PUB/MH I-1 (REVISED)

Subject: **Tab 2: Summary of Reasons For Application**
Reference: **Reason for Application Tab 2, Page 2, Tables 2.1.1, 2.1.2**

a) Please re-file table 2.1.1 incorporating the following adjustments:

- **i. Include 2002 to 2007 actual results**
- **ii. Retained Earnings for electric operations**
- **iii. The debt to equity ratio for electric operations**

ANSWER:

The attached table provides the information requested.

Years Ending March 31

(in millions of $)	Actual 2004	2005	2006	2007	2008	2009	Forecast 2010	2011	2012
General Consumers Revenue									
- at approved rates	$ 918	$ 939	$ 984	$ 1,024	$ 1,075	1,127	$ 1,160	$ 1,159	$ 1,177
- with proposed increases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	33	69
Extra Provincial Revenue (net of fuel, power purchased and water rentals)	(289)	307	571	253	366	323	192	141	195
Other Revenue	7	4	5	5	8	16	7	7	8
	636	1,250	1,560	1,282	1,449	1,466	1,358	1,342	1,449
Expenses	1,064	1,113	1,140	1,163	1,112	1,178	1,237	1,263	1,363
Non-controlling Interest									1
Net Income (electric operations)	$ (428)	$ 137	$ 420	$ 119	$ 337	$ 288	$ 121	$ 78	$ 87
Retained Earnings (electric operations)	707	845	1,265	1,386	1,795	2,084	2,183	2,261	2,331
Retained Earnings (consolidated)	734	870	1,285	1,407	1,822	2,120	2,227	2,315	2,396
Debt Ratio (electric operations)	87%	85%	81%	80%	73%	77%	74%	75%	76%
Debt Ratio (consolidated)*	87%	85%	81%	80%	73%	77%	74%	75%	76%

* Debt Ratio for 2008 and 2009 has been restated as per CAC/MSOS/MH I-116(b)

PUB/MH I-1

Subject: **Tab 2: Summary of Reasons For Application**
Reference: **Reason for Application Tab 2, Page 2, Tables 2.1.1, 2.1.2**

b) Please re-file table 2.1.2 incorporating the following adjustments:

- **i. Retained Earnings for electric operations**
- **ii. The debt to equity ratio for electric operations**

ANSWER:

Please see the attached table.

(in millions of $)	2010 MH09-1	2010 MH08-1	2010 Variance	2011 MH09-1	2011 MH08-1	2011 Variance	2012 MH09-1	2012 MH08-1	2012 Variance
General Consumers at approved rates	1,160	1,159	1	1,159	1,190	(31)	1,177	1,214	(37)
Projected Rate Increases	-	45	(45)	33	82	(49)	69	120	(51)
Extraprovincial Revenue (net of fuel, power purchased and water rentals)	191	235	(44)	141	159	(18)	195	153	42
Other	7	7	-	7	7	-	8	8	-
Total Revenues	1,358	1,445	(87)	1,342	1,438	(96)	1,449	1,495	(46)
Operating and Administrative	372	358	14	380	365	15	403	379	24
Finance Expense	417	420	(3)	413	426	(13)	468	473	(5)
Depreciation and Amortization	368	371	(3)	386	388	(2)	407	431	(24)
Capital and Other Taxes	73	71	2	76	74	2	77	74	3
Corporate Allocation	8	8	-	9	8	1	9	8	1
Total Expenses	1,237	1,228	9	1,263	1,261	2	1,363	1,365	(2)
Non-controlling Interest	-	-	-	-	-	-	1	2	(1)
Net Income	121	217	(96)	78	177	(99)	87	132	(45)
Retained Earnings	2,183	2,270	(87)	2,261	2,447	(186)	2,331	2,521	(190)
Debt Ratio	74%	75%	-1%	75%	75%	0%	76%	75%	1%

PUB/MH I-2

Subject: **Tab 2: Summary of Reasons For Application**
Reference: **Reason for Application Page 3 of 4**

a) Please file a 20 year IFF which covers the periods "decade of investments and decade of returns" which demonstrates the projected achievement of debt to equity ratio of 51:49.

ANSWER:

Please see Appendix 16.

PUB/MH I-2

Subject: **Tab 2: Summary of Reasons For Application**
Reference: **Reason for Application Page 3 of 4**

b) **Please populate the following table for each of the years 1999/00 through 2011/12:**

	1999/ 2000	**2000/01**		**2011/12**
% Rate Increase Requested				
% Rate increase approved by PUB				
Annualized dollar increase from Rate increase				
Annual Inflation Rate in Manitoba				

ANSWER:

	% Rate Inc Req.	**% Approved**	**Annul. $ Inc.**	**Inflation Rate**
1999/00	0%	-	-	2.2%
2000/01	0%	-	-	2.5%
2001/02	-1.92% Uniform Rate Legislation	-	($14.4) million	2.1%
2002/03	0%	-	-	2.3%
2003/04	0% Status Update	-0.72% Apr 1/03 BO 7/03	($6.5) million	0.9%
2004/05	3.0% Apr 1/04 (two year application)	5% Aug 1/04 Plus conditional 2.25% Apr 1/05 & 2.25% Oct 1/05 BO 101/04 & 143/04	$32.3 million	2.7%
2005/06	2.5% Apr 1/05	2.25% BO 34/05	$21.8 million	2.4%
2006/07	2.25% Feb 1/07	2.25% Mar 1/07 BO 20/07	$23.1 million	2.0%

	% Rate Inc Req.	% Approved	Annul. $ Inc.	Inflation Rate
2007/08	Application filed Aug 2007 for rates eff. Apr 1/08	-	-	1.9%
2008/09	2.9% Apr 1/08	5.0% Jul 1/08 Plus conditional 4.0% Apr 1/09 BO 90/08	$52.4 million	2.2%
2009/10	3.9% Apr 1/09	2.9% Apr 1/09 BO 32/09	$32.8 million	0.6%
2010/11*	2.9% Apr 1/10 (two year application)	2.8% Apr 1/10 Conditional BO 18/10	$32.7 million	1.9% (est)
2011/12	2.9% Apr 1/11	TBD	$35.1 If approved	2.0% (est)

* Pending interim PUB approval of rate schedules.

PUB/MH I-3

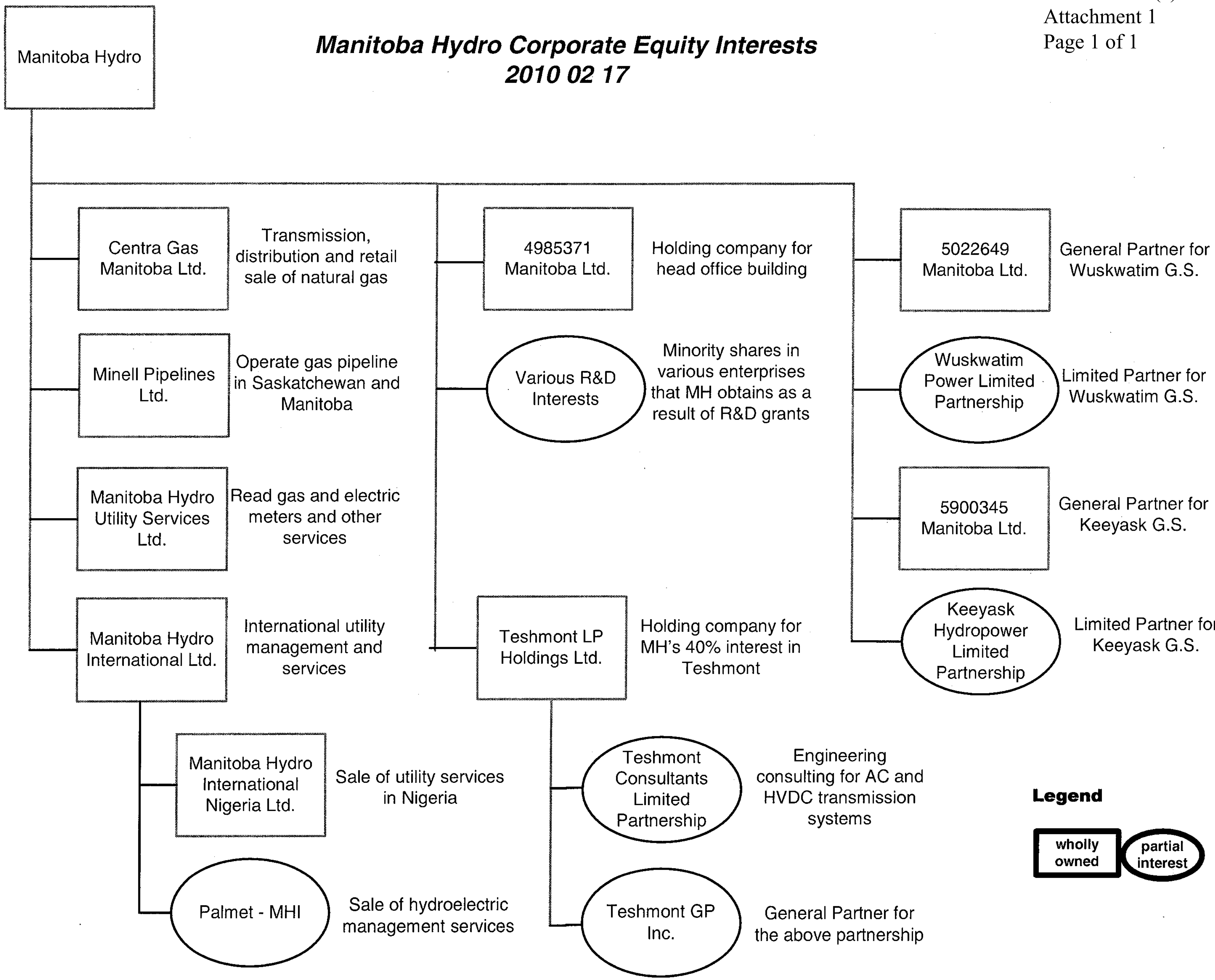
Subject: **Tab 3: Corporate Overview**
Reference: **Tab 3, Organizational Chart**

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

ANSWER:

Please see the attachment to this response.

Manitoba Hydro Corporate Equity Interests
2010 02 17



PUB/MH I-3

Subject: **Tab 3: Corporate Overview**
Reference: **Tab 3, Organizational Chart**

b) Please provide a summary of all related party transactions between MH and affiliated entities for the years 2007/08, 2008/09, and 2009/10 (year to date).

ANSWER:

Summaries of all related party transactions between Manitoba Hydro and affiliated entities are provided below. All amounts are provided in thousands of dollars unless otherwise noted.

Minell Pipelines Ltd.

The services provided by Manitoba Hydro to Minell Pipelines consist mainly of labour such as general pipeline maintenance. Minell has a line of credit arrangement with Manitoba Hydro. Funds advanced under this agreement have no fixed terms of repayment and bear interest at the average one-month banker's acceptance rate.

	2007/08	2008/09	2009/10 to December 31
Activities charged by MH	12	11	7
Interest charged by MH	44	34	12
Advance from Parent	1 081	1 145	1 108

12345 Delaware

Manitoba Hydro does not provide services to 12345 Delaware. An advance was made by Manitoba Hydro to 12345 Delaware in January 2000 for USD $19,999. 12345 Delaware does not have any employees and does not occupy any premises.

	2007/08	2008/09	2009/10 to December 31
Due to Parent	21	25	21

Teshmont Holdings Inc.

Teshmont Holdings Inc. was established as a holding company to acquire a 40% ownership of Teshmont Consultants Limited Partnership (TCLP). Teshmont Consultants Limited Partnership provides engineering related consulting services to Manitoba Hydro.

	2007/08	2008/09	2009/10 to December 31
Consulting Services	3 532	2 943	1 917

Manitoba Hydro Utilities Services (MHUS)

MHUS provides Manitoba Hydro and its wholly owned subsidiary Centra Gas Manitoba Inc. with meter reading, interactive voice response systems and other contracted services. The General Manager and the Finance & Administration Coordinator are seconded from Manitoba Hydro. MHUS is charged for these positions consistent with charges for seconded employees. MHUS leases its premises from Manitoba Hydro, and is charged on a cost recovery basis.

	2007/08	2008/09	2009/10 to December 31
Admin expense charged by MH	235	478	359
Services provided to MH	5 023	5 734	4 641
Rent charged by MH	13	12	9

Manitoba HVDC Research Centre (HVDC)

HVDC provides research and engineering services to Manitoba Hydro. The Managing Director, Manager of Research and Engineering, Manager of Finance and Administration, and the Research Development Officer have been seconded from Manitoba Hydro. HVDC is billed for the recovery of these employees' costs consistent with charges for seconded employees. HVDC was amalgamated with MHI effective April 1, 2008.

	2007/08
Services charged to MH	340
Salaries charged by MH	436

Manitoba Hydro International (MHI)

MHI currently has four business segments, International Utility Services, Manitoba HVDC Research Centre, W.I.R.E. Services and Telecom Services. International Utility Services provides professional consulting, training and electricity infrastructure management services primarily to developing markets. The Manitoba HVDC Centre provides technology products, research and development and engineering services to the electrical power system industry. W.I.R.E. Services provides aerial LiDAR data collection and analysis to determine transmission line thermal ratings. Telecom Services provides state of the art broadband telecommunication solutions for telecom carriers, internet service providers and large commercial customers.

The staffing provided by Manitoba Hydro for the execution of contracts and management of its operations is billed to MHI consistent with charges for seconded employees. MHI leases its premises from Manitoba Hydro, and is charged on a cost recovery basis.

	2007/08	2008/09	2009/10 to December 31
Payroll charged by MH	1 884	4 327	1 715
Rent charged by MH	53	84	84
Interest charged by MH	10	4	1
Due to Parent	200	-	1 000
Services charged to MH		1 489	2 290

Centra Gas Manitoba Inc.

Centra's short-term funding is financed by Manitoba Hydro with interested calculated monthly at floating rates with no fixed repayment terms. Manitoba Hydro has also provided long-term advances to Centra Gas with various interest rates and repayment terms. The following amounts are provided in millions of dollars.

	2007/08	2008/09	2009/10 to December 31
Operating & Admin charged by MH	56	59	48
Interest charged by MH	22	20	14
Common asset depreciation to Centra	6	5	4
Common asset depreciation from Centra	2	1	1
Due to Parent	98	109	109
Long term debt	235	234	265

Wuskwatim Power Limited Partnership (WPLP)

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

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

a) the Construction Agreement, whereby Manitoba Hydro will construct the Wuskwatim Generating Station and related works;
b) the Interconnection and Operating Agreement, whereby Manitoba Hydro will connect the Wuskwatim generating station to Manitoba Hydro's integrated power system;
c) the Management Agreement, whereby Manitoba Hydro will provide administrative and management functions to WPLP; and
d) the Project Financing Agreement, whereby Manitoba Hydro will provide debt financing to WPLP.

The following amounts are in millions of dollars:

	2007/08	2008/09	2009/10 to December 31
Amounts paid to MH - Construction Agreement	118	182	207
Amounts paid to MH - Interconnection	60	86	41
Amounts paid to MH - Management Agreement	4	3	3
Long term debt (due to MH)	319	543	739
Interest payable on long term debt	3	4	14
Equity contributions received from MH and the GP	20	30	35

PUB/MH I-3

Subject: **Tab 3: Corporate Overview**
Reference: **Tab 3, Organizational Chart**

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

ANSWER:

The financial statements for the following affiliate companies can be found in Appendix 17.

Centra Gas Manitoba Inc. - audited
Manitoba Hydro International Limited - audited
Minell Pipelines Ltd. - audited
Manitoba Hydro Utility Services Limited - unaudited
Teshmont Holdings LP Ltd. - unaudited
12345 Delaware Inc. - unaudited
5022649 Manitoba Ltd. (Wuskwatim Power General Partnership) - unaudited

PUB/MH I-4

Subject: **Tab 3: Corporate Overview**

Reference: **Appendix 4.4 Schedule 4.5.4, 2008/09 GRA, Schedules 3.3.1,3.3.2,**

a) **Please provide a schedule similar to schedule 3.3.1 provided at the last GRA of actual equivalent full time employees for each of the years 1999/00through 2008/09.**

ANSWER:

Please see the following schedule for EFT information from 2004/05 through 2008/09.

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

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual
President & CEO					
General Counsel	24	25	26	27	26
Public Affairs	32	30	30	31	32
Research & Development	5	3	2	2	2
Administration	23	24	26	27	27
	84	82	84	87	87
Corporate Relations					
Aboriginal Relations	44	54	59	61	67
Administration	5	8	8	8	8
	49	62	67	69	75
Corporate Planning & Strategic Analysis					
Corporate Strategic Review	5	6	5	5	6
Corporate Planning & Development	10	11	12	11	11
Administration	3	2	3	3	3
	18	19	20	19	20
Finance & Administration					
Information Technology Services	350	364	336	313	313
Treasury	17	16	15	15	15
Corporate Risk Management	1	2	3	4	5
Gas Supply	20	20	19	18	20
Rates & Regulatory Affairs	22	19	19	19	19
Corporate Controller	116	113	106	108	107
Human Resources	169	164	161	159	163
Corporate Safety & Health	31	29	26	30	30
Corporate Services	298	295	303	309	316
Administration	8	9	11	11	11
	1,032	1,031	999	986	999

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual
Power Supply					
Power Planning	32	35	42	55	58
Power Projects Development	38	38	41	46	49
HVDC	266	228	232	235	250
Generation North	234	213	211	215	219
Generation South	496	462	459	455	459
Power Sales & Operations	79	84	82	84	84
Engineering Services	163	162	176	175	183
New Generation Construction	13	14	25	55	83
Administration	23	131	137	150	191
	1,344	1,367	1,405	1,470	1,576
Transmission					
Transmission System Operations	341	346	363	362	362
Transmission Planning & Design	202	195	193	178	191
Transmission Construction & Line Maintenance	271	276	274	273	275
Apparatus Maintenance	357	362	365	397	421
Administration	37	42	38	45	49
	1,208	1,221	1,233	1,255	1,298
Customer Services & Distribution					
Customer Service Operations - Winnipeg & North	535	537	515	520	530
Customer Service Operations - South	547	569	559	561	566
Distribution Planning & Design	166	160	162	173	178
Distribution Construction	357	382	381	386	397
Administration	-	-	-	-	-
	1,605	1,648	1,617	1,640	1,671
Customer Care & Marketing					
Industrial & Commercial Solutions	48	49	51	52	54
Consumer Marketing & Sales	198	219	227	216	216
Business Support Services	230	237	239	229	229
Administration	51	47	47	48	51
	527	552	564	545	550
Total	5,867	5,982	5,989	6,071	6,276

PUB/MH I-4

Subject: **Tab 3: Corporate Overview**
Reference: **Tab 3, Organizational Chart**

b) Please provide a comparison of the actual EFT for the years 2007/08 and 2008/09 with the schedule 3.3.2 provided at the last GRA.

ANSWER:

Please see the following table for the information requested.

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

	2007/08 Actual	2007/08 Forecast	Variance	2008/09 Actual	2008/09 Forecast	Variance
President & CEO						
General Counsel	27	23	(4)	26	23	(3)
Public Affairs	31	33	2	32	32	-
Research & Development	2	2	-	2	2	-
Administration	27	28	1	27	28	2
	87	86	(1)	87	85	(2)
Corporate Relations						
Aboriginal Relations	61	68	7	67	67	-
Administration	8	8	-	8	5	(3)
	69	76	7	75	72	(3)
Corporate Planning & Strategic Analysis						
Corporate Strategic Review	5	6	1	6	6	-
Corporate Planning & Development	11	13	2	11	13	2
Administration	3	3	-	3	3	-
	19	22	3	20	22	2
Finance & Administration						
Information Technology Services	313	316	3	313	315	2
Treasury	15	16	1	15	16	1
Corporate Risk Management	4	6	2	5	6	1
Gas Supply	18	19	1	20	19	(1)
Rates & Regulatory Affairs	19	23	4	19	22	3
Corporate Controller	108	118	10	107	119	12
Human Resources	159	160	1	163	160	(3)
Corporate Safety & Health	30	25	(5)	30	24	(6)
Corporate Services	309	329	20	316	330	14
Administration	11	14	3	11	13	2
	986	1,026	40	999	1,024	25

	2007/08 Actual	2007/08 Forecast	Variance	2008/09 Actual	2008/09 Forecast	Variance
Power Supply						
Power Planning	55	59	4	58	60	2
Power Projects Development	46	49	3	49	47	(2)
HVDC	235	242	7	250	242	(8)
Generation North	215	217	2	219	217	(2)
Generation South	455	463	8	459	461	2
Power Sales & Operations	84	86	2	84	87	3
Engineering Services	175	199	24	183	211	28
New Generation Construction	55	71	16	83	101	18
Administration	150	152	2	191	152	(39)
	1,470	1,538	68	1,576	1,578	2
Transmission						
Transmission System Operations	362	360	(2)	362	362	-
Transmission Planning & Design	178	202	24	191	205	14
Transmission Construction & Line Maintenance	273	288	15	275	287	12
Apparatus Maintenance	397	385	(12)	421	386	(35)
Administration	45	51	6	49	51	2
	1,255	1,286	31	1,298	1,291	(7)
Customer Services & Distribution						
Customer Service Operations - Winnipeg & North	520	525	5	530	544	14
Customer Service Operations - South	561	553	(8)	566	553	(13)
Distribution Planning & Design	173	174	1	178	170	(8)
Distribution Construction	386	388	2	397	389	(8)
Administration	-	-	-	-	-	-
	1,640	1,640	-	1,671	1,656	(15)
Customer Care & Marketing						
Industrial & Commercial Solutions	52	55	3	54	58	4
Consumer Marketing & Sales	216	228	12	216	236	20
Business Support Services	229	242	13	229	245	16
Administration	48	49	1	51	54	3
	545	574	29	550	593	43
Total	6,071	6,248	177	6,276	6,321	45

PUB/MH I-5

Subject: **Tab 3: Corporate Overview**
Reference: **Tab 3 Staffing/ Tab 4 Appendix 4.4, Schedule 4.5.4**

a) **Please provide a table/ matrix of EFT per GWh, per domestic revenue, per domestic customers**

	1999/ 2000			**2011/12**
EFT's				
EFT per GWH of domestic Supply				
EFT per GWH of total supply				
EFT per number of domestic customers				
EFT's per $ of domestic revenue				

ANSWER:

Please see the following table for information from 2004/05 through 2011/12.

Data Table								
	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
EFTs	5,867	5,982	5,989	6,071	6,276	6,613	6,669	6,669
GWh of domestic Supply	22,452	22,622	23,327	23,985	24,285	23,968	24,346	24,718
GWh of total Supply	31,548	37,620	32,132	35,354	34,528	33,276	30,684	33,343
Electric Customers	505,666	509,791	516,861	521,599	527,472	531,804	536,267	540,756
Domestic revenue (in 000s)	938,954	983,653	1,023,613	1,074,581	1,126,812	1,160,009	1,192,762	1,245,962

Calculated Measures								
	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
EFTs	5,867	5,982	5,989	6,071	6,276	6,613	6,669	6,669
EFT per GWh of domestic supply	0.26	0.26	0.26	0.25	0.26	0.28	0.27	0.27
EFT per GWh of total supply	0.19	0.16	0.19	0.17	0.18	0.20	0.22	0.20
EFT per number of domestic customers	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
EFT per $ of domestic revenue	0.0000062	0.0000061	0.0000059	0.0000056	0.0000056	0.0000057	0.0000056	0.0000054

PUB/MH I-5 (REVISED)

Subject: Tab 3: Corporate Overview
Reference: Tab 3 Staffing/ Tab 4 Appendix 4.4, Schedule 4.5.4

b) Please provide a schedule which indicates the total increase in salary wage, benefits and overhead [both OM&A and Capitalized] related to increase in EFT's for each of the years 1999/00 to 20011/12

ANSWER:

The change in salary as a result of increases in Straight Time EFTs is calculated by multiplying the change in EFTs by the average salary for each year. Though the individual benefit cost components fluctuate, benefit costs represent on average 24% of wages & salaries.

Please see the following schedule outlining the effect of EFT change on Wages and Salaries as well as Benefits:

	Actuals 2003/04**	Actuals 2004/05	Actuals 2005/06	Actuals 2006/07	Actuals 2007/08	Actuals 2008/09	Forecast 2009/10	Forecast 2010/11
Wages and Salaries Attributable to Change in EFTs*	$ 20,069	$ 8,415	$ 3,266	$ 1,292	$ 4,189	$ 11,752	$ 20,682	$ 2,896
Benefits Attributable to Change in EFTs	$ 4,415	$ 2,020	$ 784	$ 310	$ 1,005	$ 2,820	$ 4,964	$ 695
Number of Additional Straight-time EFTs	365	147	57	22	69	188	323	44

* assume an average salary/EFT
** includes the annualization of former Winnipeg Hydro staff

There is no direct correlation between increases in EFTs and overhead. Overhead costs are driven by a number of factors that reflect the nature of the expense. Components of overhead include office & administrative building costs; depreciation expense on buildings, office equipment and computers; information technology costs; corporate services such as human resources, safety, document management etc. Examples of other cost drivers include material and external service costs pressures, technology requirements and enhanced safety needs.

PUB/MH I-5 (REVISED)

Subject: **Tab 3: Corporate Overview**
Reference: **Tab 3 Staffing/ Tab 4 Appendix 4.4, Schedule 4.5.4**

c) Please provide a schedule which indicates the salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized for each of the years 1999/00 to 2011/12

ANSWER:

Please see the following tables for salary, wages and benefits information for 2003/04 through 2011/12.

Labour & Benefits includes salary, wages, overtime and benefits.

(in thousands of $)

Labour and Benefits as a Percentage of OM&A and Domestic Revenue	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast
Labour and Benefits	$398,449	$423,093	$440,473	$457,233	$477,838	$509,592	$544,952	$556,311
Total OM&A Costs (before capitalization)	$542,660	$569,749	$596,229	$615,849	$638,594	$685,075	$723,701	$738,099
Labour and Benefits as a % of OM&A	73.4%	74.3%	73.9%	74.2%	74.8%	74.4%	75.3%	75.4%
Domestic Revenue (GCR)	$918,231	$938,954	$983,653	$1,023,613	$1,074,581	$1,126,812	$1,160,009	$1,192,762
Labour and Benefits as a % of GCR	43.4%	45.1%	44.8%	44.7%	44.5%	45.2%	47.0%	46.6%

Activity charges form the basis for cost allocation to capital projects. Activity rates are built up from a number of costs including salaries, wages and benefits, meals & accommodations, transportation costs, vehicle charges etc. An estimate of the activity charges recovering labour and benefit costs is 75%. The following outlines the amount of labour and benefits capitalized through activity charges.

(in thousands of $)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast
Capital Order Activities	($148,769)	($157,730)	($170,459)	($176,992)	($192,338)	($205,175)	($231,073)	($235,040)
Labour & Benefits Capitalized	($111,577)	($118,297)	($127,844)	($132,744)	($144,254)	($153,881)	($173,305)	($176,280)

PUB/MH I-6

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan: provide customers with exceptional value**

a) Please file a copy of the most current overall corporate marketing plan including energy options.

ANSWER:

Manitoba Hydro does not have a formal corporate marketing plan. Manitoba Hydro operates under the general guidance that its role is to provide customers with information on various options, including fuel choice to enable customers to choose the option which best meets their needs. Manitoba Hydro also promotes and markets a number of energy efficient opportunities within the Corporation's Power Smart initiative.

PUB/MH I-6

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan: provide customers with exceptional value**

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

ANSWER:

Based on the MH fiscal year the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) statistics are provided below.

Year	SAIFI	SAIDI	SAIDI (Minutes)
2009/10*	1.25	1.67	100.20
2008/09	1.39	1.68	100.80
2007/08	1.23	1.86	111.60

* Reporting period for the 2009/10 year-to-date: April 1, 2009 - February 15, 2010. Reporting period for remaining years is April 1 - March 31.

Manitoba Hydro's target for SAIDI is 92 minutes or less. Manitoba Hydro has exceeded this target over the last three fiscal years. Manitoba Hydro's target for SAIFI is 1.3 outages or less. In the years 2007/08 and 2009/10, Manitoba Hydro met this target.

The reasons for Manitoba Hydro not meeting its target performance are primarily due to equipment failures, adverse weather, and tree contact resulting in outages on the transmission and distribution systems. The two outages with the highest customer minutes for each year are detailed below.

2009/10

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

On June 27, a major wind storm resulted in multiple outages on Star Lake Feeder STL12-6. In total 538 customer interruptions and 1,383,198 customer minutes were associated with the outage.

2008/09

On August 31, a cable failure occurred on Inkster feeder IR771. In total 1,185 customer interruptions and 782,100 customer minutes were associated with the outage.

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

2007/08

On May 18, a lightning strike resulted in the tripping of 66 kV lines R94 and R95 resulting in outages at several stations in eastern Winnipeg. In total 25,336 customer interruptions and 2,278,493 customer minutes were associated with the outage.

On April 22, a scheduled outage was taken on 66 kV line 64K to complete the energization of a new circuit resulting in outages at several stations in the Interlake. In total 5,546 customer interruptions and 1,896,732 customer minutes were associated with the outage.

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Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan: provide customers with exceptional value**

c) Please provide details on the power outage experienced in the City of Winnipeg in January 2010 which impacted water pumping facilities in the city.

ANSWER:

On January 18, 2010 a semi-trailer contacted a City of Winnipeg cross walk signals light standard located at the intersection of Goulet St and Rue Youville in St. Boniface. The signal standard fell into two of Manitoba Hydro's energized 4,160 volt overhead lines creating a high fault current situation. This caused Manitoba Hydro's electrical protection equipment to operate at the nearby Goulet Station which serves the area. As the protection equipment attempted to clear the fault the inrush current caused the voltage to fluctuate at the 66,000 and 115,000 volt transmission line levels affecting a much larger area for 0.1 of a second. The outage to Goulet Station resulted in a 60 minute outage to 1,737 customers.

The voltage drop was sensed by City of Winnipeg water systems at three locations in Winnipeg and their protection relays in turn isolated their electrical systems taking the water pumps off line. An electrical fluctuation of this duration should not have impacted the City's under voltage electrical protection systems. It is our understanding that the City of Winnipeg has a policy that directs their water systems to remain off line for 10 minutes when isolation occurs. When these systems go off line gas-fired standby pumps are in place to provide back up. Due to operational problems with the City of Winnipeg gas-fired back up pumps the Winnipeg area experienced a drop in water pressure.

The City has indicated they will be upgrading the control and electrical systems associated with the Water Supply Systems in the near future.

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Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan: provide customers with exceptional value**

d) Please advise on NERC reliability and security requirements for the Manitoba Hydro system and discuss regulatory and cost implications.

ANSWER:

For many years NERC (North American Electric Reliability Corporation) produced electricity standards that reflected best practices for the reliable operation of electric systems and utilities adopted these standards on a voluntary basis, including Manitoba Hydro. Beginning in the mid-1990's there were calls for standards to be applied on a more uniform basis, because of the increased integration of the electric grid across North America, heavier usage of the grid in general, usage of the grid for competitive purposes (open access), growing congestion at particular nodes on the grid, and aging infrastructure.

The growing interdependence of the electrical grid in North America was illustrated in 2003 when a tree contacted a transmission line in Ohio and caused an outage that cascaded to a major blackout affecting Ontario and eight eastern States. A joint Canada-U.S. task force that was struck to investigate the blackout recommended a system of mandatory standards that would apply uniformly in Canada and the U.S.

NERC has no direct jurisdiction in Manitoba. NERC standards currently apply in Manitoba pursuant to Order in Council No. 206/2004, which authorized Manitoba Hydro to join the Midwest Reliability Organization (a regional delegate of NERC) in 2003 and adopt its standards. The Lieutenant Governor in Council has the authority to remand (disallow) a particular standard.

In 2005, Canadian federal and provincial authorities signed a Memorandum of Understanding with NERC which expressed support for mandatory standards. Implementation is specific to each Province. Legislation, passed in June 2009, makes compliance to NERC/MRO reliability standards a legal requirement in Manitoba for any user, owner, and operator of the electric grid. The legislation, which still awaits proclamation to become effective, gives the Lieutenant Governor in Council authority to adopt NERC/MRO standards and authorizes the MRO to monitor compliance, by way of regulation. It also gives the PUB authority to review and remand a NERC standard on a complaint basis and final enforcement authority to impose penalties and sanctions for a violation of the standards.

There are approximately 90 NERC standards currently in effect and approximately 25 more are anticipated within the next few years. Manitoba Hydro already complies with the great majority of these standards as a result of its past practice to voluntarily follow NERC standards. Effort has been underway during the past two years to document Manitoba Hydro's compliance for audit purposes, in accordance with the new mandatory system. Three new permanent staff positions were created in 2007 to manage the processes and controls necessary for an effective compliance program, including the management of cyber security standards. A project team, made up of temporary staff positions, will in the short term complete the implementation of the security standards, which requires an investment in additional physical infrastructure and cyber security technology.

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Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan: provide customers with exceptional value**

e) Please detail the number of electrical service outages by time, duration and by whether the outage was due to malfunctions in distribution, transmission or generation for the years 2002/03 through 2009/10 year-to-date.

ANSWER:

The outages due to malfunction in distribution and transmission for the years 2002/03 - 2009/10 year-to-date are provided in the following table. Loss of generation did not cause electrical service outages.

Year *	System	Number of Outages	Average Duration (Minutes) **
2009/10	Distribution & Subtransmission Outages	4479	94
to Feb 15	Transmission Outages	89	48
	Total Outages	4568	80
2008/09	Distribution & Subtransmission Outages	4731	89
	Transmission Outages	115	29
	Total Outages	4846	72
2007/08	Distribution & Subtransmission Outages	4730	104
	Transmission Outages	105	43
	Total Outages	4835	90
2006/07	Distribution & Subtransmission Outages	4,403	90
	Transmission Outages	105	54
	Total Outages	4,508	79

Year *	System	Number of Outages	Average Duration (Minutes) **
2005/06	Distribution & Subtransmission Outages	6,060	108
	Transmission Outages	181	37
	Total Outages	6,241	87
2004/05	Distribution & Subtransmission Outages	5,352	85
	Transmission Outages	171	52
	Total Outages	5,523	76
2003/04	Distribution & Subtransmission Outages	6,593	91
	Transmission Outages	122	36
	Total Outages	6,715	75
2002/03	Distribution & Subtransmission Outages	7,149	74
	Transmission Outages	94	25
	Total Outages	7,243	64

* Reporting period for the 2009/10 year-to-date: April 1, 2009 - February 15, 2010. Reporting period for remaining years is April 1 - March 31.

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

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Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan: provide customers with exceptional value**

f) Please detail the nature and frequency of transmission restrictions on exports to the USA, Ontario or Saskatchewan from the years including the Bipole I & II failure through 2009 year-to-date.

ANSWER:

Transfer limits are restricted to bind flows to reliability related limits. The limits may be in Manitoba Hydro's system, in neighbouring systems, or in distant areas.

In order to express a meaningful type of frequency calculation, attached are tables expressing monthly transfer capability in percent from 2005 through 2009 by area, by export and import, and in off-peak and on-peak periods. Data was not available to provide the calculation for the period 1996 through 2004.

Transfer limits change with time. The table below identifies the operating limits that were used to calculate the transfer capability percentages.

System Intact – Transfer Limits by Year in MW for the Ontario (ONT), Saskatchewan (SPC) and USA

	ONT				SPC				USA			
	Summer		Winter		Summer		Winter		Summer		Winter	
	Exp	Imp	Exp	Imp	Exp	Imp	Exp	Imp	Exp	Imp	Exp	Imp
2005	263	64	263	263	325	200	400	425	1968	1050	1968	1050
2006	263	113	263	113	180	75	250	275	1951	1050	1951	1050
2007	262	22	275	275	200	175	150	85	2015	850	1965	850
2008	230	20	251	210	200	175	325	325	2015	850	2015	850
2009	230	20	251	210	200	175	325	325	2015	850	2015	850

Available Transfer Capability 2005

Interface	ONT				SPC				USA			
	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp
Jan	100.00%	99.24%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.91%	99.89%	99.91%	100.00%
Feb	95.31%	72.50%	98.02%	78.25%	98.86%	97.74%	99.70%	99.40%	100.00%	100.00%	99.80%	100.00%
Mar	100.00%	95.36%	100.00%	98.84%	99.36%	96.33%	99.33%	99.15%	99.85%	99.82%	99.97%	99.89%
Apr	98.91%	91.38%	99.52%	96.57%	100.00%	100.00%	100.00%	100.00%	91.44%	89.13%	97.01%	95.13%
May	99.03%	97.21%	100.00%	100.00%	98.33%	75.54%	91.40%	82.41%	99.52%	96.87%	99.82%	98.41%
Jun	93.01%	89.09%	95.81%	96.24%	95.34%	89.90%	97.57%	94.74%	99.46%	99.46%	99.04%	99.01%
Jul	100.00%	98.92%	100.00%	100.00%	98.89%	100.00%	99.69%	100.00%	100.00%	98.48%	100.00%	98.50%
Aug	100.00%	96.71%	100.00%	97.26%	97.86%	100.00%	95.08%	100.00%	100.00%	100.00%	100.00%	100.00%
Sep	96.65	90.95	94.63	93.87	96.63	87.38	96.15	90.00	91.65	90.95	94.63	93.87
Oct	99.06	95.21	100.00	100.00	80.77	76.23	89.79	87.80	99.75	99.97	99.98	100.00
Nov	96.33	99.42	99.83	99.59	69.07	67.43	85.56	86.88	100.00	97.14	100.00	98.57
Dec	100.00	100.00	100.00	100.00	98.68	93.88	98.46	97.12	81.42	96.36	82.66	95.50

Available Transfer Capability 2006

Interface	ONT				SPC				USA			
	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp
Jan	79.07%	79.07%	80.80%	80.80%	100.00%	100.00%	100.00%	100.00%	99.75%	100.00%	100.00%	100.00%
Feb	65.52%	64.79%	67.30%	67.30%	99.66%	99.68%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Mar	39.76%	29.41%	44.98%	35.81%	86.33%	93.57%	92.07%	96.27%	92.29%	95.39%	96.30%	97.68%
Apr	47.20%	51.03%	52.76%	55.80%	68.97%	60.24%	77.50%	72.47%	88.29%	93.14%	87.42%	92.63%
May	45.31%	83.49%	51.79%	91.99%	92.49%	99.51%	99.09%	100.00%	99.78%	90.72%	99.66%	94.91%
Jun	93.90%	95.97%	96.83%	97.82%	80.14%	59.16%	83.07%	77.68%	99.40%	98.88%	99.69%	99.34%
Jul	97.80%	91.34%	94.46%	97.62%	98.78%	85.20%	98.45%	92.56%	82.45%	90.86%	78.74%	88.93%
Aug	92.07%	83.30%	93.11%	56.18%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Sep	87.54%	97.43%	94.78%	99.53%	100.00%	100.00%	100.00%	100.00%	99.54%	98.98%	100.00%	100.00%
Oct	90.30%	98.00%	98.02%	99.48%	96.28%	100.00%	100.00%	100.00%	90.06%	78.15%	93.12%	84.91%
Nov	98.89%	90.63%	100.00%	93.27%	100.00%	100.00%	100.00%	100.00%	99.23%	95.47%	100.00%	100.00%
Dec	100.00%	100.00%	100.00%	100.00%	97.76%	100.00%	99.56%	100.00%	100.00%	100.00%	100.00%	100.00%

Available Transfer Capability 2007

Interface	ONT				SPC				USA			
	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp
Jan	46.97%	46.96%	62.20%	62.90%	100.00%	100.00%	100.00%	100.00%	99.86%	99.75%	100.00%	100.00%
Feb	50.07%	50.07%	65.48%	65.48%	100.00%	78.88%	100.00%	84.17%	93.96%	94.84%	92.95%	93.98%
Mar	66.30%	66.30%	68.05%	68.05%	85.50%	87.67%	92.31%	91.21%	100.00%	97.38%	100.00%	100.00%
Apr	93.14%	90.12%	97.81%	96.69%	96.17%	90.48%	100.00%	97.12%	99.18%	100.00%	100.00%	100.00%
May	84.11%	89.46%	92.49%	95.84%	100.00%	100.00%	100.00%	100.00%	97.19%	99.59%	98.53%	100.00%
Jun	84.89%	97.54%	86.84%	99.85%	92.30%	88.22%	90.79%	88.13%	99.05%	92.66%	98.86%	97.77%
Jul	73.57%	96.66%	77.18%	97.12%	100.00%	100.00%	100.00%	100.00%	98.51%	99.58%	99.16%	100.00%
Aug	90.69%	85.46%	99.77%	95.34%	93.15%	78.16%	95.27%	83.80%	100.00%	98.87%	100.00%	99.25%
Sep	77.70%	40.10%	83.23%	54.17%	95.37%	92.91%	99.44%	99.30%	95.08%	89.31%	95.21%	99.86%
Oct	86.32%	28.00%	86.86%	26.79%	86.28%	87.89%	93.27%	93.21%	69.33%	89.40%	73.12%	99.19%
Nov	96.47%	96.94%	98.65%	98.84%	100.00%	100.00%	100.00%	100.00%	99.90%	98.75%	99.94%	100.00%
Dec	99.55%	99.51%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.72%	99.48%	100.00%	100.00%

Available Transfer Capability 2008

Interface	ONT				SPC				USA			
	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp
Jan	96.40%	96.30%	98.91%	98.80%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Feb	59.70%	76.49%	69.72%	84.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Mar	44.95%	91.81%	56.40%	94.83%	97.98%	99.40%	100.00%	100.00%	90.56%	92.90%	89.78%	100.00%
Apr	71.83%	75.81%	87.54%	93.56%	98.33%	99.73%	100.00%	100.00%	96.38%	99.81%	98.36%	100.00%
May	93.99%	87.69%	100.00%	93.05%	89.88%	86.83%	96.42%	94.77%	100.00%	95.30%	100.00%	96.25%
Jun	86.13%	100.00%	90.49%	100.00%	94.42%	92.78%	99.86%	99.90%	99.68%	100.00%	100.00%	100.00%
Jul	97.89%	100.00%	99.52%	100.00%	98.37%	94.42%	98.93%	96.34%	100.00%	100.00%	100.00%	100.00%
Aug	96.20%	100.00%	97.14%	100.00%	99.00%	98.80%	100.00%	100.00%	100.00%	98.93%	100.00%	99.74%
Sep	64.74%	93.30%	81.55%	97.50%	94.07%	95.80%	100.00%	100.00%	99.24%	96.06%	100.00%	96.25%
Oct	87.97%	77.78%	93.91%	84.62%	90.46%	93.29%	99.36%	97.80%	96.39%	91.83%	99.87%	100.00%
Nov	62.53%	66.45%	75.67%	81.75%	100.00%	97.69%	100.00%	100.00%	99.48%	97.11%	99.94%	100.00%
Dec	99.98%	99.94%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.48%	97.11%	99.94%	100.00%

Available Transfer Capability – 2009

Interface	ONT				SPC				USA			
	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp	On Exp	On Imp	Off Exp	Off Imp
Jan	86.92%	86.92%	90.68%	90.68%	100.00%	100.00%	100.00%	100.00%	99.71%	99.31%	99.80%	100.00%
Feb	64.24%	64.19%	65.72%	65.72%	66.15%	86.80%	72.22%	89.17%	100.00%	100.00%	100.00%	100.00%
Mar	50.30%	43.58%	50.74%	47.53%	99.72%	99.31%	100.00%	100.00%	98.53%	99.62%	99.29%	100.00%
Apr	90.21%	79.45%	89.78%	83.29%	94.43%	91.57%	98.68%	96.53%	92.77%	92.70%	94.58%	100.00%
May	84.23%	90.81%	95.37%	97.57%	87.24%	85.09%	95.55%	94.70%	93.89%	82.16%	95.38%	100.00%
Jun	84.01%	63.87%	89.34%	82.17%	87.82%	82.12%	96.15%	93.82%	68.24%	99.86%	69.53%	100.00%
Jul	99.09%	91.27%	99.78%	95.69%	98.57%	97.80%	100.00%	100.00%	100.00%	97.03%	100.00%	98.28%
Aug	96.32%	87.05%	98.87%	95.73%	93.11%	90.55%	98.54%	98.19%	100.00%	98.26%	100.00%	99.14%
Sep	72.33%	84.08%	78.52%	96.14%	100.00%	100.00%	100.00%	100.00%	100.00%	97.74%	100.00%	98.82%
Oct	86.87%	93.80%	94.18%	98.98%	74.04%	78.32%	100.00%	100.00%	100.00%	96.09%	100.00%	99.51%
Nov	99.76%	99.62%	99.94%	100.00%	92.64%	95.49%	96.81%	98.36%	99.06%	95.80%	100.00%	96.03%
Dec	94.12%	91.10%	96.97%	96.47%	100.00%	100.00%	100.00%	100.00%	99.36%	90.07%	99.74%	98.54%

Notes:

1. On Exp - abbreviation for On Peak Export
   On Imp – abbreviation for On Peak Import
   Off Exp – abbreviation for Off Peak Export
   Off Imp – abbreviation for Off Peak Import

2. On Peak (On) hours 0700 to 2200 hours Monday through Friday except on New Year's Day, Good Friday, Victoria Day, Canada Day, Labour Day, Thanksgiving Day and Christmas days. Periods not designated as peak hours are Off Peak (Off).

3. Seasonal Limits are used for all interfaces. Summer limits commence on May 1 and end on October 31. Winter Limits commence on November 1 and end on April 30. Seasonal limits may vary year to year and are dependent upon current year operating studies.

4. Ontario
   - ONT abbreviation for Ontario
   - Capability on the 230 kV Lines K21W and K22W from Manitoba to Ontario.
   - Import / Export limits are dependent upon Winnipeg River Flows.

5. Saskatchewan
   - SPC abbreviation for Saskatchewan
   - Capability on the 230 kV Lines R7B, P52E and R25Y.
   - Import / Export limits are dependent upon Western Area Load and Grand Rapids Generation.

6. United States
   - USA abbreviation for United States of America
   - Capability on 230 kV Lines R50M, G37C, L20D and 500 kV Line D602F.

7. Available Transfer Capability
   - Percent Available Transfer Capability = ATC %
   - ATCsi = Available Transfer Capability System Intact Conditions in MWhr
   - ATCpo= Available Transfer Capability Lost due to Planned Outages in MWhr
   - ATC% = (ATCsi – ATCpo) / ATCsi

PUB/MH I-7

Subject: **Tab 3: Corporate Overview**

Reference: **Corporate Strategic Plan "Be a leader in strengthening working relationships with aboriginal peoples"/ 2008 Annual Report Page 54**

a) For each of the measures and related targets, please provide a schedule that indicates the Corporation's performance against each target and discuss, including providing details on the number by type of jobs being created.

ANSWER:

Overall picture

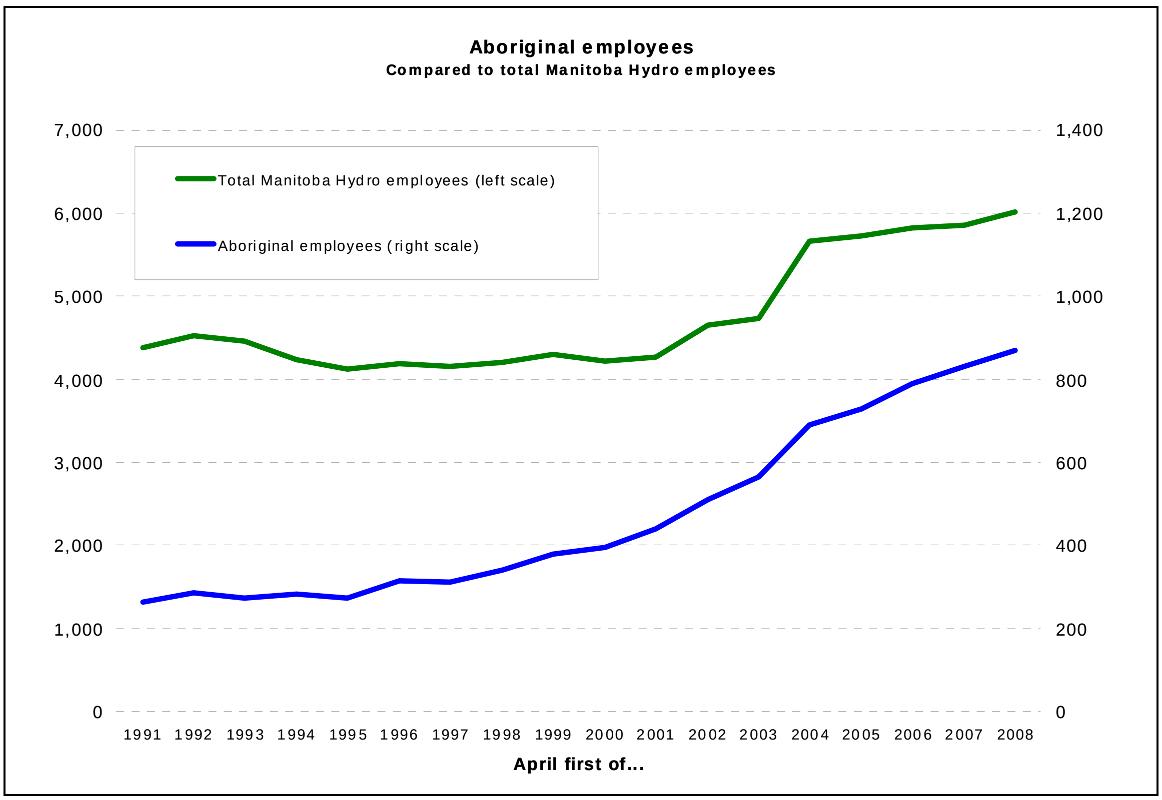


Figure 1

As can be seen in *Figure 1*, for at least the last 15 years Manitoba Hydro has been continuously increasing the aboriginal share of its workforce in terms both of absolute numbers and relative share. This growth in aboriginal workforce presence has been achieved not through the creation of new jobs for aboriginal people. Rather, Manitoba Hydro has leveraged aboriginal hiring through regular recruitment needs. *Figure 2* shows an occupational breakdown of Manitoba Hydro's recent new hires, together with a view of aboriginal representation within those new hires. (The chart covers 1106 new employees hired in the calendar years 2003 through 2008 and does not include students or term employees.)

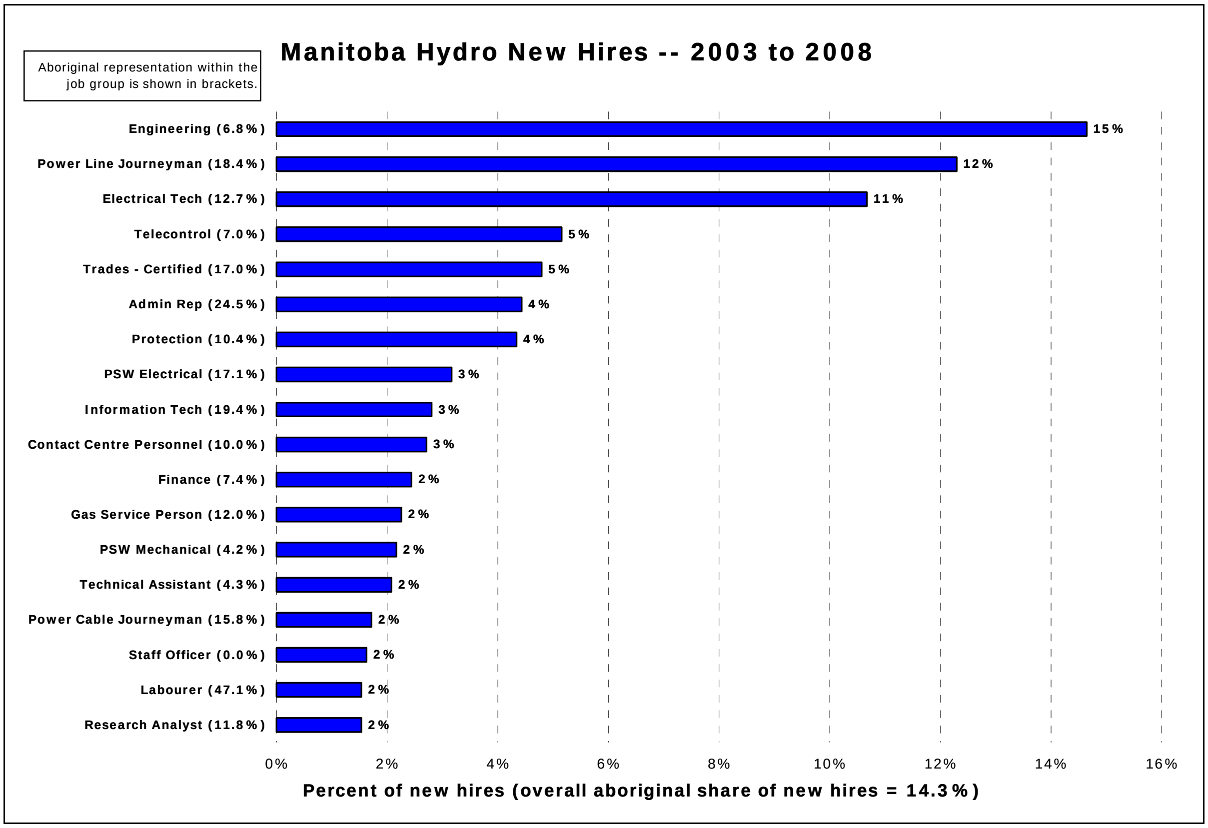
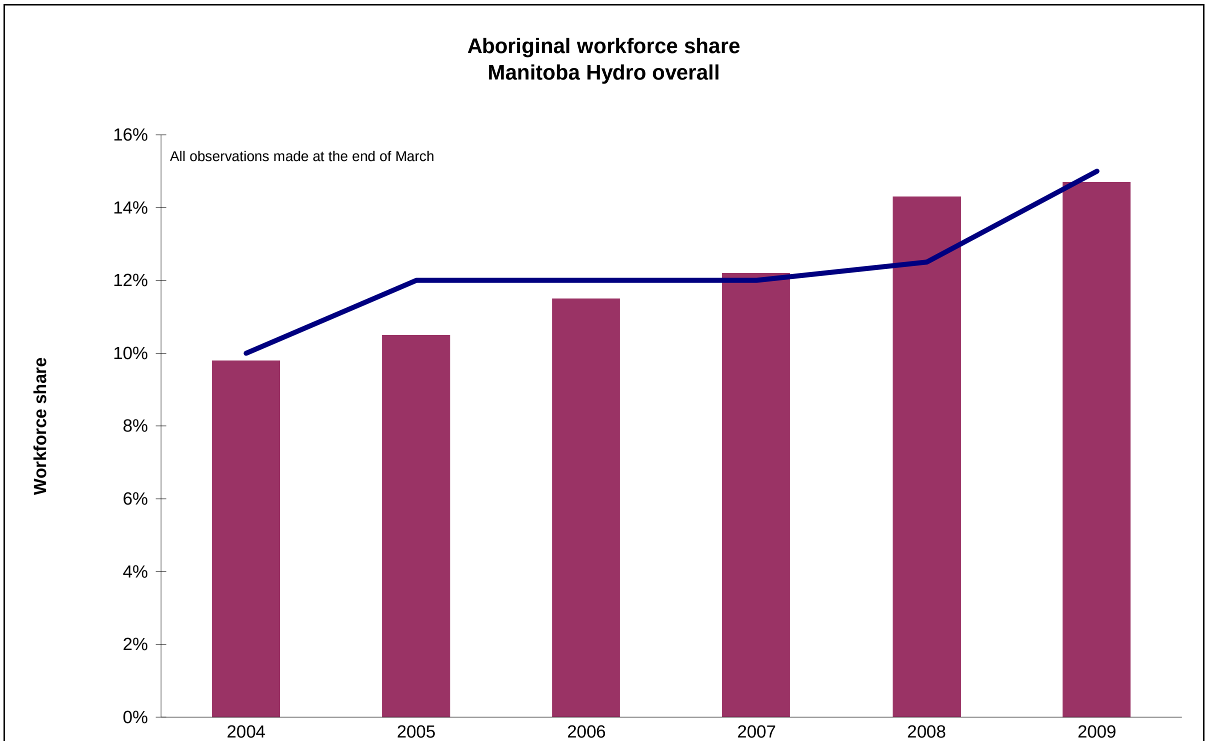


Figure 2

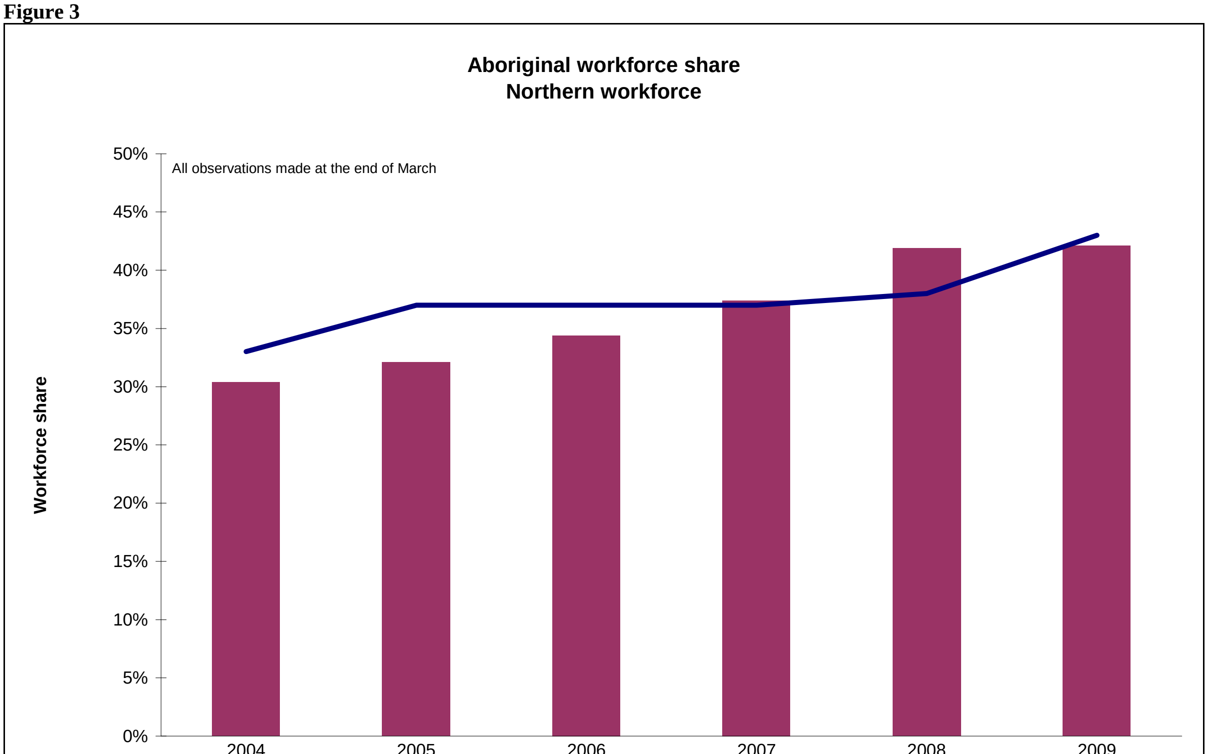
Performance against corporate goals

The following four charts detail Manitoba Hydro's aboriginal employment performance against stated corporate goals.



	2004	2005	2006	2007	2008	2009
Actual	9.8%	10.5%	11.5%	12.2%	14.3%	14.7%
Target	10.0%	12.0%	12.0%	12.0%	12.5%	15.0%

Figure 3



	2004	2005	2006	2007	2008	2009
Actual	30.4%	32.1%	34.4%	37.4%	41.9%	42.1%
Target	33.0%	37.0%	37.0%	37.0%	38.0%	43.0%

Figure 4

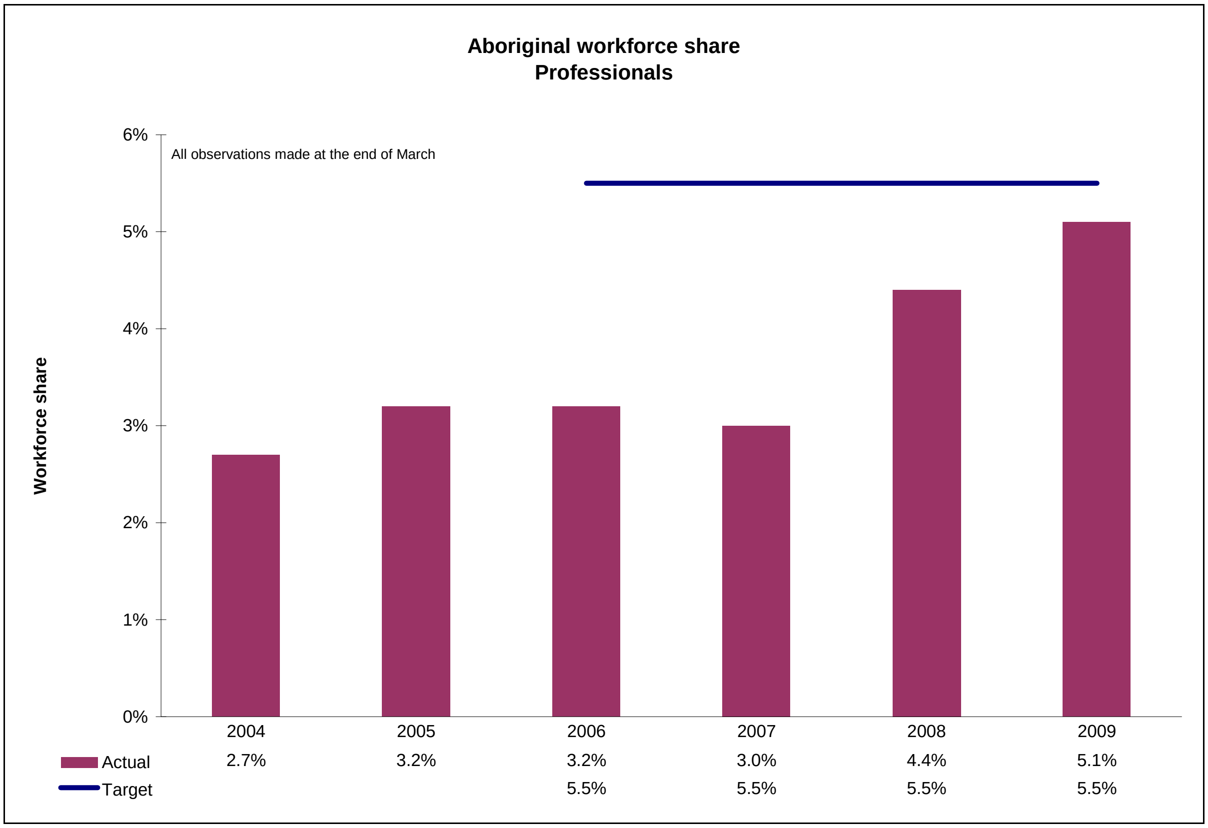


Figure 5

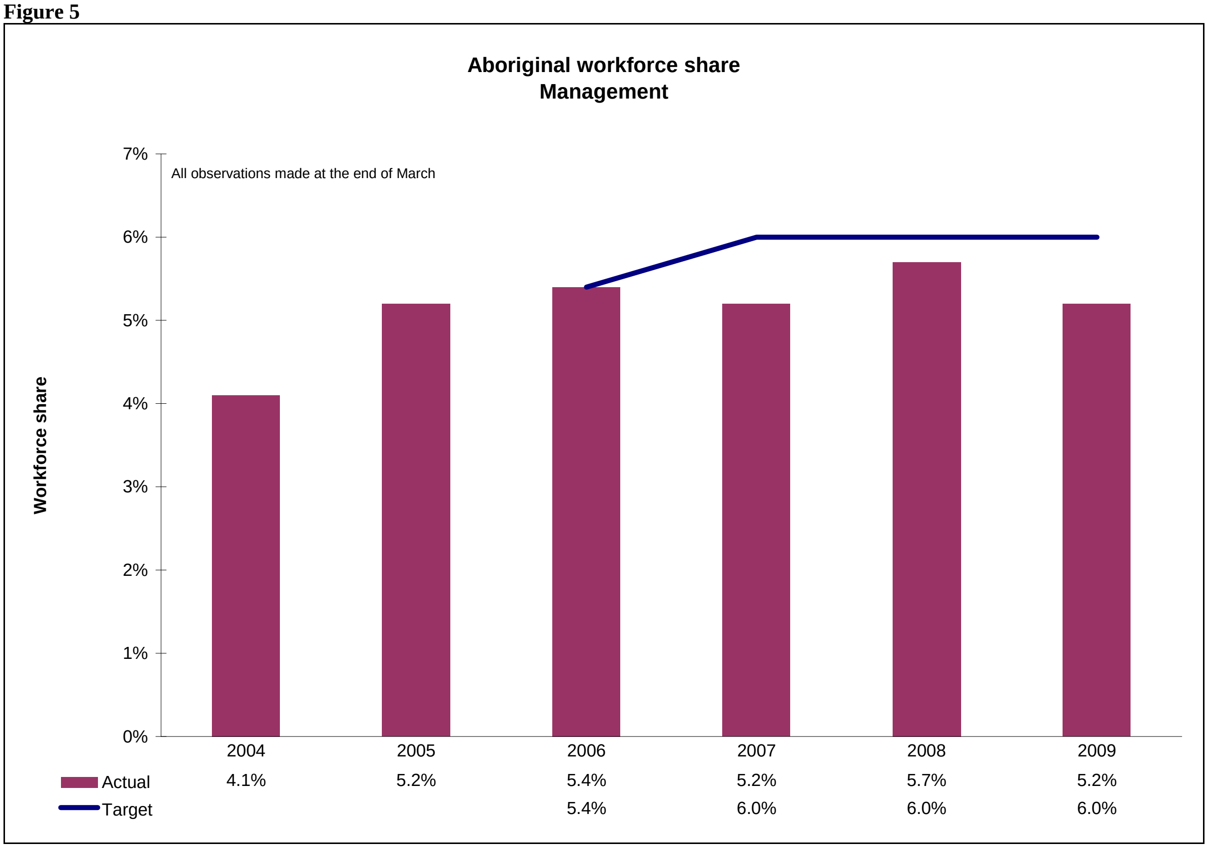


Figure 6

The Measure “Percentage of impacted Aboriginal communities with a workable management framework” has a Target of 100%. The target relates to the strategy "Resolve and manage ongoing obligations from past developments". A Workable Management Framework means an agreement with a community to address the adverse effects of existing works and operations. Comprehensive agreements to alleviate adverse effects are in place with twenty two Aboriginal communities. Processes continue with the other five affected communities.

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

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan "Be a leader in strengthening working relationships with aboriginal peoples"/ 2008 Annual Report Page 54**

b) **Please provide a schedule providing a breakdown of the $60 million funding commitment to the Hydro northern training and employment initiative by each participant, including the disbursements made by each participant in funding the commitment for the years 2007, 2008, and 2009.**

<u>ANSWER</u>:

The Hydro Northern Training and Employment Initiative is funded by Manitoba Hydro ($20 million), the Province of Manitoba ($10 million), Human Resources and Skills Development Canada ($22 million), Indian and Northern Affairs Canada ($3.26 million) and Western Economic Diversification ($5 million). It's administered by the Wuskwatim and Keeyask Training Consortium Inc.

Fiscal year ending March 31	**2007**	**2008**	**2009**
Manitoba Hydro	$3,358,282	$2,139,718	$2,267,679
Province of Manitoba	$700,000	$1,000,000	$450,121
Human Resources and Skills Development Canada	$5,612,675	$3,313,165	$1,091,681
Western Economic Diversification	$502,946	$0	$2,083,045
Indian and Northern Affairs Canada	$0	$0	$0

PUB/MH I-7

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan "Be a leader in strengthening working relationships with aboriginal peoples"/ 2008 Annual Report Page 54**

c) Please indicate the amount expended or planned to be expended by MH, and the number of individuals trained or forecast be trained through the Northern Training Initiative for each of the years 2004/05 through 2011/12

ANSWER:

As at September 30, 2009, 2,251 individuals have participated in training activities since the Hydro Northern Training and Employment Initiative began in 2001/02. The schedule shows the number of training activities started and completed each year. Some individuals take more than one training activity per year.

Fiscal year ending March 31	Manitoba Hydro Funding	Training Activities Started	Training Activities Completed
2005	$2,414,560	548	362
2006	$2,330,114	1026	633
2007	$3,358,282	944	481
2008	$2,139,718	1236	617
2009	$2,267,679	808	388
2010 *	$2,513,834	446	185
2011 Planned**	$600,000	0	0
2012 Planned	$0	0	0

* Is the actual funding to January 31, 2010 and the actual number of training activities started and completed to September 30, 2009.

** Holdback funding to be paid after the initiative ends March 31, 2010.

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

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan improve corporate financial strength**

a) **Please provide the Corporate Business Unit performance measurements that have been developed.**

<u>ANSWER</u>:

The Corporate Business Unit includes the Internal Audit Department, the Public Affairs Division, the General Counsel and Corporate Secretary, the Research and Development Manager, the Human Rights and Respectful Workplace Advisor and Subsidiary Operations. Manitoba Hydro does not report performance measures for the Corporate Group as a whole. Development of the Corporate Group performance measures is not a priority because of the nature of the activities which are largely focused on internal service and are relatively small in scale.

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

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan improve corporate financial strength**

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

<u>ANSWER</u>:

Utility	***OMA Cost ($ millions)***	***GWh's***	***$/GWh***
Hydro Quebec	*2,497*	*206,603 (Generation & Purchases)*	*12,085*
Saskpower	*430*	*18,601 (Electricity supplied)*	*23,117*
BC Hydro & BCTC	*1,122*	*103,311 (Total electricity sold)*	*8,856*
Manitoba Hydro	*360*	*35,200 (Total energy supplied)*	*12,386*

Source: 2008 & 2008-09 Annual Reports

PUB/MH I-8

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan improve corporate financial strength**

c) Please provide a comparison of the OM&A cost per customer for the years 2009 through 2017 provided at the last GRA with the current application filing of the schedule.

ANSWER:

Please see the following table for a comparison of the OM&A cost per customer for the years 2009 through 2017 (IFF09 to IFF07).

The increase in cost per customer, over the period, is primarily attributable to OM&A cost increases. The increase in OM&A between forecasts is primarily due to accounting changes and is partially offset by forecast increase to the number of customers.

(in millions of dollars)	Actual 2009	Forecast - IFF09 2010	2011	2012	2013	2014	2015	2016	2017
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

	Forecast - IFF07 (2008 Electric GRA)*								
(in millions of dollars)	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only'	349	358	365	377	386	394	402	410	418
# of Customers	524,220	528,117	531,958	535,740	539,458	543,123	546,726	550,269	553,751
OM&A (electric only) per customer (in dollars)	665	677	686	704	715	725	735	745	755

	Change								
(in millions of dollars)	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A (electric only) per customer (in dollars)	17	21	22	42	39	39	38	38	37

* The IFF07 information presented at the 2008 Electric GRA, for the years 2012-2017 has been revised to include the Wuskwatim OM&A expense consistent with the IFF09 presentation.

PUB/MH I-9

Subject: **Tab 3: Corporate Overview**
Reference: **Tab 3 Consulting & Mitigation Costs**

Please provide a table by major capital G&T project for the years 1999/00 to 2009/10 listing the annual amounts incurred/paid to External Consultants hired by MH, Internal MH Staff Costs, MH funded expenses for costs incurred by third parties, and annual mitigation costs paid to third parties.

ANSWER:

Please see the table below for Major New Generation & Transmission project annual amounts from 2004/05 to 2009/10.

(in thousands of dollars)

Sum of Actual		Year					
IM Node	Category	2005	2006	2007	2008	2009	2010
Wuskwatim - Generation	Consultants	13 031	10 732	11 036	8 481	12 310	8 009
	Contractors	94	800	25 163	109 897	121 554	190 595
	Interest	7 937	6 428	8 147	11 679	18 717	22 757
	Labour	5 020	1 996	8 190	12 901	13 147	12 994
	Materials & Other	3 313	400	7 029	5 670	4 333	5 997
	Mitigation			1 500	294	4 578	9
Wuskwatim - Generation Total		**29 395**	**20 356**	**61 064**	**148 921**	**174 639**	**240 361**
Wuskwatim - Transmission	Consultants	2 427	686	1 063	10 945	23 834	15 548
	Contractors	12	173	7 875	19 210	33 000	55 032
	Interest	(0)	2 282	1 434	3 333	7 304	9 710
	Labour	1 266	4 595	4 056	7 618	7 725	9 407
	Materials & Other	3 337	7 428	1 692	16 470	7 502	2 253
	Mitigation				10		
Wuskwatim - Transmission Total		**7 042**	**15 165**	**16 119**	**57 586**	**79 365**	**91 950**
Herblet Lake-The Pas 230 kV Transmission	Consultants			7	1 176	3 757	2 042
	Contractors				262	1 916	2 516
	Interest			2	70	298	957
	Labour			42	437	2 490	4 638
	Materials & Other			191	2 443	1 264	9 223
Herblet Lake-The Pas 230 kV Transmission Total				**241**	**4 388**	**9 727**	**19 376**
Keeyask - Generation	Consultants	18 960	17 946	18 934	21 531	24 482	20 795
	Contractors	54	12	225	839	42	134
	Interest	9 871	10 383	12 692	15 384	18 832	17 855
	Labour	2 890	2 915	3 515	4 584	4 419	6 099
	Materials & Other	1 538	1 045	718	775	719	1 177
	Mitigation					5 786	1 048
Keeyask - Generation Total		**33 314**	**32 301**	**36 083**	**43 112**	**54 280**	**47 108**
Conawapa - Generation	Consultants	4 387	8 901	14 095	15 706	16 552	9 243
	Contractors	26	415	3 107	1 540	670	955
	Interest	(1)	0	3 434	5 740	8 120	8 214
	Labour	2 503	4 793	6 764	6 342	5 795	5 311
	Materials & Other	1 563	3 624	5 237	4 703	2 292	1 837
	Mitigation						4 857
Conawapa - Generation Total		**8 478**	**17 733**	**32 636**	**34 030**	**33 429**	**30 417**
Kelsey Improvements & Upgrades	Consultants	132	389	216	142	260	376
	Contractors	3 107	10 068	15 522	13 946	27 031	20 957
	Interest	474	882	2 305	3 087	2 614	2 272
	Labour	3 025	5 329	7 267	9 885	9 155	6 668
	Materials & Other	477	1 476	4 373	4 043	5 417	5 218

(in thousands of dollars)

Sum of Actual		Year					
IM Node	**Category**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Kelsey Improvements & Upgrades Total		**7 214**	**18 144**	**29 682**	**31 103**	**44 477**	**35 491**
Kettle Improvements & Upgrades	Consultants					3	1
	Contractors					10	1 433
	Interest					21	99
	Labour				7	465	955
	Materials & Other					285	38
Kettle Improvements & Upgrades Total					**7**	**785**	**2 526**
Pointe du Bois - Generation	Consultants				4 706	7 438	4 145
	Contractors				0	189	(11)
	Interest				527	1 351	1 718
	Labour				2 275	3 893	3 539
	Materials & Other				500	473	165
	Transfer from Planning Studies				1 306		
Pointe du Bois - Generation Total					**9 314**	**13 345**	**9 554**
Pointe du Bois - Transmission	Consultants			0	18	296	254
	Contractors				3	81	14
	Interest			14	33	97	166
	Labour			273	583	1 016	1 220
	Materials & Other			1	132	225	2 797
Pointe du Bois - Transmission Total				**288**	**770**	**1 715**	**4 452**
Bipole 3	Consultants	511	484	633	344	1 447	5 728
	Contractors	11			0	2	2 154
	Interest	250	358	461	936	756	1 011
	Labour	374	369	354	639	1 764	3 207
	Materials & Other	89	2	24	36	12 890	7 684
	Transfer from Planning Studies					1 019	(0)
Bipole 3 Total		**1 235**	**1 213**	**1 472**	**1 955**	**17 878**	**19 782**
Riel 230/500kV Station	Consultants	0		101	295	563	5 461
	Contractors					24	5 763
	Interest	135	53	73	10	220	763
	Labour	51	314	44	607	2 189	4 694
	Materials & Other		0	24	1 676	663	7 326
	Costs transferred to Bipole 3				(270)	(1 651)	
Riel 230/500kV Station Total		**187**	**367**	**242**	**2 318**	**2 007**	**24 008**
Brandon CT Pipeline Upgrade	Contractors						3 640
Brandon CT Pipeline Upgrade Total							**3 640**
Northern AC Transmission System Req.	Consultants	737	277	190	31		
	Contractors	112	37	5			
	Interest	935	1 183	324	0		
	Labour	7 000	5 800	1 303	288		
	Materials & Other	10 326	1 538	2 227	76		
Northern AC Transmission System Requirements Total		**19 110**	**8 834**	**4 049**	**395**		
Brandon Combustion Turbine	Consultants	262					
	Contractors	448					
	Interest	50					
	Labour	198					
	Materials & Other	204					
Brandon Combustion Turbine Total		**1 163**					

PUB/MH I-10

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan maximize export power net revenues**

a) **What was the target for net export revenue as a percentage of total revenue for 2008/09 and the current fiscal year and how does it compare with the actual results.**

ANSWER:

Target: 25% (by 2008/09 through 2016/17)
Performance: 24.8%

PUB/MH I-10

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan maximize export power net revenues**

b) **Please discuss the actions taken to date in aggressively pursuing a balanced portfolio of export sales.**

ANSWER:

Please see Manitoba Hydro’s responses to CAC/MSOS/MH I-170(a), (b) and (c).

