 30 35 40 45 50 55 60 65 70 75 80 85 90 95 100
$/MWh
Off Peak
On Peak

<u>PUB/MH II-174</u>

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2 - SEP/NEB/MISO Clearing House Data**

b) Please explain in detail how MH would expect interveners to employ the above data in defining MC and/or avoided costs for rate design/DSM purposes.

<u>ANSWER</u>:

Manitoba Hydro marginal cost estimates for power supply are based on Manitoba Hydro's best estimates of the value of firm energy in interconnected markets in the current and future time periods. These Manitoba Hydro marginal cost estimates are most closely related to the prices associated with future long-term export contracts which are primarily for on-peak export products. These will not be identical to the value of opportunity energy (SEP rates), day ahead locational marginal prices (MISO), or rates in existing legacy firm contracts (NEB). If the foregoing indicators are to be utilized as a proxy for Manitoba Hydro's marginal cost, it is most appropriate to utilize only the on-peak components.

There will be significant correlation between SEP rates and day ahead locational marginal prices in MISO, as both of these prices relate to short-term opportunity sales. However, they are both derived from historic information while Manitoba Hydro's marginal costs are forward looking and consider additional factors that influence value of incremental energy and capacity.

Manitoba Hydro is not in a position to determine how participants would use such data. However, Manitoba Hydro does suggest that they might use it as a crosscheck on the reasonableness of Manitoba Hydro's forecast of marginal cost by examining trends over time and among time periods in the various data sets.

PUB/MH II-174

Subject: Tab 13 Board Directives
Reference: Order 150/08 Directive #2 - SEP/NEB/MISO Clearing House Data

c) Please discuss in detail how MH could employ incremental in-service costs in the Wuskwatim G&T projects as a proxy for avoided future costs and/or export import prices.

ANSWER:

Manitoba Hydro currently determines the marginal cost of an increment of power supply by assessing its value on the export market. An alternative approach is to utilize the cost of a future supply option such as the Wuskwatim G&T Project as an indicator of the cost of power. The marginal cost of this project could be determined by determining its levelized cost over its expected life. This levelized cost is determined by distributing the in-service cost of the project into annual payments over its expected life and dividing by annual energy production to obtain a unit cost per kW.h.

PUB/MH II-174

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive #2 - SEP/NEB/MISO Clearing House Data**

d) Please explain MH's intended (ongoing) use of MC in defining:

- **Class rates and special rates.**
- **COSS.**
- **DSM evaluation.**

ANSWER:

Manitoba Hydro intends to use marginal cost as a directional guideline in proposing elements in the rate structure where it is reasonable and feasible to incorporate a price signal. This would include the tail block of any class rate structure where inclining block rates are applied, such as the current Residential rate structure and the proposed Energy Intensive Industrial rate.

Manitoba Hydro is proposing to have an independent review of its Cost of Service methodology, including a review of whether and where it would be appropriate to incorporate marginal cost information.

Marginal cost is an appropriate value for determining Manitoba Hydro's level of investment in DSM similar to any other resource options such as supply-side efficiency improvements, wind development and biomass projects.

PUB/MH II-175 (REVISED)

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 6 Benchmarking, Letter to the Board Dated April 1, 2010.**

a) **Please indicate whether the Corporation has undertaken or participated any benchmarking analysis with other Utilities, If so please file.**

ANSWER:

Manitoba Hydro has not recently participated in any formal benchmarking analysis with other utilities. While Manitoba Hydro submits information to CEA's Committee on Corporate Performance and Evaluation (COPE) Program and participates in other industry benchmarking working groups through association memberships Manitoba Hydro does not recognize these activities as a formal benchmarking exercise due to the inherent differences amongst participating companies.

PUB/MH II-175

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 6 Benchmarking, Letter to the Board Dated April 1, 2010.**

b) Please explain why the Corporation cannot complete the terms of Reference: for undertaking the benchmarking study in advance of the implementation of IFRS.

ANSWER:

The Study Outline dated June 30, 2009 was filed on July 24, 2009.

Further, as part of its 2010/11 and 2011/12 GRA submission, Manitoba Hydro indicated that it would undertake this study once it had implemented IFRS and that it would provide PUB with a timeline by April 1, 2010. Accordingly, on April 1, 2010, Manitoba Hydro advised the PUB of its timeline for undertaking the study; specifically that this directive will be addressed commencing April 1, 2012, i.e. upon completion of the first full year of reporting under IFRS. The reason for this is that the greater uniformity of accounting practices among utilities under IFRS is expected to provide improved comparability across utilities.

<u>PUB/MH II-175</u>

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 6 Benchmarking, Letter to the Board Dated April 1, 2010.**

c) **Please confirm that the OM&A Benchmarking Study will primarily focus on the actual F05 to F10 period (pre-IFRS) and subsequently (retroactively) adjust these findings to be consistent with future filings by MH and as such, the study need not await the IFRS implementation.**

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-175(b).

PUB/MH II-175

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 6 Benchmarking, Letter to the Board Dated April 1, 2010.**

d) **Please confirm that actual post-IFRS benchmarking data may not be available until two or three years after the IFRS implementation.**

ANSWER:

Manitoba Hydro intends to have data available commencing with the year end report for 2011-12, the first reporting year under IFRS.

PUB/MH II-175

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 6 Benchmarking, Letter to the Board Dated April 1, 2010.**

e) Please provide an alternative timeline for the production of the study.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-175(d).

PUB/MH II-176

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive # 7 Asset Condition Assessment**

a) Please explain whether and how the current IFRS project is assisting in gathering information to undertake an Asset Condition Assessment Report.

ANSWER:

IFRS is more rigorous than GAAP in terms of its requirements to identify separate property plant and equipment components for depreciation and retirement calculations. One aspect of the IFRS project is to ensure that the level of detail in property plant and equipment records reflect the expected lives of its major components and sub-components in accordance with these more rigorous standards.

To this end, the IFRS project has undertaken to review with asset managers to what extent there are different expected asset component lives within the current plant accounts; to create a new account classifications where major differences are found; to research original cost and replacement records to develop opening account balances for any new account classifications, and to research asset condition, expected life & remaining lives for these asset groups.

As a result, a modified capital reporting framework will be created with these new accounts so that the implications of asset replacement requirements can be quantified and incorporated properly into financial forecasts. Asset condition reporting will be required to provide information in accordance with the modified financial framework.

<u>PUB/MH II-176</u>

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive # 7 Asset Condition Assessment**

b) **Please confirm that IFRS process will not actually affect the current condition/life expectancy/maintenance schedules that relate to MH's G&T&D facilities.**

<u>ANSWER</u>:

Confirmed.

PUB/MH II-176

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive # 7 Asset Condition Assessment**

c) Please provide an alternate time-line for this assessment which does not await the IFRS implementation

ANSWER:

Manitoba Hydro will provide an update on the status of projects related to the Asset Condition Assessment by June 1, 2011 (related projects include: IFRS, Depreciation Study, Enterprise Asset Management Project, GIS Enabled Transmission Line Asset Maintenance and Inspection System, Asset Investment Planning System).

PUB/MH II-176

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive # 7 Asset Condition Assessment**

d) Please confirm that MH will be providing Terms of Reference for the Asset Condition Assessment Report by April 1, 2010, or if not, then prior to the start of the 2010 GRA.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-176(c).

PUB/MH II-177

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 17- Global GHG Emissions /MH Exports vs. Domestic Usage**

a) Please provide the report on Global Environmental (GHG) and economic benefits to be achieved by exporting hydraulically generated electricity (due Jan/2010).

ANSWER:

This report will be filed with the Public Utilities Board as soon as it is completed and undergone internal review.

PUB/MH II-177

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 17- Global GHG Emissions /MH Exports vs. Domestic Usage**

b) **As a follow-up to the above report, please provide an analysis of the potential impacts of $5/GJ natural gas prices persisting for the next 5 years and for the next 10 years.**

ANSWER:

The report being prepared in response to PUB Order 150/08 is in the final stages of internal review. To refrain from any further delays in submitting this report, no additional analysis will be under taken. The requested analysis would requires substantial work as a new load forecast would need to be prepared and a number of runs containing the background information would need to be undertaken.

<u>PUB/MH II-177</u>

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 17- Global GHG Emissions /MH Exports vs. Domestic Usage**

c) **Please confirm that this report will address the full economic and environmental consequences to Manitoba rate payers of:**

- **i.** **Fuel switching (with low and high natural gas prices).**
- **ii.** **Increased ground source heating in Manitoba.**
- **iii.** **Potential for electric cars in Manitoba.**
- **iv.** **Increased imports (from coal or natural gas generation) to support export sales**

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH II-177(b). The analysis is intended to address the intended purpose, however specific sensitivity analysis is not being undertaken related to specific future natural gas prices and other potential future scenarios (e.g. variations in imports, varying take up of electric vehicles in Manitoba, etc.)

PUB/MH II-178

Subject: Tab 13 Board Directives
Reference: Order 150/08 Directive # 17 C02 Emissions

a) Please confirm that in low flow years, MH's exports currently would not result in a net reduction of CO_2 emissions.

ANSWER:

It is confirmed that Manitoba Hydro's exports would not result in a net reduction in the implications related to CO_2 emissions in low flow conditions. Net reductions in the implications related to CO_2 emissions would occur only when Manitoba Hydro is a net exporter of energy. Under the lowest flow conditions, Manitoba Hydro is not expected to be a net exporter of electricity.

PUB/MH II-178

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive # 17 C02 Emissions**

b) **Please confirm that in median flow years, MH's exports could involve buying about 3,000 GWh coal energy (matching the dependable contract sales which could be displacing coal or natural gas). The balance of the sales would serve to backstop wind (or serve peak loads) and displace natural gas generation.**

ANSWER:

There are a number of assumptions in this information request that are not correct. Firstly, Manitoba Hydro is not forecasting that it would be buying about 3,000 GW.h sourced from coal energy in each year on an expected basis. It is most appropriate to utilize the forecast in the IFF which corresponds to the average of 94 flow conditions instead of median. The response to PUB/MH I-45(b) indicates that the expected purchases of energy are about 2600 GW.h per year in the early years of the IFF, but this includes about 1400 GW.h of wind energy purchases. Consequently the forecast for the expected quantity of import energy is about 1200 GW.h per year. This quantity of imports is not sufficient to offset dependable energy contact export sales which average about 3300 GW.h in the early years of the IFF. Therefore, the assumption of imports offsetting contract sales is not correct in the information request.

Manitoba Hydro does not agree with the assumptions relating to backstopping wind generation and the type of generation sources that would be displaced by exports. Manitoba Hydro estimates the emission implication from displaced generation from all exports to be 0.75 kg CO2e/kW.h. This reflects the displacement of a mixture of fossil-fuel resources and consists of a variety of technologies and efficiencies.

<u>PUB/MH II-178</u>

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive # 17 C02 Emissions**

c) Please confirm that these exports come almost entirely from hydraulic generation and aside from dependable annual contract sales (about 8,000 GWh) would not displace coal generation.

<u>ANSWER</u>:

It is confirmed that export sales are forecasted to come almost entirely from hydraulic generation on an expected basis which is derived from an average of 94 flow conditions. Manitoba Hydro is unable to determine the source for the 8000 GW.h that is referenced in the information request. Please refer to the response to PUB/MH 178(b) for a discussion on an appropriate source of information.

Manitoba Hydro does not agree with the assumptions in the information request related to the generation type that can be expected to be displaced by export sales. It is expected that exports will displace a significant quantity of coal-fired generation. Manitoba Hydro estimates the emission implication from displaced generation from all exports to be 0.75 kg CO2e/kW.h. This reflects the displacement of a mixture of fossil-fuel resources and consists of a variety of technologies and efficiencies.

PUB/MH II-179

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 17 20-Year IFF 09-1 – Exports; Fuel and Power Purchases Market Perception of MH's CO2 Emissions**

a) Please provide a tabulation for the 1992-2009 period of MH's annual:

- **Thermal (coal) generation (GWh) and CO2 emissions (tonnes).**
- **Thermal (natural gas) generations (GWh) and CO2 emissions (tonnes).**
- **Imports (GWh) and related CO2 emissions (tonnes):**
  - **From coal generation sources**
  - **From natural gas generation sources**

ANSWER:

Note: Although Manitoba Hydro's imports and exports have indirect emission implications, the responsibility remains with generators that release emissions.

Manitoba Hydro Thermal Generation & Import Energy 1992-2009

	Coal		Natural Gas		Imports [1]	
	Energy (GWh)	Emissions (tonnes CO2e)	Energy (GWh)	Emissions (tonnes CO2e)	Energy [2] (GWh)	Indirect Implications [3] (tonnes CO2e)
1992/93	207	278,217	0	0	970	1,024,533
1993/94	249	311,456	0	0	1,130	1,193,528
1994/95	206	263,585	0	0	1,086	1,147,055
1995/96	196	243,052	0	0	1,238	1,307,600
1996/97	163	186,261	0	0	1,201	1,268,520
1997/98	273	314,857	0	0	942	994,959
1998/99	932	1,003,128	0	0	1,225	1,293,869
1999/00	675	710,784	0	0	870	918,911
2000/01	860	886,023	0	0	834	880,887
2001/02	481	474,094	0	0	1,530	1,542,921
2002/03	411	397,734	190	100,860	3,227	3,082,960
2003/04	584	632,714	269	169,659	9,596	8,658,558
2004/05	381	443,070	32	22,618	1,974	1,676,310
2005/06	382	427,645	20	14,298	133	106,269
2006/07	457	475,952	65	42,287	1,416	1,062,044
2007/08	434	454,306	22	14,318	276	206,635
2008/09	315	327,917	20	13,010	289	216,892

1 Imports (exclude Wind Purchases)

2 Import energy is generally purchased from energy markets. Identifying the generation specific resource and/or fuel source is not feasible.

3 Emissions are based on estimated intensity of market energy.

PUB/MH II-179

Subject: Tab 13 Board Directives

Reference: Order 150/08 Directive # 17 20-Year IFF 09-1 – Exports; Fuel and Power Purchases Market Perception of MH's CO2 Emissions

b) Please provide a similar tabulation for the 20-year IFF 09-1.

ANSWER:

Note: Although Manitoba Hydro's imports and exports have indirect emission implications, the responsibility remains with generators that release emissions.

Manitoba Hydro Thermal Generation & Import Energy IFF 09-1

	Coal		Natural Gas		Imports [1]	
	Energy [2] (GWh)	Emissions [3] (tonnes CO2e)	Energy [2] (GWh)	Emissions [3] (tonnes CO2e)	Energy [2] (GWh)	Indirect Implications [4] (tonnes CO2e)
2009/10	107	114,490	45	27,420	365	273,750
2010/11	125	133,750	33	20,460	1,138	853,500
2011/12	127	136,376	304	186,318	1,275	956,071
2012/13	127	135,695	310	189,544	1,235	926,000
2013/14	127	135,793	314	191,925	1,227	920,571
2014/15	127	135,695	317	193,907	1,267	950,000
2015/16	125	133,361	372	228,169	1,322	991,286
2016/17	126	134,334	406	248,749	1,375	1,031,500
2017/18	127	135,987	453	277,573	1,453	1,089,643
2018/19	119	127,525	472	290,058	2,448	1,835,714
2019/20	0	0	521	320,636	2,118	1,588,143
2020/21	0	0	599	368,653	2,018	1,513,214
2021/22	0	0	645	396,924	2,096	1,571,786
2022/23	0	0	730	449,751	1,892	1,418,929
2023/24	0	0	597	367,060	1,837	1,377,857
2024/25	0	0	597	366,702	2,039	1,529,286
2025/26	0	0	386	236,507	1,682	1,261,500
2026/27	0	0	344	210,842	1,684	1,262,786
2027/28	0	0	348	213,335	1,727	1,295,071
2028/29	0	0	347	212,929	1,765	1,323,643
2029/30	0	0	339	207,965	1,819	1,364,500

1 Imports (exclude Wind Purchases)
2 GWh of electricity from IFF 09-1
3 MH coal and natural gas generation emissions are calculated using the average intensity of the underlying generation from 2002 - 2009.
4 Based on MH market energy intensity estimate of 0.75 kg CO2e/kW.h

PUB/MH II-179

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive # 17 20-Year IFF 09-1 – Exports; Fuel and Power Purchases Market Perception of MH's CO2 Emissions**

c) Please define and discuss the probable source (coal or natural gas) of MH's imports with respect to the following time frames:

- **Summer 5x16 peak**
- **Summer 2x16 weekend**
- **Summer 7x8 off-peak**
- **Winter 5x16 peak**
- **Winter 2x16 weekend**
- **Winter 7x8 off-peak**

ANSWER:

When importing electricity, Manitoba Hydro generally purchases from energy markets and the electricity is not identified by generating source. Manitoba Hydro does not estimate the potential marginal sources of market energy during the various time periods that are outlined. In general, it can be expected that a mixture of both coal and natural gas-fired generation will be the marginal source of energy during on-peak hours and that coal-fired generation will be predominant during off-peak hours. Manitoba Hydro estimates that the average regional electricity emission intensity for its import energy is 0.75 kg CO2e/kW.h. This reflects a mixture of fossil-fuel resources and a variety of technologies and efficiencies.

PUB/MH II-179

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive # 17 20-Year IFF 09-1 – Exports; Fuel and Power Purchases Market Perception of MH's CO2 Emissions**

d) Please provide a similar definition of the probable CO2 emissions displaced by MH's exports.

ANSWER:

Similar to the response to PUB/MH I-179(c) relating to import energy, Manitoba Hydro exports to energy markets and the electricity that is displaced is not identified by generating source. In general, it can be expected that a mixture of both coal and natural gas-fired generation will be the marginal source of displaced energy during on-peak hours and that coal-fired generation will be the predominant displaced energy source during off-peak hours. Manitoba Hydro estimates that the average regional electricity emission intensity for its export energy is 0.75 kg CO_2e/kW.h. This reflects a mixture of fossil-fuel resources and a variety of technologies and efficiencies.

PUB/MH II-179

Subject: Tab 13 Board Directives

Reference: Order 150/08 Directive # 17 20-Year IFF 09-1 – Exports; Fuel and Power Purchases Market Perception of MH's CO2 Emissions

e) Provide a tabulation of the overall (net) annual CO2 emissions reflected in MH's 20 yr IFF 09-1.

ANSWER:

Note: Although Manitoba Hydro's imports and exports have indirect emission implications, the responsibility remains with generators that release emissions.

Net CO2e Implications Associated with IFF 09-1

Negative values indicate net displacement of emissions

	Direct Emissions	Indirect Implications	Net Implications
	MH Thermal Operations [1] (tonnes CO2e)	Exports Net of Imports [2] (tonnes CO2e)	(tonnes CO2e)
2009/10	141,910	-6,588,000	-6,446,090
2010/11	154,210	-4,488,000	-4,333,790
2011/12	322,695	-4,926,179	-4,603,484
2012/13	325,239	-5,188,000	-4,862,761
2013/14	327,718	-5,095,929	-4,768,210
2014/15	329,603	-4,624,000	-4,294,397
2015/16	361,530	-4,395,214	-4,033,684
2016/17	383,083	-4,281,500	-3,898,417
2017/18	413,560	-4,165,607	-3,752,047
2018/19	417,583	-3,974,536	-3,556,953
2019/20	320,636	-5,611,857	-5,291,221
2020/21	368,653	-6,373,786	-6,005,133
2021/22	396,924	-6,247,714	-5,850,791
2022/23	449,751	-7,228,571	-6,778,821
2023/24	367,060	-9,527,893	-9,160,833
2024/25	366,702	-10,103,214	-9,736,512
2025/26	236,507	-9,870,750	-9,634,243
2026/27	210,842	-9,485,464	-9,274,622
2027/28	213,335	-9,245,429	-9,032,094
2028/29	212,929	-9,016,607	-8,803,678
2029/30	207,965	-8,714,750	-8,506,785

1 MH coal and natural gas generation emissions are calculated using the average intensity of the underlying generation from 2002 - 2009.

2 Based on MH market energy intensity estimate of 0.75 kg CO2e/kW.h

PUB/MH II-179

Subject: **Tab 13 Board Directives**

Reference: **Order 150/08 Directive # 17 20-Year IFF 09-1 – Exports; Fuel and Power Purchases Market Perception of MH's CO2 Emissions**

f) **Please confirm that these exports come almost entirely from hydraulic generation and except for dependable annual contract sales MH's exports would not displace coal generation.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-178(c).

PUB/MH II-180

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive 20 - COSS-MC**

a) **Please confirm that MH has not to date defined a MC-COSS process, but intends to engage external consulting services in the development of a fresh approach to the COSS (including a revamped marginal cost).**

ANSWER:

Manitoba Hydro intends to engage external consulting services to review the matter of marginal cost as part of its overall review of the Cost of Service Study.

PUB/MH II-180

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive 20 - COSS-MC**

b) Please provide a time line and Terms of Reference for this study.

ANSWER:

The Terms of Reference were filed May 25, 2010. It is expected that the work would be completed late 2010.

PUB/MH II-180

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive 20 - COSS-MC**

c) **Please explain how the MC or avoided cost is now and will in the future be determined for DSM evaluation.**

ANSWER:

Please refer to the response to RCM/TREE/MH II-4(b) for a general description of the methodology for determining the marginal costs for the generation, transmission and distribution components that are utilized in evaluations of DSM options. It is expected that the current methodology for determining marginal cost will continue to be used in the future.

PUB/MH II-180

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directive 20 - COSS-MC**

d) Please confirm that MH has not abandoned the MC concept and the need for supporting export/import pricing and/or deferral values.

ANSWER:

Manitoba Hydro confirms that it will continue to determine marginal cost utilizing the methodology of deferral of infrastructure and change in system operating cost (including export prices and import costs) as the two principal factors. The appropriate application of these factors will continue to be undertaken for the generation, transmission and distribution components of marginal cost.

PUB/MH II-181

Subject: **Tab 13 Board Directives**
Reference: **150/08 Directives #22/23/24/25**

a) **Please confirm or revise the following table on the status on the following:**

	TOU	Inverted Rates	Rebalancing Energy Demand	Basic Customer Charge	GSS and GSM Consolidation	EIIR
Residential	N/A	Interim Rates 2010	N/A	Proposed Reduction	N/A	N/A
GSS-ND	N/A	No Action	N/A	No Action	N/A	N/A
GSS-D	Not Yet	No Action	Ongoing	No Action	Underway	N/A
GSM	Not Yet	No Action	Ongoing	No Action	Winter Ratchet Eliminated	N/A
GSL <30	Not Yet	No Action	Ongoing	N/A	Winter Ratchet Eliminated	Application Pending
GSL 30-100	EIIR Application Pending	EIIR Application Pending	Ongoing	N/A	Winter Ratchet Eliminated	Application Pending
GSL >100	EIIR Application Pending	EIIR Application Pending	Ongoing	N/A	Winter Ratchet Eliminated	Application Pending

Note: SEP/CRP/LUBD and other Special Rate Programs may be integral to some of the above.

<u>ANSWER</u>:

The following changes should be made to the table shown above:

1) **GSS-ND –** this subclass is affected by the GSS and GSM Consolidation therefore should be referenced as “Underway” not “N/A” as shown.

2) **GSL<30 –** this subclass was not included in the EIIR Application and therefore should be referenced as “N/A” not “Application Pending”.

PUB/MH II-181

Subject: **Tab 13 Board Directives**
Reference: **150/08 Directives #22/23/24/25**

b) Please provide a discussion on each of the above six chart headings and on the potential for integrating the actions on various four Board Directives.

ANSWER:

TOU (Directive 22) – Please see Manitoba Hydro response to CAC/MSOS/MH II-31(a).

Inverted Rates (Directive 23) – Manitoba Hydro has stated that in the absence of other rate revisions that future rate increases would be weighted more in the tail rate portion of the rate. This was originally proposed in the current GRA where the entire 2.9% increase was placed in the tail block. However due to concerns from CAC about this treatment for the residential class the Board requested (March 16, 2010) several different alternatives to be considered. Manitoba Hydro responded to these requests on March 18, 2010. Of the alternatives requested, the one approved by the Board for rates April 1, 2010 (Board Order 33/10) had approximately one-third of the increase in the first block and the balance in the tail block.

Energy/Demand Rebalancing (Directive 24) – Manitoba Hydro has been actively rebalancing the energy and demand components of the rate structure for the past few years. This is witnessed in that previously proposed/approved rate increases have focused the entire increase on the energy portion of the rate to expedite the rebalancing. In addition in response to the directive Manitoba Hydro has supplied various updates to the Board and to all Intervenors as to the status of this rebalancing initiative.

Basic Customer Charge (BMC) – There is no directive in the list noted in the question related to the basic monthly charge. For BMC considerations see response to PUB/MH II-182(b).

GSS & GSM Consolidation (Directive 25) – Since July 2008 Manitoba Hydro has been actively consolidating the two classes. As noted in Tab 10 of the Application, it will probably take a few more rate changes to achieve full consolidation due to the differences in the monthly Basic Charge

EIIR - Manitoba Hydro filed an application in regard to this rate February 12, 2010 that followed the intent of the Board's Order 112/09 of July 10, 2009. Since that time Manitoba Hydro has been actively consulting with customers which has resulted in some significant changes being proposed. On April 27, 2010 Manitoba Hydro representative met with MIPUG to discuss the proposal further. As a result of this meeting a cooperative framework and time line may be developed with the aim of filing a revised application to the Board in due course that represents an EIIR proposal that has been reviewed by the two parties.

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

a) **Please provide a listing of the components of the fixed residential customer costs for 2010/11 and 2011/12, only a portion of which MH recovers through the residential basic monthly charge (BMC) .**

ANSWER:

Fixed residential customer costs broadly consist of Operating and Administration expenses, Depreciation and Amortization costs, Finance expense, Capital Taxes and Contribution to Reserves. Examples of the costs recoverable through the residential BMC include some of the costs associated with distribution circuits as well as the costs associated with customer service lines, meters, meter reading, billing and general customer service.

PUB/MH II-182

Subject: Tab 13 Board Directives
Reference: Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge

b) **Please indicate the extent to which MH's BMC recovers the fixed costs of all customer classes and how this relates to MH's rate design policy.**

ANSWER:

The BMC is intended to collect a portion of those costs which are incurred to serve customers, and which do not vary with respect to customer demand or energy usage. Examples of such costs are metering, meter reading, billing and collections, and some distribution facility costs.

As shown in the table below, Manitoba Hydro currently recovers between 11% and approximately 50% of fixed customer related costs through the BMC.

Class	BMC	PCOSS10 Cust Charge	%'age
Residential	$6.85	$20.38	33.6%
GSS - Non Demand	$17.65	$33.94	52.0%
Demand	$17.65	$51.44	34.3%
GSM	$27.60	$247.59	11.1%
GSL < 30	n/a	n/a	n/a
30 - 100	n/a	n/a	n/a
> 100	n/a	n/a	n/a
A & R Lights	n/a	$8.25	n/a

Centra currently recovers between 50% and 100% of fixed customer related costs through the BMC for all customer classes. For Centra's large volume customer classes (High Volume Firm, Mainline, Interruptible, Special Contract and Power Station), 100% of fixed customer costs are recovered by the BMC. For Centra's small volume customer classes (SGS & LGS), approximately 50% of the fixed customer cost is recovered by the BMC.

The table below provides the Rate Design principles employed by both Manitoba Hydro and Centra. Rate Design Policy does not explicitly define, nor is it intended to explicitly define the appropriate level of the BMC to be recovered in rates. Utilities adopt rate design goals as a means to provide guidance in the application of ratemaking policy and the development and application of rate and billing components. In many cases, established rate design principles conflict and compromises will be effected but in aggregate support the rate design goals. For example, the desire for rate stability and public acceptability may conflict with both the desire to provide the appropriate price signals to customers and the need to recover the full revenue requirement. In other cases, some principles are reflected in the utilities rate design where practical. The ultimate rate design employed by the utility and approved by the regulator reflects the established principles, the needs of the utility, customers and other stakeholders.

Centra filed a Basic Monthly Charge report in 2005. At that time it concluded that the BMC not be changed for the SGS (residential and small commercial customers) as it strikes a reasonable compromise between various rate design considerations including customer acceptability. Since that time, the PUB has imposed several increases to Centra's BMC for both the SGS and LGS customer classes which were neither applied for by Centra nor requested by intervenors. While the current BMC for the SGS customer class is reasonably consistent with stated Rate Design Policy and the increase has not been met with significant customer resistance, Manitoba Hydro wishes to reduce and possibly eliminate both the electric and natural gas BMC. With the passage of time and the move to a greater focus on demand side management and low income programs, Manitoba Hydro views that the reduction of the BMC still conforms reasonably to stated Rate Design Policy but it also is more consistent with the Company's demand side management and low income focus. A low or no BMC allows a customer more control over usage and while any change in the BMC is revenue neutral to the Company, it benefits the low income, low users within the customer class.