PUB/MH I-10

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan maximize export power net revenues**

c) **Please provide a schedule which indicates the relative net export revenue as a percentage of total electric revenue for the years 1999/2000 through 2018/19.**

ANSWER:

Net Export Revenue is defined as Extraprovincial Revenues from power sales less all fuel expenses, power purchases and water rental expenses allocated to extraprovincial power sales.

Net Export Revenue as a % of Total Revenue

2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
26%	36%	21%	27%	23%	18%	15%	18%

2012/13 Forecast	2013/14 Forecast	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
19%	19%	17%	20%	19%	18%	19%

PUB/MH I-10

Subject: **Tab 3: Corporate Overview**
Reference: **Corporate Strategic Plan maximize export power net revenues**

d) Please provide details of Corporate actions to expand the transmission capacity and to protect transmission rights to support access to Extra Provincial and U.S. export markets.

ANSWER:

Transmission service requests for incremental power transfers across all three interfaces (Saskatchewan, Ontario, US) are in the MHEB and/or SPC/MISO transmission queues. These service requests have triggered technical studies to determine the cost and method to increase transfer levels as requested.

A capital budget item has already been approved for upgrading the MB-ON interface to allow 100 MW of firm import into Manitoba from Ontario.

Detailed studies are underway for a new 500 kV tie line to the US to provide an additional 1100 MW of export and associated import capability.

An additional 150 MW of incremental export service to Saskatchewan has been requested and will be studied jointly by SPC and MHEB.

PUB/MH I-11

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 4**

a) **Please file a copy of the Joint Keeyask Development Agreement.**

ANSWER:

The Joint Keeyask Development Agreement in its entirety is located on Manitoba Hydro's external website at http://www.hydro.mb.ca/projects/keeyask/jkd_agreement.shtml .

<u>PUB/MH I-11</u>

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 4**

b) Please provide a summary of the terms and conditions of the Wuskwatim Generating Station Civil construction contract.

<u>ANSWER</u>:

Terms and conditions for the Wuskwatim General Civil Works Contract are based on the International Federation of Consulting Engineers (FIDIC) model, customized to suit Manitoba Hydro circumstances. Key features:

- Open book, reimbursable cost contract
- Payment based on actual costs with no hidden fees
- Fixed markup for overhead and profit
- Target Cost structure, with provisions to share savings and cost overruns
- Cap on the Contractor's liability for the sharing of cost overruns
- Incentives for early completion (bonus and liquidated damage provisions)

PUB/MH I-11

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 4**

c) Please provide a summary of the terms and conditions of the term sheet with Wisconsin Public Service and Minnesota Power and a status report with time lines.

ANSWER:

Please see Manitoba Hydro's response to RCM/TREE/MH I-27. Note that certain information is redacted as it is commercially sensitive and confidential.

<u>PUB/MH I-11</u>

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 4**

d) **Please confirm that the term sheets will not be made into legally binding agreements until MH's major capital projects have been reviewed by the PUB or other Agency as directed by the Government.**

<u>ANSWER</u>:

Upon completion of negotiations, the term sheets will be legally binding contracts, subject to the fulfillment of certain conditions, such as the obtaining of all necessary licenses and permits to facilitate construction and the requisite Orders in Council issued by the Government of Manitoba.

PUB/MH I-11

Subject: Tab 4: Financial Results & Forecast
Reference: 2009 Annual Report, Page 4

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

ANSWER:

One additional Keeyask future development agreement has been reached since the signing of the JKDA in May 2009.

The agreement was signed November 24, 2009, and provides for Tataskweyak Cree Nation to undertake the development of a culturally sensitive Heritage Resources Management Plan for the Split Lake Resource Management Area applicable to the construction and operation phases of the potential Keeyask Generating Station.

The plan is designed to ensure protection of heritage resources in the area as they may be discovered during construction and operation activities. The plan will set out procedures for handling and reporting heritage resources if they are discovered by personnel in the course of their duties. The plan will become a part of the operational procedures for contractors and staff of the Keeyask project. It is anticipated this plan will be completed by the end of June 2010.

PUB/MH I-11

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 4**

f) Please provide an update on the negotiations with Babcock and Brown Canada ULC for the proposed 300 MW new wind farm project. Please indicate whether the project scope and timeline have changed.

ANSWER:

In 2009, Babcock and Brown sold their North American holdings to Riverstone Holdings, creating "Pattern Energy". Manitoba Hydro continues to negotiate with Pattern Energy for the purchase of energy from a proposed 138 MW wind farm near St. Joseph, Manitoba.

PUB/MH I-11

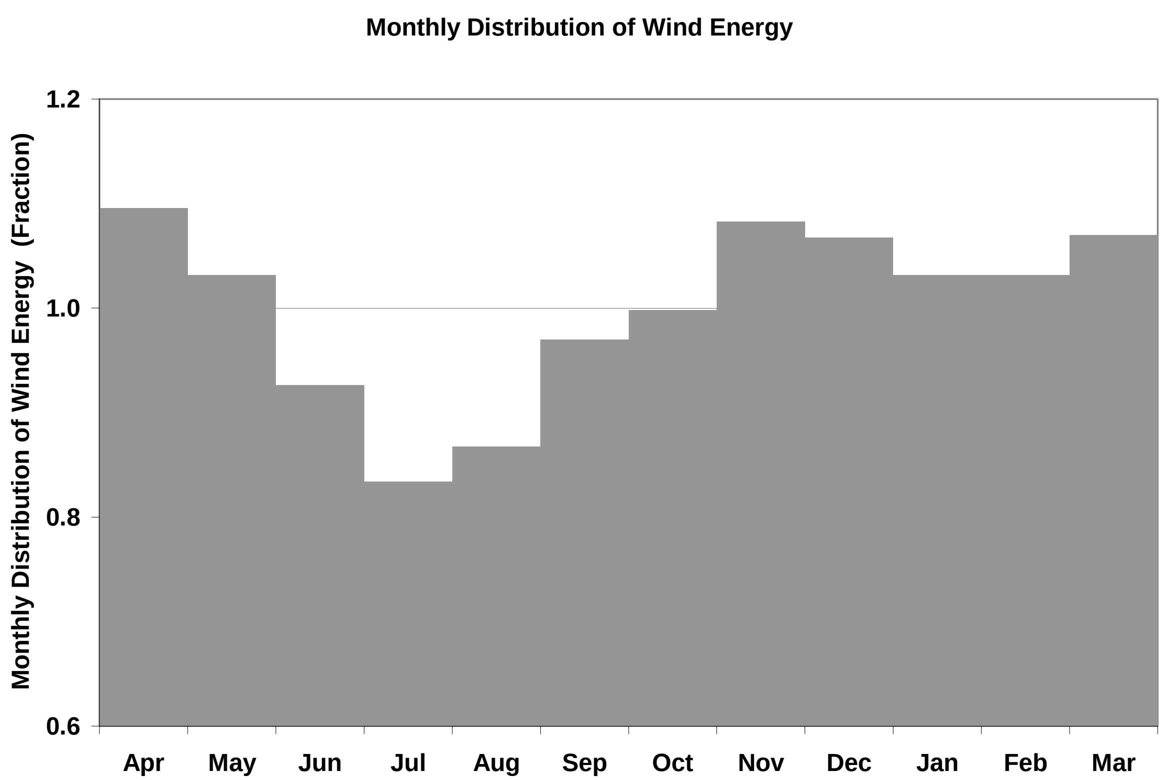
Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 4**

g) What is the Dependable Energy [GWh] associated with each wind generation project and how does this dependable energy fluctuate on a seasonal basis?

ANSWER:

For information relating to annual dependable energy, please refer to the response to PUB/MH I-86(a).

Manitoba Hydro utilizes a set of factors in order to distribute the annual dependable energy into each month of the year. This set of factors for the monthly distribution for wind energy is reproduced below and was provided in response to Information Request PUB/MH I-27(g) in the 2008 GRA. The factor in any month represents the ratio that should be applied to the monthly energy relative to a uniform distribution of energy over the months.



PUB/MH I-11

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 4**

h) Please provide the definition for dependable wind energy.

ANSWER:

Dependable energy from wind is defined as the minimum generation that could be expected from a wind farm over the period of a year compared to the long-term average generation. Dependable wind energy corresponds to an extreme year in which wind speed is consistently below average. Manitoba Hydro uses a factor of 85% to convert average annual wind production into annual dependable energy.

For more information, please see the response to PUB/MH I-86(b).

PUB/MH I-11

Subject: Tab 4: Financial Results & Forecast
Reference: 2009 Annual Report, Page 4

i) Please identify cold weather performance operating parameters of St. Leon Wind Farm.

ANSWER:

Manitoba Hydro does not own the St. Leon wind farm and consequently does not possess full knowledge of the specific characteristics of the units. However, it is Manitoba Hydro's understanding that the units at St. Leon are Vestas V82-1.65 MW wind turbines and these are equipped with an "Arctic Package" to allow for low temperature operation down to -33°C. If the temperature drops below -33°C during operation and the turbine cuts out, it will not normally cut in again until the temperature rises again to -31°C.

<u>PUB/MH I-12</u>

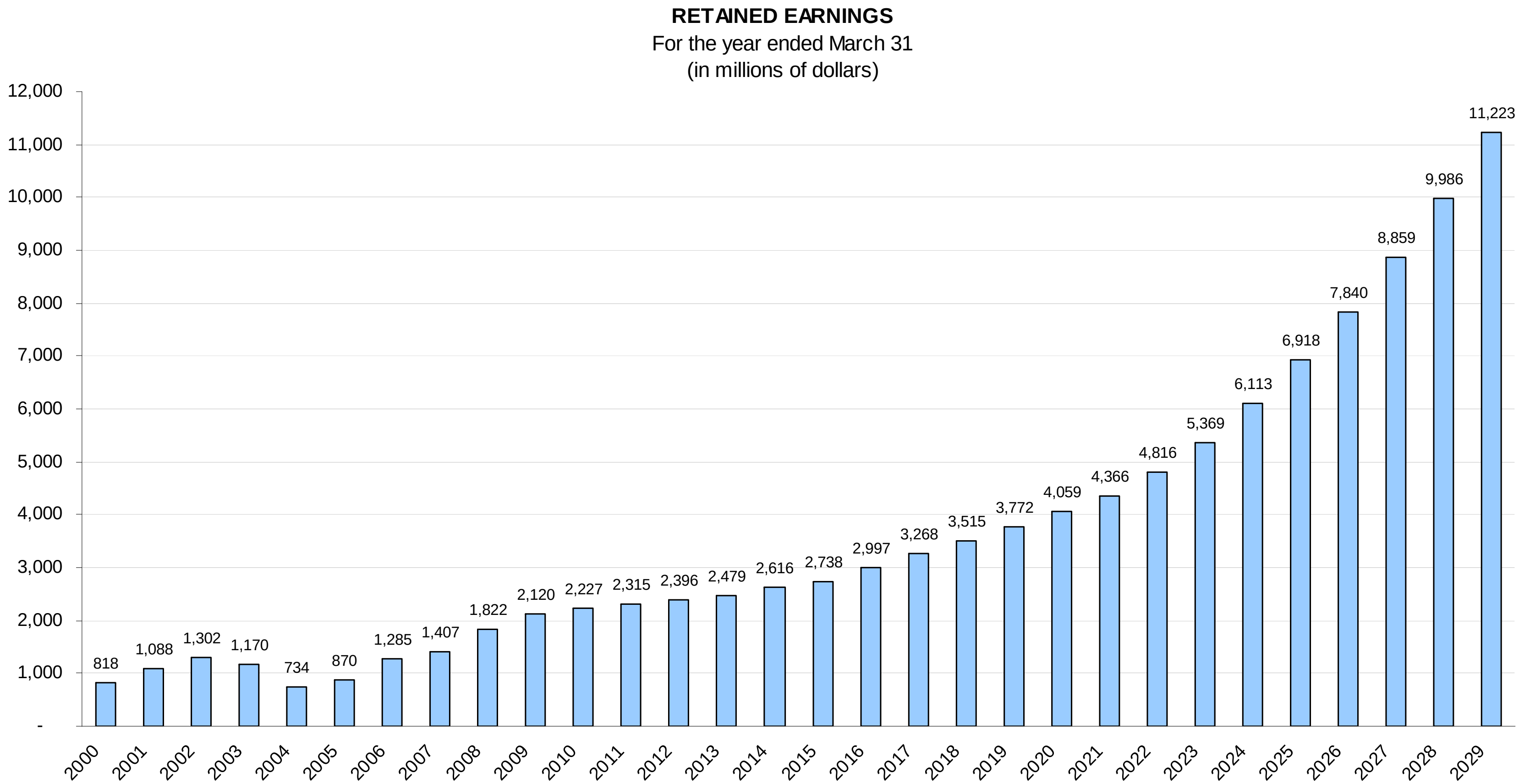
Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report Page 69**

Please provide an extension of the graphs reflecting the level of retained earnings and the debt to equity ratio forecast for each of years through 2030.

<u>ANSWER</u>:

Please see attached graphs.

Note: the 20 Year Financial Outlook extends the Integrated Financial Forecast (IFF09-1) to the year 2029 therefore data for 2030 is not available.


RETAINED EARNINGS
For the year ended March 31
(in millions of dollars)
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
818
1,088
1,302
1,170
734
870
1,285
1,407
1,822
2,120
2,227
2,315
2,396
2,479
2,616
2,738
2,997
3,268
3,515
3,772
4,059
4,366
4,816
5,369
6,113
6,918
7,840
8,859
9,986
11,223
2000
2001
2002
2003
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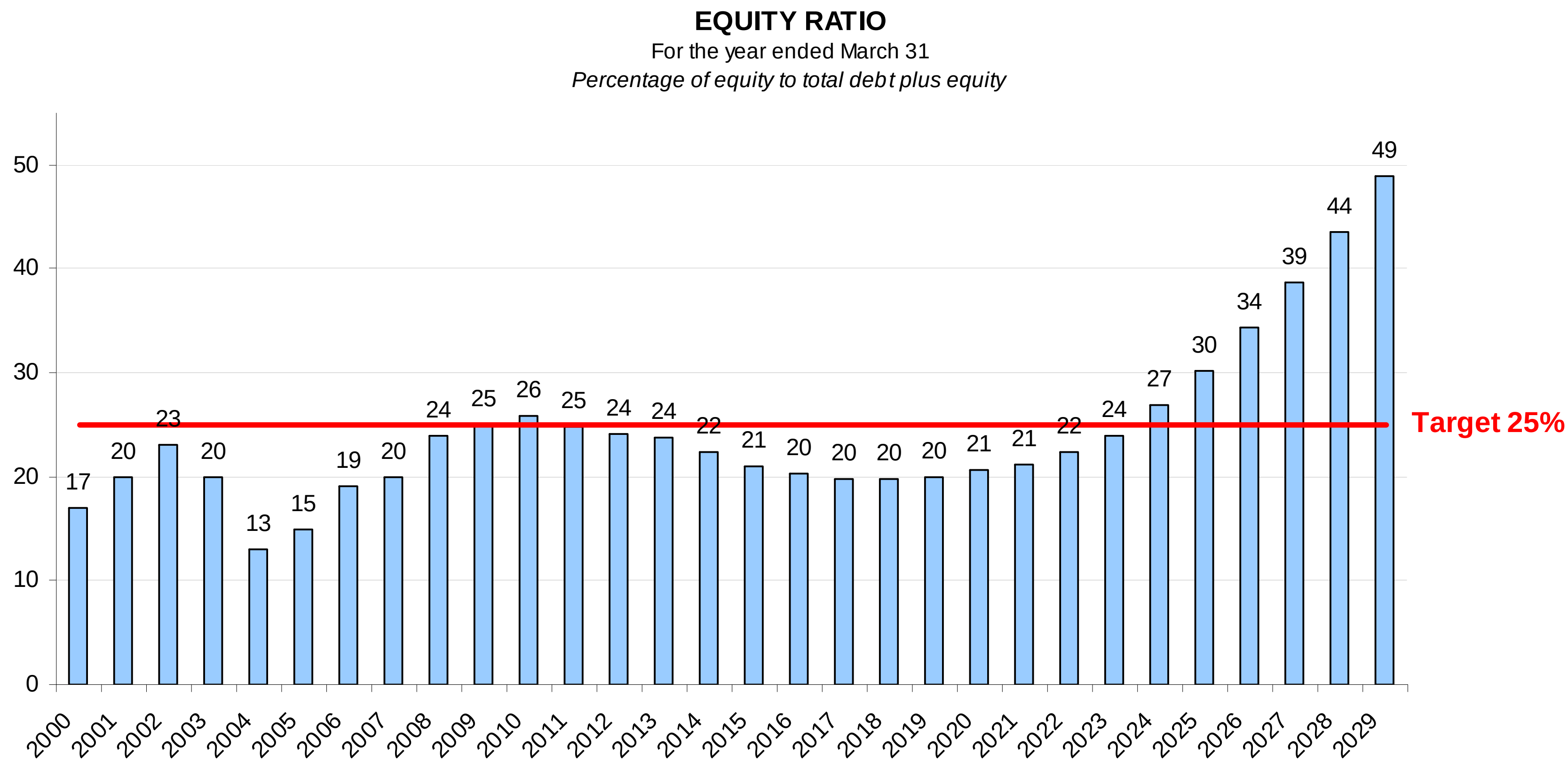

EQUITY RATIO
For the year ended March 31
Percentage of equity to total debt plus equity
0
10
20
30
40
50
17
20
23
20
13
15
19
20
24
25
26
25
24
24
22
21
20
20
20
20
21
21
22
24
27
30
34
39
44
49
Target 25%
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029

<u>PUB/MH I-13</u>

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report**

Please file MH's 3rd Quarter Reports for 2009/10.

<u>ANSWER</u>:

Please see Appendix 26.

PUB/MH I-14

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report Page 73 Depreciation Expense**

a) Please indicate the impact on the increase in depreciation expense related to the shortening of the amortization period of electric Power Smart Programs from fifteen to ten years

ANSWER:

Please see the following table for a comparison of the ten year to fifteen year amortization period for DSM.

Depreciation Expense - 10 Years vs. 15 Years **($000's)**

	2009	2010	2011	2012
Depreciation based on 10 years	20 102	21 943	24 829	28 703
Depreciation based on 15 years	13 562	14 918	17 119	19 469
Increase in Depreciation Expense	**$ 6 541**	**$ 7 025**	**$ 7 710**	**$ 9 234**

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

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report Page 73 Depreciation Expense**

b) Please indicate the impact of the change in accounting policy on revenue requirement for each of the fiscal years 2009, through 2012.

<u>ANSWER</u>:

The revenue requirement changes are identical to the change in depreciation and amortization expense. Please see part a of this response for those impacts.

PUB/MH I-14

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report Page 73 Depreciation Expense**

c) **Please provide a description of the accounting policy followed in other Canadian Jurisdictions.**

ANSWER:

Please see the following table.

Utility Name & Location (Electric)	**DSM Accounting Policies**
Manitoba Hydro	Manitoba Hydro amortizes Electric and Gas DSM costs over 10 years.
BC Hydro- British Columbia	BC Hydro recently received approval to continue amortizing demand-side management program costs over 10 years.[1]
ATCO Electric- Alberta	DSM program costs are treated as O&M expenditures, which are expensed in the year that they occur.
SaskPower- Saskatchewan	All demand-side management program costs are expensed in the year they occur.
Hydro Quebec	The costs related to implementation of the Energy Efficiency Plan, such as specific energy conservation programs, are charged to a separate account and amortized over 10 years on a straight-line basis, except for the costs incurred prior to January 1, 2006, which are amortized over five years.
Ontario Energy Board	Ontario Power Authority (OPA) provides electricity distributors with funding for their Conservation and Demand Management (CDM) programs. When a distributor's CDM program is not entirely funded by the OPA, these costs are recovered through distribution rates and are expensed in the year they occur.

[1] BCUC Order G-91-09

PUB/MH I-15

Subject: Tab 4: Financial Results & Forecast
Reference: 2009 Annual Report Environmental Initiatives

Please indicate the total funding provided or committed by MH for each of the years 2007/08 to 2011 for the following:

i. Environmental Partnership Fund (Page 48)
ii. GHG Monitoring (Page 48)
iii. Forest Enhancement Program (Page 50)

ANSWER:

Environmental Partnership Fund

Fiscal Year	2007/08	2008/09	2009/10 (Projected)	2010/11 (Projected)
Environmental Partnership Fund Expenditures	$51,750	$106,370	$100,000	$100,000

GHG Monitoring

Fiscal Year	2007/08	2008/09	2009/10 (Projected)	2010/11 (Projected)
GHG Monitoring	$90,600	$115,600	$136,000	$147,800

Forest Enhancement Program

Fiscal Year	2007/08	2008/09	2009/10 (Projected)	2010/11 (Projected)
Funds Awarded/Committed	$384,845	$305,416	$327,054	$355,704

PUB/MH I-16

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

Reference: **2009 Annual Report Page 82, Accounting Changes Section 3031 Inventories**

a) **Please provide further detail on the source of the $5 million annual increase in operating and administrative expenses as a result of the adoption of the new standard. To what extent was this change reflected in IFF08-1 and IFF09-1**

ANSWER:

Effective April 1, 2008, the Corporation adopted Canadian Institute of Chartered Accountants (CICA) Handbook Section 3031, Inventories. This standard stipulates that certain types of costs relating to inventory are not eligible for capitalization, specifically storage and carrying charges. Prior to adoption of this standard, Manitoba Hydro allocated inventory storage and carrying costs to capital and operating programs through an overhead applied as a percentage of the value of stores materials issued to each program.

Effective April 1, 2008, inventory storage and carrying charges were removed from overhead, resulting in an annual increase in Operating & Administrative expense of $5 million.

IFF08-1 did not include any provision for this accounting change.

IFF09-1 incorporates this accounting change. Overhead charges have been reduced within each capital program which involves the use of stores issue materials, resulting in an annual increase to Operating & Administrative expense of $5 million.

PUB/MH I-16

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report Page 82, Accounting Changes Section 3031 Inventories**

b) **Please re-file IFF09-1 Pages 32 to 36 including an additional line item quantifying the net impact of accounting changes reflected in the IFF. Please provide a further detailed schedule on the net amount, including narrative descriptions of the changes.**

ANSWER:

Please see the attached table below. IFF09-1 includes CICA accounting changes that incorporate general and administrative costs and research related expenditures associated with intangible assets such as planning studies, demand side management and information technology which are no longer eligible for capitalization. Also, IFF09-1 includes a general provision for International Financial Reporting Standards (IFRS) for potential changes such as accounting for property, plant and equipment, regulatory accounting, employee benefits and the first-time adoption of IFRS (IFRS1).

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
(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	361	369	377	385	394	402	411	419	441	452	471
CICA Accounting Changes:											
Reduction in Stores Overhead Capitalized	5	5	5	5	5	5	5	5	5	5	5
Reduction in Intangible Assets Capitalized	4	4	4	4	4	4	4	4	4	4	4
Reduction in Administrative & General Overhead Capitalized	2	2	2	2	2	2	2	2	2	2	2
IFRS Accounting Changes			15	15	15	15	15	15	15	15	15
Finance Expense	417	413	468	525	527	544	529	545	587	674	878
Depreciation and Amortization	372	391	412	442	453	474	485	490	511	544	578
CICA Accounting Changes Amortization	(4)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(7)	(7)	(7)
IFRS Accounting Changes Amortization	-	-	(0)	(1)	(1)	(2)	(3)	(3)	(4)	(5)	(5)
Depreciation and Amortization	368	386	407	435	446	466	476	481	501	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	1,505	1,723	1,824	1,860	1,922	1,963	2,046	2,156	2,370	2,617
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	78	87	72	125	113	248	263	235	244	276
*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
(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	12,538	13,052	15,115	15,629	16,067	16,799	17,258	17,990	20,477	21,797	25,222
CICA Accounting Changes	(11)	(18)	(26)	(33)	(41)	(48)	(56)	(63)	(71)	(78)	(86)
IFRS Accounting Changes	-	-	(15)	(30)	(45)	(60)	(75)	(90)	(105)	(120)	(135)
Accumulated Depreciation	(4,663)	(5,020)	(5,401)	(5,810)	(6,225)	(6,662)	(7,109)	(7,564)	(8,041)	(8,553)	(9,100)
CICA Accounting Changes	1	2	3	4	6	8	11	13	16	20	23
IFRS Accounting Changes	-	-	0	1	2	4	7	10	14	19	25
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	13,085	15,950
Construction in Progress	1,947	2,458	1,341	1,818	2,838	3,854	5,532	6,948	6,159	6,446	4,168
Current and Other Assets	2,791	2,758	2,911	2,965	2,746	2,898	3,084	3,296	3,601	3,385	3,720
CICA Accounting Changes	(23)	(23)	(22)	(21)	(20)	(19)	(18)	(18)	(17)	(16)	(16)
IFRS Accounting Changes	-	-	(17)	(18)	(18)	(19)	(19)	(20)	(20)	(20)	(21)
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,546	15,353	16,798	18,656	20,545	22,057	22,922	23,843
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,054	8,769	10,349	11,505	13,123	14,412	15,346	16,429	14,147
Current and Other Liabilities	2,156	1,926	2,119	2,916	2,106	2,306	2,333	2,692	3,045	2,586	5,514
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,150	2,222	2,254	2,307	2,413	2,508	2,739	2,986	3,206	3,436	3,699
CICA Accounting Changes	(33)	(39)	(45)	(50)	(55)	(59)	(63)	(67)	(71)	(75)	(78)
IFRS Accounting Changes	-	-	(32)	(47)	(61)	(74)	(87)	(99)	(111)	(121)	(131)
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,546	15,353	16,798	18,656	20,545	22,057	22,922	23,843

<u>PUB/MH I-17</u>

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report Page 88**

Please file the most recent goodwill impairment review in accordance with CICA Handbook Section 3062.

<u>ANSWER</u>:

The results of the most recent goodwill impairment reviews demonstrate that no impairment has occurred. The results were as follows:

Centra Gas

	($ millions)
Present value of free cash flows	314
Terminal value	507
Enterprise value	821
March 31, 2008 Centra Gas asset value	699
Excess enterprise value	122

Winnipeg Hydro

	($ millions)
Present value of free cash flows	3 608
Terminal value	14 156
Enterprise value	17 764
March 31, 2008 asset value	11 068
Excess enterprise value	6 696

The Winnipeg Hydro impairment review incorporates all electric operations as the Winnipeg Hydro operations can no longer be segregated as an entity.

PUB/MH I-18

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, page 91 AOCI**

a) Please discuss what factors led to the unrealized foreign exchange loss on debt in cash flow hedges of $439 million.

ANSWER:

The unrealized foreign exchange loss on debt in cash flow hedges in 2008-2009 was comprised of the following:

	$ Millions
Monthly revaluation of US Debt hedging US Export Revenues for changes in FX rates	(446)
Unrealized FX gains on FX Forward Contracts hedging USD Interest	7
Net Unrealized FX Loss on Debt in Cash Flow Hedges March 31, 2009	**(439)**

The US long term debt and its associated interest payments are in a natural hedge with US export revenues. Every month the US long term debt principal is translated into a Canadian equivalent utilizing the month end foreign exchange rate. In the absence of an accounting cash flow hedge, the resultant gain or loss would be reflected in finance expense and lead to significant income statement volatility. Therefore, accounting hedges have been established on the US debt principal so that monthly foreign exchange translation gains or losses do not flow through the income statement, and instead are recorded as unrealized foreign exchange gains (losses) in Other Comprehensive Income (OCI).

The US dollar was at $1.0279 at March 31, 2008 and $1.2602 at March 31, 2009. Consequently the US long term debt portfolio as translated into a Canadian equivalent increased by $446 million. With the establishment of accounting cash flow hedges, the income statement is protected from this volatility as the offsetting $446 million debit was recorded as an unrealized loss in OCI as opposed to an increase in finance expense.

The $7 million unrealized FX gain on FX forward contracts hedging USD interest was due to the weighted average purchase exchange rate on the contracts being lower than the March 31, 2009 exchange rate. The $7 million unrealized FX gain represents the portion of the mark to market value of FX forward contracts hedging future USD payments that have not been accrued at March 31, 2009. It is the FX rate in the contract that determines the actual payment expense so when the USD strengthens relative to the date at which the FX contacts are purchased, there is an unrealized gain that accumulates as the contract is revalued every month.

PUB/MH I-18

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, page 91 AOCI**

b) Please provide an update of the current balance of the AOCI

ANSWER:

The unaudited AOCI balance at December 31, 2009 is in a credit position of $223 million.

PUB/MH I-19

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Note 6, Page 99**

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

i. **Describe MH's policy for capitalizing Construction in Progress costs.**
ii. **Please provide a breakdown of the balances by component of capitalized costs (wages, overhead etc.) for each major Generation and Transmission project.**

ANSWER:

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

ii. See table below for breakdown of construction in progress costs for Major New Generation & Transmission projects, as at March 31, 2009.

(in thousands of dollars)

Major New Generation & Transmission	Component of Capitalized Costs					
	Wages	Overhead	Materials & Other	Interest	Contributions	Total
Wuskwatim - Generation	16		55 586	107 986		163 588
Wuskwatim - Transmission	54 745					54 745
Herblet Lake - The Pas 230kV Transmission	6 701					6 701
Keeyask - Generation	11 994	4 841		7 917	(159 399)	(134 646)
Conawapa - Generation		14 068				14 068
Kelsey Improvements & Upgrades		3 456	232 511			235 967
Kettle Improvements & Upgrades			20 276			20 276
Pointe du Bois Improvements & Upgrades			94 118			94 118
Pointe du Bois - Transmission			106 021			106 021
Bipole 3			25 536			25 536
Riel 230/500kV Station			15 681			15 681
Total	73 456	22 366	549 729	115 904	(159 399)	602 056

PUB/MH I-20

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, page 101 Pension Assets and Obligation**

a) Please provide an update of the current deficit position of MH's and Centra's pension plans.

ANSWER:

Manitoba Hydro
At March 31, 2009 the market value of the fund assets was $623 million, and the accrued benefit obligation was $730 million, for a deficit of $107 million.

At December 31, 2009 the market value of the fund assets was $698 million and the estimated accrued benefit obligation was $757 million for a deficit of $59 million.

Centra Gas
At March 31, 2009 the market value of the fund assets was $57 million, and the accrued benefit obligation was $81 million, for a deficit of $24 million.

At December 31, 2009, the market value of the fund assets was $71 million and the estimated accrued benefit obligation was $82 million for a deficit of $11 million.

PUB/MH I-20

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, page 101 Pension Assets and Obligation**

b) Please discuss MH's strategy to address the deficits.

ANSWER:

Manitoba Hydro

Manitoba Hydro funds its plan contractually at a rate that proportionately matches employee contributions made to the CSSB. The CSSB has recently recommended an increase of 2% on all pensionable salary to employee and employer contributions, thereby increasing funds available to meet future pension obligations. Prior to implementation of any such recommendations, agreements must be reached with participating employee/employer groups and legislation must be enacted.

Centra Gas

In accordance with pension legislation, Manitoba Hydro contributes quarterly to the curtailed plans an amount that is determined by actuarial funding valuations performed at December 31st of each year. These quarterly contributions are designed to eliminate any plan deficit within a 5 year period.

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

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 116, Note 20**

a) **Please provide an update on the Affordable Energy Fund (AEF) including the projected use of the funds, by program and a detailed description of the programs.**

<u>ANSWER</u>:

Projects to be supported through the Affordable Energy Fund include:

- **Low-Income/Community-Based Initiative: $19 Million**
  This initiative targets low-income Manitobans, including Aboriginals and seniors. These funds would be incremental to incentives that are available through Manitoba Hydro's Power Smart programs.

- **Geothermal Support Program: $6 Million**
  This initiative supports the application of geothermal technology.

- **Community Energy Development: $8 Million**
  This project, currently in the planning stage, will encourage the development of community-based energy projects in Manitoba. The purpose of the pilot project is to identify the issues and potential solutions associated with developing small, innovative renewable energy projects in Manitoba. This information will be used to determine whether and how similar projects might be pursued throughout the province.

- **Community Support and Outreach: $750 000**
  This initiative involves Manitoba Hydro funding additional resources for the purpose of encouraging rural and northern customers to participate in Power Smart initiatives. In addition, a lower interest rate loan applicable to First Nation Communities is subsidized through this category.

- **Oil and Propane-Heated Residential Homes: $250 000**
  This initiative extends the eligibility under the residential Power Smart Insulation and New Home programs to include homes currently heated by a source other than electricity and natural gas.

- **Special Projects: $2.4 Million (including accrued fund interest as of January 31, 2010)**

  – ***Residential Energy Assessment Service - $545 000***
    This initiative funds the incremental costs associated with delivering Manitoba Hydro's In-home Energy Assessment service under the Federal ecoEnergy Retrofit program to rural and northern Manitobans.

  – ***Oil and Propane Furnace Replacement - $150 000***
    This initiative targets the replacement of oil and propane furnaces with either an electric or high efficient natural gas furnace. The program provides a rebate of $245 to participating customers. Low Income customers will be eligible to convert at a cost of $19 per month for five years.

  – ***Residential Solar Water Heating Program - $305 000***
    This initiative supports the application of solar domestic hot water pre-heating systems and the development of the local solar industry.

  – ***Power Smart Residential Loan - Up to $1.15 Million***
    This initiative will reduce the interest rate for the Power Smart Residential Loan from the cost recovery rate to a rate of 4.9%.

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

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report, Page 116, Note 20**

b) **Please provide a continuity schedule for the forecast use of the fund including a detail on the actual and anticipated expenditures by program for the years 2008/09, 2009/10, 2010/11 and 2011/12.**

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH I-113(a).

PUB/MH I-22

Subject: **Tab 4: Financial Results & Forecast**
Reference: **2009 Annual Report Pages 118, 119 Operating Statistics**

Please provide revenue and expense results for fiscal years 2000 through 2009 in tabular form including annual data on.

i. Hydraulic Generation (GWh)
ii. Thermal Generation (GWh)
iii. Energy Purchases (GWh)
iv. Export Sales U.S. (GWh)
v. Export Sales Canada (GWh)
vi. Transmission Losses (GWh)

ANSWER:

Please refer to the following table for information for the years 2005 through 2009.

Electric Operating Statistics

	(in millions of $)	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual
	Revenue					
	Residential	386	387	410	437	462
	General Service	553	597	613	638	665
	Extraprovincial	554	827	592	625	623
	Other	4	5	5	8	16
	Total Revenue	$ 1,497	$ 1,816	$ 1,621	$ 1,707	$ 1,765
	Expenses					
	Operating, Maintenance and Administrative	299	311	323	323	360
	Finance Expense	468	468	467	401	401
	Depreciation and Amortization	289	301	311	324	346
	Water Rentals and Assessments	112	131	112	124	123
	Fuel and Power Purchased	135	125	226	135	176
	Capital and Other Taxes	51	53	55	57	64
	Corporate Allocation	6	6	7	8	8
	Total Expenses	1,360	1,396	1,502	1,370	1,478
	Net Income	$ 137	$ 420	$ 120	$ 337	$ 287
i	Hydraulic Generation (GWh)	31,134	37,218	31,610	34,897	34,193
ii	Thermal Generation (GWh)	414	401	522	457	335
iii	Energy Purchases (GWh)	2,030	739	2,249	830	1,033
iv	Export Sales to U.S. (GWh)	8,850	12,923	9,531	11,253	10,159
v	Export Sales to Canada (GWh)	1,580	1,424	373	482	417
vi	Export Losses (GWh)	751	1,219	855	986	893

PUB/MH I-23

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Extraprovincial Revenue**

a) **Please provide a table of the annual average unit export prices per MWh for the fiscal years 2000 through 2009 for:**

- **i.** **Dependable Exports (U.S.)**
- **ii.** **Dependable Exports (Canada)**
- **iii.** **Opportunity Exports (U.S.)**
- **iv.** **Opportunity Exports (Canada)**
- **v.** **Imports (U.S.)**
- **vi.** **Imports (Canada)**

ANSWER:

The annual average unit export prices per MW.h are listed below.

	Dependable Exports (US) (Cdn $)	Dependable Exports (CDN) (Cdn $)	Opportunity Exports (US) (Cdn $)	Opportunity Exports (CDN) (Cdn $)	Imports (US) (Cdn $)	Imports (CDN) (Cdn $)
1999/00	40.81	39.55	27.41	30.22	16.53	34.88
2000/01	40.69	40.50	36.95	38.93	26.84	76.53
2001/02	55.15	39.21	48.66	35.60	35.68	53.79
2002/03	56.09	38.66	42.30	46.75	38.77	45.75
2003/04	49.45	36.63	69.42	74.60	52.14	56.14
2004/05	51.44	0.00	53.00	43.51	44.58	69.41
2005/06	59.25	0.00	45.11	77.19	39.41	29.05
2006/07	59.67	0.00	45.97	67.18	52.26	44.68
2007/08	53.22	0.00	44.84	80.75	46.11	49.50
2008/09	57.15	0.00	43.80	111.89	45.59	50.61

PUB/MH I-23

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Extraprovincial Revenue**

b) For the fiscal years 2000 to 2009 in a) please indicate the annual average US exchange rates for export sales and US imports.

ANSWER:

The exchange rates used for the actual conversion of monthly exports and imports are the noon month-end Bank of Canada exchange rates. The numbers below represent a simple average of those monthly rates.

	Annual Average Exchange Rate
1999/00	1.1700
2000/01	1.1723
2001/02	1.5665
2002/03	1.5445
2003/04	1.3491
2004/05	1.2732
2005/06	1.1893
2006/07	1.1352
2007/08	1.0256
2008/09	1.1345

PUB/MH I-24

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 21 & 22 of 29 Payments to Governments**

a) **Please provide a schedule that details all payments to municipalities and the Province by year for the fiscal years 2000 through 2009 and forecast for 2010, 2011 and 2012.**

ANSWER:

Please see the attached schedule for all payments to municipalities and the Province for 2005 through 2012.

Payments to the Province and Municipalities (Millions)

Fiscal Year Ended	Water Rentals	Provincial Guarantee Fee	Sinking Fund Admin. Fee	Capital Taxes	Payroll Taxes	Provincial Mitigation or Settlement Obligations (1)	Municipal GILT and Business Taxes	Gross Electricity Operations Revenue	Gross Export Revenue
2005	$ 104	$ 68	$ 1	$ 35	$ 7	$ 13	$ 10	$ 1,508	$ 554
2006	124	66	0	36	7	2	10	1,828	827
2007	106	68	0	37	8	2	10	1,632	592
2008	117	70	1	39	8	2	11	1,707	625
2009	115	70	1	44	9	0	11	1,765	623
2010	111	72	1	45	9	2	15	1,581	414
2011	102	78	0	47	9	8	15	1,584	383
2012	100	83	0	48	9	0	15	1,808	554
2013	103	89	0	50	10	1	15	1,895	583
2014	104	93	0	55	10	0	16	1,987	615
2015	103	101	0	61	10	0	16	2,039	590
2016	103	114	0	69	10	0	16	2,219	701
2017	104	131	0	77	10	0	17	2,320	729
2018	103	147	0	82	11	0	17	2,404	742
2019	103	159	1	88	11	0	17	2,628	894
2020	112	166	0	91	11	0	18	2,907	1,093

(1) Hydro entered into an agreement with the Province whereby the Corporation assumed obligations of the Province with respect to certain northern development projects. Obligations totaling $143 million were assumed, with respect to which water rental charges had been fixed until March 31, 2001. Of these obligations, $11 million remain to be paid in fiscal 2010 and future years.

PUB/MH I-24

Subject: Tab 4: Financial Results & Forecast
Reference: Tab 4 Page 21 & 22 of 29 Payments to Governments

b) Please provide a schedule that details the calculation of the debt guarantee fee for the fiscal years 2000 through 2009 and forecast for 2010, 2011 and 2012.

ANSWER:

PUB/MH I - 24(b)

Provincial Debt Guarantee Fee Calculations
($ millions)

	Actual 2005 (1)	Actual 2006 (1)	Actual 2007 (1)	Actual 2008 (1)	Actual 2009 (1)	Actual 2010 (1) (2)	Forecast 2011 (3)	Forecast 2012 (3)
Long Term Debt Balance	7,311	7,141	7,108	7,160	7,486	8,132	8,104	8,623
Short Term Debt Balance	94	59	-	148	-	100	48	40
Trust Investment from Pre-Financing					(122)	(166)		
PDGF Assessed On	7,405	7,200	7,108	7,308	7,364	8,066	8,152	8,663
Guarantee Fee Rate	0.95%	0.95%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Amount Paid to Province	70	68	71	73	74	76	82	87
Portion Allocated to Centra	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(4)
Net Hydro Guarantee Fee	68	66	68	70	70	72	78	83

Notes:

(1) The fee calculation is based on ending debt balances at March 31 of the prior fiscal year. Manitoba Hydro is not assessed the debt guarantee fee on bonds issued for mitigation purposes. The long term debt balance presented in PUB 24(b) represents that amount of debt upon which the Provincial Debt Guarantee Fee was paid or is payable.

(2) The PDGF on US debt is paid in US dollars using the stated PDGF rate. For presentation purposes, US debt balances are translated to a Canadian equivalent using the year end exchange rate. The presentation of the US long term debt balance at March 31, 2009 was translated at the year end exchange rate of 1.2602 although the US dollar PDGF payment was made at a 1.05036 exchange rate utilizing FX forward contracts. Therefore, the Canadian equivalent of the amount paid to the Province for this year is less than 1%.

(3) US Dollar long term debt balance converted at forecast year end rate of 1.06 at March 31, 2010 for 2011 and US Dollar long term debt balance converted at forecast year end rate of 1.07 at March 31, 2011 for 2012.

PUB/MH I-24

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 21 & 22 of 29 Payments to Governments**

c) **Please provide a schedule that details the calculation of water rental payments for the fiscal years 2000 through 2009 and forecast for 2010, 2011 and 2012.**

ANSWER:

Please see the following schedule for the water rental payment calculation for the years 2005 through 2012.

Water Rental Calculation

	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Forecast 2010	Forecast 2011	Forecast 2012	
Megawatt-Hours Generated (million mWh)	31.1	37.2	31.6	34.9	34.2	33.1	30.5	30.1	
Converted to Horsepower-years	5.1	6.1	5.2	5.7	5.6	5.4	5.0	4.9	(1)
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32	20.32	20.32	20.32	(2)
Calculated Water Annual Rental ($ million)	$ 104.1	$ 124.4	$ 105.7	$ 116.7	$ 114.3	$ 110.7	$ 102.0	$ 100.5	
Minimum Rental Adjustment					0.2	0.5	0.3		(3)
Other Adjustment				0.3					(4)
Total Water Rentals	$ 104.1	$ 124.4	$ 105.7	$ 117.0	$ 114.5	$ 111.2	$ 102.3	$ 100.5	

(1) The Water Power Act defines "Horsepower-year" as kW.h/6535 X 1.075.

(2) The water rental fee was calculated at a rate of 9.90 per Horsepower-year generated up to March 31, 2001. Effective April 1, 2001 the rate was increased to its current level of $20.32 per Horsepower-year.

(3) The Water Power Act of Manitoba provides that the water rentals charged for each generation site be the greater of (a) a fixed rate multiplied by the installed capacity of that site and (b) a fixed rate multiplied by the electrical output for the year of that site. Generally , the calculation under (b) based on actual output results in the greatest amount for each generation site. In some years, such as 2009 it is necessary to adjust the amounts calculated under the (b) calculation for some specific sites to bring the total up to the amount calculated under the (a) installed capacity calculation method.

(4) Due to a rounding difference.

PUB/MH I-24

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 21 & 22 of 29 Payments to Governments**

d) **Please explain whether MH has received any indication from the Province that there will be changes to the water rental change, the provincial guarantee fee or any other government charges for 2010, 2011 and 2012.**

ANSWER:

The Province has provided no indication regarding planned changes to government charges with respect to 2010, 2011 or 2012.

.

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

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 21 & 22 of 29 Payments to Governments**

e) **Please provide a schedule that details all forecast payments to all Government by year from 2009 to 2020.**

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH I-24(a).

PUB/MH I-25

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Sinking Fund**

a) Please provide a continuity schedule of the sinking fund from fiscal years 2000 to 2020 including contributions, income earned, and withdrawals from the fund.

ANSWER:

Please see the attached schedule.

PUB/MH 1 - 25 (a)

MANITOBA HYDRO
SINKING FUND CONTINUITY

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

	Actual 2004/05	Actual 2005/06	Actual 2006/07	Actual 2007/08	Actual 2008/09	Forecast 2009/10	Forecast 2010/11	Forecast 2011/12	Forecast 2012/13	Forecast 2013/14	Forecast 2014/15	Forecast 2015/16	Forecast 2016/17	Forecast 201718	Forecast 2018/19
$CAD Sinking Fund															
Opening	301	81	(0)	(0)	(0)	(0)	13	31	103	116	19	32	39	50	62
Contributions	13	5				13	31	98	116	10	13	10	11	11	12
Withdrawals	(236)	(84)					(13)	(27)	(103)	(107)	-	(3)	-	-	-
Premiums/Discounts	3	(2)													
Total	81	(0)	(0)	(0)	(0)	13	31	103	116	19	32	39	50	62	73
$USD Sinking Fund in $CAD															
Opening	414	481	555	630	718	666	379	233	233	227	21	114	302	467	700
Contributions	86	98	100	96	124	81	67	-	-	167	95	192	150	234	192
Withdrawals	-				(261)	(262)	(214)	-	-	(376)	-	-	-	-	(456)
Premiums/Discounts/Other*	14	(1)	(13)	64	(32)	(6)	(3)	(3)	(2)	(4)	(3)	(4)	12	(1)	(1)
FX Adjustments	(34)	(22)	(12)	(72)	116	(100)	3	4	(4)	8	0	1	3	-	-
Total	481	555	630	718	666	379	233	233	227	21	114	302	467	700	434
Total Sinking Funds in $CAD	562	555	630	718	666	392	264	336	344	40	146	342	518	762	508

*Premiums/Disounts/Other includes premiums and discounts on investments; and effective 2007/08 includes changes to portfolio carrying value from premiums, discounts and changes in fair value.

PUB/MH I-25

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Sinking Fund**

b) Please provide the implication of the removal of sinking fund requirements on revenue requirement and discuss MH's efforts to remove this obligation.

ANSWER:

Manitoba Hydro estimates the net impact of removal of the sinking funds to be approximately $8 million per year. However, this does not take into consideration potential negative impacts that may result from credit rating agency reviews.

The Province of Manitoba is aware of Manitoba Hydro's objective to ultimately eliminate the sinking fund requirements.

PUB/MH I-26

Subject: Tab 4: Financial Results & Forecast
Reference: Financial Forecast General

In preparing MH's overall financial forecast for operating and administrative expenses how were productivity improvements incorporated, how were they quantified and what annual percentage was utilized in the forecast.

ANSWER:

In order to provide for productivity savings, Manitoba Hydro's practice is to allow a general escalation increase to OM&A for each business unit which is approximately 1% lower than the underlying wage & cost increases that are expected. Divisional budgets consider pertinent factors such as automation and cost reduction opportunities, including productivity improvements.

PUB/MH I-27

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

Please provide the actual MH Electric Operations financial statements (i.e. Operating Statement, Balance Sheet and Cash Flow Statement) for 2002/03 through 2008/09 in the same format as the IFF, including the actual financial ratios.

ANSWER:

The financial statements and ratios are attached.

Electric Operations
Statement of Income

(millions of dollars)

For the year ended March 31:	**2005**	**2006**	**2007**	**2008**	**2009**
Revenues					
General consumers revenue	939	984	1,024	1,075	1,127
Extraprovincial	554	827	592	625	623
Commodity	0	0	0	0	0
Distribution	0	0	0	0	0
Other	4	5	5	8	16
	1,497	1,816	1,621	1,708	1,766
Cost of Gas sold	0	0	0	0	0
	1,497	1,816	1,621	1,708	1,766
Expenses					
Operating and administrative	299	311	323	323	360
Finance expense	468	468	467	401	401
Depreciation and amortization	290	301	311	324	346
Water rentals and assessments	112	131	113	124	123
Fuel and power purchased	135	125	226	135	176
Capital and other taxes	51	54	55	57	64
Corporate allocation	6	7	7	7	8
	1,360	1,396	1,502	1,371	1,478
Net Income (Loss)	137	420	119	337	288

Financial Ratios					
Debt Ratio*	0.85	0.81	0.80	0.73	0.77
Interest Coverage	1.27	1.83	1.24	1.73	1.60
Capital Coverage	1.20	2.52	1.12	1.65	1.87

* Debt Ratio for 2008 and 2009 has been restated as per CAC/MSOS/MH I-116(b)

Electric Operations
Balance Sheet

(millions of dollars)

As at March 31:	2005	2006	2007	2008	2009
Assets					
Plant in service	10 223	10 528	10 868	11 308	11 915
Accumulated depreciation	3 267	3 475	3 734	3 987	4 231
Net plant in service	6 956	7 053	7 134	7 321	7 684
Construction in progress	474	600	873	1 235	1 446
Current and other assets	1 858	2 092	2 210	2 503	2 493
Goodwill	108	108	108	108	108
	9 396	9 853	10 325	11 167	11 731
Liabilities and Retained Earnings					
Long-term debt	6 800	6 861	6 614	6 985	7 520
Current and other liabilities	1 487	1 462	2 058	1 813	2 030
Contributions in aid of construction	264	265	267	269	266
Retained earnings	845	1 265	1 386	1 795	2 084
Accumulated other comprehensive income (loss)	0	0	0	305	(169)
	9 396	9 853	10 325	11 167	11 731

Electric Operations
Statement of Cash Flows

(millions of dollars)

For the year ended March 31:	2005	2006	2007	2008	2009
Operating Activies					
Cash receipts from customers	1 467	1 797	1 593	1 699	1 829
Cash paid to suppliers and employees	(580)	(608)	(668)	(597)	(694)
Interest paid	(510)	(510)	(539)	(536)	(504)
Interest received	29	33	32	33	35
	406	712	418	599	666
Financing Activities					
Proceeds from long-term debt	300	180	172	981	423
Sinking fund withdrawals	236	84	0	0	261
Retirement of long-term debt	(239)	(110)	(79)	(311)	(366)
Other	(58)	(111)	120	(189)	97
	239	43	213	481	415
Investing Activities					
Property, plant & equipment, net of contributions	(482)	(471)	(616)	(802)	(888)
Sinking fund payment	(100)	(103)	(100)	(96)	(124)
Other	(60)	(71)	(33)	(50)	(32)
	(642)	(645)	(749)	(948)	(1 044)
Net increase (decrease) in cash	3	110	(118)	132	37
Cash at beginning of year	6	9	119	1	133
Cash at end of year	9	119	1	133	170

PUB/MH I-28 (REVISED)

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 3 of 29, Schedule 4.1.0 Statement of Income**

a) Please re-file the schedule incorporating the years 1999/00 through 2006/07.

ANSWER:

Please see the following schedule, which includes information from 2003/04 through 2011/12.

MANITOBA HYDRO **Schedule 4.1.0**

STATEMENT OF INCOME **(000's)**

	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
Revenue									
General Consumers*	918,231	938,954	983,653	1,023,613	1,074,581	1,126,812	1,160,009	1,192,762	1,245,962
Extraprovincial	350,994	553,727	826,766	592,245	624,971	622,646	414,463	383,467	554,194
Other	6,857	4,251	5,496	5,472	7,580	15,870	6,697	7,358	7,760
Total Revenue	$ 1,276,082	$ 1,496,933	$ 1,815,915	$ 1,621,330	$ 1,707,132	$ 1,765,328	$ 1,581,168	$ 1,583,587	$ 1,807,916
Expenses									
Operating, Maintenance and Administrative	283,356	298,613	310,659	323,466	322,697	359,660	371,504	379,695	403,370
Finance Expense	452,801	467,859	468,359	467,138	400,796	401,060	416,913	412,539	467,650
Depreciation and Amortization	274,325	289,291	301,213	310,913	323,573	346,039	367,801	386,242	406,717
Water Rentals and Assessments	71,455	111,521	131,020	112,497	123,767	123,000	119,555	110,277	110,724
Fuel and Power Purchased	568,897	135,456	124,841	226,212	134,887	176,383	103,313	131,740	248,405
Capital and Other Taxes	49,860	51,043	53,438	54,859	57,152	63,808	72,881	75,771	76,877
Corporate Allocation	3,693	6,457	6,470	6,661	7,576	7,555	8,019	8,839	8,840
Total Expenses	1,704,388	1,360,240	1,396,000	1,501,746	1,370,449	1,477,505	1,459,986	1,505,102	1,722,583
Non-controlling Interest**									1,395
Net Income	$ (428,306)	$ 136,692	$ 419,915	$ 119,584	$ 336,683	$ 287,824	$ 121,182	$ 78,485	$ 86,729

*General Consumers Revenue - reflects a proposed 2.9% increase in 2010/11 and 2011/12

** Non-controlling Interest's share of net income or loss from the Wuskwatim Generation Station.

PUB/MH I-28

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 3 of 29, Schedule 4.1.0 Statement of Income**

b) **Please provide a schedule in part a) which incorporates a column for the Compound Annual Growth (CAG) for the years 2004/05 through 2008/09 and a column for the CAG for the years 2008/09 through 2011/12.**

ANSWER:

Please see the following schedule for the Compounded Annual Growth values.

MANITOBA HYDRO **Schedule 4.1.0**
STATEMENT OF INCOME **(000's)**

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	Compounded Annual Growth %
Revenue						
General Consumers*	938,954	983,653	1,023,613	1,074,581	1,126,812	4.7
Extraprovincial	553,727	826,766	592,245	624,971	622,646	3.0
Other	4,251	5,496	5,472	7,580	15,870	39.0
Total Revenue	$ 1,496,933	$ 1,815,915	$ 1,621,330	$ 1,707,132	$ 1,765,328	4.2
Expenses						
Operating, Maintenance and Administrative	298,613	310,659	323,466	322,697	359,660	4.8
Finance Expense	467,859	468,359	467,138	400,796	401,060	-3.8
Depreciation and Amortization	289,291	301,213	310,913	323,573	346,039	4.6
Water Rentals and Assessments	111,521	131,020	112,497	123,767	123,000	2.5
Fuel and Power Purchased	135,456	124,841	226,212	134,887	176,383	6.8
Capital and Other Taxes	51,043	53,438	54,859	57,152	63,808	5.7
Corporate Allocation	6,457	6,470	6,661	7,576	7,555	4.0
Total Expenses	1,360,240	1,396,000	1,501,746	1,370,449	1,477,505	2.1
Non-controlling Interest**						
Net Income	$ 136,692	$ 419,915	$ 119,584	$ 336,683	$ 287,824	20.5

	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast	Compounded Annual Growth %
Revenue					
General Consumers*	1,126,812	1,160,009	1,192,762	1,245,962	3.4
Extraprovincial	622,646	414,463	383,467	554,194	-3.8
Other	15,870	6,697	7,358	7,760	-21.2
Total Revenue	$ 1,765,328	$ 1,581,168	$ 1,583,587	$ 1,807,916	0.8
Expenses					
Operating, Maintenance and Administrative	359,660	371,504	379,695	403,370	3.9
Finance Expense	401,060	416,913	412,539	467,650	5.3
Depreciation and Amortization	346,039	367,801	386,242	406,717	5.5
Water Rentals and Assessments	123,000	119,555	110,277	110,724	-3.4
Fuel and Power Purchased	176,383	103,313	131,740	248,405	12.1
Capital and Other Taxes	63,808	72,881	75,771	76,877	6.4
Corporate Allocation	7,555	8,019	8,839	8,840	5.4
Total Expenses	1,477,505	1,459,986	1,505,102	1,722,583	5.2
Non-controlling Interest**				1,395	n/a
Net Income	$ 287,824	$ 121,182	$ 78,485	$ 86,729	-33.0

*General Consumers Revenue - reflects a proposed 2.9% increase in 2010/11 and 2011/12

** Non-controlling Interest's share of net income or loss from the Wuskwatim Generation Station.

PUB/MH I-29 (REVISED)

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 5 of 29, Schedule 4.2.0 General Consumer Revenue**

Please re-file the schedule incorporating the years 1999/00 through 2006/07.

ANSWER:

Please see the following schedule for information from 2003/04 through 2011/12.

MANITOBA HYDRO
GENERAL CONSUMERS REVENUE

Schedule 4.2.0
(000's)

	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
Residential	$ 367,393	$ 386,182	$ 386,894	$ 410,402	$ 436,634	$ 462,295	$ 480,676	$ 469,471	$ 471,106
General Service*	550,838	552,772	596,759	613,211	637,947	664,518	679,333	689,814	706,034
Additional General Consumers Revenue**								33,477	68,822
Total Revenue	$ 918,231	$ 938,954	$ 983,653	$ 1,023,613	$ 1,074,581	$ 1,126,812	$ 1,160,009	$ 1,192,762	$ 1,245,962

*Includes revenue from Energy Intensive Rate for 2010/11 and 2011/12
**Additional General Consumers Revenue - this reflects a 2.9% increase in 2010/11 and 2011/12

PUB/MH I-30

Subject: Tab 4: Financial Results & Forecast
Reference: Tab 4 Page 6 & 8 of 29, Schedule 4.3.0

a) **Please provide a breakdown of revenue by Short Term Firm, Short Term Energy, Spot Market and Merchant Trading Sales for each of the years 1999/00, through 2011/12.**

ANSWER:

A breakdown of revenue is provided below for opportunity bilateral (short term firm and energy combined), opportunity spot and merchant trading. Opportunity spot sales into the Ontario market did not commence until 2002/03. Forecast years have not been provided due to commercial sensitivity as Manitoba Hydro's long term firm export prices can be derived from this information.

	Opportunity Bilateral Revenue (CDN$)	Opportunity Spot Market Revenue (CDN$)	Merchant Trading Revenue (CDN$)
1999/00	150,636,616		0
2000/01	216,927,371		0
2001/02	280,792,868		0
2002/03	124,165,676	12,951,734	0
2003/04	38,565,560	14,093,815	0
2004/05	184,290,257	65,505,054	473,904
2005/06	156,263,711	354,120,956	10,518,118
2006/07	204,142,381	91,071,250	62,926,861
2007/08	112,528,842	255,117,487	60,134,040
2008/09	100,797,824	211,789,491	71,548,902

PUB/MH I-30

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 6 & 8 of 29, Schedule 4.3.0**

b) Please provide a definition of each of the types of sales.

ANSWER:

Total Extraprovincial sales are comprised of sales made to Canadian and US counterparties, Canadian and US energy markets, Renewable Energy Credits and Transmission Service Credits. Sales made to counterparties and markets are identified as either Opportunity or Dependable sales.

Dependable sales are sourced from Manitoba Hydro’s dependable energy resources and include the associated product of accreditable capacity, and generally have a duration of greater than six months.

Opportunity sales are sourced from Manitoba Hydro’s non-dependable energy resources or from purchases and may include short term firm or non-firm contract sales, and spot market energy sales. The quantities sold are dependant on Manitoba Hydro’s surplus capacity and energy situation in the short term based on knowledge of prevailing water flow conditions.

PUB/MH I-31

Subject: Tab 4: Financial Results & Forecast
Reference: Schedule 4.3.0 Extraprovincial Revenue

Please extend the schedule including the years 1999/00 through 2006/07 and indicate the average exchange rate used, average energy rate per kW.h and amount of exchange dollars included in US revenue for each the years.

ANSWER:

	1999/00 Actual	2000/01 Actual	2001/02 Actual	2002/03 Actual	2003/04 Actual	2004/05 Actual	2005/06 Actual
Canadian	90,233	109,275	92,615	84,143	53,601	78,255	172,938
U.S.	286,337	370,397	495,278	379,287	297,394	475,243	654,083
	376,570	479,673	587,893	463,430	350,994	553,499	827,021
Average Exchange Rate	1.17	1.1723	1.5665	1.5445	1.3491	1.2732	1.1893
Average Price/MWh	34.26	39.09	49.02	48.93	49.91	50.51	51.94
U.S. Revenue in US$	242,343	312,074	325,724	254,560	217,368	362,164	537,903

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
Canadian	85,440	110,062	131,363	87,037	68,499	49,618
U.S.	506,985	514,909	491,283	327,426	314,968	504,577
	592,426	624,971	622,646	414,463	383,467	554,195
Average Exchange Rate	1.1352	1.0256	1.1345	1.1176	1.07	1.09
Average Price/MWh	50.85	48.87	51.63	43.58	51.81	70.53
U.S. Revenue in US$	432,814	482,512	427,771	291,297	276,449	462,915

PUB/MH I-32

Subject: Tab 4: Financial Results & Forecast

Reference: Tab 4 Page 12 of 29, Appendix 4.4 Page 14 of 36 Schedule 4.5.2

a) Please provide a schedule detailing the operating and administration charged to Centra for each of the fiscal years 2004/05 – 2011/12 (actual/forecast) by:

i. Cost Element

ii. Business Unit

ANSWER:

Please see the following tables for the requested information.

i.

MANITOBA HYDRO
CENTRA GAS PROGRAM COSTS BY COST ELEMENT

($000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
Activity Charges	$ 39,680	$ 37,924	$ 38,381	$ 41,181	$ 42,310	$ 44,071	$ 44,962	$ 45,861
Primary Costs:								
External Course, Awards	54	44	41	55	26	32	33	$ 33
Material	1,460	1,256	1,107	1,326	1,472	1,359	1,386	1,414
Travel	131	125	96	102	122	134	137	140
Donations, Grants & Sponsorships	514	389	309	333	334	258	263	269
Memberships	113	95	138	98	140	109	112	114
Bad Debt & Collection Expense	2,771	4,128	2,427	2,148	2,135	2,032	2,083	2,125
Office Administration & Other	1,601	1,565	1,566	1,581	1,582	1,511	1,541	1,572
Computer Equipment & Maintenance	381	450	265	310	546	538	549	560
Meter Reading Charges (primarily MHUS)	1,698	1,738	1,677	1,765	2,190	2,182	2,226	2,270
Banking/Cash Management Services	299	90	207	205	192	227	232	236
Construction & Maintenance Services	1,204	1,214	1,116	1,288	977	1,215	1,240	1,265
Purchased Services	721	753	835	898	1,237	1,458	1,482	1,511
Promotional Items/Customer Incentives	19	38	54	20	39	21	21	22
Gas-PUB & Advisory Services	652	637	706	681	722	744	759	774
Operating Expense Recoveries	(1,109)	(1,013)	(823)	(821)	(561)	(477)	(487)	(497)
Other	522	25		2	5	5	5	5
Total Primary Costs	**11,031**	**11,534**	**9,721**	**9,989**	**11,159**	**11,349**	**11,580**	**11,812**
Corporate Allocations & Adjustments	804	221	2,035	1,455	2,027	2,064	2,070	2,111
Overhead	11,691	11,118	11,248	12,082	11,549	10,654	10,870	11,087
Total Program Costs	**63,206**	**60,797**	**61,384**	**64,707**	**67,044**	**68,138**	**69,482**	**70,872**
Depreciation, Interest and Taxes	(7,974)	(7,712)	(7,879)	(8,437)	(8,003)	(7,978)	(8,139)	(8,302)
Operating and Administrative	**55,232**	**53,085**	**53,505**	**56,270**	**59,041**	**60,160**	**61,343**	**62,570**

ii.

MANITOBA HYDRO
CENTRA GAS PROGRAM COSTS BY BUSINESS UNIT

($000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
President & CEO	$ 1,271	$ 946	$ 1,078	$ 1,073	$ 1,374	$ 1,087	$ 1,108	$ 1,130
Finance & Administration	7,260	6,333	7,085	6,833	6,830	6,733	6,860	$ 6,997
Power Supply	170	29	36	46	47	351	352	$ 359
Transmission	209	217	200	236	224	289	295	$ 301
Customer Service & Distribution	31,508	31,299	31,067	34,701	35,549	36,981	37,761	$ 38,517
Customer Care & Marketing	21,984	21,752	19,882	20,363	20,993	20,633	21,037	$ 21,457
Business Unit Subtotal	**62,402**	**60,576**	**59,349**	**63,252**	**65,017**	**66,074**	**67,412**	**68,761**
Corporate Allocations & Adjustments	804	221	2,035	1,455	2,027	2,064	2,070	2,111
Depreciation, Interest and Taxes	(7,974)	(7,712)	(7,879)	(8,437)	(8,003)	(7,978)	(8,139)	(8,302)
Operating and Administrative	**55,232**	**53,085**	**53,505**	**56,270**	**59,041**	**60,160**	**61,343**	**62,570**

PUB/MH I-32

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 12 of 29, Appendix 4.4 Page 14 of 36 Schedule 4.5.2**

b) Please provide a detailed breakdown of operating and administrative costs by division for the years 2004/05 through 2011/12.

ANSWER:

Please see the following schedule for a breakdown of OM&A costs by division for 2004/05 through 2011/12.