Centra Gas Manitoba Inc.[1]	Manitoba Hydro[2]
Rates should be reflective of the costs incurred to provide the service (cost based). *Rates should be fair and equitable.* *Rates should be competitive.* *Rates should reflect the opportunities to serve new franchise areas.*	*Recover the full revenue requirement for domestic customers.* *Collect revenues from each class that bear a reasonable relationship to the cost allocated to serve that class using acceptable cost of service study methods.* *Establish rate structures that are reasonably reflective of the underlying costs. This would suggest that energy charges should relate to the cost of providing energy, demand charges where practical should recover a reasonable share of capacity related costs, and customer charges that recover a reasonable share of costs which are not variable with changes in usage level.* *Provide, to the extent practicable, incentives to use energy in a manner that reflects the real value of that energy.* *Provide for equitable treatment of customers both between classes and within classes of service.* *Provide for rate stability, public acceptability, freedom from controversy as to their application, and to minimize adverse changes.*

[1] Centra Gas Manitoba Inc. Cost Allocation and Rate Design Review, pre-filed evidence May 31, 1996.

[2] Manitoba Hydro, 2002 Status Update Filing, Response to Information Request PUB/MH I-82.

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

c) **Please demonstrate the relationship between fixed residential customer costs, electricity consumption and household income levels.**

ANSWER:

There is no relationship of the fixed residential costs or Basic Monthly Charge (BMC) to consumption or household income levels. Any electrical residential customer of Manitoba Hydro pays the same BMC except for the few services that require a three-phase connection where the BMC is double the current BMC of $6.85/month.

In general electrical consumption does rise with income level since greater household income generally equates to larger homes and/or more electrical load.

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

d) Please provide a comparison of other Canadian electric utilities' residential BMC cost recoveries.

ANSWER:

Manitoba Hydro does not survey other utilities with respect to their BMC cost recoveries, nor is this information readily available. The following however does provide a comparison of the BMC billed by other utilities:

Utility	Monthly Charge	Comments
BC Hydro	$4.02*	Basic Charge = $0.1341 per day
Enmax Corporation	$16.60*	Billing & Admin Chg $0.2373 per day + Service & Facilities Chg $0.316286 per day
EPCOR	$18.90*	Admin Chg $6.68 per month + Customer Chg $0.40758 per day
Hydro Quebec	$12.19*	Basic Charge = 40.64¢ per day
Kenora Hydro	$14.78*	Service Charge $13.53 + Smart Meter Rate Rider $1.00 + Std Supply Service Admin Chg $0.25
Manitoba Hydro	$6.85	$4.85 proposed for April 1, 2011
Maritime Electric	$24.57	
New Brunswick Power	$19.73	
Newfoundland Power	$15.57	
Nova Scotia Power	$10.83	
Saskatoon Public Works Electric System	$17.35	Service Charge $19.09 less 10% Municipal Surcharge
SaskPower	$17.35	
St. John Energy	$15.15	
Toronto Hydro	$19.18*	Service Charge $18.25 + Smart Meter Rate Rider $0.68 + Std Supply Service Admin Chg $0.25

*based on a 30 day billing period

PUB/MH II-182

Subject: Tab 13 Board Directives
Reference: Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge

e) Please demonstrate the relative Revenue to Cost Coverage & residential customer impacts of a 50%/75%/100% recovery of fixed customer costs through the BMC.

ANSWER:

Based upon the results of PCOSS10 the fixed customer costs recoverable in the residential Basic Charge are $20.38 per month. Adjusting the Residential Energy Charge to offset for the increased revenue from the changes in Basic Charge is class revenue neutral and would result in no change in the Revenue to Cost Coverage ratio. The following bill impacts result:

(It was assumed that a 0.19¢ differential would exist between the first block rate and tail block rate as does currently with the April 1, 2010 energy rate of 900 kW.h @ 6.38¢ and tail rate of 6.57¢.)

50% Proposal

BC = $10.19 1st 900 kW.h @ 6.12¢ Balance of kW.h @ 6.31¢

Monthly kWh	April 2010 Rates	50% Proposal	$ Difference	% Difference
250	$22.80	$25.49	$2.69	11.8%
750	$54.70	$56.09	$1.39	2.5%
1000	$70.84	$71.58	$0.74	1.0%
2000	$136.54	$134.68	($1.86)	-1.4%
5000	$333.64	$323.98	($9.66)	-2.9%

75% Proposal

BC = $15.29 1st 900 kW.h @ 5.72¢ Balance of kW.h @ 5.91¢

Monthly kWh	April 2010 Rates	75% Proposal	$ Difference	% Difference
250	$22.80	$29.59	$6.79	29.8%
750	$54.70	$58.19	$3.49	6.4%
1000	$70.84	$72.68	$1.84	2.6%
2000	$136.54	$131.78	($4.76)	-3.5%
5000	$333.64	$309.08	($24.56)	-7.4%

100% Proposal

BC = $20.38 1st 900 kW.h @ 5.32¢ Balance of kW.h @ 5.51¢

Monthly kWh	April 2010 Rates	100% Proposal	$ Difference	% Difference
250	$22.80	$33.68	$10.88	47.7%
750	$54.70	$60.28	$5.58	10.2%
1000	$70.84	$73.77	$2.93	4.1%
2000	$136.54	$128.87	($7.67)	-5.6%
5000	$333.64	$294.17	($39.47)	-11.8%

If the Residential Energy Charge was not adjusted, the resulting Revenue Cost Coverage ratios would be as follows:

Recovery of Fixed Customer Costs	Basic Charge	Revised RCC
50%	$10.19	98.3%
75%	$15.29	101.2%
100%	$20.38	103.9%

Increasing the Residential Basic Charge without a corresponding reduction in the Energy Charge would have a significant impact on revenues. The Residential customer sub-class (excluding seasonal and diesel) would generate additional revenues of $18 to $71 million annually dependent on the Basic Charge applied. The bill impacts, assuming no change in Energy Charge, would be as follows:

Monthly kWh	April 2010 Rates	BMC = $10.19		BMC = $15.29		BMC = $20.38	
250	$22.80	$26.14	14.7%	$31.24	37.0%	$36.33	59.3%
750	$54.70	$58.04	6.1%	$63.14	15.4%	$68.23	24.7%
1000	$70.84	$74.18	4.7%	$79.28	11.9%	$84.37	19.1%
2000	$136.54	$139.88	2.5%	$144.98	6.2%	$150.07	9.9%
5000	$333.64	$336.98	1.0%	$342.08	2.5%	$347.17	4.1%

NOTE: The figures shown as percentages represent the percentage increase from current April 2010 rates.

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

f) Please provide a listing of the components of the fixed residential customer costs for natural gas operation, only a portion of which Centra recovers through the residential basic monthly charge (BMC)

ANSWER:

Fixed costs classified as customer related broadly consist of Operating and Administration expenses, Depreciation and Amortization costs, Finance expense, Capital and Other Taxes, Other Revenue and Net Income.

Examples of Operating and Administration costs classified as customer related include Centra's billing system, Contact Centre costs, Meter Reading costs, Inspection and maintenance of service lines and meter/regulator sets, Customer marketing costs including customer safety programs (call before you dig) and Burner Tip.

Depreciation and Amortization Expense, Municipal and Capital Taxes, Finance Expense, and Net Income associated with service lines, meters and regulators, common assets, DSM, and Furnace Replacement program costs and a portion of the Distribution system is also classified as customer related.

PUB/MH II-182

Subject: **Tab 13 Board Directives**
Reference: **Order 150/08 Directives 22, 23, 24, 25 Basic Monthly Charge**

g) Please indicate the extent to which Centra's BMC recovers the fixed costs of all customer classes and how this relates to MH's rate design policy.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-182(b).

PUB/MH II-183

Subject: **Tab 13 Board Directives**
Reference: **Appendix 25 Dunsky Report, Pages 10-12**

Please provide the supporting data table for each of the charts found on pages 10 to 12.

ANSWER:

The above noted charts were created by the Dunsky Energy Consulting. Manitoba Hydro was not provided with the supporting calculations and therefore can not provide this data.

<u>PUB/MH II-184</u>

Subject: Tab 13 Board Directives
Reference: Dunsky Report Page 38 -39

Please indicate what actions the Corporation is undertaking to address the apparent deficiency in future electricity savings goals compared to the peer groups.

<u>ANSWER</u>:

Due to competing priorities, the formal report outlining Manitoba Hydro's action plan to address the recommendations contained in the Dunsky Energy Consulting Report has not been completed at this time. The Action Plan will be filed at that time.

<u>PUB/MH II-185</u>

Subject: Tab 13 Board Directives
Reference: Appendix 25 Dunsky Report Pages 44-47

a) **Please provide the Corporations response to each of the MH programs where it has been identified that a program is in place but incomplete coverage, and proposed actions to address the incomplete coverage.**

<u>ANSWER</u>:

This information will be included in Manitoba Hydro's Action Plan to address recommendations identified in the Dunsky Report. This Action Plan has not been completed at this time due to competing priorities. A copy of this Action Plan will be filed for this proceeding once this plan is completed.

PUB/MH II-185

Subject: **Tab 13 Board Directives**
Reference: **Appendix 25 Dunsky Report Pages 44-47**

b) Please provide the Corporations response to each of the MH programs where it has been identified a program gap, little coverage or no programs in place and proposed actions to address the gap.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-185(a).

PUB/MH II-186

Subject: Tab 13 Board Directives
Reference: PUB/MH I-213 (d) & (g) Energy Burden

Please indicate whether the table is based on information gathered in the 2009 Residential Survey, if not please update the table based on that information.
Please explain to what extent the corporation will take into account energy burden in target marketing to customers with high-energy burden.

ANSWER:

The tables provided in Manitoba Hydro's responses to PUB/MH I-213(d) and PUB/MH I-213(g) were based on information obtained from the 2009 residential survey. Manitoba Hydro plans to target marketing efforts towards all customers qualifying for the Corporation's Lower Income Program. An emphasis will be placed on areas identified which include a higher concentration of customers that fall within this market sector and likely to have a higher energy burden. Targeting specific households with higher energy burdens is not possible as Manitoba Hydro does not have access to individual household income levels.

PUB/MH II-187

Subject: **Tab 13 Board Directives**

Reference: **PUB/MH I-222 (a) Attachment 1 Page 8 , PUB/MH I- 223 (a) & b) Demographic Study**

a) **MH collects information about LIEEP participants' energy use, condition of housing stock, and income data as part of the audit process. Please confirm whether MH is using this information to augment its low-income demographic data, and explain how this information is being used.**

ANSWER:

Manitoba Hydro is using the information collected from customers to enhance the Corporation's understanding of the lower income customer market segment. Information on housing stock will allow Manitoba Hydro to better measure actual savings arising from the energy efficiency up-grades and help determine the effectiveness of these up-grades. Information on demographics of the customers such as customer age, number of individuals in the household, average income as well as location of residence will also be used to better understand the customer base and assist in the Corporation's marketing efforts.

<u>PUB/MH II-187</u>

Subject: **Tab 13 Board Directives**

Reference: **PUB/MH I-222 (a) Attachment 1 Page 8 , PUB/MH I- 223 (a) & b) Demographic Study**

b) Please file a copy of the results of the 2009 Residential Customer Survey.

<u>ANSWER</u>:

A report on the 2009 Residential Customer Survey is not available. This report is expected to be completed in the Fall of 2010. Appendix 50 is a copy of Manitoba Hydro's Residential Energy Use Survey Report – Low Income Cut-Off (LICO) Sector which is a subset of the results obtained from the 2009 Residential Customer Survey.

PUB/MH II-187

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-222 (a) Attachment 1 Page 8 , PUB/MH I- 223 (a) & b) Demographic Study**

c) Please file a copy of the updated Affordable Energy Program Demographic information based on the 2009 Residential Customer Survey, detailing both natural gas and electric customers.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-187(b).

PUB/MH II-187

Subject: **Tab 13 Board Directives**

Reference: **PUB/MH I-222 (a) Attachment 1 Page 8 , PUB/MH I- 223 (a) & b) Demographic Study**

d) Please file the comparative tables for PUB/MH I-222 (b) based on LICO.

ANSWER:

The following tables provide the comparative tables to those provided in Manitoba Hydro's response to PUB/MH I-223(b) using LICO:

LICO Standard DWELLING TYPES - 2003 Survey			
	OWN	**RENT**	**TOTAL**
Single	45467	5344	50811
Multiplex	3961	2875	6836
Townhouse	1410	3067	4477
Mobile	2613	507	3120
Subtotal (Net Apartments)	**53451**	**11793**	**65244**
Apartment	2145	14762	16907
Total	**55596**	**26555**	**82151**
Total %	68%	32%	100%

LICO Standard DWELLING TYPES - 2009 Survey			
	OWN	**RENT**	**TOTAL**
Single	44200	3908	48108
Multiplex	2809	1194	4003
Townhouse	1327	1438	2765
Mobile	1787	55	1842
Subtotal (Net Apartments)	**50123**	**6595**	**56718**
Apartment	4205	14015	18220
Total	**54328**	**20610**	**74938**
Total %	72%	28%	100%

Caution must be used with the information provided based on the 2003 survey as it is difficult to accurately classify customers from the 2003 survey between LICO and non-LICO. The 2003 survey used broader ranges with regards to income information and therefore the segregation of customers based on their income is less accurate than that found in the 2009 survey.

To provide some insight into the requested information, the following method was applied. When a LICO salary limit was halfway (e.g. a 2-person family earning $24,851), the more inclusive salary range was used which accepts salaries up to $29,999. As a result, the 2003 values somewhat overestimate the LICO population. Similarly, the 2003 LICO-125 estimates, as given in Manitoba Hydro's response to PUB/MH I-223 (b), reflect the same challenges and are therefore less accurate than the information provided based on the 2009 survey.

PUB/MH II-187

Subject: **Tab 13 Board Directives**

Reference: **PUB/MH I-222 (a) Attachment 1 Page 8 , PUB/MH I- 223 (a) & b) Demographic Study**

e) Please file a description of the focus group testing undertaken and a summary of the results from that testing.

ANSWER:

Please see Appendix 57.

PUB/MH II-188

Reference: Quarterly Reports - Appendix 4(3)

a) Please provide a quarterly (Q_1, Q_2, Q_3, Q_4) tabulation of 2008/09 and 2009/10 electric utility results:

Domestic revenues:

- **Residential ($M/GWh).**
- **General service ($M/GWh).**

Expenditures breakdown:

- **Finance ($M).**
- **Depreciation ($M).**
- **OM&A ($M).**
- **Water Rentals ($M/GWh).**
- **F&PP ($/GWh).**
- **Taxes ($M).**

Net income ($M).

Power supply:

- **Hydraulic generation (GWh).**
- **Thermal generation (GWh).**
- **Wind generation (GWh).**
- **Scheduled imports (GWh).**
- **Total (GWh).**

Merchant trading:

- **Sales ($M/GWh).**
- **Purchases ($M/GWh).**

ANSWER:

Please refer to the attached tables.

($ 000)	2008/09 Q1	Q2	Q3	Q4	Annual	2009/10 Q1	Q2	Q3
Domestic revenues								
Residential	$ 93 934	$ 83 024	$ 113 713	$ 171 624	$ 462 295	$ 111 067	$ 85 531	$ 117 390
General service	152 391	157 755	166 769	187 603	664 518	165 477	157 239	165 089
	246 325	240 779	280 482	359 227	1 126 813	276 544	242 770	282 479
Extraprovincial	173 913	211 000	147 356	90 377	622 646	108 836	114 625	104 872
Other	1 555	11 381	1 549	1 385	15 870	1 626	1 596	2 022
Total revenue	421 793	463 160	429 387	450 989	1 765 329	387 006	358 991	389 373
Expenditures								
Operating and administrative	89 902	83 948	87 477	98 333	359 660	94 401	88 905	93 790
Finance	102 074	97 242	97 261	104 484	401 061	106 734	101 208	100 878
Depreciation and amortization	84 411	85 449	91 415	84 764	346 039	90 388	91 083	91 500
Water rentals and assessments	28 536	31 887	31 639	30 938	123 000	28 247	30 185	31 725
Fuel & power purchased	37 585	39 044	45 570	54 183	176 382	25 564	18 044	32 142
Capital and other taxes	15 833	15 060	18 555	14 360	63 808	17 574	17 952	21 072
Corporate allocation	1 878	1 921	1 921	1 834	7 554	1 922	1 894	2 089
	360 219	354 551	373 838	388 896	1 477 504	364 830	349 271	373 196
Net income	$ 61 574	$ 108 609	$ 55 549	$ 62 093	$ 287 825	$ 22 176	$ 9 720	$ 16 177
Merchant trading								
Sales	$ 28 146	$ 21 997	$ 19 588	$ 16 242	$ 85 973	$ 7 111	$ 6 431	$ 6 653
Purchases	24 259	19 682	18 023	14 836	76 800	6 374	5 171	5 918

	2008/09					2009/10		
	Q1	Q2	Q3	Q4	Annual	Q1	Q2	Q3
Domestic volumes (GWh)								
Residential	1,458	1,169	1,730	2,598	6,954	1,602	1,152	1,740
General service	3,404	3,368	3,573	3,967	14,312	3,353	3,150	3,399
	4,861	4,536	5,303	6,565	21,266	4,955	4,302	5,139
Expenditures (GWh)								
Water rentals	7,898	9,185	8,931	8,185	34,199	7,973	8,628	8,868
Fuel & power purchased	179	207	304	292	981	281	245	464
Power supply (GWh)								
Hydraulic generation	7,896	9,185	8,927	8,185	34,193	7,974	8,629	8,866
Thermal generation	46	93	131	65	335	25	18	74
Subtotal	*7,942*	*9,278*	*9,058*	*8,250*	*34,528*	*7,999*	*8,647*	*8,940*
Wind purchases	87	79	106	111	383	88	77	89
Scheduled imports	15	7	122	145	289	37	17	141
Total	8,044	9,364	9,286	8,506	35,200	8,124	8,741	9,170
Merchant trading (GWh)								
Sales	459	407	389	343	1,598	222	205	187
Purchases	459	407	389	343	1,598	222	205	187

PUB/MH II-188

Reference: Quarterly Reports - Appendix 4(3)

b) Please provide the same tabulation for 2011/11 based on current (updated to April 1, 2010) information on:

- **Domestic loads.**
- **Exports.**
- **Energy supply.**

ANSWER:

The latest updates for the requested information is not available at this time.

PUB/MH II-189

Reference: Tab 4 Section 4.2 / PUB/MH I-1 (Revised) Load Forecasts Domestic Revenues

a) Please confirm that MH's domestic revenues for 2009/10 could be down by about $30 M from the $1,160 M in IFF 09-1.

ANSWER:

Domestic revenues for 2009/10 decreased by approximately $15 million from IFF09-1.

PUB/MH II-189

Reference: Tab 4 Section 4.2 / PUB/MH I-1 (Revised) Load Forecasts Domestic Revenues

b) Please confirm and update MH's domestic sales as follows:

	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)	Forecast 2009/10 (GWh)	Actual 2009/10 (GWh)
Residential	**6,443**	**6,736**	**6,847**	**6,754**	**?**
GS Mass Market	**7,838**	**8,006**	**8,049**	**8,059**	**?**
GS Top Consumers	**5,989**	**6,075**	**6,065**	**5,956**	**?**
Totals	**20,270**	**20,817**	**20,961**	**20,769**	**20,500 (estimated)**

ANSWER:

Updates to the table are provided below. Note that the figures do not include sales pertaining to Diesel, Seasonal, Flat Rate Water Heating or Surplus Energy.

	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)	Forecast 2009/10 (GWh)	Actual 2009/10 (GWh)
Residential	**6,443**	**6,736**	**6,847**	**6,754**	**6,786**
GS Mass Market	**7,838**	**8,006**	**8,049**	**8,059**	**7,985**
GS Top Consumers	**5,989**	**6,075**	**6,065**	**5,956**	**5,461**
Totals	**20,270**	**20,817**	**20,961**	**20,769**	**20,232**

PUB/MH II-189

Reference: Tab 4 Section 4.2 / PUB/MH I-1 (Revised) Load Forecasts Domestic Revenues

c) Please confirm that in the absence of a sudden economic recovery, MH's forecasts for 2010/11 domestic revenues could also be by about $50 M from IFF 09-1.

ANSWER:

In the absence of an economic recovery, it is projected that forecasted energy sales for 2010/11 would be similar to 2009/10 actual energy sales.

Actual 2009/10 sales = $1,144.9 million

If energy sales are the same for both years, the 2.8% interim-approved rate increase effective April 1, 2010, would result in revenues of:

$1144.9 x 102.8% = $1,178.1 million.

Original 2010/11 GCR forecast = $1192.8 million

Estimated impact of continued economic downturn:

= $1,192.8 - $1178.1 = $14.7 million.

PUB/MH II-190

Reference: Appendix 4/ Tab 2/PUB/MH I-1 (Revised): Export Revenues

a) Please confirm that in 2009/10, MH's export revenues were approximately $350 M ($310 M U.S. and $40 M CDN) based on total export sales of about 10,000 GWh.

ANSWER:

Manitoba Hydro is unable to confirm at this time, the 2009/10 results. These numbers will be available when the 2009/10 Annual Report has been issued.

PUB/MH II-190

Reference: Appendix 4/ Tab 2/PUB/MH I-1 (Revised): Export Revenues

b) Please define the 2009/10 impact of the higher Canadian $ value.

ANSWER:

Please see Manitoba Hydro response to PUB/MH II-190(a).

<u>PUB/MH II-190</u>

Reference: Appendix 4/ Tab 2/PUB/MH I-1 (Revised): Export Revenues

c) Please confirm (or revise) that in 2009/10, MH's fuel and power purchase costs were about $100 M involving:

- **240 GWh U.S. imports.**
- **30 GWh CDN imports**
- **150 GWh thermal fuel.**
- **330 GWh wind.**

<u>ANSWER</u>:

Please see Manitoba Hydro response to PUB/MH II-190(a).

PUB/MH II-190

Reference: Appendix 4/ Tab 2/PUB/MH I-1 (Revised): Export Revenues

d) Please identify any additional merchant trading energy purchases and sales (GWh/¢/KWh/$M) undertaken by MH in 2009/10, but not included in the generation and delivery statistics of the quarterly reports

ANSWER:

Please see Manitoba Hydro response to PUB/MH II-190(a).

PUB/MH II-190

Reference: Appendix 4/ Tab 2/PUB/MH I-1 (Revised): Export Revenues

e) Please confirm that on a net basis (sales revenue minus F&PP), MH's exports in 2009/10 were:

- **Exports - $350 M ($414 M in IFF-09)**
- **F&PP - $100 M ($103 M in IFF-09)**
- **Net Exports - $250 M ($311 M)**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-190(a).

PUB/MH II-191

Reference: Tab 13, B.O. 150/08 Directive #3 NEB & SEP Data

a) Please provide a summary tabulation of MH's 2008/09 and 2009/10 monthly export sales as defined by:

NEB						SEP		
Firm		Interruptible		Import		Peak	Shoulder	Off-Peak
GWh	¢/KWh	GWh	¢/KWh	GWh	¢/KWh	¢/KWh	¢/KWh	¢/KWh
2008/09								
Permit No.								
2009/10								
Permit No.								

ANSWER:

Please see tables below for NEB and SEP data.

2008/09	SEP		
	Peak	**Shoulder**	**Off-Peak**
	¢/KWh	**¢/KWh**	**¢/KWh**
April	7.547	6.092	3.579
May	6.799	5.085	2.695
June	7.142	4.772	2.286
July	9.591	4.976	1.626
August	9.335	5.161	1.408
September	6.246	3.992	1.181
October	5.578	3.873	1.788
November	6.912	4.709	2.760
December	8.004	4.933	3.495
January	8.391	5.639	3.678
February	5.733	4.143	2.486
March	4.762	3.467	2.339
2009/10			
April	3.633	2.665	1.740
May	3.166	2.762	1.329
June	2.966	2.188	0.868
July	3.329	2.382	0.937
August	3.248	2.012	0.755
September	2.630	1.884	0.625
October	2.559	1.878	0.837
November	3.521	2.590	1.574
December	3.758	2.720	1.851
January	4.916	3.470	2.295
February	5.356	3.966	2.583
March	4.345	3.306	2.336

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

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

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

Month	NEB Permit No.	FIRM			INTERRUPTIBLE			IMPORT		
		MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Dec-08	144	18,381	1,642,812	89.38						
	155	22,080	1,382,550	62.62						
	224	158,320	10,639,551	67.20						
	259	854	52,411	61.37						
	269				197,415	13,641,499	69.10			
								48,883	1,682,653	34.42
Jan-09	144	17,600	1,595,364	90.65						
	155	21,117	1,352,687	64.06						
	224	161,779	10,888,078	67.30						
	259	1,192	68,796	57.71						
	269				123,830	7,442,112	60.10			
								61,915	2,559,045	41.33
Feb-09	144	16,000	1,506,201	94.14						
	155	19,200	1,301,862	67.81						
	224	156,110	10,944,203	70.11						
	259	833	50,946	61.16						
	269				173,600	8,571,553	49.38			
								6,749	344,517	51.05
Mar-09	144	17,568	1,623,272	92.40						
	155	21,120	1,378,863	65.29						
	224	172,308	11,550,659	67.03						
	259	833	50,946	61.16						
	269				194,748	8,194,807	42.08			
								19,095	719,180	37.66

Month	NEB Permit No.	FIRM			INTERRUPTIBLE			IMPORT		
		MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Apr-09	144	17,541	1,536,031	87.57						
	155	21,049	1,303,354	61.92						
	224	175,418	11,070,661	63.11						
	259	639	40,227	62.95						
	269				466,954	11,164,381	23.91			
								500	61,317	122.63
May-09	33	47,217	629,505	13.33						
	34	35,430	469,493	13.25						
	35	52,174	1,046,940	20.07						
	144	16,588	1,445,711	87.15						
	155	9,928	587,038	59.13						
	224	287,476	11,604,608	40.37						
	259	481	35,977	74.80						
	269				448,634	10,411,481	23.21			
								813	33,550	41.27
Jun-09	33	86,711	2,357,030	27.18						
	34	6,588	1,805,106	274.00						
	35	7,200	308,462	42.84						
	144	17,600	1,617,138	91.88						
	155	16,078	758,261	47.16						
	224	303,767	13,019,826	42.86						
	259	461	35,204	76.36						
	269				434,693	11,286,387	25.96			
								1,851	32,292	17.45

Month	NEB Permit No.	FIRM			INTERRUPTIBLE			IMPORT		
		MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Jul-09	33	119,319	2,928,700	24.55						
	34	89,632	2,197,587	24.52						
	35	2,250	58,679	26.08						
	144	18,400	1,562,504	84.92						
	155	14,731	680,137	46.17						
	224	358,969	12,602,626	35.11						
	259	394	32,545	82.60						
	269				521,232	10,303,089	19.77			
								1,851	160,870	86.91
Aug-09	33	132,126	3,214,448	24.33						
	34	9,063	2,410,700	265.99						
	35	1,650	43,737	26.51						
	144	16,800	1,463,074	87.09						
	155	13,800	653,061	47.32						
	224	362,391	12,705,102	35.06						
	259	425	33,766	79.45						
	269				512,427	11,298,361	22.05			
								495	34,035	68.76

Month	NEB Permit No.	FIRM			INTERRUPTIBLE			IMPORT		
		MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Sep-09	33	28,367	961,127	33.88						
	34	21,352	724,358	33.92						
	144	16,888	1,437,114	85.10						
	155	15,644	682,116	43.60						
	224	176,859	9,980,692	56.43						
	259	320	29,621	92.57						
	269				721,192	13,904,731	19.28			
								437	41,672	95.36
Oct-09	35	77,706	2,358,613	30.35						
	144	17,358	1,480,174	85.27						
	155	10,416	596,508	57.27						
	224	173,876	10,162,359	58.45						
	269				866,924	20,512,094	23.66			
	345	527	37,820	71.76						
								0	0	0.00
Nov-09	144	16,800	1,410,645	83.97						
	155	10,080	572,268	56.77						
	224	168,000	9,756,683	58.08						
	269				652,817	15,208,111	23.30			
	345	503	36,853	73.27						
								12,766	291,376	22.82

Month	NEB Permit No.	FIRM			INTERRUPTIBLE			IMPORT		
		MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Dec-09	144	18,337	1,510,887	82.40						
	155	11,002	602,185	54.73						
	224	178,620	10,045,274	56.24						
	269				180,369	7,233,228	40.10			
	345	785	50,708	64.60						
								96,983	2,446,474	25.23
Jan-10	144	16,800	1,420,784	84.57						
	155	10,080	576,381	57.18						
	224	157,869	9,449,930	59.86						
	269				294,690	12,031,863	40.83			
	345	1,004	61,779	61.53						
								78,020	1,928,233	24.71
Feb-10	144	1,600	1,344,224	840.14						
	155	9,600	550,946	57.39						
	224	159,086	9,384,649	58.99						
	269				238,998	9,492,286	39.72			
	345	948	58,242	61.44						
								43,325	1,060,605	24.48
Mar-10	144	18,389	1,469,898	79.93						
	155	11,033	585,515	53.07						
	224	183,900	9,935,043	54.02						
	269				496,047	14,153,374	28.53			
	345	684	46,670	68.23						
								1,107	15,147	13.68

PUB/MH II-191

Reference: Tab 13, B.O. 150/08 Directive #3 NEB & SEP Data

b) Please provide a summary tabulation of MH's 2008/09 and 2009/10 monthly NEB sales (by Permit No.) defining:

- **Volume (GWh).**
- **Unit Price (¢ per KWh)**
- **Revenue ($M)**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-191(a) for NEB filings by Permit No.

PUB/MH II-191

Reference: Tab 13, B.O. 150/08 Directive #3 NEB & SEP Data

c) Please provide MH's updated forecasts for 2010/11 with respect to:

- **5x16 export prices**
- **2x16 export prices**
- **7x5 export prices**

ANSWER:

Manitoba Hydro respectfully declines to provide this information as it is confidential and commercially sensitive.

PUB/MH II-191

Reference: Tab 13, B.O. 150/08 Directive #3 NEB & SEP Data

d) Please confirm that MH currently does file on a specific contract basis, data on capacity (MW/$/kVA) and energy (GWh/¢/KWh).

ANSWER:

Manitoba Hydro files with the NEB on an export permit number basis. Capacity and energy dollars are reported on a combined basis.

PUB/MH II-192

Reference: Energy Supply- Tab 8/PUB/MH I-76 Status of Water Supply

a) Please provide MH's current (end of April) assessment of the monthly outlook over the next four months of:

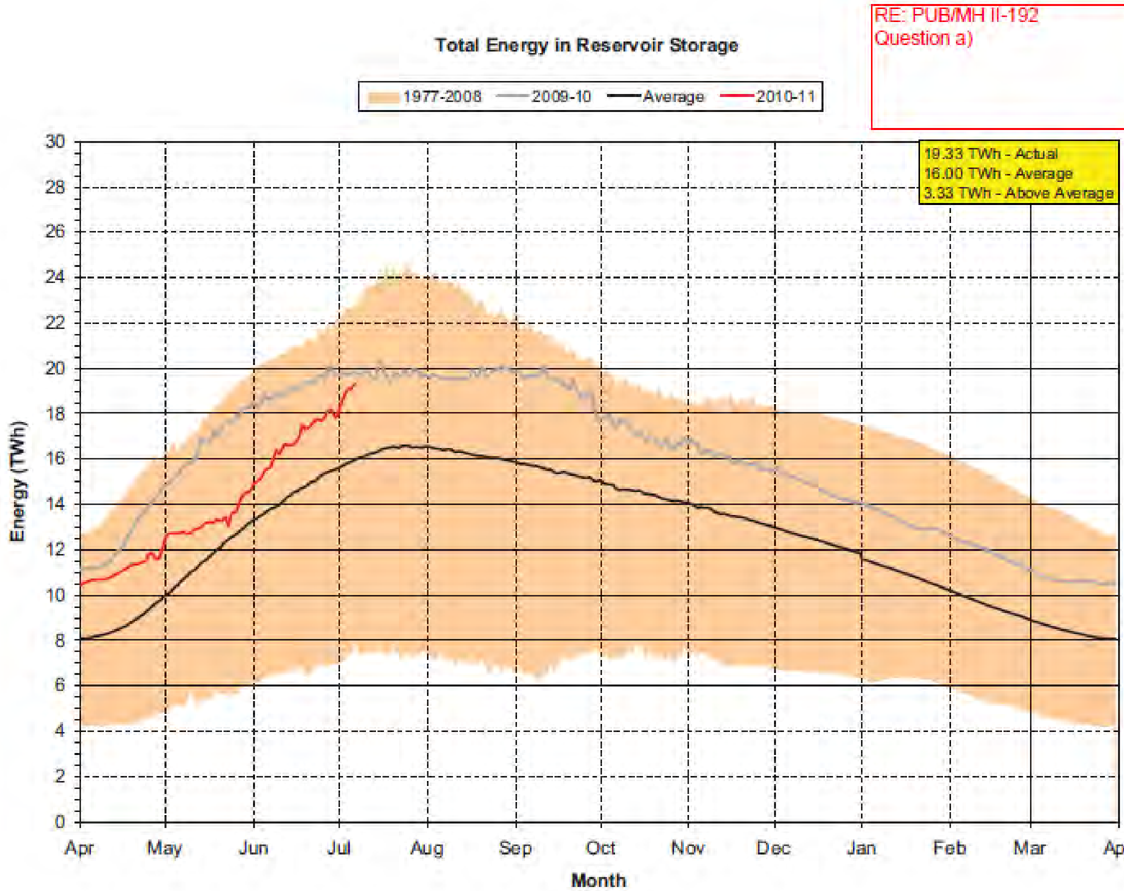
- **Energy-in-storage (GWh).**
- **Winnipeg River flows/Lake of the Woods levels.**
- **Saskatchewan River flows/Cedar Lake levels.**
- **Lake Winnipeg levels.**
- **Upper Nelson flows.**
- **Notigi and Burntwood River flows/South Indian Lake levels.**
- **Lower Churchill flows.**
- **Lower Nelson River flows.**

ANSWER:

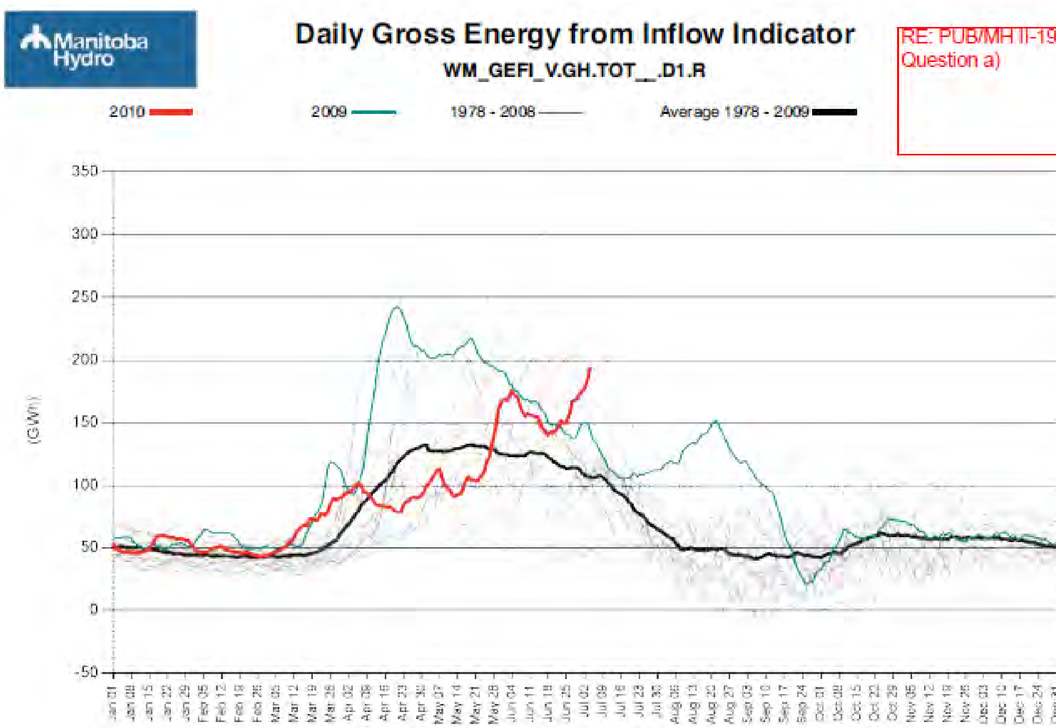
Energy in reservoir storage for the eighteen major reservoirs in Manitoba Hydro's watersheds is shown below. Storage levels were 3.3 TW.h above average on July 8, 2010.

The time-series plot of the daily gross energy from inflows to the Manitoba Hydro system compared to the 30 previous years of data is also shown. The chart indicates the below average spring melt followed by much higher than average early summer inflows.

RE: PUB/MH II-192
Question a)



RE: PUB/MH II-192
Question a)



PUB/MH II-192

Reference: Energy Supply- Tab 8/PUB/MH I-76 Status of Water Supply

b) Please provide on an individual major watershed (Winnipeg River/Red River/Saskatchewan River/Churchill River), the accumulated precipitation in:

- **The October to February 2009/10 period**
- **The March-April 2010 period.**
- **The May-September 2010 period.**

ANSWER:

Accumulated Precipitation (mm)			
Basin	**October 1, 2009 to February 28, 2010**	**March 1, 2010 to April 30, 2010**	**May 1, 2010 to September 30, 2010**
Winnipeg River	136.2	53	N/A
Red River	111.5	56	N/A
Saskatchewan River	94.7	66.1	N/A
Churchill River	111.4	53.3	N/A

<u>PUB/MH II-192</u>

Reference: Energy Supply- Tab 8/PUB/MH I-76 Status of Water Supply

c) Please provide in confidence to the Board (if necessary) on a monthly basis, MH's 2010/11 forecast hydraulic generation as contributed by flows on:

- **Winnipeg River.**
- **Red River.**
- **Saskatchewan River.**
- **Local Inflow.**
- **Burntwood River.**

<u>ANSWER</u>:

Manitoba Hydro has yet to update the 2010/11 IFF and associated hydraulic generation forecast. However as of July 20, 2010 favourable rainfall conditions across Manitoba Hydro's watersheds since mid May 2010, are anticipated to result in a 2% increase hydraulic generation or 600 GWh above forecast.

PUB/MH II-192

Reference: Energy Supply- Tab 8/PUB/MH I-76 Status of Water Supply

d) Please provide a monthly energy-in-storage curve reflecting the 2010/11 hydraulic generation forecast.

ANSWER:

Manitoba Hydro does not prepare a monthly energy-in-storage curve associated with its forecast hydraulic generation. The energy in storage curve compares current conditions with historical conditions for 18 major reservoirs in the Nelson Churchill basin whereas Manitoba Hydro's forecast of hydraulic generation only incorporates a subset of these reservoirs.

PUB/MH II-193

Reference: **Glossary of Terms/Order 150/08 Directive #2 Exports and Imports Transactions**

a) **Please provide a definition of the following export/import transactions as employed by MH:**

Firm Contract Sales

- **Dependable**
- **Merchant**

Opportunity Sales Bilateral

- **Two weeks forward written contracts.**
- **Day ahead [verbal].**
- **Real Time [verbal].**

Market

- **Day Ahead.**
- **Real Time.**

Other Sales

ANSWER:

The following is a description of the various export/import transactions identified above:

Firm Contract Sales – Dependable

Export sales that are sourced from Manitoba Hydro's dependable energy resources and include the associated product of accreditable capacity and have duration of greater than six months.

Merchant Sales

Manitoba Hydro's merchant transactions are the sale of electricity not involving Manitoba Hydro's generation assets or not related to serving or hedging its sales obligations.

Opportunity Sales Bilateral – Two weeks forward written contracts

Export sales transactions with a customer that has a term equal to or exceeding two weeks in duration and are executed and documented with a written contract.

Opportunity Sales Bilateral – Day Ahead [Verbal]

Export sales transactions that are executed on a day-ahead basis (next operating day) and are documented verbally with the purchasing party over a recorded telephone line.

Opportunity Sales Bilateral – Real Time [Verbal]

Export sales transactions that are executed in the real time market (same day) and are documented verbally with the purchasing party over a recorded telephone line.

Market – Day Ahead

Export sales transactions in a market operated by an independent system operator for the purchase and sale of power related products for the next operating day.

Market – Real Time

Export sales transactions in a market operated by an independent system operator for the purchase and sale of power related products during the operating day.

Other Sales

Revenues received from export markets (such as wheeling services, transmission credits, environmental attributes) generally from the sale of services not associated with energy or capacity.

PUB/MH II-193

Reference: **Glossary of Terms/Order 150/08 Directive #2 Exports and Imports Transactions**

b) **Please illustrate for 2008/09 and 2009/10 the revenue levels ($M) and sales volumes (GWh) for each of these transactions.**

ANSWER:

	2008/09		**2009/10**	
	GWh	**$M (Cdn)**	**GWh**	**$M (Cdn)**
Dependable	4,087	233	3,263	186
Opportunity				
Bilateral	1,305	101	2,628	60
Day Ahead	4,040	122	3,111	59
Real Time	690	60	1,858	71
Merchant	1,598	86	775	26

<u>PUB/MH II-193</u>

Reference: **Glossary of Terms/Order 150/08 Directive #2 Exports and Imports Transactions**

c) **Please provide a similar definition and illustration of import transactions for 2008/09 and 2009/10.**

<u>ANSWER</u>:

	2008/09		2009/10	
	GWh	**$M (Cdn)**	**GWh**	**$M (Cdn)**
Dependable	395	21	513	21
Opportunity				
Bilateral	9	7	6	1
Day Ahead	72	2	75	2
Real Time	505	22	726	14
Merchant	1,598	80	775	25

PUB/MH II-193

Reference: Glossary of Terms/Order 150/08 Directive #2 Exports and Imports Transactions

d) Please explain the level of risk associated with each of the transaction activities and also the distinction between arbitrage and non-arbitrage trading activities.

ANSWER:

Manitoba Hydro sponsored a workshop on May 31st, June 1st and June 2nd for the PUB, its advisors and Intervenors to discuss Manitoba Hydro's export activities. The Manitoba Hydro presentations from the workshop for May 31 and June 1 can be found in Appendix 56 which Manitoba Hydro considers fulfillment of Order 150/08 Directive #2, specifically with respect to this question. As indicated at the workshop, Manitoba Hydro does not engage in non-arbitrage trading activities.

PUB/MH II-194

Reference: **20 IFF 09-1/PUB/MH I-209/ 2008/09 & 2007/08 Load Forecasts: Domestic Load**

a) Please confirm the following domestic load forecast history:

	Net Firm Energy Load Forecast		Difference (GWh)	Domestic Sales at Generation		
	2007/08 (GWh)	2008/09 (GWh)		IFF 08-1 Assumptions (GWh)	PUB/MH I-209 IFF 09 Assumptions (GWh)	IFF Difference (GWh)
2009/10	24,937	24,080	-857	24,875	23,968	-907
2010/11	25,713	24,600	-1,113	25,488	24,346	-1,142
2011/12	26,362	25,169	-1,193	26,050	24,718	-1,332
2012/13	26,922	25,599	-1,343	26,544	25,075	-1,469
2013/14	27,241	26,012	-1,229	26,787	25,413	-1,374
2014/15	27,531	26,618	-913	27,049	26,030	-1,019
2015/16	27,827	26,973	-854	27,296	26,439	-857
2020/21	29,432	28,654	-778	28,789	27,551	-1,238
2025/26	31,108	30,516	-592	30,324	29,379	-945

ANSWER:

The following table contains the correct figures and references, including:

- Correct references to the forecasts (i.e. the forecast figures provided are associated with the May 2008 (2008/09 - 2028/29) and the May 2009 (2009/10 - 2029/30) electric forecasts;
- The correct firm energy for the May 2009 forecast during 2011/12 is 25, 159; and
- The correct forecast difference for 2011/12 is -1,203 and the correct difference for 2012/13 is -1,323.

The load forecast and IFF figures differ because the IFF excludes DSM impacts and includes several additional factors in domestic sales, such as station service and losses arising as a result of generation and transmission facilities.

	Net Firm Energy Load Forecast		Difference (GWh)	Domestic Sales at Generation		
	May 2008 (GWh)	May 2009 (GWh)		IFF 08-1 Assumptions (GWh)	PUB/MH I-209 IFF 09 Assumptions (GWh)	IFF Difference (GWh)
2009/10	24,937	24,080	-857	24,875	23,968	-907
2010/11	25,713	24,600	-1,113	25,488	24,346	-1,142
2011/12	26,362	25,159	-1,203	26,050	24,718	-1,332
2012/13	26,922	25,599	-1,323	26,544	25,075	-1,469
2013/14	27,241	26,012	-1,229	26,787	25,413	-1,374
2014/15	27,531	26,618	-913	27,049	26,030	-1,019
2015/16	27,827	26,973	-854	27,296	26,439	-857
2020/21	29,432	28,654	-778	28,789	27,551	-1,238
2025/26	31,108	30,516	-592	30,324	29,379	-945

PUB/MH II-194

Reference: 20 IFF 09-1/PUB/MH I-209/ 2008/09 & 2007/08 Load Forecasts: Domestic Load

b) Please confirm that MH's annual domestic sales at generation are currently (IFF 09-1) forecast to be about 1,000 GWh lower than in IFF 08-1.

ANSWER:

Confirmed.

PUB/MH II-194

Reference: **20 IFF 09-1/PUB/MH I-209/ 2008/09 & 2007/08 Load Forecasts: Domestic Load**

c) Please explain this apparent forecast reduction in 2009/10, 2010/11, and 2011/12 relative to:

- **Residential customers.**
- **Mass market.**
- **Top consumers.**

ANSWER:

The reductions in the Net Firm Energy Load Forecast for those three years were 857 GW.h, 1113 GW.h and 1203 GW.h. The reduction was a result of:

- The residential forecast was reduced 19 GW.h, 36 GW.h. and 69 GW.h.;
- The mass market forecast was reduced 73 GW.h., 102 GW.h and 110 GW.h.; and
- The top consumers group was reduced by 839 GW.h, 1024 GW.h and 1093 GW.h. The changes in the top consumer group was primarily due to forecast electric load reductions in the primary metals and chemical industries.

PUB/MH II-194

Reference: **20 IFF 09-1/PUB/MH I-209/ 2008/09 & 2007/08 Load Forecasts: Domestic Load**

d) **Does the 1,000 GWh/year long-term cutback include the recent step back of about 500 GWh/year in the primary metal and pulp & paper industries?**

ANSWER:

The recent step back in the primary metal industry was included. The step back in the pulp & paper industries occurred after the 2009/10 (May 2009) Electric Load Forecast was released and therefore was not included in the 2009/10 forecast.

PUB/MH II-195

Reference: PUB/MH I-109 (a) Demographic Data

Please provide a further breakdown of the 2009 demographic results between natural gas and electric heated homes.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-187(b).

PUB/MH II-196

Reference: PUB/MH I-150 (a) I-157(a) , I- 206 (a) Impact of Five year drought

a) Please refile 206 (a) and provide the impact of a five year and seven year drought including finance expense impacts.

ANSWER:

The financing expenses for the five year drought have been provided in the response to CAC/MSOS/MH I-8(b). These financing expenses have been added into the table that was provided in the response to PUB/MH I-206(a) for the 5 year drought period. The updated table is provided in below.

			2011/12	2012/13	2013/14	2014/15	2015/16	Total
Impact of 5-Year Drought on Revenues (millions of $ Cdn)								
Revenue								
Extra-Provincial Sales			-220	-295	-186	-225	-198	-1124
Expense								
Water Rental			-24	-36	-17	-19	-16	-111
Fuel & Power Purchase								
	Thermal		103	317	-20	1	-5	396
	Import	On-Peak	14	40	7	7	4	71
		Off-Peak	107	127	93	106	90	523
		Total	223	483	80	114	89	990
Net Revenue (Excluding Finance Expenses)			-419	-742	-249	-320	-271	-2003
Finance Expense			9	46	88	115	145	403
Net Revenue including Finance			-428	-788	-337	-435	-416	-2406

Similar information for the seven year drought cannot be compiled in the available timeframe.

PUB/MH II-196

Reference: PUB/MH I-150 (a) I-157(a) , I- 206 (a) Impact of Five year drought

b) Please provide the same level of detail as (a) for the scenarios for 5 year and seven year droughts provided in response to PUB/MH I-157

ANSWER:

Manitoba Hydro is unable to provide the requested details for the various drought periods in the timeframe that is available for responses.

PUB/MH II-197

Reference: **PUB/MH I-161 (a)**

Please file the requested information from PUB/MH I-161 (a) in confidence with the Board

ANSWER:

As indicated in the response to PUB/MH I-161(a), annual volumes and prices for the total of all export sales are provided in PUB/MH I-209. The breakdown of export sales that is requested is not being provided as it is commercially sensitive information and in some circumstances would violate confidentiality agreements with counterparties.

<u>PUB/MH II-198</u>

Reference: PUB/MH I-179 (f) Cost Savings Attributable to Head Office

Please file the respective referenced article excerpts when available.

<u>ANSWER</u>:

User Effective Buildings - Aardex Corporation

- ISBN 0-9755524-0-6, Copyright 2004 Aardex Corporation
- The relevant excerpt is attached as Attachment 1.

Building Green on Brownfields - Darwin Magazine

- Darwin Magazine is no longer available. Manitoba Hydro continues to search historical files for this magazine.

The Cost and Financial Benefits of Green Buildings - A report to California's Sustainable Building Task Force - Principal Author - Greg Kats, Capital E; Contributing Authors - Leon Alevantis, Department of Health Services; Adam Berman, Capital E; Evan Mills, Lawrence Berkeley Nation Laboratory; Jeff Perlman, Capital E

- The relevant excerpt is attached as Attachment 2.

"Our tenants experience productivity increases as high as 30 percent after moving into their new buildings."

– Rick Butler, CEO, Aardex Corporation

User Effective™ Buildings

Aardex Corporation

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n some of the deci-
›ersonalizing spaces,
nent that has been
coordinating them
: reorganize business
ryone is included to

There is also growing dissatisfaction with open-plan offices among some of the early adopters of the format. It is not just that the atmosphere is alien to some workers, but that it is more conducive to interaction than concentration, and many kinds of work activity require the latter, not the former.

Hierarchies are also part of the criticism of open plan office space. The traditional responsibilities and authority that managers and executives have are ill-suited to the egalitarianism of open space rooms. Status is a recognizable element in office

What Influences Productivity

Various studies estimate that employee productivity can be increased between 10 and 20 percent due to the features of high quality buildings. The features of buildings have an important effect on how their occupants perform, but the effect varies from feature to feature and even from person to person.

Among the factors affecting individual productivity:

- technical competence
- motivation and personality
- job satisfaction
- attitude
- leadership
- organizational structure
- workflow
- equipment, technology, and technical support
- personal relationships
- type of occupation
- indoor environment

The Costs and Financial Benefits of Green Buildings

A Report to California's Sustainable Building Task Force

October 2003

Principal Author: Greg Kats, Capital E

Contributing Authors: Leon Alevantis, Department of Health Services
Adam Berman, Capital E
Evan Mills, Lawrence Berkeley National Laboratory
Jeff Perlman, Capital E

This report was developed for the Sustainable Building Task Force, a group of over 40 California state government agencies. Funding for this study was provided by the Air Resources Board (ARB), California Integrated Waste Management Board CIWMB), Department of Finance (DOF), Department of General Services (DGS), Department of Transportation (Caltrans), Department of Water Resources (DWR), and Division of the State Architect (DSA). This collaborative effort was made possible through the contributions of Capital E, Future Resources Associates, Task Force members, and the United States Green Building Council.

VIII. Productivity and Health

California's Executive Order D-16-00, which established the Governor's sustainable building goals, includes the statement that sustainable building practices should "enhance indoor air quality; and improve employee health, comfort and productivity,"[220] indicating that health and productivity benefits should be explicitly recognized in the state's building design and funding decisions.

This section contains a brief overview of what is known about health, human comfort and productivity in relation to green building design and operation. The conclusion contains a reasonable and conservative estimate for the monetary value of productivity gains in green buildings. Health and productivity issues, often addressed separately, are combined here because both relate directly to worker well-being and comfort and both can be measured by their impacts on productivity.

The relationship between worker comfort/productivity and building design/operation is complicated.[221] There are thousands of studies, reports and articles on the subject. This report relies in large part on recent meta-studies that have screened tens or hundreds of other studies and have evaluated and synthesized their findings.

Potential Savings

The cost to the state of California for state employees is ten times larger than the cost of property. The following chart (Figure VIII-1) and supporting data (see Appendix I) represent state costs for 27,428 state employees in 38 state-owned buildings. Note that operations and maintenance (O&M) costs are allocated 44% for labor and 56% for property related expenses.[222] Average annual employee costs ($66,478 in salary and benefits - $65,141 - plus allocated operations and maintenance costs - $1,337), are 10.25 times larger than the cost of space per employee ($6,477).[223] Thus, measures that increase employee costs by 1% are equivalent, from a state cost perspective, to an increase in property related costs of about 10%. *In other words, if green design measures can increase productivity by 1%, this would, over time, have a fiscal impact roughly equal to reducing property costs by 10%.*

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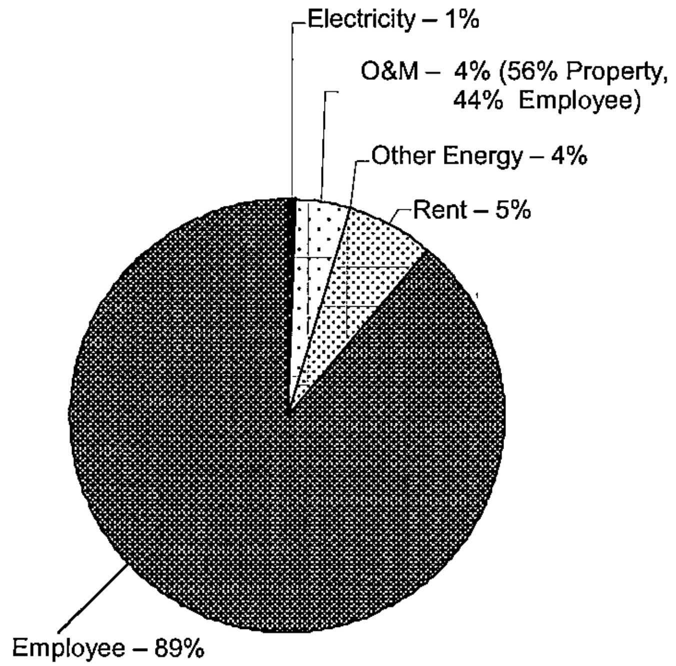
[220] State of California. Governor's Executive Order D-16-00, August 2000. Available at: http://www.governor.ca.gov/state/govsite/gov_homepage.jsp.

[221] One approach to address this complexity is offered by comprehensive building performance scoring tools for evaluating building design and operation benefits. One example of this type of scoring methodology is called the Balanced Scorecard. This approach evaluates four categories of building performance: Financial Results (cost of absenteeism, turnover, etc), Business Processes (innovation, product quality, etc), Customer Satisfaction (stakeholder relations - including public image and local economic impact), and Learning and Growth (human capital development - including work satisfaction and productivity). These kinds of broad systems approaches are valuable for explicitly demonstrating how green buildings support health, productivity and other benefits and meeting larger corporate objectives. However, these types of approaches are less helpful for quantifying the benefits of green building design. See for example: http://www.balancedscorecard.org/bscand/bsckm.html.

[222] Operations and Maintenance cost ($3,039) are allocated 44% for labor and 56% for property related expenses. Data provided by the California Department of General Services, Real Estate Services Division. December 2002.

[223] See Appendix I.

Figure VIII-1. Costs in California State Employee-Occupied Office Buildings
(December 2001 - September 2002 with projections for November-December 2002)



Source: Real Estate Services Division of Department of General Services.[224]

Increased productivity is closely linked to improved worker health. Companies with a demonstrably healthier work environment can also experience reduced insurance premiums – a topic covered in Section X.