MANITOBA HYDRO **Schedule 4.5.3**
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT **(000's)**

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
President & CEO								
General Counsel	$ 4,383	$ 5,175	$ 4,886	$ 4,629	$ 5,669	$ 5,450	$ 5,545	$ 5,673
Public Affairs	2,804	2,856	3,288	2,939	3,189	3,299	3,352	3,429
Research & Development	3,491	3,462	3,491	3,548	3,396	4,310	4,395	4,496
Administration	8,575	8,978	9,897	9,861	9,901	11,416	12,137	12,416
	$ 19,253	**$ 20,471**	**$ 21,562**	**$ 20,977**	**$ 22,155**	**$ 24,475**	**$ 25,429**	**$ 26,014**
Corporate Relations								
Aboriginal Relations	$ 2,968	$ 4,652	$ 4,324	$ 4,331	$ 4,473	$ 4,372	$ 4,448	$ 4,550
Administration	535	844	896	914	1,047	728	752	769
	$ 3,503	**$ 5,496**	**$ 5,220**	**$ 5,245**	**$ 5,520**	**$ 5,100**	**$ 5,200**	**$ 5,320**
Corporate Planning & Strategic Analysis								
Corporate Strategic Review	$ 532	$ 559	$ 581	$ 582	$ 626	$ 1,064	$ 2,658	$ 2,719
Corporate Planning & Development	777	836	924	1,042	1,069	2,078	2,592	2,652
Administration	387	257	362	362	380	558	1,050	1,074
	$ 1,696	**$ 1,652**	**$ 1,867**	**$ 1,986**	**$ 2,075**	**$ 3,700**	**$ 6,300**	**$ 6,445**
Finance & Administration								
Information Technology Services	$ 29,273	$ 29,883	$ 34,414	$ 32,709	$ 33,959	$ 35,070	$ 35,500	$ 36,317
Treasury	2,266	2,146	1,887	2,001	2,067	2,090	2,100	2,148
Corporate Risk Management	150	153	442	460	566	820	836	855
Gas Supply	1,789	2,027	1,981	2,058	2,248	2,250	2,300	2,353
Rates & Regulatory Affairs	3,105	2,913	3,037	2,998	2,918	3,700	3,741	3,827
Corporate Controller	9,085	9,161	8,800	9,475	10,053	11,480	11,626	11,893
Human Resources	10,797	10,840	11,220	11,084	10,666	10,925	10,915	11,166
Corporate Safety & Health	2,819	3,020	2,957	3,411	3,663	3,700	3,750	3,836
Corporate Services	29,836	31,216	31,952	33,117	35,279	36,200	36,644	37,487
Administration	1,160	1,294	1,680	1,820	1,901	2,520	2,555	2,614
	$ 90,280	**$ 92,653**	**$ 98,370**	**$ 99,133**	**$ 103,320**	**$ 108,755**	**$ 109,967**	**$ 112,496**
Power Supply								
Power Planning	$ 2,431	$ 1,836	$ 2,299	$ 2,955	$ 4,015	$ 6,422	$ 6,494	$ 6,643
Power Projects Development	865	624	754	411	730	383	396	405
HVDC	17,653	17,282	19,177	19,128	21,659	22,856	23,096	23,627
Generation North	28,942	29,516	29,399	30,929	33,671	28,702	28,942	29,608
Generation South	44,754	43,734	45,105	46,747	50,020	51,841	52,437	53,643
Power Sales & Operations	8,870	10,120	11,346	11,625	12,578	13,153	13,290	13,596
Engineering Services	5,784	4,488	4,449	4,909	4,534	5,074	5,171	5,290
New Generation Construction	(134)	(306)	(447)	(228)	24	(249)	(249)	(255)
Administration	4,268	9,902	11,277	11,134	14,952	16,818	18,523	18,949
	$ 113,433	**$ 117,196**	**$ 123,359**	**$ 127,610**	**$ 142,183**	**$ 145,000**	**$ 148,100**	**$ 151,506**

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
Transmission								
Transmission System Operations	$ 27,102	$ 27,638	$ 29,779	28,453	31,408	33,054	33,545	34,317
Transmission Planning & Design	4,835	4,854	5,212	3,403	5,219	4,034	4,660	4,767
Transmission Construction & Line Maintenance	14,349	14,396	14,862	15,952	15,964	16,485	16,661	17,044
Apparatus Maintenance	28,913	29,082	31,327	33,834	36,281	35,070	35,579	36,397
Administration	2,779	1,840	2,323	1,529	2,216	2,457	1,955	2,000
	$ 77,978	**$ 77,810**	**$ 83,503**	**$ 83,171**	**$ 91,088**	**$ 91,100**	**$ 92,400**	**$ 94,525**
Customer Services & Distribution								
Customer Service Operations - Winnipeg & North	$ 43,748	$ 44,302	$ 42,044	44,893	48,121	47,988	48,808	49,931
Customer Service Operations - South	39,498	44,036	42,811	43,951	46,243	48,609	49,439	50,576
Distribution Planning & Design	6,608	7,378	7,157	8,075	8,541	8,424	8,555	8,752
Distribution Construction	2,253	688	(198)	910	694	930	942	964
Administration	-	560	277	544	163	1,349	1,256	1,285
	$ 92,107	**$ 96,964**	**$ 92,091**	**$ 98,373**	**$ 103,762**	**$ 107,300**	**$ 109,000**	**$ 111,507**
Customer Care & Marketing								
Industrial & Commercial Solutions	$ 2,780	$ 1,946	$ 2,449	$ 2,669	$ 2,077	$ 3,258	$ 3,293	$ 3,369
Consumer Marketing & Sales	9,115	9,104	9,346	8,264	8,850	10,000	10,341	10,579
Business Support Services	25,448	26,929	26,661	22,937	23,128	23,329	23,622	24,165
Administration	5,357	4,676	4,869	4,989	5,288	5,413	5,744	5,876
	$ 42,700	**$ 42,655**	**$ 43,325**	**$ 38,859**	**$ 39,343**	**$ 42,000**	**$ 43,000**	**$ 43,989**
Motor Vehicle Chargeout	(14,311)	(13,984)	(15,065)	(15,394)	(16,043)	(16,154)	(16,601)	(16,983)
Payroll Tax	(7,602)	(8,136)	(8,344)	(8,774)	(9,679)	(9,873)	(10,070)	(10,272)
Corporate Allocations & Adjustments	(7,018)	(7,006)	(7,031)	(4,930)	(3,824)	(8,775)	(9,666)	(10,160)
CICA Accounting Changes*	-	-	-	-	5,000	7,000	7,000	7,000
Provision for IFRS	-	-	-	-	-	-	-	15,000
Operating & Administration Charged to Centra	(55,232)	(53,085)	(53,505)	(56,270)	(59,042)	(60,160)	(61,343)	(62,570)
Capitalized Overhead	(58,174)	(62,028)	(61,887)	(67,289)	(66,198)	(67,964)	(69,021)	(70,447)
	$ 298,613	**$ 310,658**	**$ 323,465**	**$ 322,697**	**$ 359,660**	**$ 371,504**	**$ 379,695**	**$ 403,370**

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

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Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 12 of 29, Appendix 4.4 Page 14 of 36 Schedule 4.5.2**

c) Please provide a schedule in part b) which incorporates a column for the compounded annual growth for the years 2004/05 through 2008/09 and a column for the CAG for the years 2008/09 through 2011/12

ANSWER:

Please see the following schedule for the requested information.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

(000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	Fiscal 2005-2009 Compounded Annual Growth	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast	Fiscal 2009-2012 Compounded Annual Growth
President & CEO										
General Counsel	$ 4,383	$ 5,175	$ 4,886	$ 4,629	$ 5,669	6.6	$ 5,450	$ 5,545	$ 5,673	0.0
Public Affairs	2,804	2,856	3,288	2,939	3,189	3.3	3,299	3,352	3,429	2.4
Research & Development	3,491	3,462	3,491	3,548	3,396	(0.7)	4,310	4,395	4,496	9.8
Administration	8,575	8,978	9,897	9,861	9,901	3.7	11,416	12,137	12,416	7.8
	$ 19,253	**$ 20,471**	**$ 21,562**	**$ 20,977**	**$ 22,155**	**3.6**	**$ 24,475**	**$ 25,429**	**$ 26,014**	**5.5**
Corporate Relations										
Aboriginal Relations	$ 2,968	$ 4,652	$ 4,324	$ 4,331	$ 4,473	10.8	$ 4,372	$ 4,448	$ 4,550	0.6
Administration	535	844	896	914	1,047	18.3	728	752	769	(9.8)
	$ 3,503	**$ 5,496**	**$ 5,220**	**$ 5,245**	**$ 5,520**	**12.0**	**$ 5,100**	**$ 5,200**	**$ 5,320**	**(1.2)**
Corporate Planning & Strategic Analysis										
Corporate Strategic Review	$ 532	$ 559	$ 581	$ 582	$ 626		$ 1,064	$ 2,658	$ 2,719	63.2
Corporate Planning & Development	777	836	924	1,042	1,069	8.3	2,078	2,592	2,652	35.4
Administration	387	257	362	362	380		558	1,050	1,074	41.4
	$ 1,696	**$ 1,652**	**$ 1,867**	**$ 1,986**	**$ 2,075**	**5.2**	**$ 3,700**	**$ 6,300**	**$ 6,445**	**45.9**
Finance & Administration										
Information Technology Services	$ 29,273	$ 29,883	$ 34,414	$ 32,709	$ 33,959	3.8	$ 35,070	$ 35,500	$ 36,317	2.3
Treasury	2,266	2,146	1,887	2,001	2,067	(2.3)	2,090	2,100	2,148	1.3
Corporate Risk Management	150	153	442	460	566		820	836	855	14.8
Gas Supply	1,789	2,027	1,981	2,058	2,248	5.9	2,250	2,300	2,353	1.5
Rates & Regulatory Affairs	3,105	2,913	3,037	2,998	2,918	(1.5)	3,700	3,741	3,827	9.5
Corporate Controller	9,085	9,161	8,800	9,475	10,053	2.6	11,480	11,626	11,893	5.8
Human Resources	10,797	10,840	11,220	11,084	10,666	(0.3)	10,925	10,915	11,166	1.5
Corporate Safety & Health	2,819	3,020	2,957	3,411	3,663	6.8	3,700	3,750	3,836	1.6
Corporate Services	29,836	31,216	31,952	33,117	35,279	4.3	36,200	36,644	37,487	2.0
Administration	1,160	1,294	1,680	1,820	1,901	13.1	2,520	2,555	2,614	11.2
	$ 90,280	**$ 92,653**	**$ 98,370**	**$ 99,133**	**$ 103,320**	**3.4**	**$ 108,755**	**$ 109,967**	**$ 112,496**	**2.9**
Power Supply										
Power Planning	$ 2,431	$ 1,836	$ 2,299	$ 2,955	$ 4,015	13.4	$ 6,422	$ 6,494	$ 6,643	18.3
Power Projects Development	865	624	754	411	730	(4.2)	383	396	405	(17.8)
HVDC	17,653	17,282	19,177	19,128	21,659	5.2	22,856	23,096	23,627	2.9
Generation North	28,942	29,516	29,399	30,929	33,671	3.9	28,702	28,942	29,608	(4.2)
Generation South	44,754	43,734	45,105	46,747	50,020	2.8	51,841	52,437	53,643	2.4
Power Sales & Operations	8,870	10,120	11,346	11,625	12,578	9.1	13,153	13,290	13,596	2.6
Engineering Services	5,784	4,488	4,449	4,909	4,534	(5.9)	5,074	5,171	5,290	5.3
New Generation Construction	(134)	(306)	(447)	(228)	24		(249)	(249)	(255)	
Administration	4,268	9,902	11,277	11,134	14,952	36.8	16,818	18,523	18,949	8.2
	$ 113,433	**$ 117,196**	**$ 123,359**	**$ 127,610**	**$ 142,183**	**5.8**	**$ 145,000**	**$ 148,100**	**$ 151,506**	**2.1**

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

(000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	Fiscal 2004/05-2008/09 Compounded Annual Growth	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast	Fiscal 2008/09-2011/12 Compounded Annual Growth
Transmission										
Transmission System Operations	$ 27,102	$ 27,638	$ 29,779	28,453	31,408	3.8	33,054	33,545	34,317	3.0
Transmission Planning & Design	4,835	4,854	5,212	3,403	5,219	1.9	4,034	4,660	4,767	(3.0)
Transmission Construction & Line Maintenance	14,349	14,396	14,862	15,952	15,964	2.7	16,485	16,661	17,044	2.2
Apparatus Maintenance	28,913	29,082	31,327	33,834	36,281	5.8	35,070	35,579	36,397	0.1
Administration	2,779	1,840	2,323	1,529	2,216	(5.5)	2,457	1,955	2,000	(3.4)
	$ 77,978	**$ 77,810**	**$ 83,503**	**$ 83,171**	**$ 91,088**	**4.0**	**$ 91,100**	**$ 92,400**	**$ 94,525**	**1.2**
Customer Services & Distribution										
Customer Service Operations - Winnipeg & North	$ 43,748	$ 44,302	$ 42,044	44,893	48,121	2.4	47,988	48,808	49,931	1.2
Customer Service Operations - South	39,498	44,036	42,811	43,951	46,243	4.0	48,609	49,439	50,576	3.0
Distribution Planning & Design	6,608	7,378	7,157	8,075	8,541	6.6	8,424	8,555	8,752	0.8
Distribution Construction	2,253	688	(198)	910	694	(25.5)	930	942	964	11.6
Administration	-	560	277	544	163		1,349	1,256	1,285	99.0
	$ 92,107	**$ 96,964**	**$ 92,091**	**$ 98,373**	**$ 103,762**	**3.0**	**$ 107,300**	**$ 109,000**	**$ 111,507**	**2.4**
Customer Care & Marketing										
Industrial & Commercial Solutions	$ 2,780	$ 1,946	$ 2,449	$ 2,669	$ 2,077	(7.0)	$ 3,258	$ 3,293	$ 3,369	17.5
Consumer Marketing & Sales	9,115	9,104	9,346	8,264	8,850	(0.7)	10,000	10,341	10,579	6.1
Business Support Services	25,448	26,929	26,661	22,937	23,128	(2.4)	23,329	23,622	24,165	1.5
Administration	5,357	4,676	4,869	4,989	5,288	(0.3)	5,413	5,744	5,876	3.6
	$ 42,700	**$ 42,655**	**$ 43,325**	**$ 38,859**	**$ 39,343**	**(2.0)**	**$ 42,000**	**$ 43,000**	**$ 43,989**	**3.8**
Motor Vehicle Chargeout	(14,311)	(13,984)	(15,065)	(15,394)	(16,043)	2.9	(16,154)	(16,601)	(16,983)	1.9
Payroll Tax	(7,602)	(8,136)	(8,344)	(8,774)	(9,679)	6.2	(9,873)	(10,070)	(10,272)	2.0
Corporate Allocations & Adjustments	(7,018)	(7,006)	(7,031)	(4,930)	(3,824)	(14.1)	(8,775)	(9,666)	(10,160)	38.5
CICA Accounting Changes*	-	-	-	-	5,000		7,000	7,000	7,000	11.9
Provision for IFRS	-	-	-	-	-		-	-	15,000	
Operating & Administration Charged to Centra	(55,232)	(53,085)	(53,505)	(56,270)	(59,042)	1.7	(60,160)	(61,343)	(62,570)	2.0
Capitalized Overhead	(58,174)	(62,028)	(61,887)	(67,289)	(66,198)	3.3	(67,964)	(69,021)	(70,447)	2.1
Operating & Administrative Costs Attributable to Electric Operations	**$ 298,613**	**$ 310,658**	**$ 323,465**	**$ 322,697**	**$ 359,660**	**4.8**	**$ 371,504**	**$ 379,695**	**$ 403,370**	**3.9**

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Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 12 of 29, Appendix 4.4 Page 14 of 36 Schedule 4.5.2**

d) Please provide a schedule which compares for fiscal 2007/08 and 2008/09 actual results presented in this application with the forecast results provided at the 2008 GRA in both dollar change and % change by:

i. Cost element
ii. Business unit

And explain any differences over 5%

ANSWER:

The forecast columns have been updated to reflect the current organizational structure, however, the totals, as reported in 2008/09 GRA remain unchanged with the exception of subsidiaries which are no longer reported in OM&A.

Differences of 5% and $500,000 have been explained.

Please see the following schedules for the requested information.

i)

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

	2007/08 Actual	2007/08 Forecast	2007/08 Variance	%	Ref	2008/09 Actual	2008/09 Forecast	2008/09 Variance	%	Ref
Wages, Salaries	$ 359,249	$ 371,646	$ 12,397	3%		$ 380,031	$ 382,116	$ 2,085	1%	
Overtime	41,781	39,444	(2,337)	-6%	1	45,890	42,337	(3,553)	-8%	14
Employee Benefits	76,807	78,335	1,528	2%		83,671	78,892	(4,779)	-6%	15
Employee Safety & Training	3,646	5,267	1,621	31%	2	4,145	4,470	325	7%	
Travel	28,331	29,679	1,348	5%	3	31,671	30,092	(1,579)	-5%	16
Motor Vehicle	22,423	20,017	(2,406)	-12%	4	24,125	22,218	(1,907)	-9%	17
Materials & Tools	27,824	24,663	(3,161)	-13%	5	29,338	24,809	(4,529)	-18%	18
Consulting & Professional Fees	7,503	10,071	2,568	25%	6	9,137	8,835	(302)	-3%	
Construction & Maintenance Services	15,938	15,481	(457)	-3%		18,000	15,867	(2,133)	-13%	19
Building & Property Services	25,740	24,522	(1,218)	-5%	7	28,685	27,950	(735)	-3%	
Equipment Maintenance & Rentals	11,719	12,235	516	4%		13,028	12,664	(364)	-3%	
Consumer Services	4,651	4,881	230	5%		5,230	5,111	(119)	-2%	
Computer Services	1,131	1,077	(54)	-5%		858	726	(132)	-18%	
Collection Costs	5,256	5,359	103	2%		5,019	5,463	444	8%	
Customer & Public Relations	6,665	4,581	(2,084)	-45%	8	6,355	4,848	(1,507)	-31%	20
Sponsored Memberships	1,192	1,172	(20)	-2%		1,464	1,254	(210)	-17%	
Office & Administration	14,427	15,532	1,105	7%	9	14,538	15,382	844	5%	21
Communication Systems	1,353	1,834	481	26%		1,449	1,631	182	11%	
Research & Development Costs	2,979	3,414	435	13%		3,059	3,886	827	21%	22
Miscellaneous Expense	3,292	2,757	(535)	-19%	10	901	1,033	132	13%	
Contingency Planning	-	4,940	4,940	100%	11	-	6,650	6,650	100%	23
Operating Expense Recovery	(23,314)	(19,806)	3,508	-18%	12	(21,519)	(16,267)	5,252	-32%	24
Total Costs	638,594	657,101	18,507	3%		685,075	679,967	(5,108)	-1%	
Capital Order Activities	(192,338)	(196,853)	(4,515)	2%		(205,175)	(208,469)	(3,294)	2%	
CICA Accounting Changes*	-	-	-	-		5,000	-	-	-	
Provision for IFRS	-	-	-	-		-	-	-	-	
Capitalized Overhead	(67,289)	(63,450)	3,839	-6%	13	(66,198)	(64,500)	1,698	-3%	
Operating and Administration Charged to Centra	(56,270)	(56,600)	(330)	1%		(59,042)	(58,000)	1,042	-2%	
OM&A Attributable to Electric Operations	**$ 322,697**	**$ 340,198**	**$ 17,501**	**5%**		**$ 359,660**	**$ 348,998**	**$ (5,662)**	**-2%**	

Variances Greater than 5% and $500 are explained.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT
2008 VARIANCE EXPLANATIONS

Ref	Business Unit	Fav (Unfav)	Explanation
1	Overtime	(2,337)	Higher due to storm restorations, emergency system responses and maintaining in-service dates for capital projects, such as Wuskwatim,
2	Employee Safety & Training	1,621	Lower training costs primarily due to vacancies.
3	Travel	1,348	Lower due to vacancies.
4	Motor Vehicle	(2,406)	Higher due to increased fuel charges and repairs and maintenance.
5	Materials & Tools	(3,161)	Higher due to a business initiative for a transformer sale, storm activity and increased maintenance requirements for southern generating stations and the converter stations.
6	Consulting & Professional Fees	2,568	Less consulting work on various operating programs such as environmental management, business development and business initiatives.
7	Building & Property Services	(1,218)	Higher building service costs for maintenance, janitorial and ground care. In addition higher staff house operating costs due to Kelsey Re-runnering project as well as higher payments to the Gillam municipality.
8	Customer & Public Relations	(2,084)	Higher than anticipated donations & sponsorships, offset by lower corporate advertising costs.
9	Office & Administration	1,105	Lower costs for cash management services, postage and supplies for marketing activities such as Customer Satisfaction tracking surveys, market research and educational campaigns.
10	Miscellaneous Expense	(535)	Primarily higher than expected survey and mapping services.
11	Contingency Planning	4,940	Primarily unallocated President's contingency.
12	Operating Expense Recovery	3,508	Higher revenue from WIRE Services and a business initiative for a transformer sale. In addition higher number of Special Read & Reconnect services.
13	Capitalized Overhead	3,839	Forecasted overhead rate lower than actual overhead rate.

Ref	Business Unit	Fav (Unfav)	Explanation
14	Overtime	(3,553)	Higher due to construction projects, such as Wuskwatim and Kelsey Re-runnering, storm restoration and to maintain outage/maintenance schedules.
15	Employee Benefits	(4,779)	Primarily due to higher vacation and pension costs.
16	Travel	(1,579)	Primarily due to additional travel requirements related to the higher level of trainees.
17	Motor Vehicle	(1,907)	Primarily due to higher fuel costs.
18	Materials & Tools	(4,529)	Higher due to additional requirements for maintenance outages, business initiatives and storms.
19	Construction & Maintenance Services	(2,133)	Primarily due to an increase in MISO payments for transmission studies.
20	Customer & Public Relations	(1,507)	Higher than anticipated donations and sponsorships.
21	Office & Administration	844	Lower costs for furniture, cash management services, postage and supplies.
22	Research & Development Costs	827	Lower funding on research & development projects.
23	Contingency Planning	6,650	Unallocated general and President's contingency.
24	Operating Expense Recovery	5,252	Higher revenue due to subsidiary recoveries for staff secondments, business initiatives revenues, staffhouse recoveries from the Kelsey re-runnering project and permit inspection revenue resulting from increased construction levels.

ii)

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

	2007/08 Actual	2007/08 Forecast	2007/08 Variance	%	Ref	2008/09 Actual	2008/09 Forecast	2008/09 Variance	%	Ref
President & CEO	$ 20,977	$ 23,260	$ 2,283	10%	1	$ 22,155	$ 23,760	$ 1,605	7%	6
Corporate Relations	5,245	5,562	317	6%		5,520	5,398	(122)	-2%	
Corporate Planning and Strategic Analysis	1,986	2,553	567	22%	2	2,075	2,980	905	30%	7
Finance and Administration	99,133	103,011	3,878	4%		103,320	105,567	2,247	2%	
Power Supply	127,610	128,536	926	1%		142,183	131,149	(11,034)	-8%	8
Transmission	83,171	85,314	2,143	3%		91,088	87,606	(3,482)	-4%	
Customer Service and Distribution	98,373	99,738	1,365	1%		103,762	102,342	(1,420)	-1%	
Customer Care and Marketing	38,859	43,485	4,626	11%	3	39,343	44,549	5,206	12%	9
Business Unit Subtotal	**475,354**	**491,459**	**16,105**	**3%**		**509,446**	**503,351**	**(6,095)**	**(0)**	
Motor Vehicle Chargeout	(15,394)	(15,385)	9	0%		(16,043)	(15,748)	295	-2%	
Payroll Tax	(8,774)	(8,645)	129	-1%		(9,679)	(9,040)	639	-7%	10
Corporate Allocations & Adjustments	(4,930)	(7,180)	(2,250)	31%	4	(3,824)	(7,062)	(3,238)	46%	11
CICA Accounting Changes*	-	-	-	0%		5,000	-	-	-	
Provision for IFRS	-	-	-	0%		-	-	-	-	
Operating & Administration Charged to Centra	(56,270)	(56,600)	(330)	1%		(59,042)	(58,000)	1,042	-2%	
Capitalized Overhead	(67,289)	(63,450)	3,839	-6%	5	(66,198)	(64,500)	1,698	-3%	
OM&A Costs Attributable to Electric Operations *	**$ 322,697**	**$ 340,199**	**$ 17,502**	**5%**		**$ 359,660**	**$ 349,001**	**$ (5,659)**	**-2%**	

Variances Greater than 5% and $500 are explained.

* Note - OM&A figures do not include subsiduary amounts.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
2008 VARIANCE EXPLANATIONS

Ref	Business Unit	Fav (Unfav)	Explanation
1	President & CEO	2,283	President's contingency ($3 593 F) as well as lower insurance costs ($570 F) and lower professional fees ($345 F), partially offset by higher sponsorships and donations ($2 290 U).
2	Corporate Planning and Strategic Analysis	567	Lower wages, salaries and associated benefits ($318 F) due to vacancies and lower consulting fees ($230 F) for business development and environmental management.
3	Customer Care and Marketing	4,626	Lower wages, salaries and associated benefits ($2,337 F) along with travel ($325 F) and training costs ($256 F) due to vacancies. Less than expected consulting and advertising costs ($616 F) due to delayed marketing activities such as Customer Satisfaction tracking surveys, marketing research and education campaign; lower office and administrative costs ($375 F) due to lower postage rates.
4	Corporate Allocations & Adjustments	(2,250)	Higher motor vehicle operating costs partially offset by a vehicle insurance rebate ($888 U) as well as price adjustments related to vendor payments ($866 U). The balance reflects a general budget contingency for the corporation.
5	Capitalized Overhead	3,839	Forecasted overhead rate lower than actual overhead rate.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
2009 VARIANCE EXPLANATIONS

Ref	Business Unit	Fav (Unfav)	Explanation
6	President & CEO	1,605	President's contingency ($2,869 F) partially offset by higher sponsorships and donations ($1,487 U).
7	Corporate Planning and Strategic Analysis	905	Lower wages, salaries and associated benefits ($345 F) primarily due to vacancies. In addition lower consulting fees ($253 F) for environmental management and business development as well as higher capital activities ($95 F) due to requirements for downtown building.
8	Power Supply	(11,034)	Higher requirements on maintenance activites at generating stations ($3,882 U) and trainee requirements ($3,330 U) above forecasted levels. Lower capital activities partially offset by lower wages, salaries and associated benefits ($2,351 U) due to vacancies. In addition external initiatives ($1,051 U) such as Grand Rapids Fish Hatchery and NERC compliance.
9	Customer Care and Marketing	5,206	Lower wages, salaries and associated benefits ($2,875 F) primarily due to vacancies. Higher net revenue ($894 F) primarily due to some large business intiatives such as Atomic Energy and Stony Mountain Penitentiary. In addition lower costs in marketing research ($627 F) due to delayed programs.
10	Payroll Tax	639	Accrual of payroll taxes recorded at year end.
11	Corporate Allocations & Adjustments	(3,238)	Higher benefit costs primarily for vacation and pension benefits, partially offset by unallocated general contingency.

PUB/MH I-33

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Appendix 4.4 page 9 of 36 cost escalation and wage settlement**

a) **Please provide a comparison with other Canadian utilities of wage settlement increases.**

ANSWER:

The following table is a comparison of Manitoba Hydro's wage settlements with other Canadian Utilities:

Utility	Union	Effective	Wage Settlement Over Term of Contract	Average Annual Wage Increase
BC Transmission	COPE IBEW Local 258	2006 to 2009 (4 yrs) 2007 to 2009 (3 yrs)	10.29% 9.00%	2.57% 3.00%
BC Hydro	COPE IBEW	2006 to 2009 (4 yrs) 2006 to 2009 (4 yrs)	10.19% 14.44%	2.55% 3.61%
NBPower - Transmission	IBEW	2008 to 2012 (5 yrs)	16.50%	3.30%
Ontario Power Generation	Power Workers Union	2008 to 2012 (5 yrs)	15.00%	3.00%
Hydro Quebec	SCFP	2009 to 2013 (5 yrs)	10.00%	2.00%
SaskPower	IBEW	2007 to 2009 (3 yrs)	12.00%	4.00%
*Manitoba Hydro	IBEW CUPE	2009 to 2011 (3 yrs) 2009 to 2012 (4 yrs)	6.90% 8.90%	2.30% 2.23%

*Note: Manitoba Hydro's recent negotiated settlement also provides for a 0.75% benefit improvement in 2010. These costs are not included in the table above as cost of benefit improvements for other Utilities was not available.

PUB/MH I-33

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Appendix 4.4 page 9 of 36 cost escalation and wage settlement**

b) Please reconcile the EFT set out in the schedule found on page 9 with that utilized in schedule 4.5.4.

ANSWER:

The difference between the two schedules relates to overtime and Manitoba Hydro employees working in subsidiary operations.

Reconcialiation between Appendix 4.4 (Page 9 & Schedule 4.5.4)

	Actuals 2007/08	Actuals 2008/09	Forecast 2009/10	Forecast 2010/11	Forecast 2011/12
Total Utility Operation EFTs (Schedule 4.5.4)	6071	6276	6613	6669	6669
Less - Overtime EFTs	(324)	(341)	(355)	(367)	(367)
Add - MH EFTs Engaged in Subsidiary Operations [1]	19	36	35	35	35
MH Straight Time EFTs (Page 9 table Appendix 4.4)	5766	5971	6293	6337	6337

[1] MH EFTs Engaged in Subsidiary Operationss are included in the Table on page 9 of Appendix 4.4 because the dollars are included in the Wages & Salaries line item and are subsequently removed through Operating Expense Recovery.

PUB/MH I-33

Subject: Tab 4: Financial Results & Forecast

Reference: Tab 4 Appendix 4.4 page 9 of 36 cost escalation and wage settlement

c) For each of the 2007/08 through 2011/12 please provide the average salary per EFT in the same level of detail as schedules 4.5.1 and 4.5.4.

ANSWER:

Please see the following tables for the average salary per EFT from 2007/08 through 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
President & CEO	$ 83.097	$ 86.377	$ 86.843	$ 86.568	$ 88.559
Corporate Relations	63.417	62.454	62.968	63.438	64.897
Corporate Planning & Strategic Analysis	83.763	82.711	87.730	100.745	103.062
Finance & Administration	65.988	67.423	69.143	69.319	70.913
Power Supply	64.877	66.014	68.120	67.991	69.555
Transmission	64.717	66.084	66.265	65.606	67.115
Customer Services & Distribution	56.094	57.220	59.503	59.734	61.108
Customer Care & Marketing	56.994	58.383	61.168	61.297	62.707
Corporate Accruals & Adjustments (Subsidiary)	85.384	85.433	80.017	81.577	83.453
Business Unit Total	**62.309**	**63.646**	**65.442**	**65.528**	**67.035**

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

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

PUB/MH I-33

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Appendix 4.4 page 9 of 36 cost escalation and wage settlement**

d) Please indicate whether the Corporation participated in any salary benchmarking studies, if so please provide a description of the study and a summary of the comparison results.

ANSWER:

Manitoba Hydro has not conducted, nor commissioned, any wage studies but it does periodically participate in select salary surveys.

In 2008, Manitoba Hydro participated in a compensation benchmarking study conducted by Mercer on Hydro One's behalf. Manitoba Hydro matched salary and benefit information to approximately 20 positions of which Mercer then converted into a Total Remuneration Comparison. The following is a summary of the results relating to the 20 positions:

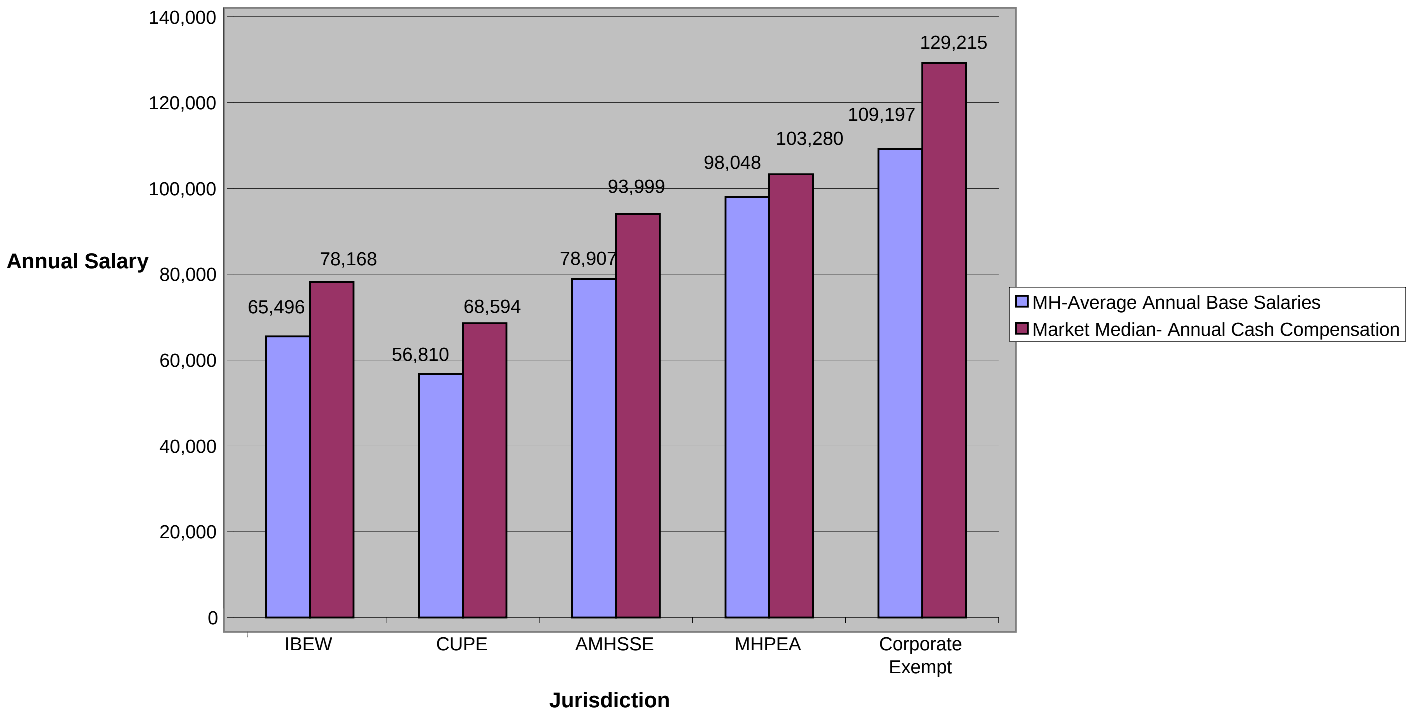
- 12 positions placed below the 25^{th} percentile of surveyed participants
- 7 positions placed between the 25^{th} and 50^{th} percentile of surveyed participants
- 1 position placed between the 50^{th} and 75^{th} percentile of surveyed participants

The results of this comparison shows that Manitoba Hydro's Total Remuneration is below the market average for 19 out of 20 positions.

Manitoba Hydro also recently participated in the Towers Perrin Power Services Survey which is a survey specific for the Utility industry. There were 30 participating employers in the Canadian Energy/Utility sector, including 17 Government owned organizations and 12 investor owned organizations.

Manitoba Hydro compiled the survey results by comparing the median salary of jobs at Manitoba Hydro to matching jobs in the survey. This was done on an aggregate basis by sorting the jobs by bargaining unit jurisdiction and comparing the median salary of the grouping with the same job grouping in the survey. Please see the following graph on the salary comparison relative to the total market sample of participants.

2009 Manitoba Hydro/Market Comparison by Jurisdiction



This comparison shows that Manitoba Hydro's average wages, on an aggregate basis, are lower than the market in all employee jurisdictions. Although the Power Services Survey does provide for an effective wage comparison, it does not tabulate total compensation numbers which include benefit programs. Further to this, cost of living disparity in various Canadian locations is not taken into consideration.

Manitoba Hydro has also participated in smaller scale salary surveys designed for specific jobs or group of jobs.

<u>PUB/MH I-34 (REVISED)</u>

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 13 of 29 Schedule 4.5.1, 4.5.4 Staffing Levels**

a) Please re-file the schedule 4.5.1 including the years 1999/00 through 2011/12.

<u>ANSWER</u>:

Please see the following schedule for EFT information from 2003/04 through 2011/12.

MANITOBA HYDRO **Schedule 4.5.1**

EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY BUSINESS UNIT

	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
President & CEO	86	84	82	84	87	87	97	99	99
Corporate Relations	43	49	62	67	69	75	69	69	69
Corporate Planning & Strategic Analysis	18	18	19	20	19	20	23	38	38
Finance & Administration	1,025	1,032	1,029	999	986	999	1,042	1,043	1,043
Power Supply	1,287	1,344	1,366	1,405	1,470	1,576	1,757	1,785	1,785
Transmission	1,207	1,208	1,221	1,233	1,255	1,298	1,355	1,358	1,358
Customer Services & Distribution	1,565	1,605	1,647	1,617	1,640	1,671	1,708	1,711	1,711
Customer Care & Marketing	538	527	552	563	545	550	561	566	566
Total	5,769	5,867	5,978	5,988	6,071	6,276	6,613	6,669	6,669

PUB/MH I-34

Subject: Tab 4: Financial Results & Forecast
Reference: Tab 4 Page 13 of 29 Schedule 4.5.1, 4.5.4 Staffing Levels

b) For each of the divisions set out in part a) please provide a continuity schedule of changes in EFT's by Division in a similar level of detail to that provided in response to PUB/MH I 20 from the 2008 GRA for the years 1999/00 through 2011/12 and indicate the number of EFT's that are attributable to:

i. Normal Growth
ii. Export Sales
iii. Generation development, and
iv. Other

ANSWER:

The attached schedules show the EFT changes from 2004/05 to 2011/12 by business unit. Please note that figures have been updated to reflect the current organizational structure.

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

Line		2004/05 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2005/06 Actual	Comments Regarding New Positions
4								
5	**President & CEO**							
6	General Counsel	24				1	25	
7	Public Affairs	32				(2)	30	
8	Research & Development	5				(2)	3	
9	President & CEO Administration	23				1	24	
		84	-	-	-	(2)	82	
10								
11	**Corporate Relations**							
12	Aboriginal Relations	44	9			1	54	Positions for policy development and seasonal utility workers
13	VP Corp Relations Administration	5	3				8	Positions for newly formed business unit.
14		49	12	-	-	1	62	
15								
16	**Corporate Planning & Strategic Analysis**							
17	Corporate Strategic Review	5				1	6	
18	Corporate Planning & Development	10	1				11	Position for strategic planning.
19	VP Corp Planning & Strat Analysis	3				(1)	2	
20		18	1	-	-	-	19	
21								
22	**Finance & Administration**							
23	Information Technology Services	350	4		7	3	364	Positions for supporting the Human Resource Management(HRMS) module of SAP after the implementation was complete.
24	Treasury	17			(1)		16	
25	Corporate Risk Mgmt	1	1		(1)	1	2	Position for new division
26	Gas Supply	20					20	
27	Rates & Regulatory Affairs	22				(3)	19	
28	Corporate Controller	116			(8)	5	113	
29	Human Resources	169			2	(7)	164	
30	Corporate Safety & Health	31				(2)	29	
31	Corporate Services	298				(3)	295	
32	Senior VP Finance & Administration	8			1		9	
33		1,032	5	-	-	(6)	1,031	

		2004/05 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2005/06 Actual	Comments Regarding New Positions
34								
35	**Power Supply**							
36	Power Planning	32			-	3	35	
37	Power Projects Development	38	3		(1)	(2)	38	Positions for new generation licensing and planning activities
38	HVDC	266			(29)	(9)	228	
39	Generation North	234			(30)	9	213	
40	Generation South	496			(23)	(11)	462	
41	Power Sales & Operations	79	8		(3)		84	Positions for power marketing, regulatory standards, and licensing activities.
42	Engineering Services	163				(1)	162	
43	New Generation Construction	13	1				14	Position for new generation construction.
44	Senior VP PS Administration	23	9		86	13	131	Positions for Power Supply Worker trainee program.
45		1,344	21	-	-	2	1,367	
46								
47	**Transmission**							
48	Transmission System Operations	341	3			2	346	Positions for Telecontrol Trainee Program
49	Transmission Planning & Design	202			(4)	(3)	195	
50	Transmission Construction & Line Mtce	271			4	1	276	
51	Apparatus Maintenance	357				5	362	
52	VP Transmission Administration	37	5			-	42	Positions for Engineer-in-Training program and establishment of HVDC Research Centre.
53		1,208	8	-	-	5	1,221	
54								
55	**Customer Service & Distribution**							
56	Customer Service Operations - Wpg&Nc	535				2	537	
57	Customer Service Operations - South	547	2			20	569	Positions for Aboriginal Line Trades Pre-Placement Trainee program.
58	Distribution Planning & Design	166			(7)	1	160	
59	Distribution Construction	357			7	18	382	
	VP Cust Service & Distribution Admin	-					-	
60		1,605	2	-	-	41	1,648	
61								
62	**Customer Care & Marketing**							
63	Industrial & Commercial Solutions	48				1	49	
64	Consumer Marketing & Sales	198	16			5	219	Positions for support of Power Smart programs.
65	Business Support Services	230	8			(1)	237	Positions to support the Banner system in Customer Accounting.
66	VP Cust Care & Marketing	51				(4)	47	
		527	24	-	-	1	552	
	Total	5,867	73	-	-	42	5,982	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2005/06 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2006/07 Actual	Comments Regarding New Positions
President & CEO							
General Counsel	25	1				26	Position for security function.
Public Affairs	30					30	
Research & Development	3				(1)	2	
President & CEO Administration	24				2	26	
	82	1	-	-	1	84	
Corporate Relations							
Aboriginal Relations	54	5				59	Position for settlement issues, policy development and community relations.
VP Corp Relations Administration	8					8	
	62	5	-	-	-	67	
Corporate Planning & Strategic Analysis							
Corporate Strategic Review	6				(1)	5	
Corporate Planning & Development	11			1		12	
VP Corp Planning & Strat Analysis	2				1	3	
	19	-	-	1	-	20	
Finance & Administration							
Information Technology Services	364			(10)	(18)	336	
Treasury	16				(1)	15	
Corporate Risk Mgmt	2				1	3	
Gas Supply	20				(1)	19	
Rates & Regulatory Affairs	19					19	
Corporate Controller	113			(7)		106	
Human Resources	164			(4)	1	161	
Corporate Safety & Health	29			(1)	(2)	26	
Corporate Services	295			4	4	303	
Senior VP Finance & Administration	9	2		1	(1)	11	Positions to support Corporate Safety & Health initiatives and the Worksmart and Business solutions projects(part year).
	1,031	2	-	(17)	(17)	999	

		2005/06 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2006/07 Actual	Comments Regarding New Positions
34								
35	**Power Supply**							
36	Power Planning	35			7		42	
37	Power Projects Development	38	2		1	-	41	Positions for new generation licensing and planning activities
38	HVDC	228				4	232	
39	Generation North	213				(2)	211	
40	Generation South	462				(3)	459	
41	Power Sales & Operations	84	6		(7)	(1)	82	Positions for power marketing, regulatory standards, and licensing activities.
42	Engineering Services	162	3			11	176	Positions for Kelsey rerunnering project.
43	New Generation Construction	14	10			1	25	Positions for new generation construction.
44	Senior VP PS Administration	131	6				137	Positions for Power Supply Worker trainee program.
45		1,367	27	-	1	10	1,405	
46								
47	**Transmission**							
48	Transmission System Operations	346	13			4	363	Positions for Telecontrol Trainee Program
49	Transmission Planning & Design	195				(2)	193	
50	Transmission Construction & Line Mtce	276				(2)	274	
51	Apparatus Maintenance	362				3	365	
52	VP Transmission Administration	42			1	(5)	38	
53		1,221	13	-	1	(2)	1,233	
54								
55	**Customer Service & Distribution**							
56	Customer Service Operations - Wpg&North	537				-22	515	
57	Customer Service Operations - South	569				-10	559	
58	Distribution Planning & Design	160				2	162	
59	Distribution Construction	382				-1	381	
	VP Cust Service & Distribution Admin	-					-	
60		1,648	-	-	-	(31)	1,617	
61								
62	**Customer Care & Marketing**							
63	Industrial & Commercial Solutions	49				2	51	
64	Consumer Marketing & Sales	219	7			1	227	Positions for support of new Power Smart programs.
65	Business Support Services	237			14	-12	239	
66	VP Cust Care & Marketing	47					47	
		552	7	-	14	(9)	564	
	Total	5,982	55	-	-	(48)	5,989	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

Line		2006/07 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2007/08 Actual	Comments Regarding New Positions
4								
5	**President & CEO**							
6	General Counsel	26				1	27	
7	Public Affairs	30				1	31	
8	Research & Development	2					2	
9	President & CEO Administration	26				1	27	
		84	-	-	-	3	87	
10								
11	**Corporate Relations**							
12	Aboriginal Relations	59				2	61	
13	VP Corp Relations Administration	8					8	
14		67	-	-	-	2	69	
15								
16	**Corporate Planning & Strategic Analysis**							
17	Corporate Strategic Review	5					5	
18	Corporate Planning & Development	12		(1)			11	
19	VP Corp Planning & Strat Analysis	3					3	
20		20	-	(1)	-	-	19	
21								
22	**Finance & Administration**							
23	Information Technology Services	336			(14)	(9)	313	
24	Treasury	15					15	
25	Corporate Risk Mgmt	3	1				4	Position to provide administrative support.
26	Gas Supply	19				(1)	18	
27	Rates & Regulatory Affairs	19					19	
28	Corporate Controller	106			10	(8)	108	
29	Human Resources	161			(2)		159	
30	Corporate Safety & Health	26	1		2	1	30	Position to provide administrative support.
31	Corporate Services	303			2	4	309	
32	Senior VP Finance & Administration	11					11	
33		999	2	-	(2)	(13)	986	
34								

		2006/07 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2007/08 Actual	Comments Regarding New Positions
34								
35	**Power Supply**							
36	Power Planning	42	6		4	3	55	Positions to support Keeyask, Conawapa, and Pointe du Bois.
37	Power Projects Development	41	7		(2)		46	Positions to support Keeyask, Conawapa, and Pointe du Bois.
38	HVDC	232				3	235	
39	Generation North	211				4	215	
40	Generation South	459				(4)	455	
41	Power Sales & Operations	82	1			1	84	Position to support export power marketing/trading function.
42	Engineering Services	176				(1)	175	
43	New Generation Construction	25	25			5	55	Positions to support Keeyask, Conawapa, and Pointe du Bois.
44	Senior VP PS Administration	137	15		(2)		150	Positions for Power Supply Worker Trainee program.
45		1,405	54	-	-	11	1,470	
46								
47	**Transmission**							
48	Transmission System Operations	363				(1)	362	
49	Transmission Planning & Design	193	4		(19)		178	Positions to support Wuskwatim Transmission.
50	Transmission Construction & Line Mtce	274				(1)	273	
51	Apparatus Maintenance	365	13		19		397	Positions for Power Electrician Trainee program.
52	VP Transmission Administration	38	2		2	3	45	Positions for new International Education Engineer Qualification Program
53		1,233	19	-	2	1	1,255	
54								
55	**Customer Service & Distribution**							
56	Customer Service Operations - Wpg&North	515	6			(1)	520	Positions for Gas Trades Trainee Program.
	Customer Service Operations - South	559	7			(5)	561	Positions for Power Line Technician Trainee program and Aboriginal Line
57								Trades Pre-Placement Trainee program.
58	Distribution Planning & Design	162	7		4		173	Positions to support engineering & design functions.
59	Distribution Construction	381	3		(4)	6	386	Positons for Power Line Technician Trainee program.
	VP Cust Service & Distribution Admin	-					-	
60		1,617	23	-	-	-	1,640	
61								
62	**Customer Care & Marketing**							
63	Industrial & Commercial Solutions	51				1	52	
64	Consumer Marketing & Sales	227				-11	216	
65	Business Support Services	239				-10	229	
66	VP Cust Care & Marketing	47				1	48	
		564	-	-	-	(19)	545	
	Total	5,989	98	(1)	-	(15)	6,071	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2007/08 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2008/09 Actual	Comments Regarding New Positions
President & CEO							
General Counsel	27				(1)	26	
Public Affairs	31				1	32	
Research & Development	2					2	
President & CEO Administration	27					27	
	87	-	-	-	-	87	
Corporate Relations							
Aboriginal Relations	61	5			1	67	Positions for Utility workers in Cross Lake to take on work previously done by external contractors.
VP Corp Relations Administration	8					8	
	69	5	-	-	1	75	
Corporate Planning & Strategic Analysis							
Corporate Strategic Review	5				1	6	
Corporate Planning & Development	11					11	
VP Corp Planning & Strat Analysis	3					3	
	19	-	-	-	1	20	
Finance & Administration							
Information Technology Services	313					313	
Treasury	15					15	
Corporate Risk Mgmt	4	1				5	Position to support middle office function.
Gas Supply	18	1			1	20	Position for transportation and storage.
Rates & Regulatory Affairs	19					19	
Corporate Controller	108				(1)	107	
Human Resources	159	1		-	3	163	Position to assist with trades training.
Corporate Safety & Health	30					30	
Corporate Services	309	2			5	316	Positions to support building operations at 360 Portage Ave.
Senior VP Finance & Administration	11					11	
	986	5	-	-	8	999	

Line		2007/08 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2008/09 Actual	Comments Regarding New Positions
34								
35	**Power Supply**							
36	Power Planning	55	2			1	58	Positions to support ongoing requirements for Emerging Energy Systems and Energy Policy & Emissions Trading.
37	Power Projects Development	46	3				49	Positions to support Keeyask, Conawapa, Pointe du Bois, and Planning Studies.
38	HVDC	235				15	250	
39	Generation North	215				4	219	
40	Generation South	455				4	459	
41	Power Sales & Operations	84					84	
42	Engineering Services	175	7			1	183	Positions for major capital projects such as Halon Replacement and Physical Security Upgrades, as well as Keeyask and Conawapa.
43	New Generation Construction	55	24			4	83	Positions to support Wuskwatim, Keeyask, Conawapa and Pointe du Bois.
44	Senior VP PS Administration	150	39			2	191	Positions for Power Supply Worker Trainee program.
45		1,470	75	-	-	31	1,576	
46								
47	**Transmission**							
48	Transmission System Operations	362					362	
49	Transmission Planning & Design	178	7			6	191	Positions to support Riel Station.
50	Transmission Construction & Line Mtce	273				2	275	
51	Apparatus Maintenance	397	24				421	Positions for Power Electrician Trainee program.
52	VP Transmission Administration	45	10		(7)	1	49	Positions for Engineer-in-Training program.
53		1,255	41	-	(7)	9	1,298	
54								
55	**Customer Service & Distribution**							
56	Customer Service Operations - Wpg&North	520	16			(6)	530	Positions for Gas Trades Trainee Program & two additional staff for Special Northern Collections Initiative.
57	Customer Service Operations - South	561	6	(2)		1	566	Positions for Power Line Technician Trainee program. .
58	Distribution Planning & Design	173			4	1	178	
59	Distribution Construction	386	6		(4)	9	397	Positions for Power Line Technician Trainee program.
	VP Cust Service & Distribution Admin	-					-	
60		1,640	28	(2)	-	5	1,671	
61								
62	**Customer Care & Marketing**							
63	Industrial & Commercial Solutions	52				2	54	
64	Consumer Marketing & Sales	216					216	
65	Business Support Services	229					229	
66	VP Cust Care & Marketing	48				3	51	
		545	-	-	-	5	550	
	Total	6,071	154	(2)	(7)	60	6,276	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

Line		2008/09 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2009/10 Forecast	Comments Regarding New Positions
4								
5	**President & CEO**							
6	General Counsel	26	1			2	29	Positions for additional legal counsel.
7	Public Affairs	32	1			1	34	Position for public relations.
8	Research & Development	2					2	
9	President & CEO Administration	27	2		2	1	32	Positions for new business units .
		87	4	-	2	4	97	
10								
11	**Corporate Relations**							
12	Aboriginal Relations	67				(3)	64	
13	VP Corp Relations Administration	8			(4)		4	
14		75	-	-	(4)	(3)	69	
15								
16	**Corporate Planning & Strategic Analysis**							
17	Corporate Strategic Review	6	4		1	(2)	9	Positions to support new business unit .
18	Corporate Planning & Development	11				(1)	10	
19	VP Corp Planning & Strat Analysis	3	1		2	(2)	4	Position to support new business unit .
20		20	5	-	3	(5)	23	
21								
22	**Finance & Administration**							
23	Information Technology Services	313					313	
24	Treasury	15					15	
25	Corporate Risk Mgmt	5	1				6	Position to support middle office.
26	Gas Supply	20					20	
27	Rates & Regulatory Affairs	19	3			(1)	21	Positions to meet increased demands from GRA & Cost of Gas hearings, overall administration of Load Research and gas policies review.
28	Corporate Controller	107				12	119	
29	Human Resources	163			(2)	(3)	158	
30	Corporate Safety & Health	30					30	
31	Corporate Services	316	4		4	23	347	Positions for building operator/maintainance functions for 360 Portage Ave.
32	Senior VP Finance & Administration	11	1			1	13	Position as a result of organization changes.
33		999	9	-	2	32	1,042	
34								

		2008/09 Actual	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2009/10 Forecast	Comments Regarding New Positions
34								
35	**Power Supply**							
36	Power Planning	58	10				68	Positions to support Keeyask Licencing, Conawapa Licencing & Pointe du Bois.
37	Power Projects Development	49	9				58	Positions to support Keeyask Licencing, Conawapa Licencing & Pointe du Bois.
38	HVDC	250	11			7	268	Positions for HVDC Thyrsistor Module Cooling Components capital project, Protection & Telecontrol Trainee program, caretaking services, and engineering.
39	Generation North	219				8	227	
40	Generation South	459	8			2	469	Positons for ice/safety management at Winnipeg River, NERC Cyber Security capital program, CT Maintenance related to Brandon Unit 5 restrictions, and Divisional Reorganization at Winnipeg River
41	Power Sales & Operations	84				4	88	
42	Engineering Services	183	26			4	213	Positions related to major capital projects such as Domestic Water and Sewer Upgrades, Halon Replacement and Physical Security Upgrades, as well as Keeyask and Conawapa.
43	New Generation Construction	83	45			14	142	Positions hired to support Wuskwatim, Keeyask, Conawapa, Pointe du Bois and Bipole 3 Converter Stations projects.
44	Senior VP PS Administration	191	25			8	224	Positions for Power Supply Worker Trainee program and to support new organization structure.
45		1,576	134	-	-	47	1,757	
46								
47	**Transmission**							
48	Transmission System Operations	362	2			6	370	Positions for NERC compliance.
49	Transmission Planning & Design	191	7		(1)	18	215	Positions to support Wuskwatim and Riel Station projects.
50	Transmission Construction & Line Mtce	275	5			15	295	Positions to support Wuskwatim and Riel Station projects.
51	Apparatus Maintenance	421	11			-	432	Positions for Power Electrician Trainee program.
52	VP Transmission Administration	49			(3)	(2)	44	
53		1,298	25	-	(4)	37	1,355	
54								
55	**Customer Service & Distribution**							
56	Customer Service Operations - Wpg&North	530	3		(7)	5.5	532	Positions related to Special Northern Collections Initiative.
57	Customer Service Operations - South	566	1		8	4	578	Position to support new organization structure.
58	Distribution Planning & Design	178			(1)	8	185	
59	Distribution Construction	397	8		(1)	2	406	Positons for Power Line Technician Trainee program
60	VP Cust Service & Distribution Admin	-	3		3		6	Positions to support new organization structure.
61		1,671	15	-	2	20	1,708	
62								
63	**Customer Care & Marketing**							
64	Industrial & Commercial Solutions	54				6	60	
65	Consumer Marketing & Sales	216				(1)	215	
66	Business Support Services	229					229	
67	VP Cust Care & Marketing	51			(1)	7	57	
		550	-	-	(1)	12	561	
	Total	6,276	192	-	-	144	6,613	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2009/10 Forecast	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2010/11 Forecast	Comments Regarding New Positions
President & CEO							
General Counsel	29					29	
Public Affairs	34					34	
Research & Development	2					2	
President & CEO Administration	32				2	34	
	97	-	-	-	2	99	
Corporate Relations							
Aboriginal Relations	64					65	
VP Corp Relations Administration	4					4	
	69	-	-	-	-	69	
Corporate Planning & Strategic Analysis							
Corporate Strategic Review	9	12				21	Positions to support new business unit.
Corporate Planning & Development	10				2	12	
VP Corp Planning & Strat Analysis	4	1				5	Position to support new business unit.
	23	13	-	-	2	38	
Finance & Administration							
Information Technology Services	313				1	314	
Treasury	15					15	
Corporate Risk Mgmt	6					6	
Gas Supply	20					20	
Rates & Regulatory Affairs	21					21	
Corporate Controller	119					119	
Human Resources	158					158	
Corporate Safety & Health	30					30	
Corporate Services	347					347	
Senior VP Finance & Administration	13					13	
	1,042	-	-	-	1	1,043	

		2009/10 Forecast	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2010/11 Forecast	Comments Regarding New Positions
34								
35	**Power Supply**							
36	Power Planning	68					68	
37	Power Projects Development	58					58	
38	HVDC	268				2	270	
39	Generation North	227				2	229	
40	Generation South	469				1	470	
41	Power Sales & Operations	88				1	89	
42	Engineering Services	213				-	213	
43	New Generation Construction	142				1	143	
44	Senior VP PS Administration	224	22				246	Positions for Power Supply Worker Trainee program
45		1,757	22	-	-	7	1,785	
46								
47	**Transmission**							
48	Transmission System Operations	370					370	
49	Transmission Planning & Design	215				1	216	
50	Transmission Construction & Line Mtce	295				1	296	
51	Apparatus Maintenance	432				1	433	
52	VP Transmission Administration	44					44	
53		1,355	-	-	-	3	1,358	
54								
55	**Customer Service & Distribution**							
56	Customer Service Operations - Wpg&North	532				2	534	
57	Customer Service Operations - South	578				1	579	
58	Distribution Planning & Design	185					185	
59	Distribution Construction	406				1	407	
60	VP Cust Service & Distribution Admin	6					6	
61		1,708	-	-	-	4	1,711	
62								
63	**Customer Care & Marketing**							
64	Industrial & Commercial Solutions	60					60	
65	Consumer Marketing & Sales	215				3	218	
66	Business Support Services	229				-2	227	
67	VP Cust Care & Marketing	57				3	60	
		561	-	-	-	4	566	
	Total	6,613	35	-	-	23	6,669	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2010/11 Forecast	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2011/12 Forecast	Comments
President & CEO							
General Counsel	29					29	
Public Affairs	34					34	
Research & Development	2					2	
President & CEO Administration	34					34	
	99	-	-	-	-	99	
Corporate Relations							
Aboriginal Relations	65					65	
VP Corp Relations Administration	4					4	
	69	-	-	-	-	69	
Corporate Planning & Strategic Analysis							
Corporate Strategic Review	21					21	
Corporate Planning & Development	12					12	
VP Corp Planning & Strat Analysis	5					5	
	38	-	-	-	-	38	
Finance & Administration							
Information Technology Services	314					314	
Treasury	15					15	
Corporate Risk Mgmt	6					6	
Gas Supply	20					20	
Rates & Regulatory Affairs	21					21	
Corporate Controller	119					119	
Human Resources	158					158	
Corporate Safety & Health	30					30	
Corporate Services	347					347	
Senior VP Finance & Administration	13					13	
	1,043	-	-	-	-	1,043	

		2010/11 Forecast	New Positions	Eliminated Positions	Transfers	Overtime, Vacancies & Other	2011/12 Forecast	Comments
34								
35	**Power Supply**							
36	Power Planning	68					68	
37	Power Projects Development	58					58	
38	HVDC	270					270	
39	Generation North	229					229	
40	Generation South	470					470	
41	Power Sales & Operations	89					89	
42	Engineering Services	213					213	
43	New Generation Construction	143					143	
44	Senior VP PS Administration	246					246	
45		1,785	-	-	-	-	1,785	
46								
47	**Transmission**							
48	Transmission System Operations	370					370	
49	Transmission Planning & Design	216					216	
50	Transmission Construction & Line Mtce	296					296	
51	Apparatus Maintenance	433					433	
52	VP Transmission Administration	44					44	
53		1,358	-	-	-	-	1,358	
54								
55	**Customer Service & Distribution**							
56	Customer Service Operations - Wpg&North	534					534	
57	Customer Service Operations - South	579					579	
58	Distribution Planning & Design	185					185	
59	Distribution Construction	407					407	
60	VP Cust Service & Distribution Admin	6					6	
61		1,711	-	-	-	-	1,711	
62								
63	**Customer Care & Marketing**							
64	Industrial & Commercial Solutions	60					60	
65	Consumer Marketing & Sales	218					218	
66	Business Support Services	227					227	
67	VP Cust Care & Marketing	60					60	
		566	-	-	-	-	566	
	Total	6,669	-	-	-	-	6,669	

<u>PUB/MH I-34</u>

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 13 of 29 Schedule 4.5.1, 4.5.4 Staffing Levels**

c) Please indicate the current number of unfilled EFT's

<u>ANSWER</u>:

The budgeted EFT complement for January 2010 was 6,229 as compared to the actual EFT level of 6,041, resulting in a shortfall of 188 EFTs.

PUB/MH I-35

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

a) **Please provide a summary of total interest and finance costs incurred/ forecasted by major category [debt charges, foreign currency gains/losses etc] both capitalized and expended for the fiscal years 2000 to 2009 (actual) and forecast for 2009/10 through 2011/12 in a similar level of detail provided in PUB/MH I-43 a) of the 2008 GRA**

ANSWER:

The schedule filed with PUB/MH I-43(a) at the 2008 GRA outlined total interest and finance costs incurred by major category. Please see the attached schedule for the requested updates.

For the updated schedule, Manitoba Hydro has reclassified the presentation of other foreign exchange gains and losses arising from miscellaneous foreign exchange revaluations. In the schedule provided at the 2008 GRA, other foreign exchange gains or losses were included in gross interest on short term debt. The presentation in the requested updated schedule segregates these amounts as a separate line item.

Manitoba Hydro also notes there are differences between the presentation of total finance expense in the requested schedule and the presentation of electric finance expense as outlined in Schedule 4.6.0 in Tab 4 of the current Application.

The requested schedule presents the consolidated amount paid or forecast for the provincial debt guarantee fee (PDGF) and presents the PDGF amounts recovered from Centra Gas on its intercompany advances within Interest - Non Electric Operations. Schedule 4.6.0 presents PDGF as the net amount charged to electric operations having been reduced by the amount recovered from Centra Gas.

The requested schedule also presents finance expense without a reduction for the amount of finance expense related to Centra Gas acquisition costs that are not recovered through the corporation allocation. Schedule 4.6.0 presents finance expense for the electric operations only, with all amounts related to the corporate allocation as a reduction to electric finance expense. As a result, the finance expense outlined in the requested schedule attached is higher in all years by this difference in comparison to the presentation of finance expense as outlined in Schedule 4.6.0.

PUB/MH I - 35 (a)

MANITOBA HYDRO
SUMMARY OF TOTAL FINANCE EXPENSE

All in $Millions CAD

	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Forecast 2010	Forecast 2011	Forecast 2012
Gross Interest on Long Term Debt	478	474	482	493	491	470	471	484	534
Gross Interest on Short Term Debt	4	1	(4)	(4)	(1)	(3)	(1)	2	3
Total Gross Interest on Debt	**482**	**476**	**478**	**489**	**490**	**467**	**470**	**486**	**537**
Add:									
Provincial Guarantee Fee	70	70	68	71	73	74	76	82	87
Interest Portion of Wpg Hydro Payment	16	16	16	16	16	16	16	16	16
Amortization of Debt Discount or (Premium) and Transaction Fees	(14)	(9)	(9)	(9)	(11)	(12)	(10)	2	2
Amortization of Discount or (Premium) on Sinking Fund	7	5	4	5	5	6	5	3	3
Total Additions	79	82	80	83	83	84	86	103	109
Deduct:									
Net Interest Earned on Sinking Fund	(50)	(33)	(35)	(33)	(35)	(31)	(30)	(21)	(14)
Interest - Non Electric Operations	(18)	(17)	(18)	(20)	(21)	(20)	(18)	(20)	(22)
Capitalized Interest	(32)	(33)	(35)	(47)	(60)	(74)	(91)	(131)	(137)
FX (Gains) or Losses on SF Contributions	-	-	-	-	(52)	(11)	8	4	-
Other Foreign Exchange (Gains) or Losses	(7)	(2)	3	(0)	4	(7)	(1)	-	-
Other Finance Expense	-	0	(1)	0	(2)	(2)	(1)	(3)	2
Total Deductions	(106)	(84)	(85)	(100)	(167)	(145)	(133)	(170)	(171)
Total Finance Expense	**454**	**473**	**473**	**472**	**406**	**407**	**423**	**419**	**474**

PUB/MH I-35

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

b) **Please re-file schedule 4.6.0 utilizing short and long term interest rates approved by the Board at the Centra GRA for the two MH test years and quantify any differences with that used in the application .**

ANSWER:

Manitoba Hydro notes that PUB/MH I-46(h) requested an adjustment to projected finance expense reflecting the short and long term interest rates approved by the Board in Order 128/09 for 2009/10 and 2010/11. The updated consolidated projection used in PUB/MH I-46(h) has been used to update the attached revised Schedule 4.6.0 for Manitoba Hydro electric operations.

MANITOBA HYDRO **Schedule 4.6.0 Revised for PU B 1-35(b)**
FINANCE EXPENSE **PUB 1-35(b)** (000s)

Schedule 4.6.0 As Filed:	**2007/08 Actual**	**2008/09 Actual**	**2009/10 Forecast**	**2010/11 Forecast**	**2011/12 Forecast**
Interest on Short & Long-Term Debt					
Gross Interest	$ 500,512	$ 468,685	$ 475,783	$ 492,011	$ 553,011
Provincial Guarantee Fee	69,865	70,360	72,274	78,099	82,920
Amortization of (Premiums), Discounts, and Transaction Costs	(11,054)	(11,605)	(10,498)	2,321	2,276
Intercompany Interest Receivable	(19,774)	(18,182)	(16,380)	(19,416)	(25,015)
Total Interest on Short & Long-Term Debt	539,549	509,259	521,179	553,015	613,192
Interest Earned on Sinking Fund	(30,180)	(24,920)	(24,908)	(17,585)	(10,720)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	(52,407)	(11,359)	8,011	4,398	-
Interest Allocated to Construction	(60,015)	(74,493)	(91,267)	(130,789)	(137,126)
Corporate Allocation	(17,483)	(17,543)	(17,880)	(18,704)	(18,704)
Other Amortization	21,331	20,116	21,776	22,204	21,008
Total Finance Expense	$ 400,796	$ 401,060	$ 416,913	$ 412,539	$ 467,650

Schedule 4.6.0 Revised for PUB/MH I - 35 (b):	**2007/08 Actual**	**2008/09 Actual**	**2009/10 Forecast**	**2010/11 Forecast**	**2011/12 Forecast**
Interest on Short & Long-Term Debt					
Gross Interest	$ 500,512	$ 468,685	$ 475,875	$ 483,869	$ 543,345
Provincial Guarantee Fee	69,865	70,360	72,274	78,100	82,895
Amortization of (Premiums), Discounts, and Transaction Costs	(11,054)	(11,605)	(10,498)	2,321	2,276
Intercompany Interest Receivable	(19,774)	(18,182)	(16,421)	(18,197)	(24,285)
Total Interest on Short & Long-Term Debt	539,549	509,259	521,230	546,093	604,231
Interest Earned on Sinking Fund	(30,180)	(24,920)	(24,908)	(17,569)	(10,720)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	(52,407)	(11,359)	8,011	4,398	-
Interest Allocated to Construction	(60,015)	(74,493)	(91,267)	(120,284)	(132,636)
Corporate Allocation	(17,483)	(17,543)	(17,880)	(18,704)	(18,704)
Other Amortization	21,331	20,116	21,776	22,204	21,008
Total Finance Expense utilizing short and long term interest rates approved by the Board at the Centra GRA	$ 400,796	$ 401,060	$ 416,964	$ 416,138	$ 463,179

Difference from Schedule 4.6.0 as Filed	**2007/08 Actual**	**2008/09 Actual**	**2009/10 Forecast**	**2010/11 Forecast**	**2011/12 Forecast**
Interest on Short & Long-Term Debt					
Gross Interest	$ -	$ -	$ 92	$ (8,142)	$ (9,666)
Provincial Guarantee Fee	-	-	-	1	(25)
Amortization of (Premiums), Discounts, and Transaction Costs	-	-	-	-	-
Intercompany Interest Receivable	-	-	(41)	1,219	730
Total Interest on Short & Long-Term Debt	-	-	51	(6,922)	(8,961)
Interest Earned on Sinking Fund	-	-	-	16	-
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	-	-	-	-	-
Interest Allocated to Construction	-	-	-	10,505	4,490
Corporate Allocation	-	-	-	-	-
Other Amortization	-	-	-	-	-
Total Finance Expense Increase (Decrease) from IFF-09	$ -	$ -	$ 51	$ 3,599	$ (4,471)

PUB/MH I-35

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

c) **Please explain the variation in Corporate Allocation experienced in the years 2007/08 through 2011/12.**

ANSWER:

Schedule 4.6.0 was re-submitted on Tuesday, February 9, 2010, to correct a typographical error in the schedule submitted with the original application. As a result, there is no significant variation in Corporate Allocation.

PUB/MH I-35

Subject: Tab 4: Financial Results & Forecast
Reference: Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense

d) Please provide a continuity schedule of the short and long-term debt for the fiscal years 2000 to 2030 detailing the retirement of existing debt and the issue of new debt. Please indicate the proportion of short-term debt to total debt for each of the years.

ANSWER:

Please see the attached schedule.

Short term debt is defined as debt issued with maturities of less than one year. Manitoba Hydro's short term borrowing program is a credit facility to safeguard Manitoba Hydro from liquidity risk and to provide sufficient liquidity for the Corporation's temporary cash requirements. Short term borrowings are not intended as a financing vehicle to reduce Manitoba Hydro's overall debt servicing costs.

Manitoba Hydro uses its short term debt line to fund seasonal working capital requirements and to bridge the timing between long term debt issues. It is inappropriate to utilize the Corporation's overdraft credit facilities and Commercial Paper Program to permanently fund capital construction that should more appropriately be financed through long term debt.

PUB 1-35(d)

MANITOBA HYDRO
CONTINUNITY SCHEDULE
SHORT AND 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													
Opening Balance	7,268	7,390	7,204	7,169	7,227	7,570	8,179	8,118	8,637	9,251	9,631	10,462	11,780
LTD Issued	1,013	300	180	173	981	423	900	800	600	600	1,600	1,400	1,800
LTD Retired	(473)	(241)	(111)	(80)	(311)	(365)	(448)	(304)	(27)	(183)	(849)	(100)	(262)
Foreign Exchange and Adjustments*	(418)	(245)	(104)	(35)	(328)	552	(514)	23	41	(36)	80	18	19
Closing Balance	7,390	7,204	7,169	7,227	7,570	8,179	8,118	8,637	9,251	9,631	10,462	11,780	13,337

Foreign Exchange and Adjustments* includes changes in foreign exchange rates on US dollar denominated debt and effective 2007/08 and 2008/09 with presentation changes from financial instruments reporting standards includes changes to portfolio carrying value from premiums/discounts and transaction costs.

Short Term Debt	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
Opening Balance	128	93	59	-	148	-	100	48	40	23	109	-	-
Increase(Decrease)	(35)	(34)	(59)	148	(148)	100	(52)	(8)	(17)	86	(109)	-	41
Closing Balance	93	59	-	148	-	100	48	40	23	109	-	-	41

	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	7,390	7,204	7,169	7,227	7,570	8,179	8,118	8,637	9,251	9,631	10,462	11,780	13,337
Short Term Debt	93	59	-	148	-	100	48	40	23	109	-	-	41
Total Debt	7,483	7,263	7,169	7,375	7,570	8,279	8,166	8,677	9,274	9,740	10,462	11,780	13,378
Proportion Short Term Debt	1%	1%	0%	2%	0%	1%	1%	0%	0%	1%	0%	0%	0%

PUB 1-35(d)

MANITOBA HYDRO
CONTINUNITY SCHEDULE
SHORT AND 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													
Opening Balance	13,337	14,955	16,228	16,763	17,445	18,164	18,022	18,653	18,656	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)	(869)	(321)	(285)	(745)	(171)	-	-	(300)	-	-	(60)
Foreign Exchange and Adjustments*	19	3	3	3	3	3	2	2	2	2	2	2	2
Closing Balance	14,955	16,228	16,763	17,445	18,164	18,022	18,653	18,656	18,658	18,360	18,362	18,364	18,306

Foreign Exchange and Adjustments* includes changes in foreign exchange rates on US dollar denominated debt and effective 2007/08 and 2008/09 with presentation changes from financial instruments reporting standards includes changes to portfolio carrying value from premiums/discounts and transaction costs.

Short Term Debt	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
Opening Balance	41	21	-	72	-	-	-	-	-	-	-	-	-
Increase(Decrease)	(20)	(21)	72	(72)	-	-	-	-	-	-	-	-	-
Closing Balance	21	-	72	-	-	-	-	-	-	-	-	-	-

	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	14,955	16,228	16,763	17,445	18,164	18,022	18,653	18,656	18,658	18,360	18,362	18,364	18,306
Short Term Debt	21	-	72	-	-	-	-	-	-	-	-	-	-
Total Debt	14,976	16,228	16,835	17,445	18,164	18,022	18,653	18,656	18,658	18,360	18,362	18,364	18,306
Proportion Short Term Debt	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

PUB/MH I-35

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

e) Please provide a schedule of new debt issues of long-term borrowings for the years 2009/10, 2010/11 and 2011/12 years and the forecast and Interest per year at forecast rate interest rates used for each loan.

ANSWER:

Please see the attached schedule.

PUB 1-35 (e)

New Long Term Debt Issues
Forecast as at September 30, 2009 in Schedule 4.6.0 Interest Costs
(all amounts in $millions)
(rates exclude PGF)

Fiscal Year	Series	Amount	Currency	Issue Date	Maturity Date	Coupon Rate	Interest Cost 2009/10	Interest Cost 2010/11	Interest Cost 2011/12
2009/10	C107	100.0	CAD	2-Jun-2009	4-Sep-2012	Floating 3 BA + 0.40%	0.7	1.6	3.6
	FK-2	300.0	CAD	5-Jun-2009	5-Mar-2040	4.65%	11.6	14.0	14.0
	FM-4	100.0	CAD	1-Sep-2009	1-Sep-2014	Floating 3 BA + 0.484%	0.6	1.8	3.7
	Forecast	200.0	CAD	Feb-2010	Feb-2040	4.60%	0.8	9.2	9.2
	Forecast	200.0	CAD	Mar-2010	Mar-2040	4.60%	0.0	9.2	9.2
	Total New Debt	900.0					13.7	35.8	39.7
2010/11	Forecast	200.0	CAD	Jun-2010	Jun-2040	4.65%		7.0	9.3
	Forecast	200.0	CAD	Aug-2010	Aug-2040	4.65%		5.4	9.3
	Forecast	200.0	CAD	Nov-2010	Nov-2040	4.65%		3.1	9.3
	Forecast	200.0	CAD	Mar-2011	Mar-2041	4.65%		0.0	9.3
	Total New Debt	800.0						15.5	37.2
2011/12	Forecast	200.0	CAD	Sep-2011	Sep-2041	5.20%			5.2
	Forecast	200.0	CAD	Dec-2012	Dec-2042	5.20%			2.6
	Forecast	200.0	CAD	Mar-2012	Mar-2042	5.20%			0.0
	Total New Debt	600.0							7.8

PUB/MH I-35

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

f) Please file a copy of term sheets related to long-term debt issued in 2008/09 and 2009/10.

ANSWER:

Please see Appendix 48.

PUB/MH I-35

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

g) Please provide a schedule detailing the maturities of MH's current long term debt issues.

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-142(a) for a schedule of long term debt maturities as at December 31, 2009.

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

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

h) **For each of the years 2004 through 2013, assuming the refinancing plan in the application, please provide weighted average term of outstanding debt, the principal amount and proportion of debt maturing within:**

- **i.** **10 years;**
- **ii.** **Twenty years; and**
- **iii.** **Greater than twenty years**

<u>ANSWER</u>:

Please see the attached schedule that reflects long term debt balances and the refinancing plan as at September 30, 2009.

MANITOBA HYDRO
PUB 1-35(h)
AS AT SEPTEMBER 30, 2009

Fiscal Year Ended	Debt Maturing <= 10 Years		Debt Maturing > 10 years and <= 20 Years		Debt Maturing > 20 Years		Total Long Term Debt	Weighted Average Term To Maturity In Years
	CAD$Millions	% of Total	CAD$Millions	% of Total	CAD$Millions	% of Total	CAD$Millions	
March 31, 2004	$2,586	35.1%	$3,521	47.7%	$1,268	17.2%	$7,375	13.8
March 31, 2005	2,377	33.1%	3,346	46.5%	1,468	20.4%	7,191	13.8
March 31, 2006	2,397	33.5%	3,317	46.3%	1,443	20.2%	7,158	13.7
March 31, 2007	2,623	36.3%	3,094	42.9%	1,501	20.8%	7,218	12.9
March 31, 2008	2,996	39.5%	2,513	33.1%	2,081	27.4%	7,590	13.5
March 31, 2009	3,763	45.8%	2,026	24.7%	2,421	29.5%	8,209	13.6
March 31, 2010	3,583	43.8%	1,726	21.1%	2,871	35.1%	8,180	14.9
March 31, 2011	3,558	40.9%	2,069	23.8%	3,071	35.3%	8,698	15.8
March 31, 2012	4,265	45.8%	1,383	14.9%	3,662	39.3%	9,310	15.8
March 31, 2013	4,207	43.4%	1,249	12.9%	4,232	43.7%	9,688	16.0
March 31, 2014	3,435	32.7%	1,249	11.9%	5,832	55.5%	10,516	18.4

PUB/MH I-36 (REVISED)

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

a) **Please re-file the schedule including the years 1999/00 through 2006/07**

ANSWER:

Please see schedule attached.

MANITOBA HYDRO
FINANCE EXPENSE
PUB/ MH 1 - 36 a

	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
Interest on Short & Long-Term Debt									
Gross Interest	$ 489,978	$ 485,696	$ 492,656	$ 496,204	$ 500,512	$ 468,685	$ 475,783	$ 492,011	$ 553,011
Provincial Guarantee Fee	66,844	67,801	65,905	67,997	69,865	70,360	72,274	78,099	82,920
Amortization of (Premiums), Discounts, and Transaction Costs	(14,375)	(9,326)	(8,802)	(8,658)	(11,054)	(11,605)	(10,498)	2,321	2,276
Intercompany Interest Receivable	(15,259)	(15,392)	(16,470)	(16,827)	(19,774)	(18,182)	(16,380)	(19,416)	(25,015)
Total Interest on Short & Long-Term Debt	527,188	528,778	533,289	538,716	539,549	509,259	521,179	553,015	613,192
Interest Earned on Sinking Fund	(43,028)	(27,656)	(30,640)	(28,535)	(30,180)	(24,920)	(24,908)	(17,585)	(10,720)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	-	-	-	-	(52,407)	(11,359)	8,011	4,398	-
Interest Allocated to Construction	(31,564)	(32,683)	(34,496)	(47,071)	(60,015)	(74,493)	(91,267)	(130,789)	(137,126)
Corporate Allocation	(16,830)	(16,763)	(16,809)	(17,141)	(17,483)	(17,543)	(17,880)	(18,704)	(18,704)
Other Amortization	17,035	16,166	17,015	21,170	21,331	20,116	21,776	22,204	21,008
Total Finance Expense	$ 452,801	$ 467,843	$ 468,359	$ 467,139	$ 400,796	$ 401,060	$ 416,913	$ 412,539	$ 467,650

PUB/MH I-36

Subject: Tab 4: Financial Results & Forecast
Reference: Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense

b) Please provide a schedule which compares finance expense forecasts for 2007/08 and 2008/09 presented at the 2008 GRA and explain any major variances.

ANSWER:

The finance expense forecasts for 2007/08 and 2008/09 were filed for the 2008 GRA as Schedule 5.3.6. For the current Application, Schedule 4.6.0 contains actual finance expenses for 2007/08 and 2008/09, and forecasts for 2009/10, 2010/11 and 2011/12.

For the current Application, the following finance expense reclassifications were adopted:

- Amortization of FMV Write-up was reclassified to Other Amortization,
- Interest on Temporary Investments was reclassified to Gross Interest,
- An amount related to interest on loans that was classified as Other Amortization was reclassified to Gross Interest, and
- Interest charged to the Wuskwatim Power Limited Partnership has been reclassified from Intercompany Interest Receivable to Interest Allocated to Construction.

In order to provide comparability with the presentation adopted for the current Application, the following schedule outlines the forecasts for 2007/08 and 2008/09 as presented at the last GRA, the forecasts as they would have been presented with the current presentation, along with variances between this revised presentation and actuals as shown in Schedule 4.6.0.

Please see the attached schedule.

MANITOBA HYDRO
FINANCE EXPENSE
($000's)

	2007/08 Forecast As Filed Schedule 5.3.6 2008/09 GRA (A)	**2007/08 Forecast** Reclassified Schedule 5.3.6 2008/09 GRA (B)	**2007/08 Actual** As Filed Schedule 4.6.0 2010/11 GRA (C)	**2007/08 Variance** (B - C)	**2008/09 Forecast** As Filed Schedule 5.3.6 2008/09 GRA (D)	**2008/09 Forecast** Reclassified Schedule 5.3.6 2008/09 GRA (E)	**2008/09 Actual** As Filed Schedule 4.6.0 2010/11 GRA (F)	**2008/09 Variance** (E - F)
Interest on Short & Long-Term Debt								
Gross Interest (Note 1)	$ 508,656	$ 505,356	$ 500,512	$ 4,844	$ 523,543	$ 523,543	$ 468,685	$ 54,858
Provincial Guarantee Fee	69,865	69,865	69,865	0	71,290	71,290	70,360	930
Amortization of (Premiums), Discounts, and Transaction Costs (Note 2)	(8,823)	(8,823)	(11,054)	2,231	(9,656)	(9,656)	(11,605)	1,949
Amortization of FMV Write-up	(744)			-	(685)			-
Interest on Temporary Investments	(1,914)			-	-			-
Intercompany Interest Receivable (Note 3)	(34,086)	(19,935)	(19,774)	(161)	(52,635)	(21,772)	(18,182)	(3,590)
Total Interest on Short & Long-Term Debt	532,954	546,463	539,549	6,914	531,857	563,405	509,259	54,146
Interest Earned on Sinking Fund (Note 4)	(30,133)	(30,133)	(30,180)	47	(31,708)	(31,708)	(24,920)	(6,788)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges (Note 5)	(53,975)	(53,975)	(52,407)	(1,568)	(25,127)	(25,127)	(11,359)	(13,768)
Interest Allocated to Construction (Note 6)	(52,782)	(66,933)	(60,015)	(6,918)	(58,593)	(89,456)	(74,493)	(14,963)
Corporate Allocation	(17,484)	(17,484)	(17,483)	(1)	(17,542)	(17,542)	(17,543)	1
Other Amortization	19,991	20,633	21,331	(698)	21,257	20,572	20,116	456
Total Finance Expense	**$ 398,571**	**$ 398,571**	**$ 400,796**	**$ (2,225)**	**$ 420,144**	**$ 420,144**	**$ 401,060**	**$ 19,084**

Note 1 **Gross Interest** - the favourable variances are primarily from lower than forecast interest rates on floating rate long term debt, short term debt and new fixed rate long term debt, as well as lower than forecast foreign exchange rates.

Note 2 **Amortization of (Premiums), Discounts and Transaction Costs** - the variances are due to the adoption of the financial instruments accounting standards.

Note 3 **Intercompany Interest Receivable** - the variances are primarily from lower than forecast short term interest rates on intercompany advances.

Note 4 **Interest on Sinking Fund** - the variances in 2008/09 are largely from lower sinking fund returns as a result of lower than forecast foreign exchange and interest rates.

Note 5 **Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges** - the variance in 2008/09 is primarily due to the addition of US debt series C094 that was added to the US debt portfolio in February 2008.

Note 6 - Interest Allocated to Construction - the variances are due to lower than forecast interest capitalization rates and lower than forecast capital expenditures.

PUB/MH I-37 (REVISED)

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4- Schedule 4.7.0 Depreciation & Amortization**

a) Please re-file the schedule including the years 1999/00 through 2006/07

ANSWER:

Please see the following schedule, which includes information from 2003/04 through 2011/12.

	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
Generation									
Hydraulic Generating Stations	58,336	59,815	60,615	61,596	68,451	70,911	75,678	79,051	87,683
Thermal Generating Stations	17,098	16,857	17,019	17,191	17,170	17,276	17,661	18,234	18,660
Amortization of Planning Studies	4,168	4,621	5,485	2,437	2,366	2,539	0	0	0
Demand Side Management	5,024	5,957	7,247	9,973	11,357	20,102	21,943	24,829	28,703
Diesel Generating Stations	2,742	3,029	3,126	3,197	4,067	3,933	3,572	3,695	3,893
Amortization of Contributions	(37)	(22)	(1,335)	(2,660)	(2,774)	(2,796)	(2,824)	(2,923)	(3,206)
	$ 87,331	$ 90,257	$ 92,157	$ 91,734	$ 100,637	$ 111,965	$ 116,029	$ 122,886	$ 135,733
Transmission									
Transmission	11,363	11,552	11,699	12,163	14,120	14,317	14,337	14,496	16,533
Amortization of Contributions	(1,655)	(1,655)	(1,671)	(1,683)	(1,631)	(1,638)	(1,639)	(1,640)	(1,640)
	$ 9,708	$ 9,897	$ 10,028	$ 10,480	$ 12,489	$ 12,680	$ 12,698	$ 12,856	$ 14,893
Stations									
Substations	56,454	58,382	61,010	62,980	70,616	72,512	73,985	76,510	83,226
Transformers	2,463	2,667	7,070	6,102	3,681	2,288	1,829	1,749	1,813
Amortization of Contributions	(1,159)	(1,169)	(1,230)	(1,186)	(1,461)	(1,462)	(1,463)	(1,466)	(1,469)
	$ 57,758	$ 59,880	$ 66,850	$ 67,896	$ 72,836	$ 73,338	$ 74,352	$ 76,793	$ 83,570
Distribution									
Subtransmission Lines	6,791	7,128	7,329	7,682	8,905	9,166	9,192	9,417	9,730
Distribution Lines	65,509	69,733	73,784	77,580	72,410	77,730	80,856	85,067	90,054
Meters & Transformers	1,309	1,343	1,358	1,435	1,551	1,597	2,033	2,027	2,242
Amortization of Contributions	(8,052)	(8,315)	(8,582)	(8,891)	(9,769)	(10,180)	(10,613)	(10,812)	(11,117)
	$ 65,557	$ 69,889	$ 73,889	$ 77,806	$ 73,097	$ 78,312	$ 81,468	$ 85,699	$ 90,909
Other									
Communications	9,837	12,910	12,634	13,591	17,636	19,473	21,235	22,952	24,521
Motor Vehicles	6,555	7,169	7,879	8,324	8,275	8,691	9,290	9,692	10,236
Structures & Improvements	3,033	2,863	3,239	3,380	3,216	5,614	6,543	6,785	7,363
General Equipment	21,173	21,310	19,180	18,555	20,572	19,118	18,356	18,898	20,273
Computer Development	11,250	12,624	13,119	15,198	13,582	13,352	15,553	16,099	16,616
Affordable Energy Fund	0	0	0	875	625	1,441	10,108	12,101	3,658
Miscellaneous	3,902	4,185	3,899	4,596	2,701	4,067	4,309	3,615	1,080
Corporate Allocation	(1,779)	(1,694)	(1,661)	(1,520)	(2,093)	(2,012)	(2,139)	(2,135)	(2,136)
	$ 53,971	$ 59,367	$ 58,289	$ 62,999	$ 64,514	$ 69,745	$ 83,254	$ 88,007	$ 81,611
Total Depreciation and Amortization Expense	$ 274,325	$ 289,290	$ 301,213	$ 310,915	$ 323,573	$ 346,039	$ 367,801	$ 386,242	$ 406,717

PUB/MH I-37

Subject: Tab 4: Financial Results & Forecast

Reference: Tab 4- Schedule 4.7.0 Depreciation & Amortization

b) Please provide a schedule which compares depreciation and amortization expense forecasts for 2007/08 and 2008/09 presented at the 2008 GRA with actual depreciation and amortization expense included in this application for those years.

ANSWER:

Please see the following table for the requested information.

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE

	2007/08 Actual	2007/08 Forecast	Difference	2008/09 Actual	2008/09 Forecast	Difference
Generation						
Hydraulic Generating Stations	68 451	68 070	381	70 911	71 315	(404)
Thermal Generating Stations	17 170	17 197	(27)	17 276	17 508	(232)
Amortization of Planning Studies	2 366	2 366	0	2 539	2 471	68
Demand Side Management	11 357	11 328	29	20 102	13 704	6 398
Diesel Generating Stations	4 067	4 062	5	3 933	3 885	48
Amortization of Contributions	(2 774)	(2 819)	45	(2 796)	(2 924)	128
	$ 100 637	$ 100 204	$ 433	$ 111 965	$ 105 959	$ 6 006
Transmission						
Transmission	14 120	14 132	(12)	14 317	14 380	(63)
Amortization of Contributions	(1 631)	(1 634)	3	(1 638)	(1 637)	(1)
	$ 12 489	$ 12 498	$ (9)	$ 12 680	$ 12 743	$ (63)
Stations						
Substations	70 616	73 110	(2 494)	72 512	74 142	(1 630)
Transformers	3 681	4 838	(1 157)	2 288	4 819	(2 531)
Amortization of Contributions	(1 461)	(1 462)	1	(1 462)	(1 462)	0
	$ 72 836	$ 76 486	$ (3 650)	$ 73 338	$ 77 499	$ (4 161)
Distribution						
Subtransmission Lines	8 905	8 846	59	9 166	9 168	(2)
Distribution Lines	72 410	72 903	(493)	77 730	75 015	2 715
Meters & Transformers	1 551	1 771	(220)	1 597	1 701	(104)
Amortization of Contributions	(9 769)	(9 789)	20	(10 180)	(10 154)	(26)
	$ 73 097	$ 73 731	$ (634)	$ 78 312	$ 75 730	$ 2 582
Other						
Communications	17 636	17 903	(267)	19 473	20 678	(1 205)
Motor Vehicles	8 275	8 283	(8)	8 691	8 702	(11)
Structures & Improvements	3 216	3 324	(108)	5 614	7 487	(1 873)
General Equipment	20 572	20 673	(101)	19 118	19 186	(68)
Computer Development	13 582	14 630	(1 048)	13 352	16 536	(3 184)
Affordable Energy Fund	625	2 342	(1 717)	1 441	3 923	(2 482)
Miscellaneous	2 701	1 789	912	4 067	(2 044)	6 111
Corporate Allocation	(2 093)	(2 092)	(1)	(2 012)	(2 024)	12
	$ 64 514	$ 66 852	$ (2 338)	$ 69 745	$ 72 444	$ (2 699)
Total Depreciation and Amortization Expense	$ 323 573	$ 329 771	$ 6 198	$ 346 039	$ 344 375	$ (1 664)

PUB/MH I-38

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 20 to 29, Manitoba Hydro Electric Plant Depreciation Rates**

a) Please file a full detail listing of current Electric Plant Depreciation Rates

ANSWER:

Please see the following tables for the detailed listing of the current Electric Plant depreciation rates. All of the rates have remained the same as the last GRA, except for the newly created rates for Wuskwatim and the New Head Office.

MANITOBA HYDRO - ELECTRIC PLANT
DEPRECIATION RATES

	Effective April 1, 2007
Hydraulic Generation:	
Great Falls	
Civil Works	1.33
Turbines and Generators	2.18
Accessory Station Equipment	2.30
Other	2.01
Pointe Du Bois	
Civil Works	11.75
Turbines and Generators	11.59
Accessory Station Equipment	11.48
Other	11.46
Seven Sisters	
Civil Works	1.31
Turbines and Generators	1.88
Accessory Station Equipment	2.34
Other	2.14
Slave Falls	
Civil Works	1.90
Turbines and Generators	2.01
Accessory Station Equipment	2.25
Other	2.42
Pine Falls	
Civil Works	1.55
Turbines and Generators	1.91
Accessory Station Equipment	2.07
Other	2.01
Community Development Costs	1.90
McArthur Falls	
Civil Works	1.48
Turbines and Generators	0.98
Accessory Station Equipment	2.01
Other	2.25
Kelsey	
Civil Works	1.32
Turbines and Generators	1.61
Accessory Station Equipment	2.04
Other	2.25
Grand Rapids	
Civil Works	1.21
Turbines and Generators	1.83
Accessory Station Equipment	1.96
Other	2.54
Community Development Costs	1.38
Kettle Rapids	
Civil Works	1.21
Turbines and Generators	1.58
Accessory Station Equipment	1.95
Other	2.01

MANITOBA HYDRO - ELECTRIC PLANT
DEPRECIATION RATES

	Effective April 1, 2007
Laurie River	
Civil Works	1.92
Turbines and Generators	2.06
Accessory Station Equipment	2.24
Other	2.43
Lake Winnipeg Regulation	
Civil Works	1.41
Water Channels	1.33
Community Development Costs	1.12
Jenpeg	
Civil Works	1.25
Turbines and Generators	1.69
Accessory Station Equipment	2.44
Other	2.20
Community Development Costs	1.00
Long Spruce	
Civil Works	1.24
Turbines and Generators	1.67
Accessory Station Equipment	1.69
Other	2.32
Keeyask GS - not filed	
Civil Works	1.10
Turbines and Generators	1.69
Accessory Station Equipment	2.44
Other	2.20
Community Development Costs	1.00
Limestone	
Civil Works	1.24
Turbines and Generators	1.60
Accessory Station Equipment	2.03
Other	2.23
Wuskwatim	
Civil Works	1.10
Turbines and Generators	1.69
Accessory Station Equipment	2.44
Other	2.20
Thermal Generation:	
(Excluding Life Assurance Projects)	
Brandon Units 1 - 4 (Sync Condenser)	0.42
Brandon Unit 5	3.71
Brandon Combustion Turbine	4.40
Selkirk	2.97
Thermal Life Assurance	
Brandon Unit 5	4.85
Selkirk	2.46

MANITOBA HYDRO - ELECTRIC PLANT
DEPRECIATION RATES

	Effective April 1, 2007
Easements	1.33
Diesel Generation	
Structures and Improvements - Metal	7.27
Accessory Station Equipment	11.23
Engines and Generators - Post 1987 04 01	12.78
Substation Plant	
Structures and Improvements	1.66
Poles and Fixtures	3.36
Serialized Equipment	2.99
Serialized Equipment	2.71
Accessory Station Equipment	9.37
Transmission Plant	
Metal Towers	1.45
Poles and Fixtures	2.60
Ground Line Treating	10.00
Concrete Poles	1.41
Conductors and Devices	1.85
Underground Conductors and Devices	2.38
Roads, Trails and Bridges	2.25
Transmission - HVDC Purchase	
Metal Towers	1.92
Conductors and Devices	2.37
Distribution	
Poles, Conductor & Attachments	4.51
Ground Line Treating	10.00
Underground Conductors and Devices	2.44
Serialized Equipment	5.09
Street Lighting	2.49
Services	5.03
Subtransmission	
Metal Towers	2.91
Poles, Conductors & Attachments	3.68
Ground Line Treating	10.00
Underground Conductors and Devices	3.35
Serialized Equipment	6.01
Roads, Trails and Bridges	1.97
Meters	
Meters	3.47
Metering Transformers	1.17

MANITOBA HYDRO - ELECTRIC PLANT
DEPRECIATION RATES

	Effective April 1, 2007
Buildings	
Structures and Improvements - Wood	1.69
Structures and Improvements - Concrete	1.99
Structures and Improvements - Metal	1.88
Head Office - 360 Portage	1.18
Communication	
Structures and Improvements	1.85
Communication & Control Equipment	6.01
Fibre Optic Cable	2.59
Fibre Optic System - End Electronics	6.71
Vehicles and Equipment	
Passenger Vehicles	7.34
Light Trucks	9.10
Heavy Trucks	6.08
Construction Equipment	4.57
Large Soft-Track Equipment	3.39
Trailers	2.00
Miscellaneous	11.79

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

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 20 to 29, Manitoba Hydro Electric Plant Depreciation Rates**

b) Please indicate when the next Depreciation Study will be completed and available.

<u>ANSWER</u>:

It is currently planned that the next depreciation study for Manitoba Hydro will be based upon March 31, 2010 year end values. It should be completed in 2nd quarter 2010/11 and its results will be incorporated in IFF 10 which will be available approximately November 2010.

PUB/MH I-38

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 20 to 29, Manitoba Hydro Electric Plant Depreciation Rates**

c) Please explain how the Corporation determined the depreciation rate for the new head office of 1.2% and explain how if any the rate for that building differs from the existing head office as well as other buildings where depreciation rates range from 1.7% to 1.9%.

ANSWER:

The depreciation rate for the new head office was calculated using a weighted-average life expectancy for the new Manitoba Hydro office building of 85 years based upon the engineering estimate of the life of the concrete structure. The 820 Taylor office, and other buildings in Manitoba Hydro's portfolio, were estimated to have a life expectancy of 55 to 60 years and will be reviewed at the next depreciation study.

PUB/MH I-38

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 20 to 29, Manitoba Hydro Electric Plant Depreciation Rates**

d) Please indicate the annual impact on revenue requirements related to depreciation and amortization of the new head office.

ANSWER:

The 2010/11 forecasted amount of depreciation for the new head office is $3.1 million dollars.

PUB/MH I-39

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 22 of 29 Water Rental & Assessments**

Please provide the details of the Land Rental Assessment related to the Wuskwatim Transmission Development Fund.

ANSWER:

The Land Rental Assessment is not related to the Wuskwatim Transmission Development Fund.

PUB/MH I-40

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 24 & 25 of 29 Schedule 4.10.0**

Please provide the tax assessment form from the City of Winnipeg related to the new head office building.

ANSWER:

Copies of the Supplementary Tax Notices received from the City of Winnipeg with respect to the grant-in-lieu of property tax and business tax on the head office building for calendar year 2009 are attached.

Copies of the Assessment Advice for 2010 property and business tax property valuations are also attached. Tax bills with respect to calendar year 2010 will not be received until May of 2010, at which time the property and business tax expense for the new building will be known.

Winnipeg

THE CITY OF WINNIPEG

SUPPLEMENTARY GRANT- IN- LIEU PROPERTY TAX NOTICE

Statement Date: **November 9, 2009** Owner(s) : **4985371 MANITOBA LTD**

Roll Number: **12097557800**

Civic Address: **360 PORTAGE AVE**

Part of lot	Lot	Block	Plan	Parish lot
	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

This notice reflects the adjustment to your tax account as a result of the change(s) on the attached Assessment Notice(s), in accordance with Section 340/341 of The City of Winnipeg Charter.

Any taxes in arrears are subject to a monthly penalty at the prevailing penalty rates. Taxes must be paid by the due date regardless of any appeals which may be filed.

If you have any questions regarding this adjustment or wish to enrol in the Tax Instalment Payment Plan (TIPP), contact 311 or toll free 1-877-311-4974. Visit our website at www.winnipegassessment.com

ACCOUNT INFORMATION	Portioned Assessment Change	Mill Rate	No of Effective Days	Adjusted Taxes
2009 June 1, 2009 to December 31, 2009			214	
Municipal	60,373,950	25.448		900,791.25
Education #2	60,373,950	16.049		568,091.74
School Division No. 01	60,373,950	28.337		1,003,054.13
			TOTAL - 2009	2,471,937.12
SUPPLEMENTARY TAXES DUE December 31, 2009				$2,471,937.12
Balance Forward				0.00
TOTAL OUTSTANDING				$2,471,937.12

PROPERTY DEPT.
RECEIVED
NOV 12 2009
MANITOBA HYDRO

PLEASE DETACH AND RETURN WITH YOUR PAYMENT - VEUILLEZ DÉTACHER ET RETOURNER AVEC VOTRE PAIEMENT

THE CITY OF WINNIPEG - SUPPLEMENTARY PROPERTY TAX NOTICE / VILLE DE WINNIPEG - AVIS DE TAXES FONCIÈRES SUPPLÉMENTAIRES

ROLL NUMBER / NUMÉRO DU RÔLE	TOTAL PAYABLE / TOTAL EXIGIBLE	AMOUNT PAID / MONTANT PAYÉ
12097557800	$2,471,937.12	

R120975578000247193712120975578OO

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

REMIT TO :
The City of Winnipeg
Assessment and
Taxation Department
510 Main Street
Winnipeg, MB R3B 3M2

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

13373 900

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THE CITY OF WINNIPEG - VILLE DE WINNIPEG
NOTICE OF CHANGE IN ASSESSMENT
AVIS DE MODIFICATION DE L'ÉVALUATION

Winnipeg

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

Ville de Winnipeg
Service de l'évaluation et des taxes
510, rue Main
Winnipeg (Manitoba) R3B 3M2

Roll Number / Numéro du rôle : 12097557800
Civic Address / Adresse de voirie :
360 PORTAGE AVE

PART OF LOT / PARTIE DU LOT	LOT	BLOCK / ÎLOT	PLAN	PARISH LOT / LOT DE LA PAROISSE
	594-597	3	129	1 ST J
	600-603	3	129	1 ST J
*** SEE SUPP LEGAL IN TAX OFFICE ***				
	13-14		19168	1 ST J

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

Statement Date / Date du relevé :

November 9, 2009

Owner(s) / Propriétaire(s) :
4985371 MANITOBA LTD

This notice is being issued based on information reported by the City Assessor, in accordance with the provisions of Section 340/341 of the City of Winnipeg Charter, for the reasons noted below.
Le présent avis est délivré sur la foi des renseignements que l'évaluateur de la ville a fournis en conformité avec les articles 340 et 341 de la Charte de la ville de Winnipeg, et ce, pour les raisons indiquées ci-après.

CHANGED ASSESSMENT EFFECTIVE / ÉVALUATION MODIFIÉE À COMPTER DU
JUNE 1, 2009 TO DECEMBER 31,2009

Class Code / Code de catégorie	Tax Status / Statut fiscal	Previous Assessment / Évaluation précédente	Revised Assessment / Évaluation modifiée	Change to Assessment / Modification de l'évaluation	Portioned % / Taux de fractionnement	Changed Portioned Assessment / Modification de la valeur fractionnée
60 - Other Property	G	0	94,890,000	94,890,000	65.0%	61,678,500
60 - Other Property	T	2,007,000	0	-2,007,000	65.0%	-1,304,550
Total		2,007,000	94,890,000	92,883,000		60,373,950

New Building Added

An application for revision of this assessment may be made within 20 days after the attached tax notice was received, in respect of liability to taxation, amount of assessed value, or classification of property.
An application for revision must be filed in writing with the Board of Revision and addressed to the Secretary of the Board of Revision, Unit 1 - 756 Pembina Highway, Winnipeg, MB R3M 2M7. The application for revision must describe the property and must set out the matters which are in issue and the grounds for each of those matters.

If you have any questions regarding this Notice of Change in Assessment please contact 311 or toll free 1-877-311-4974.

Il est permis, dans les 20 jours qui suivent la réception de l'avis d'imposition ci-joint, de présenter une demande de révision de la présente évaluation relativement à l'assujettissement à la taxe, au montant de la valeur imposable ou à la catégorie du bien.
Les demandes de révision doivent être faites par écrit au Comité de révision, 756, chemin Pembina, unité 1, Winnipeg (MB), R3M 2M7. Elles doivent comporter une description du bien et faire état des questions soulevées ainsi que des motifs correspondants.

Si vous avez des questions sur cet avis de modification de l'évaluation, 311 or toll free 1-877-311-4974.

DEADLINE FOR APPEALS IS 20 DAYS FROM RECEIPT OF ATTACHED NOTICE
LES APPELS DOIVENT ÊTRE INTERJETÉS DANS LES 20 JOURS QUI SUIVENT LA RÉCEPTION DE L'AVIS CI-JOINT.

Winnipeg

THE CITY OF WINNIPEG

ASSESSMENT AND TAXATION DEPARTMENT
SERVICE DE L'ÉVALUATION ET DES TAXES

SUPPLEMENTARY BUSINESS TAX NOTICE

Statement Date : November 18, 2009

Page 1 of 1

Roll Number : 38290

Taxable Party : MANITOBA HYDRO

Premises Assessed :
360 PORTAGE AVE

This notice reflects the adjustment to your tax account as a result of the change(s) on the attached Assessment Notice(s), in accordance with Section 340/341 of The City of Winnipeg Charter.

ACCOUNT INFORMATION	Annual Rental Value	Tax Rate	No. of Effective Days	Adjusted Taxes
2009 June 1, 2009 to December 31, 2009			214	
Business Tax	10,834,320	7.75		492,293.69
			TOTAL - 2009	492,293.69
BUSINESS TAX DUE December 31, 2009				$492,293.69
Balance Forward				0.00
TOTAL OUTSTANDING				$492,293.69

Any taxes in arrears are subject to a monthly penalty at the prevailing penalty rates. Taxes must be paid by the due date regardless of any appeals which may be filed.

A DISTRESS WARRANT MAY BE ISSUED AFTER THE DUE DATE TO ENFORCE PAYMENT WITHOUT FURTHER NOTICE.

If you have any questions regarding this adjustment or wish to enrol in the Tax Instalment Payment Plan (TIPP), contact 311 or toll free 1-877-311-4974. Visit our website at www.winnipegassessment.com

PLEASE DETACH AND RETURN WITH YOUR PAYMENT - VEUILLEZ DÉTACHER ET RETOURNER AVEC VOTRE PAIEMENT

THE CITY OF WINNIPEG SUPPLEMENTARY BUSINESS TAX NOTICE / VILLE DE WINNIPEG AVIS DE TAXES D'ENTREPRISE SUPPLÉMENTAIRES

ROLL NUMBER / NUMÉRO DU RÔLE	TOTAL PAYABLE / TOTAL EXIGIBLE	AMOUNT PAID / MONTANT PAYÉ
38290	$492,293.69	

B38290XXXXXX004922936938290XXXXXX

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

REMIT TO :
The City of Winnipeg
Assessment and
Taxation Department
510 Main Street
Winnipeg, MB R3B 3M2

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

⑆13373⑈900⑆

96

THE CITY OF WINNIPEG - VILLE DE WINNIPEG
NOTICE OF CHANGE IN RENTAL VALUE
AVIS DE MODIFICATION RELATIVE À LA VALEUR LOCATIVE

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

Ville de Winnipeg
Service de l'évaluation et des taxes
510, rue Main
Winnipeg (Manitoba) R3B 3M2

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

Roll Number / Numéro du rôle 38290
Premises Assessed / Locaux évalués
360 PORTAGE AVE

Taxable Party / Personne assujettie à la taxe
MANITOBA HYDRO

Effective / À partir du **June 1, 2009**

Statement Date / Date du relevé November 18, 2009

This notice is being issued based on information reported by the City Assessor, in accordance with the provisions of Section 340/341 of the City of Winnipeg Charter, for the reasons noted below.

Le présent avis est délivré sur la foi des renseignements que l'évaluateur de la ville a fournis en conformité avec les articles 340 et 341 de la Charte de la ville de Winnipeg, et ce, pour les raisons indiquées ci-après.

REVISED ANNUAL RENTAL VALUE (ARV) EFFECTIVE /
VALEUR LOCATIVE ANNUELLE MODIFIÉE À PARTIR DU
JUNE 1, 2009

Current BIZ Zone Zone d'amélioration commerciale actuelle	Previous ARV Valeur locative annuelle précédente	Revised ARV Valeur locative annuelle modifée	Change to ARV Modification de la valeur locative annuelle
1	0	10,834,320	10,834,320

341-New Entry-Business

An application for revision of this assessment may be made within 20 days after the attached tax notice was received, in respect of liability to taxation, or amount of assessed value.
An application for revision must be filed in writing with the Board of Revision and addressed to the Secretary of the Board of Revision, Unit 1 - 756 Pembina Highway, Winnipeg, MB R3M 2M7. The application for revision must describe the property and must set out the matters which are in issue and the grounds for each of those matters.

If you have any questions regarding this Notice of Change in Rental Value, please call 311 or toll free 1-877-311-4974.

Il est permis, dans les 20 jours qui suivent la réception de l'avis ci-joint, de présenter une demande de révision de la présente évaluation relativement à l'assujettissement à la taxe ou au montant de la valeur imposable.
Les demandes de révision doivent être faites par écrit au Comité de révision et être adressées au secrétaire du Comité de révision, 756, chemin Pembina, unité 1, Winnipeg (MB), R3M 2M7. Elles doivent comporter une description du bien et faire état des questions soulevées ainsi que des motifs correspondants.

Si vous avez des questions sur cet avis de modification relative à la valeur locative, veuillez composer le 311 ou (sans frais) le 1-877-311-4974.

DEADLINE FOR APPEALS IS 20 DAYS FROM RECEIPT OF THIS NOTICE
LES APPELS DOIVENT ÊTRE INTERJETÉS DANS LES 20 JOURS QUI SUIVENT LA RÉCEPTION DU PRÉSENT AVIS.

THE CITY OF WINNIPEG

Winnipeg

ASSESSMENT AND TAXATION DEPARTMENT
MAIN FLOOR 457 MAIN STREET WINNIPEG MANITOBA - R3B 1B5

CERTIFIE 9001:2000 CERTIFIED

ASSESSOR ADVICE TO:

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

Take notice that, under the authority of Section 14(2) of the Municipal Assessment Act, I have this day November 25, 2009, corrected the 2010 RealtyAssessment Roll in respect of the property assessment at Roll Number 12097557800, also known as: 360 PORTAGE AVE.

Legal Description:

Part of lot / Partie du lot	Lot	Block / Îlot	Plan	Parish lot / Lot de la paroisse
	631-633	3	129	1 ST J
	13-14		19168	1 ST J

** See Supplementary Legal in Tax Office **

BY:
New Building Added

FROM		
ASSESSED VALUE	STATUS CODE	PROPERTY CLASS CODE
$4,796,000.00	T	60 - Other Property
Total Assessment		**$4,796,000**

TO		
ASSESSED VALUE	STATUS CODE	PROPERTY CLASS CODE
$0	T	60 - Other Property
$130,845,000	G	60 - Other Property
Total Assessment		**$130,845,000**

INQUIRIES
QUOTE ROLL NO. IN ALL COMMUNICATIONS
Inquiries regarding this notice should be directed to Property Assessment Department, MAIN FLOOR 457 MAIN STREET WINNIPEG MANITOBA - R3B 1B5. Phone (204) 986-2353.

CITY ASSESSOR

City Assessor may amend rolls
14(2) The City Assessor may at any time, for the purpose of correcting an error or omission, amend the latest revised real or personal property assessment roll or business assessment roll, as the case requires, of The City of Winnipeg as certified, amended and revised by the City Assessor.

Notice, revision and appeal re corrections
14(3) After amending an assessment roll under this section, the assessor must send written notice of the amendment to the person in whose name the subject property is assessed. The revision and appeal process set out in Part 8 (The

THE CITY OF WINNIPEG

ASSESSMENT AND TAXATION DEPARTMENT
MAIN FLOOR 457 MAIN STREET WINNIPEG MANITOBA - R3B 1B5

ASSESSOR ADVICE TO:

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

Take notice that, under the authority of Section 14(2) of the Municipal Assessment Act, I have this day January 08, 2010, corrected the 2010 BusinessAssessment Roll in respect of the property assessment at Roll Number 38290, also known as: 360 PORTAGE AVE.

BY:
14-2-New Entry-Business

TO		
ASSESSED VALUE	STATUS CODE	PROPERTY CLASS CODE
$12,690,060	G	BA - Business Assessment
Total Assessment		**$12,690,060**

INQUIRIES
QUOTE ROLL NO. IN ALL COMMUNICATIONS
Inquiries regarding this notice should be directed to Property Assessment Department, MAIN FLOOR 457 MAIN STREET WINNIPEG MANITOBA - R3B 1B5. Phone (204) 986-2353.

CITY ASSESSOR

City Assessor may amend rolls
14(2) The City Assessor may at any time, for the purpose of correcting an error or omission, amend the latest revised real or personal property assessment roll or business assessment roll, as the case requires, of The City of Winnipeg as certified, amended and revised by the City Assessor.

Notice, revision and appeal re corrections
14(3) After amending an assessment roll under this section, the assessor must send written notice of the amendment to the person in whose name the subject property is assessed. The revision and appeal process set out in Part 8 (The Municipal Assessment Act) applies in respect of the amendment, except that an application for revision must be made within 20 days after the day the notice of the amendment was received by the person in whose name the property was assessed.

The application for revision must be directed to the Secretary of The Board of Revision, Unit 1 - 756 Pembina Highway, Winnipeg, MB R3M 2M7

PUB/MH I-41

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 25 of 29 Capital Tax**

Please provide the details of the taxable paid up capital balance for Manitoba capital tax purposes for the fiscal years 2008, 2009 and the projected taxable capital for the fiscal years 2010 through 2012.

ANSWER:

Please see the following table for capital tax information for the years 2008 through 2012.

Taxable Paid Up Capital Calculation:
($ Billions)

	Actual 2008	Actual 2009	Forecast 2010	Forecast 2011	Forecast 2012
Total Debt	7.8	8.5	8.4	8.9	9.5
Retained Earnings	1.8	2.1	2.2	2.3	2.3
AOCI	0.3	-0.2	0.2	0.2	0.1
Total Paid Up Capital (A)	9.9	10.5	10.7	11.3	11.9
Temporary Investments	0.1	0.2	0.0	0.0	0.0
Sinking Fund Assets	0.7	0.6	0.4	0.3	0.3
Pension Investments	0.8	0.6	0.7	0.7	0.8
Investment in Subsidiaries	0.3	0.3	0.3	0.3	0.3
Loans to Subsidiaries	0.5	0.6	0.7	0.8	1.3
Total Eligible Assets (B)	2.4	2.3	2.0	2.1	2.6
Total Assets (C)	12.0	12.6	12.1	12.6	13.2
Total Paid Up Capital	9.9	10.5	10.7	11.3	11.9
Less Investment Allowance (B/C X A)	2.0	1.9	1.8	1.9	2.4
Taxable Paid Up Capital	8.0	8.6	8.9	9.5	9.6
Capital Tax Calculation ($ millions)					
Capital Tax at 0.5% X D	40	43	45	47	48

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

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

Reference: **Tab 4 Page 29 of 29 Appendix 4-1: 2009 Annual Report Page 78, IFF09-1 Section 2.3.5 Wuskwatim Power Limited Partnership**

a) Please provide the most recent financial statements related to the WPLP

<u>ANSWER</u>:

The most recent financial statements for WPLP can be found in Appendix 23.

PUB/MH I-42

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 29 of 29 Appendix 4-1: 2009 Annual Report Page 78, IFF09-1 Section 2.3.5 Wuskwatim Power Limited Partnership**

b) Please provide the most recent financial projects for the WPLP.

ANSWER:

Please see the IFF09-1 WPLP operating statement on the following page.

Wuskwatim Power Limited Partnership (IFF09)
Projected Income Statement

For the fiscal years ending March 31

thousands of dollars

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Revenues	-	-	44,373	104,480	112,490	118,734	129,276	134,637	138,558	143,771	142,361
Expenses											
Operating & administrative	-	-	6,119	6,229	6,341	6,593	6,712	6,834	6,958	7,084	7,213
Depreciation	-	-	14,244	26,572	26,572	26,572	26,573	26,575	26,575	26,575	26,575
Water rentals	-	-	2,185	5,062	5,062	5,062	5,062	5,062	5,062	5,062	5,062
	-	-	22,548	37,864	37,975	38,228	38,348	38,471	38,595	38,721	38,850
Income/(loss) before finance expense	-	-	21,826	66,616	74,515	80,506	90,928	96,166	99,963	105,050	103,511
Finance expense	(0)	(0)	26,053	69,127	67,854	66,496	65,033	63,666	62,377	61,044	59,863
Net Income/(Loss)	**0**	**0**	**(4,228)**	**(2,510)**	**6,660**	**14,011**	**25,894**	**32,500**	**37,587**	**44,006**	**43,648**

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

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 29 of 29 Appendix 4-1: 2009 Annual Report Page 78, IFF09-1 Section 2.3.5 Wuskwatim Power Limited Partnership**

c) **Please file a summary of the terms of the agreement MH has with TPC & NCN and indicate if there has been any changes to the agreements since the 2008 GRA.**

<u>ANSWER</u>:

The following summary was provided in response to PUB/MH I-4(c) in the 2008/09 GRA:

> The Nisichawayasihk Cree Nation has the option of being a Limited Partner in the Wuskwatim G.S. with an interest of up to 33%. Manitoba Hydro, through a holding company as General Partner, would have a 0.01% interest, with Manitoba Hydro as a Limited Partner holding the balance.
>
> The assets of the Partnership would consist of the Wuskwatim G.S. and, to the degree required, a small amount of working capital. The capital cost would include planning studies, engineering and licensing from April 1, 2002 plus the unamortized balance of prior expenditures. Accounting policies would mirror those of Manitoba Hydro.
>
> Revenues received by the Partnership from the sale of power to Manitoba Hydro would be based on the actual output of Wuskwatim G.S. and be priced in accordance with an agreed methodology which reflects Manitoba Hydro's actual selling prices for exports. The Partnership would pay Manitoba Hydro a percentage of gross revenues to contribute towards the marketing and transmission risks borne by the Corporation.
>
> A Transmission charge would be levied which recovers the depreciation, interest, maintenance and operating costs associated with the incremental facilities specifically

required to serve Wuskwatim G.S. An additional charge would be included for any facilities that Manitoba Hydro requires for its other system needs but is advancing in order to accommodate the Wuskwatim G.S. This extra cost recovery would only be for the period of advancement.

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

For the purposes of the projections, and consistent with Manitoba Hydro's Integrated Financial Forecast, water rental rates are assumed to continue at current levels. As in the economic analysis, annual operating cost estimates are based on a long run average which includes some provision for minor capital maintenance. Larger periodic scheduled capital expenditures are assumed to generally fall outside of the study period which extends to 2034/35. It is expected that the partnership will accumulate a reserve to fund these larger capital expenditures in the future. The administrative costs of the Partnership would be charged on an actual basis, assumed for purposes of this analysis to be $0.5 million per year, escalated at the rate of inflation.

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

The debt/equity ratio would be a primary parameter in determining the portion of profits that may be distributed as dividends. Although it is generally expected that dividends would not normally exceed net income, the projections presented here assume maximum dividend payouts, subject only to maintaining the 25% equity ratio.

Dividends would be reduced somewhat if the partners establish reserves for future capital replacement, but the level of these reserves has not yet been established.

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

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

- The two Limited Partners would invest equity in the project by subscribing for units worth, in total, 25% of the total capital. The analysis in this submission assumes that the Nisichawayasihk Cree Nation will subscribe for a 33% share of these units. The Nisichawayasihk Cree Nation is required to make an initial cash downpayment of not less than $1 million at the project commitment date (currently planned as December, 2003) and would finance the balance of its investment during construction through loans from Manitoba Hydro. Upon the in-service of Wuskwatim G.S., the Nisichawayasihk Cree Nation would be required to provide an additional cash equity payment (referred to, in conjunction with the $1 million downpayment, as the *cash component* of its investment). The balance (the *financed component*) would be

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

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

With the exception of the treatment of transmission costs, there have been no changes to the agreements since the 2008 GRA. The final agreement on the treatment of transmission costs is as below:

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

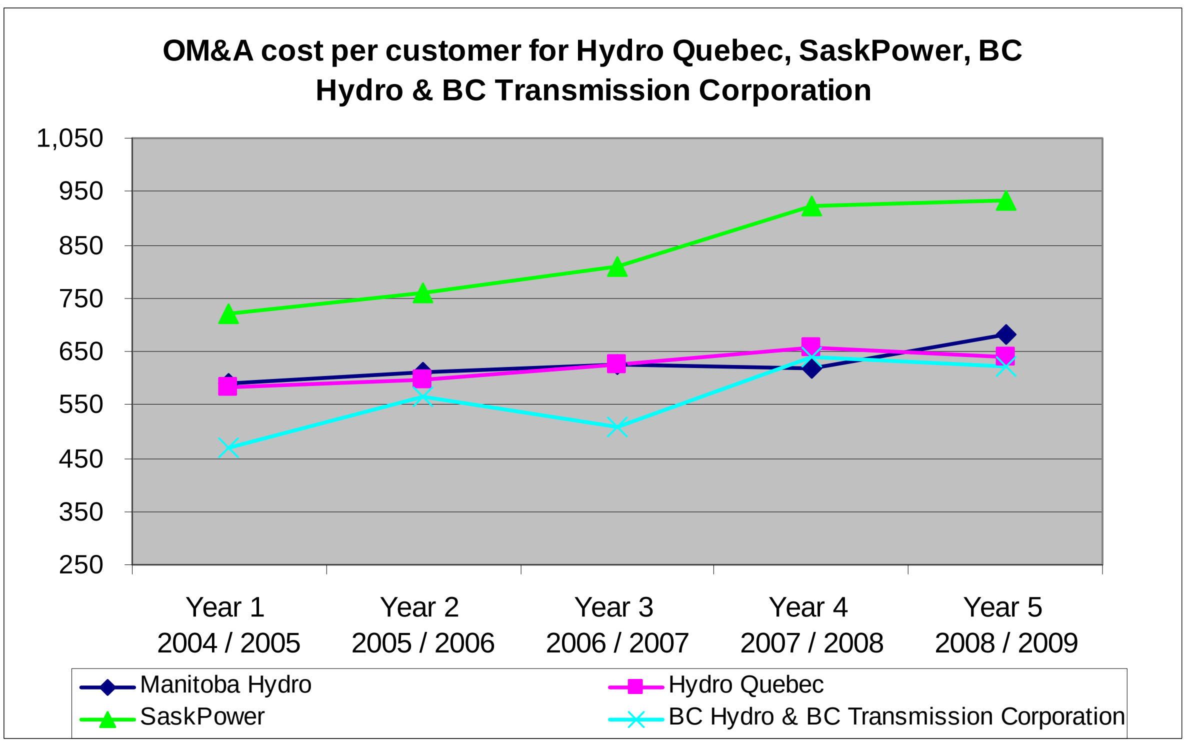
PUB/MH I-43

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Appendix 4.4 page 4 of 36, OM&A Comparisons**

Please provide a graph with the corresponding data table of the OM&A cost per customer for Hydro Quebec, SaskPower , BC Hydro & BC Transmission Corporation.

ANSWER:

Please see the following graph and data table.



Manitoba Hydro	**2005**	**2006**	**2007**	**2008**	**2009**
OM&A	299	311	323	323	360
Number of Customers	505,666	509,791	516,861	521,599	527,472
OM&A Cost per Customer - Electric	591	609	626	619	682

Source: Page 2 of Appendix 4.4 & Manitoba Hydro 2009 Annual Report

Hydro Quebec	**2004**	**2005**	**2006**	**2007**	**2008**
OM&A	2,154	2,245	2,389	2,541	2,497
Number of Customers	3,701,275	3,752,510	3,815,126	3,868,972	3,913,444
OM&A Cost per Customer	582	598	626	657	638

Source: Hydro Quebec 2008 Annual Report

SaskPower	**2004**	**2005**	**2006**	**2007**	**2008**
OM&A	317	336	360	416	430
Number of Customers	439,165	441,692	445,569	451,713	460,006
OM&A Cost per Customer	722	761	808	921	935

Source: SaskPower 2008 Annual Report

BC Hydro & BC Transmission Corporation	**2005**	**2006**	**2007**	**2008**	**2009**
BC Hydro OM&A	717	805	716	942	915
BC Transmission Corporation OM&A	72	157	168	186	207
Total OM&A	789	962	884	1,128	1,122
BC Hydro Number of Customers	1,675,258	1,704,892	1,736,987	1,767,194	1,801,328
OM&A Cost per Customer	471	564	509	638	623

Source: BC Hydro 2009 Annual Report, BCTC 2005-2009 Annual Reports

PUB/MH I-44

Subject: Tab 4: Financial Results & Forecast
Reference: Tab 4 Appendix 4.4 Page 5 &6 of 36 Staff Attrition

a) From 2005 through 2009 please indicate the number of staff by year lost to other utilities.

ANSWER:

Every termination is classified into one of 14 termination codes. The termination codes are grouped into five broad termination types: retirement, resignation, health-related, involuntary termination, and job completion. For the years 2005 through 2009, resignation terminations are as follows (all numbers reported in this section exclude students and term employees):

Resignation termination code	2005	2006	2007	2008	2009	Total
Another Job	18	19	31	30	9	107
Leaving Prov/Work Locale	14	11	17	11	5	58
Leaving Work Force		2	2	3	8	15
Personal/No Reason Given	11	15	15	18	19	78
Returning to School	3		1	1	5	10
Total	46	47	66	63	46	268

In the five calendar years covering 2005 through 2009, Manitoba Hydro lost 268 employees (none of whom were term or student employees, whose employment terms are temporary by definition) to voluntary resignation. The largest single reason for resignation, accounting for 107 (almost 40%) of those resigning, was “another job”.

PUB/MH I-44

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Appendix 4.4 Page 5 &6 of 36 Staff Attrition**

b) **Please provide table of corresponding data points for the graph of Manitoba Hydro retirement overview. Please indicate in the same table the total staffing level, the retirement attrition percentage of total staffing levels for each year through 2023.**

ANSWER:

Calendar year	Permanent active workforce at start of year	Actual retirements	Retirement rate	Number eligible in current year	Number becoming eligible in forecast year	Predicted number of retirements
1991	4357†	62	1.4%			
1992	4220	67	1.6%			
1993	4230	203	4.8%			
1994	4052	66	1.6%			
1995	4002	34	0.8%			
1996	4007	109	2.7%			
1997	3906	57	1.5%			
1998	3957	41	1.0%			
1999	4049	127	3.1%			
2000	3986	58	1.5%			
2001	4054	54	1.3%			
2002	4358	77	1.8%			
2003	4410	79	1.8%			
2004	4826	104	2.2%			
2005	5386	118	2.2%			
2006	5376	127	2.4%			
2007	5375	168	3.1%			
2008	5482	138	2.5%			
2009	5629	141	2.5%			

Calendar year	Permanent active workforce at start of year	Actual retirements	Retirement rate	Number eligible in current year	Number becoming eligible in forecast year	Predicted number of retirements
2010				776		155
2011					186	161
2012					178	165
2013					174	167
2014					194	172
2015					189	175
2016					218	184
2017					225	192
2018					213	196
2019					262	209
2020					222	212
2021					208	211
2022					188	207
2023					159	197
2024					139	185

† Data to count the permanent active workforce at the beginning of calendar year 1991 are not available. The number reported (4357) relates to 1991-03-27.

Definitions

Permanent active workforce -- the count of all non-terminated employees whose employment type is not "Term" or "Student". Include individuals on leaves of absence. Forecasts for the future size of this workforce are not available.

Actual retirements -- does not include disability retirements.

Retirement rate -- Actual retirements divided by the permanent active workforce.

Number eligible in current year -- those becoming eligible for a full, undiscounted pension in 2010 (based on age and years of service.) Includes individuals who were eligible in previous years but who have not taken up the retirement opportunity.

Number becoming eligible in forecast year -- those becoming eligible in each of the years in the forecast window.

Predicted number of retirements -- Based on a historical retirement take-up rate of 20%. That rate is applied to the number eligible in the current year to arrive at the retirement prediction for the current year. The remainder is carried forward to the next year and is added to the number becoming eligible in that forecast year. The take-up rate is applied to that sum to arrive at the forecast prediction for that year. The process carries forward to the end of the forecast window.

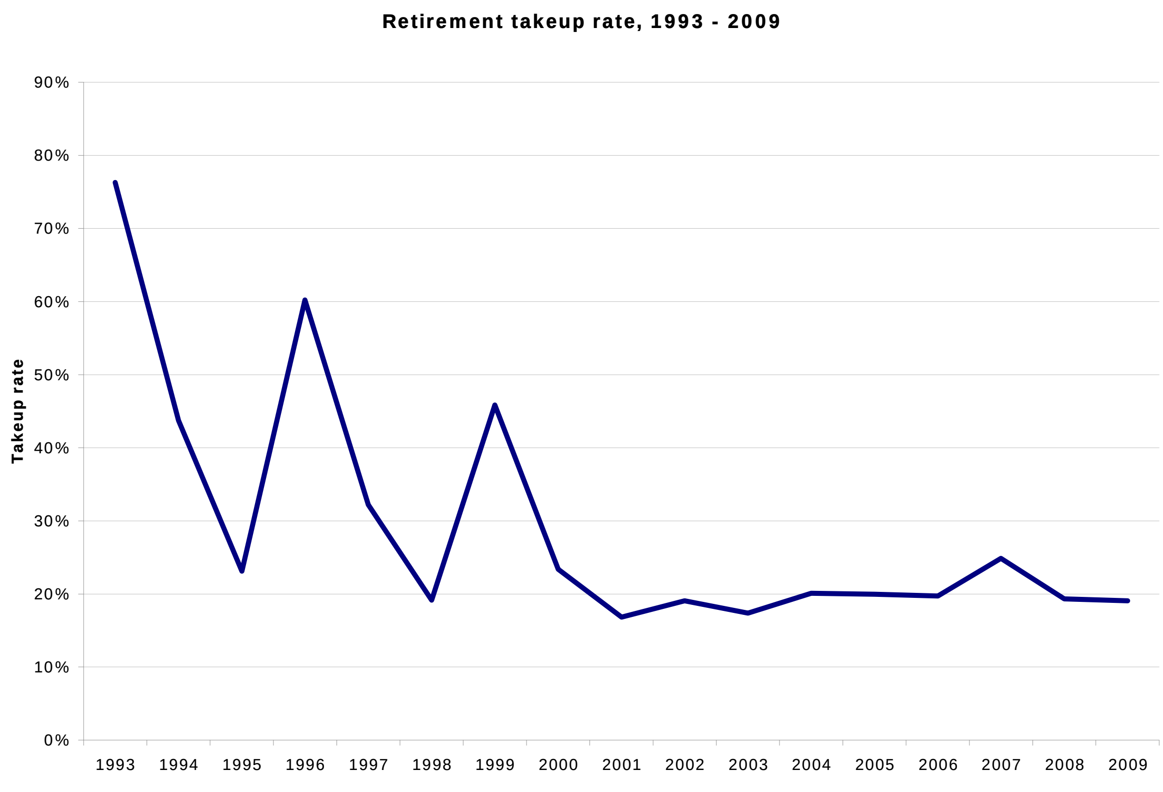
PUB/MH I-44

Subject: Tab 4: Financial Results & Forecast
Reference: Tab 4 Appendix 4.4 Page 5 &6 of 36 Staff Attrition

c) Please indicate how MH determined the pension take up rate.

ANSWER:

The retirement take-up rate is based on historical observation. At the beginning of the calendar year, we determine the number of people eligible for a full, undiscounted pension based on age and years of service. The retirement take-up rate for a year is the portion of the fully-eligible population which actually "takes up" the retirement opportunity. The take-up rate is quite stable over time as observed in the chart below.



The chart shows spikes in the take-up rate for the years 1993, 1996 and 1999. Those were years in which we offered special retirement incentives.

<u>PUB/MH I-44</u>

Subject: Tab 4: Financial Results & Forecast
Reference: Tab 4 Appendix 4.4 Page 5 &6 of 36 Staff Attrition

d) Please describe the retirement policies of MH including retirement eligibility.

<u>ANSWER</u>:

Manitoba Hydro is a participating employer in the Civil Service Superannuation Board (CSSB) plan. This fund is governed by the Civil Service Superannuation Act and Regulations. Employees are eligible to retire on or after their 65th birthday providing they have at least one year of qualifying service. Employees can retire early, any time on or after age 55, if they have at least 10 years of qualifying service. Employees must stop making pension contributions and begin receiving a pension by December 31 of the year they turn age 71. This does not mean that the member must stop working at that age.

If employees retire between the ages of 55 and 60, their pension is unreduced if they meet the "Rule of 80". The Rule of 80 is when the combination of age (minimum age 55) and qualifying service equals 80 or more (e.g. Age 55 with 25 years of qualifying service or more). The pension is also unreduced if the employee retires on or after their 60th birthday with 10 years of service.

Manitoba Hydro also is a participating employer in the Winnipeg Civic Employee Benefits Program (WCEBP). Manitoba Hydro became a participating employer with the purchase of Winnipeg Hydro in 2002. A closed group of employees (approx. 530) continue to be members in this plan. This plan is also a defined benefit plan that provides for early retirement provisions, similar to the CSSB.

Manitoba Hydro also administers three curtailed pension plans know as the "Centra" plans. Although the plans are curtailed, accumulated pension values up to 2002 are maintained for the former Centra Gas employees. This group of employees (approx. 400) are now active participants of the CSSB.

The Corporation provides employees that retire from Manitoba Hydro with a retirement health spending account. The retirement health spending account provides:

- employees retired before 2002 12 31— an annual amount of $400
- employees retired on/after 2002 12 31— an annual amount of $612.26

PUB/MH I-44

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Appendix 4.4 Page 5 &6 of 36 Staff Attrition**

e) Please describe any policies being employed to incent workers to stay beyond retirement.

ANSWER:

There are no specific policies in place to incent workers to stay beyond their earliest retirement date.

PUB/MH I-45

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1/IFF08-1, PUB/MH – 3 (09/02/20)**

a) Please provide 20 year IFF 09 on similar format to 20-year IFF 08-1.

ANSWER:

The 20 year IFF09 was filed with the Public Utilities Board on February 3, 2010. Please see Appendix 16.

PUB/MH I-45

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1/IFF08-1, PUB/MH – 3 (09/02/20)**

b) **Please provide all supporting assumptions for the domestic and export revenue, including volumes and price per kW.h employed in IFF 09-1 similar to those in PUB/MH-3 (09/02/20).**

ANSWER:

Please see the attached schedule.

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	24,718	25,075	25,413	26,030	26,439	26,790	26,743	26,929	27,229
Total Export Sales	9,149	7,122	7,843	8,152	8,022	7,432	7,182	7,084	7,007	7,747	9,600

(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	50.41	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	66.89	71.71	73.93	90.87	92.31	94.95	105.30	105.56

PUB/MH I-45

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1/IFF08-1, PUB/MH – 3 (09/02/20)**

c) **Confirm that MH's export volumes in PUB/MH 3 include 10% or about 800 + GWh that are sold but not delivered in each year.**

ANSWER:

Manitoba Hydro assumes that the 800 GW.h in the information request is derived from the energy corresponding to "Export Transmission Losses" in the table provided in the reference PUB/MH-3 (09/02/20). It is not correct to assume that this is energy that is sold but not delivered. These losses are energy that is generated but is lost in the transmission process of delivery to export customers. These transmission losses cannot be sold and were included in the table for completeness in accounting for all energy that is generated. Export energy is sold and metered at the border, and losses up to this interface are the responsibility of Manitoba Hydro.

<u>PUB/MH I-45</u>

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1/IFF08-1, PUB/MH – 3 (09/02/20)**

d) Are these 800 GWh + of non-deliveries resold in the MISO market?

<u>ANSWER</u>:

Please refer to the response to PUB/MH I-45(c) for an explanation of the 800 GW.h of energy. Since this energy is that is lost to the system due to transmission, it cannot be sold.

PUB/MH I-45

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1/IFF08-1, PUB/MH – 3 (09/02/20)**

e) **Provide the initial sales price and quantity compared to the non- delivery resale price for 2005/06, 2006/07, and 2008/09.**

ANSWER:

Please refer to the response to PUB/MH I-45(c) and (d) for an explanation of the 800 GW.h of energy. Since this is energy that is lost to the system due to transmission, this energy cannot be sold and there is no initial sales price and a second resale price.

<u>PUB/MH I-45</u>

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1/IFF08-1, PUB/MH – 3 (09/02/20)**

f) **Identify the merchant trading revenues and volumes (gross and net) that are included in extra-provincial revenue for the entire 20 year IFF.**

<u>ANSWER</u>:

Since it is uncertain whether merchant trading will continue into the long term, it is assumed that there is no net revenue from merchant trading starting in the year 2011/12 and extending to the end of the 20 year IFF.

<u>PUB/MH I-45</u>

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

Reference: **IFF 09-1/IFF08-1, PUB/MH – 3 (09/02/20)**

g) Identify the ancillary services revenues included in the extra-provincial revenues.

<u>ANSWER</u>:

The following table provides the ancillary services revenues that are included in the 20 year IFF.

Table 1: Ancillary services revenues in millions of dollars

Fiscal Year	Ancillary Services Market (ASM)
2009/10	2.6
2010/11	3.0
2011/12	3.4
2012/13	3.4
2013/14	3.6
2014/15	3.7
2015/16	3.8
2016/17	3.9
2017/18	4.0
2018/19	4.1
2019/20	4.1
2020/21	4.2
2021/22	4.3
2022/23	4.4
2023/24	4.5
2024/25	4.6
2025/26	4.6
2026/27	4.7
2027/28	4.8
2028/29	4.9

<u>PUB/MH I-46</u>

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

a) **Please describe what methodological changes have been employed by MH in forecasting interest rates given the recommendations provided by Mr. McCormick at the past Centra GRA and Board direction flowing from Order 128/09.**

<u>ANSWER</u>:

Ongoing enhancements are reflected in the forecast of interest rates that are embedded in the IFF for the years 2009/10 through 2012/13 as part of the updated information provided in Tab 5, page 2 and Appendix 5.2, page 5. These include:

- Only statistically independent forecasters were used in the update;
- Forecasts were based on comparable average period data basis;
- Current forecasts were used from each of the forecasters;
- Credit spread forecasts reflect 10 years of historical data where available. If not available, the longest period of historical data available on Bloomberg was utilized to calculate the mean.

The long-term Economic Outlook is produced annually in the spring of each year. A review of certain variables including short and long-term interest rates, exchange rate and CPI is conducted each summer for the first few years of the forecast and updated if required. Therefore, the interest rate forecasts in years 2013/14 and beyond reflected the Spring 2009 Economic Outlook as filed in Appendix 5.1.

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

ANSWER:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ANSWER:

Please see the following attachment.

Backup Forecasts

for 2009/10

to 2012/13

Canadian Economic Outlook

BMO Capital Markets Economics

October 9, 2009

	2008 Q1	2008 Q2	2008 Q3	2008 Q4	2009 Q1	2009 Q2	2009 Q3	2009 Q4	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2007	2008	2009	2010
PRODUCTION (quarter/quarter % change : a.r.)																
Real GDP (chain-weighted)	-0.7	0.3	0.4	-3.7	-6.1	-3.4	1.3	3.4	2.9	3.3	3.5	2.9	2.5	0.4	-2.4	2.6
Final Sales	4.4	-1.3	0.1	-2.4	-0.9	-3.0	-1.3	2.9	2.1	2.8	2.6	2.4	2.4	0.7	-1.3	1.7
Final Domestic Demand	2.8	1.5	0.5	-4.9	-6.0	0.4	1.8	1.8	2.5	3.0	3.1	2.8	4.1	2.6	-1.9	2.3
Consumer Spending	2.5	1.1	0.6	-3.1	-1.2	1.8	1.6	2.6	2.5	3.1	3.1	2.9	4.6	3.0	-0.1	2.6
durables	16.7	-3.0	-0.8	-11.6	-8.4	6.0	2.5	2.0	1.0	3.0	3.0	2.5	7.6	5.6	-3.2	2.4
nondurables	0.1	0.8	-0.2	-1.4	1.4	0.7	1.3	2.4	2.2	3.0	3.0	3.0	3.2	1.5	0.6	2.3
services	0.1	1.7	1.0	-1.4	-0.2	1.7	1.5	2.7	3.0	3.2	3.3	2.9	4.3	2.9	0.6	2.7
Government Spending	7.6	5.4	0.9	3.6	2.9	5.0	6.1	6.1	6.8	4.2	4.0	3.2	3.7	4.8	3.9	5.4
Business Investment	0.8	-2.6	2.1	-16.2	-31.3	-17.0	-9.5	-11.5	-5.0	1.0	1.7	2.5	3.7	0.2	-16.5	-5.4
non-residential construction	1.5	1.0	7.6	-1.3	-24.1	-17.8	-12.0	-12.0	-6.0	1.0	1.5	2.0	3.0	-0.1	-11.4	-6.2
machinery and equipment	0.2	-5.8	-2.9	-28.5	-37.6	-16.1	-7.0	-11.0	-4.0	1.0	2.0	3.0	4.4	0.5	-21.2	-4.5
Residential Construction	-6.1	-1.3	-4.9	-23.0	-21.2	6.2	8.0	0.0	-3.0	0.0	1.0	1.0	2.9	-2.7	-9.1	0.8
Exports	-2.3	-4.1	-4.1	-17.7	-30.4	-19.3	15.2	7.9	2.7	4.1	4.6	5.5	1.1	-4.7	-14.2	4.2
Imports	-4.7	3.0	-3.4	-23.4	-38.9	-8.5	25.0	3.8	3.8	4.6	6.1	6.4	5.8	0.8	-14.9	6.0
(billions of chained 2002 dollars : a.r.)																
Inventory Change	9.2	14.5	15.0	10.3	-8.9	-10.5	-3.6	-1.8	0.8	2.5	5.7	7.4	15.0	12.2	-6.2	4.1
Contribution to GDP Growth	-3.9	1.3	0.1	-1.3	-5.2	-0.4	2.6	0.6	0.8	0.5	1.0	0.5	0.1	-0.2	-1.1	0.9
Net Exports	-87.1	-96.6	-96.7	-82.2	-59.2	-70.8	-83.4	-80.1	-82.0	-83.5	-86.3	-88.6	-61.8	-90.7	-73.4	-85.1
Contribution to GDP Growth	0.8	-2.4	-0.4	2.5	5.1	-3.3	-3.1	1.1	-0.3	-0.2	-0.5	-0.3	-1.7	-2.0	0.6	-0.6
(billions of dollars : a.r.)																
Nominal GDP	1,579	1,618	1,633	1,571	1,522	1,512	1,526	1,544	1,561	1,580	1,603	1,624	1,533	1,600	1,526	1,592
(% chng : a.r.)	4.8	10.4	3.6	-14.4	-11.9	-2.4	3.7	4.8	4.4	4.8	6.1	5.2	5.8	4.4	-4.6	4.3
INFLATION (quarter/quarter % change : a.r.)																
GDP Price Index	5.5	10.1	3.3	-11.2	-6.2	1.0	2.5	1.4	1.5	1.5	2.5	2.2	3.2	3.9	-2.2	1.7
CPI All Items	2.2	4.2	4.6	-3.1	-0.9	0.1	0.6	2.6	1.2	1.2	2.6	1.6	2.1	2.4	0.3	1.5
Excl. Food & Energy	0.7	1.7	1.5	1.1	0.8	1.3	0.6	1.9	1.1	1.0	2.7	1.3	2.0	1.2	1.2	1.4
Food Prices	2.4	7.2	9.8	8.3	4.8	2.6	1.0	2.9	2.4	1.7	2.2	2.2	2.6	3.5	5.2	2.2
Energy Prices	13.3	18.7	20.3	-42.1	-23.6	-14.4	-0.8	8.4	0.5	1.9	2.8	2.4	2.3	9.8	-15.0	1.4
Services	1.6	6.2	3.8	1.5	0.2	3.6	1.6	1.7	2.2	2.3	3.4	1.3	3.4	3.4	2.2	2.2
(year/year % change)																
CPI All Items	1.8	2.4	3.4	1.9	1.2	0.1	-0.9	0.7	1.2	1.4	1.9	1.7				
BoC Core	1.4	1.5	1.7	2.2	1.9	1.9	1.6	1.4	1.3	1.2	1.4	1.4	2.1	1.7	1.7	1.3
FINANCIAL (average for the quarter : %)																
Overnight Rate	3.83	3.00	3.00	2.00	0.83	0.25	0.25	0.25	0.25	0.25	0.58	1.08	4.35	2.96	0.40	0.54
3-Month T-Bill	2.99	2.54	2.31	1.47	0.64	0.25	0.22	0.22	0.22	0.30	0.78	1.25	4.14	2.33	0.33	0.64
90-Day BAs	3.89	3.24	3.25	2.35	0.82	0.35	0.31	0.30	0.30	0.38	0.87	1.35	4.57	3.18	0.45	0.73
10 Year Bond Yield	3.73	3.67	3.63	3.40	2.89	3.20	3.42	3.30	3.43	3.54	3.65	3.76	4.27	3.61	3.20	3.60
Canada/US spread: (bps)																
90 day	90	89	79	116	43	8	6	12	12	20	55	53	-34	94	17	35
10 year	7	-22	-23	14	15	-11	-10	0	-7	-11	-15	-19	-36	-6	-2	-13
FOREIGN TRADE (billions of dollars : a.r.)																
Current Account Balance	23.5	27.0	13.0	-31.0	-30.9	-44.8	-54.1	-50.2	-50.4	-51.7	-52.9	-53.1	15.6	8.1	-45.0	-52.0
Merchandise Balance	52.0	64.9	56.5	14.1	3.1	-6.9	-13.9	-8.6	-9.0	-9.9	-10.7	-10.7	47.9	46.9	-6.6	-10.1
Non-Merchandise Balance	-28.5	-37.9	-43.4	-45.1	-34.0	-37.9	-40.2	-41.6	-41.5	-41.7	-42.1	-42.4	-32.3	-38.8	-38.4	-41.9
(average for the quarter)																
Exchange Rate (US¢/C$)	99.6	99.0	96.0	82.5	80.3	85.6	91.1	94.3	96.5	98.4	100.3	100.3	93.5	94.3	87.8	98.9
Exchange Rate (C$/US$)	1.004	1.010	1.042	1.212	1.245	1.168	1.097	1.061	1.037	1.017	0.997	0.997	1.069	1.067	1.143	1.012
Exchange Rate (¥/C$)	104.8	103.6	103.3	79.5	75.2	83.5	85.3	88.4	92.4	95.5	98.7	99.9	110.0	97.8	83.1	96.6
Exchange Rate (C$/Euro)	1.51	1.58	1.56	1.60	1.62	1.59	1.57	1.56	1.54	1.53	1.52	1.54	1.47	1.56	1.58	1.53
INCOMES (billions of dollars : a.r.)																
Corporate Profits Before Tax	213.1	229.5	237.7	182.9	147.5	131.2	138.0	144.3	146.2	148.0	148.7	152.4	204.1	215.8	140.2	148.8
Corporate Profits After Tax	154.9	167.5	173.3	125.5	98.3	90.8	98.1	103.7	109.8	111.1	111.6	114.9	142.6	155.3	97.7	111.8
(year/year % change)																
Corporate Profits Before Tax	6.2	13.0	15.7	-11.7	-30.8	-42.9	-41.9	-21.1	-0.9	12.8	7.7	5.6	4.1	5.7	-35.0	6.1
Personal Income	5.7	5.0	4.6	3.8	0.7	0.3	0.5	1.1	3.1	4.1	4.7	4.6	5.8	4.8	0.6	4.1
Real Disposable Income	4.5	5.3	3.6	3.4	0.2	0.4	1.1	1.1	2.8	3.1	3.3	3.0	3.6	4.2	0.7	3.1
(average for the quarter : %)																
Savings Rate	3.3	3.4	3.1	4.9	4.5	4.5	4.6	5.0	5.1	5.1	5.0	5.0	2.5	3.7	4.6	5.1
OTHER INDICATORS (quarter average or period end : a.r.)																
Unemployment Rate (%)	5.9	6.1	6.1	6.4	7.6	8.4	8.6	8.8	8.9	8.7	8.5	8.3	6.0	6.1	8.3	8.6
Housing Starts (thousands)	235	218	208	185	140	128	149	149	147	148	150	155	228	211	141	150
Motor Vehicle Sales (millions)	1.84	1.72	1.65	1.49	1.42	1.45	1.51	1.52	1.52	1.55	1.58	1.59	1.69	1.67	1.48	1.56
(quarter/quarter % change : a.r.)																
Employment Growth	1.9	0.8	-0.1	0.5	-5.5	-1.5	-0.8	0.0	0.9	1.8	2.3	2.3	2.3	1.5	-1.6	0.8
Industrial Production	-7.3	-1.3	-0.4	-12.0	-19.3	-17.5	-5.7	1.1	2.7	3.1	4.1	3.4	0.1	-4.2	-11.5	0.2

Note: Outlined areas represent forecast periods

MARKET CALL

- The market is still clinging to the notion that better economic news should imply a weaker greenback. We see such a linkage as bound to break down, but we're giving it some respect in adjusting our FX outlook this month. While we view the C$, the euro and some other dollar alternatives looking pricey (see page 6) we've moved back a material US dollar rebound to Q1, when we also expect slower growth figures for the US economy. Longer term, there's room for renewed C$ appreciation once global commodity prices recover further.

- More market analysts seem to be joining our view that the Fed has a long fuse before rate hikes will make sense. Where we still differ is in our call that the Bank of Canada will also hold off on the first hike until early 2011, as a generally strong C$, contained core inflation, and prospects for fiscal tightening in 2011, keep rate hikes at bay.

- The long end of the bond market needs an equity market correction or slower growth to hold at these historically low yields. Best bets for such developments on a temporary basis lie early in 2010, when we expect the North American economy to lose momentum after inventory restocking is completed. But we look for higher bond yields over the course of 2010, particularly for Treasuries, as markets anticipate continued heavy supply, somewhat higher inflation, and overnight rate hikes in 2011.

INTEREST & FOREIGN EXCHANGE RATES

		2009		2010			
END OF PERIOD:		**29-Sep**	**Dec**	**Mar**	**Jun**	**Sep**	**Dec**
CDA	Overnight target rate	0.25	0.25	0.25	0.25	0.25	0.25
	98-Day Treasury Bills	0.24	0.23	0.25	0.30	0.30	0.30
	2-Year Gov't Bond	1.28	1.15	1.25	1.30	1.40	1.60
	10-Year Gov't Bond	3.33	3.30	3.50	3.70	3.85	3.95
	30-Year Gov't Bond	3.86	3.90	4.10	4.25	4.30	4.35
U.S.	Federal Funds Rate	0.25	0.25	0.25	0.25	0.25	0.25
	91-Day Treasury Bills	0.13	0.15	0.15	0.20	0.25	0.25
	2-Year Gov't Note	1.00	1.00	1.20	1.30	1.45	1.65
	10-Year Gov't Note	3.29	3.40	3.80	4.05	4.20	4.35
	30-Year Gov't Bond	4.02	4.25	4.60	4.85	5.00	5.00
Canada - US T-Bill Spread		0.11	0.08	0.10	0.10	0.05	0.05
Canada - US 10-Year Bond Spread		0.04	-0.10	-0.30	-0.35	-0.35	-0.40
Canada Yield Curve (30-Year — 2-Year)		2.58	2.75	2.85	2.95	2.90	2.75
US Yield Curve (30-Year — 2-Year)		3.02	3.25	3.40	3.55	3.55	3.35
EXCHANGE RATES	CADUSD	0.922	0.901	0.855	0.877	0.909	0.943
	USDCAD	1.085	1.110	1.170	1.140	1.100	1.060
	USDJPY	90	93	97	95	90	87
	EURUSD	1.46	1.44	1.35	1.35	1.37	1.40
	GBPUSD	1.60	1.60	1.58	1.59	1.62	1.67
	AUDUSD	0.871	0.840	0.795	0.825	0.855	0.895
	USDCHF	1.04	1.05	1.11	1.11	1.09	1.08
	USDBRL	1.79	1.84	1.95	1.89	1.82	1.75
	USDMXN	13.5	13.6	14.0	13.5	13.0	12.5

ECONOMIC UPDATE

CANADA	09Q2A	09Q3F	09Q4F	10Q1F	10Q2F	10Q3F	10Q4F	2008A	2009F	2010F	2011F
Real GDP Growth (AR)	-3.4	3.1	2.9	1.8	2.1	2.4	2.6	0.4	-2.3	2.0	3.8
Real Final Domestic Demand (AR)	0.4	0.8	1.7	2.1	2.7	3.2	3.0	2.6	-2.0	2.1	3.5
All Items CPI Inflation (Y/Y)	0.1	-0.9	0.2	0.9	1.3	1.5	1.6	2.4	0.1	1.3	2.2
Core CPI Ex Indirect Taxes (Y/Y)	1.9	1.6	1.3	1.5	1.4	1.5	1.7	1.7	1.7	1.5	2.0
Unemployment Rate (%)	8.4	8.7	8.8	9.0	9.1	9.0	8.9	6.1	8.4	9.0	8.2
U.S.											
Real GDP Growth (AR)	-1.0	3.8	2.4	0.5	1.2	1.9	1.4	0.4	-2.5	1.5	3.3
Real Final Sales (AR)	0.4	0.2	0.7	1.1	0.9	1.9	1.0	0.8	-2.0	0.9	3.0
All Items CPI Inflation (Y/Y)	-1.2	-1.7	0.7	1.3	1.3	1.9	2.4	3.8	-0.5	1.7	3.6
Core CPI Inflation (Y/Y)	1.8	1.5	1.8	2.0	1.9	2.2	2.6	2.3	1.7	2.2	3.1
Unemployment Rate (%)	9.3	9.6	10.0	10.1	10.0	9.9	9.8	5.8	9.3	10.0	9.4

CANADA

We marginally upgraded our call for growth over the balance of the year and next year in our September "Forecast" publication. While exports boosted by US inventory demand will allow the economy to average a healthy 3% pace over the second half of the year, the outlook for 2010 is less rosy. With a US slowdown and the overvalued C$ acting as a net drag on exports, growth will revert to a below-trend 2% print in 2010, underperforming the Bank of Canada's expectations, and making it more likely that interest rates will remain unchanged throughout the year.

UNITED STATES

A government-induced boost to consumption and inventory restocking should help US real GDP growth look quite impressive in the second half of the year. However, this initial strength is unlikely to be sustained into 2010. Monthly job losses have slowed, but net hiring has yet to be seen, supporting our view that unemployment will keep rising into next year. Year-over-year inflation has likely troughed, but pricing pressure is expected to remain very soft through 2010.