The Building-Productivity Link

There is growing recognition of the large health and productivity costs imposed by poor indoor environmental quality (IEQ) in commercial buildings – estimated variously at up to hundreds of billions of dollars per year. This is not surprising as people spend 90% of their time indoors, and

[224] Data provided by the California Department of General Services. November 2002. Note that these include state owned buildings leased to state agencies and that on average these rental rates are slightly below market average – perhaps by about 10%. The data were not adjusted to account for this (by about 3%) because doing so has no significant effect on calculations or conclusions. Conditioned area per employee is assumed to be 225ft^2 – the number indicated by the California Department of General Services, Real Estate Services Division. This is significantly below the aggregate data summarized in Appendix I, provided by DGS, reflecting the fact that a substantial portion of building space is not conditioned occupied. Annual average energy cost is about \$1.60, conservatively projected to decline to \$1.47/ft^2. (Also see discussion of this data in Energy Use section.)

What Do Tenants Want?

Given the large impact that poor IEQ has on the health and comfort of office workers, it is not surprising that recent surveys of workers suggest that IEQ is one of the most important components of job satisfaction. For example, the study, *What Office Tenants Want: 1999 BOMA/ULI Office Tenant Survey Report*[230] is based on questionnaires from 1800 office tenant surveys in 126 metropolitan areas. Conducted by the Building Owners and Managers Association (BOMA) and the Urban Land Institute, the study affirms that office tenants highly value comfort in office buildings. Survey respondents attributed the highest importance to tenant comfort features, including comfortable air temperature (95%) and indoor air quality (94%). Office temperature and the ability to control temperature are the only features that were both "most important" and also on the list of things with which tenants are least satisfied. The BOMA/ULI study found that the number one reason that tenants move out is because of HVAC heating/cooling problems.

The BOMA/ULI survey found that office tenants also highly value intelligent building features. These include modern energy-efficient HVAC systems and automatic sensors for lighting. According to the BOMA/ULI study, over 75% of office buildings do not have these intelligent features. The survey found that 72% of tenants who want an intelligent feature would be willing to pay additional rent to have the feature made available.

This and other studies make it clear that a high percentage of office tenants are dissatisfied with the indoor air quality (IAQ) and comfort of their work environment and express a willingness to pay for a greener, more comfortable and productive one.

California has developed its own requirements for IAQ that differ from and are in some ways more stringent than IAQ prerequisites contained in LEED. Although the new California IAQ requirements have been adopted for use in the East End complex, they are not required in new construction and have, as yet, not been generally applied. Until these new standards are incorporated, the LEED approach to IAQ offers a significant improvement over current California practices.

"Greening the Building and the Bottom Line: Increasing Productivity Through Energy-Efficient Design," a compilation of widely quoted original research and review of 20 case studies on documented productivity gains, (Joseph Romm and Bill Browning, "Greening the Building and the Bottom Line: Increasing Productivity Through Energy-Efficient Design," RMI, 1994. Available at: http://www.rmi.org/images/other/GDS-GBBL.pdf. See also: Joseph Romm, "Cool Companies," *Island Press*, 1999 for a useful set of business case studies), and "Green Development: Integrating Ecology & Real Estate," a general overview of green building case studies with a focus on productivity and health in green buildings (Excerpts from "Green Development: Integrating Ecology & Real Estate" available at: http://www.rmi.org/sitepages/pid219.php).
Some good general databases on the subject include: http://www.ciwmb.ca.gov/GreenBuilding/Basics.htm; http://www.gbapgh.org/On%20Green%20Building/ogb_economic_benefits.html; http://www.conservationeconomy.net/content.cfm?PatternID=30; and http://www.ci.sf.ca.us/sfenvironment/aboutus/greenbldg/gb_productivity.pdf.
See also EPA's excellent database on indoor air quality: http://www.epa.gov/iaq/largebldgs/i-beam_html/bibliography.htm.

[230] "What Office Tenants Want: 1999 BOMA/ULI Office Tenant Survey Report." To order, call 1-800-426-6292, or order on-line at www.boma.org, item #159-TENANT-029.

Figure VIII-2. Potential Productivity Gains from Improvements in Indoor Environments

Source of Productivity Gain	Potential Annual Health Benefits	Potential U.S. Annual Savings or Productivity Gain (2002 dollars)
1) Reduced respiratory illness	16 to 37 million avoided cases of common cold or influenza	\$7 - \$16 billion
2) Reduced allergies and asthma	8% to 25% decrease in symptoms within 53 million allergy sufferers and 16 million asthmatics	\$1 - \$5 billion
3) Reduced sick building syndrome symptoms	20% to 50% reduction in SBS health symptoms experienced frequently at work by ~15 million workers	\$10 - \$35 billion
4) Sub-total		*\$18 - \$56 billion*
5) Improved worker performance from changes in thermal environment and lighting	Not applicable	\$25 - \$180 billion
6) Total		*\$43 - \$235 billion*

Adapted from: William Fisk, "Health and Productivity Gains from Better Indoor Environments"[234]

The first two sources of productivity gain outlined in Figure VIII-2 are only partially attributable to the work environment, so this report assumes that potential health benefits are therefore reduced to a range of \$12 to \$45 billion annually. Productivity benefits from both health improvement and from improvement in thermal environment and lighting are reduced to a range of \$35 to \$225 billion. Note that there are other, less substantial sources of potential health related benefits that are not included in Figure VIII-2, making these estimates of benefits potentially low.

Assuming a low value of \$25 billion, this translates into \$385 in direct health improvement potential for each of the 65 million full time office workers and teachers in the US.[235] If one third of these benefits can be achieved in a green building, this translates into about \$130 per year in health-related financial benefits. With 225 ft^2 in average space per worker, this suggests a potential annual productivity gain of \$0.58/ft^2.

If we assume a mid-range value of \$140 billion in potential productivity benefits (line 6 in Figure VIII-2), and assume that 1/3 of these benefits could be achieved from respiratory health benefits

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[234] William Fisk, "Health and Productivity Gains from Better Indoor Environments," summary of prior publications (see Appendix J), with figures inflation-adjusted for 2002 dollars and rounded.
See also:
W.J. Fisk, "Health and Productivity Gains from Better Indoor Environments and Their Relationship with Building Energy Efficiency," *Annual Review of Energy and Environment* 25(1): pp. 537-566.
W.J. Fisk and A.H. Rosenfeld. "Estimates of Improved Productivity and Health from Better Indoor Environments," *Indoor Air* 7(3), 1997: pp. 158-172.

[235] Adjusted up from 63.5 million in Fisk. Note that Fisk includes ½ of military personnel, who are assumed to be office workers. For more on the size and composition of the US workforce, see: *Statistical Abstract of the United States*, US Census Bureau, 2001.
Available at: http://www.census.gov/prod/2002pubs/01statab/stat-ab01.html.

technical characteristics of buildings, in areas such as lighting and ventilation, to tenant responses, such as productivity. Of these studies, the Center has identified 95 that are sufficiently rigorous and quantitative to meet their criteria for inclusion in the BIDS database and decision making tool, making it perhaps the most valuable database of its kind.[240]

Collectively, these studies demonstrate that better building design and performance in areas such as lighting, ventilation and thermal control correlate to increases in tenant/worker well-being and productivity. The BIDS data set includes a number of controlled laboratory studies where speed and accuracy at specific tasks was measured in low and high performance ventilation, thermal control and lighting control environments. These studies used a range of speed and accuracy performance measures including: typing, addition, proof reading, paragraph completion, reading comprehension, and creative thinking.[241]

Increases in tenant control over ventilation, temperature and lighting each provide measured benefits from 0.5% up to 34%, with average measured workforce productivity gains of 7.1% with lighting control, 1.8% with ventilation control, and 1.2% with thermal control. Additionally, measured improvements have been found with increased daylighting, as discussed in the following section.

Figures VIII-3, VIII-4 and VIII-5 on the subsequent pages were supplied by the Department of Architecture at Carnegie Mellon University. They represent ongoing research, and as such should be considered interim.[242]

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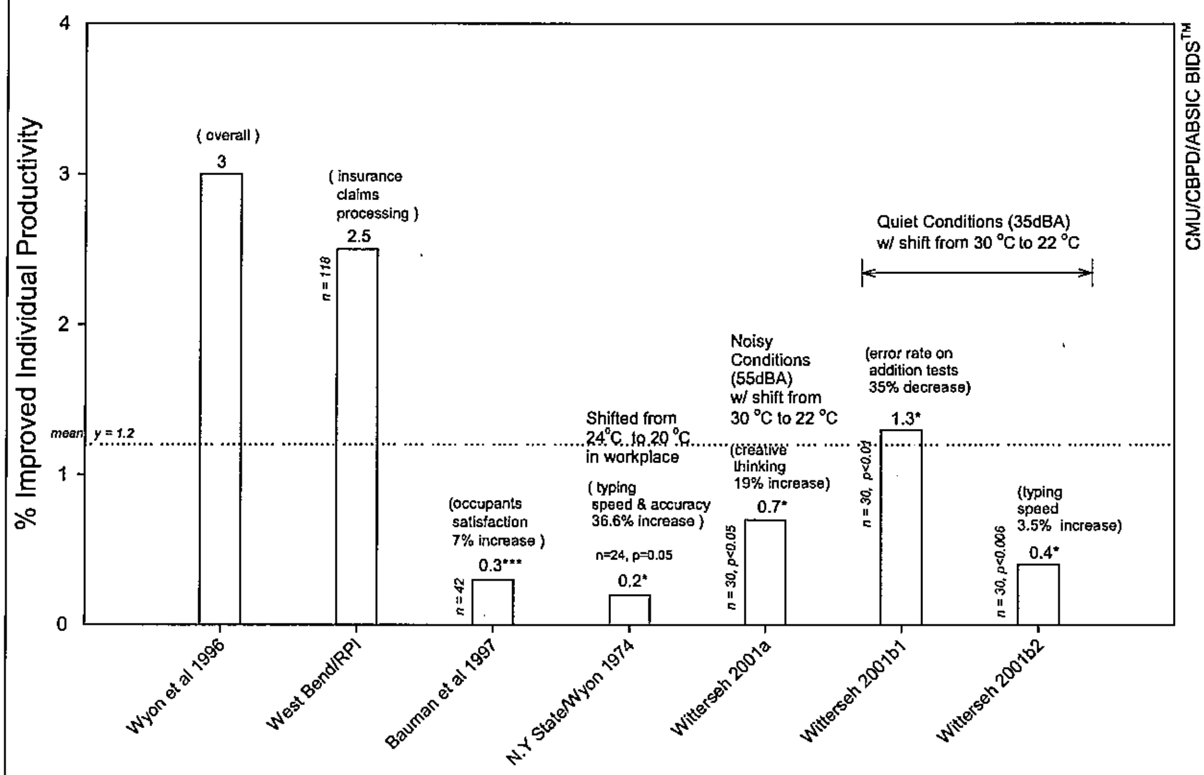
[240] Vivian Loftness et al., "Building Investment Decisions Support (BIDS)," *ABSIC Research 2001-2002 Year End report.* See: http://nodem.pc.cc.cmu.edu/bids. Carnegie Mellon's BIDS™, for Building Investment Decision Support, is a case-based decision-making tool that calculates the economic value added of investing in high performance building systems, based on the findings of building owners and researchers around the world.

[241] Communication with Vivian Loftness, CMU, February 2003.

[242] Data extracted from BIDS™. Carnegie Mellon University Department of Architecture. February 2003. (Vivan Loftness).

Figure VIII-4: Increased Temperature Control

The Center also looked at studies examining productivity impacts of worker control over temperature. As noted earlier, the BOMA/ULI study found that lack of control over temperature was one of only two features considered by respondents as both most important and of lowest tenant satisfaction. The mean productivity increase for temperature control in these seven studies is 1.2%.



Case Studies Introducing Improved Performance with Temperature Control
(* Performance improvement for specific tasks multiplied by estimated time at tasks)
(*** Occupant satisfaction calculated relative to productivity gains from other studies)

Increased Daylighting

A study by the Heschong Mahone Group evaluated the test score performance of over 21,000 students in three school districts in San Juan Capistrano, CA; Seattle, WA; and Fort Collins, CO. The study found that in classrooms with the most daylighting, students' learning progressed 20% faster in math and 26% faster in reading than similar students in classrooms with the least daylighting. The overall findings show that increased daylighting and generally improving quality of lighting significantly improves student test performance.[243] The study's results have been widely quoted, although the large impact of daylighting quality surprised some people and raised questions about the technical thoroughness of the report. To ensure the study's validity, California's Public Interest Energy Research (PIER) program, administered by the CEC, funded a follow up study, employing an independent technical advisory group to reanalyze the data. The reanalysis confirmed the initial study's findings with a 99.9% confidence level.[244]

The kind of work done by "knowledge workers" – most state employees – is very similar to the work students do. Tasks include: reading comprehension, synthesis of information, writing, calculations, and communications. Large-scale studies correlating daylighting with student performance on standard tests therefore provide relevant insight about the impact of increased daylighting on state employees.

This study is important for its size, rigor and the large measured impact of lighting quality on standardized test performance. Note that the study compares performance between students with the greatest amount of daylighting and those with the least daylighting – two extremes. Therefore it is difficult to use this study to predict benefits of enhanced daylighting common in green buildings relative to conventional buildings. The productivity benefits that could conservatively be expected are much less than 26% (which reflects extremes in daylighting), perhaps on the order of 2% to 6%.

Sick Building Syndrome

Following (see text box, *The cost of sick building syndrome for California state and school employees,* below) are the results of an analysis of the cost of sick building syndrome (SBS) for California state and school employees.[245] It assumes a "conservative" 2% productivity decrease due to SBS symptoms. By comparison, a 2000 evaluation of three buildings with a total of over 600 occupants for the Portland Energy Office estimated a 1% increase in productivity and noted that this is "a very conservative estimate." [246] A National Energy Management Institute (NEMI) study entitled *Productivity and Indoor Environmental Quality*, estimates that productivity gains

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[243] Heschong Mahone Group, "Daylighting in Schools: An Investigation into the Relationship Between Daylight and Human Performance," 1999. Available at: http://www.h-m-g.com; Follow up studies verified the rigor of analysis and subsequent research continues to show positive correlation between daylighting and student performance.
[244] Heschong Mahone Group. 2002. "Daylighting in Schools Re-Analysis." Available at: http://www.newbuildings.org/pier/index.html.
[245] Original report by Leon Alevantis, Deputy Chief of Indoor Air Quality Section, California Department of Health Services, updated for this report by the author.
[246] "Green City Buildings: Applying the LEED Rating System," prepared for the Portland Energy Office by Xenergy, Inc and SERA Architects, June 18, 2000.
Available at: http://www.sustainableportland.org/CityLEED.pdf.

PUB/MH II-199

Reference: PUB/MH I-186 (c) Diesel Communities Wind Generation

Please provide an update on the wind generation time frame for the diesel communities including additional studies or implementation

ANSWER:

No commitment has been made for additional studies that may lead to the implementation of a plan to proceed with wind generation for the diesel communities. However, if and when a commitment is made to proceed with wind development, Manitoba Hydro estimates an overall timeline of 2 to 2.5 years per site from project commitment to final design, which includes initial site visits, wind resource assessments, feasibility studies, conceptual system design, and final system design. For a low-penetration wind-diesel system, project construction for each site is expected to take up to a year following the final system design stage, depending on the number and size of wind turbines installed.

PUB/MH II-200

Reference: PUB/MH I-209 Alternative Scenarios

a) Please file both the respective IFFs and detail impacts set out in I-209 for both the low and high forecasts for the following scenarios the CAD/USD exchange rate at parity throughout the forecast period and interest rates being 3% higher than currently forecast for the forecast. Please discuss the impacts on the high and low scenario.

ANSWER:

Please refer to PUB/MH I-210(b) for the impacts of interest rates being 3% higher that forecast in IFF09-1. Please also refer to PUB/MH II-49 for a discussion of the impacts of CAD/USD exchange rates at parity.

PUB/MH II-200

Reference: PUB/MH I-209 Alternative Scenarios

b) Please provide IFF's and detail impacts as in (a) for the following scenarios CAD/USD exchange rate at parity for the first ten years of the forecast and interest rates 3% higher for the same period.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-200(a).

PUB/MH II-201

Reference: IFF09-1 Export Revenues

Please provide the annual export revenue net of F& PP (and % of total revenue) for the 20 Year forecast period in IFF09-1

ANSWER:

Please refer to the following table for the annual export revenue net of F & PP for the twenty year forecast period in MH09-1.

MH09-1 Annual Export Revenue Net of F&PP

In Millions

Year	Extraprovincial Revenue	F&PP	Export Revenue Net of F&PP	Total Revenue	% of Total Revenue
2009/10	414	103	311	1,581	20%
2010/11	383	132	252	1,584	16%
2011/12	554	248	306	1,808	17%
2012/13	583	250	333	1,895	18%
2013/14	615	260	355	1,987	18%
2014/15	590	269	321	2,039	16%
2015/16	701	297	404	2,219	18%
2016/17	729	341	388	2,320	17%
2017/18	742	363	380	2,404	16%
2018/19	894	441	453	2,628	17%
2019/20	1,093	419	674	2,907	23%
2020/21	1,201	435	766	3,073	25%
2021/22	1,223	460	763	3,153	24%
2022/23	1,379	474	905	3,370	27%
2023/24	1,758	460	1,298	3,812	34%
2024/25	1,940	492	1,448	4,060	36%
2025/26	1,908	420	1,488	4,100	36%
2026/27	1,903	396	1,507	4,170	36%
2027/28	1,928	425	1,503	4,273	35%
2028/29	1,950	446	1,504	4,370	34%

<u>PUB/MH II-202</u>

Reference: IFF09-1 MH I-199 (a), Section 7.0 Financial Targets

a) Please refile the comparison graphs and a respective table of data-points for electric operations MH09-1 vs MH08-1for the equity ratio, interest coverage ratio and capital coverage ratio

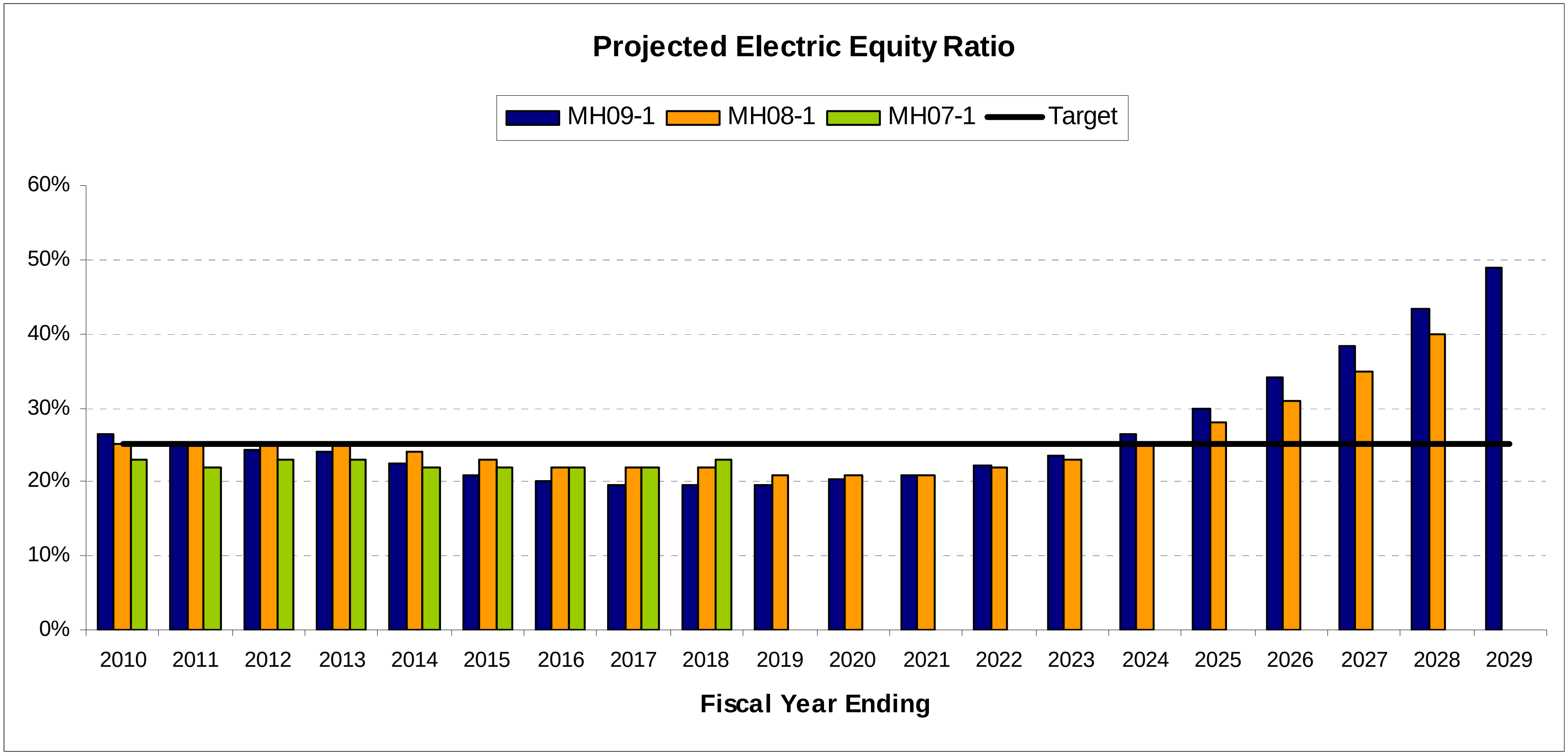
<u>ANSWER</u>:

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

Projected Electric Financial Ratios

	MH09-1			MH08-1*			MH07-1		
	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio
2010	26%	1.24	1.37	25%	1.40	1.20	23%	1.18	0.70
2011	25%	1.14	1.11	25%	1.30	1.22	22%	1.19	0.77
2012	24%	1.14	1.14	25%	1.20	1.31	23%	1.18	0.87
2013	24%	1.11	1.31	25%	1.15	1.52	23%	1.15	1.13
2014	22%	1.19	1.25	24%	1.24	1.66	22%	1.19	1.06
2015	21%	1.15	1.53	23%	1.20	1.80	22%	1.22	1.10
2016	20%	1.30	1.89	22%	1.33	2.12	22%	1.29	1.22
2017	20%	1.28	1.87	22%	1.33	2.23	22%	1.28	1.22
2018	20%	1.23	1.96	22%	1.22	1.99	23%	1.28	1.41
2019	20%	1.22	2.21	21%	1.18	2.01	NA	NA	NA
2020	20%	1.22	2.71	21%	1.12	1.89	NA	NA	NA
2021	21%	1.24	2.32	21%	1.14	1.93	NA	NA	NA
2022	22%	1.36	2.26	22%	1.26	2.14	NA	NA	NA
2023	24%	1.45	2.30	23%	1.32	2.32	NA	NA	NA
2024	26%	1.59	2.59	25%	1.43	2.65	NA	NA	NA
2025	30%	1.66	2.50	28%	1.51	2.53	NA	NA	NA
2026	34%	1.79	2.81	31%	1.62	2.86	NA	NA	NA
2027	38%	1.90	2.95	35%	1.75	2.97	NA	NA	NA
2028	43%	2.05	3.19	40%	1.90	3.07	NA	NA	NA
2029	49%	2.22	3.19	NA	NA	NA	NA	NA	NA

**Data is from the January 2009 Twenty Year Financial Forecast for Electricity Operations*


Projected Electric Equity Ratio
MH09-1
MH08-1
MH07-1
Target
60%
50%
40%
30%
20%
10%
0%
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
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2021
2022
2023
2024
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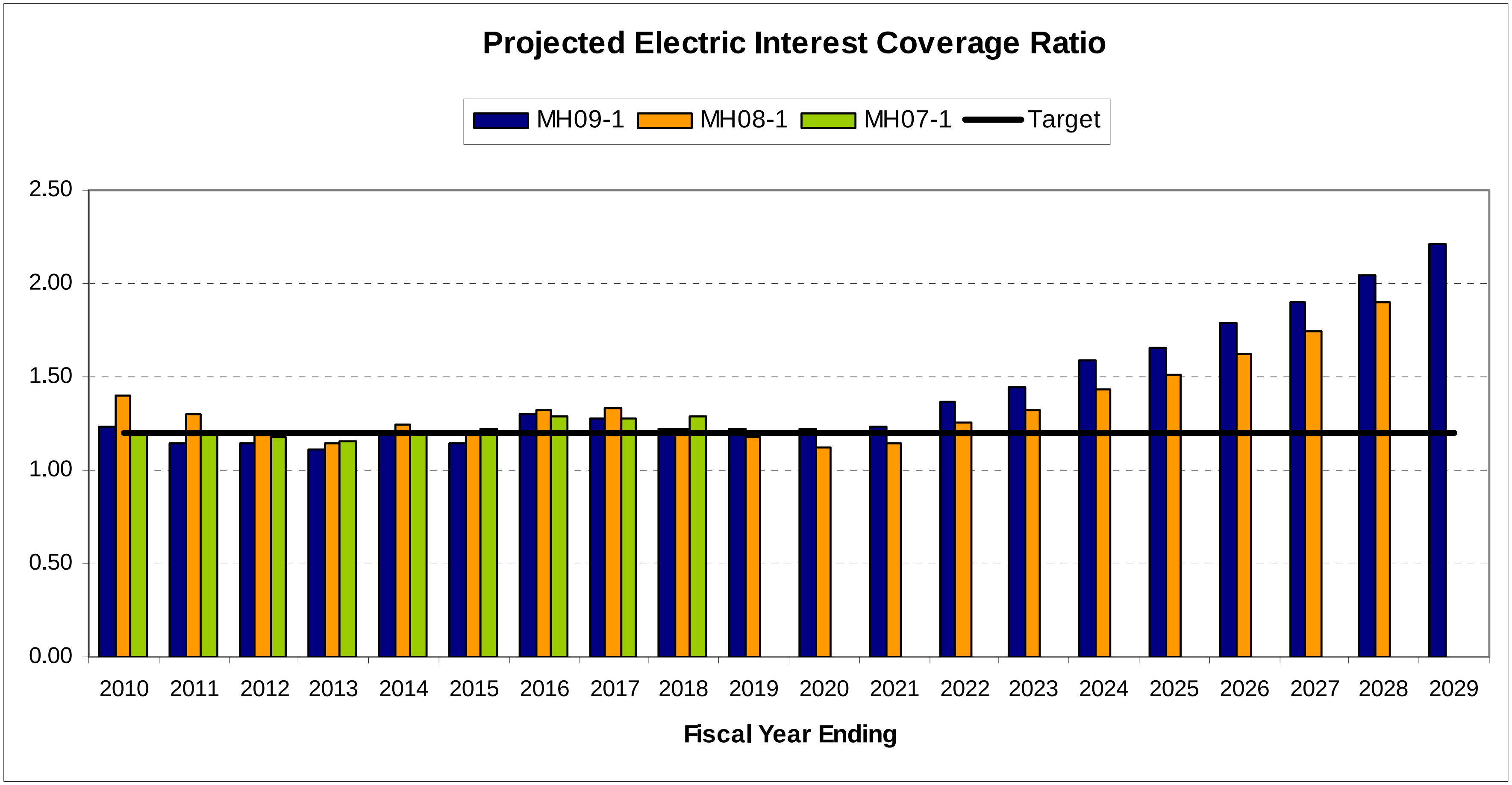
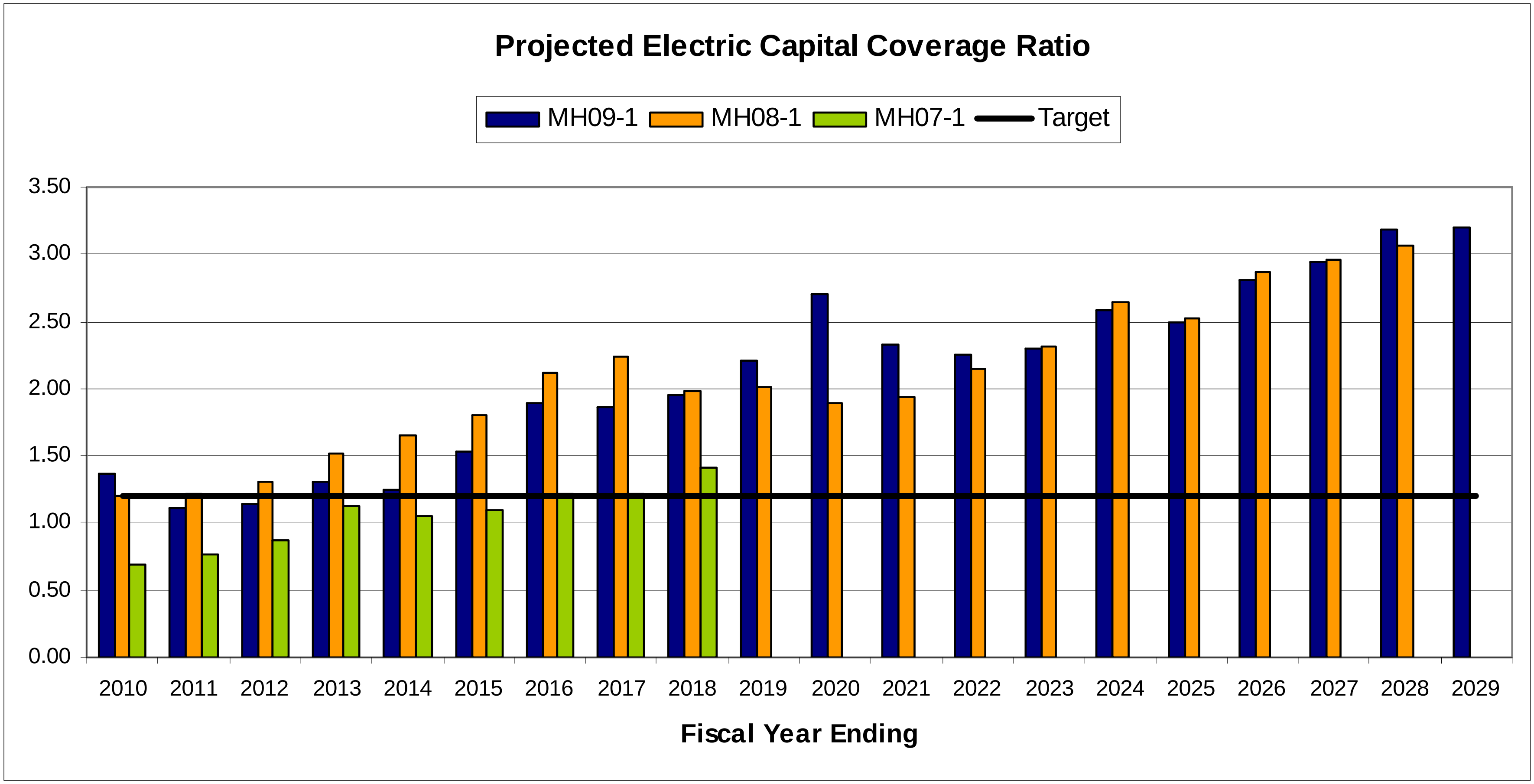
2027
2028
2029
Fiscal Year Ending


Projected Electric Interest Coverage Ratio
MH09-1
MH08-1
MH07-1
Target
2.50
2.00
1.50
1.00
0.50
0.00
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
Fiscal Year Ending


Projected Electric Capital Coverage Ratio
MH09-1
MH08-1
MH07-1
Target
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
Fiscal Year Ending

PUB/MH II-202

Reference: IFF09-1 MH I-199 (a), Section 7.0 Financial Targets

b) Please provide a comparison similar to (a) for between MH09-1 and MH07-1.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-202(a).