NATIONAL BANK
FINANCIAL GROUP

Monthly **ECONOMIC** Monitor

Canada
Economic Forecast

Annualized rate of change*	2006	2007	2008	2009	2010	Q4/Q4 2009	Q4/Q4 2010
Gross domestic product (1997 $)	2.9	2.5	0.4	(2.1)	2.9	(0.6)	3.2
Consumption	4.1	4.6	3.0	0.1	2.2	1.4	2.0
Residential construction	2.0	2.9	(2.7)	(8.2)	2.7	(0.2)	0.6
Business investment	10.0	3.7	0.2	(13.6)	5.4	(9.9)	7.5
Government expenditures	3.3	3.7	4.8	3.5	3.0	4.0	2.4
Exports	0.8	1.1	(4.7)	(13.8)	4.7	(8.1)	4.2
Imports	4.7	5.8	0.8	(14.0)	6.3	(5.4)	3.0
Change in inventories (millions $)	12,122	14,990	12,241	(2,105)	8,000	7,000.0	8,000.0
Domestic demand	4.5	4.1	2.6	(1.5)	2.8	0.4	2.7
Real disposable income	5.8	3.6	4.2	0.3	2.0	(0.0)	2.5
Employment	1.9	2.3	1.5	(1.6)	0.8	(1.7)	1.1
Unemployment rate	6.3	6.0	6.2	8.3	8.2	8.5	8.1
Inflation	2.0	2.2	2.4	0.4	1.9	1.2	2.0
Before-tax profits	5.1	4.1	5.7	(34.7)	13.6	(19.8)	15.0
Federal balance (Public Acc., bil. $)	$13.8	$9.6	$0.0	($45.0)	($30.0)	....	....
Current account (bil. $)	$20.3	$15.6	$8.1	($21.9)	$4.5	$0.0	$5.0

** or as noted*

Financial Forecast

	Current 9/23/09	Q4	Q1/10	Q2	Q3	2009*	2010*
Overnight rate	0.25	0.25	0.75	1.25	1.75	*0.25*	*2.00*
Prime rate	2.25	2.25	2.75	3.25	3.75	*2.25*	*3.75*
3 month T-Bills	0.26	0.31	0.96	1.46	1.92	*0.31*	*2.17*
Treasury yield curve							
2-Year	1.28	1.58	2.43	2.69	2.93	*1.58*	*3.22*
5-Year	2.65	2.93	3.43	3.59	3.79	*2.93*	*4.04*
10-Year	3.42	3.76	4.06	4.15	4.24	*3.76*	*4.37*
30-Year	3.93	4.15	4.34	4.41	4.47	*4.15*	*4.54*
Exchange rates*							
USD per CAD	0.93	0.88	0.86	0.89	0.92	*0.88*	*0.92*

National Bank Financial
** end of period*
*** NBF forecast*

Interest rate outlook

%, end of period

	09Q1	09Q2	09Q3	09Q4	10Q1	10Q2	10Q3	10Q4
Canada								
Overnight	0.50	0.25	0.25	0.25	0.25	0.25	0.75	1.25
Three-month	0.39	0.24	0.22	0.35	0.50	0.75	1.25	1.85
Two-year	1.07	1.20	1.26	1.20	1.30	1.50	2.10	2.60
Five-year	1.75	2.46	2.57	2.75	2.80	2.85	3.10	3.40
10-year	2.79	3.36	3.31	3.15	3.35	3.50	3.70	3.85
30-year	3.74	3.91	3.84	4.00	4.00	4.25	4.45	4.75
United States								
Fed funds	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0.50
Three-month	0.21	0.19	0.14	0.10	0.15	0.25	0.35	0.75
Two-year	0.81	1.11	0.95	1.00	1.00	1.20	1.50	1.85
Five-year	1.67	2.54	2.31	2.25	2.25	2.50	2.60	3.00
10-year	2.71	3.53	3.31	3.00	3.25	3.50	3.75	3.95
30-year	3.56	4.32	4.03	4.40	4.25	4.50	4.75	5.00
United Kingdom								
Repo	0.50	0.50	0.50	0.50	0.50	0.50	0.50	1.00
Two-year	1.20	1.33	0.87	1.00	1.10	1.30	1.40	1.60
10-year	3.17	3.69	3.59	4.10	4.60	5.00	5.40	5.60
Eurozone								
Minimum bid	1.50	1.00	1.00	1.00	1.00	1.00	1.25	1.75
Two-year	1.20	1.37	1.28	1.30	1.40	1.70	1.90	2.30
10-year	3.00	3.38	3.24	3.65	3.80	4.10	4.30	4.40
Australia								
Cash target rate	3.25	3.00	3.00	3.50	4.00	4.50	4.50	4.50
Two-year	2.60	4.03	4.55	4.75	5.00	5.15	5.20	5.25
10-year	4.25	5.52	5.36	5.25	5.60	5.85	6.15	6.35
New Zealand								
Cash target rate	3.00	2.50	2.50	2.50	2.50	3.00	3.50	4.00
Three-year	3.20	3.82	3.90	4.10	4.25	4.50	4.75	5.00
10-year	4.50	5.96	5.64	5.85	6.00	6.25	6.50	6.50
Yield curve*								
Canada	172	216	205	195	205	200	160	125
United States	190	242	236	200	225	230	225	210
United Kingdom	197	236	272	310	350	370	400	400
Eurozone	180	201	196	235	240	240	240	210
Australia	165	149	81	50	60	70	95	110
New Zealand**	130	214	174	175	175	175	175	150

* 2-year/10-year spread in basis points **New Zealand's yield curve: 10-year vs. three-year

Source: Reuters, RBC Economics Research

Central bank policy rates

%, end of period

		Current	Last				Current	Last	
United States	Fed funds	0.0-0.25	1.00	Dec. 16, 2008	Eurozone	Min. bid rate	1.00	1.25	May 13, 2009
Canada	Overnight rate	0.25	0.50	Apr. 21 2009	Australia	Cash rate	3.00	3.25	Apr 8, 2009
United Kingdom	Repo rate	0.50	1.00	Mar. 5, 2009	New Zealand	Cash rate	2.50	3.00	Apr. 30, 2009

Source: Bloomberg, Reuters, RBC Economics Research

Currency outlook

Level, end of period

	09Q1	09Q2	09Q3	Forecast 09Q4	10Q1	10Q2	10Q3	10Q4
Canadian dollar	1.26	1.16	1.07	1.09	1.08	1.07	1.05	1.05
Euro	1.33	1.40	1.46	1.42	1.44	1.45	1.51	1.52
U.K. pound sterling	1.43	1.65	1.60	1.75	1.80	1.84	1.91	1.92
New Zealand dollar	0.56	0.65	0.72	0.70	0.71	0.72	0.72	0.72
Japanese yen	99.0	96.4	90.0	90.0	88.0	87.0	85.0	85.0
Chinese renminbi	6.83	6.83	6.83	6.83	6.80	6.67	6.60	6.50
Australian dollar	0.69	0.81	0.88	0.86	0.88	0.89	0.90	0.90
Mexican peso	14.17	13.19	13.10	12.75	12.50	12.25	12.00	11.75

Canadian dollar cross-rates

	09Q1	09Q2	09Q3	09Q4	10Q1	10Q2	10Q3	10Q4
EUR/CAD	1.67	1.63	1.56	1.55	1.56	1.55	1.59	1.60
GBP/CAD	1.80	1.91	1.76	1.91	1.94	1.96	2.01	2.02
NZD/CAD	0.70	0.75	0.77	0.76	0.77	0.77	0.76	0.76
CAD/JPY	78.5	82.9	84.1	82.6	81.5	81.3	81.0	81.0
AUD/CAD	0.87	0.94	0.94	0.94	0.95	0.95	0.95	0.95

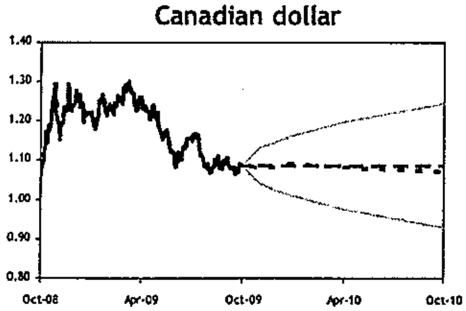
Rates are expressed in currency units per US$ and currency units per C$, except the euro, U.K. pound , Australian dollar and New Zealand dollar, which are expressed in US$ per currency unit and C$ per currency unit.

Source: Bloomberg, RBC Economics Research

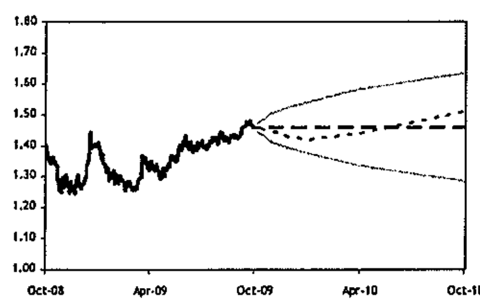
RBC Economics outlook compared to the market

The following charts track historical exchange rates plus the forward rate (dashed line) compared to the RBC Economics forecast (dotted line) out one year. The cone for the forecast period frames the forward rate with confidence bounds using implied option volatilities as of the date of publication.

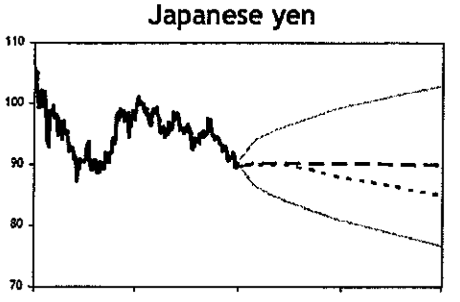
Canadian dollar



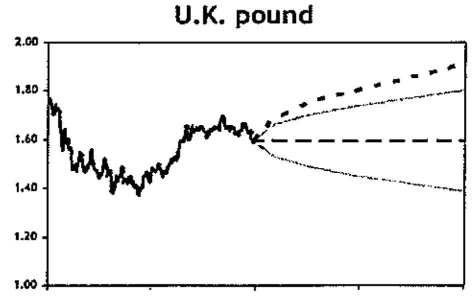
Euro



Japanese yen



U.K. pound



Source: Reuters, RBC Economics Research

Financial Markets	09Q1	09Q2	09Q3f	09Q4f	10Q1f	10Q2f	10Q3f	10Q4f
				(%, end of period)				
Canada								
BoC Overnight Target Rate	0.50	0.25	0.25	0.25	0.25	0.25	0.75	1.50
3-month T-bill	0.40	0.25	0.23	0.30	0.35	0.50	1.30	2.25
2-year Canada	1.08	1.21	1.26	1.20	1.40	1.55	2.05	2.85
5-year Canada	1.75	2.47	2.58	2.70	3.10	3.45	3.60	3.90
10-year Canada	2.78	3.36	3.31	3.50	3.80	4.20	4.45	4.70
30-year Canada	3.56	3.36	3.84	4.00	4.10	4.65	4.85	4.90
Real GDP (q/q, ann. % change)	-6.1	-3.4	2.5	3.5	4.0	3.0	2.5	2.5
Real GDP (y/y, % change)	-2.3	-3.2	-2.7	-1.0	1.6	3.3	3.3	3.0
Consumer Prices (y/y, % change)	1.2	0.1	0.0	1.7	2.2	2.0	1.8	2.0
Core CPI (y/y % change)	1.9	1.9	1.7	1.4	1.4	1.3	1.3	1.6
United States								
Fed Funds Target Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.75	1.50
3-month T-bill	0.20	0.15	0.11	0.12	0.15	0.45	1.25	2.25
2-year Treasury	0.80	1.10	0.95	0.95	1.20	1.80	2.20	3.00
5-year Treasury	1.66	2.55	2.31	2.40	2.75	3.25	3.45	3.80
10-year Treasury	2.66	3.53	3.31	3.50	3.75	4.15	4.40	4.65
30-year Treasury	3.53	4.33	4.05	4.25	4.30	4.80	4.95	5.00
Real GDP (q/q, ann. % change)	-6.4	-0.7	4.0	2.0	4.0	4.0	2.5	2.0
Real GDP (y/y, % change)	-3.3	-3.8	-2.2	-0.4	2.3	3.5	3.1	3.1
Consumer Prices (y/y, % change)	-0.2	-0.9	-1.6	0.9	1.9	2.1	1.8	1.9
Core CPI (y/y % change)	1.7	1.8	1.5	1.4	1.3	1.1	1.1	1.5
Spreads								
Target Rate	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3-month T-bill	0.20	0.10	0.12	0.18	0.20	0.05	0.05	0.00
2-year	0.28	0.11	0.31	0.25	0.20	-0.25	-0.15	-0.15
5-year	0.10	-0.08	0.27	0.30	0.35	0.20	0.15	0.10
10-year	0.12	-0.17	0.00	0.00	0.05	0.05	0.05	0.05
30-year	0.03	-0.97	-0.21	-0.25	-0.20	-0.15	-0.10	-0.10
Central Bank Rates								
Bank of England	0.50	0.50	0.50	0.50	0.50	0.75	1.25	1.50
European Central Bank	1.50	1.00	1.00	1.00	1.25	1.50	1.75	2.00
Bank of Japan	0.10	0.10	0.10	0.10	0.10	0.25	0.25	0.25
Reserve Bank of Australia	3.25	3.00	3.00	3.25	3.50	3.75	4.00	4.25
Swiss National Bank	0.25	0.25	0.25	0.25	0.25	0.50	0.75	1.00
Exchange Rates								
Canadian Dollar (USD/CAD)	1.26	1.16	1.07	1.04	1.03	1.01	1.00	0.99
Canadian Dollar (CAD/USD)	0.79	0.86	0.94	0.96	0.97	0.99	1.00	1.01
Yen (USD/JPY)	99	96	90	92	90	88	86	85
Euro (EUR/USD)	1.33	1.40	1.46	1.50	1.53	1.56	1.58	1.60
Euro (EUR/GBP)	0.93	0.85	0.92	0.91	0.92	0.93	0.93	0.94
Sterling (GBP/USD)	1.43	1.65	1.60	1.64	1.66	1.67	1.69	1.71
Australian Dollar (AUD/USD)	0.69	0.81	0.88	0.88	0.90	0.94	0.94	0.91
Mexican Peso (USD/MXN)	14.2	13.2	13.4	13.7	14.1	14.0	14.0	14.0
Chinese Yuan (USD/CNY)	6.8	6.8	6.8	6.8	6.6	6.5	6.4	6.3

Forecast Changes

Financial

- Australia was the first of the G20 nations to begin the process of normalizing its short-term interest rates. We look for the Reserve Bank of Australia to continue to push short-term borrowing costs higher over the next year in response to the improving growth outlook, underpinned by strengthening commodity markets, throughout the Asia-Pacific region.
- The European Central Bank is forecast to begin raising interest rates in 10Q1, followed by the Bank of England in 10Q2. Both the Bank of Canada and the Federal Reserve are now expected to begin taking back some of the extraordinary monetary stimulus early in 10Q3. With the North American economies projected to be on a firmer foundation, and downward pressure on inflation abating, the central banks are likely to gradually increase their benchmark overnight rates.
- We have tempered our government long bond yield forecasts in both the United States and Canada to the lower end of a 4½-5% range.
- The Canadian dollar is expected to continue its slow rise towards parity. The broader decline in the U.S. dollar, the relative fundamental position of Canada versus the U.S., and our favourable outlook for oil prices continue to be the driving forces behind our positive Canadian dollar outlook. We expect the Canadian dollar to reach parity on a sustainable level in mid-2010 and to move through parity from there.
- We continue to be in a secular U.S. dollar downtrend and accordingly believe that the euro, sterling and Canadian dollar will close both 2009 and 2010 higher than current levels.

Scotia Economics

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CANADIAN FIXED INCOME

The Canadian bond market has asserted its independence over the past month, significantly underperforming the U.S., with a special emphasis on the short end of the curve. In fact, whereas U.S. yields are slightly lower over the past month, Canadian yields have increased. And while the U.S. curve is a smidgen steeper, the Canadian curve is significantly flatter.

What has enabled this bold decoupling of the Canadian market? International investors have glommed onto the Canadian story in recent weeks due to the potent combination of blockbuster economic data – a second month of robust job gains, for instance – and the Australian rate hikes that have initiated a mad scramble by investors to locate the next central bank hankering to pull the trigger. Canada is identified as a promising candidate due to its swift housing market recovery and its status as a commodity player – both similar to Australia.

Ultimately, TD believes that the similarities between Australia and Canada – while apt in certain ways – are somewhat of a red herring as powerful Canadian dollar strength will significantly dampen the Canadian economy, and the housing market rebound is less widespread or vigorous than commonly imagined. For now, the Bank of Canada has no reason to retract its commitment to keep rates unchanged through to mid-2010, and TD remains comfortable with the view that a first hike will not occur until the fourth quarter of 2010.

The sorts of issues that baffle the U.S. bond market are also in evidence for Canada, though in a much more muted fashion. Bond supply is up, but relatively contained. Inflation risks will grow, but the inflation-targeting mandate should prevent any undesirable extremes. And Canada continues to possess structural advantages that – while seemingly unable to translate into outsized economic growth – will at least allow investors to sleep more peacefully at night.

All of this argues that Canadian bond yields – while likely to drift generally upwards as the economic recovery gains tractions – should reverse their recent relative course and start to outperform the U.S. The historical record is supportive of this assessment. While higher yields will generally go hand-in-hand with a flatter yield curve over the next few years, we must first highlight the prospect that the Canadian curve will steepen into year-end as the market comes to terms with the fact that the Bank of Canada will not be raising rates in the near term after all. This will necessitate lower short-dated yields.

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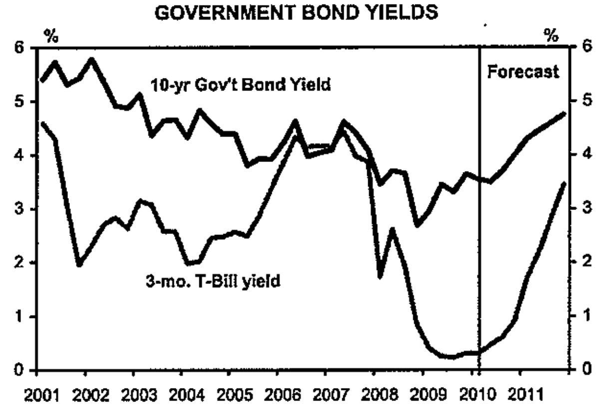
CANADIAN 3-MONTH T-BILL RATES & 10-YEAR GOVERNMENT BOND YIELDS



Actual data to: Q3 2009; Forecast by TDBFG as at October 2009;
Source: Bank of Canada/Haver Analytics

CANADIAN FIXED INCOME OUTLOOK

	Spot Rate	2009				2010				2011			
	14/10/2009	Q1	Q2	Q3	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Overnight Target Rate (%)	0.25	0.50	0.25	0.25	0.25	0.25	0.25	0.25	0.75	1.50	2.00	2.75	3.25
3-mth T-Bill Rate (%)	0.24	0.35	0.25	0.23	0.30	0.30	0.45	0.60	0.90	1.70	2.20	2.85	3.45
2-yr Govt. Bond Yield (%)	1.71	1.08	1.21	1.27	1.55	1.60	1.60	1.95	2.55	3.05	3.35	3.55	3.85
5-yr Govt. Bond Yield (%)	2.87	1.75	2.47	2.58	2.80	2.65	2.60	2.85	3.30	3.70	3.90	4.10	4.30
10-yr Govt. Bond Yield (%)	3.53	2.78	3.36	3.31	3.65	3.55	3.50	3.70	4.00	4.30	4.45	4.60	4.75
30-yr Govt. Bond Yield (%)	3.98	3.56	3.86	3.84	4.10	4.10	3.85	3.90	4.15	4.45	4.60	4.75	4.90
10-yr-2-yr Govt. Spread (%)	1.82	1.70	2.15	2.04	2.10	1.95	1.90	1.75	1.45	1.25	1.10	1.05	0.90
Canada-U.S. Spreads													
3-mth T-Bill Rate (%)	0.18	0.17	0.07	0.12	0.05	0.00	0.10	0.20	0.40	0.45	0.20	0.10	0.20
2-yr Govt. Bond Yield (%)	0.79	0.28	0.10	0.32	0.30	0.25	0.20	0.20	0.20	0.15	0.15	0.10	0.10
5-yr Govt. Bond Yield (%)	0.54	0.09	-0.08	0.24	0.20	0.10	0.10	0.00	-0.05	-0.05	-0.10	-0.10	-0.15
10-yr Govt. Bond Yield (%)	0.12	0.12	-0.17	0.00	0.00	-0.05	-0.05	-0.15	-0.25	-0.25	-0.30	-0.35	-0.40
30-yr Govt. Bond Yield (%)	-0.28	0.03	-0.47	-0.21	-0.40	-0.40	-0.40	-0.45	-0.60	-0.60	-0.65	-0.70	-0.70

f: Forecast by TD Bank Financial Group as at Oct 14, 2009; All forecasts are for end of period. Source: Bloomberg, TDBFG

CANADIAN DOLLAR

The Canadian dollar has powered ahead over the last week, finally hitting our end-Q3 target of 1.05 for USD/CAD, and then continuing to push all the way below 1.03. In fact, since the last issue of Global Markets, only AUD has outperformed CAD, as the Australian central bank has already begun to tighten monetary policy.

As we have been saying for some time, we think that parity with the US dollar will be the next stop for CAD, and we expect to see that move happen by the end of 2009; this would be USD/CAD's first brush with parity since August 2008. And turning to 2010, we have upgraded our forecast for CAD, and now expect to see an overshoot through parity, with USD/CAD spending most of the first half of next year below 1.00. In the second half of the year, we expect to see USD/CAD turn a little higher as the USD bear trend comes to an end.

Much of this upgrade for CAD is based on USD weakness. As mentioned earlier, the USD downtrend looks like it still has some legs, so we're extending the move deeper into 2010. However, we still expect CAD to hold up well against the other major currencies, with EUR/CAD and GBP/CAD remaining near their lows of the last several quarters, given the Canadian economy's solid fiscal and financial system fundamentals.

Although USD/CAD is at new lows for the cycle, we still don't think that the Bank of Canada is considering, or should consider, currency intervention. Remember it was just a couple of weeks ago that the G7 reiterated its commitment for the G20's "Framework for Strong, Sustainable and Balanced Growth," part of which advocates "market oriented exchange rates that reflect underlying economic fundamentals." At the current pace of appreciation, Canada could not possibly justify intervening to weaken CAD to the rest of the G20 community, so we think that such a move is still a long shot.

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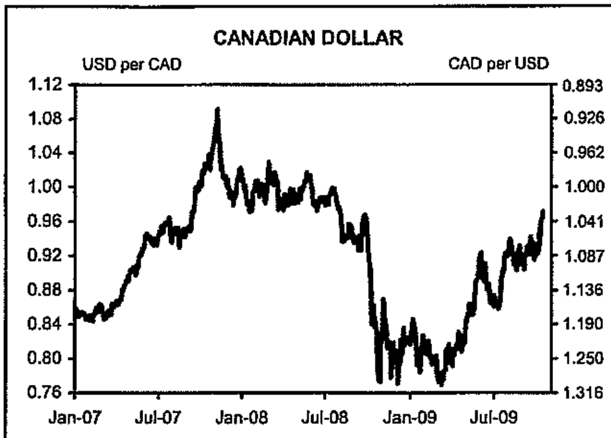
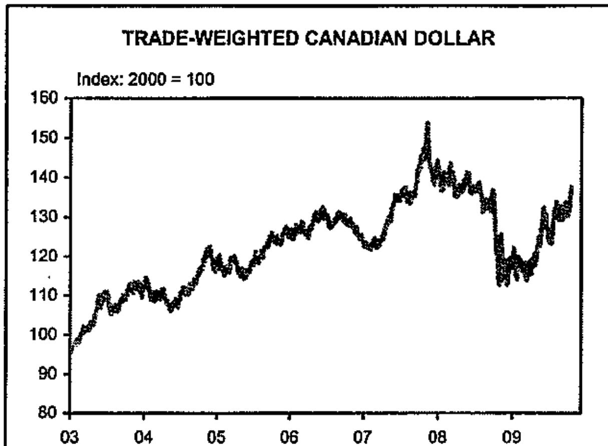


Source: Federal Reserve Bank of New York/Haver Analytics



*Nominal broad effective exchange rate
Source: Haver Analytics/JP Morgan

CANADIAN DOLLAR FUNDAMENTALS			
Interest Rate Spreads	N	Business Cycle	–
Inflation Differential	+	Fiscal Balances	N
Current Account	N	Politics	N

Legend: - is negative, + is positive, N is neutral for currency

CANADIAN DOLLAR OUTLOOK

	Spot Price	2009				2010				2011			
	14/10/2009	Q1	Q2	Q3	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CAD per USD	1.027	1.260	1.162	1.069	1.000	0.990	0.980	1.020	1.075	1.087	1.099	1.111	1.124
USD per CAD	0.973	0.794	0.860	0.935	1.000	1.010	1.020	0.980	0.930	0.920	0.910	0.900	0.890
JPY per CAD	87	79	83	84	92	91	92	90	91	94	94	94	93
CAD per EUR	1.532	1.670	1.631	1.566	1.500	1.505	1.520	1.531	1.559	1.522	1.484	1.444	1.404
CAD per GBP	1.64	1.804	1.913	1.709	1.613	1.618	1.652	1.664	1.713	1.691	1.648	1.641	1.633

f: Forecast by TDBFG as at Oct 14, 2009; All forecasts are for end of period; Source: Federal Reserve Bank of New York, Bloomberg, TDBFG

Fcst Date	Cdn Bonds 10 Yrs+ 16-Sep-09	Cdn T-Bill Rates 16-Sep-09	Exchange Rate 16-Sep-09
2008.1			
2008.2			
2008.3			
2008.4			
2009.1	3.69	0.71	1.245
2009.2	3.93	0.23	1.167
2009.3	4.01	0.22	1.106
2009.4	3.96	0.20	1.100
2010.1	3.71	0.18	1.097
2010.2	3.53	0.25	1.094
2010.3	3.54	0.69	1.090
2010.4	3.72	1.47	1.087
2011.1	4.03	2.46	1.085
2011.2	4.41	3.44	1.082
2011.3	4.72	4.14	1.080
2011.4	4.96	4.54	1.078
2012.1	5.07	4.58	1.076
2012.2	5.18	4.58	1.074
2012.3	5.28	4.59	1.071
2012.4	5.36	4.59	1.069
2013.1	5.43	4.60	1.068
2013.2	5.49	4.60	1.066
2013.3	5.55	4.60	1.064
2013.4	5.60	4.60	1.062

Source: Conference Board of Canada
Reports downloaded from eData on October 22, 2009
Forecast date is September 16, 2009 for all variables

Global Insight
Table 1
Selected Economic Indicators

	09Q1	09Q2	09Q3	09Q4	10Q1	10Q2	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4
Real GDP (Bil. chained 2002 $)	1292.4	1281.4	1283.7	1292.7	1300.4	1309.2	1320.3	1330.9	1342.7	1354.3	1366.5	1378.6	1390.9	1403.7	1415.6	1426.7	1437.9	1448.8	1460.1	1469.8
Annual % Ch.	-6.1	-3.4	0.7	2.8	2.4	2.7	3.4	3.3	3.6	3.5	3.7	3.6	3.6	3.7	3.5	3.2	3.2	3.1	3.2	2.7
Consumer	804.5	808.1	809.6	811.6	815.6	819.4	823.4	828.4	834.3	839.8	845.4	851.1	857.2	863.3	868.6	873.7	879.0	884.2	889.4	894.6
Annual % Ch.	-1.2	1.8	0.8	1.0	2.0	1.9	2.0	2.4	2.9	2.7	2.7	2.7	2.9	2.9	2.5	2.3	2.5	2.4	2.4	2.3
Government	314.3	318.1	323.1	327.7	330.7	333.4	336.1	338.8	341.5	344.2	346.8	349.3	351.9	354.7	357.2	359.4	361.6	363.7	365.8	367.9
Annual % Ch.	3.1	5.0	6.3	5.8	3.8	3.4	3.3	3.2	3.2	3.2	3.1	2.9	3.1	3.2	2.8	2.5	2.5	2.4	2.3	2.3
Bus. Res. Investment	69.7	70.8	70.5	70.4	70.7	71.1	71.4	71.8	72.3	72.7	73.3	73.7	74.3	74.8	75.3	75.7	76.1	76.5	76.8	77.1
Annual % Ch.	-21.2	6.2	-1.7	-0.5	1.7	2.0	1.9	2.4	2.5	2.6	2.9	2.7	3.0	3.0	2.5	2.3	1.9	1.9	1.6	1.4
Bus. Non-Res. Inv.	171.6	163.7	161.7	160.4	161.3	162.2	163.3	164.8	166.3	167.7	169.4	170.9	172.5	174.0	175.3	176.6	177.9	179.2	180.4	181.4
Annual % Ch.	-31.3	-17.0	-4.9	-3.1	2.1	2.3	2.7	3.7	3.9	3.4	4.2	3.5	3.7	3.6	3.1	3.0	2.8	3.0	2.7	2.4
Exports	424.7	402.5	405.4	408.1	411.8	416.6	422.1	428.1	434.5	441.0	447.5	454.4	461.9	469.5	476.8	484.4	490.8	497.7	504.6	511.3
Annual % Ch.	-30.4	-19.3	2.9	2.7	3.7	4.8	5.3	5.8	6.1	6.1	6.1	6.3	6.8	6.7	6.4	6.5	5.5	5.7	5.7	5.4
Imports	483.9	473.3	481.8	484.6	489.3	494.8	500.9	506.6	511.7	516.5	521.4	526.4	531.5	536.7	541.7	546.6	550.9	555.8	560.8	566.1
Annual % Ch.	-38.9	-8.5	7.4	2.4	3.9	4.6	5.0	4.6	4.1	3.8	3.9	3.9	3.9	3.9	3.8	3.6	3.3	3.6	3.6	3.8
Business Inventory Ch.	-8.9	-10.5	-3.6	0.4	0.9	2.6	6.0	6.9	6.8	6.6	6.8	6.9	6.0	5.3	5.4	4.7	4.7	4.5	5.0	4.6
Statistical error	1.1	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nominal GDP (Bil. $)	1521.6	1512.4	1528.3	1546.6	1561.9	1579.2	1601.0	1623.0	1645.8	1669.8	1694.2	1720.2	1745.1	1771.8	1798.1	1822.1	1846.0	1870.3	1895.5	1918.7
Annual % Ch.	-11.9	-2.4	4.3	4.9	4.0	4.5	5.6	5.6	5.7	6.0	6.0	6.3	5.9	6.3	6.1	5.4	5.4	5.4	5.5	5.0
Raw Mat. Price Index	136.4	152.5	151.8	151.4	151.9	153.2	154.3	154.3	154.6	155.2	154.9	154.4	154.0	154.7	155.7	156.3	156.8	157.0	157.3	158.1
% Ch. Year Ago	-30.0	-31.3	-30.1	-0.1	11.3	0.5	1.6	2.0	1.8	1.3	0.4	0.1	-0.3	-0.3	0.5	1.2	1.8	1.5	1.0	1.2
Industry Price Index	117.6	116.6	116.1	115.9	116.8	117.7	118.3	118.4	119.4	120.8	121.5	121.9	122.5	123.0	123.5	123.9	124.6	125.2	125.8	126.3
% Ch. Year Ago	0.8	-4.1	-6.4	-3.4	-0.7	0.9	1.9	2.1	2.2	2.6	2.7	3.0	2.6	1.8	1.7	1.7	1.8	1.8	1.8	1.9
GDP Deflator	117.7	118.0	119.0	119.6	120.1	120.6	121.3	121.9	122.6	123.3	124.0	124.8	125.5	126.2	127.0	127.7	128.4	129.1	129.8	130.5
Annual % Ch.	-6.2	1.0	3.6	2.0	1.6	1.7	2.2	2.3	2.1	2.4	2.2	2.6	2.2	2.4	2.5	2.2	2.1	2.2	2.3	2.2
CPI	113.6	114.6	114.7	115.2	115.3	116.2	116.6	117.4	118.0	118.6	119.1	119.7	120.4	121.0	121.6	122.2	122.8	123.4	124.0	124.6
% Ch. Year Ago	1.2	0.1	-0.8	1.1	1.5	1.4	1.7	1.9	2.3	2.1	2.1	1.9	2.0	2.0	2.1	2.1	2.0	2.0	2.0	2.0
Employment (Thousands)	16907	16844	16809	16870	16900	16947	17036	17108	17171	17249	17310	17391	17476	17540	17585	17649	17722	17792	17868	17931
Annual % Ch.	-5.5	-1.5	-0.8	1.5	0.7	1.1	2.1	1.7	1.5	1.8	1.4	1.9	2.0	1.5	1.0	1.5	1.7	1.6	1.7	1.4
Unemployment Rate (%)	7.6	8.3	8.6	8.8	9.0	9.0	8.8	8.7	8.6	8.5	8.4	8.2	8.0	7.9	7.9	7.8	7.7	7.7	7.6	7.5
Productivity (Annual % Ch.)	-0.6	-1.9	1.6	1.4	1.7	1.6	1.3	1.6	2.1	1.7	2.2	1.7	1.7	2.2	2.4	1.7	1.5	1.5	1.4	1.3
Average Hourly Earnings	20.46	20.38	20.50	20.59	20.66	20.74	20.82	20.91	21.01	21.11	21.23	21.38	21.52	21.66	21.87	22.09	22.29	22.49	22.70	22.90
Annual % Ch.	1.1	-1.6	2.2	1.8	1.4	1.4	1.7	1.8	1.9	1.9	2.2	2.8	2.6	2.8	3.9	4.0	3.6	3.7	3.7	3.7
3-Month T-Bill Rate (%)	0.71	0.23	0.23	0.25	0.28	0.53	0.79	1.30	1.98	2.24	2.50	2.75	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.50
US 3-Month T-Bill Rate (%)	0.21	0.17	0.16	0.16	0.23	0.32	0.57	0.97	1.43	1.89	2.39	2.86	3.16	3.38	3.44	3.44	3.44	3.47	3.63	4.09
Canada-U.S. Differential (% pts.)	0.50	0.06	0.08	0.09	0.05	0.21	0.22	0.33	0.55	0.35	0.11	-0.11	-0.15	-0.13	0.06	0.31	0.56	0.78	0.87	0.41
Prime Rate (%)	2.83	2.25	2.24	2.25	2.25	2.50	2.75	3.25	4.00	4.25	4.50	4.75	5.00	5.25	5.50	5.75	6.00	6.25	6.50	6.50
Overnight Rate (%)	0.83	0.24	0.24	0.25	0.25	0.50	0.75	1.25	2.00	2.25	2.50	2.75	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.50
Bank Rate (%)	1.08	0.50	0.49	0.50	0.50	0.75	1.00	1.50	2.25	2.50	2.75	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.75	4.75
GOC Bond Rate (1-3 yrs.) (%)	1.25	1.06	1.28	1.66	1.70	1.85	2.02	2.34	2.76	2.94	3.11	3.33	3.58	3.82	3.99	4.14	4.29	4.45	4.68	4.86
GOC Bond Rate (3-5 yrs.) (%)	1.83	2.06	2.38	2.67	2.71	2.80	2.89	3.08	3.32	3.44	3.54	3.75	4.00	4.23	4.34	4.42	4.50	4.60	4.80	5.12
GOC Ten-Year Bond Rate (%)	2.96	3.37	3.41	3.78	3.83	3.84	3.86	3.90	3.94	3.99	4.02	4.20	4.46	4.67	4.73	4.73	4.73	4.76	4.94	5.41
U.S. Ten-Year T-Note Rate (%)	2.74	3.31	3.52	3.37	3.43	3.45	3.52	3.64	3.76	3.84	3.86	4.07	4.26	4.48	4.54	4.54	4.54	4.57	4.75	5.24
U.S. Real GDP (Bil. 2005 $)	12925.4	12901.5	13014.6	13097.9	13155.3	13214.5	13286.6	13374.6	13466.7	13585.4	13708.8	13829.7	13959.8	14091.2	14215.7	14327.0	14422.5	14517.9	14612.0	14704.5
Annual % Ch.	-6.4	-0.7	3.6	2.6	1.8	1.8	2.2	2.7	2.8	3.6	3.7	3.6	3.8	3.8	3.6	3.2	2.7	2.7	2.6	2.6
Household Credit (Billion $)	1319.2	1341.0	1364.8	1390.3	1417.1	1444.8	1473.5	1502.8	1532.7	1562.6	1592.3	1621.1	1649.2	1676.4	1703.1	1729.2	1754.9	1780.1	1805.0	1829.6
Annual % Ch.	7.2	6.8	7.3	7.7	7.9	8.1	8.2	8.2	8.2	8.0	7.8	7.5	7.1	6.8	6.5	6.3	6.1	5.9	5.7	5.6
ExCh. Rate (U.S.-Can.)	80.3	85.7	91.1	90.3	88.4	88.1	88.3	88.8	89.7	91.0	91.9	92.3	92.9	93.8	93.1	92.3	92.2	93.9	94.1	92.7
Curr. Acct. Bal. (Billion $)	-30.9	-44.8	-46.5	-44.7	-39.5	-43.0	-38.5	-35.0	-30.2	-26.7	-22.6	-18.2	-14.4	-10.9	-7.9	-5.8	-1.0	1.2	3.3	3.6

Global Insight

Canadian Interest Rates - Table 24
(Percent)

	09Q1	09Q2	09Q3	09Q4	10Q1	10Q2	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4
Overnight Money	0.83	0.24	0.24	0.25	0.25	0.50	0.75	1.25	2.00	2.25	2.50	2.75	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.50
Bank Rate	1.08	0.50	0.49	0.50	0.50	0.75	1.00	1.50	2.25	2.50	2.75	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.75	4.75
Government of Canada																				
Treasury Bills																				
3 Months	0.71	0.23	0.23	0.25	0.28	0.53	0.79	1.30	1.98	2.24	2.50	2.75	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.50
6 Months	0.75	0.35	0.34	0.36	0.39	0.64	0.90	1.41	2.09	2.35	2.61	2.86	3.11	3.36	3.61	3.86	4.11	4.36	4.61	4.61
Bonds																				
1-3 Years	1.25	1.06	1.28	1.66	1.70	1.85	2.02	2.34	2.76	2.94	3.11	3.33	3.58	3.82	3.99	4.14	4.29	4.45	4.68	4.86
3-5 Years	1.83	2.06	2.38	2.67	2.71	2.80	2.89	3.08	3.32	3.44	3.54	3.75	4.00	4.23	4.34	4.42	4.50	4.60	4.80	5.12
5 Years	2.03	2.38	2.63	2.77	2.82	2.90	2.98	3.16	3.38	3.49	3.59	3.79	4.04	4.27	4.38	4.45	4.52	4.61	4.81	5.15
5-10 Years	2.43	2.80	3.06	3.48	3.52	3.56	3.60	3.68	3.77	3.84	3.89	4.08	4.33	4.55	4.63	4.65	4.67	4.71	4.90	5.33
10 Years	2.96	3.37	3.41	3.78	3.83	3.84	3.86	3.90	3.94	3.99	4.02	4.20	4.46	4.67	4.73	4.73	4.73	4.76	4.94	5.41
10+ Years	3.69	3.93	3.98	4.18	4.22	4.22	4.23	4.26	4.29	4.34	4.36	4.53	4.78	5.00	5.05	5.05	5.04	5.07	5.25	5.71
30 Years	3.72	3.97	3.93	4.28	4.32	4.32	4.32	4.35	4.38	4.43	4.44	4.62	4.87	5.08	5.13	5.12	5.12	5.14	5.32	5.79
Prime Corporate Paper																				
30 Days	1.22	0.61	0.39	0.36	0.39	0.64	0.90	1.41	2.09	2.35	2.61	2.86	3.11	3.36	3.61	3.86	4.11	4.36	4.61	4.61
90 Days	1.19	0.61	0.41	0.38	0.41	0.66	0.92	1.43	2.11	2.37	2.63	2.88	3.13	3.38	3.63	3.88	4.13	4.38	4.63	4.63
Bankers' Acceptances																				
30 Days	0.78	0.29	0.29	0.35	0.38	0.63	0.89	1.40	2.08	2.34	2.60	2.85	3.10	3.35	3.60	3.85	4.10	4.35	4.60	4.60
90 Days	0.76	0.31	0.31	0.37	0.40	0.65	0.91	1.42	2.10	2.36	2.62	2.87	3.12	3.37	3.62	3.87	4.12	4.37	4.62	4.62
Chartered Bank Non-Chequable Deposits	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
5-Yr Personal Fixed Term	1.95	1.65	1.73	1.69	1.66	1.86	2.07	2.53	3.16	3.38	3.60	3.81	4.02	4.23	4.45	4.67	4.88	5.11	5.33	5.30
Chartered Bank Prime	2.83	2.25	2.24	2.25	2.25	2.50	2.75	3.25	4.00	4.25	4.50	4.75	5.00	5.25	5.50	5.75	6.00	6.25	6.50	6.50
Chartered Bank Mortgage Rate																				
1 Year	4.83	3.85	3.73	4.00	4.03	4.28	4.54	5.05	5.73	5.99	6.25	6.50	6.76	7.00	7.25	7.50	7.75	8.00	8.25	8.25
5 Years	5.71	5.45	5.73	5.89	5.89	5.85	5.83	5.83	5.83	5.86	5.85	6.01	6.24	6.44	6.48	6.46	6.45	6.46	6.63	7.09
3-Month Euro Deposit Rate	1.13	0.60	0.48	0.50	0.55	0.62	0.88	1.39	2.07	2.33	2.59	2.84	3.09	3.34	3.59	3.84	4.09	4.34	4.59	4.59

Backup Forecasts

for 2013/14 and on

Forecast Completed: December 18, 2008

TABLE 1 - KEY ECONOMIC INDICATORS

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CAN -GROSS DOMESTIC PRODUCT	1246064	1284819	1319681	1328766	1346126	1395333	1445007	1493629	1533589	1573623	1607487	1641674	1674562
AT MARKET PRICES (MILLIONS $ 2002)	2.9	3.1	2.7	0.7	1.3	3.7	3.6	3.4	2.7	2.6	2.2	2.1	2.0
GDP DEFLATOR	1.101	1.129	1.164	1.211	1.223	1.246	1.268	1.290	1.316	1.341	1.365	1.390	1.415
	3.4	2.5	3.1	4.1	1.0	1.9	1.8	1.8	2.0	1.9	1.8	1.8	1.8
U.S. -GROSS DOMESTIC PRODUCT	10990	11295	11524	11730	11771	12083	12568	13056	13539	13990	14363	14736	15112
AT MARKET PRICES (BILLIONS $ 2000)	2.9	2.8	2.0	1.8	0.3	2.6	4.0	3.9	3.7	3.3	2.7	2.6	2.6
CONSUMER PRICE INDEX	1.070	1.091	1.115	1.143	1.164	1.186	1.209	1.234	1.260	1.285	1.310	1.335	1.362
	2.2	2.0	2.1	2.6	1.8	1.9	2.0	2.1	2.1	2.0	1.9	1.9	2.0
TOTAL EMPLOYMENT ('000s)	16172	16485	16865	17127	17129	17383	17660	17883	18088	18276	18444	18599	18742
	1.4	1.9	2.3	1.6	0.0	1.5	1.6	1.3	1.1	1.0	0.9	0.8	0.8
UNEMPLOYMENT RATE	6.76	6.30	6.03	6.05	6.86	6.65	6.25	6.00	5.80	5.65	5.58	5.52	5.46
PRIVATE NON-FARM	23.440	24.098	24.992	25.658	26.380	27.191	28.052	28.994	30.075	31.134	32.185	33.235	34.330
AVERAGE HOURLY EARNINGS	4.1	2.8	3.7	2.7	2.8	3.1	3.2	3.4	3.7	3.5	3.4	3.3	3.3
REAL DISPOSABLE INCOME	756075	797686	830410	864860	881538	908165	935417	962581	992770	1019276	1044282	1068019	1091571
	2.6	5.5	4.1	4.1	1.9	3.0	3.0	2.9	3.1	2.7	2.5	2.3	2.2
PRIVATE NON-FARM	49	50	50	50	50	52	53	54	55	56	57	57	58
PRODUCTIVITY	3.0	1.4	0.7	-1.0	1.3	2.5	2.2	2.4	1.8	1.8	1.3	1.4	1.4
FEDERAL GOV'T BALANCE	2052	10241	15387	3282	1235	1692	2349	1672	1595	3485	3833	4155	4196
CORPORATE PROFITS	185895	196719	203231	215606	202827	227105	247935	269734	282273	295261	298101	304023	308240
BEFORE TAXES	10.5	5.8	3.3	6.1	-5.9	12.0	9.2	8.8	4.6	4.6	1.0	2.0	1.4
HOUSING STARTS ('000s)	225	227	228	213	183	183	190	195	197	199	201	202	202
PRIME RATE	4.42	5.81	6.10	4.79	4.26	5.69	6.25	6.25	6.25	6.25	6.25	6.25	6.25
CAN - 3 MONTH TREASURY BILL	2.73	4.03	4.15	2.56	2.25	3.91	4.55	4.58	4.60	4.60	4.60	4.61	4.61
U.S. - 3 MONTH TREASURY BILL	3.21	4.85	4.47	1.56	0.94	2.72	3.52	4.07	4.54	4.75	4.81	4.85	4.87
EXCHANGE RATE U.S./CANADA	0.826	0.882	0.935	0.956	0.906	0.933	0.945	0.948	0.952	0.951	0.950	0.947	0.945
	1.211	1.134	1.070	1.046	1.104	1.072	1.058	1.055	1.050	1.051	1.053	1.056	1.058
U.S. FEDERAL FUNDS RATE	3.21	4.96	5.02	2.06	1.20	3.43	4.21	4.73	5.16	5.30	5.30	5.30	5.30
MERCHANDISE TERMS OF TRADE	1.145	1.152	1.190	1.291	1.273	1.285	1.290	1.290	1.296	1.302	1.303	1.306	1.308
CURRENT ACCOUNT BALANCE	26453	20230	13608	18823	-578	4052	13671	20577	28071	35007	38011	41700	44767

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAN -GROSS DOMESTIC PRODUCT	1710456	1745877	1781221	1817222	1852321	1887053	1922127	1958644	1994862	2031374	2068984	2106291	2144221
AT MARKET PRICES (MILLIONS $ 2002)	2.1	2.1	2.0	2.0	1.9	1.9	1.9	1.9	1.8	1.8	1.9	1.8	1.8
GDP DEFLATOR	1.441	1.467	1.495	1.523	1.551	1.581	1.612	1.642	1.673	1.704	1.736	1.769	1.802
	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
U.S. -GROSS DOMESTIC PRODUCT	15501	15903	16319	16747	17180	17614	18061	18518	19002	19505	20019	20545	21099
AT MARKET PRICES (BILLIONS $ 2000)	2.6	2.6	2.6	2.6	2.6	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.7
CONSUMER PRICE INDEX	1.389	1.416	1.444	1.473	1.503	1.533	1.564	1.595	1.627	1.659	1.692	1.726	1.760
	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
TOTAL EMPLOYMENT ('000s)	18874	18994	19128	19257	19384	19500	19625	19738	19827	19923	20017	20117	20213
	0.7	0.6	0.7	0.7	0.7	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5
UNEMPLOYMENT RATE	5.42	5.42	5.33	5.30	5.27	5.29	5.25	5.22	5.24	5.24	5.24	5.23	5.25
PRIVATE NON-FARM	35.466	36.632	37.846	39.100	40.400	41.742	43.124	44.552	45.988	47.467	48.995	50.571	52.191
AVERAGE HOURLY EARNINGS	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.2	3.2	3.2	3.2	3.2
REAL DISPOSABLE INCOME	1115103	1137554	1160400	1182617	1205177	1227759	1250388	1272882	1293920	1315277	1336838	1358877	1380880
	2.2	2.0	2.0	1.9	1.9	1.9	1.8	1.8	1.7	1.7	1.6	1.6	1.6
PRIVATE NON-FARM	59	60	61	62	63	63	64	65	66	67	68	69	70
PRODUCTIVITY	1.6	1.6	1.4	1.4	1.4	1.4	1.3	1.4	1.5	1.4	1.5	1.4	1.4
FEDERAL GOV'T BALANCE	4546	4933	5336	5706	5582	5492	5576	5761	5218	4770	4416	3854	3394
CORPORATE PROFITS	316632	326186	333928	342538	349807	357465	365032	374040	383425	392363	402565	410624	419732
BEFORE TAXES	2.7	3.0	2.4	2.6	2.1	2.2	2.1	2.5	2.5	2.3	2.6	2.0	2.2
HOUSING STARTS ('000s)	202	202	200	199	196	194	191	188	185	182	179	176	173
PRIME RATE	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25
CAN - 3 MONTH TREASURY BILL	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
U.S. - 3 MONTH TREASURY BILL	4.88	4.88	4.88	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89
EXCHANGE RATE U.S./CANADA	0.943	0.941	0.940	0.939	0.936	0.937	0.937	0.937	0.939	0.940	0.943	0.946	0.950
	1.061	1.063	1.064	1.065	1.068	1.068	1.068	1.067	1.065	1.063	1.060	1.057	1.052
U.S. FEDERAL FUNDS RATE	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30
MERCHANDISE TERMS OF TRADE	1.309	1.310	1.310	1.309	1.307	1.307	1.307	1.306	1.304	1.301	1.298	1.295	1.293
CURRENT ACCOUNT BALANCE	48504	53393	57154	59446	60638	62121	63135	63087	61427	59175	57591	54743	52751

The Conference Board of Canada

Forecast Completed: December 18, 2008

TABLE 33: SELECTED CANADIAN AND U.S. INTEREST RATES

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CANADA																										
PERSONAL SAVINGS DEPOSITS	0.05	0.05	0.08	0.09	0.02	0.06	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
3-MONTH TREASURY BILL	2.73	4.03	4.15	2.56	2.25	3.91	4.55	4.58	4.60	4.60	4.60	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
90-DAY PRIME CORPORATE PAPER	2.84	4.21	4.63	3.20	2.91	4.58	5.18	5.15	5.12	5.10	5.09	5.08	5.08	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07	5.07
PRIME LENDING RATE	4.42	5.81	6.10	4.79	4.26	5.69	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25
5-YEAR GIC	2.71	3.16	3.31	2.96	2.86	3.69	4.29	4.54	4.68	4.76	4.80	4.82	4.84	4.85	4.85	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86
5-YEAR CONVENTIONAL MORTGAGE	5.99	6.66	7.07	6.89	6.13	7.00	7.59	7.74	7.81	7.83	7.85	7.85	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86
FEDERAL BONDS: 1-3 YEARS	3.18	4.07	4.22	2.78	2.63	3.84	4.57	4.81	4.91	4.95	4.97	4.98	4.98	4.98	4.98	4.98	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99
FEDERAL BONDS:3-10 YEARS	3.72	4.15	4.24	3.36	3.34	4.31	4.96	5.21	5.34	5.41	5.45	5.47	5.48	5.49	5.49	5.49	5.49	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50
FEDERAL BONDS: 10 YEARS AND OVER	4.39	4.30	4.34	3.97	3.84	4.57	5.16	5.46	5.64	5.75	5.82	5.86	5.88	5.90	5.91	5.91	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92
SCOTIA MCLEOD 10 PROVINCIALS	4.83	4.78	4.79	4.62	4.23	5.07	5.71	6.03	6.23	6.36	6.44	6.49	6.53	6.55	6.56	6.57	6.58	6.58	6.58	6.59	6.59	6.59	6.59	6.59	6.59	6.59
SCOTIA MCLEOD 10 INDUSTRIALS	5.36	5.40	5.52	5.22	4.62	5.42	6.05	6.38	6.58	6.71	6.78	6.83	6.86	6.88	6.89	6.90	6.90	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91	6.91
SCOTIA MCLEOD 10 MUNICIPALS	5.19	5.23	5.23	4.89	4.36	5.20	5.84	6.16	6.36	6.49	6.57	6.62	6.66	6.68	6.69	6.70	6.71	6.71	6.71	6.72	6.72	6.72	6.72	6.72	6.72	6.72
TSE EARNINGS-PRICE RATIO	5.36	5.68	5.76	5.39	3.84	3.45	3.79	3.98	4.04	4.01	3.79	3.63	3.54	3.53	3.56	3.55	3.55	3.53	3.50	3.49	3.49	3.47	3.45	3.45	3.44	3.43
BANK RATE	2.92	4.31	4.60	3.29	2.76	4.19	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75
UNITED STATES																										
FEDERAL FUND RATE	3.21	4.96	5.02	2.06	1.20	3.43	4.21	4.73	5.16	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30	5.30
3-MONTH TREASURY BILL	3.21	4.85	4.47	1.56	0.94	2.72	3.52	4.07	4.54	4.75	4.81	4.85	4.87	4.88	4.88	4.88	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89
MOODY'S AAA CORPORATE BOND	5.23	5.59	5.56	5.50	4.94	5.08	5.36	5.68	6.02	6.30	6.50	6.65	6.76	6.84	6.90	6.95	6.98	7.01	7.03	7.04	7.05	7.06	7.06	7.07	7.07	7.07

Table 1
Global Insight

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Real GDP (Bil. chained 2002 dollars)	1246.1	1284.8	1319.7	1327.8	1304.0	1337.0	1388.6	1436.4	1482.1	1522.6	1558.3	1596.6	1635.9
Percent Change	2.9	3.1	2.7	0.6	-1.8	2.5	3.9	3.4	3.2	2.7	2.3	2.5	2.5
Consumer	723.2	764.2	788.2	814.2	810.1	829.3	851.2	873.4	894.6	915.0	934.0	953.5	974.7
Percent Change	3.7	4.3	4.5	3.3	0.2	1.6	2.6	2.6	2.4	2.3	2.1	2.1	2.2
Government	275.4	286.7	298.8	309.8	314.2	324.1	334.2	343.0	351.5	359.2	366.8	374.7	382.6
Percent Change	2.6	4.1	4.2	3.7	1.4	3.2	3.1	2.7	2.5	2.2	2.1	2.1	2.2
Bus. Res. Investment	76.9	78.6	81.0	79.2	74.9	75.3	77.2	79.1	80.7	81.8	82.9	84.1	85.5
Percent Change	3.4	2.2	3.0	-2.1	-5.5	0.5	2.5	2.5	2.0	1.3	1.4	1.4	1.7
Bus. Non-Res. Inv.	169.7	186.5	193.1	198.3	188.9	194.7	202.9	209.4	215.6	220.4	223.8	226.1	228.4
Percent Change	12.1	9.9	3.5	2.7	-4.7	3.1	4.2	3.2	2.9	2.2	1.6	1.0	1.0
Exports	500.3	503.3	508.4	481.1	439.0	452.4	480.2	509.9	540.5	571.9	604.6	639.3	674.5
Percent Change	1.8	0.6	1.0	-5.4	-8.8	3.0	6.2	6.2	6.0	5.8	5.7	5.7	5.5
Imports	516.1	539.8	569.4	567.8	529.5	546.6	566.0	590.1	610.6	635.4	663.7	692.4	722.5
Percent Change	7.1	4.6	5.5	-0.3	-6.7	3.2	3.9	3.9	3.5	4.1	4.5	4.3	4.3
Business Inventory Change	12.8	10.8	13.2	6.6	0.9	6.6	9.7	10.3	8.2	7.4	6.6	7.1	7.2
Statistical Error	460.3.	553.5	-587.5	-208.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nominal GDP (Billion dollars)	1372.6	1450.5	1535.6	1604.9	1568.0	1624.2	1720.8	1818.8	1914.3	2004.1	2086.2	2176.6	2269.7
Percent Change	6.3	5.7	5.9	4.5	-2.3	3.6	6.0	5.7	5.3	4.7	4.1	4.3	4.3
Raw Mat. Price Index	1.5	1.6	1.7	2.0	1.6	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Percent Change	13.3	11.3	7.7	13.6	-20.4	-4.2	-4.6	-3.1	-2.1	0.1	1.4	1.7	0.5
Industry Price Index	111.2	113.8	115.6	120.6	120.3	121.0	122.0	123.9	126.2	128.2	129.8	131.9	133.7
Percent Change	1.5	2.4	1.6	4.3	-0.2	0.6	0.8	1.6	1.8	1.6	1.3	1.6	1.4
GDP Deflator	110.2	112.9	116.4	120.9	120.2	121.5	123.9	126.6	129.2	131.6	133.9	136.3	138.7
Percent Change	3.4	2.5	3.1	3.9	-0.5	1.0	2.0	2.2	2.0	1.9	1.7	1.8	1.8
CPI	107.0	109.1	111.5	114.1	114.3	116.3	118.3	120.7	123.1	125.5	128.1	130.6	133.2
Percent Change	2.2	2.0	2.1	2.4	0.2	1.8	1.7	2.0	2.0	2.0	2.0	2.0	2.0
Employment (Thousands)	16172	16485	16865	17123	16890	17025	17352	17696	17973	18187	18385	18544	18687
Percent Change	1.4	1.9	2.3	1.5	-1.4	0.8	1.9	2.0	1.6	1.2	1.1	0.9	0.8
Unemployment Rate (Percent)	6.8	6.3	6.0	6.2	7.9	8.3	7.6	6.7	6.4	6.4	6.4	6.5	6.5
Productivity (Percent change)	1.5	1.2	0.4	-0.9	-0.4	1.7	1.9	1.5	1.6	1.5	1.3	1.6	1.7
Average Hourly Earnings	18.11	18.55	19.13	19.85	20.45	20.90	21.38	22.08	23.01	23.98	24.94	25.85	26.87
Percent Change	2.1	2.4	3.1	3.8	3.0	2.2	2.3	3.3	4.2	4.2	4.0	4.1	3.5
3-Month T-Bill Rate (Percent)	2.73	4.03	4.15	2.39	0.68	1.06	2.29	3.38	4.31	4.75	4.75	4.75	4.50
U.S. 3-Month T-Bill Rate (Percent)	3.13	4.72	4.38	1.40	0.23	0.53	2.21	3.42	3.49	4.45	4.59	4.59	4.59
Canada-U.S. Differential	-0.41	-0.69	-0.23	0.98	0.45	0.52	0.09	-0.05	0.82	0.30	0.16	0.16	-0.09
Prime Rate (Percent)	4.42	5.81	6.10	4.71	2.33	2.65	4.13	5.13	6.06	6.50	6.50	6.50	6.25
Overnight Rate (Percent)	2.68	4.02	4.34	2.96	0.58	0.90	2.38	3.38	4.31	4.75	4.75	4.75	4.50
Bank Rate (Percent)	2.92	4.31	4.60	3.21	0.83	1.15	2.63	3.63	4.56	5.00	5.00	5.00	4.75
GOC Bond Rate (1-3 yrs.) (Percent)	3.18	4.07	4.22	2.66	1.53	1.93	3.18	3.92	4.57	5.11	5.11	5.11	4.96
GOC Bond Rate (3-5 yrs.) (Percent)	3.50	4.10	4.21	2.96	2.13	2.56	3.81	4.30	4.76	5.36	5.36	5.36	5.28
GOC Ten-Year Bond Rate (Percent)	4.05	4.22	4.28	3.57	2.80	3.25	4.50	4.73	4.96	5.64	5.64	5.64	5.64
U.S. Ten-Year T-Note Rate (Percent)	4.29	4.79	4.63	3.67	2.65	3.10	4.35	4.58	4.81	5.49	5.49	5.49	5.49
U.S. Real GDP (Bil. 2000 US$)	10990	11295	11524	11671	11361	11589	12000	12395	12755	13097	13431	13781	14161
Percent Change	2.9	2.8	2.0	1.3	-2.7	2.0	3.5	3.3	2.9	2.7	2.5	2.6	2.8
Household Credit (Billion dollars)	926.5	1024.6	1138.3	1268.9	1380.7	1492.5	1604.8	1711.8	1814.5	1914.1	2011.9	2110.7	2212.1
Percent Change	11.1	10.6	11.1	11.5	8.8	8.1	7.5	6.7	6.0	5.5	5.1	4.9	4.8
Standard of Living Canada/U.S. (Nominal GDP per Capita at PPP Can/U.S.)	0.845.	0.846	0.846	0.839	0.848	0.850	0.853	0.854	0.855	0.855	0.852	0.850	0.847
Exchange Rate (U.S.-Can.)	82.6	88.2	93.5	94.3	81.4	88.2	94.3	96.2	96.5	94.0	91.5	90.8	92.5
Curr. Acct. Bal. (Billions of dollars)	26	20	14	18	-46	-74	-81	-78	-70	-63	-62	-55	-49
			1.06953	1.060816	1.228175	1.133777	1.060008	1.039186	1.03659	1.064067	1.093267	1.101098	1.080598
Fed. Gov't. NA Bal. (Billion dollars)	2.1	10.2	15.4	2.7	0.9	9.2	18.1	22.9	23.7	20.8	16.5	9.4	5.6
Percent GNP	0.2	0.7	1.0	0.2	0.1	0.6	1.0	1.2	1.2	1.0	0.8	0.4	0.2
Before-Tax Profit (Billion dollars)	185.9	196.7	203.2	214.8	155.3	185.0	216.8	229.2	228.9	238.9	252.0	227.7	220.8
Percent Change	10.5	5.8	3.3	5.7	-27.7	19.1	17.2	5.7	-0.1	4.3	5.5	-9.6	-3.0
Housing Starts (Thousands)	224	229	228	211	166	172	172	179	185	185	183	183	182
Auto Sales (Thous. SAAR)	1630.3	1666.3	1690.5	1675.0	1519.8	1506.6	1531.7	1551.2	1600.9	1650.2	1643.0	1638.7	1632.3
Nominal Exports (Billion dollars)	516.9	522.7	532.1	543.9	450.5	468.5	494.8	528.1	567.7	607.7	645.0	689.6	729.1
Nominal Imports (Billion dollars)	467.9	487.0	502.3	515.2	493.7	539.1	571.6	602.2	633.1	666.3	702.4	739.6	773.4
Nominal Trade Balance (Billion dollars)	51.1	35.7	29.9	28.7	-43.2	-70.6	-76.8	-74.0	-65.4	-58.7	-57.4	-49.9	-44.3
Personal Saving Rate (Percent)	2.0	3.1	2.7	3.1	2.8	2.2	1.5	2.0	3.2	4.2	4.9	5.5	5.0
Real Disp. Inc. Growth (Percent)	2.6	5.5	4.1	3.9	-0.5	0.5	1.6	3.1	3.8	3.4	3.1	3.2	2.4
Industrial Production - Percent Change	1.6	0.2	0.2	-3.8	-5.6	3.0	5.7	3.6	2.9	2.7	2.3	2.3	2.3

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Real GDP (Bil. chained 2002 dollars)	1676.6	1715.5	1754.8	1790.6	1840.4	1883.6	1930.0	1975.7	2022.6	2070.4	2121.5	2169.9	2219.5
Percent Change	2.5	2.3	2.3	2.4	2.4	2.3	2.5	2.4	2.4	2.4	2.5	2.3	2.3
Consumer	995.5	1018.3	1038.3	1061.7	1086.0	1110.7	1135.8	1161.1	1187.0	1213.3	1240.2	1267.5	1295.5
Percent Change	2.1	2.1	2.2	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2
Government	391.0	399.2	407.8	416.5	425.2	434.2	443.4	452.6	462.3	472.2	482.3	492.8	503.4
Percent Change	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2
Bus. Res. Investment	86.9	88.5	90.1	91.3	92.1	92.8	93.3	93.7	94.0	94.2	94.4	94.7	94.8
Percent Change	1.6	1.8	1.8	1.4	0.9	0.7	0.6	0.4	0.3	0.3	0.2	0.2	0.2
Bus. Non-Res. Inv.	230.4	231.7	232.8	234.6	237.3	240.4	243.8	247.2	251.0	255.2	259.2	263.4	267.8
Percent Change	0.9	0.6	0.5	0.8	1.1	1.3	1.4	1.4	1.5	1.7	1.6	1.6	1.6
Exports	711.8	751.4	791.5	832.4	873.9	913.9	956.9	1000.1	1043.2	1086.4	1132.2	1174.5	1217.3
Percent Change	5.5	5.6	5.3	5.2	5.0	4.6	4.7	4.5	4.3	4.1	4.2	3.7	3.6
Imports	752.8	786.8	822.1	857.4	892.3	927.1	962.2	996.5	1034.8	1071.5	1108.4	1145.4	1182.5
Percent Change	4.2	4.5	4.5	4.3	4.1	3.9	3.8	3.8	3.6	3.5	3.4	3.3	3.2
Business Inventory Change	7.3	7.4	7.7	8.0	8.2	8.4	8.7	8.7	8.9	9.1	9.3	9.6	9.8
Statistical Error	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nominal GDP (Billion dollars)	2366.9	2464.2	2566.1	2675.1	2790.2	2909.4	3043.2	3177.8	3313.1	3453.2	3602.7	3758.0	3922.1
Percent Change	4.3	4.1	4.1	4.2	4.3	4.3	4.6	4.4	4.3	4.2	4.3	4.3	4.4
Raw Mat. Price Index	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Percent Change	0.6	0.0	0.6	0.4	0.4	0.3	0.4	0.1	0.4	0.5	0.7	0.7	0.7
Industry Price Index	135.3	137.3	139.5	141.7	144.0	146.5	149.2	151.8	154.5	157.2	160.0	162.8	165.7
Percent Change	1.2	1.5	1.5	1.6	1.6	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.8
GDP Deflator	141.2	143.6	146.2	148.9	151.6	154.5	157.7	160.8	163.8	166.8	169.8	173.2	176.7
Percent Change	1.8	1.8	1.8	1.8	1.8	1.9	2.1	2.0	1.8	1.8	1.8	2.0	2.0
CPI	135.9	138.6	141.4	144.2	147.1	150.0	153.0	156.1	159.2	162.4	165.6	168.9	172.3
Percent Change	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Employment (Thousands)	18854	18933	19034	19128	19230	19339	19449	19557	19644	19696	19749	19802	19855
Percent Change	0.9	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.4	0.3	0.3	0.3	0.3
Unemployment Rate (Percent)	6.5	6.5	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Productivity (Percent change)	1.6	1.9	1.7	1.9	1.9	1.8	1.9	1.8	1.9	2.1	2.2	2.0	2.0
Average Hourly Earnings	27.76	28.68	29.53	30.34	31.15	31.97	33.10	34.43	35.65	36.77	37.87	39.07	40.28
Percent Change	3.3	3.3	3.0	2.7	2.7	2.6	3.5	4.0	3.5	3.1	3.0	3.2	3.1
3-Month T-Bill Rate (Percent)	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.49
U.S. 3-Month T-Bill Rate (Percent)	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59
Canada-U.S. Differential	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.10
Prime Rate (Percent)	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25
Overnight Rate (Percent)	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
Bank Rate (Percent)	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75
GOC Bond Rate (1-3 yrs.) (Percent)	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.95
GOC Bond Rate (3-5 yrs.) (Percent)	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28
GOC Ten-Year Bond Rate (Percent)	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64
U.S. Ten-Year T-Note Rate (Percent)	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49
U.S. Real GDP (Bil. 2000 US$)	14575	14992	15414	15792	16185	16581	16995	17440	17880	18314	18749	19192	19662
Percent Change	2.9	2.9	2.8	2.5	2.5	2.4	2.5	2.6	2.5	2.4	2.4	2.4	2.4
Household Credit (Billion dollars)	2318.3	2430.5	2548.1	2670.0	2795.4	2924.4	3058.7	3199.6	3347.0	3500.2	3659.9	3827.2	4002.5
Percent Change	4.8	4.8	4.8	4.8	4.7	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Standard of Living Canada/U.S. (Nominal GDP per Capita at PPP Can/U.S.)	0.842	0.837	0.832	0.830	0.829	0.828	0.827	0.824	0.822	0.821	0.822	0.821	0.819
Exchange Rate (U.S.-Can.)	92.8	92.8	92.8	92.8	92.8	92.8	92.8	92.8	92.8	92.6	92.2	91.7	91.4
Curr. Acct. Bal. (Billions of dollars)	-42	-36	-34	-30	-25	-21	-9	1	6	10	18	26	36
	1.077991	1.077685	1.077765	1.077787	1.07776	1.077805	1.077822	1.077638	1.077966	1.07995	1.084887	1.090106	1.093827
Fed. Gov't. NA Bal. (Billion dollars)	8.9	13.9	17.0	16.3	23.1	33.4	45.7	56.8	70.0	89.6	112.8	138.0	152.5
Percent GNP	0.4	0.6	0.6	0.6	0.8	1.1	1.5	1.7	2.0	2.5	3.0	3.5	3.7
Before-Tax Profit (Billion dollars)	245.5	266.8	268.7	250.3	277.4	313.8	331.2	329.0	342.9	375.9	405.3	427.5	370.6
Percent Change	11.2	8.7	0.7	-6.8	10.8	13.1	5.6	-0.7	4.2	9.6	7.8	5.5	-13.3
Housing Starts (Thousands)	181	177	173	169	165	164	164	162	159	157	156	155	152
Auto Sales (Thous. SAAR)	1627.5	1622.2	1619.6	1617.1	1614.3	1613.0	1611.6	1611.4	1611.2	1612.0	1613.1	1613.9	1616.1
Nominal Exports (Billion dollars)	775.4	828.0	883.0	941.2	1002.6	1067.3	1145.2	1222.3	1295.8	1371.5	1453.5	1537.3	1626.1
Nominal Imports (Billion dollars)	811.7	858.4	908.5	960.4	1014.7	1073.4	1135.5	1200.8	1268.1	1338.4	1411.4	1487.1	1566.1
Nominal Trade Balance (Billion dollars)	-36.3	-30.5	-25.4	-19.2	-12.1	-6.1	9.6	21.5	27.7	33.1	42.1	50.1	60.1
Personal Saving Rate (Percent)	4.0	3.4	4.6	3.7	3.4	3.4	5.0	6.4	6.6	6.9	6.6	6.8	6.6
Real Disp. Inc. Growth (Percent)	2.8	2.7	2.4	2.0	2.1	2.4	3.6	3.6	2.7	3.0	3.4	3.3	3.0
Industrial Production - Percent Change	2.3	2.2	2.2	2.2	2.3	2.2	2.3	2.2	2.1	2.1	2.2	2.0	2.0

Table 24

Global Insight

Interest Rates
(Percent)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Overnight Money	2.66	4.02	4.34	2.96	0.58	0.90	2.38	3.38	4.31	4.75	4.75	4.75	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
Bank Rate	2.92	4.31	4.60	3.21	0.83	1.15	2.63	3.63	4.56	5.00	5.00	5.00	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75
Government of Canada																										
Treasury Bills																										
3 Months	2.73	4.03	4.15	2.39	0.68	1.06	2.29	3.38	4.31	4.75	4.75	4.75	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.49
6 Months	2.87	4.11	4.26	2.52	0.79	1.17	2.40	3.49	4.42	4.86	4.86	4.86	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.60
Bonds																										
1-3 Years	3.18	4.07	4.22	2.66	1.53	1.93	3.18	3.92	4.57	5.11	5.11	5.11	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.96	4.95
3-5 Years	3.50	4.10	4.21	2.96	2.13	2.56	3.81	4.30	4.76	5.36	5.36	5.36	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28
5 Years	3.59	4.12	4.22	3.01	2.19	2.62	3.87	4.34	4.77	5.39	5.39	5.39	5.31	5.31	5.31	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.31	5.31
5-10 Years	3.89	4.18	4.25	3.36	2.62	3.06	4.31	4.61	4.90	5.56	5.56	5.56	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54	5.54
10 Years	4.05	4.22	4.28	3.57	2.80	3.25	4.50	4.73	4.96	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64
10+ Years	4.39	4.30	4.34	4.04	3.25	3.64	4.85	5.06	5.27	5.94	5.93	5.93	5.93	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92
30 Years	4.40	4.28	4.32	4.05	3.36	3.74	4.94	5.14	5.35	6.02	6.01	6.00	6.00	6.00	5.99	5.99	5.99	5.99	5.99	5.99	5.99	5.99	5.99	5.99	5.99	5.99
Prime Corporate Paper																										
30 Days	2.75	4.15	4.57	3.17	0.78	1.16	2.40	3.48	4.42	4.86	4.86	4.86	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.60	4.60	4.60
90 Days	2.84	4.21	4.63	3.23	0.80	1.18	2.42	3.50	4.44	4.88	4.88	4.88	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.62	4.62	4.62
Bankers' Acceptances																										
30 Days	2.74	4.13	4.51	3.04	0.78	1.16	2.39	3.48	4.41	4.85	4.85	4.85	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.59
90 Days	2.84	4.19	4.57	3.08	0.80	1.18	2.41	3.50	4.43	4.87	4.87	4.87	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.62	4.61
Chartered Bank																										
Non-Chequable Deposits	0.05	0.05	0.08	0.10	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
5-Yr Personal Fixed Term	2.46	2.91	3.09	2.81	1.60	1.86	3.01	4.01	4.89	5.27	5.23	5.20	4.92	4.90	4.88	4.87	4.85	4.84	4.84	4.83	4.82	4.82	4.82	4.81	4.81	4.80
Chartered Bank Prime	4.42	5.81	6.10	4.71	2.33	2.65	4.13	5.13	6.06	6.50	6.50	6.50	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25
Chartered Bank Mortgage Rate																										
1 Year	5.06	6.28	6.90	6.70	4.86	5.31	6.29	5.81	6.56	7.00	7.00	7.00	6.75	6.75	6.75	6.75	6.75	6.75	6.75	6.75	6.75	6.75	6.75	6.75	6.75	6.74
5 Years	5.99	6.66	7.07	7.06	5.96	5.87	6.76	6.76	6.83	7.41	7.35	7.30	7.27	7.26	7.24	7.24	7.23	7.23	7.23	7.22	7.22	7.22	7.22	7.22	7.22	7.22
3-Month Euro Deposit Rate	2.80	4.11	4.57	3.38	0.87	1.15	2.38	3.47	4.40	4.84	4.84	4.84	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.58

PRICES & MONETARY INDICATORS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP Deflator (Chained, 1997=1)	1.19	1.22	1.25	1.32	1.3	1.33	1.36	1.39	1.41	1.44	1.47	1.49	1.52	1.55	1.58	1.61	1.64	1.67	1.69	1.72	1.75	1.79	1.82	1.85	1.89	1.92
Inflation (% change year-to-year)	3.4	2.5	3.1	4.9	-0.9	1.8	2.1	2.3	1.8	1.8	2	1.9	2	1.8	1.7	1.9	2	1.7	1.6	1.7	1.7	1.8	1.9	1.9	1.8	1.7
Consumer Price Index (1992=100)	127.3	129.9	132.6	136.1	136.8	139.5	142.3	145.5	148.4	151.3	154.6	157.6	160.7	163.6	166.4	169.8	173.4	176.6	179.7	183.1	186.5	190.1	193.8	197.6	201.4	205.0
Inflation (% change year-to-year)	2.2	2	2.1	2.6	0.6	1.9	2.1	2.2	2	1.9	2.1	2	2	1.8	1.8	2	2.1	1.8	1.7	1.9	1.9	1.9	2	2	1.9	1.8
Wage & Salary Rate ($000 nominal per employee)	36.79	38.33	38.31	39.46	40.16	41.86	43.71	45.71	47.29	48.83	50.53	52.26	54.01	55.75	57.53	59.33	61.13	62.93	64.74	66.61	68.59	70.69	72.85	75.02	77.17	79.36
Unit Labour Costs (Nominal Labour Income / $1997 GDP	0.64	0.66	0.66	0.69	0.7	0.72	0.73	0.75	0.76	0.78	0.8	0.81	0.83	0.85	0.86	0.87	0.89	0.9	0.91	0.92	0.93	0.94	0.96	0.97	0.99	1
Import Price Deflator (Chained, 1997=1)	0.99	0.98	0.96	0.97	1	1.01	1.04	1.06	1.09	1.1	1.12	1.14	1.15	1.16	1.18	1.21	1.24	1.26	1.28	1.3	1.33	1.35	1.38	1.4	1.43	1.45
Merchandise Terms of Trade (1997=1)	1.14	1.15	1.19	1.32	1.22	1.24	1.25	1.25	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.23	1.23	1.23	1.22	1.22	1.22	1.22	1.21	1.21	1.21	1.2
International Crude Oil Price (WTI $U.S. per bbl)	48.93	58.89	67.08	106.0	50.0	65.0	78.8	81.1	83.6	84.4	85.3	86.1	87.0	87.8	88.7	89.6	91.3	93.0	94.8	97.1	99.7	102.1	104.1	105.9	108.1	110.6
Exchange Rate ($Can per $U.S.)	1.21	1.13	1.07	1.06	1.16	1.18	1.18	1.18	1.19	1.18	1.18	1.18	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.18	1.18
Real Exchange Rate [2]	1.13	1.07	1.01	0.97	1.09	1.07	1.06	1.06	1.07	1.07	1.06	1.05	1.04	1.04	1.04	1.05	1.05	1.06	1.06	1.06	1.06	1.07	1.08	1.08	1.08	1.09
Exchange Rate (cents U.S. per $Can)	82.5	88.2	93.1	94	86	84.8	84.6	84.6	84.4	84.5	84.8	85	85.2	85.4	85.6	85.8	85.7	85.6	85.5	85.5	85.4	85.3	85.3	85.2	85.1	84.9
Commercial Paper - 90 day (%)	2.8	4.2	4.6	3.3	3	3.8	4.3	4.6	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
AAA Industrial Bonds	5.4	5.4	5.6	5.5	5.4	5.5	5.8	6	6.1	6.2	6.2	6.2	6.2	6.2	6.2	6.1	6.1	6	6	6.2	6.3	6.3	6.4	6.4	6.4	6.4
Government of Canada Bonds (10+ years)	4.4	4.3	4.3	4.1	4	4.3	4.7	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.8	4.8	4.7	4.7	4.6	4.8	4.9	5	5	5	5.1	5.1
10+ Years Canada Bonds (real [3])	2	1.6	1.3	0.7	1.4	2	2.5	2.8	3.5	3	2.9	3	3	3	3	2.9	2.9	2.9	2.8	3	3.2	3.3	3.3	3.2	3.2	3.3
AAA Industrial Bonds (real)	3	2.7	2.5	2.1	2.9	3.3	3.6	4	4.7	4.2	4.2	4.3	4.3	4.3	4.3	4.3	4.2	4.2	4.2	4.4	4.5	4.6	4.6	4.6	4.6	4.6
US Treasury Bill	3.147	4.727	4.353	1.483	0.56	0.549	1.177	2.024	3.187	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822	3.822
Canadian Treasury Bill	2.726	4.033	4.151	2.448	2.4	3.325	3.822	3.927	3.874	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821	3.821

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Canada																										
3-Month T-Bills	2.7	4	4.2	2.6	2.6	3.1	4	4.9	5.1	4.3	3.7	3.5	3.6	4.2	4.6	4.7	4.6	4.4	4	3.8	3.7	3.7	3.8	3.9	3.9	3.7
10-Year GOCs	4.1	4.2	4.3	3.8	4	4	5.3	6.8	6.9	6.1	5.5	5.2	4.6	5.2	5.6	5.7	5.6	5.4	5	4.8	4.7	4.7	4.8	4.9	4.9	4.7
30-Year GOCs	4.4	4.3	4.3	4	4.2	4.3	5.6	7.1	7.2	6.4	5.8	5.5	5	5.5	5.9	6	6	5.7	5.4	5.1	5	5	5.1	5.2	5.2	5.1
10+ Year GOCs	4.4	4.3	4.3	4	4.2	4.2	5.5	7.1	7.2	6.4	5.7	5.4	4.9	5.5	5.9	6	5.9	5.7	5.3	5.1	4.9	5	5.1	5.2	5.2	5
Prime Rate	4.4	5.8	6.1	4.4	4.3	4.8	5.6	6.5	6.8	5.9	5.3	5	5.2	5.8	6.2	6.3	6.2	5.9	5.6	5.3	5.2	5.3	5.4	5.4	5.4	5.3
1-Year Mortgages	5.1	6.3	6.9	4.6	4.4	4.8	5.7	6.6	6.8	5.9	5.3	5.1	5.3	5.8	6.2	6.3	6.2	6	5.6	5.4	5.2	5.3	5.4	5.5	5.5	5.3
5-year Mortgages	6	6.7	7.1	5.5	5.4	5.9	6.7	7.7	7.9	7	6.4	6.2	6.3	6.9	7.3	7.4	7.3	7.1	6.7	6.5	6.3	6.4	6.5	6.6	6.6	6.4
Real Rates																										
3-Month T-Bills	1	2.6	2.6	0.4	0.3	0.8	1.6	2.5	2.9	2.2	1.7	1.6	1.7	2.1	2.5	2.6	2.5	2.3	2.1	1.9	1.8	1.9	2	2.1	2.1	2
10-Year Bonds	2.3	2.8	2.7	1.6	1.7	1.7	2.9	4.4	4.6	4	3.5	3.3	2.7	3.1	3.5	3.6	3.5	3.3	3.1	2.9	2.8	2.9	3	3.1	3.1	3
United States																										
3-Month T-Bills	3.1	4.7	4.4	1.5	1	1.8	2.7	2.7	2.9	2.9	3	3.1	4	4	4	4	4	4	4	4	4	4	4	4	4	4
10-Year Treasury Bonds	4.3	4.8	4.6	3.7	3.4	3.7	4.5	4.6	4.6	4.7	4.8	4.8	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Canada-U.S. Differentials (Unadjusted)																										
3-Month T-Bills	-0.4	-0.7	-0.2	1.1	1.6	1.3	1.3	2.2	2.3	1.4	0.7	0.4	-0.4	0.2	0.6	0.7	0.6	0.4	0	-0.2	-0.3	-0.3	-0.2	-0.1	-0.1	-0.3
10-Year Bonds	-0.2	-0.6	-0.3	0.1	0.6	0.3	0.8	2.2	2.3	1.4	0.7	0.4	-0.4	0.2	0.6	0.7	0.6	0.4	0	-0.2	-0.3	-0.3	-0.2	-0.1	-0.1	-0.3
Monetary Aggregates $B																										
M1	348426	378451	413449	437701	451401	466967	482444	493401	501080	512843	530550	552481	576273	599072	618515	635278	652041	671776	695616	723262	752986	782501	810201	836356	861405	887024
% Change	7	8.6	9.2	5.9	3.1	3.4	3.3	2.3	1.6	2.3	3.5	4.1	4.3	4	3.2	2.7	2.6	3	3.5	4	4.1	3.9	3.5	3.2	3	3
Canada-U.S. Exchange Rate																										
$US	0.825	0.881	0.93	0.96	0.901	0.871	0.856	0.856	0.853	0.842	0.828	0.818	0.807	0.805	0.807	0.806	0.804	0.799	0.792	0.786	0.782	0.78	0.78	0.78	0.78	0.779
$C	1.212	1.135	1.075	1.042	1.109	1.148	1.168	1.168	1.172	1.188	1.208	1.222	1.239	1.242	1.24	1.24	1.244	1.252	1.263	1.272	1.279	1.282	1.282	1.282	1.282	1.284
PPP	0.8	0.813	0.82	0.819	0.821	0.821	0.821	0.819	0.815	0.809	0.804	0.802	0.802	0.801	0.799	0.795	0.791	0.788	0.785	0.784	0.783	0.783	0.783	0.783	0.782	0.782

Table 1.1
Average Private Sector Forecasts

	2008	2009	2010	Average 2011–13
	(per cent, unless otherwise indicated)			
Real GDP growth				
February 2008 budget	1.7	2.4	2.9	2.6
November 2008 *Economic and Fiscal Statement*	0.6	0.3	2.6	2.9
GDP inflation				
February 2008 budget	1.8	1.9	1.8	1.6
November 2008 *Economic and Fiscal Statement*	3.8	0.5	1.8	2.2
Nominal GDP growth				
February 2008 budget	3.5	4.3	4.7	4.2
November 2008 *Economic and Fiscal Statement*	4.4	0.8	4.4	5.1
Nominal GDP level (billions of dollars)				
February 2008 budget[1]	1,590	1,659	1,738	1,890
November 2008 *Economic and Fiscal Statement*	1,603	1,615	1,687	1,870
3-month treasury bill rate				
February 2008 budget	3.2	3.8	4.5	4.5
November 2008 *Economic and Fiscal Statement*	2.4	1.9	2.7	4.2
10-year government bond rate				
February 2008 budget	3.6	4.2	4.8	5.0
November 2008 *Economic and Fiscal Statement*	3.7	3.7	4.2	5.0
Consumer Price Index (CPI) inflation				
February 2008 budget	1.5	1.9	2.0	2.1
November 2008 *Economic and Fiscal Statement*	2.6	1.7	1.9	2.1
Oil price level (US dollars per barrel)				
February 2008 budget	82.1	79.8	82.3	77.5
November 2008 *Economic and Fiscal Statement*	102.5	72.0	79.0	91.1
Exchange rate (US cents/C$)				
February 2008 budget	98.0	95.5	95.5	96.2
November 2008 *Economic and Fiscal Statement*	94.9	85.6	88.7	95.8
Unemployment rate				
February 2008 budget	6.3	6.4	6.2	6.0
November 2008 *Economic and Fiscal Statement*	6.1	6.9	6.7	6.2
U.S. real GDP growth				
February 2008 budget	1.5	2.4	3.0	2.7
November 2008 *Economic and Fiscal Statement*	1.4	-0.4	2.1	3.0

[1] Nominal GDP levels have been adjusted to reflect 2008 revisions to Canada's National Income and Expenditure Accounts.

Source: Department of Finance survey of private sector forecasters.

Table 3.9.4 Major Economic Assumptions

	2007	2008	2009	2010	Forecast 2011	2012	2013
GDP (billions)							
Canada real (2002 $; chain-weighted)	1,320	1,328 [e]	1,312	1,337	1,370	1,404	1,439
(% change)	2.7	0.6	-1.2	1.9	2.5	2.5	2.5
US real (1996 US$; chain-weighted)	11,524	11,671	11,405	11,612	11,908	12,214	12,535
(% change)	2.0	1.3	-2.3	1.8	2.6	2.6	2.6
Japan real (2000 Yen; chain-weighted)	561,403	562,940 [e]	550,680	554,073	562,689	572,893	583,119
(% change)	2.4	0.3	-2.2	0.6	1.6	1.8	1.8
Europe real[1] (% change)	2.7	0.9 [e]	-1.9	0.5	2.0	2.0	2.0
Industrial production index							
US (2002 = 100)	111.4	109.5	102.8	104.2	106.8	109.6	112.4
(% change)	1.7	-1.7	-6.1	1.4	2.6	2.6	2.6
Japan (2000 = 100)	107.3	103.9	90.6	91.1	92.5	94.2	95.9
(% change)	2.9	-3.1	-12.8	0.5	1.6	1.8	1.8
Europe[1] (2000 = 100)	111.7	111.4 [e]	105.3	105.7	107.8	109.9	112.1
(% change)	3.5	-0.3	-5.4	0.3	2.0	2.0	2.0
Housing starts[2] (000's)							
Canada	228	211	160	160	168	176	180
(% change)	0.4	-7.6	-24.2	0.0	5.0	4.8	2.3
US	1,341	902	650	815	1,100	1,300	1,300
(% change)	-26.0	-32.7	-28.0	25.4	35.0	18.2	0.0
Japan	1,061	1,093	1,020	1,020	1,047	1,065	1,065
(% change)	-17.8	3.1	-6.7	0.0	2.6	1.7	0.0
Consumer price index							
Canada (2001 = 100)	111.5	114.1	115.0	117.3	119.7	122.1	124.5
(% change)	2.2	2.3	0.8	2.0	2.0	2.0	2.0
Canadian interest rates (%)							
3-Month treasury bills	4.2	2.4	0.9	1.7	2.9	3.9	4.8
10-year government bonds	4.3	3.6	2.9	3.4	4.0	4.9	5.8
United States interest rates (%)							
3-Month treasury bills	4.4	1.4	0.2	1.1	2.8	3.9	4.8
10-year government bonds	4.7	3.7	2.4	3.1	3.8	4.9	5.8
Exchange rate (US cents / Canadian $)	93.1	93.7	79.3	86.2	89.4	89.5	88.6
British Columbia goods and services Export price deflator (% change)	0.2	5.7 [e]	2.5	-0.8	1.8	2.2	3.1

[1] Euro zone (12) is Austria, Belgium, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal and Spain.
[2] British Columbia housing starts appear in Table 3.9.2.
[e] Ministry of Finance estimate.

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France

* % change over previous year	Historical 2004	2005	2006	2007	Consensus Forecasts 2008	2009	2010	2011	2012	2013	2014-2018[1]
Gross Domestic Product*	2.2	1.9	2.4	2.1	0.9	0.5	1.7	2.1	2.2	2.1	2.1
Household Consumption*	2.5	2.6	2.5	2.5	1.0	0.8	1.9	2.2	2.2	2.1	2.1
Business Investment*	3.6	3.8	5.4	7.3	2.3	-0.4	2.9	3.8	3.8	3.8	3.8
Industrial Production*	2.1	0.4	1.3	1.4	-0.2	-0.3	1.9	2.1	2.1	2.2	2.1
Consumer Prices*	2.1	1.7	1.7	1.5	3.1	2.0	1.9	2.0	2.0	1.9	1.9
Current Account Balance (Euro bn	10.0	-10.9	-12.3	-22.3	-35.1	-36.2	-33.6	-32.0	-30.6	-16.2	-15.7
10 Year Treasury Bond Yield, %[2]	3.7	3.3	4.0	4.4	4.1 [3]	4.1 [4]	4.2	4.4	4.5	4.5	4.6

United Kingdom

* % change over previous year	Historical 2004	2005	2006	2007	Consensus Forecasts 2008	2009	2010	2011	2012	2013	2014-2018[1]
Gross Domestic Product*	2.8	2.1	2.8	3.0	1.1	-0.2	1.2	1.8	2.0	2.2	2.4
Household Consumption*	3.1	2.0	2.0	3.0	1.9	-0.4	0.8	1.2	1.4	1.6	2.1
Gross Fixed Investment*	4.9	2.2	6.0	7.1	-3.3	-4.0	0.6	0.9	2.1	2.5	3.2
Manufacturing Production*	2.2	-0.2	1.5	0.7	-0.6	-1.2	0.1	0.7	1.0	1.2	1.3
Retail Prices (underlying rate)*	2.2	2.3	2.9	3.2	4.6	3.2	2.7	3.0	3.1	3.0	3.0
Consumer Prices*	1.3	2.1	2.3	2.3	3.7	2.9	2.2	2.3	2.4	2.4	2.3
Current Account Balance (£ bn)	-19.3	-31.0	-45.0	-52.6	-41.8	-42.5	-52.5	-49.6	-44.2	-42.2	-47.1
10 Year Treasury Bond Yield, %[2]	4.5	4.1	4.7	4.6	4.3 [3]	4.3 [4]	4.6	4.9	4.9	4.8	4.9

Italy

* % change over previous year	Historical 2004	2005	2006	2007	Consensus Forecasts 2008	2009	2010	2011	2012	2013	2014-2018[1]
Gross Domestic Product*	1.4	0.7	1.9	1.4	0.0	0.0	1.0	1.3	1.4	1.4	1.4
Household Consumption*	0.7	0.9	1.1	1.5	-0.3	0.2	1.0	1.3	1.3	1.5	1.4
Gross Fixed Investment*	1.6	1.2	2.7	0.8	-0.3	-0.5	0.7	1.4	1.5	1.6	1.5
Industrial Production*	-0.3	-0.8	2.4	-0.2	-1.8	-0.7	1.0	1.1	1.0	1.3	1.1
Consumer Prices*	2.1	1.8	2.0	1.8	3.5	2.4	2.0	1.9	2.0	2.0	2.0
Current Account Balance (Euro bn)	-13.1	-23.6	-38.5	-37.4	-43.2	-34.7	-28.9	-22.3	-18.9	-23.5	-23.2
10 Year Treasury Bond Yield, %[2]	3.8	3.5	4.2	4.6	4.1 [3]	4.3 [4]	4.5	4.7	4.8	4.8	4.7

Canada

* % change over previous year	Historical 2004	2005	2006	2007	Consensus Forecasts 2008	2009	2010	2011	2012	2013	2014-2018[1]
Gross Domestic Product*	3.1	2.9	3.1	2.7	0.7	1.1	2.8	2.8	2.6	2.4	2.3
Personal Expenditure*	3.3	3.7	4.3	4.5	3.9	2.3	2.7	2.7	2.5	2.4	2.2
Machinery & Eqpt Investment*	9.1	13.8	10.6	7.1	5.2	2.0	5.4	4.6	3.7	2.9	2.9
Industrial Production*	1.5	1.6	0.2	0.2	-3.4	0.2	3.1	4.1	3.3	2.3	2.2
Consumer Prices*	1.8	2.2	2.0	2.2	2.7	2.1	2.0	2.1	2.1	2.0	2.0
Current Account Balance (C$ bn)	29.8	26.5	20.2	13.6	17.1	1.9	-4.0	-8.2	-4.0	0.5	2.9
10 Year Treasury Bond Yield, %[2]	4.3	4.0	4.1	4.0	3.5 [3]	3.8 [4]	4.5	4.9	5.2	5.2	5.1

Euro zone

* % change over previous year	Historical 2004	2005	2006	2007	Consensus Forecasts 2008	2009	2010	2011	2012	2013	2014-2018[1]
Gross Domestic Product*	1.9	1.8	3.0	2.6	1.2	0.5	1.6	2.0	2.0	2.0	1.9
Private Consumption*	1.5	1.8	2.0	1.6	0.4	0.6	1.4	1.9	2.0	2.0	1.9
Gross Fixed Investment*	1.9	3.4	5.9	4.3	1.8	-0.3	2.2	2.8	2.9	2.5	2.4
Industrial Production*	2.1	1.4	4.0	3.4	0.3	0.1	1.5	1.8	1.7	1.7	1.6
Consumer Prices*	2.1	2.2	2.2	2.1	3.4	2.2	2.0	2.0	2.0	2.0	2.0
Current Account Balance (Euro bn)	62.1	18.1	-1.3	26.6	-39.1	-26.2	-38.5	-26.2	-19.2	-15.5	-10.5

[1]Signifies average for period [2]End period [3]End January, 2009 [4]End October, 2009

PUB/MH I-46

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

d) **Please file the detailed calculations in support of the short and long term interest rates utilized for MH's fiscal years 2009/10, 2010/11 & 2011/12 with narrative of the steps taken to derive the forecast.**

ANSWER:

Refer to the response to PUB/MH I-46(b), Table 1 and Table 3 for the detailed information on the 90 day T-Bill and Canada Bond Yield 10 year+ rates, respectively, for the 2009/10, 2010/11 and 2011/12 periods. The calculations of the rates were as follows:

– The average of the forecasts was calculated for Canada 90 day T-Bills and Canada Bond Yield 10 year+ rates for each quarter. For example, the average for Q4 2010 for the forecasts was 1.31% for Canada 90 day T-Bills and 4.12% for Canada Bond Yield 10 year+ rates, as depicted in Table 1 and Table 3, respectively.

– The fiscal year average was calculated using the quarters applicable to that fiscal year. The 2009/10 forecast included the average of Q2, Q3, Q4 of 2009 and Q1 of 2010. The 2010/11 forecast included the average of Q2, Q3, Q4 of 2010 and Q1 of 2011. The 2011/12 forecast included the average of Q2, Q3, Q4 of 2011 and Q1 of 2012. For example, the Canada 90 day T-Bill rate for 2010/11 of 1.20% in Table 1 was calculated as follows:

2010 Q2:	0.50%
2010 Q3:	0.83%
2010 Q4:	1.31%
2011 Q1:	2.22%
Average:	1.21% rounds to 1.20%

– The Manitoba Hydro Canadian short term rate (exclusive of the guarantee fee of 1.00%) was calculated by adding the appropriate spread (between the 3 month T-Bill interest rate and 3 month Bloomberg BA interest rate) to the 90 day T-Bill rate as follows:

	Canada 90 day T-Bill	Spread	MH Cdn Short Term Rate
2009/10	0.25%	0.20%	0.45%
2010/11	1.20%	0.20%	1.40%
2011/12	3.40%	0.20%	3.60%

As part of IFF preparations, in the summer of 2009, Manitoba Hydro reviewed the actual year to date spreads during 2009/10. The first fiscal quarter had a spread of 20 basis points and a decision was made to utilize a 20 basis point spread for the balance of the forecasting period.

In October 2009, the calculation of the historic average spread was revisited. For comparative purposes, weekly Bloomberg data sources were utilized to obtain the 3 month T-Bill interest rate and 3 month Bloomberg BA interest rate (C1033M and CDOR03 respectively). Three month BAs are utilized for forecasting purposes as predominantly most of the floating rate Canadian long-term debt utilizes this basis for resets. In light of the recent credit crisis and in order to obtain greater longitudinal data, the historic period for analysis was extended from 5 to 10 years (note that aforementioned Bloomberg indices commenced October 2000 and as such become the starting point for the analysis). The historic spread from October 2000 to October 2009 was just over 23 basis points. Given the immateriality of the difference between this 10 year historic average and the actual fiscal year to date results, the 20 basis point short term spread was retained for forecasting purposes.

- The Manitoba Hydro Canadian long term rate (exclusive of the guarantee fee) was calculated by adding the appropriate credit spread to Canada Bond Yield 10 Year+ rate as follows:

	Canada Bond Yield 10 Yr+	Spread	MH Cdn Long Term Rate
2009/10	3.70%	0.90%	4.60%
2010/11	4.00%	0.65%	4.65%
2011/12	4.60%	0.60%	5.20%

Please see Manitoba Hydro's response to CAC/MSOS/MH I-31(b) for detailed calculations of the forecast long term spreads.

PUB/MH I-46

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

e) **Please provide an analysis which shows how the long term borrowing rates of 4.65% for 2010/11 and 5.20% for 2011/12 was derived. In that analysis please provide the projected Manitoba to Canada spread.**

ANSWER:

Please refer to Manitoba Hydro's response to PUB/MH I-46(d) for the explanation of the derivation of the long term borrowing rates for 2010/11 and 2011/12 which includes the Manitoba to Canada borrowing spread.

The Canadian GOC 10 Yr+ rates for 2010/11 and 2011/12 were derived as explained in the response to PUB/MH I-46(b).

PUB/MH I-46

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

f) Please describe with detailed calculations how the forecasted Manitoba to Canada spreads in part e) were determined.

ANSWER:

A historical spread is considered as part of the interest rate forecast. The mean of the historical spread is determined utilizing ten years of historical index information from Bloomberg. The all-in historical spread (including commissions) incorporated into the forecasted long term Canadian debt rate of 0.60% for 2011/12 was calculated by taking an average of the 10 year and 30 year credit spreads from Bloomberg and commissions supplied by various financial institutions in the Province of Manitoba's debt syndicate. The all-in historical spread was calculated as follows:

30 Year Canadian Index		
C30230Y	5.46	Prov of MB Curve
C10130Y	4.85	Canada Govt Curve
30 Year Spread	0.61	
10 Year Canadian Index		
C30210Y	5.11	Prov of MB Curve
C10110Y	4.66	Canada Govt Curve
10 Year Spread	0.45	
Average of 10 & 30 Year Spreads	0.53	
Commissions		
Average 10 & 30 Year	0.06	
Total Spread & Commissions	0.59	

On the basis that the financial markets will return to a more normal environment in 2011/12, the all-in spread of 0.65% for 2010/11 was calculated by taking an average of the quarterly spread forecasts. The quarterly spread forecasts were derived from a straight-line interpolation from the all-in spread at the end of 2009/10 Quarter 2: 0.75% and the 2011/12 all-in spread of 0.60% (rounded using the aforementioned historical average).

PUB/MH I-46

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

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

ANSWER:

Debt Series C110
Date of Issue: November 23, 2009
Size: $125,000,000
Coupon: 5.20%
Offered Yield at Issue: 4.617%
Spread over Comparable Canada: 65 basis points
Current Market Yield: 4.813%
Current Spread over Comparable Canada: 72.4 basis points

PUB/MH I-46

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

h) Please provide an updated IFF09-1 reflecting the short and long term interest rates approved by the Board in Order 128/09 for 2009/10 and 2010/11.

ANSWER:

PUB Order 128/09 was applicable to Centra Gas Manitoba and directed that:

a) "Finance Expense is adjusted by utilizing short term interest rate forecast of 0.5% in 2009/10 and 1.0% in 2010/11, and long term interest rate forecasts of 4.0% in 2009/10 and 2010/11."

For clarity, Manitoba Hydro's forecast rates compared to the PUB Order are as follows (all rates include the debt guarantee fee):

	2009/10		2010/11	
	Short Term	Long Term	Short Term	Long Term
IFF09	1.45%	5.60%	2.40%	5.65%
PUB Order	1.50%	5.00%	2.00%	5.00%

Please refer to the attached schedules for the projected impacts of interest rates at PUB requested rates.

PUB-MH I-46(h)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF09-1)
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	1,652	1,670	1,739	1,808	1,869	1,953	2,028	2,101	2,178	2,256	2,336
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
	2,066	2,054	2,293	2,390	2,484	2,543	2,729	2,830	2,920	3,151	3,429
Cost of Gas Sold	351	332	340	346	342	349	350	351	352	353	352
	1,715	1,722	1,953	2,044	2,142	2,193	2,379	2,479	2,568	2,798	3,077
Other	28	29	31	32	32	33	34	34	35	36	36
	1,742	1,751	1,984	2,076	2,174	2,227	2,412	2,513	2,603	2,834	3,113
EXPENSES											
Operating and Administrative	446	456	482	492	501	512	522	532	555	568	589
Finance Expense	454	454	504	561	562	579	565	581	623	709	913
Depreciation and Amortization	394	415	438	468	481	502	513	519	540	573	607
Water Rentals and Assessments	120	110	111	113	114	114	115	115	115	115	124
Fuel and Power Purchased	103	131	248	249	259	268	296	341	362	440	418
Capital and Other Taxes	97	99	100	104	109	116	125	134	140	146	150
	1,613	1,666	1,883	1,987	2,026	2,092	2,136	2,222	2,335	2,552	2,802
Non-controlling Interest	-	-	1	0	(3)	(5)	(9)	(11)	(13)	(15)	(15)
Net Income	129	86	103	90	145	130	267	280	255	267	297
Additional General Consumers Revenue											
General electricity rate increases		2.90%	2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
General gas rate increases		0.00%	1.50%	0.00%	1.00%	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%
Financial Ratios											
Debt	74%	75%	76%	76%	77%	79%	80%	80%	80%	80%	79%
Interest Coverage	1.24	1.15	1.16	1.13	1.21	1.17	1.31	1.28	1.24	1.24	1.23
Capital Coverage	1.39	1.08	1.15	1.30	1.27	1.55	1.89	1.84	1.95	2.17	2.60

PUB-MH I-46(h)

CONSOLIDATED PROJECTED BALANCE SHEET (IFF09-1)
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	13,097	13,626	15,686	16,208	16,649	17,382	17,839	18,574	21,066	22,396	25,830
Accumulated Depreciation	(4,800)	(5,171)	(5,562)	(5,985)	(6,414)	(6,864)	(7,320)	(7,786)	(8,274)	(8,798)	(9,356)
Net Plant in Service	8,297	8,455	10,124	10,223	10,235	10,518	10,519	10,787	12,792	13,598	16,474
Construction in Progress	1,949	2,455	1,343	1,820	2,840	3,856	5,534	6,950	6,161	6,448	4,170
Current and Other Assets	2,421	2,373	2,502	2,550	2,285	2,431	2,674	2,913	3,252	2,977	3,395
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,390	14,076	14,699	15,469	16,912	18,835	20,757	22,313	23,130	24,146
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,786	10,166	11,322	13,140	14,429	15,363	16,446	14,164
Current and Other Liabilities	2,246	1,995	2,178	2,967	2,300	2,483	2,355	2,732	3,110	2,582	5,584
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,313	2,398	2,488	2,633	2,763	3,030	3,310	3,565	3,832	4,128
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,390	14,076	14,699	15,469	16,912	18,835	20,757	22,313	23,130	24,146

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF09-1)
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
OPERATING ACTIVITIES											
Cash Receipts from Customers	2,171	2,159	2,401	2,495	2,590	2,649	2,836	2,938	3,029	3,261	3,540
Cash Paid to Suppliers and Employees	(1,175)	(1,227)	(1,364)	(1,382)	(1,414)	(1,441)	(1,493)	(1,561)	(1,613)	(1,712)	(1,726)
Interest Paid	(474)	(449)	(500)	(561)	(570)	(564)	(568)	(588)	(649)	(740)	(929)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	551	506	551	568	620	648	791	816	803	846	918
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	900	800	600	600	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	(448)	(304)	(27)	(183)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(36)	(12)	19	(10)	(13)	(12)	(13)	(14)	(15)	(26)	(15)
	678	712	619	509	1,020	1,288	1,728	1,585	1,255	961	835
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1,151)	(1,110)	(1,046)	(1,035)	(1,495)	(1,774)	(2,163)	(2,173)	(1,723)	(1,658)	(1,299)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(107)	(201)	(159)	(242)	(199)	(256)
Other	(36)	(20)	(16)	(17)	(17)	(31)	(29)	(41)	(28)	(27)	(27)
	(1,281)	(1,229)	(1,160)	(1,168)	(1,687)	(1,912)	(2,393)	(2,372)	(1,993)	(1,885)	(1,582)
Net Increase (Decrease) in Cash	(52)	(11)	11	(90)	(47)	25	126	29	66	(77)	171
Cash at Beginning of Year	(32)	(84)	(96)	(85)	(175)	(222)	(197)	(71)	(42)	24	(53)
Cash at End of Year	(84)	(96)	(85)	(175)	(222)	(197)	(71)	(42)	24	(53)	118

PUB/MH I-47

Subject: Tab 5: Integrated Financial Forecast
Reference: Tab 5 Appendix 5.2 IFF09-1 page 34

a) Please provide a breakdown of Other income.

ANSWER:

Please see attached schedule of Other Income.

Other Income Forecast (MH09-1)
(in Millions of Dollars)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hot Water Tank (Leasing & Other)	1	1	1	1	1	1	1	1	1	1	1
Joint Use	5	5	5	5	6	6	6	6	6	6	6
Sask Power /Island Falls	1	1	1	1	1	1	1	1	1	1	1
Tenant Rent from New Head Office	0	1	1	1	1	1	1	1	1	1	1
Total Other Revenue	7	7	8	8	8	8	8	9	9	9	9

Note: May not add due to rounding.

PUB/MH I-47

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **Tab 5 Appendix 5.2 IFF09-1 page 34**

b) Please describe what is represented by other controlling interest.

ANSWER:

Non-Controlling Interest is the reduction in Manitoba Hydro net income associated with Nisichawayasihk Cree Nation’s ownership interest in Wuskwatim Power Limited Partnership.

PUB/MH I-48

Subject: Tab 5: Integrated Financial Forecast
Reference: IFF09-1/IFF08-1 Assumptions

a) Can MH confirm that in IFF09-1, export prices [on average] are expected to be:

Year	¢/kW.h
2010/11	5.6
2011/12	7.7
2012/13	7.6
2013/14	7.8
2014/15	7.8
2015/16	9.6
2016/17	9.8
2017/18	10.2
2018/19	11.0
2019/20	11.2

ANSWER:

Not confirmed, please see the response to PUB/MH I-45(b).

PUB/MH I-48

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF09-1/IFF08-1 Assumptions**

b) Can MH confirm that the above average prices would infer natural gas prices going from $7/Gj to $11/Gj over the next five years? If not, explain.

ANSWER:

The inference in the information request that natural gas prices rise from $7/Gj to $11/Gj is not correct. The inference appears to be based on the assumption that average export prices are directly correlated to natural gas prices. This inference is not correct in that, while there is a correlation between these two entities, it is not a one to one relationship. If average export prices over the period increased by 60%, it does not mean that natural gas prices had also increased by 60%. While gas-fired generation is a factor in driving the on-peak price of export power, coal-fired generation also is a factor during some on-peak periods and coal is a predominant fuel source in off-peak periods. The average prices of Manitoba Hydro's export sales in the IFF are derived from both on-peak and off-peak sales. As a result, it is not expected that there is a one to one relationship between natural gas prices and export prices.

In addition to the cost of the primary fuel source, there are many other factors that can influence the marginal clearing price in the MISO market. One of the additional factors that is expected to play a major role in influencing electricity prices in the U.S. is increasing consideration of emissions, particularly greenhouse gases. It is expected that the U.S. will enact legislation to reduce greenhouse gas emissions with increasing targets reductions over time. As noted in the response to PUB/MH I-156(a), all five of the price forecast consultants forecasts used to prepare the Manitoba Hydro electricity export price forecast used some level of CO2 premiums in their analysis, resulting is a forecast of export prices that increases gradually due to this increasing regulation of greenhouse gas emissions. Note that in order to infer natural gas prices from electricity prices, appropriate consideration must be given to the greenhouse gas premium component of the electricity price.

Manitoba Hydro considers its natural gas price forecast a key driver of its electricity export price forecast and assumptions, and as such is considered commercially sensitive. Therefore the specific natural gas price forecast cannot be publicly disclosed. However in order to provide a general indication of its forecast for natural gas prices, it can be stated that

Manitoba Hydro expects long-term natural gas prices to follow the general trend outlined by publicly available natural gas price forecasts such as the U.S. Energy Information Administration's *Annual Energy Outlook 2010* and the Canadian National Energy Board's *Energy Market Assessment - July 2009.* These publicly available forecasts do not show a significant increase in the next five years and this indicates that the inference in the information request that natural gas prices rise from $7/Gj to $11/Gj is not correct.

PUB/MH I-48

Subject: Tab 5: Integrated Financial Forecast
Reference: IFF09-1/IFF08-1 Assumptions

c) Can MH confirm that these average prices after 2014/15 also reflect CO2 pricing of at least $30/ tonne? If not, explain.

ANSWER:

Please see the response to PUB/MH I-156(a) for an explanation of why Manitoba Hydro cannot provide information on the timing and magnitude of CO2 pricing.

PUB/MH I-48

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF09-1/IFF08-1 Assumptions**

d) Can MH confirm that these average prices require peak [5x16] opportunities sales prices typically higher than firm contract prices? Explain.

ANSWER:

Manitoba Hydro cannot confirm this statement applies in all time periods. In the early years of the time period up to 2015 there are several existing long-term contracts that were negotiated many years ago at somewhat low prices relative to opportunity export prices currently being forecasted. Therefore, in these early years it is possible that the future on-peak opportunity prices in the projection are higher than the average of firm contract prices. However, the majority of these existing firm contracts end by 2015 and new contracts with higher firm contract prices are projected to begin. Therefore, in years post 2015 forecast on-peak opportunity prices are not typically higher than prices associated with new contract sales.

PUB/MH I-49

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1 PUB/MH-3 (09/02/20)**

a) Please confirm that in IFF 08-1, MH anticipated its thermal generation costs to increase as follows:

		¢/KW.h
i.	2010/11	9.00
ii.	2013/14	9.37
iii.	2016/17	10.53
iv.	2019/20	13.11
v.	2022/23	14.26
vi.	2025/26	15.38

ANSWER:

It is confirmed that these are the projected costs of thermal generation in IFF08-1.

PUB/MH I-49

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1 PUB/MH-3 (09/02/20)**

b) Please confirm that these costs essentially reflect the costs of fuel supply and operation for the Brandon SCCT (natural gas) units.

ANSWER:

The line item entitled “MH Thermal Generation” reflects the combined average usage estimate for all of Manitoba Hydro’s thermal resources in each of the corresponding years. This estimate reflects operation of Brandon G.S. Units 6 & 7 (gas turbines), Selkirk G.S. (natural gas) and Brandon coal-fired Unit 5. Since Brandon Unit 5 is now projected to be operated in accordance with restrictions imposed by *The Climate Change and Emissions Reductions Act*, the expected usage of this coal-fired generation is relatively low on average. The coal-fired generation at Brandon Unit 5 is assumed to be retired in 2018/19. For the years prior to 2019 it can be confirmed that a large proportion of the projected costs reflect gas-fired generation from units at both Brandon G.S. and Selkirk G.S. In addition, after the year 2019 it is confirmed that all thermal generation is projected to be gas-fired since coal-fired generation at Brandon Unit 5 is assumed to be retired. It is projected that about 2/3 of gas-fired generation will be produced at the Brandon G.S. and the remaining 1/3 at the Selkirk G.S.

PUB/MH I-49

Subject: Tab 5: Integrated Financial Forecast
Reference: IFF 09-1 PUB/MH-3 (09/02/20)

c) Please confirm (or provide otherwise) that in forecasting the above SCCT generation costs, MH anticipated natural gas supply prices to rise from about $7/GJ to about $15/GJ during the 15 year period.

ANSWER:

It is not confirmed that Manitoba Hydro anticipated natural gas supply prices to rise from about $7/GJ to about $15/GJ during the 15 year period**.** If the increase in natural gas prices is being inferred from electricity export prices, please refer to the response to PUB/MH I-48(b) for information relating to why it is not correct to make this inference. However, if the increase in natural gas prices is being inferred from the price of thermal generation referenced in PUB/MH I-49(a), it is not correct to assume that those increases in the cost of thermal generation are due solely to the commodity price of natural gas. The thermal generation costs in PUB/MH I-49(a) are primarily driven by natural gas prices but also have a significant component related to consideration of CO2 costs in the future.

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

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **Tab 5 IFF09-1, IFF08-1, PUB/MH – 3 (09/02/20)**

a) Please define the circumstances that result in non-delivery of firm export energy to customers in:

i. High flow years?
ii. Mean flow years?
iii. Low flow years?

<u>ANSWER</u>:

Delivery of firm export energy is not excused by reason of water flow variability.

The circumstances that result in non-delivery of firm export energy are negotiated between Manitoba Hydro and its customers and include, without limitation, the following circumstances:

a) force majeure;
b) emergencies;
c) loss of transmission;
d) curtailment in order to maintain the reliability of the Manitoba Hydro system or the Balancing Authority of the receiving system; and
e) to the extent necessary to protect service to higher priority firm loads such as domestic Manitoba load.

PUB/MH I-50

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **Tab 5 IFF09-1, IFF08-1, PUB/MH – 3 (09/02/20)**

b) Does the support of wind energy result in non-deliveries of contracted energy?

ANSWER:

Support of wind energy in Manitoba is not a reason for non-delivery of contracted energy.

PUB/MH I-50

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **Tab 5 IFF09-1, IFF08-1, PUB/MH – 3 (09/02/20)**

c) Please explain the complementary role that MH's exports play in supporting wind energy in the MISO region.

ANSWER:

Manitoba Hydro's Exports Support Wind Energy in the MISO Region by:

Providing Diversity and Complementary Patterns of Production
Hydraulic energy production and wind energy production are not correlated and together result in a diversified generation mix. Hydraulic generation is complementary to wind because it is highly dispatchable and provides storage. Wind generation is not dipatchable and provides no storage.

Influencing Significant Transmission Additions and Reinforcements
Hydro and wind generation are generally relatively remote, both requiring transmission improvements which provide system-wide reliability and market access benefits. Existing major transmission interconnections with MISO and the new US-Canada transmission which will be built to support major export sales will facilitate the integration of wind in the MISO region by spreading wind generation variations over a much larger load area as well as providing access to diverse and complementary sources of production.

Providing Energy Storage (the "Battery Effect")
Surplus, off-peak wind energy often results in operational problems as the energy may be produced in periods when there is insufficient load demand. This "minimum generation" problem, which is characterized by low prices (sometimes negative prices, meaning that MH is paid to take the energy) and by other generators (typically fossil and nuclear) being forced to operate at undesirably low levels, is a significant concern for MISO.

Since large amounts of hydraulic energy can be stored as water in reservoirs, MH has the capability of providing an outlet for the region's low priced, off-peak wind energy when there is not enough load to consume it, storing the energy and using it later to generate energy when it is needed (on-peak).

In summary, while Manitoba Hydro hydropower plays a complementary role in supporting wind energy in the MISO region, there are limited opportunities for similar complementary generation to be developed. MISO has recognized the importance of hydropower generation and has been cooperative in developing market mechanisms (such as the Ancillary Service market) so that Manitoba Hydro receives appropriate price signals to recognize the value of Manitoba Hydro hydropower in providing energy, capacity, regulation and load following products to the MISO market. As a result, Manitoba Hydro is able to monetize the role its generators can play in supporting wind energy in MISO. However, to the extent that those Manitoba Hydro resources for regulation and load following are used to support domestic wind development in Manitoba, the associated export revenue will be foregone.

PUB/MH I-50

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **Tab 5 IFF09-1, IFF08-1, PUB/MH – 3 (09/02/20)**

d) **Do exports and wind resources tend to have an over lap (duplication) in the on-line/off line process of energy supply continuity? Explain.**

ANSWER:

Wind resources provide only non-dispatchable energy and require a dispatchable capacity resource (such as Natural Gas Combustion Turbines or Hydraulic generation) as back up in order to provide a comparable firm supply resource.

PUB/MH I-50

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **Tab 5 IFF09-1, IFF08-1, PUB/MH – 3 (09/02/20)**

e) In IFF 09-1, does MH also anticipate natural gas supply prices to rise to $15/GJ by 2025/26 from the current levels of about $5/GJ? Explain.

ANSWER:

Manitoba Hydro does not anticipate natural gas prices to rise to $15/GJ by 2025/26 from the current levels of about $5/GJ. Please refer to the responses to PUB/MH I-48(b) and PUB/MH I-49(c) for information on why it is not correct to infer such high prices.

PUB/MH I-50

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **Tab 5 IFF09-1, IFF08-1, PUB/MH – 3 (09/02/20)**

f) Please confirm that CCCT units in the MISO market area can typically supply electricity at about 60 to 70% of the cost of the Brandon SCCT units.

ANSWER:

The fuel efficiency and hence the variable operating cost of combustion turbines and combined cycle combustion turbines varies with the specific turbine models used and the plant design. However in general, it can be confirmed that CCCT units in any given location or market can typically supply electricity at about 60 to 70% of the cost of SCCT units because they are more fuel efficient. The variable operating cost of the Brandon SCCT units is comparable to similar SCCTs within the MISO market.

PUB/MH I-51

Subject: Tab 5: Integrated Financial Forecast
Reference: IFF 09-1 Alternative Scenario

a) Please provide alternative 20 year IFF scenarios that reflects export revenues based on:

i. Natural gas prices gradually rising from $5/GJ to $10/GJ over the forecast period.
ii. CO2 pricing gradually rising from zero to $30/tonne over the forecast period.
iii. Zero carbon pricing.

ANSWER:

Please see the response to question PUB/MH I-156 (a) for a description of how the Electricity Export Price Forecast is prepared,. The Electricity Export Price Forecast contains an Expected Forecast Scenario, as well as a Low Forecast Scenario and a High Forecast Scenario.

The IFF09 High Price scenario can be used to show the directional impact of higher prices as requested in (i) and (ii) and the IFF09 Low Price scenario can be used to show the directional impact of lower prices as requested in (iii). Please see Appendix 15 for the projections supporting these specific scenarios.

<u>PUB/MH I-51</u>

Subject: Tab 5: Integrated Financial Forecast
Reference: IFF 09-1 Alternative Scenario

b) File in confidence with the Board only MH's Carbon adders for the entire forecast period.

<u>ANSWER</u>:

Manitoba Hydro's electricity export price forecast is prepared using information from several external price forecast consultants who each have their own electricity price forecast models and assumptions, including those related to carbon adders. As a result, Manitoba Hydro does not have its own carbon price forecast to release. For a description of how the export price forecast is prepared, please see the response to PUB/MH I-156(a).

PUB/MH I-51

Subject: Tab 5: Integrated Financial Forecast
Reference: IFF 09-1 Alternative Scenario

c) Please file the reports on which MH's carbon adder is based.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-51(b).

PUB/MH I-51

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1 Alternative Scenario**

d) Please confirm MH's export agreements escalate in price equivalent to the carbon adders included in the forecast.

ANSWER:

Manitoba Hydro's export agreements may include both real and inflationary price escalators. Real price escalators reflect Manitoba Hydro's expectation that the value of energy will grow in real terms in part due to factors such as the cost of carbon legislation.

PUB/MH I-51

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **IFF 09-1 Alternative Scenario**

e) Please explain MH's pricing assumptions for both exports and imports in the periods:

i. 2009/10.
ii. 2010/11 to 2015/16.
iii. 2016/17 to 2019/20.
iv. 2020/21 to 2028/29.

ANSWER:

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

For a general comment on how Manitoba Hydro's electricity export price forecast is prepared, including a comment on carbon impacts, please see the response to PUB/MH I-156(c).

For a general comment on the export prices that underlay the export revenue projections in for 2010, 2011 and 2012, please see the response to CAC/MSOS/MH I-7(a).

For a general comment on how gas pricing impacts the electricity export price forecast, please see the response to PUB/MH I-48(b).

PUB/MH I-52

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1**

a) Please explain why the CEF 08-1 cost of Conawapa G.S. has increased by $1,346.4 M from $4,978.4 M to $6,324.8 M.

ANSWER:

The increase is primarily due to the following:

- Interest and escalation increased by $571.8 million and $67.6 million respectively as a result of higher base costs and a one year later in service.

- Base costs increased by $606.0 million related mainly to concrete quantity and prices, intake and spillway gate prices, contractor labour rates, and turbine and generator prices. The previous base estimate was in 2006 dollars and the new base estimate is in 2008 dollars.

- Improvements to the alignment and surface condition of Provincial Road 280 and 290 were not included in the previous estimate ($55.4 million).

- Higher Licensing costs due to more extensive consultations and a longer duration to achieve the required licenses ($45.5 million).

It is important to note that CEF08 was a factored estimate based on Limestone GS actual costs and CEF09 is a first principles estimate based on the preliminary design of the Conawapa GS.

PUB/MH I-52

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1**

b) Please provide details on the significant component cost increase with respect to the generation station, associated transmission facilities, and access roadway improvements.

ANSWER:

The Generating Station increase of $1,291.0 million is primarily due to the following:

- Interest and escalation increased by $571.8 million and $67.6 million respectively as a result of higher base costs and a one year later in service.
- Higher Licensing costs due to more extensive consultations and a longer duration to achieve the required licenses ($45.6 million).
- Higher base costs ($606 million) for materials and labour: gates and guides ($65 million), concrete ($395 million), turbines and generators ($21 million), earth fill dykes and dams ($32 million), river management ($30 million), rock excavation ($18 million), miscellaneous direct cost (-$66 million), administration / service contracts ($45 million), construction camp and work area ($51 million), and environmental and mitigation ($15 million).

There is no change from CEF08 to CEF09 for associated transmission facilities.

Improvements to the alignment and surface condition of Provincial Road 280 and 290 were not included in the previous estimate ($55.4 million).

PUB/MH I-53

Subject: Tab 6: Capital Expenditures
Reference: CEF 09-1/CEF 08-1

a) Please provide the overall rationale used in the Wuskwatim justification at the 2003 Clean Environment Commission Hearing.

ANSWER:

As recorded in the CEC Report on Wuskwatim Generation and Transmission Projects, the Wuskwatim project was proposed as the next generation resource to meet domestic load growth, and was forecast to be required by 2019. The opportunity to advance the in-service date from 2019 to 2009 (now expected in 2011/12) became apparent. The surplus capacity and energy available from this plant, prior to being required for domestic load, could be sold on the export market. The resultant return would more than pay for the advancement of the plant. Overall the early investment would protect Manitoba Hydro's position in the export market, reduce the cost of the Wuskwatim Generating Station that is to be borne by ratepayers and thus support continued low rates within the Province.

<u>PUB/MH I-53</u>

Subject: Tab 6: Capital Expenditures
Reference: CEF 09-1/CEF 08-1

b) By what amount does this project increase generation available for export purposes in the initial five years?

<u>ANSWER</u>:

The Wuskwatim project is expected to provide 200 MW of capacity, 1250 GW.h of dependable energy, and 1520 GW.h of energy on average. As the plant is not expected to be fully constructed in 2011/12, the first year of operation, only 550 GW.h of dependable energy and 670 GW.h of energy on average is expected to be available in the first year of operation.

From a planning perspective, in the initial five years of operation, almost all of the energy from the Wuskwatim project is expected to be surplus to Manitoba's domestic requirements and therefore would be available to the export market.

Depending on the actual flow conditions in each year and Manitoba load growth, Manitoba Hydro's energy supply in each year would be dispatched in an efficient and economic manner. The energy from the Wuskwatim project becomes part of the supply to the system and this additional supply is expected to be used for additional export sales, to reduce imports or to displace Manitoba Hydro gas-fired generation as well as coal-fired generation from Brandon Unit 5 during drought periods.

<u>PUB/MH I-53</u>

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1**

c) When does the need for Wuskwatim change from generation for export power purposes to serving only domestic load requirements?

<u>ANSWER</u>:

The Manitoba Hydro system is planned for lowest flow dependable energy conditions in each year and this is the condition that is summarized in the supply/demand table in the power resource plan. However, it is likely that flows will be higher than dependable in each of these years. Consequently, the precise timing as to when the generating resource is required for either domestic or export purposes depends largely on the extent to which water flows are higher than dependable. 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. The output of the Wuskwatim G.S. will become part of the integrated system supply which meets the total of the Manitoba load and export obligations.

Under the assumptions in the 2009/10 power resource plan as shown in the response to RCM/TREE/MH I-28(a) new resources would be required to supply Manitoba Hydro's firm commitments by 2019/20 under dependable flow conditions when considered without the dependable quantity of energy from the Wuskwatim G.S. Please refer to the response to PUB/MH I-53(d) for a summary of the proportion of Wuskwatim energy that is required to meet Manitoba Hydro's firm commitments up to the year 2022/23. This response indicates that an amount in excess of the dependable energy from Wuskwatim would be required for domestic load beginning in 2022/23 under the assumption of no new export sales or new hydro development.

PUB/MH I-53

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1**

d) **Please provide load data to illustrate the increased domestic and export contract requirements to be met by Wuskwatim.**

ANSWER:

From the planning perspective the domestic and export contract requirements to be met by Wuskwatim are dependent on the load forecast, the future commitments to export sales and the in-service dates of new hydroelectric developments. The table below is based on the assumption that the proposed sales to NSP, MP and WPS do not proceed and that there is no further hydroelectric development. Under the assumptions in the 2009/10 power resource plan as shown in the response to RCM/TREE/MH I-28(a), new resources would be required to supply Manitoba Hydro's firm commitments beginning in 2019/20 under dependable flow conditions for the case without the 1250 GW.h of dependable energy from the Wuskwatim G.S.

Wuskwatim Dependable Energy required to meet Manitoba Hydro Firm Commitments In GW.h

2009/10	0
2010/11	0
2011/12	0
2012/13	0
2013/14	0
2014/15	19
2015/16	0
2016/17	0
2017/18	0
2018/19	0
2019/20	465
2020/21	798
2021/22	1130
2022/23	1250

PUB/MH I-54

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, Major Generation and Transmission**

a) Please provide details on the main contract components for Wuskwatim G.C. construction including estimated final costs versus current expenditure levels.

ANSWER:

The details of the main contract components for Wuskwatim Generating Station construction include:

- General Civil Works - The general civil works contract at Wuskwatim is a cost reimbursable, fee and target price contract awarded to O'Connell, Neilson, EBC (O.N.E.).

- Turbines & Generators - The design, supply and install of the turbines and generators is two contracts, each being lump sum and awarded to Andritz Hydro.

- Spillway Gates, Guides and Hoists -The supply and install of spillway gates, guides and hoists is a lump sum contract awarded to HMI Construction Inc.

- Intake Gates, Guides and Hoists - The supply and install of intake gates, guides and hoists is lump sum contract awarded to Canmec Industriel.

- Electrical and Mechanical Equipment - The supply and install of electrical and mechanical equipment is a lump sum contract awarded to GJ Cahill & Co. Ltd.

Current expenditure levels as of December 31, 2009 for Wuskwatim Generating Station including indirect costs and interest was $782 million. The estimated final cost remains at $1.3 billion.

PUB/MH I-54

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, Major Generation and Transmission**

b) Please provide the contractual requirements for Manitoba and Manitoba aboriginal workforce component requirement for the Wuskwatim project.

ANSWER:

The contractual requirements for Manitoba and aboriginal workforce component requirement for the Wuskwatim project are summarized in the relevant provisions in the Burntwood/Nelson Agreement (BNA) in relation to aboriginal and Manitoba hiring as follows:

When a job order is activated, the Job Referral Service refers candidates out of northern Manitoba in the following order:

a) Northern Aboriginals who reside within the Churchill/Burntwood/ Nelson River area, which area shall be defined as: i) the area of the Churchill River Water Power Reserve from Granville Lake downstream to Hudson Bay; ii) the area of the Burntwood River Water Power Reserve from South Indian Lake downstream to Split Lake; iii) the area of the Nelson River Water Power Reserve from the outlet of Lake Winnipeg downstream to Hudson Bay; and iv) the following communities: the incorporated community of South Indian Lake; the Northern Affairs communities of Granville Lake, Nelson House, Ilford, Wabowden, Thicket Portage, Pikwitonei, Norway House and Cross Lake; the towns of Leaf Rapids, Churchill, and Gillam; the City of Thompson; and Nisichawayasihk Cree Nation, Tataskweyak Cree Nation,York Factory First Nation, Fox Lake First Nation, War Lake First Nation, Norway House Cree Nation and Cross Lake First Nation,

b) secondly, if job vacancies remain, any Northern Residents who are members of the appropriate Local Union of the Allied Hydro Council and are not covered by a) above,

c) thirdly, if job vacancies remain, any other Northern Aboriginals who are not covered by a) or b) above,

d) fourthly, if job vacancies remain, any other Northern Residents who are not covered by a), b), or c) above.

If the job order remains unfulfilled, the Allied Hydro Council may then refer qualified persons. Should the job order still remain unfulfilled, it reverts back to the Job Referral Service for the referral of other Manitobans. The Contractor may only hire non-Manitobans if the job order cannot be filled as outlined above.

There is also a special provision for Northern Manitoba Aboriginal Contractors under direct contract to Manitoba Hydro, which stipulates that such contractors may direct hire Northern Aboriginal workers as long as, prior to such a hire, the person to be hired provides the Job Referral Service with information that confirms that he qualifies as a Northern Aboriginal.

PUB/MH I-54

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, Major Generation and Transmission**

c) Please provide actual breakdown of the aboriginal workforce by provincial domicile.

ANSWER:

Since the start of construction on the Wuskwatim Project up to January 31, 2010 there have been a total of 1545 Aboriginal workers hired. As of January 31, 2010, there were 223 Aboriginal workers at site.

	AB	BC	MB	NL	NS	NT	ON	QC	SK	Total
Total Aboriginal Workers	4	6	1506	2	1	1	19	3	3	1545
Aboriginal Workers at site as of January 31, 2010	2	-	216	2	1	-	2	-	-	223

PUB/MH I-54

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, Major Generation and Transmission**

d) Please provide particulars on the main contract components for Wuskwatim transmission construction including estimated final costs versus current expenditure levels.

ANSWER:

The details of the main contract components for Wuskwatim Transmission construction include:

- The construction of the Thompson Birchtree Station 230 kV & SVC yard foundations is a lump sum contract awarded to Arnason Industries Ltd.
- The Wuskwatim Switching Station site improvement work is a lump sum contract awarded to Arnason Industries Ltd.
- The construction of the Thompson Birchtree Station SVC building is a lump sum contract awarded to Crane Steel Structures.
- The construction of the Thompson Birchtree to Wuskwatim 230 kV transmission line is s lump sum contract awarded to Interlake Power Line Contractors.
- The clearing and construction of the Wuskwatim to Herblet Lake 230 kV transmission line is s lump sum contract awarded to Interlake Power Line Contractors.
- The installation of the Thompson Birchtree Station 150 MVAR SVC and associated equipment is a lump sum contract awarded to Magna Electric Corp.
- The clearing of ROW for Wuskwatim to Herblet Lake 230kV transmission line is a lump sum contract awarded to NCPL/TLINE Contractors.
- The Thompson Birchtree to Wuskwatim and portion of Wuskwatim to Herblet Lake clearing of ROW is a lump sum contract issued to NHFI / STRILKIWSKI 2006 Joint Venture.
- The Wuskwatim Switching Station construction of GIS building is a lump sum contract issued to PCL Contractors Canada.
- The site preparation of the Thompson Birchtree 230 kV Station is a lump sum contract issued to Smook Bros (Thompson) Ltd.
- The site preparation of the Wuskwatim 230 kV Switching Station is a lump sum contract issued to Smook Bros (Thompson) Ltd.

Current expenditure levels as of December 31, 2009 for Wuskwatim Transmission including indirect costs and interest was $222 million. The estimated final cost remains at $316 million.

PUB/MH I-55

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, CEF 08-1 (Appendix 4.3)**

	In-Service Date	
Major Project	**CEF 09-1**	**CEF 08-1**
Wuskwatim G.S.	**September 2011**	**September 2011**
Wuskwatim Transmission	**September 2011**	**September 2011**
Keeyask G.S.	**December 2018**	**December 2018**
Conawapa G.S.	**May 2022**	**May 2022**
Bipole West Route	**October 2017**	**October 2017**
Pointe du Bois Rebuild	**May 2014**	**October 2022**
Slave Falls G.S. Upgrade	**December 2017**	**December 2017**

a) Please confirm that the above in service dates have all been updated and are still valid.

ANSWER:

The in-service date for the first unit at the Wuskwatim G.S. is still valid as September 2011 and the Wuskwatim Transmission project continues to have a 2011 in-service date.

No commitment has been made for constructing either Keeyask or Conawapa, and the projected in-service dates for the first unit of each plant are uncertain at this time. However, the listed in-service dates are consistent with the 2009 power resource plan and the 2009 IFF and CEF projections.

There has been no change to the estimated in-service date for Bipole III which is currently estimated to be October, 2017.

The Pointe du Bois Modernization Project is now taking the form of a new spillway and new concrete and earth dams. The existing Pointe du Bois powerhouse will continue to operate indefinitely with ongoing maintenance. The anticipated in-service date of the new spillway and dam is estimated to be May 2014. It should be noted that the in-service date for this project in CEF08-1 was 2017 and not 2022 as listed. The timing of the Slave Falls Upgrade is uncertain at this time but has a 2017 in-service date as a placeholder.

PUB/MH I-55

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, CEF 08-1 (Appendix 4.3)**

	In-Service Date	
Major Project	**CEF 09-1**	**CEF 08-1**
Wuskwatim G.S.	**September 2011**	**September 2011**
Wuskwatim Transmission	**September 2011**	**September 2011**
Keeyask G.S.	**December 2018**	**December 2018**
Conawapa G.S.	**May 2022**	**May 2022**
Bipole West Route	**October 2017**	**October 2017**
Pointe du Bois Rebuild	**May 2014**	**October 2022**
Slave Falls G.S. Upgrade	**December 2017**	**December 2017**

b) Please provide the rationale for the changed in-service date for the Pointe du Bois Rebuild.

ANSWER:

The in-service date (ISD) for the Pointe du Bois Rebuild project, as stated in CEF08, is October 2017. The ISD for the Pointe du Bois modernization project, as stated in CEF09, is October 2014.

The earlier ISD in CEF09 is due to a reduction in scope of the Pointe du Bois Modernization project. The Pointe du Bois Modernization Project will now take the form of a new spillway and new concrete and earth dams. The existing powerhouse will continue to operate with ongoing maintenance. A new powerhouse is no longer included as part of the project.

PUB/MH I-55

Subject: Tab 6: Capital Expenditures
Reference: CEF 09-1, CEF 08-1 (Appendix 4.3)

	In-Service Date	
Major Project	**CEF 09-1**	**CEF 08-1**
Wuskwatim G.S.	**September 2011**	**September 2011**
Wuskwatim Transmission	**September 2011**	**September 2011**
Keeyask G.S.	**December 2018**	**December 2018**
Conawapa G.S.	**May 2022**	**May 2022**
Bipole West Route	**October 2017**	**October 2017**
Pointe du Bois Rebuild	**May 2014**	**October 2022**
Slave Falls G.S. Upgrade	**December 2017**	**December 2017**

c) Has the relative capital redevelopment priority of Pointe du Bois and Slave Falls G.S. changed?

ANSWER:

The relative capital redevelopment priority between Pointe du Bois and Slave Falls G.S. has not changed. Pointe du Bois modernization project is a major capital upgrade with high priority in order to increase spillway capacity at the station. A number of initiatives are ongoing at Slave Falls Generating Station including the Slave Falls access improvements and turbine and generator overhauls.

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PUB/MH I-56

Subject: Tab 6: Capital Expenditures
Reference: CEF 09-1, CEF 08-1, Order No. 116/08 (CEF 04-1 to CEF 07-1)

a) Please confirm the accuracy of the progression of project costs, in the table that follows:

Progression of Project Costs in $ M							
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275
Wuskwatim Transmission		199	200	257	320	316	316
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591
Herblet Lake Transmission	57	55	54	54	95	93	93
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248
Riel C.S.	96	101	103	103	105	268	268
Kelsey G.S.	121	121	166	166	184	190	190
Kettle G.S.		61	61	61	61	76	76
Pointe du Bois	421	288	692	834	818	818	318
Pointe du Bois Trans.					83	86	86
Slave Falls G.S.				179	192	198	198
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325
Keeyask G.S.						3,700	4,592
500 KV Dorsey U.S. Border						205	205

ANSWER:

Confirmed with minor rounding differences.

PUB/MH I-56

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, CEF 08-1, Order No. 116/08 (CEF 04-1 to CEF 07-1)**

b) Please provide an explanation for the project changes for the Major Capital Projects in similar format to that provided in response to PUB/MH II-47 (a).

ANSWER:

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

PUB/MH I-56

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, CEF 08-1, Order No. 116/08 (CEF 04-1 to CEF 07-1)**

c) **Which of CEF 09-1 Major G&T estimates have not been updated to reflect construction cost "sticker shock"? Please provide the most recent and pending updates.**

ANSWER:

As indicated in appendix 4.4, there has been some reduction of cost pressures since the last GRA, however costs remain relatively high and continue to show volatility. Given the uncertainties and the long term nature of these projects, many of the approved project cost estimates have not changed since CEF08-1. Manitoba Hydro continues to monitor project requirements and cost estimates and authorizes updates when there is a high degree of support and confidence in the updated estimates.

<u>PUB/MH I-56</u>

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, CEF 08-1, Order No. 116/08 (CEF 04-1 to CEF 07-1)**

d) Please provide a 20-year CEF 09-1.

<u>ANSWER</u>:

Please see Attachment 1.

ATTACHMENT 1

CAPITAL EXPENDITURE FORECAST FOR 20 YEAR OUTLOOK (2009/10 - 2028/29) - JANUARY 2010

(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	20 Year Total
ELECTRIC																						
Major New Generation & Transmission																						
Wuskwatim - Generation	1,274.6	364.4	275.3	105.1	12.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	756.8
Wuskwatim - Transmission	316.3	90.1	30.5	18.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	139.5
Herblet Lake - The Pas 230 kV Transmission	93.2	41.9	30.4	7.2	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81.5
Keeyask - Generation	4,591.6	67.7	85.0	195.3	198.6	182.3	485.5	799.1	808.3	584.7	537.5	263.9	74.9	-	-	-	-	-	-	-	-	4,282.8
Conawapa - Generation	6,324.8	60.4	60.4	75.0	111.8	190.1	231.5	308.2	290.3	513.6	846.1	881.7	905.0	833.8	632.2	240.7	7.0	-	-	-	-	6,188.0
Kelsey Improvements & Upgrades	189.6	45.1	6.8	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52.5
Kettle Improvements & Upgrades	75.6	11.1	18.4	6.6	20.1	18.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.8
Pointe du Bois Improvements & Upgrades	318.0	13.8	14.8	15.5	53.0	83.1	110.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	290.9
Pointe du Bois - Transmission	85.9	9.0	26.3	10.4	20.6	13.9	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	83.2
Bipole 3	2,247.8	16.6	21.4	36.7	113.4	266.5	420.2	627.7	557.9	159.9	-	-	-	-	-	-	-	-	-	-	-	2,220.4
Riel 230/500 kV Station	267.6	36.1	58.4	79.6	45.1	38.2	4.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	262.0
Firm Import Upgrades	4.8	0.6	2.1	2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8
Dorsey - US Border New 500 kV Transmission Line	204.8	-	0.5	1.9	8.2	17.6	32.4	79.3	64.8	-	-	-	-	-	-	-	-	-	-	-	-	204.8
Brandon Combustion Turbine Pipeline Upgrade	5.4	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4
Demand Side Management	NA	40.3	43.0	42.5	38.4	33.9	29.9	29.0	27.1	25.6	25.1	21.8	21.6	21.5	21.4	20.6	16.0	16.3	16.6	17.0	17.3	524.9
Planning Study Costs	NA	5.7	8.0	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.6
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	-	-	-	-	-	-	45.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	56.6	299.1
Additional North South Transmission	345.0	-	-	-	-	-	-	-	-	-	-	-	-	-	345.0	-	-	-	-	-	-	345.0
		808.1	681.5	599.4	623.1	844.1	1,318.0	1,843.4	1,748.4	1,283.8	1,408.7	1,167.4	1,046.5	887.6	1,019.7	270.7	37.4	31.5	42.4	96.3	73.9	15,831.9
New Head Office																						
New Head Office	278.1	14.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.8
Corporate Relations																						
Waterways Management Program	NA	5.3	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.7

CAPITAL EXPENDITURE FORECAST FOR 20 YEAR OUTLOOK (2009/10 - 2028/29) - JANUARY 2010

ATTACHMENT 1

(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	20 Year Total
Power Supply																						
Converter Transformer Bushing Replacement	5.9	0.1	0.4	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3
Bipole 1 & 2 Electrode Line Monitoring	1.7	0.0	0.0	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6
Dorsey Synchronous Condenser Refurbishment	32.3	3.0	2.5	3.6	2.5	2.6	2.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.0
HVDC Bipole 1 Roof Replacement	5.9	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	0.3	1.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9
HVDC AC Filter PCB Capacitor Replacement	34.5	2.4	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3
HVDC Transformer Replacement Program	NA	1.0	1.1	7.3	5.3	1.1	-	-	-	-	-	-	0.5	4.6	6.4	32.9	6.7	7.0	50.3	22.5	77.8	224.6
Dorsey 230 kV Relay Building Upgrade	73.8	1.1	1.9	4.0	16.4	32.1	12.0	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	72.5
HVDC Stations Ground Grid Refurbishment	4.3	0.6	0.5	0.6	0.6	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	9.4	2.7	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1
HVDC Bipole 1 Pole Differential Protection	3.3	-	1.0	2.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.5	4.6	8.2	5.6	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.1
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.8	7.2	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.0
HVDC Bipole 1 Smoothing Reactor Replacement	31.8	0.0	0.1	0.1	0.1	4.0	18.0	7.2	2.5	-	-	-	-	-	-	-	-	-	-	-	-	31.8
HVDC Bipole 1 Converter Station, P1 & P2 Battery Bank Separation	3.2	-	0.0	1.0	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	-	0.6	2.8	0.8	3.9	1.1	2.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	11.7
HVDC BP1 & BP2 DC Converter Transformer Bushing Replacements	8.7	-	-	0.5	1.0	1.7	5.2	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Hall Wall Bushing Replacements	19.2	-	0.1	3.3	4.5	4.6	4.7	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	19.2
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.0	1.1	1.5	0.9	1.0	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	4.7	1.8	1.7	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.3
HVDC Bipole 2 Smoothing Reactor Replacement	17.1	0.8	3.5	3.2	5.7	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.1
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.8	1.0	1.0	1.6	1.6	1.1	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8
HVDC Bipole 2 Upgrades & Replacements	444.2	-	-	-	-	-	-	-	-	-	-	-	12.3	52.7	57.4	64.1	98.1	103.5	56.2	-	-	444.2
Pine Falls Rehabilitation	56.2	2.8	4.2	17.4	12.2	2.1	2.9	3.2	4.8	-	-	-	-	-	-	-	-	-	-	-	-	49.6
Jenpeg Unit Overhauls	115.9	-	-	-	-	-	-	2.3	2.6	18.6	24.5	25.1	25.6	17.2	-	-	-	-	-	-	-	115.9
Power Supply Dam Safety Upgrades	34.0	9.7	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.4
Winnipeg River Riverbank Protection Program	19.7	1.3	1.2	1.2	1.3	1.3	1.3	1.3	1.5	-	-	-	-	-	-	-	-	-	-	-	-	10.4
Power Supply Hydraulic Controls	16.0	3.1	1.9	1.2	-	-	-	-	-	2.2	2.7	0.7	-	-	-	-	-	-	-	-	-	11.7
Slave Falls Rehabilitation	198.3	13.0	4.0	1.1	16.3	11.8	15.6	54.3	59.4	11.8	-	-	-	-	-	-	-	-	-	-	-	187.3
Great Falls Unit 4 Overhaul	19.7	3.0	7.0	7.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.8
Great Falls 115 kV Indoor Station Safety Improvements	11.6	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6
Generation South Transformer Refurbish & Spares	21.0	0.0	1.5	3.1	5.3	4.4	2.8	2.7	1.1	-	-	-	-	-	-	-	-	-	-	-	-	20.9
Generation South Overhauls & Improvements	384.8	-	-	-	-	-	-	-	-	-	-	-	4.7	10.2	40.3	29.4	48.6	28.5	33.3	82.8	53.3	331.1
Water Licenses & Renewals	40.8	4.4	6.0	6.0	5.7	5.9	4.9	3.2	-	-	-	-	-	-	-	-	-	-	-	-	-	36.1
Generation South PCB Regulation Compliance	4.7	0.2	0.3	0.1	0.1	0.2	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.7
Kettle Transformer Overhaul Program	35.6	1.6	6.6	6.5	6.6	6.8	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.4
Generation South Breaker Replacements	9.4	1.6	3.1	2.2	2.0	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.3
Seven Sisters Upgrades	9.5	1.8	5.3	1.2	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.4
Generation South Excitation Upgrades	32.3	-	2.0	1.0	1.1	1.7	1.4	1.3	1.5	0.6	7.7	0.0	4.4	5.0	3.4	1.2	-	-	-	-	-	32.3
Brandon Unit 5 License Review	18.7	0.3	2.5	11.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.9
Selkirk Enhancements	14.2	5.8	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.0
Laurie River/CRD Communications and Annunciation Upgrades	4.8	0.2	3.5	0.0	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8
Notigi Marine Vessel Replacement & Infrastructure Improvements	2.6	0.0	1.3	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
Fire Protection Projects - HVDC	5.2	0.5	0.4	1.6	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.2
Halon Replacement Project	42.5	14.6	13.1	9.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36.8
Power Supply Fall Protection Program	13.5	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2
Oil Containment - Power Supply	19.1	0.6	0.4	1.0	0.5	0.3	0.3	0.1	0.9	-	-	-	-	-	-	-	-	-	-	-	-	4.1
Grand Rapids Townsite House Renovations	5.2	0.1	0.4	0.9	1.2	1.3	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2
Grand Rapids Fish Hatchery	2.2	0.1	1.1	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2
Generation Townsite Infrastructure	52.1	7.8	8.4	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21.6
Site Remediation of Contaminated Corporate Facilities	34.7	2.3	1.2	1.1	1.1	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.9
High Voltage Test Facility	26.9	10.6	13.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.1
Power Supply Security Installations / Upgrades	43.2	9.7	16.0	8.7	2.1	1.5	1.0	1.0	0.5	-	-	-	-	-	-	-	-	-	-	-	-	40.6
Power Supply Sewer & Domestic Water System Install and Upgrade	15.1	7.3	3.4	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.4
Power Supply Domestic	NA	19.1	19.3	19.7	20.1	20.5	20.9	21.4	21.8	22.2	22.7	23.1	23.6	24.1	24.5	25.0	25.5	26.0	26.6	27.1	27.6	460.9
		139.5	161.4	157.2	134.6	116.4	108.9	108.1	96.5	55.5	57.5	48.9	71.0	113.7	132.0	152.6	178.9	165.0	166.4	132.4	158.7	2,455.4

CAPITAL EXPENDITURE FORECAST FOR 20 YEAR OUTLOOK (2009/10 - 2028/29) - JANUARY 2010

(in millions of dollars)

ATTACHMENT 1

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	20 Year Total
Transmission																						
Winnipeg - Brandon Transmission System Improvements	40.0	3.1	1.6	3.4	3.6	5.0	21.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.4
Transcona East 230-66 kV Station	31.0	1.1	11.0	13.2	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.5
Neepawa 230 - 66 kV Station	30.0	1.1	14.1	9.5	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9
Pine Falls - Bloodvein 115 kV Transmission Line	34.1	-	0.3	0.9	4.4	20.6	7.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34.1
Transmission Line Re-Rating	24.1	3.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	-	-	0.8	0.9	2.6	6.0	9.6	12.3	-	-	-	-	-	-	-	-	32.2
Rosser Station 230 - 115 kV Bank 3 Replacement	5.8	2.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
Rosser - Inkster 115 kV Transmission	5.1	3.3	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.7
Transcona Station 66 kV Breaker Replacement	6.0	0.0	3.6	1.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.0
Transcona & Ridgeway Stations 66 kV Bus Upgrades	2.8	1.7	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4
Dorsey 500 kV R502 Breaker Replacement	2.6	2.3	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
13.2kV Shunt Reactor Replacements	33.0	0.0	0.0	4.1	4.2	4.3	4.4	4.4	4.5	4.6	2.5	-	-	-	-	-	-	-	-	-	-	33.0
Birtle South-Rossburn 66 kV Line	4.9	-	-	-	-	0.1	0.3	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9
Stanley Station 230-66 kV Transformer Addition	21.1	-	-	-	1.8	8.1	7.6	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	21.1
Stanley Station 230-66 kV Hot Standby Installation	6.2	4.9	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.1
Ashern Station 230 kV Shunt Reactor Replacement	2.7	0.0	0.0	-	2.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Tank Farm Upgrade	1.1	0.5	0.5	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.0
Interlake Digital Microwave Replacement	19.7	3.5	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.8
Communication System - Southern MB (Great Plains)	21.9	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4
Communications Upgrade Winnipeg Area	7.4	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
Pilot Wire Replacement	9.6	1.3	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.7
Transmission Line Protection & Teleprotection Replacement	21.1	1.4	6.1	6.1	2.3	1.1	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.9
Winnipeg Central Protection Wireline Replacement	9.3	2.5	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1
Mobile Radio System Modernization	30.7	0.3	2.5	9.2	10.6	8.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.6
Cyber Security Systems	10.1	3.6	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.0
Site Remediation	13.3	1.3	3.8	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.2
Oil Containment	7.4	0.9	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.4
Station Battery Bank Capacity & System Reliability Increase	46.5	5.3	4.7	6.4	6.4	6.6	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7
Red River Floodway Expansion Project	1.8	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3
Waverley Service Centre Oil Tank Farm Replacement	3.0	0.5	1.0	0.6	0.4	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0
115 kV Transmission Lines	NA	-	-	-	-	-	-	-	-	-	-	-	10.3	16.1	19.8	21.1	25.8	23.7	25.5	28.4	28.9	199.7
230 kV Transmission Lines	NA	-	-	-	-	-	-	-	-	-	-	-	5.9	9.2	11.3	12.1	14.8	13.6	14.6	16.3	16.5	114.3
Sub-Transmission	NA	-	-	-	-	-	-	-	-	-	-	-	4.3	6.7	8.3	8.8	10.8	9.9	10.6	11.9	12.1	83.4
Communications	NA	-	-	-	-	-	-	-	-	-	-	-	14.7	23.0	28.2	30.0	36.8	33.8	36.3	40.5	41.2	284.4
Site Remediation	NA	-	-	-	-	-	-	-	-	-	-	-	1.2	1.8	2.2	2.4	2.9	2.7	2.9	3.2	3.2	22.4
Transmission Domestic	NA	29.6	30.0	30.6	31.2	31.8	32.4	33.1	33.8	34.4	35.1	35.8	36.5	37.3	38.0	38.8	39.5	40.3	41.1	42.0	42.8	714.1
		77.5	86.0	86.9	78.3	86.2	81.4	46.4	39.2	41.6	43.6	45.4	85.1	94.1	107.8	113.2	130.7	124.1	131.1	142.2	144.7	1,785.4
Customer Service & Distribution																						
Winnipeg Distribution Infrastructure Requirements	14.9	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.7
Defective RINJ Cable Replacement	8.7	0.5	2.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1
Brereton Lake Station Area	9.0	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3
Stony Mountain New 115 - 12 kV Station	5.0	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
Rover Substation Replace 4 kV Switchgear	12.7	0.4	3.3	3.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	1.0	14.5	9.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27.0
Frobisher Station Upgrade	14.4	4.4	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.5
Burrows New 66 kV-12 kV Station	28.6	9.1	12.2	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.3
Winnipeg Central District Oil Switch Project	7.1	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8
William New 66 kV-12 kV Station	10.3	0.5	3.6	3.1	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply - Stage 1	6.5	4.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.4
St. James 24 kV System Refurbishment	65.9	1.3	14.1	31.6	18.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65.8
Shoal Lake New 33 - 12.47 kV DSC	3.6	3.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2
York Station	4.0	2.0	1.8	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.9
Cromer North Station & Reston RE12-4 25 kV Conversion	4.3	3.0	0.1	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.3
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	0.6	3.1	1.9	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.2
Winkler Market Feeder M25-13 Conversion	2.9	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8
Neepawa North Feeder NN12-2 & Line 57 Rebuild	1.9	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9
Perimeter South Station Distribution Supply Centre Installation	2.4	0.4	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4
Niverville Station 66-12 kV Bank Replacements	2.6	2.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
Winnipeg Central District Underground Network Asbestos Removal	3.0	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
Gas SCADA Replacement	4.6	1.0	3.0	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.6
Distribution		-	-	-	-	-	-	-	-	-	-	-	30.5	47.9	58.8	62.6	76.7	70.5	75.7	84.4	85.8	592.9
Customer Service & Distribution Domestic	NA	115.9	117.5	119.9	122.3	124.7	127.2	129.8	132.4	135.0	137.7	140.5	143.3	146.1	149.1	152.0	155.1	158.2	161.3	164.6	167.9	2,800.4
		158.1	177.8	176.3	147.0	124.7	127.2	129.8	132.4	135.0	137.7	140.5	173.8	194.0	207.8	214.7	231.8	228.7	237.0	249.0	253.6	3,576.9
Customer Care & Marketing																						
Advanced Metering Infrastructure	30.9	-	4.0	5.3	5.4	5.6	4.3	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	28.8
Customer Care & Marketing Domestic	NA	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	61.1
		2.5	6.5	8.0	8.1	8.3	7.1	7.1	2.9	2.9	3.0	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	89.9
Finance & Administration																						
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	160.0
Workforce Management (Phase 1 to 4)	11.3	3.9	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9
Fleet	NA	13.3	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	16.5	16.8	17.1	17.5	17.8	18.2	18.6	18.9	19.3	321.9
Finance & Administration Domestic	NA	24.1	24.4	24.9	25.4	25.9	26.4	27.0	27.5	28.1	28.6	29.2	29.8	30.4	31.0	31.6	32.2	32.9	33.5	34.2	34.9	582.0
		49.2	46.9	46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	54.3	55.2	56.1	57.1	58.1	59.1	60.1	61.1	62.2	1,068.9
Capital Increase Provision		-	-	-	-	-	-	63.1	90.4	82.8	97.3	99.2	-	-	-	-	-	-	-	-	-	432.8
ELECTRIC CAPITAL SUBTOTAL		**1,255.0**	**1,165.5**	**1,074.5**	**1,038.6**	**1,228.0**	**1,691.7**	**2,247.6**	**2,160.5**	**1,653.3**	**1,800.3**	**1,557.9**	**1,433.8**	**1,347.8**	**1,526.8**	**811.5**	**640.2**	**611.8**	**640.5**	**684.6**	**696.8**	**25,266.8**

ATTACHMENT 1

CAPITAL EXPENDITURE FORECAST FOR 20 YEAR OUTLOOK (2009/10 - 2028/29) - JANUARY 2010

(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	20 Year Total
GAS																						
Customer Service & Distribution																						
Customer Service & Distribution Domestic	NA	20.7	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	25.9	26.4	26.9	27.5	28.0	28.6	29.2	29.7	30.3	505.8
		20.7	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	25.9	26.4	26.9	27.5	28.0	28.6	29.2	29.7	30.3	505.8
Customer Care & Marketing																						
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.6
Demand Side Management	NA	13.5	13.1	11.6	11.7	11.1	10.2	10.6	10.3	7.7	5.5	5.1	5.1	5.0	5.1	5.1	3.6	3.5	3.5	3.5	3.4	148.1
Customer Care & Marketing Domestic	NA	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4	3.4	3.5	3.6	3.6	3.7	3.8	3.9	3.9	4.0	66.9
		16.2	16.9	19.8	22.9	14.1	13.2	13.7	13.5	11.0	8.8	8.4	8.5	8.5	8.6	8.7	7.3	7.3	7.4	7.4	7.4	229.6
Capital Increase Provision		-	-	-	-	-	-	-	-	2.3	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	61.6
GAS CAPITAL SUBTOTAL		**37.0**	**38.2**	**41.5**	**45.0**	**36.6**	**36.2**	**37.2**	**37.4**	**37.6**	**38.5**	**38.8**	**39.4**	**40.1**	**40.8**	**41.6**	**40.8**	**41.5**	**42.2**	**43.0**	**43.7**	**797.0**
CONSOLIDATED CAPITAL		**1,292.0**	**1,203.6**	**1,116.0**	**1,083.6**	**1,264.6**	**1,727.9**	**2,284.8**	**2,197.9**	**1,690.9**	**1,838.8**	**1,596.6**	**1,473.2**	**1,387.9**	**1,567.6**	**853.1**	**681.0**	**653.3**	**682.7**	**727.6**	**740.5**	**26,063.8**
TARGET ADJUSTMENT		(188.0)	(118.6)	(80.0)	(59.1)	221.4	37.1	(128.8)	(32.7)	25.4	(187.8)	(305.6)	-	-	-	-	-	-	-	-	-	(816.7)
		1,104.0	**1,085.0**	**1,036.0**	**1,024.5**	**1,486.0**	**1,765.0**	**2,156.0**	**2,165.2**	**1,716.3**	**1,651.0**	**1,291.0**	**1,473.2**	**1,387.9**	**1,567.6**	**853.1**	**681.0**	**653.3**	**682.7**	**727.6**	**740.5**	**25,247.0**

PUB/MH I-57

Subject: Tab 6: Capital Expenditures
Reference: CEF 09-1/CEF 08-1 Point du Bois, Slave Falls

a) **Please provide updated details on both the Pointe du Bois G.S. and Slave Falls G.S. project showing expenditure changes and scope modifications.**

ANSWER:

Pointe du Bois

As a result of the change in the economic climate and rising construction costs, a decision has been made that the Pointe du Bois Modernization Project will now take the form of 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. A new powerhouse is no longer included as part of the project. As a result of the reduction in scope the estimated expenditure has been reduced from $818 million to $318 million. The $318 million is a placeholder amount and will be revised when a new estimate for the re-scoped Pointe du Bois project is completed.