PUB/MH II-202

Reference: IFF09-1 MH I-199 (a), Section 7.0 Financial Targets

c) Please include the respective data tables comparing MH09-1 with MH08-1 and MH09-1 with MH07-1.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-202(a).

PUB/MH II-202

Reference: IFF09-1 MH I-199 (a), Section 7.0 Financial Targets

d) Please provide a comparison graphs and comparative data table as in part (a) and (c) of the financial targets comparing the IFF09-1 20-year forecast with the IFF08-1 20 year forecast

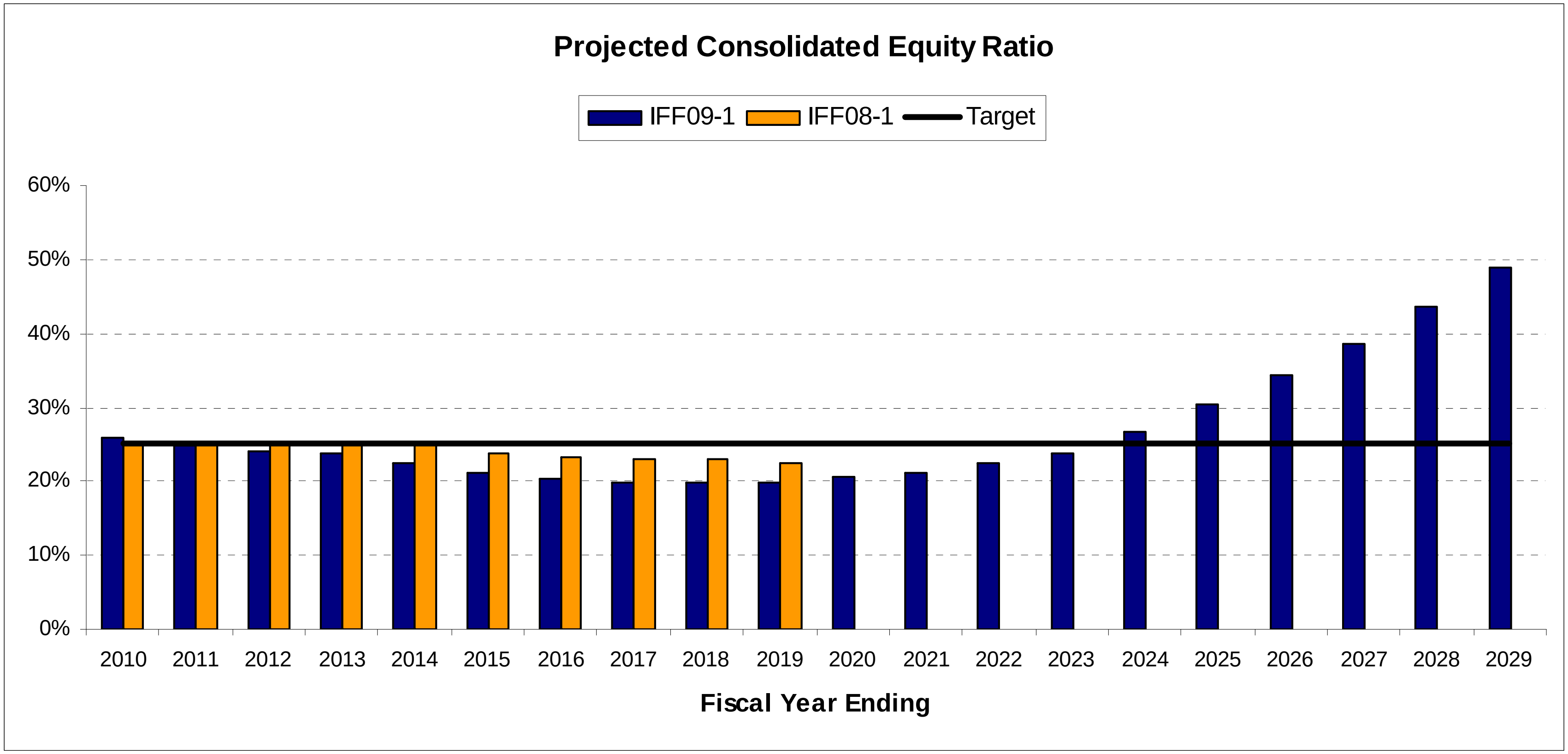
ANSWER:

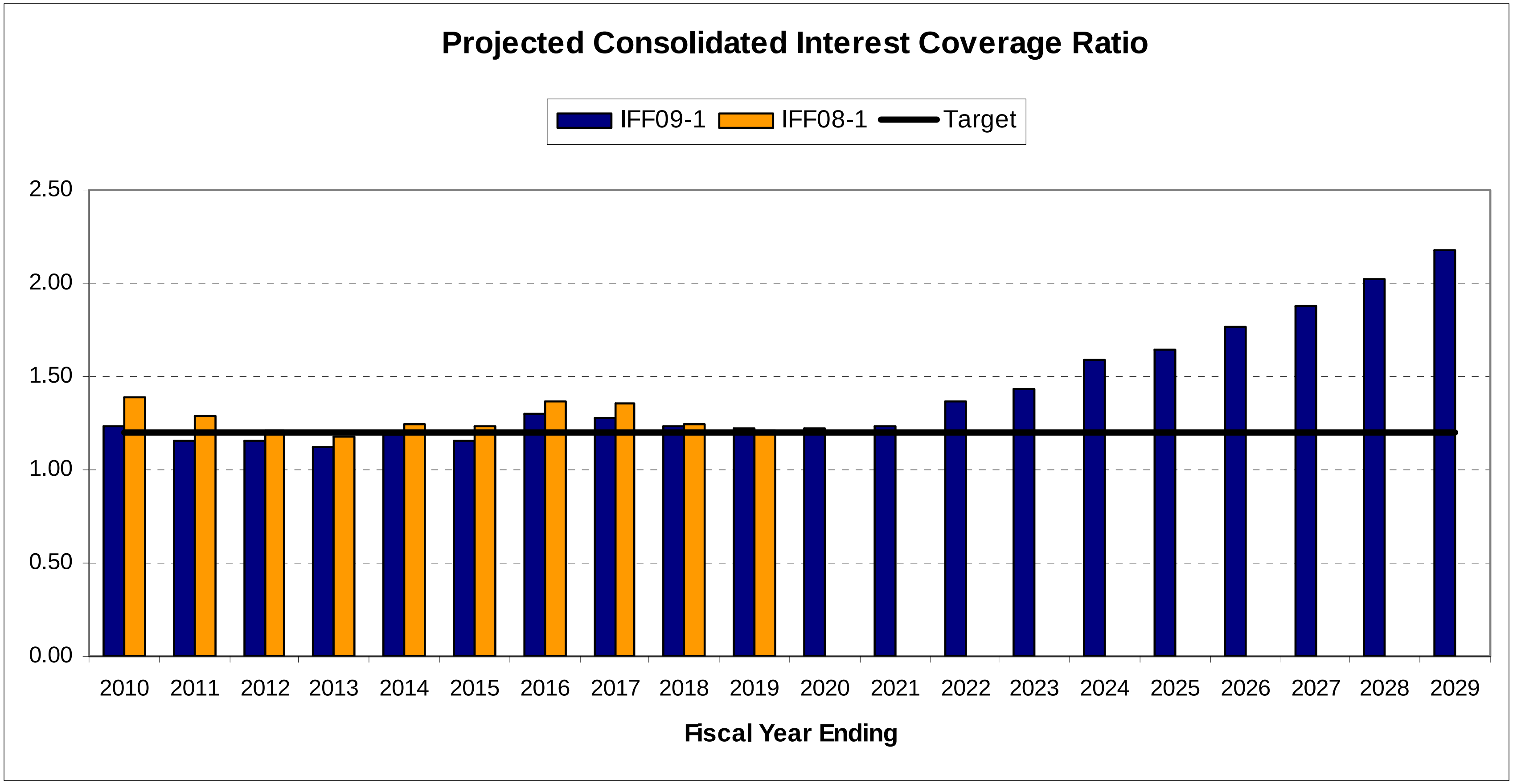
Please see the attached graphs and tables.

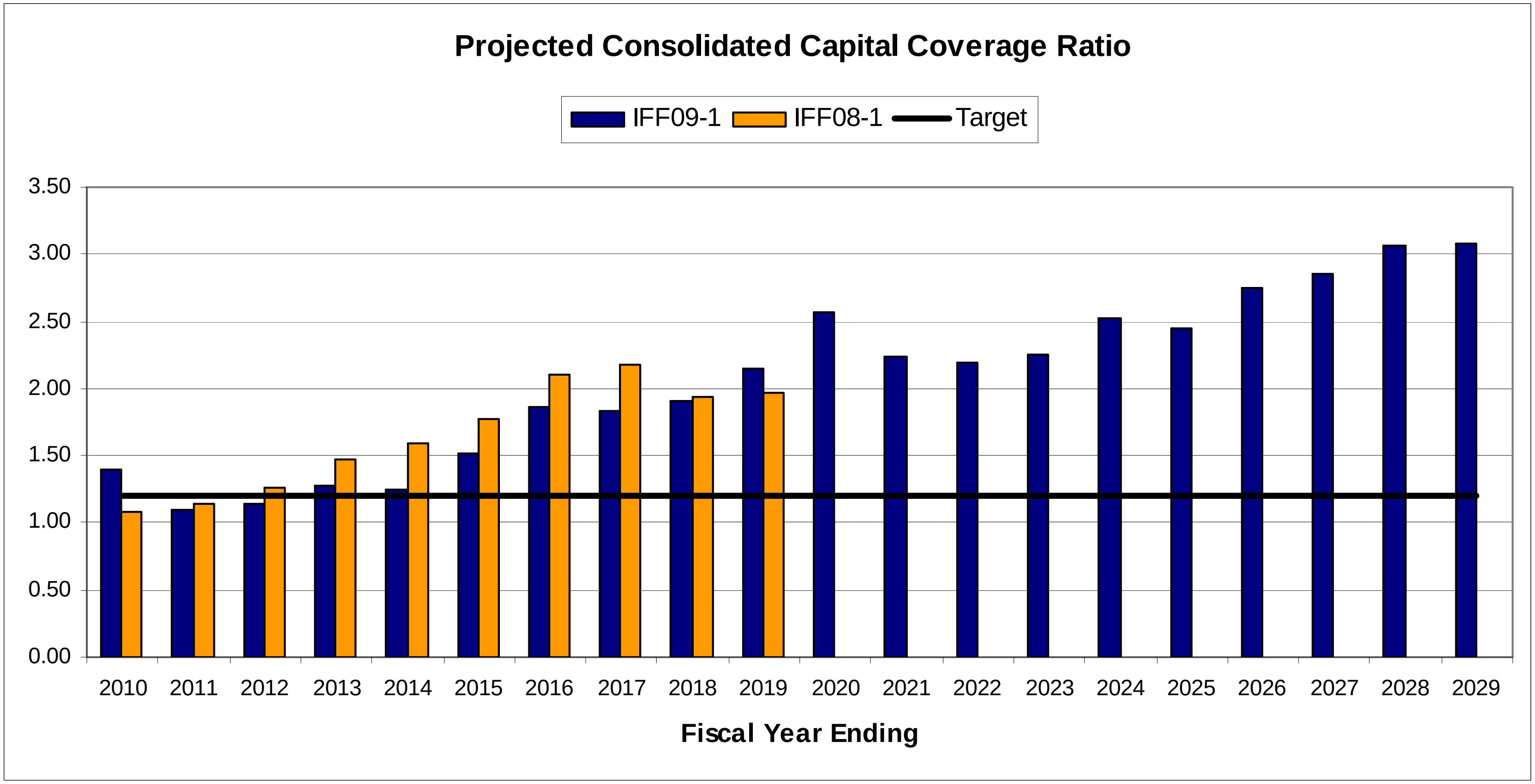
Projected Consolidated Financial Ratios

	IFF09-1			IFF08-1*		
	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio
2010	26%	1.24	1.39	25%	1.39	1.07
2011	25%	1.15	1.09	25%	1.29	1.15
2012	24%	1.15	1.14	25%	1.21	1.26
2013	24%	1.12	1.28	25%	1.18	1.47
2014	22%	1.19	1.25	25%	1.24	1.59
2015	21%	1.15	1.52	24%	1.23	1.78
2016	20%	1.30	1.86	23%	1.37	2.10
2017	20%	1.27	1.83	23%	1.36	2.17
2018	20%	1.23	1.91	23%	1.24	1.94
2019	20%	1.22	2.14	23%	1.21	1.96
2020	21%	1.22	2.56	NA	NA	NA
2021	21%	1.24	2.23	NA	NA	NA
2022	22%	1.36	2.19	NA	NA	NA
2023	24%	1.44	2.25	NA	NA	NA
2024	27%	1.58	2.53	NA	NA	NA
2025	30%	1.65	2.45	NA	NA	NA
2026	34%	1.77	2.74	NA	NA	NA
2027	39%	1.88	2.85	NA	NA	NA
2028	44%	2.02	3.07	NA	NA	NA
2029	49%	2.18	3.09	NA	NA	NA

**A twenty year financial forecast was prepared for electricity operations only.*


Projected Consolidated Equity Ratio
IFF09-1
IFF08-1
Target
60%
50%
40%
30%
20%
10%
0%
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
Fiscal Year Ending


Projected Consolidated Interest Coverage Ratio
IFF09-1
IFF08-1
Target
2.50
2.00
1.50
1.00
0.50
0.00
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
Fiscal Year Ending


Projected Consolidated Capital Coverage Ratio
IFF09-1
IFF08-1
Target
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2010
2011
2012
2013
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2015
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2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
Fiscal Year Ending

PUB/MH II-203

Reference: PUB/MH I-210 (a), I-46 (b) 2010 Economic Outlook

a) The Corporation indicates that the Economic outlook is prepare in the spring. Given volatility in both interest and CAD/USD exchange rates please file the 2010 Economic Outlook when available.

ANSWER:

The 2010 Economic Outlook is filed as Appendix 51.

PUB/MH II-203

Reference: PUB/MH I-210 (a), I-46 (b) 2010 Economic Outlook

b) Please provide a table which indicates the CAD/USD exchange rate forecasts relied upon, date of the forecast, and provide detailed calculations of how the CAD/USD exchange rate was determined for 2009/10 , 2010/11 and 2011/12 and for each of the years for the remainder of the 20-year forecast.

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS/MH II-97(m) for the source forecasts of CAD/USD exchange rates that were used in the 2010 Economic Outlook.

The first three years of the CAD/US exchange rate forecast, 2009/10-2011/12, uses sources that provide quarterly forecasts. Years 2012/13 and on of the forecast use sources that provide calendar year forecasts. The six financial institutions only provide forecasts for a two year period, with the exception of CIBC. Although IHS Global Insight and the Conference Board of Canada provide quarterly forecasts for the first four years of their outlooks, Informetrica and Spatial Economics only provide calendar year forecasts. In order to have more than two sources in years three and on and to have data that is determined on a consistent calendar year basis, the forecast for years three and on uses calendar year data from IHS Global Insight, Conference Board of Canada, Informetrica and Spatial Economics.

Table 1 summarizes the sources used to derive the forecast of CAD/USD exchange rates as provided in the 2010 Economic Outlook for the 2009/10-2011/12 period. Table 2 summarizes the sources used to derive the forecast of CAD/USD exchange rates as provided in the 2010 Economic Outlook for the remainder of the 20 year forecast.

Table 1 provides forecasts that were available on a quarterly basis. The shaded area in Table 1 reflects actual, average period CAD/USD exchange rates for Q1, Q2, Q3, and Q4 of 2009 from the Bank of Canada. For the subsequent quarters of years 2010, 2011 and 2012 Q1, for forecasters that provided average period rates, the rates in Table 1 reflect the forecast provided from that forecaster. For forecasters that provided end of period rates, the rates in Table 1 reflect rates adjusted to a comparable average period basis. For example, Royal Bank's forecast provided end of period rates. Their forecast of CAD/USD exchange rates for 2010 Q1 end of period was 1.02. In order to place the forecast on an equivalent average period basis for 2010 Q1, Royal Bank's 2010 Q1 end of period forecast of 1.02 was averaged with the Bank of Canada 2009 Q4 end of period actual rate of 1.05 to approximate an average period 2010 Q1 forecast of 1.04. This process was followed for all subsequent quarters and for all forecasters that provided end of period rates in Table 1. i.e., Q2 end of period forecast for 2010 was averaged with Q1 end of period forecast for 2010 to obtain an average period Q2 2010 forecast, etc.

Table 2 provides forecasts that were available on a calendar year basis. All forecasts provided in Table 2 are expressed on an average period basis.

Short-term forecast of exchange rate - The first four years of the CDN/US exchange rate forecast as reported in the 2010 Economic Outlook were derived from the average of the 2010 forecast survey.

Forecast - Years One to Three (2009/10 - 2011/12)

The forecast of the CAD/USD exchange rates in the 2010 Economic Outlook for fiscal years 2009/10 through to 2011/12 (first three years) was determined as follows:

- A forecast for each quarter was determined by taking the average of each of the 2010 source forecasts expressed on a quarterly basis (shown as "Average 2010 Survey" in Table 1).
- The average of the respective Q2, Q3, and Q4 forecasts of the first year and Q1 of the following year resulted in the fiscal year basis forecast (shown as "EO2010-Fiscal" in Table 1).

Forecast - Year Four (2012/13)

The forecast of the CAD/USD exchange rate in the 2010 Economic Outlook for fiscal year 2012/13 (year four) was determined as follows:

- A calendar year basis forecast was determined by taking the average of each of the 2010 source forecasts expressed on a calendar year basis for years 2012 and 2013 (shown as "Average 2010 Survey" in Table 2).
- The calendar year basis forecast for 2012 and 2013 (shown as "EO2010-Calendar" in Table 2), is equivalent to the "Average 2010 Survey" values.
- A fiscal year basis forecast for 2012/13 was determined by using a 75%/25% ratio from the 2012 calendar year forecast to the 2013 calendar year forecast, respectively (shown as "EO2010-Fiscal" in Table 2).

Long-term forecast of exchange rate - Due to the extreme volatility in the long-term outlook of exchange rates from one year to the next and to reduce the degree of influence of current circumstances in the long-term forecast, an approach that provides a smoother transition from one year to the next was applied. The long-term forecast of exchange rate, beyond the first four years, is based on the average of the previous year's survey average and the current year's survey average. A gradual trending up or down to merge the fourth year forecast to the long-term average was applied.

Forecast - Years Four and on

The forecast of the CAD/USD exchange rates in the 2010 Economic Outlook for fiscal years 2013/14 to the end of the forecast period was determined as follows:

- A calendar year basis forecast for 2010 was determined by taking the average of each of the 2010 source forecasts expressed on a calendar year basis (shown as "Average 2010 Survey" in Table 2).
- The calendar year basis forecast for 2009, was determined by taking the average of each of the 2009 source forecasts expressed on a calendar year basis (shown as "Average 2009 Survey" in Table 2).
- The calendar year basis forecast for 2014 and on, provided in the 2010 Economic Outlook, was determined by taking the average of the 2009 and 2010 average survey forecasts (shown as "EO2010-Calendar" in Table 2).
- A fiscal year basis forecast was determined by using a 75%/25% ratio from one calendar year to the next (shown as "EO2010-Fiscal" in Table 2).

Table 1 - CAD/USD Exchange Rate, 2009/10 to 2011/12

Source	Fcst Date	Original Forecast - End Period or Average	2009 - Bank of Canada Actual Rates				2010				2011				2012			
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
BMO Nesbitt Burns	Mar 26-10	Average					1.04	1.02	1.00	1.00	1.00	0.99	0.98	0.98				
CIBC	Mar 10-10	End Period					1.04	1.02	1.00	1.01	1.04	1.02	n/a	n/a				
National Bank	Mar-2010	End Period					1.04	1.04	1.06	1.08	1.05	1.05	1.05	1.05				
Royal Bank	Mar 11-10	End Period					1.04	1.00	1.00	1.02	1.02	1.02	1.03	1.03				
Scotiabank	Mar 3-10	End Period					1.04	1.01	0.99	0.98	0.97	0.97	0.96	0.95				
TD Bank	Mar 18-10	End Period					1.04	1.02	1.02	1.02	1.02	1.04	1.05	1.08				
IHS Global Insight	Mar 12-10	Average					1.05	1.06	1.07	1.07	1.07	1.07	1.07	1.07	1.07			
Conference Board	Mar 18-10	Average					1.04	1.02	1.01	1.00	1.00	0.99	0.99	0.99	0.99			
Informetrica	Jan 26-10	Average					n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00			
Spatial Economics *	Apr 16-10	Average					n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a			
Average 2010 Survey			1.25	1.17	1.10	1.06	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.04			
			2009/10	**2010/11**	**2011/12**													
EO2010 - Fiscal			**1.09**	**1.02**	**1.02**													

Table 2 - CAD/USD Exchange Rate, 2012/13 to 2030/31

Source	Fcst Date	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
IHS Global Insight	10-Feb	1.07	1.07	1.09	1.12	1.13	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.13	1.13	1.13	1.14
Conference Board	10-Jan	0.99	1.00	1.01	1.06	1.05	1.05	1.05	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Informetrica	10-Jan	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Spatial Economics *	10-Apr	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Average 2010 Survey		1.04	1.04	1.05	1.07	1.08	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.08	1.08
Average 2009 Survey				1.12	1.13	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
EO2010 - Calendar		1.04	1.04	1.09	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11
		2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	
EO2010 - Fiscal		**1.04**	**1.05**	**1.09**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	**1.11**	

n/a - not available

* Spatial Economics did not give Manitoba Hydro permission to share its most recent forecasts of economic and financial variables for reasons of confidentiality.

PUB/MH II-203

Reference: PUB/MH I-210 (a), I-46 (b) 2010 Economic Outlook

c) Please describe how the Corporation determines whether a forecast would be considered an outlier and excluded from the forecasting process.

ANSWER:

Manitoba Hydro would not typically exclude a forecast from the forecasting process due to the fact that it is an “outlier”. The intent of utilizing several views in the forecasting process is to capture a range of possible outlooks that may or may not be similar. This results in a collective view.

Refer to Manitoba Hydro’s response to CAC/MSOS/MH II-161(a) related to exclusion of a forecast due to its date of publication.

PUB/MH II-204

Reference: PUB/MH I-213 (b) Low Income Energy Burden

a) Please provide the electric and natural gas rates utilized in the determination of the chart.

ANSWER:

Please see the attachment.