Slave Falls

No significant changes in the scope or level of expenditures are envisioned for Slave Falls. The level of expenditure remains at approximately $198.3 million. A number of initiatives are ongoing at Slave Falls Generating Station including the Slave Falls access improvements and turbine and generator overhauls.

PUB/MH I-57

Subject: Tab 6: Capital Expenditures
Reference: CEF 09-1/CEF 08-1 Point du Bois, Slave Falls

b) What is the status of the access road to Slave Fall G.S.?

ANSWER:

A contract was awarded to Sagkeeng/TCIG-Munro Joint Venture on November 23, 2009 to construct the portion of road from Pointe du Bois to the start of the rock filled dam. A winter access road has been installed to the start of the rock fill dam. Drilling, blasting and grade building operations are in progress at multiple locations along the right of way. Drilling operations are also in progress in the quarry in preparation for setup of the crusher. This contract is scheduled to be complete in the fall of 2010.

Separate tender packages are being prepared for the portion of the road from the start of the rock filled dam to the Slave Falls powerhouse and for decommissioning of the rail system. These packages are scheduled to be issued in the spring of 2010 and complete late in the fall of 2010.

PUB/MH I-58

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1 Keeyask**

a) **Please explain why the CEF 08-1 budgeted cost of Keeyask G.S. has increased by $891.2 million from $3,700.4 million to $4,591.6 million.**

ANSWER:

The increase in the CEF08-1 budgeted cost of Keeyask Generating Station is based on the Applied Wuskwatim GS bidder information and the advanced detailed engineering design information outlined in CEF09. The infrastructure required for the construction of the project was advanced by one year adding an additional year of construction to the overall schedule.

PUB/MH I-58

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1 Keeyask**

b) Please provide details on the significant component cost increases for each of the generation station, associated transmission facilities, and access roadways.

ANSWER:

The significant component cost increase for the Keeyask Generating Station of $864.2 million is primarily due to an increase in interest by $381.2 million and higher base costs of $483 million. The higher base costs ($483 million) for materials and labour include gates and guides ($88 million), concrete ($108 million), turbines and generators ($70 million), earthfill dykes and dams ($29 million), river management ($14 million), rock excavation ($11 million), miscellaneous direct cost ($17 million), administration/service contracts ($46 million), construction camp and work area ($52 million), environmental and mitigation ($32 million), and electrical and communication ($16 million).

There was no change to cost from CEF08 to CEF09 for associated transmission facilities.

The higher cost associated with the access roadways ($27 million) includes PR 280 Upgrade, North Access Road, South Access Road and Batnau Dam Upgrade.

PUB/MH I-59

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1**

a) Please provide the most recent budget estimates for the major components of Bipole III:

i. Northern Converter
ii. Transmission Lines
iii. Southern Converter

ANSWER:

Please see the following table for the major components of Bipole III.

COMPONENTS	**APPROVED BUDGET (IN THOUSANDS)**
Transmission Base Estimate	814,312
Escalation & Interest	319,336
Subtotal	1,133,648
Northern Converter Base Estimate	388,482
Southern Converter Base Estimate	485,116
Escalation & Interest - Converters	240,591
Subtotal	1,114,189
TOTAL	**2,247,837**

PUB/MH I-59

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1**

b) Please provide component cost details and function description on the Riel Converter Station.

ANSWER:

Please see the following table for the major components of the Riel Converter Station.

COMPONENTS	APPROVED BUDGET (IN THOUSANDS)
Riel Converter Station	460,197
Riel Site Development for Converters & AC Switchyard	21,540
Riel Electrode Line	3,379
TOTAL	**485,116**

Function Descriptions:

Riel Converter Station: Design and construct a converter station with 2000 MW of converters at Riel Station, including four 250 Megavolt Ampere Reactive (MVAR) synchronous compensators.

- Synchronous Condensers
  Four 250 Mvar Rotating Electrical Machines that provide Reactive Power support for the Riel HVDC Converter. They are required to support 230 kV bus voltage, provide system inertia and for system stability.

- HVDC Converter and associated Buildings
  The HVDC Converters consist of two series 250 kV Valve Groups per Pole. The Poles are opposite polarity for a +/- 500 kV 2000 MW total Bipole rating. The converter buildings contain the indoor control and HVDC converter equipment which consists of power electronic Thyristor based valves.

- Converter Transformers

  There are 12 in-service converter transformer units with a total 2000 MVA capacity. The converter transformers are required to provide the correct voltage levels for the converter valves as well as provide DC isolation.

- DC Switchyard

  The DC switchyard consists of high-voltage circuit breakers and switches used to connect and isolate DC lines, Converter Equipment, DC filters and DC Smoothing Reactors.

- HVDC Filter Area

  The AC Filters provide reactive power to the HVDC Converter as well filtering out harmonics (electrical noise) created by the process of converting DC to AC.

Riel Converter & 230 kV AC Switchyard Site Development: Site development work for Riel Converter site that is being done in conjunction with the Riel Sectionalization project site preparation work. Riel 230 kV AC Switchyard, includes 50% costs of the sectionalization 230 kV AC switchyard costs (establishing the first five bays); and the full establishment of the expansion, four additional bays required.

- Site development work for Riel Converter site

- 230 kV AC Switchyard

  The 230 kV AC Switchyard consists of HV circuit breakers and switches used to connect and isolate AC lines, Converter transformers and AC filters.

Riel Electrode Line: Electrode line between Riel Converter Station and the Riel Electrode Site.

- Electrode Line

  The electrode line provides a ground reference for the +/-500 kV bipole. The electrode and associated line may be used for ground return during monopolar operation.

PUB/MH I-59

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1**

c) Please provide component cost details and function description on the transmission connection between Dorsey and Riel stations.

ANSWER:

There is currently no new/additional transmission planned with Bipole III between Dorsey and Riel. The description in the CEF09 booklet incorrectly referenced paralleling between Dorsey and Riel stations for a western Bipole III line. With a western Bipole III line, paralleling was not feasible and was removed from the budget.

PUB/MH I-59

Subject: Tab 6: Capital Expenditures
Reference: CEF 09-1/CEF 08-1

d) Please provide component cost details and function description on the 500kV from Dorsey to the U.S. border.

ANSWER:

Please see the following table for the major components of the Dorsey US Border New 500 kV Transmission project.

COMPONENTS	APPROVED BUDGET (IN THOUSANDS)
Dorsey-US Border New 500kV Transmission Line	124,580
Dorsey-US Border New 500kV Transmission Station	80,185
TOTAL	**204,765**

Function Descriptions:

Dorsey-US Border New 500kV Transmission - Transmission Line:
Design and construct one 63 km 500 kV transmission line between the Riel and Dorsey stations. Design and construct one 125 km 500 kV transmission line between the Dorsey Station and the U.S. border. Acquire property for the right of way. Conduct environmental impact assessment, consult with communities, obtain licensing and perform environmental monitoring for all facilities.

Dorsey-US Border New 500kV Transmission – Station:
Purchase and install four 230-500-46 kV 240/320/400 MVA single phase autotransformers at the Riel Station. Purchase and install two 73.4 MVAR capacitor banks on the 46 kV tertiary of the Riel transformer. Purchase and install four 100 MVAR 500 kV single phase shunt reactors on the new 500 kV transmission in the Dorsey Station. Terminate the transmission lines in existing breaker positions at the Dorsey and Riel Stations. Design, install and commission communication system additions for the protection and control of the transmission facilities.

<u>PUB/MH I-60</u>

Subject: **Tab 6: Capital Expenditures**
Reference: **Bipole III**

a) With respect to Bipole III please compare East- side routing to the Westside routing based on:

i. Current cost estimates of construction;
ii. Annual operating costs;
iii. Transmission line losses;
iv. Converter costs;
v. Maximum capacity under outage conditions for Bipole I & II; and
vi. Maximum capacity when Bipole I & II are in service.

<u>ANSWER</u>:

The Manitoba Hydro-Electric Board has determined that a West Side route for Bipole III was the best option to proceed with given that an East Side route was not available. Manitoba Hydro has no current information on a hypothetical east side route.

PUB/MH I-60

Subject: **Tab 6: Capital Expenditures**
Reference: **Bipole III**

b) Confirm that the decision on the routing on the west side of the Province has been mandated by the provincial government.

ANSWER:

The Manitoba Hydro-Electric Board has determined that a West Side route for Bipole III was the best option to proceed with given that an East Side route was not available.

<u>PUB/MH I-60</u>

Subject: **Tab 6: Capital Expenditures**
Reference: **Bipole III**

c) **Assume all costs for Bipole III are allocated to domestic customers, please provide the annual revenue requirement and rate impacts for a West-side route compared to an East- side route.**

<u>ANSWER</u>:

The Manitoba Hydro-Electric Board has determined that a West Side route for Bipole III was the best option to proceed with given that an East Side route was not available. Manitoba Hydro has no current information on a hypothetical east side route.

PUB/MH I-61

Subject: Tab 6: Capital Expenditures
Reference: CEF 09-1/CEF 08-1 (Appendix 4.3) Domestic Cost Allocations

Domestic Items/(Total Capital Expenditures)	11 Year Total $ M	
	CEF 09	CEF 08
Power Supply	231 (1,185)	233 (1,198)
Transmission	358 (713)	-
Transmission & Distribution	-	1,082 (1,770)
Customer Service & Distribution	1,403 (1,586)	-
Customer Service & Marketing	-	733 (767)
Customer Care & Marketing	31 (60)	-
Finance & Administration	292 (546)	271 (367)
Total	2,224	2,319

a) Please confirm the above revisions to the domestic item expenditure forecast.

ANSWER:

The total for the CEF09 column should be 2,315. All other values are correct, with minor rounding differences.

PUB/MH I-61

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1 (Appendix 4.3) Domestic Cost Allocations**

Domestic Items/(Total Capital Expenditures)	11 Year Total $ M	
	CEF 09	CEF 08
Power Supply	231 (1,185)	233 (1,198)
Transmission	358 (713)	-
Transmission & Distribution	-	1,082 (1,770)
Customer Service & Distribution	1,403 (1,586)	-
Customer Service & Marketing	-	733 (767)
Customer Care & Marketing	31 (60)	-
Finance & Administration	292 (546)	271 (367)
Total	2,224	2,319

b) **Please provide the rationale and particulars of changes made to the categorization and budgeted amounts.**

ANSWER:

Manitoba Hydro realigned business units in February 2009. Changes to the categorization and budgeted amounts were made to correspond to the Corporation's new organization structure.

PUB/MH I-62

Subject: **Tab 6: Capital Expenditures**
Reference: **Appendix 6.1 CEF 09-1: Major Capital Projects**

a) Please file CEF 06-1, CEF 08-1(20 Year) Capital forecasts.

ANSWER:

Please see the attachments.

CAPITAL EXPENDITURE FORECAST (CEF06-1)
(In Millions of Dollars)

	Project Cost	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	11 Year Total
ELECTRIC													
MAJOR GENERATION & TRANSMISSION													
Wuskwatim	1,351.4	116.9	159.3	197.4	217.1	220.6	203.0	76.9	4.7	-	-	-	1,196.0
Keeyask Generating Station Licensing	371.7	38.3	36.8	32.2	31.8	34.5	22.9	-	-	-	-	-	196.5
Conawapa Generating Station	4,978.4	34.8	39.5	50.8	49.3	69.1	51.0	89.0	128.9	209.5	215.0	427.2	1,364.0
Kelsey GS Improvements & Upgrades	165.5	29.5	33.5	28.3	26.6	16.4	-	-	-	-	-	-	134.2
Kettle GS Improvements & Upgrades	61.0	-	-	-	-	-	6.8	6.4	4.0	3.9	6.6	6.8	34.5
Pointe du Bois Rehabilitation	834.1	1.7	30.5	40.7	39.6	35.2	48.2	94.2	149.6	211.5	137.3	45.5	834.0
Planning Studies		5.5	2.4	1.6	1.7	1.5	1.9	0.7	0.7	0.9	1.3	1.3	19.3
Henday - Riel +/- 500kV HVDC Line	1,879.9	1.0	1.9	2.9	9.1	12.6	23.4	118.9	266.7	349.1	501.9	453.5	1,740.9
Riel 230/500kV Station	102.9	0.2	0.6	1.8	5.3	16.9	29.2	28.3	19.6	0.0	-	-	101.9
Northern AC Transmission System Requirements	43.4	4.4	-	-	-	-	-	-	-	-	-	-	4.4
Herblet Lake - The Pas Ralls Island 230 kV Trans	54.1	0.5	20.1	17.6	12.9	3.0	-	-	-	-	-	-	54.1
Demand Side Management	396.8	40.5	39.6	41.3	40.8	37.5	37.8	35.9	36.0	32.4	28.1	26.9	396.8
MAJOR GENERATION & TRANSMISSION TOTAL		**273.2**	**364.3**	**414.5**	**434.2**	**447.1**	**424.0**	**450.2**	**610.2**	**807.3**	**890.2**	**961.3**	**6,076.5**
NEW HEAD OFFICE													
New Head Office	**258.1**	**93.9**	**125.5**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**219.4**
CORPORATE RELATIONS													
Waterways Management Programs		4.5	4.5	4.6	4.6	4.4	-	-	-	-	-	-	22.6
Mitigation		16.5	13.8	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	52.7
CORPORATE RELATIONS TOTAL		**21.0**	**18.3**	**7.1**	**7.1**	**6.9**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**75.3**

ATTACHMENT 1

CAPITAL EXPENDITURE FORECAST (CEF06-1)
(In Millions of Dollars)

	Project Cost	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	11 Year Total
POWER SUPPLY													
Bipole 1 Pole 2 Thyristor Valve Project	66.8	1.7	-	-	-	-	-	-	-	-	-	-	1.7
Converter Transformer Bushing Replace	4.7	0.7	0.9	-	-	-	-	-	-	-	-	-	1.6
BP 1 & 2 Electrode Line Monitoring	1.7	0.0	0.7	1.0	0.0	-	-	-	-	-	-	-	1.7
HVDC Auxiliary Power Supply	3.7	1.2	0.0	-	-	-	-	-	-	-	-	-	1.2
Dorsey Synchronous Condenser Refurbishment	16.7	5.3	4.0	0.7	-	-	-	-	-	-	-	-	10.0
Bipole 1 Chiller	13.8	4.1	0.2	-	-	-	-	-	-	-	-	-	4.2
ASEA SYNC Condenser Glycol Cooler Upgrade	2.6	0.4	0.1	-	-	-	-	-	-	-	-	-	0.4
HVDC Bipole 1 Roof Replacement	5.9	1.2	0.9	0.5	0.3	-	-	-	-	-	-	-	3.0
HVDC System Transformer and Reactor FP&P	8.4	2.1	0.4	-	-		-	-	-	-	-	-	2.5
HVDC AC Filter PCB Capacitor Replacement	44.3	8.6	6.8	4.9	14.4	-	-	-	-	-	-	-	34.8
HVDC Transformer Replacement Program	94.2	10.2	2.2	1.9	1.5	-	-	-	-	-		-	15.7
Dorsey 230KV Relay Building Upgrade	6.5	1.2	2.3	2.6	-	-	-	-	-	-		-	6.1
EE SYNC Condenser Glycol Cooler Upgrade	4.0	0.7	1.1	-	-	-	-	-	-	-	-	-	1.8
HVDC Stations Ground Grid Refurbishment	4.1	2.1	1.2	-	-	-	-	-	-	-	-	-	3.4
HVDC BP2 HLR Breaker Replacements	4.2	1.5	0.4	0.0	-	-	-	-	-	-	-	-	2.0
BP1 Pole Differential Protection	3.3	-	-	3.3	-	-	-	-	-	-	-	-	3.3
BP1 Pole 1 Bypass Vacuum Switch Removal	15.1	-	1.5	3.3	5.0	2.5	2.8	-	-	-	-	-	15.1
HVDC BP2 Refrigerant Condenser Replace	10.8	-	-	2.7	6.8	1.2	-	-	-	-	-	-	10.8
BP1 Smoothing Reactor Replacement	20.1	-	-	2.8	11.3	6.1	-	-	-	-	-	-	20.1
BP2 Valve Hall Wall Bushing Replacements	19.2	-	-	-	3.5	4.7	4.8	4.9	1.4		-	-	19.2
HVDC BP1 CQ Disconnect Replacement	5.2	-	0.4	0.5	1.0	1.5	1.1	0.7	-	-	-	-	5.2
Great Falls G.S. Rehabilitation	30.4	1.0	1.3	-	-	-	-	-	-	-	-	-	2.2
Pine Falls G.S. Rehabilitation	26.4	1.5	3.5	16.1	0.5	-	-	-	-	-	-	-	21.6
Laurie River GS Phase 2&3 Rehabilitation	9.4	5.1	-	-	-	1.0	0.8	1.2	-	-	-	-	8.1
Jenpeg G.S. Unit Overhauls	35.3	2.2	0.2	0.3	4.2	0.3	4.2	0.3	4.3	0.2	4.3	4.4	24.8
Power Supply Dam Safety Upgrades	15.0	4.6	-	-	-	-	-	-	-	-	-	-	4.6
Winnipeg River Control System	10.4	0.5	0.3	0.4	0.5	-	-	-	-	-	-	-	1.7
Winnipeg River Riverbank Protection	10.9	0.7	1.1	1.1	1.2	-	-	-	-	-	-	-	4.2
Power Supply Hydraulic Controls	10.1	1.1	2.1	1.9	4.4	-	-	-	-	-	-	-	9.6
Slave Falls GS Creek Spillway Rehab	5.3	0.0	0.0	5.2	-	-	-	-	-	-	-	-	5.3
Slave Falls GS Rehabilitation	179.4	1.9	5.6	6.0	8.9	19.0	24.4	24.5	25.2	15.8	16.0	16.6	163.8
Generating Station Roof Replacements	9.2	2.5	2.7	3.9	-	-	-	-	-	-	-	-	9.1
Great Falls Unit 4 Overhaul	16.5	1.4	6.4	7.4	1.3	-	-	-	-	-	-	-	16.5
Great F 115kV Indoor S-Stn Safety Improvements	9.6	1.9	4.7	2.5	0.0	-	-	-	-	-	-	-	9.2
Water Licenses & Renewals	9.1	1.8	2.2	1.7	1.2	1.1	0.4	-	-	-	-	-	8.4
Brandon G.S. Unit 5 License Review	18.7	2.6	1.6	8.7	5.1	-	-	-	-	-	-	-	17.9
Selkirk G.S. License Review	46.9	2.1	1.8	11.5	14.4	16.1	-	-	-	-	-	-	45.9
Fire Protection Projects-HVDC	5.2	1.6	3.1	0.1	0.2	0.3	-	-	-	-	-	-	5.2
Halon Replacement Project	47.1	0.5	8.5	9.2	9.4	9.6	9.9	-	-	-	-	-	47.1
Power Supply Fall Protection Program	11.3	3.3	2.4	2.4		-	-	-	-	-	-	-	8.2
Oil Containment Projects-HVDC	17.0	2.0	3.8	2.5	0.8	0.2	0.4	-	0.1	-	0.4	-	10.3
Generation Townsite Infrastructure	38.3	4.8	2.9	4.7	0.3	0.3	0.3	0.3	-	-	-	-	13.8
Site Remediation	25.0	4.2	1.0	0.5	0.5	0.6	0.4	0.4	0.4	-	-	-	8.0
High Voltage Laboratory	1.2	0.1	-	-	-	-	-	-	-	-	-	-	0.1
Power Supply Security Installations/Upgrades	11.6	2.2	4.2	3.6	1.0	0.2	0.3	-	-	-	-	-	11.6
PS Sewer & Dom Water System Instal/Upgr	12.9	4.0	4.6	2.7	1.4	-	-	-	-	-	-	-	12.7
Domestic Item		19.6	20.0	20.4	19.4	19.8	20.2	20.6	21.0	21.4	21.8	22.3	226.2
POWER SUPPLY TOTAL		**114.4**	**107.3**	**137.2**	**118.5**	**84.4**	**69.7**	**52.9**	**52.4**	**37.5**	**42.5**	**43.3**	**859.8**

ATTACHMENT 1

CAPITAL EXPENDITURE FORECAST (CEF06-1)
(In Millions of Dollars)

	Project Cost	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	11 Year Total
TRANSMISSION & DISTRIBUTION													
Wpg to Brandon Trans System Improvements	34.9	-	-	2.0	1.1	3.1	2.8	4.5	21.4	-	-	-	34.9
Transcona New 230-66kV Station	9.2	0.1	1.0	4.7	3.5	-	-	-	-	-	-	-	9.2
Dorsey- LaVerendrye- St. Vital 230kV Trans	28.0	-	-	-	-	-	-	5.6	7.6	9.2	5.6	-	28.0
Rosser - Silver 230kV Transmission	34.8	3.7	-	-	-	-	-	-	-	-	-	-	3.7
Raven Lake Station 230-66kV Transformation	8.7	-	-	-	-	-	-	-	-	0.7	1.6	3.1	5.4
Neepawa 230-66 kV Station	20.9	-	-	0.2	1.0	8.6	11.1	-	-	-	-	-	20.9
Richer South 230 - 66kV Transformer Addition	9.6	5.2	2.4	0.3	-	-	-	-	-	-	-	-	7.9
Pine Falls - Bloodvein 115 kV Transmission	32.1	-	0.3	0.9	4.3	20.0	6.6	-	-	-	-	-	32.1
Ridgeway - Selkirk 230 kV Transmission	27.2	-	-	-	4.7	5.3	6.0	11.2	-	-	-	-	27.2
Transmission Line Re-Rating	12.7	2.2	-	-	-	-	-	-	-	-	-	-	2.2
Dorsey 230kV Bus Enhancements	19.5	0.5	-	-	-	-	-	-	-	-	-	-	0.5
Pine Falls - Great Falls 115 - 66kV Supply	12.1	0.0	0.0	0.1	0.3	1.8	0.9	-	-	-	-	-	3.2
Flin Flon Area Trans Improvements Phase II	13.2	2.4	1.5	-	-	-	-	-	-	-	-	-	4.0
St. Vital - Steinbach 230 kV Transmission	32.2	-	-	-	-	-	-	-	-	-	0.9	1.0	1.8
Rosser Stn 230-115kV Bank 3 Replacement	3.7	0.3	0.3	3.1	-	-	-	-	-	-	-	-	3.7
Birtle South - Rossburn 66 kV Line	4.9	-	-	-	-	-	-	-	0.1	0.3	4.5	-	4.9
St. Boniface - Plessis Rd Bank 2 Addition	2.1	-	-	-	-	-	-	-	-	-	-	-	-
Brandon Crocus Plains - Bank Addition	9.4	-	-	-	1.0	5.1	3.1	0.3	-	-	-	-	9.4
Perimeter South DSC Installation	2.3	0.0	0.2	2.0	-	-	-	-	-	-	-	-	2.3
Portage South 230 - 66kV Transformer Addition	12.3	3.2	0.4	-	-	-	-	-	-	-	-	-	3.6
Winnipeg Central 66kV Breaker Replacement	5.4	3.2	1.3	-	-	-	-	-	-	-	-	-	4.5
Virden Area Distribution Changes	18.4	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Defective RINJ Cable Replacement	8.6	1.4	1.4	0.7	-	-	-	-	-	-	-	-	3.5
Brereton Lake Station Area	8.6	0.6	0.9	-	-	-	-	-	-	-	-	-	1.5
Holland 8kV - 25kV Conversion & Dist. Supply Centre	4.3	3.1	-	-	-	-	-	-	-	-	-	-	3.1
35MVA Mobile Transformer Purchase	2.8	2.4	-	-	-	-	-	-	-	-	-	-	2.4
Stony Mountain New Station	3.4	2.7	0.3	0.3	-	-	-	-	-	-	-	-	3.2
Rover Substation Replace 4kV Switchgear	16.3	0.4	5.1	6.0	-	-	-	-	-	-	-	-	11.5
Martin Substation	10.5	0.3	0.5	2.2	4.4	2.5	-	-	-	-	-	-	9.9
Frobisher Station Upgrade	10.1	0.5	3.7	3.9	1.8	0.1	-	-	-	-	-	-	10.0
Burrows New 66-12kV Station	22.7	0.2	2.1	9.2	4.3	4.4	2.4	-	-	-	-	-	22.6
Wpg Central 12&4kV Manhole Oil Switch Replacement	3.3	1.5	1.5	-	-	-	-	-	-	-	-	-	3.0
William Station New 66-12kV Station	10.2	0.1	0.1	0.9	2.0	4.0	3.0	-	-	-	-	-	10.1
St. James 24 kV System Refurbishment	1.3	-	1.3	-	-	-	-	-	-	-	-	-	1.3
Ness Station Feeder Conversions	2.8	2.8	-	-	-	-	-	-	-	-	-	-	2.8
Communications	120.6	12.7	30.4	16.5	14.7	20.0	1.3	-	-	-	-	-	95.5
Integration of System Control Centres	6.6	1.3	0.9	0.0	-	-	-	-	-	-	-	-	2.3
Site Remediation	11.4	1.2	2.0	1.9	0.5	0.6	-	-	-	-	-	-	6.2
Oil Containment	7.4	1.0	1.0	1.2	1.2	-	-	-	-	-	-	-	4.4
Station Battery Bank Replacement & Upgrade	46.5	3.4	5.0	5.1	5.2	5.1	5.2	5.3	5.4	5.5	-	-	45.2
Red River Floodway Expansion (Electric)	1.8	1.8	-	-	-	-	-	-	-	-	-	-	1.8
Domestic Item		97.3	100.0	101.9	104.0	106.1	108.2	110.4	112.6	114.8	117.1	119.4	1,191.7
TRANSMISSION & DISTRIBUTION TOTAL		**156.3**	**163.7**	**162.9**	**153.9**	**186.8**	**150.5**	**137.3**	**147.1**	**130.5**	**129.6**	**123.5**	**1,642.0**

ATTACHMENT 1

CAPITAL EXPENDITURE FORECAST (CEF06-1)
(In Millions of Dollars)

	Project Cost	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	11 Year Total
CUSTOMER SERVICE & MARKETING													
Automatic Meter Reading Implementation	30.9	1.2	5.4	3.9	3.9	4.0	4.0	4.1	4.3	-	-	-	30.8
Distribution PCB Testing & Transformer Replacement	19.6	3.5	1.3	-	-	-	-	-	-	-	-	-	4.7
Winnipeg Distribution Infrastructure Requirements	14.9	2.0	2.0	2.0	2.3	-	-	-	-	-	-	-	8.3
WCD U/G Network Asbestos Removal	3.0	0.8	0.8	1.3	-	-	-	-	-	-	-	-	2.8
Domestic Item		60.8	59.0	60.2	61.4	62.6	63.9	65.2	66.5	67.8	69.2	70.6	707.2
CUSTOMER SERVICE & MARKETING TOTAL		**68.3**	**68.5**	**67.4**	**67.6**	**66.6**	**67.9**	**69.3**	**70.8**	**67.8**	**69.2**	**70.6**	**753.8**
FINANCE & ADMINISTRATION													
Corporate Building Program		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
Customer Information System	21.0	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Enterprise GIS Project	21.9	7.0	1.4	-	-	-	-	-	-	-	-	-	8.4
Workforce Management	11.3	2.8	5.3	3.2	-	-	-	-	-	-	-	-	11.3
WorkSmart	5.4	2.3	3.1	-	-	-	-	-	-	-	-	-	5.4
Domestic Item		23.7	22.4	24.1	23.3	25.0	25.3	26.1	25.2	27.1	26.2	29.4	277.8
FINANCE & ADMINISTRATION TOTAL		**44.5**	**40.3**	**35.3**	**31.3**	**33.0**	**33.3**	**34.1**	**33.2**	**35.1**	**34.2**	**37.4**	**391.7**
ELECTRIC CAPITAL SUBTOTAL		**771.5**	**887.7**	**824.4**	**812.6**	**824.9**	**747.9**	**746.1**	**916.2**	**1,080.6**	**1,168.2**	**1,238.5**	**10,018.6**
ELECTRIC COST FLOW ADJUSTMENT		**(123.9)**	**(112.2)**	**(77.7)**	**55.5**	**16.1**	**42.6**	**28.3**	**32.9**	**52.1**	**55.0**	**(15.5)**	**(47.0)**
ELECTRIC TOTAL		**647.6**	**775.5**	**746.6**	**868.1**	**840.9**	**790.5**	**774.4**	**949.0**	**1,132.7**	**1,223.3**	**1,223.0**	**9,971.6**
GAS													
TRANSMISSION & DISTRIBUTION													
Southloop Capacity Upgrades	3.4	0.2	3.2	-	-	-	-	-	-	-	-	-	3.4
New Franchise Expansion - Shoal Lake	0.4	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Riser Rehabilitation Program	14.1	2.1	1.7	-	-	-	-	-	-	-	-	-	3.7
Minnedosa Husky Ethanol Plant	2.3	0.7	1.6	-	-	-	-	-	-	-	-	-	2.3
Steinbach Capacity Upgrades	1.3	1.3	-	-	-	-	-	-	-	-	-	-	1.3
Domestic Item		14.4	14.7	17.2	17.5	17.8	18.2	18.6	18.9	19.3	19.7	20.1	196.5
TRANSMISSION & DISTRIBUTION TOTAL		**19.0**	**21.2**	**17.2**	**17.5**	**17.8**	**18.2**	**18.6**	**18.9**	**19.3**	**19.7**	**20.1**	**207.6**
CUSTOMER SERVICE & MARKETING													
Automatic Meter Reading	15.0	0.3	3.1	4.2	3.7	3.7	-	-	-	-	-	-	15.0
Demand Side Management	100.3	8.6	11.1	8.6	8.7	8.8	8.9	8.9	8.3	6.3	5.8	5.9	89.9
Domestic Item		6.5	6.6	6.7	6.9	6.8	6.9	7.1	7.2	7.4	7.5	7.7	77.2
CUSTOMER SERVICE & MARKETING TOTAL		**15.4**	**20.8**	**19.5**	**19.3**	**19.3**	**15.8**	**16.0**	**15.5**	**13.7**	**13.3**	**13.6**	**182.1**
Gas Regulatory Costs		**1.2**	**1.6**	**1.0**	**2.1**	**1.0**	**2.1**	**1.1**	**2.2**	**1.1**	**2.3**	**1.9**	**17.5**
GAS CAPITAL SUBTOTAL		**35.6**	**43.6**	**37.7**	**38.8**	**38.1**	**36.2**	**35.6**	**36.7**	**34.1**	**35.3**	**35.5**	**407.2**
GAS COST FLOW ADJUSTMENT		**(2.5)**	**(2.3)**	**(2.6)**	**(2.7)**	**(2.9)**	**(2.9)**	**(2.9)**	**(3.0)**	**(3.0)**	**(3.1)**	**(3.2)**	**(30.9)**
GAS TOTAL		**33.1**	**41.3**	**35.1**	**36.1**	**35.2**	**33.3**	**32.7**	**33.7**	**31.0**	**32.2**	**32.4**	**376.3**
CONSOLIDATED CORPORATE SUMMARY													
CONSOLIDATED CAPITAL SUBTOTAL		**807.1**	**931.3**	**862.0**	**851.5**	**863.0**	**784.1**	**781.7**	**952.8**	**1,114.7**	**1,203.6**	**1,274.0**	**10,425.8**
CONSOLIDATED COST FLOW ADJUSTMENT		**(126.4)**	**(114.5)**	**(80.3)**	**52.8**	**13.2**	**39.7**	**25.3**	**29.9**	**49.1**	**51.9**	**(18.6)**	**(77.9)**
CONSOLIDATED CORPORATE TOTAL		**680.7**	**816.8**	**781.7**	**904.3**	**876.2**	**823.8**	**807.1**	**982.7**	**1,163.7**	**1,255.5**	**1,255.4**	**10,347.9**

ATTACHMENT 2

CAPITAL EXPENDITURES FORECAST FOR 20 YEAR FINANCIAL FORECAST (ELECTRICITY OPERATIONS) - JANUARY 2009

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	20 Year Total
ELECTRIC																						
MAJOR GENERATION & TRANSMISSION																						
Wuskwatim Generation	1,274.6	200.6	326.9	256.4	126.8	20.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	931.5
Wuskwatim Transmission	315.5	117.4	52.5	32.2	15.5	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	218.5
Herblet Lake - The Pas 230 kV Transmission	93.2	16.1	39.3	29.0	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88.6
Keeyask Generating Station	4,591.6	58.5	47.0	77.7	62.6	97.7	269.1	531.0	855.5	873.3	619.7	549.0	250.9	45.0	-	-	-	-	-	-	-	4,337.1
Conawapa Generating Station	6,323.8	58.7	60.8	61.0	58.2	62.8	130.0	220.9	298.0	280.3	505.5	857.4	903.7	932.2	866.9	663.5	257.9	2.6	-	-	-	6,220.4
Kelsey Generating Station Improvements & Upgrades	189.6	43.4	45.8	7.4	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	96.9
Kettle Generating Station Improvements & Upgrades	75.6	0.4	7.0	7.3	6.4	6.0	3.8	3.7	6.1	6.4	4.0	3.8	4.0	5.5	5.6	5.7	-	-	-	-	-	75.6
Pointe du Bois Rebuild	818.0	13.0	13.8	14.8	15.5	91.5	141.1	310.7	105.0	94.8	4.0	-	-	-	-	-	-	-	-	-	-	804.3
Pointe du Bois & Slave Falls Transmission	85.9	7.9	19.1	12.5	13.2	16.4	13.0	2.8	-	-	-	-	-	-	-	-	-	-	-	-	-	84.9
Planning Study Costs		5.7	5.9	4.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.3
Bipole 3 Western Route	2,247.8	9.2	16.6	21.4	36.7	113.4	266.5	420.2	627.7	557.9	168.6	-	-	-	-	-	-	-	-	-	-	2,238.3
Riel 230/ 500 kV Station	267.6	4.2	30.7	68.8	75.7	43.5	36.4	4.7	-	-	-	-	-	-	-	-	-	-	-	-	-	264.0
Firm Import Upgrades	4.8	0.1	0.4	2.1	2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8
Dorsey - US Border New 500kV Transmission Line	204.8	-	-	-	0.8	1.8	10.7	11.8	56.7	58.5	61.0	3.4	-	-	-	-	-	-	-	-	-	204.8
Demand Side Management - Electric		42.7	34.6	33.3	31.8	29.4	26.0	26.6	25.4	25.2	24.8	20.3	20.7	21.2	21.6	22.0	22.5	22.9	23.4	23.8	24.3	522.6
Additional North South Transmission	344.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	344.4	-	-	-	-	-	344.4
Generating Station Improvements & Upgrades	535.7	-	-	-	-	-	-	-	-	-	-	-	1.4	6.1	9.7	25.1	41.7	51.8	48.8	50.0	65.4	300.0
MAJOR GENERATION & TRANSMISSION TOTAL		**578.1**	**700.5**	**628.6**	**450.0**	**484.1**	**896.6**	**1,532.4**	**1,974.5**	**1,896.4**	**1,387.6**	**1,434.0**	**1,180.8**	**1,010.0**	**903.8**	**1,060.6**	**322.0**	**77.3**	**72.2**	**73.9**	**89.7**	**16,753.0**
NEW HEAD OFFICE																						
New Head Office	**278.1**	**84.1**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**84.1**
CORPORATE RELATIONS																						
Waterways Management Program		**5.2**	**5.3**	**5.5**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**16.0**

ATTACHMENT 2

CAPITAL EXPENDITURES FORECAST FOR 20 YEAR FINANCIAL FORECAST (ELECTRICITY OPERATIONS) - JANUARY 2009

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	20 Year Total
POWER SUPPLY																						
Converter Transformer Bushing Replacement	5.9	0.1	1.3	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4
Bipole 1 & 2 Electrode Line Monitoring	1.7	0.1	1.5	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.7
HVDC Auxiliary Power Supply Upgrades	3.7	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1
Dorsey Synchronous Condenser Refurbishment	32.3	2.7	4.5	2.8	3.8	2.6	2.7	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	22.4
Dorsey ASEA Synchronous Condenser Cooler Upgrade	3.5	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5
HVDC Bipole 1 Roof Replacement	5.9	0.4	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.0
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	1.1	1.1	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.8
HVDC AC Filter PCB Capacitor Replacement	34.5	5.3	3.0	4.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0
HVDC Transformer Replacement Program	105.7	0.8	4.5	10.0 -	0.2	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.3
Dorsey 230KV Relay Building Upgrade	73.8	0.6	2.8	3.5	1.7	15.8	32.9	12.2	3.6	-	-	-	-	-	-	-	-	-	-	-	-	73.0
HVDC Stations Ground Grid Refurbishment	4.3	0.9	0.4	0.3	0.4	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	9.4	2.9	1.3	0.8	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.3
HVDC Bipole 1 Pole Differential Protection	3.3	-	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.2	4.7	5.4	4.4	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.4
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.9	7.2	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.0
HVDC Bipole 1 Smoothing Reactor Replacement	31.8	0.3	3.1	10.5	12.8	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31.8
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Separation	3.2	0.0	0.0	1.0	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	0.8	2.5	1.2	3.5	1.3	1.8	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	11.7
HVDC BP1 & BP2 DC Converter Transformer Bushing Replacement	8.7	-	0.5	1.0	1.6	5.1	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	19.2	-	3.4	4.6	4.7	4.8	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19.2
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.0	1.2	1.6	0.9	1.1	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2
HVDC - Bipole 2 Thyristor Module Cooling Refurbishment	4.7	0.4	1.8	1.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.7
HVDC BP2 Smoothing Reactor Replacement	17.1	-	-	-	7.0	6.5	3.0	0.5	0.1	-	-	-	-	-	-	-	-	-	-	-	-	17.1
Great Falls Generating Station Rehabilitation	31.1	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2
Pine Falls Generating Station Rehabilitation	56.2	2.3	4.6	24.5	5.2	3.8	3.2	5.9	0.7	-	-	-	-	-	-	-	-	-	-	-	-	50.3
Laurie River GS Phase 2 & 3 Rehabilitation	7.7	-	-	1.0	0.8	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0
Jenpeg Generating Station Unit Overhauls	128.1	0.1	-	-	-	-	-	-	2.4	2.6	19.1	25.1	26.4	27.7	29.1	30.5	32.1	33.7	35.4	37.1	39.0	340.3
Power Supply Dam Safety Upgrades	34.0	2.1	3.5	1.2	1.2	1.2	1.3	1.3	1.9	-	-	-	-	-	-	-	-	-	-	-	-	13.7
Winnipeg River Control System	10.4	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
Winnipeg River Riverbank Protection Program	19.7	1.3	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.5	-	-	-	-	-	-	-	-	-	-	-	11.3
Power Supply Hydraulic Controls	16.0	5.1	1.8	0.9	2.5	2.4	0.9	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	14.5
Slave Falls Rehabilitation	198.3	10.2	13.7	10.4	8.9	23.6	29.9	29.7	20.6	25.9	20.3	-	-	-	-	-	-	-	-	-	-	193.1
Generating Station Roof Replacements	9.2	3.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.9
Great Falls Unit 4 Overhaul	19.7	1.4	4.1	8.1	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19.0
Great Falls 115 kV Indoor Station Safety Improvements	11.6	2.6	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.5
Generation South Transformer Refurbish & Spares	21.0	0.9	2.9	5.3	4.5	3.1	2.6	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	20.9
Water Licenses & Renewals	40.8	3.5	5.1	5.6	4.9	4.8	4.6	4.9	4.6	-	-	-	-	-	-	-	-	-	-	-	-	38.0
Generation South PCB Regulation Compliance	4.7	0.0	2.0	1.6	0.4	0.4	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.7
Kettle Transformer Overhaul Program	35.6	1.0	3.3	3.8	4.6	4.9	5.7	5.7	5.9	0.8	-	-	-	-	-	-	-	-	-	-	-	35.6
Generation South Breaker Replacements	9.4	1.6	2.5	0.9	2.8	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.4
Seven Sisters Generating Station Upgrades	9.5	1.3	3.5	2.5	1.2	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.5
Generation South Excitation Upgrades	18.3	-	-	2.0	3.2	3.9	3.3	3.2	2.7	0.1	-	-	-	-	-	-	-	-	-	-	-	18.3
Brandon Generating Station Unit 5 License Review	18.7	0.3	6.2	7.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.3
Selkirk Generating Station Enhancements	14.2	5.1	4.9	2.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.7
Fire Protection Projects - HVDC	5.2	2.0	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.5
Halon Replacement Project	42.5	11.0	19.2	11.0	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41.6
Power Supply Fall Protection Program	13.5	2.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
Oil Containment - Power Supply	19.1	7.5	2.1	0.5	0.1	0.1	0.3	0.1	0.2	0.0	-	-	-	-	-	-	-	-	-	-	-	11.0
Generation Townsite Infrastructure	52.1	5.7	9.6	5.3	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.2
Site Remediation of Contaminated Corporate Facilities	30.9	1.4	0.7	0.5	0.4	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4
High Voltage Laboratory	26.9	3.4	15.9	5.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.9
Power Supply Security Installations / Upgrades	36.3	6.1	21.4	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0
Power Supply Sewer & Domestic Water System Instal / Upgr	15.1	6.2	4.1	1.6	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.2
Thermal Decommissioning		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48.9	-	-	-	48.9
Domestic Item - Power Supply		20.4	19.4	19.8	20.2	20.6	21.0	21.4	21.8	22.3	22.7	23.2	24.3	25.5	26.8	28.2	29.6	31.0	32.6	34.2	35.9	500.7
POWER SUPPLY TOTAL		**126.9**	**195.3**	**184.7**	**125.3**	**123.7**	**117.8**	**93.2**	**65.8**	**53.2**	**62.1**	**48.3**	**50.7**	**53.2**	**55.9**	**58.7**	**61.6**	**113.7**	**67.9**	**71.3**	**74.9**	**1,804.3**

CAPITAL EXPENDITURES FORECAST FOR 20 YEAR FINANCIAL FORECAST (ELECTRICITY OPERATIONS) - JANUARY 2009

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	20 Year Total
TRANSMISSION & DISTRIBUTION																						
Winnipeg - Brandon Transmission Improvements	40.0	2.3	1.4	1.6	3.6	3.7	5.2	22.0	-	-	-	-	-	-	-	-	-	-	-	-	-	39.8
Transcona New 230 - 66 kV Station	31.0	0.7	8.6	11.9	9.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.7
Neepawa 230 - 66 kV Station	30.0	0.2	5.8	11.3	12.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0
Pine Falls - Bloodvein 115 kV Transmission Line	34.1	-	-	0.3	0.9	4.5	21.2	7.1	-	-	-	-	-	-	-	-	-	-	-	-	-	34.1
Transmission Line Re-Rating	24.1	4.4	0.4	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2
Dorsey 230 kV Bus Enhancement	24.0	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
St Vital-Steinbach 230kV Transmission	32.2	-	-	-	-	-	-	-	0.9	1.0	2.6	5.1	5.3	5.6	5.9	6.2	6.5	6.8	7.2	7.5	7.9	68.5
Rosser Station 230 - 115 kV Bank 3 Replacement	5.8	2.9	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.3
Rosser - Inkster 115kV Transmission	5.1	2.8	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.0
Transcona Station 66kV Breaker Replacement	6.0	0.1	1.0	2.9	1.7	0.3	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.0
Transcona & Ridgeway Station 66kV Bus Upgrade	2.8	1.0	1.5	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.8
Dorsey 500kV R502 Breaker Replacement	2.6	2.3	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
Birtle South-Rossburn 66kV Line	4.9	-	-	-	-	-	0.1	0.3	4.5	-	-	-	-	-	-	-	-	-	-	-	-	4.9
Perimeter South Station Distribution Supply Centre Installation	2.4	0.1	0.3	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4
Winnipeg Central District 66 kV Breaker Replacement	6.1	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4
Stanley Station 230-66 kV Transformer Addition	21.1	-	-	-	-	1.9	8.4	7.9	2.9	-	-	-	-	-	-	-	-	-	-	-	-	21.1
Stanley Station 230-66kV Hot Standby	6.2	1.5	3.8	0.8	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.2
Defective RINJ Cable Replacement	8.7	1.1	1.1	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1
Brereton Lake Station Area	9.0	1.0	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2
Stony Mountain New 115 - 12 kV Station	5.0	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2
Mobile Transformer	3.5	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0
Rover Substation Replace 4 kV Switchgear	12.7	0.2	5.9	1.1	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	0.1	12.6	9.0	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27.1
Frobisher Station Upgrade	14.4	7.6	2.9	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.5
Burrows New 66 kV/ 12 kV Station	28.6	4.6	10.7	10.2	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27.9
Winnipeg Central District Oil Switch Project	7.1	2.8	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3
William New 66 kV/ 12 kV Station	10.3	0.0	2.8	3.9	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.1
Waverley West Sub Division Supply - Stage 1	6.5	3.2	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.6
St. James 24 kV System Refurbishment	65.9	0.7	19.1	11.1	22.5	12.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65.9
Transcona Area Distribution Conversion	4.4	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
Shoal Lake New 33 - 12.47 kV DSC	3.6	0.2	3.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4
York Station	4.0	0.2	1.1	2.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.0
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	0.1	0.8	3.1	1.8	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.3
Winkler Market Feeder M25-13 Conversion	2.9	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.9
Neepawa N Feeder NN12-2 & Line 57 Rebuild	1.9	0.0	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9
Interlake Digital Microwave Replacement	19.7	7.4	3.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.3
Communication System Southern MB (Great Plains)	21.9	4.0	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.6
Communications Upgrade Wpg Area	7.4	1.1	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9
Pilot Wire Replacement	9.6	1.5	0.4	1.1	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.9
Trans Line Protection & Teleprotection Replacement	21.1	1.9	2.0	5.7	6.4	2.4	1.2	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	19.8
Winnipeg Central Protection Wireline Replacement	9.3	2.5	2.4	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.1
Mobile Radio System Modernization	30.7	0.1	0.5	13.9	16.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.7
Gas SCADA Replacement	4.6	0.4	1.1	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.6
Cyber Security Systems	10.1	4.0	2.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4
Site Remediation	13.3	1.0	3.1	2.0	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.5
Oil Containment	7.4	1.8	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1
Station Battery Bank Capacity & System Reliability Increase	46.5	4.9	6.9	7.0	6.7	6.7	3.9	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	39.6
Red River Floodway Expansion Project	1.8	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5
Fleet	39.8	13.0	13.3	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.6	17.5	18.3	19.2	20.2	21.2	22.3	23.4	24.6	341.4
Domestic Item - Transmission & Distribution Electric		88.9	90.7	92.6	94.4	96.3	98.2	100.2	102.2	104.2	106.3	108.4	113.9	119.6	125.5	131.8	138.4	145.3	152.6	160.2	168.2	2,338.0
TRANSMISSION & DISTRIBUTION TOTAL		**178.9**	**222.8**	**214.2**	**203.0**	**142.7**	**152.6**	**155.9**	**125.3**	**120.4**	**124.5**	**129.4**	**135.8**	**142.6**	**149.8**	**157.3**	**165.1**	**173.4**	**182.0**	**191.1**	**200.7**	**3,267.6**

ATTACHMENT 2

CAPITAL EXPENDITURES FORECAST FOR 20 YEAR FINANCIAL FORECAST (ELECTRICITY OPERATIONS) - JANUARY 2009

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	20 Year Total
CUSTOMER SERVICE & MARKETING																						
Automatic Meter Reading	30.9	-	3.9	4.0	4.0	4.1	4.3	4.3	4.5	-	-	-	-	-	-	-	-	-	-	-	-	29.1
Distribution PCB Testing & Transformer Replacement	19.6	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4
Winnipeg Distribution Infrastructure Requirements	14.9	2.0	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.8
Winnipeg Central District Underground Network Asbestos Removal	3.0	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5
Domestic Item - Customer Service & Marketing - Electric		60.2	61.4	62.6	63.9	65.2	66.5	67.8	69.1	70.5	71.9	73.4	77.0	80.9	84.9	89.2	93.7	98.3	103.3	108.4	113.8	1,582.1
CUSTOMER SERVICE & MARKETING TOTAL		**63.3**	**67.9**	**66.6**	**67.9**	**69.2**	**70.7**	**72.1**	**73.6**	**70.5**	**71.9**	**73.4**	**77.0**	**80.9**	**84.9**	**89.2**	**93.7**	**98.3**	**103.3**	**108.4**	**113.8**	**1,616.9**
FINANCE & ADMINISTRATION																						
Corporate Buildings	-	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.4	8.8	9.3	9.7	10.2	10.7	11.3	11.8	12.4	180.6
Enterprise GIS Project	21.9	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4
Workforce Management (Phase 1 to 4)	11.3	6.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.7
WorkSmart	5.4	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9
Domestic Item - Finance & Administration		22.3	22.7	23.2	23.7	24.1	24.6	25.1	25.6	26.1	26.6	27.2	28.5	30.0	31.4	33.0	34.7	36.4	38.2	40.1	42.1	585.7
FINANCE & ADMINISTRATION TOTAL		**38.3**	**30.7**	**31.2**	**31.7**	**32.1**	**32.6**	**33.1**	**33.6**	**34.1**	**34.6**	**35.2**	**36.9**	**38.8**	**40.7**	**42.7**	**44.9**	**47.1**	**49.5**	**52.0**	**54.6**	**774.4**
CAPITAL INCREASE PROVISION		-	-	-	-	-	-	-	**63.1**	**90.4**	**82.8**	**97.3**	102.2	107.3	112.6	118.3	124.2	130.4	136.9	143.8	150.9	**1,460.1**
ELECTRIC CAPITAL SUBTOTAL		**1,074.9**	**1,222.6**	**1,130.8**	**877.8**	**851.8**	**1,270.4**	**1,886.8**	**2,335.9**	**2,265.1**	**1,763.5**	**1,817.5**	**1,583.4**	**1,432.8**	**1,347.8**	**1,526.8**	**811.5**	**640.2**	**611.8**	**640.5**	**684.6**	**25,776.5**
GAS																						
TRANSMISSION & DISTRIBUTION																						
Southloop Capacity Upgrade - Winkler	4.3	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.6
Gas Riser Rehabilitation Program	16.5	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.0
Natural Gas Pipeline Replacement Red River at North Perimeter	1.7	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6
Brandon Unodourised Pipeline Improvement	5.5	0.3	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5
Domestic Item - Transmission & Distribution Gas		15.2	17.2	17.5	17.9	18.3	18.6	19.0	19.4	19.8	20.2	20.6	-	-	-	-	-	-	-	-	-	203.5
TRANSMISSION & TRANSMISSION TOTAL		**22.8**	**22.4**	**17.5**	**17.9**	**18.3**	**18.6**	**19.0**	**19.4**	**19.8**	**20.2**	**20.6**	-	-	-	-	-	-	-	-	-	**216.3**
CUSTOMER SERVICE & MARKETING																						
Automatic Meter Reading - Gas	15.0	-	3.7	3.7	3.5	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.7
Demand Side Management - Gas		13.5	14.2	13.3	12.4	11.5	10.7	10.1	9.5	9.1	7.0	4.5	-	-	-	-	-	-	-	-	-	115.8
Domestic Item - Customer Service & Marketing Gas		6.7	6.9	6.7	6.8	7.0	7.1	7.3	7.4	7.6	7.7	7.9	-	-	-	-	-	-	-	-	-	79.0
CUSTOMER SERVICE & MARKETING TOTAL		**20.2**	**24.7**	**23.7**	**22.8**	**22.3**	**17.8**	**17.4**	**16.9**	**16.7**	**14.7**	**12.4**	-	-	-	-	-	-	-	-	-	**209.5**
CAPITAL INCREASE PROVISION		-	-	-	-	-	-	-	-	-	**2.3**	**4.9**	-	-	-	-	-	-	-	-	-	**7.2**
GAS CAPITAL SUBTOTAL		**42.9**	**47.2**	**41.2**	**40.7**	**40.5**	**36.5**	**36.4**	**36.3**	**36.4**	**37.1**	**37.8**	-	-	-	-	-	-	-	-	-	**433.0**
CONSOLIDATED CAPITAL SUBTOTAL		**1,117.9**	**1,269.8**	**1,172.0**	**918.5**	**892.3**	**1,306.9**	**1,923.1**	**2,372.2**	**2,301.5**	**1,800.7**	**1,855.3**	**1,583.4**	**1,432.8**	**1,347.8**	**1,526.8**	**811.5**	**640.2**	**611.8**	**640.5**	**684.6**	**26,209.5**
CONSOLIDATED CAPITAL COST FLOW ADJUSTMENT		**(60.1)**																				**(60.1)**
CONSOLIDATED CORPORATE TOTAL		**1,057.8**	**1,269.8**	**1,172.0**	**918.5**	**892.3**	**1,306.9**	**1,923.1**	**2,372.2**	**2,301.5**	**1,800.7**	**1,855.3**	**1,583.4**	**1,432.8**	**1,347.8**	**1,526.8**	**811.5**	**640.2**	**611.8**	**640.5**	**684.6**	**26,149.4**

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Subject: **Tab 6: Capital Expenditures**
Reference: **Appendix 6.1 CEF 09-1: Major Capital Projects**

b) **Please provide a schedule that details and compares the Capital expenditures by project (Project Total) forecast in CEF-09 with CEF08-1 and CEF-06-1 by major component, including capitalized Interest, Labour and Overhead.**

ANSWER:

Please see the table below for comparison between CEF09 and CEF08, for all projects with differences greater than $10 million.

(in thousands of dollars)

	CEF08	CEF09	Difference	Change Explanation
Major New Generation & Transmission				
Keeyask - Generation	3 700 391	4 591 575	891 184	Increase reflects both the current market pricing for concrete, steel, civil work, earthworks and other major components as experienced from the recent Wuskwatim generating station contract bidding process, and project design progressing from preliminary design estimates to more detailed design estimates. In addition, the infrastructure required for the construction of the project was advanced by one year adding an additional year of construction to the overall schedule.
Conawapa - Generation	4 978 400	6 324 842	1 346 442	Increase reflects current market pricing for materials and labour, higher licensing costs due to more extensive consultations along with a longer duration to achieve the required licensing, and a one year delay in the in-service date.
Pointe du Bois - Generation	818 001	318 000	(500 001)	The Pointe du Bois Modernization Project will now take the form of 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. A new powerhouse is no longer included as part of the project.

Please see the table below for comparison between CEF09 and CEF06, for all projects with differences greater than $10 million.

(in thousands of dollars)

	CEF06	CEF09	Difference	Change Explanation
Major New Generation & Transmission				
Wuskwatim	1 351 431	1 590 944	239 513	Estimate updated to reflect market increases for the general civil contracts.
Herblet Lake-The Pas 230 kV Trans	54 104	93 223	39 120	Estimate updated to reflect significant market increases for material and labour.
Keeyask - Generation	371 720	4 591 575	4 219 855	Estimate updated from licensing costs only, to include the design and construction costs associated with the Keeyask generating station.
Conawapa - Generation	4 978 392	6 324 842	1 346 450	Increase reflects higher construction costs, and a transition from an estimate based on Limestone GS actual costs, to an estimate based on the preliminary design for the Conawapa GS.
Kelsey Improvements & Upgrades	165 499	189 662	24 163	Estimate updated to include project scope additions including: turbine pit monorails, scroll case hatches, gas-in-oil monitoring for the generator transformers and shaft alignment boring templates.
Kettle Improvements & Upgrades	61 000	75 639	14 640	Estimate increased to include the replacement of the core and winding for generator Unit # 4.
Pointe du Bois - Generation	834 141	318 000	(516 141)	Estimate decrease reflects a change in project scope from plant modernization to replacement of the spillway only.
Bipole 3	1 879 896	2 247 836	367 940	Estimate updated to reflect a 45 km increase in line length (1,296 kms to 1,341 kms) and to reflect market increases for material and labour.
Riel 230/500kV Station	102 909	267 578	164 669	Estimate increase reflects project scope change to include increasing the Riel station site area, adding converter facilities, and reconfiguring the yard to accommodate a new transfer bus scheme. In addition, estimate has been revised to reflect market increases for material and labour.
New Head Office				
New Head Office	258 100	278 126	20 026	Estimate updated to reflect significant market increases for materials and labour.

(in thousands of dollars)

	CEF06	CEF09	Difference	Change Explanation
Power Supply				
HVDC Dorsey Synch Condenser Refurb.	16 725	32 330	15 605	Estimate increased to reflect additional costs to resolve excessive brush wear problems.
HVDC AC Filter PCB Capacitor Repl.	44 321	34 460	(9 860)	Estimate decrease reflects lower costs for the purchase and installation of capacitor banks, and a reduction in the scope to exclude the cost of: developing a PCB reporting system; detailed labeling of the equipment that is being destroyed; and a reduction in the level of activities required to cleanup soil that is contaminated with oil; due to a change in the Federal Government requirements.
HVDC Transformer Replacement Program	94 180	105 711	11 530	Estimate revised to include the addition of eight spare converter transformers.
Dorsey 230KV Relay Building Upgrade	6 515	73 849	67 334	Estimate increase reflects the cost to separate the existing 230 kV switchyard and relay building into three separate zones, with each served by its own zone relay building. These buildings will withstand the worst credible wind event and be equipped with reliable fire detection and suppression systems.
BP1 Smoothing Reactor Replacement	20 109	31 835	11 726	Estimate updated to reflect a more defined project scope and current market pricing for eight oil-filled reactors with air core units.
Pine Falls Rehabilitation	26 350	56 174	29 824	Estimate updated to increase the project scope for Units # 1 and 2 to include electrical work. In addition, a new sub-project was added to the rehabilitation work for the replacement of potential transformers, synchronizers, annunciators, generator breakers, excitation and governor systems, step-up transformers and electrical back-up systems.
Jenpeg G.S. Units 1 - 6 Overhaul	35 269	128 090	92 821	Estimate updated to reflect a more comprehensive scope of work (new runners, generator rewinds, wicket gate and seal upgrades, water passage concrete modifications, modernization of components, upgrades of station auxiliary systems, and new intake gates and hoists), in addition to market price increases.
Power Supply Dam Safety Upgrades	15 017	34 014	18 997	Estimate revised to expand project scope to include: weather warning systems at all plants; public early warning systems and dike rip rap rehabilitation at Grand Rapids and Seven Sisters; and spillway hoist replacement and 2,200v supply at Pointe du Bois.
Slave Falls Rehabilitation	179 359	198 290	18 931	Estimate revised to expand project scope to include the replacement of six of the Automatic Voltage Regulator (AVR) units, the installation of a Unit Control & Monitoring System, and an extension of the proposed road to the Slave Falls powerhouse. In addition, estimate revised to reflect market increases for construction costs and additional environmental studies requirements.
Water Licenses & Renewals	9 135	40 769	31 634	Estimate revised to expand project scope to include Pointe du Bois, Grand Rapids and Kelsey generating stations renewals, and a system-wide aquatic data collection program.
Selkirk Enhancements	46 921	14 244	(32 677)	Estimate revised to reduce project scope by deleting the installation of the cooling tower and adding the refurbishment of the intake fish screen and lube oil modifications.

(in thousands of dollars)

	CEF06	CEF09	Difference	Change Explanation
Power Supply - continued				
Generation Townsite Infrastucture	38 300	52 104	13 804	Estimate revised to reflect: a specification change from Ready-To-Move homes to on-site built homes; an increase in the number of homes to be constructed as some of the homes to be renovated were in poorer condition than initially assessed; more extensive renovation requirements than planned; and increases in material and contractor costs.
Site Rem.of Contaminated Corp. Facilities	25 014	34 727	9 713	Estimate revised to include additional costs to complete the clean-up of sub-surface contaminated soil and surface construction debris scattered along the length of both the Eight-Mile Channel and the South Bay Channel.
Power Supply Security Install/Upgrades	11 579	43 214	31 634	Estimate revised to expand project scope to include upgraded facility security to anticipated NERC regulatory standards, including the installation of crash-rated gates at main entrances to facilities, installing gates and barriers to restrict access onto dams and dykes, upgrading card access systems at perimeter entry points into all facilities, and upgrading rooms and cabinets housing critical cyber assets.
Transmission				
Transcona East 230-66kV Station	9 210	31 030	21 820	Estimate revised to expand project scope to include additional costs for station site improvements; as well as updating estimate to reflect significant market increases for materials and labour.
Transmission Line Re-rating	12 723	24 118	11 394	Estimate revised to expand project scope to address all high risk, all medium risk and certain low risk spans of four 115kV and five 230kV transmission lines, in order to minimize public safety concerns associated with line sag violations.
Customer Service & Distribution				
Martin New Outdoor Station	10 540	28 197	17 657	Estimate revised to expand project scope to include conversion of distribution feeds to 12kV, installation of 6kV circuits to the new station, and the addition of a SCADA system.

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Subject: **Tab 6: Capital Expenditures**
Reference: **CEF09-1/ Appendix 13.6, Order 150/08**

a) **Please provide an update on the future status of Pointe du Bois G.S. with specific reference to future power output.**

ANSWER:

Operation of the existing 78 MW powerhouse at Pointe du Bois will continue indefinitely with ongoing maintenance to ensure safety.

PUB/MH I-63

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF09-1/ Appendix 13.6, Order 150/08**

b) **Does the Pointe du Bois powerhouse have to be decommissioned in the near future? Explain.**

ANSWER:

Manitoba Hydro does not foresee the need to decommission Pointe du Bois in the near future. The powerhouse will continue to be repaired and maintained to ensure ongoing safety and reliability.

PUB/MH I-63

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF09-1/ Appendix 13.6, Order 150/08**

c) Does MH anticipate a similar scenario for the Slave Falls G.S.?

ANSWER:

Manitoba Hydro does not have a plan to replace the spillway or powerhouse at Slave Falls. Slave Falls continues to be repaired and maintained to ensure ongoing safety and reliability.

PUB/MH I-64

Subject: Tab 6: Capital Expenditures
Reference: Appendix 6.1 CEF-09-1: Information Technology

Please provide details of all major information technology expenditures by project for each of the years 1999/00, to 2011/12.

ANSWER:

Detail of all major information technology expenditures by project for each of the years 1999/00 to 2011/12

(IN MILLIONS OF $)

Description	Actual Expenditures										Forecast		
	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Major Capital Projects	**10.1**	**4.1**	**0.7**	**8.4**	**13.2**	**12.7**	**15.7**	**10.9**	**9.6**	**5.5**	**3.9**	**1.0**	**0.0**
WorkSmart								1.2	3.3	1.5			
Year 2000 Conversion	5.5												
Customer Information System					3.9	5.3	10.6	1.5					
Human Resource Management System			0.7	6.3	4.3	4.8	0.4						
Enterprise G.I.S.				2.1	5.0	2.7	3.8	4.9	0.3	1.1			
Workforce Management (Phase 1 to 4)								1.4	3.2	1.9	3.9	1.0	
Map Info	4.6	4.1											
Winnipeg Central Data Conversion							0.9	2.0	2.8	1.1			
Infrastructure	**9.4**	**10.1**	**14.9**	**12.2**	**9.8**	**9.0**	**9.4**	**8.7**	**10.7**	**12.3**	**9.9**	**10.2**	**10.2**
Application S/W & H/W	0.6	1.0	0.2	0.1	0.1	0.1	0.2	0.1					
Storage Area Network (SAN)			1.3	2.2	1.8	1.2	1.4	0.9	2.5	1.1	1.5	1.5	1.5
Eng Application Hardware			0.2	0.2	0.1	0.1		0.1		0.2	0.3	0.3	0.3
Infrastructure	2.7	4.4	5.0	3.4	3.4	2.4	3.1	3.3					
Desktop Software / Hardware	6.1	4.7	5.7	4.9	3.7	3.7	3.4	3.4	4.1	5.3	4.2	4.2	4.2
AutoDesk Product Suite			2.1	0.8	0.4	0.5	0.5	0.5		0.4	0.4	0.5	0.5
DFIS			0.1	0.1	0.1								
Multi-Functional Device Equipment			0.3	0.5	0.2	1.0	0.8	0.4		1.2	0.3	0.4	0.4
Application Related Servers									1.0	1.0	0.9	0.9	0.9
Data Communication Network									2.7	3.0	2.3	2.3	2.3
OTHER									0.4	0.1		0.1	0.1
Domestic Projects	**9.1**	**7.9**	**9.4**	**7.9**	**7.4**	**7.4**	**8.4**	**9.7**	**7.1**	**5.9**	**11.6**	**11.6**	**12.0**
Project System Management System (PSM)	3.8	4.7	0.1										
Enterprise Management System	0.9	0.6	0.5	0.1									
Windows NT Conversion	1.5	0.5											
Electronic Drawing Mgmt System		1.4	2.1	1.2	0.7								
SAP 4.6 Upgrade - Plan & Implementation			3.3	0.1									
SAP Licensing			1.3	0.7									
Office XP Project			0.1	0.6	0.7								
MS Exchange 2000				0.6	0.8								
MySAP.Com Licenses				2.0	0.1								
WebTrader Enterprise Project					0.2	1.4	0.4	0.1					
TLMS System Replacement						0.3	1.0	0.6					
myBudget Project						0.4	2.3	1.6					
Repatriation of Major Projects						1.0							
EAM Data Integrity - Phase 1A								0.6	1.4				
Project Portfolio Mgmt System (xRPM)								0.7					
SAP Software Upgrade - Realization								2.0	2.6				
Corporate Document Mgmt Infrastructure								1.4					
EAM Project - Data Integrity Phase 1B									0.5	1.4	0.9		
Transmission GIS											1.8	0.1	
Worksmart Phase 2											1.9		
Banner Oracle 10G Upgrade											1.2	0.2	
Biz Talk											1.0	0.6	
Transmission Operations Data Systems Phase 2											1.3	0.7	
E-Recruitment Upgrade											1.4		
Cashier Software Replacement												1.3	
Asset Investment Planning												2.0	
OTHER	3.0	0.6	2.0	2.5	4.9	4.3	4.7	2.8	2.7	4.5	2.1	6.7	12.0
Total ITS spending by fiscal year	**28.6**	**22.0**	**25.0**	**28.4**	**30.4**	**29.2**	**33.5**	**29.4**	**27.5**	**23.7**	**25.4**	**22.8**	**22.2**

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Subject: Tab 6: Capital Expenditures

Reference: Tab 6 and Appendix 6.1 and Wuskwatim G.S.

Please provide a continuity schedule that compares the growth in capital costs by major component, from the estimate presented to the Clean Environment Commission to IFF09-1 and provide an explanation for the changes.

ANSWER:

(In millions of dollars)

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

Variance Explanation CEC to IFF05-1

Generation Station:

- In-service date deferred 2 years - revised timeline for federal and provincial approvals as well as for the completion of the project development agreements
- Increase due to an extended studies and investigation period as well as an extended construction schedule related to the 2 year delay
- Increase due to a change in the construction camp requirements to allow for both a road construction camp and a start-up camp - previously only one camp was assumed
- Catering contract was updated to incorporate the increased camp requirements

Transmission:

- In-service date deferred 2 years - revised timeline for federal and provincial approvals as well as for the completion of the project development agreements
- Addition of planning and licensing activities previously included in the generating station budget (corresponding decrease in the generating station cost estimate)
- Increase due to detailed design work revisions on station items and increased transmission line lengths
- The construction of certain components were anticipated to occur earlier in the schedule compared to the previous estimate resulting in higher capitalized interest

Variance Explanation IFF05-1 to IFF06-4

Generating Station:

- In-service date deferred 12 months
- Increase in powerhouse concrete
- Increase in contractors' markup and overhead
- Increase in turbine and generator costs
- Increases for design revisions, quantity revisions and general escalation

Transmission:

- In-service date deferred 12 months
- 40% increase in transmission line construction costs to reflect market conditions
- Included contingency on all projects (10-15%)
- Increase in station items based on recent experience with related equipment/materials

<u>Variance Explanation IFF06-4 to IFF07-1</u>

Generating Station:

- In-service date advanced 9 months
- Increase to general civil contract
- Increase to site infrastructure costs

Transmission:

- In-service date advanced 9 months
- Design & material increased to reflect current market conditions
- Transmission line construction cost increased to reflect recent experience with related equipment/materials
- Refined estimates for station costs

<u>Variance Explanation IFF07-1 to IFF09-1</u>

There has been very little change to the in-service costs between IFF07-1 and IFF09-1. The slight decrease has been due to declining interest rates.

PUB/MH I-66

Subject: Tab 6: Capital Expenditures
Reference: Comparison to CEF-08

Please explain the $511 million target adjustments to forecast total capital expenditures and provide details on how the amount was determined and specific projects the amount relates.