Calculation of the weighted average Natural Gas Rate - 2009

2003 Consumption		Billing Rates						Billing Percentage split		Total Billing				
Month	Volume M^3	Elec (gas space) kW.h	Elec only kW.h	Transportation (to Centra)	Distribution (to Customer)	Primary Gas	Supplemental Gas	Primary Gas	Supplemental Gas	Transportation (to Centra)	Distribution (to Customer)	Primary Gas	Supplemental Gas	Total
		7,839 kW.h	24,079 kW.h											
January	511 M^3	861 kW.h	3438 kW.h	$ 0.0379	$ 0.0885	$ 0.3018	$ 0.2686	97%	3%	$ 19.37	$ 45.22	$ 149.59	$ 4.12	$ 218.30
February	410 M^3	846 kW.h	3575 kW.h	$ 0.0379	$ 0.0885	$ 0.2799	$ 0.2686	94%	6%	$ 15.54	$ 36.29	$ 107.87	$ 6.61	$ 166.31
March	345 M^3	777 kW.h	3126 kW.h	$ 0.0379	$ 0.0885	$ 0.2799	$ 0.2686	94%	6%	$ 13.08	$ 30.53	$ 90.77	$ 5.56	$ 139.94
April	204 M^3	631 kW.h	2231 kW.h	$ 0.0379	$ 0.0885	$ 0.2799	$ 0.2686	94%	6%	$ 7.73	$ 18.05	$ 53.67	$ 3.29	$ 82.75
May	100 M^3	548 kW.h	1631 kW.h	$ 0.0379	$ 0.0885	$ 0.2451	$ 0.2686	81%	19%	$ 3.79	$ 8.85	$ 19.85	$ 5.10	$ 37.60
June	57 M^3	497 kW.h	1124 kW.h	$ 0.0379	$ 0.0885	$ 0.2451	$ 0.2686	81%	19%	$ 2.16	$ 5.04	$ 11.32	$ 2.91	$ 21.43
July	47 M^3	587 kW.h	916 kW.h	$ 0.0379	$ 0.0885	$ 0.2451	$ 0.2686	81%	19%	$ 1.78	$ 4.16	$ 9.33	$ 2.40	$ 17.67
August	51 M^3	630 kW.h	930 kW.h	$ 0.0429	$ 0.0896	$ 0.2494	$ 0.1578	81%	19%	$ 2.19	$ 4.57	$ 10.30	$ 1.53	$ 18.59
September	77 M^3	581 kW.h	1016 kW.h	$ 0.0429	$ 0.0896	$ 0.2494	$ 0.1578	81%	19%	$ 3.30	$ 6.90	$ 15.56	$ 2.31	$ 28.07
October	188 M^3	523 kW.h	1255 kW.h	$ 0.0429	$ 0.0896	$ 0.2494	$ 0.1578	81%	19%	$ 8.07	$ 16.84	$ 37.98	$ 5.64	$ 68.53
November	319 M^3	616 kW.h	1914 kW.h	$ 0.0429	$ 0.0896	$ 0.2213	$ 0.1578	96%	4%	$ 13.69	$ 28.58	$ 67.77	$ 2.01	$ 112.05
December	460 M^3	741 kW.h	2922 kW.h	$ 0.0429	$ 0.0896	$ 0.2213	$ 0.1578	96%	4%	$ 19.73	$ 41.22	$ 97.73	$ 2.90	$ 161.58
Total Avg (LICO +125)	2,769									$ 110.42	$ 246.26	$ 671.75	$ 44.38	$ 1,072.80

Weighted Avg Natural Gas Rate: **0.3874**

Calculation of the weighted average Electricity Rate - 2009

Weighted Average Electricity Rate for customers using Natural Gas for heating

2003 Consumption Month	Volume	kW.h	Rates 1st tier Rate (<175kW.h)	2nd tier Rate (>175kW.h)	Consumption by tier 1st tier Consumption	2nd tier Consumption	Billing by tier 1st tier Rate	2nd tier Rate	Total
January	861	kW.h	$ 0.0608	$ 0.0612	861	-	$ 52.35	$ -	$ 52.35
February	846	kW.h	$ 0.0608	$ 0.0612	846	-	$ 51.44	$ -	$ 51.44
March	777	kW.h	$ 0.0608	$ 0.0612	777	-	$ 47.24	$ -	$ 47.24
April	631	kW.h	$ 0.0625	$ 0.0630	631	-	$ 39.44	$ -	$ 39.44
May	548	kW.h	$ 0.0625	$ 0.0630	548	-	$ 34.25	$ -	$ 34.25
June	497	kW.h	$ 0.0625	$ 0.0630	497	-	$ 31.06	$ -	$ 31.06
July	587	kW.h	$ 0.0625	$ 0.0630	587	-	$ 36.69	$ -	$ 36.69
August	630	kW.h	$ 0.0625	$ 0.0630	630	-	$ 39.38	$ -	$ 39.38
September	581	kW.h	$ 0.0625	$ 0.0630	581	-	$ 36.31	$ -	$ 36.31
October	523	kW.h	$ 0.0625	$ 0.0630	523	-	$ 32.69	$ -	$ 32.69
November	616	kW.h	$ 0.0625	$ 0.0630	616	-	$ 38.50	$ -	$ 38.50
December	741	kW.h	$ 0.0625	$ 0.0630	741	-	$ 46.31	$ -	$ 46.31
Total Avg (LICO +125)	7,839						$ 485.65	$ -	$ 485.65

Weighted Avg Electricity Rate: **0.0620**

Weighted Average Electricity Rate for customers using Electricity for heating

2003 Consumption Month	Volume	kW.h	Rates 1st tier Rate (<175kW.h)	2nd tier Rate (>175kW.h)	Consumption by tier 1st tier Consumption	2nd tier Consumption	Billing by tier 1st tier Rate	2nd tier Rate	Total
January	3438	kW.h	$ 0.0608	$ 0.0612	900	2,538	$ 54.72	$ 155.40	$ 210.12
February	3575	kW.h	$ 0.0608	$ 0.0612	900	2,675	$ 54.72	$ 163.79	$ 218.51
March	3126	kW.h	$ 0.0608	$ 0.0612	900	2,226	$ 54.72	$ 136.30	$ 191.02
April	2231	kW.h	$ 0.0625	$ 0.0630	900	1,331	$ 56.25	$ 83.85	$ 140.10
May	1631	kW.h	$ 0.0625	$ 0.0630	900	731	$ 56.25	$ 46.05	$ 102.30
June	1124	kW.h	$ 0.0625	$ 0.0630	900	224	$ 56.25	$ 14.11	$ 70.36
July	916	kW.h	$ 0.0625	$ 0.0630	900	16	$ 56.25	$ 1.01	$ 57.26
August	930	kW.h	$ 0.0625	$ 0.0630	900	30	$ 56.25	$ 1.89	$ 58.14
September	1016	kW.h	$ 0.0625	$ 0.0630	900	116	$ 56.25	$ 7.31	$ 63.56
October	1255	kW.h	$ 0.0625	$ 0.0630	900	355	$ 56.25	$ 22.37	$ 78.62
November	1914	kW.h	$ 0.0625	$ 0.0630	900	1,014	$ 56.25	$ 63.88	$ 120.13
December	2922	kW.h	$ 0.0625	$ 0.0630	900	2,022	$ 56.25	$ 127.39	$ 183.64
Total Avg (LICO +125)	24,079				10,800	13,278	$ 670.41	$ 823.35	$ 1,493.76

Weighted Avg 1 st tier Electricity Rate: **0.0621**
Weighted Avg 2 nd tier Electricity Rate: **0.0620**

PUB/MH II-204

Reference: PUB/MH I-213 (b) Low Income Energy Burden

b) Please re-file the table utilizing natural gas prices based on rates reflecting natural rates at $0.34 per M3 and $0.30 per M3

ANSWER:

The energy costs and energy burdens for the natural gas heated residences shown in the chart on page 18 of the Bill Assistance Report have been recalculated by applying an assumed natural gas rate of $0.34 per m^3 and $0.30 per m^3 to the natural gas consumption level from the 2003 Residential Energy Use Survey. This calculation applies $0.34 per m^3 and $0.30 per m^3 to be representative of the bundle of all variable rate components including Primary Gas, Supplemental Gas, Transportation to Centra and Distribution to Customer. In addition to the bundled variable rate, the energy cost calculation also includes the annual amount for the Basic Monthly Charge. The results for the energy cost and energy burden for gas heated residences are shown in the tables below.

Natural Gas rate: $0.34 per m^3

Heat Source	**Energy Cost**	**Income**	**Energy Burden**
Electric	$1,684	$17,000	9.9%
Electric	$1,684	$24,000	7.0%
Gas	$1,802	$17,000	10.6%
Gas	$1,802	$24,000	7.5%

Natural Gas rate: $0.30 per m^3

Heat Source	**Energy Cost**	**Income**	**Energy Burden**
Electric	$1,684	$17,000	9.9%
Electric	$1,684	$24,000	7.0%
Gas	$1,685	$17,000	9.9%
Gas	$1,685	$24,000	7.0%

PUB/MH II-205

Reference: PUB/MH I-224 (b) SDG&E Program

Please indicate the level of the Public Goods Charge and the rate classes for which it is applied.

ANSWER:

Manitoba Hydro understands that the SDG&E Public Goods Charge, also known as Public Purpose Program (PPP) Charge, is that it reflects the cost of state-mandated programs, such as low-income and energy efficiency programs. The following links provide various rate schedules showing the differing PPP charges for SDG&E's customer classes.

http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_DR.pdf Residential

http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_A.pdf Small Commercial

http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_AL-TOU.pdf Medium/Large Commercial and Industrial

http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_PA.pdf Agricultural

http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_LS-1.pdf Lighting. The lighting PPP rate is based on a fixed charge per month, and an assumed usage level per lamp type.

http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_DWR-BC.pdf DWR Bond Charges

http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_EECC.pdf Commodity Charges

PUB/MH II-206

Reference: CAC/MSOS I-13 (k) Export Revenue Assumptions

Please adjust the table removing the impact of CAD/USD exchange rate impacts and indicate the average exchange rate used for each year.

ANSWER:

Please see the table below.

	MH07-1	**MH08-1**	**MH09-1**
Total Export Sales for 2009/10	6,608 GWh	7,901 GWh	9,149 GWh
Average USD Export Price for 2009/10	$57.7 / MWh	$65.0 / MWh	$32.2 / MWh
Average CDN Export Price for 2009/10	$51.2 / MWh	$72.0 / MWh	$45.0 / MWh
Average Exchange Rate for 2009/10	1.11	1.06	1.11
Total Export Sales for 2010/11	6,442 GWh	6,867 GWh	7,122 GWh
Average USD Export Price for 2010/11	$59.0 / MWh	$63.2 / MWh	$38.3 / MWh
Average CDN Export Price for 2010/11	$53.7 / MWh	$72.5 / MWh	$41.4 / MWh
Average Exchange Rate for 2010/11	1.11	1.06	1.07
Total Export Sales for 2011/12	7,066 GWh	7,191 GWh	7,843 GWh
Average USD Export Price for 2011/12	$61.0 / MWh	$61.8 / MWh	$60.2 / MWh
Average CDN Export Price for 2011/12	$56.6 / MWh	$76.8 / MWh	$68.8 / MWh
Average Exchange Rate for 2011/12	1.11	1.07	1.09

PUB/MH II-207

Reference: Domestic Values

Please define from a utility net revenue perspective (Domestic versus Exports), MH's actual average short-term positive or negative impacts (in ¢/KWh) from DSM activities in the following sectors:

	2007/08	2008/09	2009/10
▪ Residential Sector			
▪ GSS-ND			
▪ GSS-D			
▪ GSM			
▪ GSL <30			
▪ GSL 30-100			
▪ GSL >100			

ANSWER:

Manitoba Hydro does not allocate historical DSM savings by rate class. Further, it is not possible to link energy savings through DSM to a particular export sale. Even if that were possible, it is not appropriate to compare results within a single year. DSM programming is intended to influence domestic usage and export availability over a long period of time, and annual comparisons would be misleading.

<u>PUB/MH II-208</u>

Reference: PUB/MH I-209/IFF 09-1 Revenue & Cost Assumptions

a) Please provide the following (additional) information for each of the high, expected (mean?), and low price circumstances with respect to IFF 09-1:

- **Domestic sales and revenue ($M/GWh/¢/KWh).**
- **Retained earnings.**
- **Total debt.**
- **Debt/equity ratio.**

<u>ANSWER</u>:

Please see the attached schedules.

HIGH PRICE SENSITIVITY

	Manitoba Domestic Energy Sales (in GWh)	Manitoba Domestic Energy Sales (in millions of $)	Manitoba Domestic Energy Sales Average Price (in $/MWh)	Retained Earnings (in millions of $)	Total Debt * (in millions of $)	Debt/Equity Ratio
2010	23,968	1,160	48.40	2,227	8,168	74%
2011	24,346	1,193	48.99	2,315	8,680	75%
2012	24,728	1,246	50.39	2,509	9,161	75%
2013	25,075	1,305	52.03	2,717	9,483	74%
2014	25,413	1,365	53.69	2,999	10,066	75%
2015	26,030	1,441	55.36	3,259	11,184	75%
2016	26,439	1,510	57.13	3,709	12,614	75%
2017	26,790	1,582	59.05	4,187	13,996	75%
2018	26,743	1,653	61.80	4,652	15,032	74%
2019	26,929	1,725	64.07	5,156	15,367	73%
2020	27,229	1,805	66.30	5,771	15,849	71%
2021	27,551	1,862	65.52	6,419	16,367	69%
2022	27,893	1,920	64.72	7,219	15,826	67%
2023	28,363	1,981	63.65	8,141	15,857	64%
2024	28,638	2,044	63.04	9,437	15,859	59%
2025	28,979	2,110	62.29	10,873	15,861	53%
2026	29,379	2,182	61.45	12,579	15,264	46%
2027	29,795	2,257	60.59	14,422	15,266	38%
2028	30,215	2,334	59.75	16,412	15,268	29%
2029	30,600	2,409	58.99	18,554	15,210	20%

** Total Debt is the sum of total Long-Term Debt, Current Portion of Long-Term Debt and Total Short-Term Debt*

EXPECTED PRICES (IFF09-1)

	Manitoba Domestic Energy Sales (in GWh)	Manitoba Domestic Energy Sales (in millions of $)	Manitoba Domestic Energy Sales Average Price (in $/MWh)	Retained Earnings (in millions of $)	Total Debt * (in millions of $)	Debt/Equity Ratio
2010	23,968	1,160	48.40	2,227	8,168	74%
2011	24,346	1,193	48.99	2,315	8,680	75%
2012	24,728	1,246	50.39	2,396	9,278	76%
2013	25,075	1,305	52.03	2,479	9,744	76%
2014	25,413	1,365	53.69	2,616	10,466	78%
2015	26,030	1,441	55.36	2,738	11,784	79%
2016	26,439	1,510	57.13	2,997	13,382	80%
2017	26,790	1,582	59.05	3,268	14,980	80%
2018	26,743	1,653	61.80	3,515	16,232	80%
2019	26,929	1,725	64.07	3,772	16,838	80%
2020	27,229	1,805	66.30	4,059	17,449	79%
2021	27,551	1,862	65.52	4,366	18,167	79%
2022	27,893	1,920	64.72	4,816	18,026	78%
2023	28,363	1,981	63.65	5,369	18,657	76%
2024	28,638	2,044	63.04	6,113	18,659	73%
2025	28,979	2,110	62.29	6,918	18,661	70%
2026	29,379	2,182	61.45	7,840	18,064	66%
2027	29,795	2,257	60.59	8,859	18,066	61%
2028	30,215	2,334	59.75	9,986	18,068	56%
2029	30,600	2,409	58.99	11,223	18,010	51%

** Total Debt is the sum of total Long-Term Debt, Current Portion of Long-Term Debt and Total Short-Term Debt*

LOW PRICE SENSITIVITY

	Manitoba Domestic Energy Sales (in GWh)	Manitoba Domestic Energy Sales (in millions of $)	Manitoba Domestic Energy Sales Average Price (in $/MWh)	Retained Earnings (in millions of $)	Total Debt * (in millions of $)	Debt/Equity Ratio
2010	23,968	1,160	48.40	2,227	8,168	74%
2011	24,346	1,193	48.99	2,315	8,680	75%
2012	24,728	1,246	50.39	2,342	9,332	76%
2013	25,075	1,305	52.03	2,362	9,870	77%
2014	25,413	1,365	53.69	2,425	10,637	79%
2015	26,030	1,441	55.36	2,475	12,024	81%
2016	26,439	1,510	57.13	2,634	13,774	82%
2017	26,790	1,582	59.05	2,794	15,491	83%
2018	26,743	1,653	61.80	2,921	16,838	83%
2019	26,929	1,725	64.07	3,041	17,611	84%
2020	27,229	1,805	66.30	3,139	18,449	84%
2021	27,551	1,862	65.52	3,248	19,167	84%
2022	27,893	1,920	64.72	3,495	19,426	83%
2023	28,363	1,981	63.65	3,818	20,057	83%
2024	28,638	2,044	63.04	4,203	20,259	81%
2025	28,979	2,110	62.29	4,591	20,261	80%
2026	29,379	2,182	61.45	4,982	19,664	78%
2027	29,795	2,257	60.59	5,436	19,666	76%
2028	30,215	2,334	59.75	5,965	19,668	74%
2029	30,600	2,409	58.99	6,572	19,610	71%

** Total Debt is the sum of total Long-Term Debt, Current Portion of Long-Term Debt and Total Short-Term Debt*

PUB/MH II-208

Reference: PUB/MH I-209/IFF 09-1 Revenue & Cost Assumptions

b) Please confirm that MH anticipated the combined effect of natural gas prices and carbon adders could support average unit prices as follows:

	High Prices		Expected Prices		Low Prices	
	Export ¢/KWh	Import ¢/KWh	Export ¢/KWh	Import ¢/KWh	Export ¢/KWh	Import ¢/KWh
2009/10	3.62	5.32	3.62	5.32	3.62	5.32
2010/11	4.10	3.86	4.10	3.86	4.10	3.86
2011/12	8.55	7.70	6.59	6.53	5.61	5.98
2012/13	8.75	7.98	6.59	6.68	5.61	6.10
2014/15	9.59	8.17	7.17	6.91	5.98	6.34
2019/20	14.01	9.39	10.60	7.05	8.44	6.43
2024/25	15.39	11.23	11.94	9.61	9.44	7.37
2029/30	18.71	11.80	13.86	9.48	10.05	7.64

ANSWER:

Manitoba Hydro does not accept that only natural gas prices and carbon adders comprise average unit prices for imports and exports. There are many factors that affect the price of export sales and cost for import energy that Manitoba Hydro experiences. As explained in the response to question PUB/MH I-156(a):

> "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."

The above discussion confirms that natural gas price and carbon adders are two of the many factors that influence the unit prices in the table that is provided in the information request.

Manitoba Hydro has the following comments on the summarized information provided in the table in this information request which appears to be derived from the response to PUB/MH I-209. Manitoba Hydro is able to verify many of the unit prices as part of the information provided in PUB/MH I-209, however there are also many errors in the table provided in the information request. The correct unit prices have been inserted into a revised table that is provided below with the revised unit prices shown in red, italic format and the hatched border style.

	High Prices		**Expected Prices**		**Low Prices**	
	Export ¢/KWh	**Import ¢/KWh**	**Export ¢/KWh**	**Import ¢/KWh**	**Export ¢/KWh**	**Import ¢/KWh**
2009/10	3.62	5.32	3.62	5.32	3.62	5.32
2010/11	4.10	3.86	4.10	3.86	4.10	3.86
2011/12	8.55	*7.56*	6.59	6.53	5.61	5.98
2012/13	*8.76*	7.70	*6.69*	6.68	5.61	6.10
2014/15	*9.69*	8.17	*7.39*	*7.05*	*6.13*	6.34
2019/20	14.01	9.39	*10.56*	*7.62*	8.44	6.43
2024/25	15.39	11.23	11.94	*9.01*	9.44	7.37
2029/30	18.71	11.80	13.86	9.48	10.05	7.64

PUB/MH II-208

Reference: PUB/MH I-209/IFF 09-1 Revenue & Cost Assumptions

c) Please explain the logic behind the increase in the spread (divergence) of export and import prices after 2014/15:

- **High price scenario - 1.5¢/KWh differential going to 7¢/KWh.**
- **Expected price scenario - 0.5¢/KWh differential going to 4¢/KWh.**
- **Low price scenario - minus 0.5¢/KWh differential going to 2.5¢/KWh.**

ANSWER:

The increased spread between import and export prices begins to occur after 2018/19 which is the date of the new interconnection to the U.S. that is associated with the export sales to MP and WPS. The increased spread is not due to a divergence in the forecasted market prices of the export and import energy; rather it is due to the characteristics of Manitoba Hydro's ability to participate in the electricity export and import market.

Manitoba Hydro does not assume that there is a single price for export and import energy in each on-peak and off-peak period. Instead, a price structure is defined separately for exports and imports, which represents the variability of prices over the hours of the month and Manitoba Hydro's limited ability to access the market through the use of interconnections. The reason for the increased spread between import and export prices after 2018/19 is that the new interconnection to the U.S. allows more export energy to be sold at higher prices, thus increasing the average price of export energy after 2018/19. Similarly, the new interconnection increases the capability to import more low priced energy and this has the effect of decreasing the average price of imports after 2018/19. The combined effects of increased export prices and reduced import costs results in the increased spread which begins to occur after 2018/19.

PUB/MH II-208

Reference: PUB/MH I-209/IFF 09-1 Revenue & Cost Assumptions

d) Is it MH's position that future export prices will be driven by <u>both</u> rising natural prices and CO_2 implications for both coal and natural gas generation? Explain.

ANSWER:

Please refer to the response to PUB/MH II-208(b) which states that future export prices will be driven by many factors including rising natural gas prices and CO_2 implications for both coal and natural gas generation.

<u>PUB/MH II-208</u>

Reference: PUB/MH I-209/IFF 09-1 Revenue & Cost Assumptions

e) Is it MH's position that future import prices will <u>not</u> be affected by <u>both</u> rising natural gas prices and CO_2 implications for coal and natural gas generation? Explain.

<u>ANSWER</u>:

It is not Manitoba Hydro's position that future import prices will not be affected by both rising natural gas prices and CO_2 implications for coal and natural gas generation. Import prices for the same hours are related to export prices and thus would be affected by the same factors. The reason for the increased spread between export and import prices is described in the response to PUB/MH II-208(d). This response indicates that it is the addition of the interconnection that causes a change in Manitoba Hydro's ability to export and import greater volumes of energy when prices are more attractive.

In summary, the increased spread between export and import prices after 2018/19 is not due to rising natural gas prices and consideration of CO2 having a different effect on export and import prices. The increased spread is the result of the addition of the interconnection in 2018/19.

PUB/MH II-209

Reference: **PUB/MH I-75/PUB/MH I-81(a) Historic & Current Potential Hydraulic Generation.**

a) Please confirm and explain the increased system output currently being forecast for:

- **Pre-1980.**
- **1980 to 1986.**
- **1987 to 1993.**
- **1996 and 1997.**
- **1999 and 2000.**
- **2004 and 2005.**

Year	Historical Annual Hydraulic Energy (GWh)	PUB/MH I-81(a) Current System Output (GWh)	Increase (GWh)	Increase (%)
1978	17,065	31,927	14,862	87
1979	20,530	33,632	13,102	64
1980	19,186	25,825	6,639	34
1981	17,989	22,798	4,809	27
1982	20,587	30,392	9,805	48
1983	21,977	29,677	7,700	35
1984	21,312	26,734	5,424	25
1985	22,498	33,347	10,849	48
1986	23,924	34,508	10,584	44
1987	19,392	22,950	3,558	18
1988	15,463	19,445	3,982	26
1989	18,409	24,863	6,454	35
1990	19,837	24,732	4,895	25
1991	22,660	25,248	2,583	11
1992	26,540	30,307	3,767	14
1993	26,972	29,548	2,576	10
1994	28,249	28,200	(49)	0
1995	29,115	29,479	364	1
1996	30,976	34,459	3,483	11
1997	33,493	36,215	2,722	8
1998	30,876	30,012	(864)	(3)

Year	Historical Annual Hydraulic Energy (GWh)	PUB/MH I-81(a) Current System Output (GWh)	Increase (GWh)	Increase (%)
1999	**28,233**	**30,039**	**1,806**	**6**
2000	**31,638**	**32,517**	**879**	**3**
2001	**32,999**	**32,908**	**(91)**	**(1)**
2002	**29,006**	**28,990**	**(16)**	**0**
2003	**20,348**	**20,182**	**(166)**	**(1)**
2004	**27,338**	**33,577**	**6,239**	**23**
2005	**36,543**	**37,646**	**1,103**	**3**
2006	**33,736**			
2007	**33,612**			
2008	**34,690**			

<u>ANSWER</u>:

The "Historical Annual Hydraulic Energy" that was utilized in the table was based on a calendar year period, and should not be used in the comparison with "Current System Output" which is based on a fiscal year period. The "Historical Annual Hydraulic Energy" estimate has been revised in the table below to make it consistent with a fiscal year summary. The "Current System Output" is derived from the year 2011/12 which includes an average of about 880 GW.h of energy production from the Wuskwatim Generating Station. In order to make the comparison more consistent with the historical energy production, the Wuskwatim energy was removed and a revised summary of "Current System Output" is provided in the table below.

The revised difference between the historical and current estimated hydraulic energy production is summarized in the table below. The difference pre-1980 is due to the fact that Long-Spruce and Limestone Generating Stations do not exist in the historical record. The difference for the period between 1980 and 1991 is due to Limestone not being in service over this period in the historical record. The differences are relatively small in the period 1992 to 2005 since the composition of the system is common between the two cases.

Fiscal Year Beginning	Historical Annual Hydraulic Energy (GWh)	PUB/MH I-81(a) Current System Output (GWh)	Increase (Decrease) (GWh)	Increase (Decrease) (%)
1978	18,622	30,996	12,373	66
1979	20,704	32,721	12,017	58
1980	18,483	24,905	6,422	35

Fiscal Year Beginning	Historical Annual Hydraulic Energy (GWh)	PUB/MH I-81(a) Current System Output (GWh)	Increase (Decrease)	
			(GWh)	(%)
1981	17,722	21,929	4,207	24
1982	21,606	29,505	7,899	37
1983	21,905	28,788	6,883	31
1984	20,970	25,852	4,882	23
1985	23,156	32,443	9,287	40
1986	23,966	33,602	9,636	40
1987	18,034	22,070	4,036	22
1988	15,237	18,559	3,322	22
1989	18,673	23,977	5,303	28
1990	20,565	23,896	3,331	16
1991	23,626	24,368	742	3
1992	27,608	29,406	1,799	7
1993	27,199	28,803	1,604	6
1994	27,914	27,347	(567)	(2)
1995	29,122	28,605	(517)	(2)
1996	31,679	33,554	1,875	6
1997	33,759	35,293	1,535	5
1998	29,111	29,239	128	0
1999	29,471	29,133	(337)	(1)
2000	31,826	31,593	(233)	(1)
2001	32,152	32,038	(114)	(0)
2002	28,567	28,133	(433)	(2)
2003	18,484	19,383	899	5
2004	31,134	32,675	1,541	5
2005	37,218	36,717	(501)	(1)
2006	31,610			
2007	34,897			
2008	34,193			

PUB/MH II-209

Reference: PUB/MH I-75/PUB/MH I-81(a) Historic & Current Potential Hydraulic Generation.

b) Please complete the above table to 2009.

ANSWER:

Manitoba Hydro has not derived the unregulated inflows past the year 2005/06 and has not undertaken a simulation of system operation for these years. Consequently, there is no information available to update the table as requested.

PUB/MH II-210

Reference: PUB/MH I-206/PUB/MH I-90 Fiscal 1988 1992 Flows & Hydraulic Generation

a) Please confirm that the energy supply (pre-Limestone G.S.) situation in 1987/88 to 1991/92 was as follows:

	Nelson River @ Kettle (cfs)	Major Stream Inflow (cfs)	Historical System Generation (GWh)
1987/88	94,000	68,000	18,000
1988/89	74,000	63,000	15,200
1989/90	90,000	80,000	18,600
1990/91	89,500	75,000	20,500
1991/92	89,000	74,000	23,600

ANSWER:

Manitoba Hydro cannot confirm that all of the values in the table are correct since it did not provide these values in this form. If the annual values in this table were derived from the monthly values provided in PUB/MH I-75 correctly, the Nelson River flow and the historical system hydraulic generation should be representative of the historic information. It is not known what components comprise the "Major Stream Inflow", and therefore these values cannot be confirmed.

PUB/MH II-210

Reference: PUB/MH I-206/PUB/MH I-90 Fiscal 1988 1992 Flows & Hydraulic Generation

b) Please confirm that MH's 5-year drought evaluation for 2011/12 to 2016/17 employed the following 1987/88 to 1991/92 post-Wuskwatim hydraulic generation values:

In PUB/MH I-206	**In PUB/MH I-90**
• **1987/88 - 22,900 GWh (30,000-7,100).**	**22,353 GWh**
• **1988/89 - 19,300 GWh (30,000-10,700).**	**18,850 GWh**
• **1989/90 - 25,000 GWh (30,000-5,000).**	**24,274 GWh**
• **1990/91 - 24,400 GWh (30,000-5,600).**	**24,162 GWh**
• **1991/92 - 25,200 GWh (30,000-4,800).**	**24,468 GWh**

ANSWER:

Manitoba Hydro is unable to confirm that the values in the table provided in the information request are for post-Wuskwatim hydraulic generation.

The values in the second column do not include Wuskwatim generation and therefore are representative of pre-Wuskwatim development. It should be noted that the value of 24,468 GW.h as the last value in the second column should be 24,658 GW.h as provided in the response to PUB/MH I-90.

In the first column it appears that the deviation from average was utilized to infer the hydraulic generation in each year. The deviation from average hydraulic generation was provided in the response to PUB/MH I-206. The hydraulic generation in the first column for each year assumed that 30,000 GW.h is the estimate of average post-Wuskwatim hydraulic generation. It would have been more appropriate to utilize a hydraulic generation value of

29,200 GW.h as the pre-Wuskwatim average annual generation since the hydraulic generation in the second column does not include Wuskwatim generation. The use of 29,200 GW.h would reduce the difference in the estimates of hydraulic energy generation between the two columns.

PUB/MH II-211

Reference: PUB/MH I-143 Absence of Bipole I and II

a) Please indicate (in the event of a Bipoles I and II outage during the four winter months of December, January, February, and March), what MH's revenue shortfall (with respect to IFF 09-1) would be:

	Imports for Domestic	Foregone Exports	Reduced Water Rentals	Total
2009/10	___ GWh @___ ¢/KWh	___ GWh @____ ¢/KWh	___ GWh @ ____ ¢/KWh	_____ $M
2023/24	___ GWh @____ ¢/KWh	___ GWh @ ___¢/KWh	___ GWh @___ ¢/KWh	_____ $M

ANSWER:

In order to respond to this information request, it would be necessary to undertake a complex analysis of system operation under each of 94 flow conditions with reduced energy supply due to a Bipole I and II outage. Manitoba Hydro is unable to provide the requested information in the timeframe that is available for responses.

PUB/MH II-211

Reference: PUB/MH I-143 Absence of Bipole I and II

b) Please indicate (in the event of a Bipole I and II outage during the four summer months of June, July, August, and September), what MH's revenue shortfall (with respect to IFF 09-1) would be:

	Imports for Domestic	Foregone Exports	Reduced Water Rentals	Total
2009/10	___ GWh @ ___¢/KWh	___ GWh @ ____¢/KWh	___ GWh @ ___¢/KWh	_____ $M
2023/24	___ GWh @___ ¢/KWh	___ GWh @___ ¢/KWh	___ GWh @___ ¢/KWh	_____ $M

ANSWER:

In order to respond to this information request, it would be necessary to undertake a complex analysis of system operation under each of 94 flow conditions with reduced energy supply due to a Bipole I and II outage. Manitoba Hydro is unable to provide the requested information in the timeframe that is available for responses.

PUB/MH II-212

Reference: PUB/MH I-75; PUB/MH I-89/PUB/MH I-90 Historic Post-LWR/CRD Flows and Hydraulic Generation

a) With respect to the following table of historic post-LWR/CRD flows and hydraulic generation, which is an approximate restatement of data supplied by MH, please confirm that on an approximate proportional basis that post-Limestone G.S. annual average inflows from:

- **The Burntwood River (CRD) system have ranged from 20,700 cfs (equivalent to about 3,900 GWh) to 37,000 cfs (equivalent to about 6,900 GWh).**
- **The Saskatchewan River system have ranged from 7,500 cfs (equivalent to about 2,100 GWh) to 37,700 cfs (equivalent to about 9,100 GWh).**
- **The Red River system have ranged from 5,100 cfs (equivalent to about 1,100 GWh) to 21,000 cfs (equivalent to about 3,900 GWh); between 1980 and 1992 lower flow occurred six times.**
- **The Winnipeg River System have ranged from 18,100 cfs (equivalent to about 6,900 GWh) to 5,200 cfs (equivalent to about 15,200 GWh); between 1980 and 1992 lower flows occurred twice.**
- **The Lake Winnipeg/Nelson River local drainage and net storage have ranged from 5,300 cfs (equivalent to about 1,800 GWh) to 47,800 cfs (equivalent to about 8,100 GWh).**

ANSWER:

Manitoba Hydro is not prepared to confirm the information in the table that is provided in the information request because it requests confirmation of confidential information. This information was not developed by Manitoba Hydro and it involves specific water flows and potential generation from post-Limestone development for the range of flow conditions. Such information is considered to be proprietary and commercially sensitive since it can be used to assess characteristics of Manitoba Hydro’s hydraulic resource.

<u>PUB/MH II-212</u>

Reference: PUB/MH I-75; PUB/MH I-89/PUB/MH I-90 Historic Post-LWR/CRD Flows and Hydraulic Generation

b) Please complete the table for 2008/09 and 2009/10.

<u>ANSWER</u>:

As stated in the response to PUB/MH II-212(a) Manitoba Hydro considers that the requested information on potential generation from post-Limestone development is proprietary and commercially sensitive since it can be used to assess characteristics of Manitoba Hydro's hydraulic resource. Therefore, the information to complete the table is not provided.

PUB/MH II-212

Reference: **PUB/MH I-75; PUB/MH I-89/PUB/MH I-90 Historic Post-LWR/CRD Flows and Hydraulic Generation**

c) Please provide a revised table employing post-limestone generation capacity for the entire 1978 to date period.

	Total Hydraulic Generation (GWh)	Burntwood River		Saskatchewan River		Red River		Winnipeg River		Calculated Net Local Inflow and Storage		Lower Nelson River (1,000 cfs)	Total Major Stream Inflow (1,000 cfs)	Energy in Storage Change (GWh)
		(1,000 cfs)	(GWh)	(1,000 cfs)	(GWh)	(1,000 cfs)	(GWh)	(1,000 cfs)	(GWh)	(1,000 cfs)	(GWh)			
1978/79	17,400	30.8	2,700	20.0	2,200	7.1	800	37.5	8,700	10.3	1,500	105.7	95.4	+2,700
1979/80	20,600	30.5	3,000	17.9	3,400	14.0	1,600	34.9	8,400	31.4	4,200	128.7	97.3	+600
1980/81	18,500	32.4	3,900	16.8	3,800	2.9	400	21.0	6,100	24.4	4,300	97.5	73.1	-3,800
1981/82	18,000	28.4	3,700	23.1	5,000	2.5	300	18.0	6,000	9.1	2,400	81.1	72.0	-2,300
1982/83	21,500	28.5	3,500	18.3	4,100	8.0	1,200	35.1	9,400	17.0	3,300	106.9	89.9	+3,900
1983/84	21,800	31.0	3,800	19.1	4,300	7.2	1,100	25.7	7,600	42.1	5,000	112.1	73.0	-600
1984/85	22,000	34.7	4,300	15.7	3,600	6.1	900	27.3	8,100	21.1	5,100	104.9	83.8	-4,100
1985/86	23,100	32.6	3,400	25.6	4,700	8.3	1,000	38.6	9,300	32.4	4,700	137.5	105.1	+5,100
1986/87	23,900	31.4	3,600	22.2	4,400	10.5	1,400	33.7	8,700	35.0	5,500	133.8	97.8	-3,000
1987/88	18,000	32.7	4,000	14.4	3,300	5.9	900	15.2	4,800	25.9	5,000	94.1	68.2	-3,900
1988/89	15,200	30.1	3,800	11.8	2,700	1.9	300	19.7	6,000	10.4	2,400	73.9	63.5	-200
1989/90	18,600	31.0	3,700	12.4	2,800	4.0	300	32.1	8,900	11.5	2,600	90.0	79.5	-100
1990/91	20,500	26.4	3,700	22.3	5,600	2.4	400	24.3	7,600	14.1	3,200	89.5	75.4	-700
1991/92	23,600	30.8	5,600	14.2	4,100	3.6	800	25.7	9,300	14.3	3,800	88.6	74.3	+3,000
1992/93	27,600	30.5	5,600	12.7	3,600	5.1	1,100	50.3	14,900	8.2	2,400	106.8	98.6	+1,300
1993/94	28,200	20.7	3,900	24.7	7,200	10.3	2,200	34.8	11,600	12.8	3,300	103.3	90.5	+200
1994/95	28,200	24.2	4,600	16.3	4,800	10.0	2,200	34.1	11,700	19.3	4,900	103.9	84.6	+300
1995/96	39,400	23.6	4,500	18.3	5,600	7.3	1,600	31.8	11,300	26.8	6,400	107.8	81.0	-300
1996/97	30,100	29.0	4,900	24.1	6,400	14.5	2,700	46.9	11,700	20.6	4,440	135.1	114.5	+2,800
1997/98	32,500	34.9	5,900	21.9	5,800	21.0	3,900	33.2	8,800	39.5	8,100	150.5	111.0	+1,200
1998/99	29,000	36.0	6,700	17.1	5,000	11.4	2,400	19.5	7,200	31.8	7,700	115.8	84.0	-5,100
1999/00	28,800	27.0	5,100	21.2	6,300	16.2	3,500	38.5	13,000	3.0	1,100	105.9	102.9	+2,000
2000/01	31,800	36.6	6,900	12.2	3,500	10.0	2,100	41.4	13,300	34.3	6,000	124.5	90.2	+100
2001/02	32,100	29.9	5,400	7.5	2,100	14.5	2,900	48.8	14,400	33.8	7,300	134.5	100.7	-3,000
2002/03	29,500	29.7	5,400	15.7	5,500	10.3	2,100	36.5	11,100	21.6	5,400	113.9	92.3	-2,100
2003/04	18,500	24.6	4,700	8.6	2,600	5.1	1,100	18.1	6,900	10.0	3,200	66.4	56.4	+1,800
2004/05	31,200	31.4	5,800	19.5	5,700	12.7	2,700	50.2	15,200	5.3	1,800	118.9	113.6	+5,800
2005/06	37,100	31.4	4,700	37.7	9,100	18.1	3,000	47.0	12,200	47.8	8,100	182.0	134.2	+600
2006/07	31,200	37.2	6,600	28.4	8,000	12.4	2,500	22.2	7,400	32.7	6,700	132.9	100.2	-4,100
2007/08	34,800	37.1	6,900	29.1	8,300	12.7	2,600	36.6	11,800	21.9	5,200	137.4	115.5	+3,100
2008/09														-300
2009/10														

ANSWER:

As stated in the response to PUB/MH II-212(a) Manitoba Hydro considers that the requested information on potential generation from post-Limestone development is proprietary and commercially sensitive since it can be used to assess characteristics of Manitoba Hydro's hydraulic resource. Therefore, a revised table employing post-limestone generation capacity is not provided.

<u>PUB/MH II-213</u>

Reference: PUB/MH I-164 (a) Level Export Obligations Under Low Flow Conditions

a) Please confirm that MH continues to have an obligation to purchase power and/or thermally generate energy to meet all its current and pending contractual commitments when hydraulic generation is at or above dependable energy levels of approximately:

- **22,000 GWh in 2014/15.**
- **25,000 GWh in 2019/20 (after Keeyask G.S.).**
- **30,000 GWh in 2024/25 (after Conawapa G.S.).**

<u>ANSWER</u>:

Manitoba Hydro's long-term export contracts define circumstances during which Manitoba Hydro has the right to curtail a portion or all of its export obligations without penalty. During these events Manitoba Hydro has the option to continue to serve the sale. During other circumstances (including water supply conditions at or above dependable flows) that are not excused under the contract, Manitoba Hydro is obligated to continue supplying power using purchased power or by utilizing Manitoba thermal generation.

PUB/MH II-213

Reference: PUB/MH I-164 (a) Level Export Obligations Under Low Flow Conditions

b) Please explain and quantify the level of obligation to purchase power and/or thermally generate energy to meet all or a portion of its current and pending contractual commitments when hydraulic generation falls significantly below the above dependable energy levels (less than the worst case on record) as listed:

- **15,000 GWh in 2014/15.**
- **25,000 GWh in 2019/20 (after Keeyask G.S.).**
- **30,000 GWh in 2024/25 (after Conawapa G.S.).**

ANSWER:

Should water supply conditions occur below the historic minimum of record, this would qualify as a "force majeure" event under Manitoba Hydro's existing long-term contracts and as such would be treated as a curtailment event as described in the response to PUB/MH II-213(a).

Under the proposed sale agreements to MP and WPS such an extreme occurrence would relieve Manitoba Hydro of all its supply and financial obligations.

However, under both existing and proposed agreements it may be financially or otherwise advantageous for Manitoba Hydro to continue supplying all or a portion of its obligations in spite of having a curtailment right.

PUB/MH II-213

Reference: PUB/MH I-164 (a) Level Export Obligations Under Low Flow Conditions

c) Please confirm that a new record low flow scenario would not release MH from its total contract obligations to supply energy.

ANSWER:

Under the existing export contracts, Manitoba Hydro is relieved of its delivery obligations only to the extent necessary to serve higher priority load including Manitoba firm load.

Under the proposed sales to MP and WPS in the circumstances of a new low flow event, Manitoba Hydro would be relieved of all its contract obligations.

PUB/MH II-214

Reference: PUB/MH I-157(a); PUB/MH I-143(e) Import Capacity Requirements

a) Please indicate whether MH's current import capacity is in excess of identified drought scenario requirements.

ANSWER:

As indicated in the response to PUB/MH II-218(a), the Manitoba Hydro system of energy supply is planned and operated to be able to provide electricity under a repeat of the most severe period of low water supply, which corresponds to a seven year drought period from 1936 to 1942. The dependable energy supply of the Manitoba Hydro system includes thermal generation and contracted imports in addition to hydraulic energy under low flows. It is confirmed that the import capability of the interconnections is in excess of the import requirement for contracted imports during this low flow period.

PUB/MH II-214

Reference: PUB/MH I-157(a); PUB/MH I-143(e) Import Capacity Requirements

b) Please file an updated summary of export and import capabilities to/from the U.S./Ontario/Saskatchewan.

ANSWER:

Please refer to Page 2 of the response to PUB/MH I-6(f) which provides the transfer capability limits for exports and imports. The 2009 information is representative of current capabilities.

<u>PUB/MH II-214</u>

Reference: PUB/MH I-157(a); PUB/MH I-143(e) Import Capacity Requirements

c) Please discuss the need, if any, for enhanced import capacity in the context of 2003/04 actual imports. (Approximately 10,000 GWh)

<u>ANSWER</u>:

The actual imports in the 2003/04 drought were significantly less than 10,000 GW.h. The purchases in that year were about 9600 GW.h which included about 2600 GW.h of buyback of export contract obligations which did not require transmission capability. In addition, about 1000 GW.h of the import energy was obtained from Canadian sources. Therefore, the actual U.S. import was about 6000 GW.h, which would require about 685 MW of import capability on a continuous basis over a year. This capability requirement is well below the existing U.S. import transfer capability which is in the order of 850 MW.

PUB/MH II-215

Reference: PUB/MH I-201 Domestic Revenue Forecasts

a) Please confirm the following table is an expansion of the response to PUB/MH I-201 Domestic Load and Revenue Forecasts.

	F2009	F2010	F2011	F2012	F2016	F2020	F2024	F2028
Total Sales	**21,210**							
Domestic Revenue								
IFF 09-1	**$1,127 M**	**$1,160 M**	**$1,191 M**	**$1,246 M**	**$1,510 M**	**$1,805 M**	**$2,044 M**	**$2,344 M**
IFF 08-1	**$1,110 M**	**$1,204 M**	**$1,272 M**	**$1,335 M**	**$1,549 M**	**$1,759 M**	**$1,829 M**	**$1,902 M**
Variance	**+$17 M**	**-$44 M**	**-$119 M**	**-$89 M**	**-$39 M**	**+$48 M**	**+$215 M**	**+$432 M**
Domestic Load at Generation								
IFF 09-1 (GWh)	**24,262**	**23,968**	**24,346**	**24,728**	**26,439**	**27,229**	**26,638**	**30,215**
IFF 08-1 (GWh)	**24,117**	**24,875**	**25,488**	**26,050**	**27,296**	**28,167**	**29,517**	**30,761**
Variance	**+145**	**-907**	**-1,142**	**-1,322**	**-857**	**-939**	**-879**	**-545**
Average Domestic Revenue at Generation								
IFF 09-1 (¢/KWh)	**4.645**	**4.84**	**4.89**	**5.039**	**5.713**	**6.630**	**7.138**	**7.724**
IFF 08-1 (¢/KWh)	**4.60**	**4.84**	**4.99**	**5.123**	**5.676**	**6.239**	**6.197**	**6.182**

ANSWER:

Please note that the table below has been updated for IFF08-1 as some of the data points were incorrect in PUB/MH I-201.

Domestic Revenue		2009	2010	2011	2012	2016	2020	2024	2028
IFF09-1	Act	1,127	1,160	1,193	1,246	1,510	1,805	2,044	2,334
IFF08-1		1,110	1,204	1,272	1,335	1,549	1,808	2,107	2,453
Variance		17	(44)	(79)	(89)	(39)	(2)	(63)	(119)

Domestic Sales Avg Price (¢/KW.h)	2009	2010	2011	2012	2016	2020	2024	2028
IFF09-1	4.645	4.840	4.899	5.039	5.713	6.630	7.138	7.724
IFF08-1	4.601	4.840	4.990	5.123	5.676	6.417	7.137	7.974

Domestic Load @ Generation (GW.h)	2009	2010	2011	2012	2016	2020	2024	2028
IFF09-1	24,262	23,968	24,346	24,728	26,439	27,229	28,638	30,215
IFF08-1	24,117	24,875	25,489	26,050	27,296	28,167	29,517	30,761
Variance	145	(907)	(1,143)	(1,322)	(857)	(939)	(879)	(545)

<u>PUB/MH II-215</u>

Reference: PUB/MH I-201 Domestic Revenue Forecasts

b) Please confirm that in F2009, MH's domestic results were achieved in actual sales of 21,240 GWh implying an average <u>sales rate</u> of 5.31¢/KWh (or 1.143 x average revenue at generation).

<u>ANSWER</u>:

Confirmed, with the exception that actual sales were 21,210 GWh implying an average sales rate of 5.31¢/kWh or 1.142 x average revenue at Generation.

PUB/MH II-215

Reference: PUB/MH I-201 Domestic Revenue Forecasts

c) Please confirm (or vary) the assumption that the "domestic sales average price" in PUB/MH I-201 at the point of sales would be almost 15% higher than the values provided above.

ANSWER:

Confirmed.

PUB/MH II-215

Reference: PUB/MH I-201 Domestic Revenue Forecasts

d) Please confirm that in IFF 09-1 that MH's projected domestic rates for electricity in 2028 would be about 166% of the current F2010 rates; IFF 08-1 would have seen 2028 rates at about 128% of current 2010 rates.

ANSWER:

Please see revised Average Domestic Revenue rates for PUB/MH I-201.

Domestic Sales Avg Price ($Cdn/MW.h)	2012	2016	2020	2024	2028
IFF09-1	50.39	57.13	66.30	71.38	77.24
IFF08-1	51.23	56.76	64.17	71.37	79.74
Variance	(0.84)	0.36	2.13	0.01	(2.50)

For IFF09-1 fiscal year 2027/28, cumulative rate increases would be 63.4% over 2009/10. IFF08-1 cumulative rate increases were forecasted to be 67.3% over 2009/10.

PUB/MH II-215

Reference: PUB/MH I-201 Domestic Revenue Forecasts

e) Please define and explain the primary factors driving (justifying) the higher 2028 revenue requirement of $2,588 M in IFF 09-1 versus $2,051 M in IFF 08.1

ANSWER:

Total domestic revenue forecast in IFF09 is $2,334 M in 2028, which is lower than the domestic revenue forecast in IFF08 of $2,453 M in 2028.

<u>PUB/MH II-216</u>

Reference: PUB/MH I-157(a); PUB/MH I-206 Drought Pricing of Imports

a) Please confirm that MH analysis of a 5-year drought during 2011/12 to 2015/16 contemplates:

- **Revenue losses of $1,124 (17,318 GWh @ 6.49¢/KWh), but retains export revenues of $1,715 M (21,700 @ 7.9¢/KWh).**
- **Additional imports costing $594 M (9,500 @ 6.25¢/KWh).**
- **Additional thermal generation costing $396 M (3,850 GWh @ 10.3¢/KWh).**

<u>ANSWER</u>:

Manitoba Hydro confirms the information relating to revenue losses from exports, the additional costs of imports and the additional thermal generation which can be derived from the response to PUB/MH I-206(a). Manitoba Hydro is unable to confirm the information related to retained export revenues during the referenced 5-year drought.

<u>PUB/MH II-216</u>

Reference: PUB/MH I-157(a); PUB/MH I-206 Drought Pricing of Imports

b) Given that MH typically has about 10,000 GWh (2,000 GWh/year) of contract commitments @ about 6¢/KWh, does it follow that opportunity sales of about 12,000 GWh would require prices of about 10¢/KWh to achieve a total export average of 7.9¢/KWh.

<u>ANSWER</u>:

Given the information assumed in the information request, the calculation of the opportunity sales price appears correct. However, the energy quantities and price for contract commitments and the quantity for opportunity sales for the referenced 5-year drought period do not appear to be accurate. Manitoba Hydro cannot provide information on the breakdown of volumes and prices for contract energy export sales as it is commercially sensitive and would in some circumstances violate confidentiality agreements with counterparties.

PUB/MH II-216

Reference: PUB/MH I-157(a); PUB/MH I-206 Drought Pricing of Imports

c) Please explain and quantify the energy market scenario which would support opportunity export sales at 10¢/KWh and coincidentally allow MH to purchase energy at about 6¢/KWh.

ANSWER:

As indicated in PUB/MH II-216(b) Manitoba Hydro cannot confirm the opportunity sale price. If the sale price was correct, it would be possible to have this differential between opportunity sales during on-peak periods and purchases during off-peak periods.

PUB/MH II-216

Reference: PUB/MH I-157(a); PUB/MH I-206 Drought Pricing of Imports

d) Can MH confirm that import prices of 10¢/KWh for drought shortfalls and IFF 09-1 scheduled (non-contract) imports could result in a further net income reduction of about $400M.

ANSWER:

Based on assumptions in PUB/MH II-216(a) for the price of additional imports of 6.25¢/KWh, Manitoba Hydro can confirm that import prices of 10¢/kWh could result in a further net income reduction of about $400M during the referenced 5-year drought.

PUB/MH II-216

Reference: PUB/MH I-157(a); PUB/MH I-206 Drought Pricing of Imports

e) Please provide an alternative drought impact analysis (as above) and include the impact on finance costs.

ANSWER:

Manitoba Hydro is not able to provide this analysis within the timeframe available to respond to this second round information request.

PUB/MH II-217

Reference: PUB/MH I-157(a)/ CAC/MSOS/MH I-62(g): Shortage Pricing

a) Please revise the tabular responses to PUB/MH I-157(a) to reflect import prices (for all imports) at the same level as forecast peak opportunity export prices within each drought scenario and time frames.

ANSWER:

This represents a significant amount of new work and Manitoba Hydro is not able to provide this analysis within the timeframe available to respond to this second round information request.

<u>PUB/MH II-217</u>

Reference: PUB/MH I-157(a)/ CAC/MSOS/MH I-62(g): Shortage Pricing

b) Please revise the tabular responses to PUB/MH I-157(a) to reflect export and import prices as per PUB/MH I-209 low price sensitivity.

<u>ANSWER</u>:

Manitoba Hydro is not able to provide this analysis within the timeframe available to respond to this second round information request.

<u>PUB/MH II-217</u>

Reference: PUB/MH I-157(a)/ CAC/MSOS/MH I-62(g): Shortage Pricing

c) Please explain the price spike in the SEP last quarter of 2006/07 when:

- **Peak prices were about 10¢/KWh.**
- **Shoulder prices were about 7¢/KWh.**
- **Off-peak prices were about 6-7¢/KWh**

<u>ANSWER</u>:

Energy prices across the market were up over previous years due largely to higher loads and equipment outages. Congestion into the northwest region of the MISO market was above average for the quarter and particularly high in February 2007.

As explained in the publicly available MISO market report (February Monthly Report, March 14, 2007):

> *"Coal was the primary marginal fuel followed by gas. Gas, as a marginal fuel, increased by 21.3% this month as compared to last month. Average price of Natural Gas was 23.8% higher in February than in January 2007. In February severe winter weather and extremely low temperatures increased peak electricity demand approximately by 5.5% over last February and caused several generation and transmission outages in Midwest ISO regions. Outages reduced available capacity by an estimated 3469 MW."*
>
> And
>
> *"Several Winter storms and below freezing temperatures were major contributors of multiple transmission and generation outages and supply shortfalls that caused market prices to rise at all hubs."*

Manitoba Hydro hydraulic generation was also below average due mostly to well below average flows on the Winnipeg River and below average flows on the Nelson River. Combined with above normal Manitoba Load in February, 2007, this required imports at above average levels which added further upward pressure on MHEB locational marginal price (LMP) at the MISO market interface.

MISO Market Reports for 2007 are publically available at:
http://mktweb.midwestiso.org/publish/Folder/54a750_1206d339413_-7c760a48324a?rev=1

<u>PUB/MH II-217</u>

Reference: PUB/MH I-157(a)/ CAC/MSOS/MH I-62(g): Shortage Pricing

d) Please confirm that in 2006/07, MH did or could have incurred import prices in excess of the average export revenue rate of less than 6¢/KWh.

<u>ANSWER</u>:

Manitoba Hydro can confirm that there were occurrences when it incurred purchase prices in excess of 6¢/kWh.

One example of this was provided in the response to part (c) of this question. In February, 2007: Manitoba Hydro's on-peak hydraulic generation was restricted due to low flows on the Winnipeg River; Manitoba load was above normal due to extreme cold temperatures; and market prices were high due to high loading and numerous equipment outages in the MISO footprint.

PUB/MH II-218

Reference: PUB/MH I-81(a); PUB/MH I-154 (a) & (b) Drought Probabilities

a) **Please provide an in-depth discussion of MH's "worst case" water supply situation with respect to current infrastructure flow management, hydraulic generation, and energy-in-storage for:**

- **The Black Swan event mentioned in the filed ICF report.**
- **Anecdotal events in the preceding centuries.**
- **1929-33 five-year drought.**
- **1936-42 seven-year drought.**
- **1961.**
- **1980-81.**
- **1967-91 five-year drought.**
- **2003/04 one-year drought.**
- **2006/07 min-drought.**

ANSWER:

The Manitoba Hydro system of energy supply is designed to be able to provide sufficient electricity under a repeat of the most severe period of low water supply over the last 100 years. This design period corresponds to a seven year drought period from 1936 to 1942 for hydraulic generation and includes supplementary energy from Manitoba Hydro thermal generation as well as energy from firm imports associated with contracts. Given this design criteria, the system is capable of supplying the firm demand in all other years in the historic flow record referenced in the information request.

Actual power system operation during a drought will recognize the availability of additional non-firm resources and may utilize them in order to increase the reliability of the energy supply or to reduce the financial cost of a drought. These additional resources would assist Manitoba Hydro in managing energy supply during extreme events such as a Black Swan event mentioned in the ICF report or the anecdotal events in the preceding centuries, since these events correspond to droughts of greater severity and duration than the 1936 to 1942 design period. During such extreme adverse water supply situations, which Manitoba Hydro would categorize as "acts of god" or "force majeure" events, Manitoba Hydro has the contractual right to curtail firm export deliveries in order to serve Manitoba load first. In addition, special measures such as requests for voluntary reductions in power usage and load shedding might be required in order to maintain the supply and demand balance in the Province.

<u>PUB/MH II-218</u>

Reference: PUB/MH I-81(a); PUB/MH I-154 (a) & (b) Drought Probabilities

b) Please confirm that in a shorter term frequency context, MH would over the 100-year flow record, have experienced seven significant drought periods involving 22 drought years that would constrain hydraulic generation and require greater imports.

<u>ANSWER</u>:

Manitoba Hydro would not characterize all of the periods of low flows that are referenced in the information request as significant drought periods. For example, the 2006/07 period resulted in annual hydraulic generation that was only slightly below the long-term average and this can hardly be considered as a significant drought period.

As discussed in the response to PUB/MH II-218(a), the Manitoba Hydro system of energy supply is designed to be able to provide sufficient supply under a repeat of the most severe period of low water supply which corresponds to a seven year drought period from 1936 to 1942. The dependable energy of the power system corresponding to this low flow condition is determined by considering the maximum use of energy-in-storage, and includes supplementary energy from Manitoba Hydro thermal generation as well as energy from firm imports associated with contracts. Given this design criteria, the power system is capable of supplying the firm demand in all years in the historic flow record that are referenced in the information request by utilizing the dependable resources.

Actual power system operation during a drought will recognize the availability of additional non-firm resources such as imports in excess of those available under firm contracts, and Manitoba Hydro may utilize them in order to increase the reliability of the energy supply or to reduce the financial cost of a drought.

PUB/MH II-219

Reference: Order 150-08/Tab 13, Directive #27 Lake Winnipeg Summer Levels/Outflows

a) **During the 1978-2010 periods, please identify the years when MH would and would not have been faced with licence limitations on Lake Winnipeg water levels which precluded increased summer storage levels:**

Year	Lake Winnipeg Summer Level Maximum Monthly Average		July Nelson River Flows	
			Bladder Rapids	Kelsey G.S.
1977/78	712.0		40,600 cfs	40,600
1978/79	714.4		41,900 cfs	41,300
1979/80	715.4		152.900 cfs	142,400
1980/81	713.8		35,400 cfs	34,600
1981/82	713.2		47,700 cfs	46,600
1982/83	714.2		55,600 cfs	53,000
1983/84	714.6	2 months*	62,400 cfs	58,300
1984/85	714.0		59,300 cfs	55,500
1985/86	714.8	4 months*	70,100 cfs	61,900
1986/87	715.2	5 months*	121,100 cfs	107,400
1987/88	714.4		48,700 cfs	39,600
1988/89	712.4		29,500 cfs	27,200
1989/90	713.3		43,100 cfs	39,600
1990/91	714.0		46,100 cfs	42,000
1991/92	712.8		48,000 cfs	42,700
1992/93	714.6	1 month*	46,200 cfs	42,700
1993/94	714.8	2 month*	43,200 cfs	39,900
1994/95	714.1		62,700 cfs	57,600
1995/96	714.0		68,300 cfs	62,900
1996/97	714.7	3 months*	144,800 cfs	135,700
1997/98	715.3	4 months*	154,600 cfs	144,900
1998/99	714.6	2 months*	101,900 cfs	96,800
1999/00	714.1		69,500 cfs	67,500
2000/01	714.5		73,400 cfs	71,000

Year	Lake Winnipeg Summer Level Maximum Monthly Average		July Nelson River Flows	
			Bladder Rapids	Kelsey G.S.
2001/02	**714.7**	**3 months***	**141,300 cfs**	**132,700**
2002/03	**713.9**		**78,200 cfs**	**76,000**
2003/04	**712.0**		**N/A**	**45,100**
2004/05	**714.5**	**5 months***	**N/A**	**95,700**
2005/06	**716.2**	**6 months***	**N/A**	**147,500**
2006/07	**714.6**	**2 months***	**N/A**	**108,000**
2007/08	**714.7**	**2 months***	**N/A**	**110,900**
2008/09	**714.8**	**3 months***	**N/A**	**120,500**
2009/10				

Note: * months above 714.5

ANSWER:

With respect to the upper level of the power production range on Lake Winnipeg, Manitoba Hydro is required by its Water Power Act Licence to effect maximum discharge out of Lake Winnipeg when the wind eliminated level on Lake Winnipeg exceeds 715 feet. The years when this level was exceeded are listed in Table 1.

Table 1. Years when Lake Winnipeg Wind Eliminated level exceeded 715 feet.

1979/80
1985/86
1986/87
1997/98
2005/06
2007/08
2008/09
2009/10

Simply listing when Lake Winnipeg levels exceeded the upper level of the power production range (715 feet) certainly does not provide a full account of all the times that this limit influenced Manitoba Hydro operations. Indeed, Manitoba Hydro continuously monitors conditions on Lake Winnipeg and all other reservoirs with established upper and lower limits and plans its operations with the intent to not exceed (or fall below) these limits. Manitoba Hydro does not keep records of all the times when the upper level of the power production range was influencing its planned operations.

PUB/MH II-219

Reference: Order 150-08/Tab 13, Directive #27 Lake Winnipeg Summer Levels/Outflows

b) Please confirm and explain the substantial difference between recorded flows at the WSC Bladder Rapids gauging station and the Kelsey generation station.

ANSWER:

Manitoba Hydro cannot explain the difference in recorded flows at Bladder Rapids and Kelsey. Manitoba Hydro is aware of the discrepancy but is only responsible for the accuracy of the flow record at Kelsey.

<u>PUB/MH II-219</u>

Reference: Order 150-08/Tab 13, Directive #27 Lake Winnipeg Summer Levels/Outflows

c) Please confirm that inferred local drainage inflows along the Nelson River itself are derived from historical:

- **Lower Nelson River flows.**
- **Minus Burntwood River flows.**
- **Minus Upper Nelson River flows at Kelsey G.S. and/or at Bladder Rapids gauging station.**

<u>ANSWER</u>:

Manitoba Hydro calculates local drainage inflows to the Nelson River downstream of Lake Winnipeg and downstream of Thompson utilizing the recorded flow at Kettle Generating Station, gauged tributary flows, Lake Winnipeg outflows and Burntwood River flows at Thompson including adjustments for storage changes on Stephens Lake, Split Lake, Sipiwesk Lake and Cross Lake.

PUB/MH II-219

Reference: Order 150-08/Tab 13, Directive #27 Lake Winnipeg Summer Levels/Outflows

d) Please confirm that these inferred local inflows would be 5,000 to 10,000 cfs lower (in the summer) if Bladder Rapids gauge data were employed.

ANSWER:

Manitoba Hydro cannot confirm this statement as the local inflows downstream of Lake Winnipeg are independent of the Bladder Rapids flows.

<u>PUB/MH II-220</u>

Reference: Order 150/08 2009 EIIR Hearing

a) Please provide on an industry sector basis the 5 year history of GSL > 30:

- **Monthly demand (MW) usage**
- **Monthly energy (GWh) consumption**
- **Contract demand (MW) commitments**

<u>ANSWER</u>:

The tables below provide the 5 year historical data for the GSL >30 kV customers by industry type. The contract demand commitments were derived by taking the maximum kVA recorded over the 5 year period for each customer in each industry sector, then adding them together.

CHEMICAL (contract demand commitments = 268,315 kVA per month)

kWh	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Apr	148,601,183	155,892,021	157,927,794	176,891,767	146,405,193
May	146,781,207	152,247,362	146,944,903	168,708,061	134,806,557
Jun	149,290,582	154,831,998	140,606,667	169,713,271	160,468,355
Jul	157,589,204	159,534,571	156,949,601	154,281,069	171,009,832
Aug	154,873,461	160,498,597	159,295,545	172,911,909	174,636,600
Sep	151,860,894	136,798,401	150,627,759	169,165,142	158,381,897
Oct	161,588,348	158,015,891	159,327,729	174,235,816	175,117,431
Nov	155,237,054	156,100,283	151,846,285	171,896,675	163,471,668
Dec	154,159,102	163,256,634	163,808,332	132,627,931	178,355,248
Jan	161,152,004	162,532,896	168,328,709	173,512,201	181,902,400
Feb	147,732,278	144,273,938	160,259,063	145,493,335	170,208,155
Mar	163,694,945	155,015,952	177,169,640	174,554,890	153,366,637
Total	**1,852,560,262**	**1,858,998,544**	**1,893,092,027**	**1,983,992,067**	**1,968,129,973**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	224,547	227,921	231,027	258,752	222,893
May	225,366	232,489	229,245	253,699	222,726
Jun	225,544	229,860	229,540	254,554	237,036
Jul	225,576	229,772	229,668	254,921	253,939
Aug	221,586	230,693	230,635	254,097	254,680
Sep	224,652	204,407	229,745	254,254	254,116
Oct	180,910	230,022	232,565	253,064	253,581
Nov	228,758	230,009	232,358	253,177	259,069
Dec	221,845	229,993	233,436	210,632	259,610
Jan	229,939	229,469	235,015	258,715	258,942
Feb	228,909	231,120	255,829	252,078	265,755
Mar	229,951	230,309	260,317	258,771	231,428
Total	**2,667,584**	**2,736,065**	**2,829,378**	**3,016,714**	**2,973,774**

FOOD AND BEVERAGE (contract demand commitments = 22,193 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	7,331,721	7,940,843	7,978,390	8,194,913	9,351,095
May	6,804,038	8,074,449	7,745,234	8,628,881	9,806,690
Jun	7,069,018	7,814,565	8,443,883	9,219,983	10,179,624
Jul	6,762,615	7,909,607	8,618,722	8,809,288	8,736,116
Aug	7,097,174	7,508,813	9,225,730	8,357,472	9,597,020
Sep	7,189,369	8,325,854	9,266,409	9,660,346	9,773,546
Oct	6,815,200	8,764,392	9,207,625	10,331,645	9,762,676
Nov	7,646,995	9,122,564	9,458,058	10,166,645	9,000,635
Dec	7,782,850	8,782,313	9,181,531	9,597,913	10,038,982
Jan	7,886,723	8,648,604	9,695,433	9,831,074	9,729,823
Feb	7,956,942	8,753,895	8,815,121	9,478,288	8,920,691
Mar	8,079,588	8,569,844	8,977,461	8,819,300	8,793,745
Total	**88,422,233**	**100,215,743**	**106,613,597**	**111,095,748**	**113,690,643**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	16,696	16,978	18,500	18,966	19,335
May	16,700	17,509	18,357	18,710	19,907
Jun	17,136	17,791	19,249	18,674	19,958
Jul	17,936	17,935	19,378	18,559	19,628
Aug	16,747	19,071	19,163	19,407	19,952
Sep	16,568	17,622	20,021	19,650	19,960
Oct	16,461	17,974	19,452	19,051	19,881
Nov	16,263	18,216	19,188	19,183	19,090
Dec	17,242	18,112	19,338	19,007	19,124
Jan	17,185	18,288	19,064	18,999	19,376
Feb	17,152	18,301	19,017	19,100	19,172
Mar	17,092	18,475	18,833	19,376	19,141
Total	**203,178**	**216,273**	**229,561**	**228,681**	**234,524**

MINING (contract demand commitments = 20,409 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	3,327,731	5,025,099	4,891,176	5,401,801	7,159,513
May	2,807,664	2,059,903	4,308,792	4,692,516	6,508,480
Jun	3,065,689	3,437,747	3,793,876	4,609,059	5,240,836
Jul	2,653,635	3,299,686	3,860,997	4,824,177	5,705,635
Aug	2,594,475	3,157,047	3,929,730	4,400,529	4,562,212
Sep	2,570,100	3,475,376	3,824,034	4,302,224	4,243,254
Oct	2,810,304	3,489,820	3,743,476	5,178,034	5,214,065
Nov	3,416,305	3,723,049	5,020,588	5,542,167	5,543,285
Dec	3,427,185	4,280,880	4,846,813	5,785,477	5,427,867
Jan	3,573,438	4,476,594	5,299,429	6,456,118	5,694,618
Feb	3,830,498	4,912,986	5,346,203	6,712,561	5,893,792
Mar	3,727,073	4,658,074	5,073,788	7,253,063	5,626,032
Total	**37,804,097**	**45,996,261**	**53,938,902**	**65,157,726**	**66,819,589**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	9,026	8,297	10,034	10,825	13,979
May	8,689	7,857	9,445	10,404	13,378
Jun	8,666	8,374	9,079	9,841	11,665
Jul	8,395	8,162	8,637	10,031	11,609
Aug	8,452	7,672	7,574	9,977	10,800
Sep	8,608	7,858	7,870	9,913	11,483
Oct	8,991	6,963	8,293	10,623	12,258
Nov	6,840	8,745	9,799	10,788	12,653
Dec	6,779	9,116	10,250	11,775	9,971
Jan	7,656	9,951	10,060	13,011	10,498
Feb	7,323	9,824	10,463	13,851	12,137
Mar	7,616	9,756	11,066	14,731	11,843
Total	**97,041**	**102,574**	**112,570**	**135,772**	**142,275**

MISC. INDUSTRY (contract demand commitments = 19,344 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	2,405,700	2,442,552	4,003,706	3,641,075	5,228,683
May	2,296,200	2,235,647	3,822,673	3,319,108	4,542,723
Jun	2,404,500	2,303,544	3,995,373	3,554,598	4,187,744
Jul	2,470,500	2,565,451	4,323,107	3,558,923	3,837,595
Aug	2,520,000	2,574,190	3,884,738	3,461,263	3,925,088
Sep	2,504,700	2,530,603	3,612,707	3,444,621	3,741,488
Oct	2,457,300	3,640,820	3,632,903	3,972,671	3,868,445
Nov	2,777,100	3,410,570	3,644,743	6,817,232	3,819,334
Dec	2,655,000	3,502,950	3,767,931	4,111,100	4,024,852
Jan	2,844,300	3,480,737	3,813,912	4,096,530	4,209,609
Feb	2,810,100	3,787,826	3,721,935	4,143,184	3,911,511
Mar	2,643,977	3,764,979	3,797,911	4,540,236	3,262,965
Total	**30,789,377**	**36,239,869**	**46,021,639**	**48,660,541**	**48,560,037**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	5,615	6,759	11,367	10,595	11,431
May	5,578	6,751	10,862	10,503	11,305
Jun	6,537	6,109	10,997	9,762	12,095
Jul	6,726	8,237	12,459	9,913	13,560
Aug	6,582	6,818	11,020	11,031	12,068
Sep	6,189	6,982	10,230	10,513	11,868
Oct	6,174	10,181	10,406	10,762	12,072
Nov	6,333	9,622	9,499	16,152	11,095
Dec	6,453	9,246	9,164	10,289	11,365
Jan	6,383	9,766	9,860	11,107	11,032
Feb	7,178	10,416	10,555	11,708	9,656
Mar	6,655	10,525	11,055	12,431	8,379
Total	**76,403**	**101,414**	**127,474**	**134,766**	**135,925**

PETROLEUM (contract demand commitments = 200,719 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	68,684,760	77,252,876	74,915,154	76,770,611	73,269,161
May	64,512,976	68,937,372	64,629,758	70,560,836	70,410,420
Jun	63,243,195	66,828,266	67,429,250	77,140,533	84,788,210
Jul	69,240,765	72,584,134	72,747,357	79,578,937	87,259,561
Aug	69,106,224	77,225,485	83,130,272	80,039,315	73,473,067
Sep	67,357,484	75,516,115	72,646,716	74,894,904	72,036,262
Oct	71,572,688	80,753,890	71,681,068	82,374,133	71,231,601
Nov	71,685,494	78,434,802	78,124,094	86,970,224	73,112,755
Dec	82,569,859	80,759,036	75,234,007	91,095,650	77,112,343
Jan	84,217,077	77,181,923	81,535,327	84,750,806	82,350,671
Feb	75,497,443	75,189,964	69,059,186	74,278,174	70,093,618
Mar	75,555,518	81,827,612	81,792,569	76,293,721	79,870,008
Total	**863,243,483**	**912,491,475**	**892,924,758**	**954,747,844**	**915,007,677**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	134,272	161,135	168,636	162,647	163,627
May	141,933	154,803	151,068	147,850	175,099
Jun	146,422	149,325	153,487	164,373	182,462
Jul	143,477	156,362	168,586	161,835	182,801
Aug	135,618	157,984	170,811	160,281	178,588
Sep	138,228	158,361	165,808	160,831	182,796
Oct	143,669	170,922	167,574	167,132	181,289
Nov	155,434	173,154	168,701	173,183	179,450
Dec	153,289	168,973	171,837	185,598	174,044
Jan	164,971	166,609	174,420	169,004	179,396
Feb	164,717	175,755	165,937	169,088	171,794
Mar	155,780	172,466	167,169	163,993	170,167
Total	**1,777,810**	**1,965,849**	**1,994,036**	**1,985,815**	**2,121,512**

PIPELINE (contract demand commitments = 11,358 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	-	-	-	-	-
May	-	-	-	-	-
Jun	-	-	-	-	-
Jul	-	-	-	-	-
Aug	-	-	-	-	-
Sep	-	-	-	-	-
Oct	-	-	-	-	-
Nov	-	-	-	-	-
Dec	-	-	-	-	-
Jan	-	-	-	-	108,000
Feb	-	-	-	-	108,000
Mar	-	-	-	-	126,000
Total	**-**	**-**	**-**	**-**	**342,000**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	-	-	-	-	-
May	-	-	-	-	-
Jun	-	-	-	-	-
Jul	-	-	-	-	-
Aug	-	-	-	-	-
Sep	-	-	-	-	-
Oct	-	-	-	-	-
Nov	-	-	-	-	-
Dec	-	-	-	-	-
Jan	-	-	-	-	10,764
Feb	-	-	-	-	11,799
Mar	-	-	-	-	10,877
Total	**-**	**-**	**-**	**-**	**33,440**

PRIMARY METALS (contract demand commitments = 382,502 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	188,933,503	182,660,783	192,869,654	188,356,310	165,806,506
May	193,912,944	189,271,715	198,145,512	194,225,067	168,124,697
Jun	186,043,477	180,118,914	183,846,440	176,883,947	161,320,690
Jul	159,245,576	176,349,365	156,810,451	170,763,210	161,332,967
Aug	139,056,043	168,040,469	173,229,085	178,074,758	122,339,720
Sep	156,304,142	170,022,971	186,862,349	183,837,410	162,845,897
Oct	195,536,921	184,824,548	196,429,849	188,825,363	181,313,054
Nov	201,328,038	194,629,494	193,096,365	202,126,743	178,423,574
Dec	204,010,494	200,825,326	202,395,382	189,992,499	184,774,310
Jan	207,060,363	205,807,881	209,213,905	203,256,945	190,035,940
Feb	194,131,728	186,197,229	198,770,197	173,143,331	175,374,034
Mar	211,789,797	209,123,472	207,962,371	187,726,350	181,634,902
Total	**2,237,353,026**	**2,247,872,167**	**2,299,631,560**	**2,237,211,933**	**2,033,326,291**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	315,688	325,184	345,058	338,326	314,896
May	313,981	320,316	333,118	329,242	315,863
Jun	305,536	318,425	319,189	311,789	310,782
Jul	301,951	309,100	307,496	307,594	298,947
Aug	285,061	307,638	311,822	309,364	283,131
Sep	313,719	298,888	323,564	316,759	304,226
Oct	319,062	300,404	326,699	328,598	309,465
Nov	334,618	335,072	330,821	336,426	319,170
Dec	341,097	342,169	327,913	345,809	316,701
Jan	343,164	352,539	338,853	345,647	315,712
Feb	344,686	346,504	340,457	328,975	320,229
Mar	333,571	340,696	344,757	327,442	327,983
Total	**3,852,134**	**3,896,935**	**3,949,748**	**3,925,971**	**3,737,106**

PULP & PAPER (contract demand commitments = 196,177 kVA per month)

kWh	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	65,462,742	62,392,907	63,892,905	56,406,230	66,963,654
May	64,966,706	63,763,003	65,613,499	61,475,290	69,931,644
Jun	63,134,669	64,076,655	63,348,587	61,651,751	41,436,505
Jul	69,639,800	66,763,152	74,068,655	63,595,564	18,784,805
Aug	69,556,426	63,261,771	69,920,817	62,752,543	38,994,446
Sep	68,909,784	63,442,432	59,295,535	58,714,842	15,697,408
Oct	64,115,364	57,087,426	65,021,461	60,512,807	13,591,911
Nov	61,352,244	57,980,835	61,628,186	57,459,095	12,835,293
Dec	62,626,292	62,240,933	59,660,710	42,852,821	14,028,490
Jan	66,102,928	62,617,615	62,508,975	53,310,089	12,902,400
Feb	59,298,869	57,355,092	56,614,098	34,792,372	11,789,316
Mar	64,540,726	62,930,087	64,721,804	62,445,715	16,622,693
Total	**779,706,550**	**743,911,908**	**766,295,232**	**675,969,119**	**333,578,565**

kVA	2005/06	2006/07	2007/08	2008/09	2009/10
Apr	103,871	101,375	98,583	100,093	112,534
May	105,121	103,285	99,913	101,008	113,010
Jun	111,322	106,451	104,703	102,802	100,993
Jul	113,744	103,716	118,396	111,743	96,288
Aug	111,256	103,643	115,567	105,109	99,066
Sep	108,994	101,776	114,412	102,836	89,500
Oct	121,180	99,482	103,593	103,954	78,102
Nov	107,181	103,430	111,176	102,181	80,997
Dec	106,113	98,789	104,984	99,358	45,250
Jan	102,808	102,108	102,334	99,726	46,764
Feb	102,258	100,487	101,955	102,908	44,813
Mar	117,574	99,784	118,259	113,504	55,919
Total	**1,311,422**	**1,224,326**	**1,293,876**	**1,245,222**	**963,236**

UNIVERSITY (contract demand commitments = 893 kVA per month)

kWh	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Apr	-	-	-	-	-
May	-	-	-	-	-
Jun	-	-	-	-	-
Jul	-	-	-	-	24,000
Aug	-	-	-	-	48,000
Sep	-	-	-	-	72,000
Oct	-	-	-	-	72,000
Nov	-	-	-	-	72,000
Dec	-	-	-	-	235,200
Jan	-	-	-	-	264,000
Feb	-	-	-	-	240,000
Mar	-	-	-	-	259,200
Total	**-**	**-**	**-**	**-**	**1,286,400**

kVA	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Apr	-	-	-	-	-
May	-	-	-	-	-
Jun	-	-	-	-	-
Jul	-	-	-	-	295
Aug	-	-	-	-	190
Sep	-	-	-	-	180
Oct	-	-	-	-	211
Nov	-	-	-	-	182
Dec	-	-	-	-	494
Jan	-	-	-	-	556
Feb	-	-	-	-	542
Mar	-	-	-	-	826
Total	**-**	**-**	**-**	**-**	**3,477**

PUB/MH II-220

Reference: Order 150/08 2009 EIIR Hearing

b) Please provide for GSL 30-100 and GSL>100 on an industry sector basis the 5, 10, 15 and 20 year forecasts of:

- **Demand (MW)**
- **Energy consumption (GWh)**
- **EIIR revenues**

ANSWER:

Manitoba Hydro does not forecast customer class energy and demand data by industry sector. This information is provided below by customer class only. Information on EIIR revenue can be found in response to CAC/MSOS-MH II 32 b) for fiscal years 2010/11 and 2011/12.

Fiscal	**Large 30-100 kV**		**Large >100 kV**	
Year	kWh	kV.A	kWh	kV.A
2014/15	1,090,553,223	2,223,138	6,078,400,000	10,252,171
2019/20	1,107,324,571	2,258,975	6,465,400,000	10,838,148
2024/25	1,127,870,848	2,302,878	6,965,400,000	11,599,183
2029/30	1,148,660,762	2,347,302	7,465,400,000	12,360,218

PUB/MH II-220

Reference: Order 150/08 2009 EIIR Hearing

c) Please identify the impacted & non impacted customers.

ANSWER:

Manitoba Hydro does not provide information related to specific customers impacted by the Energy Intensive Interruptible Rate due to the commercial sensitivity of this information. Competing customers in the same industrial sector may or may not be impacted by the proposed rate due to the nature of their future growth plans.

PUB/MH II-220

Reference: Order 150/08 2009 EIIR Hearing

d) Please explain the 2.5% growth allowance and indicate which customers would benefit.

ANSWER:

Relative to the EIIR Application filed on February 12, 2010:

– The annual growth allowance is intended for application at the start of each fiscal period (April 1st), increasing the annual on-peak baseline by an amount equal to 2.5 percent of the previous year's baseline.

– The growth allowance is intended for application in the first five years after the rate commences or the first five years after a customer obtains service and a baseline is established.

– The annual growth allowance is cumulative over the five year period, resulting in a net increase to the on-peak baseline of 13.1 percent over the first five years.

– All customers impacted by the Energy Intensive Industrial Rate will benefit from the application of the growth allowance.

<u>PUB/MH II-220</u>

Reference: Order 150/08 2009 EIIR Hearing

e) Please indicate which customers would be impacted by the minimum 50% of contract demand provision.

<u>ANSWER</u>:

None of the customers, included within the scope of the EIIR Application filed on February 12th, 2010 that obtain service in the General Service Large Greater than 30 kV rate categories, will be impacted by the 50 percent contract demand provision while operating under normal conditions.

PUB/MH II-220

Reference: Order 150/08 2009 EIIR Hearing

f) Please identify the individual sector revenue gains for MH.

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS/MH II-32 as it refers to the projected revenues for the February 12, 2010 filing of the EIIR Application.

Information is provided on a rate category basis instead of individual sector basis as the IFF develops growth forecasts on the basis of rate category rather than sector basis for the majority of customers in the Greater than 30 kV rate categories.

PUB/MH II-220

Reference: Order 150/08 2009 EIIR Hearing

g) Will “previous” EIIR filings be made part of the record?

ANSWER:

Assuming the previous EIIR filings are relevant to the current Application, Manitoba Hydro would not object to making them part of the record.

PUB/MH II-221

Reference: Order 150/08 2009 Items 22/28/29- February 12, 2010 EIIR Application, Section 1.0 (Page 2)

a) **Please provide a listing (including dates) of actual Stakeholder Consultation subsequent to B.O. 112/09, defining the nature of each consultation:**

- **General public meetings/attendees**
- **Individual face-to-face meetings**
- **Individual telephone discussions**
- **Written correspondence to (and from) individual Stakeholders**

ANSWER:

– **General Public Meetings (including attendees)**

The attached list provides information on the dates and attendees of Customer Advisory Group and Customer Information meetings held during the winter/spring of 2010. Attendees were provided with a general overview (verbal) of the Energy Intensive Industrial Rate as part of these proceedings.

– **Individual Face-to-Face Meetings**

Individual face-to-face meetings were held with the following General Service Large customers on the dates noted below:

Tolko	Feb 12, 2010
Hudson Bay Mining & Smelting	Feb 12, 2010
Vale	Feb 13, 2010
Koch Fertilizer	Feb 17, 2010
Canexus	Feb 17, 2010
Gerdau Ameristeel	Feb 18, 2010
Amsted Griffin	Feb 19, 2010
Erco Worldwide	Feb 19, 2010

Discussion surrounded the history of previous applications, format and structure of the filed application, and conceptual revisions to the filed application that might be considered. Subsequent analysis examined the impact that the proposed and revised rates may have with respect to each customer's growth projections.

An additional face-to-face meeting was held with MIPUG's representatives, including representation from Canexus and Gerdau Ameristeel on April 27th, to review the filed Application, the process going forward, and to discuss proposed revisions that may be considered for inclusion in a revised Application to be filed at a later date.

– **Individual Telephone Discussion (Teleconference)**

Teleconference calls were held with two customers (noted below). Discussion surrounded the history of previous applications, format and structure of the filed application, and conceptual revisions to the filed application that could be considered. Subsequent analysis examined the impact that the proposed and revised rates may have with respect to each customer's growth projections.

Enbridge Pipelines	Feb 10, 2010
TransCanada Power	Feb 11, 2010

– **Written Correspondence with Individual Stakeholders**

Manitoba Hydro provided individual stakeholders with the following written materials:

- During the February 12-19 meetings a presentation describing the program included in the February 12 filing to the PUB and also individual analysis for each customer of the potential impacts of the proposal (and an example of a proposed revision) relative to projected load growth scenarios.

- For the April 27th meeting with MIPUG, Manitoba Hydro provided a presentation of a potential revised EIIR, which took into account concerns expressed by customers during the February 12-19 meetings.

General Public Meetings/Attendees, February 2010

Customer Advisory Group meeting
February 24, 2010, 8:00 - 9:30 a.m., Winnipeg

As part of a larger discussion of natural gas and electricity topics of interest, there was general discussion of Manitoba Hydro's EIIR application and potential revisions, and next steps

Company
Health Sciences Centre
MacDon Industries
Manitoba Centennial Centre
Manitoba Government Services
Manitoba Government Services
Motor Coach Industries
Winnipeg Airport Authority Inc
Red River College
Red River College
Standard Aero Ltd
Winpak Ltd

PUB/MH II-221

Reference: Order 150/08 2009 Items 22/28/29- February 12, 2010 EIIR Application, Section 1.0 (Page 2)

b) Please provide a summary of the Stakeholder positive and negative inputs on an industry sector basis.

ANSWER:

The following provides a summary of positive and negative inputs obtained from customers, by industry sector, during consultation outlined in the response to PUB/MH II-221(a):

Pipelines (Oil and Gas Transportation):

Positive

– 50 percent of contract demand as minimum demand billing was reasonable

Negative

– Rate only applied to on-peak consumption,
– Rate only applied to energy consumption, nothing related to demand,
– Why is a discounted off-peak rate not included to encourage load shift,
– Contemplated changes to Service Extension Policy are a concern as it relates to:
    i) Retroactivity
    ii) Relationship to rate structure
– Treatment of new versus existing customers does not appear uniform,
– Impact on expansion plans presently being implemented,

General Comments:
Sector is concerned about retroactivity to existing plans for expansion that are presently being implemented. Feel that such retroactive measures are punitive in nature.

Mining:

Positive

- Environmental considerations in rate are important, as industry makes adjustments for changes in environmental legislation.

Negative

- Proposed application of EIIR will impact decisions related to investment for expansion until matter is resolved.
- No minimum qualifying threshold for the EIIR
- No Baseline credits for previously achieved Power Smart energy reductions
- Insufficient growth allowance
- Growth should be based on total energy consumption
- No consideration for investment in existing infrastructure

General Comments:

Sector is considering expansion opportunities, concerned about the impact that the filed Application will have on mining expansion in Manitoba, particularly smaller mines that are no longer provided with a minimum threshold to buffer the impact of the rate.

Primary Metals

Positive

- Nothing

Negative

- Proposed that baseline be established based on total energy consumption versus on-peak consumption only.
- Concern over the sector's ability to shift energy use from on-peak to off-peak periods
- Concern that 2.5% growth allowance was insufficient, as the economy comes out of the recession
- Concern over the duration of the historic period used to establish baseline.
- Concern over the removal of minimum consumption threshold
- Concern over elimination of baseline credits for previously achieved Power Smart energy reductions
- Concern over the 50 percent of contract clause for minimum demand

General Comments:
Industry is presently experiencing difficult market conditions. Rate may impact ability to optimize production to market demand and retain production and employment.

Chemical

Positive
- 2.5 percent growth allowance important
- Elimination of previous maximum energy consumption cap

Negative
- Concern regarding the impact on cost competitiveness (detrimental to business),
- Concern regarding calculation and date used for setting baseline levels
- Insufficient growth allowance after 5 years
- Difficulty in applying proposed rate to monthly billing cycle hampers ability to allocate costs to production activities on a monthly basis, and
- Concern over retroactivity of changes to Service Extension Policy

General Comments:
Sector is under the impression that they are targeted by the EIIR Application

Pulp & Paper

Positive
- Baseline levels and 2.5 percent growth allowance accommodate projected growth

Negative
- Concern that growth allowance was insufficient after 5 years, as the economy comes out of the recession
- Concern over the duration of the historic period used to establish baseline.
- Concern over the removal of minimum consumption threshold
- Concern over elimination of baseline credits for previously achieved Power Smart energy reductions

General Comments:
Significant load growth is not a consideration for this sector given current and projected market conditions.