ANSWER:

Manitoba Hydro has increased its target adjustment by $511 million to result in a net $169 million reduction to the previously authorized Capital Expenditure Forecast over the ten year period to 2018/19. The target adjustment is a general provision and not related to specific projects.

PUB/MH I-67

Subject: **Tab 6: Capital Expenditures**
Reference: **Mitigation Costs**

a) **Please provide a schedule of mitigation costs incurred from 1999/2000 through 2009/10 in major categories for major projects, for amounts expensed in those years.**

ANSWER:

Please see the following table for the mitigation costs incurred from 2004/05 through 2009/10.

Mitigation Annual Operating Expenditures						**(in millions)**
	2005 Actual	**2006 Actual**	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 Forecast**
CRD & LWR (NFA)						
Cross Lake	0.05	0.11	0.08	0.33	0.25	0.25
Nelson House	0.16	0.26	0.45	0.31	0.55	0.52
Norway House	-	-	0.07	-	0.06	0.09
Split Lake	0.01	0.02	0.01	-	-	0.19
York Landing	0.02	0.01	0.04	-	-	0.05
	0.24	0.40	0.66	0.64	0.87	1.11
CRD & LWR (Non-NFA)						
Churchill	0.02	0.03	0.06	0.07	0.11	0.08
Fox Lake	-	-	-	-	-	-
South Indian Lake	0.06	0.10	0.34	0.20	0.23	0.16
Thompson	-	-	-	-	0.08	-
	0.08	0.14	0.40	0.27	0.42	0.24
Grand Rapids						
Grand Rapids Community	0.20	0.19	0.19	0.23	0.22	0.26
Total	**$ 0.53**	**$ 0.73**	**$ 1.25**	**$ 1.13**	**$ 1.51**	**$ 1.61**

Notes:
CRD - Churchill River Diversion
LWR - Lake Winnipeg Regulation
NFA - Northern Flood Agreement

PUB/MH I-67

Subject: **Tab 6: Capital Expenditures**
Reference: **Mitigation Costs**

b) Please provide a schedule of mitigation costs capitalized for the years 1999/2000 through 2009/10 by major classification, by major project.

ANSWER:

Please see the following table for expenditures incurred or settlements reached to mitigate the impacts of capital projects for 2004/05 through 2009/10.

Mitigation Capital Spending **(in millions)**

	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast
CRD & LWR (NFA)	26.7	14.9	13.7	26.7	20.1	11.8
CRD & LWR (Non-NFA)	0.6	2.6	3.3	1.4	0.6	3.8
Grand Rapids	4.1	10.2	0.1	8.4	1.0	10.4
Winnipeg River	0.1	0.2	0.2	0.3	0.3	9.6
	$ 31.5	**$ 27.9**	**$ 17.3**	**$ 36.8**	**$ 21.9**	**$ 35.6**

Notes:
CRD - Churchill River Diversion
LWR - Lake Winnipeg Regulation
NFA - Northern Flood Agreement

PUB/MH I-67

Subject: **Tab 6: Capital Expenditures**
Reference: **Mitigation Costs**

c) Please provide a schedule of Provincial mitigation cost obligations assumed by MH.

ANSWER:

Please see the following table for the Provincial mitigation cost obligations for 2004/05 through 2009/10.

Provincial Obligations Paid by Manitoba Hydro **(in millions)**

	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast
Moose Lake/Grand Rapids Settlement	0.4	0.7	0.4	1.2	-	-
Cross Lake Settlement and Negotiating	0.8	0.4	0.5	0.4	0.4	0.4
South Indian Lake Road and Ferry	1.9	0.0	-	-	-	-
Continuing NFA Settlement Costs	-	-	-	-	-	0.5
South Indian Lake Water/Sewer	0.1	0.4	0.2	-	-	-
Other South Indian Lake Upgrades	-	0.3	-	-	-	-
Cross Lake Sewer Treatment Plant	-	0.1	-	-	-	-
NetNak Bridge - Cross Lake	6.4	-	-	-	-	-
Fox Lake	3.0	0.3	0.3	-	-	-
War Lake	0.6	0.1	0.1	0.1	0.1	0.1
Cormorant Sewage Treatment Plant	-	-	-	0.4	-	-
Nelson House Water Treatment Plant	-	-	-	-	-	0.8
Total Payments	**$ 13.3**	**$ 2.3**	**$ 1.5**	**$ 2.1**	**$ 0.4**	**$ 1.7**

<u>PUB/MH I-68</u>

Subject: **Tab 6: Capital Expenditures**
Reference: **Appendix 6.2 Debt Management Strategy**

Please provide the most recent bond/ credit rating agencies report on Manitoba Hydro from DBRS, Moody, and Standards & Poors.

<u>ANSWER</u>:

Please see Appendix 39 for the credit rating reports for Manitoba Hydro from DBRS (February 12, 2009), Moody's Investors Service (February 8, 2010) and Standard & Poor's (November 20, 2008).

PUB/MH I-69

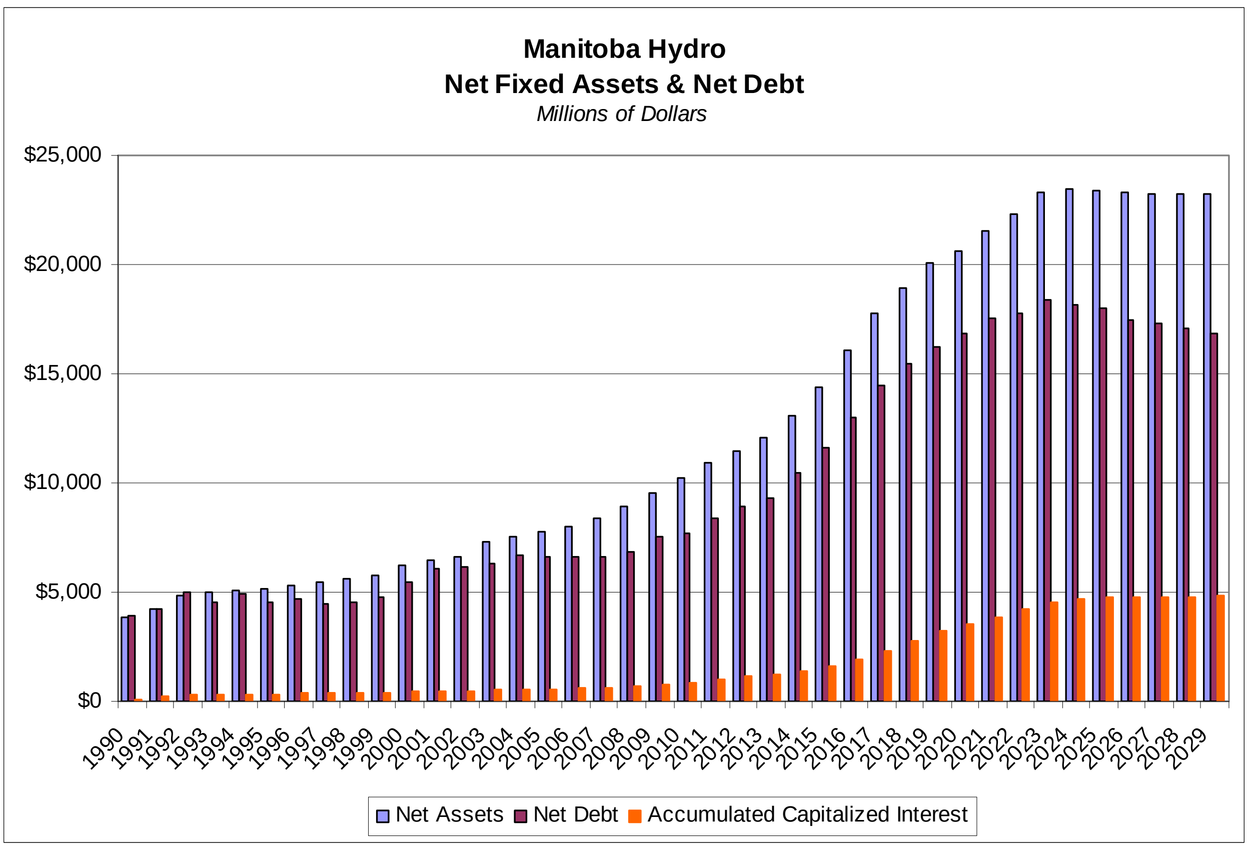
Subject: **Tab 6: Capital Expenditures**

Reference: **Appendix 6.2 Debt Management Strategy Page 4m Net Fixed Assets & Net Debt**

a) **Please recast the graph of Net Fixed Assets & Net Debt for the years 1990 through 2030 identifying the level of accumulated capitalized interest in each year. Please provide a table of corresponding data points.**

ANSWER:

Please note that as per the presentation in the Debt Management Strategy, the year end data points contained in this graph represent Consolidated Operations. The values for the years 1990 to 2009 are based on actuals, and 2010 to 2029 values are based on the forecast (IFF09).



The chart illustrates the growth in net fixed assets and net long term debt that has occurred over the past 20 years, as well as the projected growth in the decades of investment and returns. While net debt is expected to grow to approximately $16.9 billion as at March 31, 2029, the corresponding investment in generation, transmission, distribution and other assets is expected to grow at a much greater pace to a net book value of approximately $23.2 billion at March 31, 2029.

A table of corresponding data points is as follows:

Year Ending	Net Assets	Capitalized Interest	Accumulated Capitalized Interest	Net Debt
1990	3,882	97	97	3,889
1991	4,267	110	207	4,199
1992	4,857	72	279	4,972
1993	4,983	32	312	4,533
1994	5,067	16	328	4,948
1995	5,170	15	342	4,508
1996	5,310	19	361	4,685
1997	5,464	16	377	4,493
1998	5,608	20	396	4,559
1999	5,774	20	416	4,772
2000	6,235	15	431	5,488
2001	6,428	16	447	6,114
2002	6,626	26	473	6,146
2003	7,305	28	501	6,320
2004	7,536	32	532	6,675
2005	7,776	33	565	6,642
2006	8,010	34	600	6,614
2007	8,415	47	647	6,597
2008	8,912	60	707	6,870
2009	9,520	74	781	7,514
2010	10,246	92	873	7,728
2011	10,915	131	1,003	8,376
2012	11,472	137	1,141	8,919
2013	12,048	110	1,251	9,291
2014	13,081	144	1,395	10,426
2015	14,379	208	1,603	11,638
2016	16,058	306	1,909	12,999
2017	17,742	408	2,317	14,441
2018	18,958	449	2,766	15,470
2019	20,051	430	3,197	16,259
2020	20,648	365	3,562	16,854
2021	21,516	300	3,862	17,555
2022	22,324	353	4,215	17,787
2023	23,277	330	4,545	18,369
2024	23,454	160	4,704	18,169
2025	23,417	31	4,735	17,965
2026	23,335	30	4,765	17,494
2027	23,263	18	4,783	17,289
2028	23,232	23	4,805	17,079
2029	23,202	25	4,830	16,861

PUB/MH I-69

Subject: **Tab 6: Capital Expenditures**
Reference: **Appendix 6.2 Debt Management Strategy Page 4m Net Fixed Assets & Net Debt**

b) Please provide a corresponding table of Net Assets, Net Debt, Retained Earnings and Debt to Equity ratio and Interest Coverage ratio of the corresponding years.

ANSWER:

Please see the attached schedule.

Financial ratios are projected to weaken slightly in the first decade but rebound strongly in the second decade (the decade of returns).

Year Ending	Net Assets	Net Debt	Retained Earnings	D/E Ratio	I/C Ratio
	Millions of dollars	*Millions of dollars*	*Millions of dollars*		
1990	3,882	3,889	117	95:05	1.07
1991	4,267	4,199	165	94:06	1.13
1992	4,857	4,972	183	94:06	1.04
1993	4,983	4,533	159	95:05	0.95
1994	5,067	4,948	228	93:07	1.16
1995	5,170	4,508	284	92:08	1.13
1996	5,310	4,685	354	91:09	1.16
1997	5,464	4,493	455	88:12	1.23
1998	5,608	4,559	566	86:14	1.25
1999	5,774	4,772	666	84:16	1.23
2000	6,235	5,488	818	83:17	1.35
2001	6,428	6,114	1,088	80:20	1.62
2002	6,626	6,146	1,302	77:23	1.42
2003	7,305	6,320	1,170	80:20	1.14
2004	7,536	6,675	734	87:13	0.17
2005	7,776	6,642	870	85:15	1.25
2006	8,010	6,614	1,285	81:19	1.77
2007	8,415	6,597	1,407	80:20	1.23
2008	8,912	6,870	1,822	76:24	1.69
2009	9,520	7,514	2,120	75:25	1.58
2010	10,246	7,728	2,227	74:26	1.24
2011	10,915	8,376	2,315	75:25	1.15
2012	11,472	8,919	2,396	76:24	1.15
2013	12,048	9,291	2,479	76:24	1.12
2014	13,081	10,426	2,616	78:22	1.19
2015	14,379	11,638	2,738	79:21	1.15
2016	16,058	12,999	2,997	80:20	1.30
2017	17,742	14,441	3,268	80:20	1.27
2018	18,958	15,470	3,515	80:20	1.23
2019	20,051	16,259	3,772	80:20	1.22
2020	20,648	16,854	4,059	79:21	1.22
2021	21,516	17,555	4,366	79:21	1.24
2022	22,324	17,787	4,816	78:22	1.36
2023	23,277	18,369	5,369	76:24	1.44
2024	23,454	18,169	6,113	73:27	1.58
2025	23,417	17,965	6,918	70:30	1.65
2026	23,335	17,494	7,840	66:34	1.77
2027	23,263	17,289	8,859	61:39	1.88
2028	23,232	17,079	9,986	56:44	2.02
2029	23,202	16,861	11,223	51:49	2.18

<u>PUB/MH I-70</u>

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Table 6 (Page 18)**

a) **Please confirm that MH anticipates an increase in residential units (number of meters) of about 17% (75,000 units) over the next 20 years compared to 8% (33,000 units) in the previous 10 years**

<u>ANSWER</u>:

Confirmed.

PUB/MH I-70

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Table 6 (Page 18)**

b) **Confirm that the residential energy consumption is expected to rise by 28% (1,882 GWh) over the next 20 years compared to 27% (1,463 GWh) over the previous 10 years.**

ANSWER:

Confirmed.

PUB/MH I-70

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Table 6 (Page 18)**

c) **Please discuss the apparent divergence between the growth of residential customers and the energy consumption.**

ANSWER:

The reason is due to the expected reduction in the rate of growth of the average use per customer. Total energy consumption growth depends on both customer growth and average use growth.

Residential average use per customer is expected to grow 9% in the next 20 years compared to 18% in the previous 10 years. See the following table.

	Total Basic		
	Custs	**GW.h**	**Ave Use**
1998/99	404478	5383	13310
2008/09	437262	6847	15659
growth	32784	1464	2349
% growth	8%	27%	18%

	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%

PUB/MH I-70

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Table 6 (Page 18)**

d) Please explain in detail the variable nature of average unit per customer consumption increases for:

Fiscal Years	Basic Standard Basic	All-Electric
1999 to 2007	**+17.4%**	**+5.7%**
2007 to 2013	**+1.6%**	**0**
2013 to 2030	**+8.6%**	**+2.7%**

ANSWER:

Part of the reason is because the numbers in Table 6 are the actual GW.h. The following tables provide the weather adjusted energy use.

	Basic Standard		
	Custs	**GW.h**	**Ave Use**
1998/99	287368	2661	9260
2006/07	297137	3119	10497
% growth			13.4%

	Basic All-Electric		
	Custs	**GW.h**	**Ave Use**
1998/99	117110	2930	25019
2006/07	130749	3304	25050
			0.1%

	Basic Standard		
	Custs	**GW.h**	**Ave Use**
2006/07	297137	3119	10497
2012/13	306459	3319	10830
			3.2%

	Basic All-Electric		
	Custs	**GW.h**	**Ave Use**
2006/07	130749	3304	25270
2012/13	147064	3686	25065
			-0.8%

The following table provides the weather adjusted percentage changes:

Fiscal Years	Basic Standard	Basic All-Electric
1999 to 2007	+13.4%	+0.1%
2007 to 2013	+3.2%	-0.8%
2013 to 2030	+8.6%	+2.7%

Another reason for the differences in growth rates is due to the varying time periods being considered. The first interval covers 8 years, the second interval covers six years and the third interval covers 17 years. Converting this analysis into annual growth rates provides the following results:

Fiscal Years	Basic Standard	Basic All-Electric
1999 to 2007	+1.6%	+0.0%
2007 to 2013	+0.5%	-0.1%
2013 to 2030	+0.5%	+0.2%

The growth rate is higher in standard than all-electric in all years primarily due to the conversion of gas water heaters to electric over the entire period. The growth rate for basic standard customers from 1999 to 2007 is higher than later years primarily due the large increase in computers, televisions and miscellaneous electrical use during those years.

PUB/MH I-70

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Table 6 (Page 18)**

e) Please explain what primary factors were or are at play in defining these increases.

ANSWER:

When a low or mid efficiency gas furnace is replaced with a high efficiency gas furnace, the furnace no longer exhausts through the chimney. This change in type of furnace may require additional work to be undertaken within a home to ensure the gas water heater is safely vented. The additional work involves either lining the chimney or venting the water heater directly outdoors. Both options are relatively expensive and an alternative is for the customer to simply replace the gas water heater with an electric water heater.

<u>PUB/MH I-70</u>

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Table 6 (Page 18)**

f) **Explain why standard service residential units are using increasing amounts of electricity but all-electric units are not?**

<u>ANSWER</u>:

Standard service residential are using more electricity primarily due to the conversion of gas water heating to electric.

PUB/MH I-71

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **2009/10 Electric Load Forecast, Appendix 7.1, Table 8, Page 27**

a) Please indicate the number of GSL >100, GSL 30-100, and GSL <30 customers included in the Top Consumers listing.

ANSWER:

There are 14 GSL > 100, 8 GSL 30-100, 3 GSL < 30 and 1 Medium customer, totaling the 26 Top Consumers.

PUB/MH I-71

Subject: Tab 7: Load Forecast And Load Research
Reference: 2009/10 Electric Load Forecast, Appendix 7.1, Table 8, Page 27

b) Please categorize these Top Consumers and their annual energy demands (MW/GWh) by sector for 2005/06 to 2008/09 inclusive:

- **i. Chemical.**
- **ii. Petroleum Transport.**
- **iii. Primary Metals.**
- **iv. Pulp and Paper.**
- **v. Mining.**
- **vi. Food and Beverage.**
- **vii. Colleges and Universities.**
- **viii. Other.**

ANSWER:

Listed below is the annual GW.h consumption for the 26 Top Consumers:

GW.h	2005/06	2006/07	2007/08	2008/09
Chemicals	1,841	1,847	1,865	1,929
Petroleum	849	899	879	944
Primary Metals	2,237	2,248	2,300	2,237
Pulp/Paper	763	742	764	674
Mining	5	4	4	4
Food/Beverage	182	176	188	202
College	70	73	75	75
Other	0	0	0	0
Total	5,948	5,989	6,075	6,065

PUB/MH I-71

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **2009/10 Electric Load Forecast, Appendix 7.1, Table 8, Page 27**

c) What are the sector by sector industry growth forecasts for Fiscal 2010, 2011 and 2012?

ANSWER:

Listed below is the annual forecasted GW.h consumption for the 25 Top Consumers. Note that the Mining customer that was previously included in the history of this group was not forecasted this year as part of this group due to its low consumption.

GW.h	2009/10	2010/11	2011/12
Chemicals	1,870	1,870	1,970
Petroleum	1,027	1,093	1,156
Primary Metals	2,014	2,236	2,353
Pulp/Paper	765	715	720
Mining	0	0	0
Food/Beverage	204	205	205
College	76	77	78
Other	0	0	0
Total	5,956	6,196	6,482

PUB/MH I-72

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Table 8, Page 27, PUB/MH I-3(a)/ Supplementary Filing at EIIR**

a) **Please provide 2008/09 and 2009/10 annual energy consumption and demand data for GSL >100 and GSL 30-100 broken down on an industry sector basis (similar in format to PUB/MH I-3(a) Supplementary in EIIR filings).**

ANSWER:

The tables below provide the energy and demand sales for all Large 30-100 kV and Large >100 kV customers for fiscal 2008/09 and 2009/10 by industry type. It is important to recognize however that customers in these classes do not necessarily translate to the same customers reported as "Top Consumers" in Appendix 7.1, Table 8, Page 27.

Chemical Industry: 8 customers

2008/09	kW.h	kV.A Recorded	kV.A Billed
Apr	176,891,767	258,612	258,752
May	168,708,061	253,478	253,699
Jun	169,713,271	254,299	254,554
Jul	154,281,069	254,613	254,921
Aug	172,911,909	253,796	254,097
Sep	169,165,142	254,069	254,254
Oct	174,235,816	222,982	253,064
Nov	171,896,675	253,036	253,176
Dec	132,627,931	210,632	210,632
Jan	173,512,201	258,715	258,715
Feb	145,493,335	251,520	252,077
Mar	174,554,890	258,771	258,771
Total	1,983,992,067	2,984,524	3,016,713

2009/10	kW.h	kV.A Recorded	kV.A Billed
Apr	146,405,193	222,730	222,893
May	134,806,557	222,494	222,726
Jun	160,468,355	236,769	237,036
Jul	171,009,832	253,676	253,939
Aug	174,636,600	254,460	254,680
Sep	158,381,897	253,987	254,116
Oct	175,117,431	253,581	253,581
Nov	163,471,668	259,069	259,069
Dec	178,355,248	259,610	259,610
Jan	181,902,400	258,942	258,942
Feb	N/A	N/A	N/A
Mar	N/A	N/A	N/A
Total	1,644,555,181	2,475,318	2,476,592

Food and Beverage Industry: 6 customers

2008/09	kW.h	kV.A Recorded	kV.A Billed
Apr	8,194,913	18,965	18,965
May	8,628,881	18,710	18,710
Jun	9,219,983	18,674	18,674
Jul	8,809,288	18,558	18,558
Aug	8,357,472	19,407	19,407
Sep	9,660,346	19,650	19,650
Oct	10,331,645	19,051	19,051
Nov	10,166,645	19,183	19,183
Dec	9,597,913	12,456	19,007
Jan	9,831,074	18,999	18,999
Feb	9,478,288	19,101	19,101
Mar	8,819,300	19,376	19,376
Total	111,095,748	222,130	228,681

2009/10	kW.h	kV.A Recorded	kV.A Billed
Apr	9,351,095	19,335	19,335
May	9,806,690	19,906	19,906
Jun	10,865,292	20,042	23,560
Jul	7,697,238	14,767	16,025
Aug	7,981,868	16,474	16,474
Sep	8,658,525	16,538	16,538
Oct	8,008,578	16,376	16,376
Nov	7,826,827	15,666	15,666
Dec	8,372,544	15,605	15,605
Jan	7,876,106	15,854	15,854
Feb	N/A	N/A	N/A
Mar	N/A	N/A	N/A
Total	86,444,763	170,563	175,339

Mining Industry: 4 customers

2008/09	kW.h	kV.A Recorded	kV.A Billed
Apr	5,401,801	9,994	10,825
May	4,692,516	9,681	10,404
Jun	4,609,059	8,992	9,841
Jul	4,824,177	9,308	10,031
Aug	4,400,529	9,225	9,978
Sep	4,302,224	9,550	9,913
Oct	5,178,034	10,623	10,623
Nov	5,542,167	10,788	10,788
Dec	5,785,477	11,776	11,776
Jan	6,456,118	13,011	13,011
Feb	6,712,561	13,851	13,851
Mar	7,253,063	14,731	14,731
Total	65,157,726	131,530	135,772

2009/10	kW.h	kV.A Recorded	kV.A Billed
Apr	7,159,513	13,979	13,979
May	6,508,480	13,378	13,378
Jun	5,240,836	11,122	11,665
Jul	5,705,635	10,882	11,609
Aug	4,562,212	9,739	10,800
Sep	4,243,254	10,473	11,483
Oct	5,214,065	10,719	12,258
Nov	5,543,285	11,215	12,653
Dec	5,427,867	9,971	9,971
Jan	5,694,618	10,498	10,498
Feb	N/A	N/A	N/A
Mar	N/A	N/A	N/A
Total	55,299,765	111,976	118,294

Other Industry: 6 customers

2008/09	kW.h	kV.A Recorded	kV.A Billed
Apr	3,641,075	10,596	10,596
May	3,319,108	10,377	10,503
Jun	3,554,598	9,762	9,762
Jul	3,558,923	9,891	9,913
Aug	3,461,263	10,985	11,031
Sep	3,444,621	10,460	10,513
Oct	3,972,671	10,762	10,762
Nov	6,817,232	11,535	16,152
Dec	4,111,100	7,020	10,289
Jan	4,096,530	11,084	11,107
Feb	4,143,184	11,703	11,708
Mar	4,540,236	12,431	12,431
Total	48,660,541	126,606	134,767

2009/10	kW.h	kV.A Recorded	kV.A Billed
Apr	5,228,683	11,161	11,431
May	4,542,723	11,233	11,305
Jun	4,187,744	12,095	12,095
Jul	3,837,595	13,560	13,560
Aug	3,925,088	12,044	12,068
Sep	3,741,488	11,868	11,868
Oct	3,868,445	12,072	12,072
Nov	3,819,334	11,089	11,095
Dec	4,024,852	11,358	11,365
Jan	4,209,609	11,025	11,032
Feb	N/A	N/A	N/A
Mar	N/A	N/A	N/A
Total	41,385,561	117,505	117,891

Petroleum Industry: 11 customers

2008/09	kW.h	kV.A Recorded	kV.A Billed
Apr	76,770,611	162,647	162,647
May	70,560,836	146,262	147,850
Jun	77,140,533	164,373	164,373
Jul	80,215,612	161,827	161,835
Aug	79,402,640	159,999	160,281
Sep	74,894,904	160,831	160,831
Oct	82,374,133	167,132	167,132
Nov	86,970,224	173,183	173,183
Dec	91,095,650	185,478	185,598
Jan	84,750,806	169,004	169,004
Feb	74,278,174	168,141	169,088
Mar	76,293,721	162,692	163,993
Total	954,747,844	1,981,567	1,985,815

2009/10	kW.h	kV.A Recorded	kV.A Billed
Apr	73,269,161	163,542	163,627
May	70,410,420	175,099	175,099
Jun	84,788,210	182,457	182,462
Jul	87,259,561	182,801	182,801
Aug	73,473,067	178,588	178,588
Sep	72,036,262	182,554	182,796
Oct	71,231,601	181,289	181,289
Nov	73,112,755	179,155	179,450
Dec	77,112,343	174,044	174,044
Jan	82,350,671	179,396	179,396
Feb	N/A	N/A	N/A
Mar	N/A	N/A	N/A
Total	765,044,051	1,778,924	1,779,553

Pipeline Transport Industry: 3 customers

2008/09	kW.h	kV.A Recorded	kV.A Billed
Apr	0	0	0
May	0	0	0
Jun	0	0	0
Jul	0	0	0
Aug	0	0	0
Sep	0	0	0
Oct	0	0	0
Nov	0	0	0
Dec	0	0	0
Jan	0	0	0
Feb	0	0	0
Mar	0	0	0
Total	0	0	0

2009/10	kW.h	kV.A Recorded	kV.A Billed
Apr	0	0	0
May	0	0	0
Jun	0	0	0
Jul	0	0	0
Aug	0	0	0
Sep	0	0	0
Oct	0	0	0
Nov	0	0	0
Dec	0	0	0
Jan	108,000	10,764	10,764
Feb	N/A	N/A	N/A
Mar	N/A	N/A	N/A
Total	108,000	10,764	10,764

Primary Metal Industry: 6 customers

2008/09	kW.h	kV.A Recorded	kV.A Billed
Apr	188,356,310	338,326	338,326
May	194,225,067	329,242	329,242
Jun	176,883,947	311,789	311,789
Jul	170,763,210	307,594	307,594
Aug	178,074,758	309,364	309,364
Sep	183,837,410	316,759	316,759
Oct	188,825,363	328,598	328,598
Nov	202,126,743	336,426	336,426
Dec	189,992,499	345,809	345,809
Jan	203,256,945	345,647	345,647
Feb	173,143,331	328,975	328,975
Mar	187,726,350	327,132	327,442
Total	2,237,211,933	3,925,662	3,925,972

2009/10	kW.h	kV.A Recorded	kV.A Billed
Apr	165,806,506	312,655	314,896
May	168,124,697	312,881	315,863
Jun	161,320,690	307,388	310,782
Jul	161,320,571	289,579	298,947
Aug	122,349,037	275,435	283,131
Sep	162,848,976	300,145	304,226
Oct	181,313,054	293,174	309,465
Nov	178,423,574	303,169	319,170
Dec	184,774,310	311,959	316,701
Jan	190,095,544	310,874	315,712
Feb	N/A	N/A	N/A
Mar	N/A	N/A	N/A
Total	1,676,376,959	3,017,258	3,088,894

Pulp and Paper Industry: 4 customers

2008/09	kW.h	kV.A Recorded	kV.A Billed
Apr	56,406,230	100,093	100,093
May	61,475,290	101,008	101,008
Jun	61,651,751	102,802	102,802
Jul	63,595,564	111,743	111,743
Aug	62,752,543	105,108	105,108
Sep	58,714,842	105,520	102,836
Oct	60,512,807	103,954	103,954
Nov	57,459,095	102,181	102,181
Dec	42,852,821	99,358	99,358
Jan	53,310,089	99,726	99,726
Feb	34,792,372	114,720	102,908
Mar	62,445,715	113,504	113,504
Total	675,969,119	1,259,718	1,245,222

2009/10	kW.h	kV.A Recorded	kV.A Billed
Apr	66,963,654	112,534	112,534
May	69,931,644	113,010	113,010
Jun	41,436,505	100,993	100,993
Jul	18,784,805	96,288	96,288
Aug	38,994,446	99,066	99,066
Sep	15,697,408	42,380	89,500
Oct	13,591,911	30,928	78,102
Nov	12,835,293	33,785	80,997
Dec	14,028,490	30,602	45,250
Jan	12,902,400	31,175	46,764
Feb			
Mar			
Total	305,166,556	690,762	862,504

University & Colleges: 2 customers (new to this rate class)

2008/09	kW.h	kV.A Recorded	kV.A Billed
Apr			
May			
Jun			
Jul			
Aug			
Sep			
Oct			
Nov			
Dec			
Jan			
Feb			
Mar			
Total			

2009/10	kW.h	kV.A Recorded	kV.A Billed
Apr			
May			
Jun			
Jul	24,000	283	295
Aug	48,000	190	190
Sep	72,000	190	180
Oct	72,000	211	211
Nov	72,000	182	182
Dec	235,200	494	494
Jan	264,000	556	556
Feb			
Mar			
Total	787,200	2,106	2,108

PUB/MH I-72

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Table 8, Page 27, PUB/MH I-3(a)/ Supplementary Filing at EIIR**

b) To what extent did the economic downturn result in a change in industry sector consumption levels and load factors? Please provide a comparative listing by sector and explain.

ANSWER:

Many industries sectors were impacted by the economic downturn. The impacts were however not necessarily felt universally by all companies within a particular sector due to factors such as primary market location (e.g. US vs CDN), ability to manage inventory levels, production flexibility, etc. Some companies were able to shift production towards product lines for which demand was more robust, resulting in a lesser impact to the company's energy consumption and/or operations. Other factors unrelated to the economic downturn also affect consumption and load factors such as weather and production changes (new products, phased-out products, etc). The small number of companies in some industrial sector groups makes specific information related to impacts commercially-sensitive and therefore privileged.

Please see Manitoba Hydro's response to PUB/MH I-72(a) for sector changes between 2008/09 and 2009/10.

<u>PUB/MH I-73</u>

Subject: **Tab 7: Load Forecast And Load Research**

Reference: **Appendix 7.1 – 2008/09 Load Forecast, Table8, Page 27, 2006/07 Load Forecast, Table 10 (Page 29)**

a) **Please confirm that MH's Basic General Services sales forecast is largely unchanged after 2015 from that provided in Table 10 (Page 29) of the 2006/07 load forecast for commercial and industrial sales:**

Table 10 (2006/07 Forecast)	Table 8 (2009/10 Forecast)
2006-07 - 14,896 GWh	13,828 GWh (actual)
2011-12 - 15,891 GWh	14,798 GWh
2016-17 - 16,699 GWh	16,270 GWh
2021-22 - 17,391 GWh	17,272 GWh
2026-27 - 18,060 GWh	18,408 GWh

<u>ANSWER</u>:

The number of 14,896 GW.h for 2006-07 from the 2006/07 forecast is incorrect and should be: 13,896 GW.h.

The 2009/10 forecast compared to the 2006/07 forecast in 2016-17 is 3% lower, in 2021-22 is 1% lower and in 2026-27 is 2% higher. This sales forecast has changed moderately and reflects current and updated information. For example, the early years such as 2016-17 are lower due to the effects of the recent economic downturn. The 2009/10 forecast is expecting a higher rate of growth for basic general service than the 2006/07 forecast.

<u>PUB/MH I-73</u>

Subject: **Tab 7: Load Forecast And Load Research**

Reference: **Appendix 7.1 – 2008/09 Load Forecast, Table8, Page 27, 2006/07 Load Forecast, Table 10 (Page 29)**

b) How does MH rationalize the actual 2007/08 to 2009/10 industrial load levels with the longer range forecast in Table 10.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH I-73(c)

PUB/MH I-73

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1 – 2008/09 Load Forecast, Table8, Page 27, 2006/07 Load Forecast, Table 10 (Page 29)**

c) **Is MH suggesting the economic downturn will have little or no impact on the timing of future load levels? Please explain.**

ANSWER:

The current economic downturn is factored into future load levels.

The 2009/10 total basic general service forecast in Table 8, Page 27 for 2009/10 is 14,016 GW.h. That is down 84 GW.h from the weather adjusted value of 14,100 GW.h for the previous year (2008/09) which is shown in the table on Page 20. Also, the weather adjusted growth from 2007/08 to 2008/09 is only 35 GW.h. Normal growth in the general service sector is about 300 GW.h per year, so the impact of the economic downturn through these two years is over 600 GW.h.

PUB/MH I-74

Subject: Tab 7: Load Forecast And Load Research
Reference: Appendix 7.1, Page 36 Transmission losses

a) **Please confirm that transmission losses from generation to the common bus for domestic load and export power are equitably shared on an annual energy flow basis. If not, please clarify.**

ANSWER:

Transmission losses percentages are calculated monthly. Transmission losses for both export and domestic load are then calculated hourly using the same loss monthly share percentages and aggregated on a monthly and annual basis.

<u>PUB/MH I-74</u>

Subject: Tab 7: Load Forecast And Load Research
Reference: Appendix 7.1, Page 36 Transmission losses

b) **Should MH recognize the historical roles that Winnipeg River G&T and Grand Rapid G&T played as domestic energy providers and assume that all export sales involve HVDC transmission? Please explain why or why not.**

<u>ANSWER</u>:

During the 2006 Cost of Service Review, Manitoba Hydro outlined its concerns with a COSS approach which assigns the lowest cost generation resources to domestic customers, while the higher cost resources are allocated to residual domestic consumption and an Export class (See pages 24-26 of PCOSS06 which was filed as Manitoba Hydro's application in that proceeding). To summarize:

1) The magnitude of benefits to domestic classes as a result of a two tier Generation costing methodology is not significant relative to the overall impacts of creating an Export class.

2) The two tier approach, if applied at that time, reduces the total cost of Generation to be allocated to the domestic classes and also reduces the amount of net export revenue available for allocation to the domestic classes. The costs of this approach are not allocated among the domestic classes in the same proportion as the benefits.

3) Generation resources which are currently low cost may not remain that way into the future, as new expenditures are required to upgrade these facilities. This concern has been borne out with the passage of time. Today, the cost per kW.h of generation at Winnipeg River plants and Grand Rapids combined is higher than the cost per kW.h at the plants connected to the DC system.

4) Preparing a COSS on a Generation vintage basis involves significant additional effort without yielding significantly different results.

During Final Argument in this proceeding, on June 2, 2006, Manitoba Hydro noted: "*the Corporation does not believe that the Generation Vintage method adds any reasonable value* *to the cost study. And the other Intervenors, even Mr. Lazar who initiated the proposal, either concur or are taking no position."* (Tr. 2520: 14-19.)

During that proceeding, Manitoba Hydro recommended a specific methodology, which did not include any Generation Vintaging. PUB Order 117/06 directed that Manitoba Hydro vary its recommended method in several respects; however, it did not direct incorporation of Generation Vintaging.

Manitoba Hydro intends to commission a complete review of its Cost of Service Study methodology, including the treatment of export sales, and the question of dedicated generation could be an issue to be re-considered in that review.

<u>PUB/MH I-74</u>

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Page 36 Transmission losses**

c) Please provide the rationale and illustrate on a quantitative basis the assignment of approximately 10% transmission losses to domestic load regardless of the supply source.

<u>ANSWER</u>:

Transmission losses associated with serving Manitoba load are estimated in the load forecast. These losses from generation to common bus are estimated to be 8.94% in the 2009 Manitoba Hydro Electric Load Forecast. Power at the generation level is metered at the various locations that supply power to the Manitoba Hydro system. Power at the common bus is defined as the metered power at a hub comprised of about 120 substations that receive power from generation sources. The difference between metered power at generation and metered power at the common bus represents the average losses between these two levels in the system. It is not practical to attribute different losses to each generation source because the system is a wide ranging grid with power injections at various locations and with withdrawals of power at various locations. Therefore, the approach that has been taken is to use the average loss for all generation serving Manitoba domestic load.

<u>PUB/MH I-74</u>

Subject: **Tab 7: Load Forecast And Load Research**
Reference: **Appendix 7.1, Page 36 Transmission losses**

d) **Please provide the rationale (and quantify) for allocating only approximately 10% transmission losses to exports when there are additional Common Bus to U.S. border losses?**

<u>ANSWER</u>:

Please refer to the response to PUB/MH I-74(c) for information on how Manitoba Hydro determines the losses to common bus. As indicated in that response the location of the common bus is not a specific physical location because it is a hub of about 120 substations at various locations in the Province. A detailed study to quantify the difference between transmission losses to common bus and losses to the border would be cost prohibitive and so an approximate estimate of 10% is utilized for export losses. Using 10% is reflective of higher transmission losses to the border than those to common bus.

PUB/MH I-75

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8 – Energy Supply – Page 17, Figure 8.6.2, 2008 GRA PUB/MH I-3(f)**

Please provide the tabular data supporting MH's current potential monthly hydraulic generation for the entire 1978-2009 period of historical post LWR/CRD record defining

- **i. Lower Nelson River flows at Kettle G.S. and total annual hydraulic generation.**
- **ii. Upper Nelson River flows at Kelsey G.S. compared total (net) Lake Winnipeg inflows.**
- **iii. Unregulated annual Lake Winnipeg inflows and attributed post- Limestone hydraulic generation as defined by:**
  - **Winnipeg River flows.**
  - **Red River flows.**
  - **Saskatchewan River flows.**
  - **Other local inflows (net of evaporation).**
- **iv. Actual Burntwood River flows and attributed post-Limestone hydraulic generation.**

ANSWER:

The tables on the following pages provide Manitoba Hydro's recorded hydraulic generation and flow for the post LWR/CRD period of 1978-2009. The information was compiled from historical records consistent with the format provided in the reference 2008 GRA PUB/MH I-3(f). The generating stations along the Winnipeg River include Pointe du Bois, Slave Falls, Seven Sisters, McArthur, Great Falls and Pine Falls. The sole generating station along the Saskatchewan River is Grand Rapids. The generating stations along the Upper Nelson include Jenpeg and Kelsey, while the generating stations along the Lower Nelson include Kettle, Long Spruce and Limestone.

The attributed post-Limestone hydraulic generation that is developed from Manitoba Hydro's simulation studies is not being provided because it is information that is considered to be commercially sensitive since it can be used to assess specific characteristics of Manitoba Hydro's hydraulic resource.

Date	Winnipeg River		Saskatchewan River		Upper Nelson		Lower Nelson		Laurie River	
	Flow @ Slave Falls (cms)	Generation (GWh)	Flow @ Grand Rapids (cms)	Generation (GWh)	Flow @ Kelsey (cms)	Generation (GWh)	Flow @ Kettle (cms)	Generation (GWh)	Flow @ LR #2 (cms)	Generation (GWh)
Jan 1978	1,340	387	708	165	1,790	184	2,860	718	27	5
Feb 1978	1,230	355	578	122	1,830	168	2,693	617	32	6
Mar 1978	1,280	394	438	100	1,960	169	3,117	768	28	5
Apr 1978	1,300	375	409	90	1,690	159	2,477	617	34	7
May 1978	977	389	203	43	1,430	176	2,382	658	34	7
Jun 1978	1,060	378	158	29	1,250	169	2,443	641	26	5
Jul 1978	1,350	386	180	37	1,170	167	2,191	625	31	6
Aug 1978	998	398	255	57	1,250	174	2,415	729	30	6
Sep 1978	1,250	388	380	88	1,440	181	2,517	694	37	7
Oct 1978	1,040	403	668	130	2,180	211	3,329	812	33	7
Nov 1978	941	381	743	167	2,500	205	3,651	944	33	7
Dec 1978	990	399	838	207	2,560	196	3,623	1,141	28	6
Jan 1979	996	399	1,180	284	2,490	198	3,693	1,187	29	6
Feb 1979	957	354	1,130	232	2,540	173	3,562	1,043	27	5
Mar 1979	878	372	639	141	2,420	177	3,630	1,145	26	5
Apr 1979	989	375	301	62	2,080	193	3,087	951	26	5
May 1979	1,620	350	279	62	2,910	173	4,066	922	29	6
Jun 1979	1,600	332	803	101	3,900	135	5,330	958	35	7
Jul 1979	890	334	461	81	4,030	158	5,315	1,044	26	5
Aug 1979	577	255	246	55	2,890	154	4,277	1,148	25	5
Sep 1979	649	276	173	38	1,530	195	2,551	898	24	4
Oct 1979	771	332	222	51	1,830	231	2,847	1,033	23	4
Nov 1979	782	332	250	56	2,450	228	3,481	1,235	22	4
Dec 1979	846	359	712	180	2,290	242	3,369	1,235	18	3
Jan 1980	905	375	888	221	2,100	244	3,260	1,198	16	3
Feb 1980	961	363	911	209	2,070	222	3,083	1,059	18	3
Mar 1980	1,040	388	827	197	2,160	228	3,301	1,185	19	3
Apr 1980	1,030	374	199	42	1,980	224	3,085	1,021	22	4
May 1980	735	315	227	52	1,340	158	2,689	940	26	5
Jun 1980	369	160	248	57	1,180	170	2,071	734	15	2
Jul 1980	259	118	728	180	979	128	2,022	739	8	1
Aug 1980	269	123	589	145	1,090	165	2,146	789	19	4
Sep 1980	308	138	544	129	1,320	186	2,553	895	21	4
Oct 1980	405	184	753	185	1,740	249	2,928	1,056	28	6
Nov 1980	538	234	727	170	2,140	232	3,066	1,076	27	5
Dec 1980	735	326	720	171	2,150	231	3,193	1,155	24	5
Jan 1981	818	351	528	124	2,140	239	3,321	1,214	28	6
Feb 1981	846	325	323	64	2,170	209	3,118	1,063	33	6
Mar 1981	619	288	117	18	1,820	215	2,934	1,067	28	6
Apr 1981	368	167	127	21	915	136	1,961	708	25	5
May 1981	264	126	257	58	940	131	2,332	879	26	5
Jun 1981	283	136	634	153	966	133	2,108	750	18	3
Jul 1981	507	230	785	193	1,320	188	2,499	905	13	2
Aug 1981	317	150	996	243	952	154	2,090	753	11	2
Sep 1981	407	183	726	173	1,320	209	2,334	821	11	2
Oct 1981	574	262	461	109	1,770	277	2,571	935	15	3
Nov 1981	639	277	408	93	2,330	256	3,034	1,083	16	3

Date	Winnipeg River		Saskatchewan River		Upper Nelson		Lower Nelson		Laurie River	
	Flow @ Slave Falls	Generation	Flow @ Grand Rapids	Generation	Flow @ Kelsey	Generation	Flow @ Kettle	Generation	Flow @ LR #2	Generation
	(cms)	(GWh)	(cms)	(GWh)	(cms)	(GWh)	(cms)	(GWh)	(cms)	(GWh)
Dec 1981	623	287	868	211	2,170	241	3,107	1,138	17	3
Jan 1982	686	313	1,180	278	1,840	237	2,424	892	16	3
Feb 1982	797	317	686	142	1,800	211	2,537	871	10	2
Mar 1982	660	309	719	163	1,690	236	2,585	948	15	3
Apr 1982	606	292	564	121	1,610	233	2,305	812	19	3
May 1982	766	339	288	64	1,890	226	3,379	1,245	29	7
Jun 1982	1,090	356	211	45	1,460	205	2,528	887	38	7
Jul 1982	1,000	366	217	51	1,500	220	2,360	847	30	6
Aug 1982	916	368	265	65	1,490	230	2,595	933	25	4
Sep 1982	771	331	498	118	1,860	255	2,947	1,028	24	5
Oct 1982	905	364	386	93	2,330	275	3,453	1,258	15	2
Nov 1982	1,070	380	438	103	2,440	246	3,526	1,248	21	4
Dec 1982	1,330	390	453	110	2,300	233	3,513	1,285	21	4
Jan 1983	1,300	391	584	140	2,190	232	3,391	1,241	24	4
Feb 1983	1,130	361	1,190	251	2,240	210	3,202	1,094	23	4
Mar 1983	1,060	400	1,110	252	2,300	219	3,129	1,140	23	4
Apr 1983	956	377	696	146	2,340	209	3,194	1,119	36	6
May 1983	573	280	309	67	1,930	225	3,143	1,148	27	5
Jun 1983	506	240	364	80	1,780	212	3,352	1,201	21	4
Jul 1983	610	277	172	35	1,650	248	2,694	979	15	3
Aug 1983	532	249	374	86	1,710	254	3,032	1,114	15	3
Sep 1983	451	198	344	77	1,750	248	2,898	1,030	28	5
Oct 1983	620	277	591	142	1,990	275	3,140	1,160	34	7
Nov 1983	838	342	480	110	2,320	247	3,460	1,241	34	6
Dec 1983	921	378	1,050	249	2,220	227	3,375	1,241	33	6
Jan 1984	941	389	760	176	2,180	225	3,296	1,218	31	6
Feb 1984	936	368	460	99	2,080	211	3,392	1,168	33	6
Mar 1984	862	366	894	199	2,180	216	3,338	1,218	32	7
Apr 1984	716	315	420	90	1,860	213	3,125	1,122	29	6
May 1984	568	272	449	104	1,560	227	3,217	1,188	19	2
Jun 1984	835	340	487	110	1,610	225	2,800	994	19	2
Jul 1984	866	368	326	74	1,570	240	2,847	1,036	23	5
Aug 1984	619	287	387	88	1,550	247	2,674	970	29	6
Sep 1984	542	249	227	47	1,690	253	2,612	930	27	6
Oct 1984	595	285	366	83	1,880	270	2,926	1,077	20	2
Nov 1984	796	342	379	85	1,990	246	2,848	1,023	29	6
Dec 1984	916	387	660	156	2,080	242	3,244	1,215	31	6
Jan 1985	936	385	993	229	2,030	230	3,244	1,203	24	4
Feb 1985	936	346	460	89	2,050	197	3,027	1,036	29	5
Mar 1985	931	385	182	35	1,780	232	3,095	1,146	35	7
Apr 1985	764	333	242	49	1,850	221	2,773	991	30	6
May 1985	1,250	375	345	80	1,880	238	3,668	1,359	34	7
Jun 1985	1,930	345	294	65	1,730	246	3,008	1,074	29	6
Jul 1985	2,200	352	324	76	1,860	255	3,337	1,231	30	6
Aug 1985	1,540	372	387	91	1,690	256	3,104	1,128	25	5
Sep 1985	1,440	359	621	146	1,940	234	3,013	1,044	26	5
Oct 1985	1,600	372	379	89	2,250	270	3,303	1,191	24	5
Nov 1985	1,770	367	830	195	2,390	245	3,464	1,220	29	6
Dec 1985	1,340	394	692	163	2,470	216	3,483	1,276	30	6

Date	Winnipeg River		Saskatchewan River		Upper Nelson		Lower Nelson		Laurie River	
	Flow @ Slave Falls	Generation	Flow @ Grand Rapids	Generation	Flow @ Kelsey	Generation	Flow @ Kettle	Generation	Flow @ LR #2	Generation
	(cms)	(GWh)	(cms)	(GWh)	(cms)	(GWh)	(cms)	(GWh)	(cms)	(GWh)
Jan 1986	1,300	391	695	161	2,650	192	3,824	1,403	29	6
Feb 1986	1,270	360	1,060	221	2,700	177	3,705	1,255	25	5
Mar 1986	1,310	394	625	138	2,600	185	3,554	1,294	24	5
Apr 1986	1,220	374	295	60	2,360	210	3,363	1,196	22	4
May 1986	1,620	369	206	44	3,490	177	5,111	1,409	16	2
Jun 1986	1,380	370	273	61	3,900	189	5,239	1,406	24	3
Jul 1986	739	331	436	104	3,040	243	4,462	1,394	32	7
Aug 1986	694	315	637	155	2,020	258	3,306	1,141	34	7
Sep 1986	628	286	554	131	1,930	246	3,263	1,155	34	7
Oct 1986	789	347	569	139	1,980	275	3,219	1,183	26	5
Nov 1986	819	339	877	209	2,240	228	3,352	1,199	19	3
Dec 1986	886	377	731	177	2,450	230	3,683	1,364	27	5
Jan 1987	898	376	984	234	2,320	228	3,660	1,355	27	5
Feb 1987	910	348	1,110	233	2,180	205	3,450	1,161	22	4
Mar 1987	885	384	805	185	2,090	242	3,400	1,267	25	5
Apr 1987	735	337	762	170	2,000	243	3,120	1,126	19	4
May 1987	453	221	431	100	1,710	235	3,100	1,162	27	5
Jun 1987	326	158	403	92	1,230	172	2,420	868	22	4
Jul 1987	290	146	340	80	1,190	182	2,590	956	14	3
Aug 1987	232	116	323	76	1,130	177	2,100	784	14	2
Sep 1987	228	108	274	62	1,380	212	2,400	866	14	2
Oct 1987	297	145	237	55	1,510	262	2,440	900	21	4
Nov 1987	406	190	178	37	1,750	254	2,690	975	28	5
Dec 1987	566	266	187	41	1,750	262	2,920	1,096	21	4
Jan 1988	585	272	856	206	1,630	253	2,710	1,015	19	4
Feb 1988	594	258	706	154	1,600	228	2,780	966	18	3
Mar 1988	488	231	205	45	1,430	223	2,720	1,012	17	3
Apr 1988	354	169	183	38	1,110	173	1,970	710	17	3
May 1988	251	128	220	50	1,360	198	2,850	1,072	29	6
Jun 1988	212	103	196	42	1,010	141	2,200	798	20	4
Jul 1988	193	99	169	37	771	119	1,780	674	16	3
Aug 1988	183	91	256	59	727	116	1,600	597	16	3
Sep 1988	285	133	232	52	730	115	1,850	676	17	3
Oct 1988	693	312	339	80	890	163	1,820	683	17	3
Nov 1988	875	361	197	43	1,330	224	2,110	773	25	5
Dec 1988	909	384	193	43	1,370	231	2,300	868	29	6
Jan 1989	934	389	279	65	1,340	219	2,230	845	24	5
Feb 1989	969	362	1,000	216	1,270	189	2,240	762	22	4
Mar 1989	955	400	759	177	1,210	200	2,180	809	19	4
Apr 1989	941	387	289	62	1,100	176	1,970	722	17	3
May 1989	976	407	177	37	1,210	190	2,450	927	34	7
Jun 1989	1,220	387	170	34	929	149	1,990	725	29	6
Jul 1989	1,850	378	252	57	1,120	184	1,980	739	27	5
Aug 1989	1,070	382	207	45	1,380	227	2,430	904	25	5
Sep 1989	742	322	237	52	1,520	250	2,670	963	27	5
Oct 1989	624	294	438	104	1,840	260	2,590	964	26	5
Nov 1989	549	256	534	123	1,790	253	2,810	1,018	20	4
Dec 1989	711	320	582	135	1,810	249	2,770	1,035	18	3
Jan 1990	769	341	284	64	1,770	234	2,920	1,094	25	5

Date	Winnipeg River		Saskatchewan River		Upper Nelson		Lower Nelson		Laurie River	
	Flow @ Slave Falls (cms)	Generation (GWh)	Flow @ Grand Rapids (cms)	Generation (GWh)	Flow @ Kelsey (cms)	Generation (GWh)	Flow @ Kettle (cms)	Generation (GWh)	Flow @ LR #2 (cms)	Generation (GWh)
Feb 1990	769	308	613	127	1,610	211	2,820	937	18	3
Mar 1990	681	315	434	100	1,450	225	2,530	942	20	4
Apr 1990	582	273	425	95	1,290	201	2,240	816	29	6
May 1990	465	233	367	87	1,450	220	2,510	944	25	5
Jun 1990	794	340	525	123	1,270	189	2,720	980	21	4
Jul 1990	1,170	390	919	225	1,190	193	2,220	816	17	3
Aug 1990	873	361	896	220	1,340	216	2,300	843	16	3
Sep 1990	632	281	704	167	1,580	244	2,370	915	13	2
Oct 1990	505	237	909	220	1,940	273	2,700	1,076	13	2
Nov 1990	547	248	353	80	2,000	251	2,850	1,176	14	2
Dec 1990	588	277	581	137	1,940	245	2,860	1,304	17	3
Jan 1991	656	303	891	208	1,790	232	2,650	1,261	17	3
Feb 1991	722	292	603	124	1,610	209	2,530	1,120	14	2
Mar 1991	733	328	498	110	1,510	225	2,290	1,219	14	2
Apr 1991	585	271	339	73	1,490	217	2,180	1,096	22	4
May 1991	494	242	440	103	1,390	209	2,630	1,312	23	5
Jun 1991	577	274	555	125	1,190	186	2,140	1,124	25	5
Jul 1991	764	346	227	50	1,210	196	2,180	1,190	28	6
Aug 1991	581	273	376	90	1,150	191	2,370	1,285	21	4
Sep 1991	495	230	576	137	1,040	168	2,080	1,135	19	3
Oct 1991	676	314	414	100	1,350	231	2,470	1,414	37	7
Nov 1991	826	352	432	99	1,600	247	2,610	1,456	25	5
Dec 1991	964	405	516	123	1,580	253	2,570	1,463	23	4
Jan 1992	877	401	458	106	1,640	248	2,810	1,577	22	4
Feb 1992	909	370	374	83	1,650	218	2,770	1,455	18	3
Mar 1992	990	412	90	20	1,510	223	2,630	1,481	18	3
Apr 1992	1,110	398	5	1	1,430	204	2,480	1,358	23	4
May 1992	1,450	380	473	63	1,500	204	2,710	1,582	34	7
Jun 1992	1,670	345	334	63	1,390	197	2,690	1,454	35	7
Jul 1992	1,360	359	234	50	1,210	180	2,370	1,262	25	5
Aug 1992	1,140	369	363	84	1,310	200	2,320	1,318	21	4
Sep 1992	2,190	306	473	110	1,610	233	2,530	1,367	26	5
Oct 1992	2,510	311	306	73	2,710	244	3,680	1,797	25	5
Nov 1992	1,420	374	235	53	2,680	258	3,760	1,961	22	4
Dec 1992	1,140	403	533	131	2,300	255	3,450	1,943	26	5
Jan 1993	1,060	403	513	124	2,280	231	3,300	1,837	26	5
Feb 1993	1,030	366	460	100	2,400	204	3,630	1,821	22	4
Mar 1993	1,020	406	376	89	2,240	223	3,350	1,855	23	4
Apr 1993	864	352	140	28	1,670	220	2,390	1,323	18	3
May 1993	693	313	126	25	1,250	184	2,080	1,203	20	4
Jun 1993	635	272	162	33	1,010	145	1,690	955	10	1
Jul 1993	755	321	835	203	1,130	164	1,930	1,126	9	1
Aug 1993	1,270	357	1,280	230	1,980	251	2,570	1,413	19	4
Sep 1993	1,290	351	824	192	3,280	218	4,130	1,490	18	3
Oct 1993	1,300	373	670	166	2,610	258	3,700	1,942	15	3
Nov 1993	1,200	370	692	167	2,120	259	2,820	1,555	19	3
Dec 1993	1,050	382	712	175	2,490	255	3,520	2,003	21	4
Jan 1994	961	376	988	235	2,610	213	3,670	2,028	18	3
Feb 1994	934	342	958	202	2,430	194	3,450	1,717	16	3

Date	Winnipeg River		Saskatchewan River		Upper Nelson		Lower Nelson		Laurie River	
	Flow @ Slave Falls (cms)	Generation (GWh)	Flow @ Grand Rapids (cms)	Generation (GWh)	Flow @ Kelsey (cms)	Generation (GWh)	Flow @ Kettle (cms)	Generation (GWh)	Flow @ LR #2 (cms)	Generation (GWh)
Mar 1994	985	389	995	225	2,200	218	3,170	1,751	16	3
Apr 1994	767	332	448	97	2,070	224	2,730	1,486	19	3
May 1994	558	279	303	64	1,960	237	3,080	1,773	28	6
Jun 1994	471	215	418	95	1,650	237	2,680	1,491	30	6
Jul 1994	697	293	271	61	1,630	245	2,740	1,561	17	3
Aug 1994	937	354	251	57	1,690	259	2,700	1,530	16	3
Sep 1994	795	329	258	58	1,770	238	2,650	1,455	15	2
Oct 1994	946	366	263	60	2,040	269	2,820	1,597	13	2
Nov 1994	1,140	368	606	143	2,170	262	3,140	1,728	15	2
Dec 1994	1,350	385	928	221	2,290	252	2,970	1,696	16	3
Jan 1995	1,350	377	620	142	2,450	227	3,310	1,894	18	3
Feb 1995	1,320	328	519	108	2,370	208	3,280	1,687	16	3
Mar 1995	1,260	374	668	154	2,340	236	3,200	1,820	15	3
Apr 1995	1,260	371	362	75	2,260	231	3,140	1,721	14	2
May 1995	990	376	272	55	1,970	238	3,030	1,725	14	2
Jun 1995	967	331	440	98	1,870	229	2,880	1,585	28	5
Jul 1995	690	290	428	102	1,780	268	2,540	1,441	10	1
Aug 1995	830	323	569	139	2,100	264	2,980	1,655	6	1
Sep 1995	689	280	671	160	2,250	247	3,090	1,704	4	1
Oct 1995	634	264	376	90	2,490	271	3,410	1,938	17	3
Nov 1995	891	338	656	158	2,260	247	3,160	1,745	13	2
Dec 1995	1,010	390	746	183	2,170	236	3,110	1,760	17	3
Jan 1996	1,000	398	1,090	261	2,130	231	3,200	1,802	15	2
Feb 1996	939	365	934	204	2,020	218	3,090	1,621	13	2
Mar 1996	917	380	664	153	1,990	233	3,020	1,698	13	2
Apr 1996	945	372	734	163	1,930	220	3,020	1,650	9	2
May 1996	1,500	345	623	96	2,350	239	3,400	1,848	17	4
Jun 1996	1,820	327	280	47	3,340	191	4,790	1,999	14	2
Jul 1996	1,540	372	653	147	3,840	201	5,100	1,903	18	2
Aug 1996	1,010	376	542	127	3,390	236	4,570	2,120	16	2
Sep 1996	818	347	340	80	2,260	255	3,380	1,442	8	1
Oct 1996	783	340	557	139	2,560	256	3,460	1,952	12	2
Nov 1996	1,360	379	531	126	2,340	233	3,500	1,923	24	5
Dec 1996	1,670	370	968	233	2,590	224	3,720	2,100	34	7
Jan 1997	1,570	364	862	205	2,510	220	3,630	2,029	30	6
Feb 1997	1,480	335	1,060	223	2,480	202	3,640	1,819	27	5
Mar 1997	1,440	378	1,040	235	2,470	217	3,720	2,033	22	4
Apr 1997	1,640	355	625	134	2,540	200	3,920	2,091	22	4
May 1997	2,130	330	464	104	3,270	179	4,410	2,170	30	6
Jun 1997	1,170	341	438	96	4,140	163	5,420	2,114	20	4
Jul 1997	716	330	721	175	4,100	181	5,370	2,072	15	3
Aug 1997	530	263	453	108	3,380	236	4,860	2,208	19	4
Sep 1997	488	232	386	90	2,070	239	3,830	2,089	32	6
Oct 1997	629	301	654	157	2,030	253	3,660	2,089	45	8
Nov 1997	747	324	570	130	2,490	250	3,890	2,164	35	7
Dec 1997	823	344	774	186	2,710	217	3,980	2,251	35	7
Jan 1998	860	345	980	231	2,690	205	4,040	2,243	32	7
Feb 1998	786	305	866	183	2,600	193	3,950	1,994	35	7
Mar 1998	770	337	519	120	2,350	247	3,810	2,117	33	7

Date	Winnipeg River		Saskatchewan River		Upper Nelson		Lower Nelson		Laurie River	
	Flow @ Slave Falls (cms)	Generation (GWh)	Flow @ Grand Rapids (cms)	Generation (GWh)	Flow @ Kelsey (cms)	Generation (GWh)	Flow @ Kettle (cms)	Generation (GWh)	Flow @ LR #2 (cms)	Generation (GWh)
Apr 1998	735	327	465	106	2,320	244	3,660	1,984	36	7
May 1998	727	329	326	75	2,130	246	3,900	2,164	36	8
Jun 1998	609	299	234	49	2,610	247	4,000	2,132	22	4
Jul 1998	440	219	361	83	2,740	234	4,260	2,269	30	6
Aug 1998	316	151	686	170	2,250	250	3,860	2,137	20	4
Sep 1998	241	112	723	174	1,640	229	2,780	1,513	30	6
Oct 1998	276	141	440	106	1,720	257	2,810	1,622	30	6
Nov 1998	408	195	329	73	1,840	263	2,810	1,581	31	6
Dec 1998	617	293	421	101	1,920	261	2,870	1,644	30	6
Jan 1999	722	328	759	181	1,900	255	2,820	1,604	28	6
Feb 1999	791	312	485	103	1,950	227	2,940	1,496	24	4
Mar 1999	731	332	576	140	1,830	253	2,680	1,529	23	5
Apr 1999	753	326	518	121	1,890	232	2,830	1,552	28	5
May 1999	957	368	751	182	1,820	248	2,430	1,396	44	8
Jun 1999	1,560	374	569	133	1,850	257	2,870	1,589	29	6
Jul 1999	1,380	400	548	132	1,910	265	2,800	1,594	27	5
Aug 1999	1,050	390	503	120	1,910	267	2,650	1,513	28	6
Sep 1999	817	337	361	83	1,970	257	2,750	1,551	26	5
Oct 1999	1,160	397	379	91	2,220	277	3,190	1,823	23	5
Nov 1999	1,390	379	478	110	2,160	253	3,070	1,710	28	6
Dec 1999	1,230	413	691	165	2,220	257	3,210	1,843	25	5
Jan 2000	952	399	978	229	2,290	237	3,290	1,824	21	4
Feb 2000	935	376	790	168	2,330	220	3,430	1,780	22	4
Mar 2000	933	407	653	145	2,110	254	3,490	1,962	24	5
Apr 2000	827	349	442	93	2,090	250	3,160	1,744	29	5
May 2000	750	339	342	76	1,710	215	3,170	1,826	36	7
Jun 2000	1,029	364	289	62	1,520	232	2,840	1,566	45	4
Jul 2000	1,750	390	334	75	2,010	268	3,370	1,927	34	5
Aug 2000	1,450	408	260	59	2,080	264	3,630	2,038	26	5
Sep 2000	1,390	397	205	45	2,260	253	3,550	1,944	22	4
Oct 2000	941	397	316	73	2,410	264	3,780	2,131	26	5
Nov 2000	1,290	377	416	93	2,390	246	3,640	1,971	29	6
Dec 2000	1,410	399	883	203	2,450	227	3,580	2,012	27	6
Jan 2001	1,150	409	260	59	2,650	219	3,760	2,095	25	5
Feb 2001	1,060	358	390	80	2,670	189	3,990	1,977	24	5
Mar 2001	1,040	390	194	44	2,440	223	3,840	2,144	29	6
Apr 2001	1,080	367	348	76	2,310	226	3,510	1,909	28	6
May 2001	1,830	379	258	57	2,980	258	4,370	2,345	26	6
Jun 2001	2,370	353	116	22	3,460	220	4,760	2,316	9	2
Jul 2001	2,340	364	133	28	3,750	215	5,010	2,383	8	2
Aug 2001	1,770	383	133	28	2,990	256	4,430	2,148	9	2
Sep 2001	1,390	391	77	15	2,520	240	3,630	1,982	13	3
Oct 2001	899	373	113	24	2,480	268	3,500	1,987	24	5
Nov 2001	962	377	152	33	2,380	244	3,520	1,933	31	6
Dec 2001	1,040	417	172	39	2,300	223	3,320	1,883	28	6
Jan 2002	1,019	414	227	51	2,250	233	3,560	2,005	29	6
Feb 2002	997	368	243	48	2,030	218	3,180	1,610	26	5
Mar 2002	901	386	576	126	2,000	236	2,930	1,643	22	4
Apr 2002	868	362	374	69	1,730	231	2,690	1,474	29	6

Date	Winnipeg River		Saskatchewan River		Upper Nelson		Lower Nelson		Laurie River	
	Flow @ Slave Falls (cms)	Generation (GWh)	Flow @ Grand Rapids (cms)	Generation (GWh)	Flow @ Kelsey (cms)	Generation (GWh)	Flow @ Kettle (cms)	Generation (GWh)	Flow @ LR #2 (cms)	Generation (GWh)
May 2002	880	388	372	72	1,770	224	2,810	1,608	27	5
Jun 2002	1,537	372	360	75	1,830	231	3,190	1,780	20	4
Jul 2002	2,473	355	395	89	2,150	224	3,210	1,816	24	5
Aug 2002	1,879	376	393	87	2,430	254	3,320	1,869	21	4
Sep 2002	955	372	246	54	2,410	254	3,220	1,778	18	3
Oct 2002	664	316	382	85	2,340	268	3,300	1,868	15	3
Nov 2002	614	287	349	73	2,160	254	2,990	1,638	18	3
Dec 2002	610	295	287	58	2,230	235	3,200	1,821	30	6
Jan 2003	622	296	630	146	2,130	227	3,410	1,905	25	5
Feb 2003	682	278	894	189	1,900	205	3,010	1,499	20	4
Mar 2003	632	289	567	126	1,780	221	2,730	1,521	20	4
Apr 2003	464	220	291	58	1,600	214	2,410	1,323	17	3
May 2003	365	184	274	50	1,500	229	2,310	1,342	14	3
Jun 2003	280	145	377	75	1,270	199	1,920	1,079	11	2
Jul 2003	250	132	514	122	1,280	208	2,050	1,185	10	2
Aug 2003	284	145	510	121	1,230	198	1,760	1,014	4	1
Sep 2003	250	125	80	16	861	132	1,510	841	8	2
Oct 2003	417	217	46	8	765	126	1,420	816	14	3
Nov 2003	531	257	42	7	941	160	1,560	870	17	3
Dec 2003	733	340	56	12	1,050	174	1,850	1,067	20	4
Jan 2004	820	369	254	62	1,020	166	1,850	1,065	20	4
Feb 2004	890	364	159	37	1,070	167	1,840	991	18	3
Mar 2004	856	379	315	79	1,190	184	2,060	1,179	17	3
Apr 2004	926	392	445	106	1,150	178	1,790	996	15	3
May 2004	1,176	380	388	93	1,550	215	2,220	1,253	17	3
Jun 2004	2,132	348	167	37	2,220	229	2,950	1,609	23	5
Jul 2004	1,639	383	387	94	2,710	255	3,380	1,903	18	3
Aug 2004	1,031	407	451	112	2,560	265	3,410	1,933	14	3
Sep 2004	1,325	380	613	147	2,350	252	3,340	1,814	17	3
Oct 2004	1,797	382	521	129	2,480	258	3,540	2,008	18	3
Nov 2004	1,692	378	431	101	2,630	250	3,870	2,113	15	2
Dec 2004	1,388	405	828	199	2,520	241	3,600	2,015	14	2
Jan 2005	1,310	403	795	191	2,770	219	4,030	2,206	11	2
Feb 2005	1,330	366	682	149	2,970	184	4,240	2,066	12	2
Mar 2005	1,330	402	924	224	2,860	196	4,060	2,232	27	6
Apr 2005	1,680	375	434	100	3,080	195	4,210	2,230	33	6
May 2005	1,530	395	621	149	3,790	184	5,110	2,418	32	7
Jun 2005	2,160	351	1,410	292	4,140	182	5,850	2,255	37	7
Jul 2005	2,340	350	1,330	295	4,170	182	6,090	2,384	51	8
Aug 2005	1,310	395	767	186	4,310	181	6,430	2,293	62	8
Sep 2005	868	362	1,350	309	4,420	176	6,550	2,032	90	7
Oct 2005	713	328	1,510	355	4,020	206	6,010	2,170	72	7
Nov 2005	727	323	945	226	2,820	243	4,620	2,400	52	7
Dec 2005	1,000	409	1,060	253	2,770	231	4,010	2,217	47	7
Jan 2006	1,210	413	1,030	245	2,840	230	4,240	2,358	22	7
Feb 2006	1,240	373	1,440	298	2,910	191	4,240	2,120	36	7
Mar 2006	1,210	405	908	214	2,980	210	4,490	2,446	33	7
Apr 2006	1,300	390	449	103	3,100	198	4,260	2,146	31	6
May 2006	1,300	402	922	221	3,640	195	5,110	2,401	36	6

Date	Winnipeg River		Saskatchewan River		Upper Nelson		Lower Nelson		Laurie River	
	Flow @ Slave Falls	Generation	Flow @ Grand Rapids	Generation	Flow @ Kelsey	Generation	Flow @ Kettle	Generation	Flow @ LR #2	Generation
	(cms)	(GWh)	(cms)	(GWh)	(cms)	(GWh)	(cms)	(GWh)	(cms)	(GWh)
Jun 2006	991	367	997	233	3,690	218	5,230	2,320	42	5
Jul 2006	536	256	970	234	3,060	275	4,530	2,449	32	5
Aug 2006	393	193	758	181	2,810	275	4,300	2,397	50	5
Sep 2006	333	157	303	68	2,050	220	3,430	1,873	29	4
Oct 2006	308	152	536	129	1,380	206	2,590	1,478	17	3
Nov 2006	297	140	641	152	1,630	228	2,690	1,483	20	3
Dec 2006	401	195	665	163	2,200	219	3,290	1,857	18	3
Jan 2007	523	253	1,120	272	2,290	216	3,460	1,959	18	3
Feb 2007	573	244	1,420	293	2,100	183	3,210	1,607	18	3
Mar 2007	567	261	771	175	1,860	208	3,060	1,716	19	3
Apr 2007	586	276	692	155	1,730	211	2,990	1,620	23	4
May 2007	476	246	775	183	1,890	216	3,590	2,060	62	7
Jun 2007	971	377	1,290	294	2,310	238	3,660	2,002	47	7
Jul 2007	1,320	408	957	234	3,140	233	4,360	2,418	25	5
Aug 2007	963	385	704	172	3,270	231	4,660	2,491	33	7
Sep 2007	701	303	469	109	2,470	248	3,860	2,126	36	7
Oct 2007	938	361	463	111	2,680	261	3,900	2,143	36	7
Nov 2007	1,610	362	590	138	2,990	240	4,350	2,368	33	7
Dec 2007	1,420	395	1,060	250	2,630	220	3,690	2,073	29	6
Jan 2008	1,230	387	1,060	246	2,850	207	4,000	2,222	29	6
Feb 2008	1,180	349	1,200	248	2,740	193	3,980	2,041	29	5
Mar 2008	1,050	377	648	144	2,620	206	3,740	2,043	37	7
Apr 2008	882	364	324	71	2,550	202	3,790	2,049	37	7
May 2008	997	371	370	86	2,010	232	3,490	1,978	28	6
Jun 2008	1,630	345	472	106	2,110	258	3,340	1,816	25	5
Jul 2008	2,060	334	660	156	3,410	217	4,310	2,347	23	4
Aug 2008	1,940	336	513	121	4,050	207	5,250	2,483	19	4
Sep 2008	968	334	431	97	3,470	250	4,660	2,291	24	5
Oct 2008	719	342	299	67	3,210	264	4,330	2,347	21	4
Nov 2008	885	373	342	77	3,100	238	4,280	2,323	28	6
Dec 2008	1,030	388	647	154	2,770	207	3,790	2,130	28	6

Total Historical Annual Hydraulic Generation.

Year	Annual Hydraulic Energy (GWh)
1978	17,065
1979	20,530
1980	19,186
1981	17,989
1982	20,587
1983	21,977
1984	21,312
1985	22,498
1986	23,924
1987	19,392
1988	15,463
1989	18,409
1990	19,837
1991	22,660
1992	26,540
1993	26,972
1994	28,249
1995	29,115
1996	30,976
1997	33,493
1998	30,876
1999	28,233
2000	31,638
2001	32,999
2002	29,006
2003	20,348
2004	27,338
2005	36,543
2006	33,736
2007	33,612
2008	34,690

Recorded monthly flows for the Red and Burntwood Rivers and the Nelson River flows at Limestone G.S after 1990.

Date	Red River Flows (cms)	Burntwood River Flows (cms)	Limestone Flows (cms)
Jan 1978	56	877	-
Feb 1978	49	861	-
Mar 1978	63	856	-
Apr 1978	1,270	691	-
May 1978	493	642	-
Jun 1978	164	853	-
Jul 1978	134	913	-
Aug 1978	77	887	-
Sep 1978	54	863	-
Oct 1978	48	966	-
Nov 1978	31	953	-
Dec 1978	31	930	-
Jan 1979	25	925	-
Feb 1979	30	935	-
Mar 1979	41	927	-
Apr 1979	941	890	-
May 1979	2,200	778	-
Jun 1979	611	902	-
Jul 1979	342	798	-
Aug 1979	144	790	-
Sep 1979	83	822	-
Oct 1979	61	851	-
Nov 1979	71	915	-
Dec 1979	58	894	-
Jan 1980	64	854	-
Feb 1980	61	866	-
Mar 1980	65	900	-
Apr 1980	467	918	-
May 1980	99	859	-
Jun 1980	61	825	-
Jul 1980	45	864	-
Aug 1980	38	878	-
Sep 1980	45	941	-
Oct 1980	44	938	-
Nov 1980	44	939	-
Dec 1980	30	974	-
Jan 1981	22	981	-
Feb 1981	25	982	-
Mar 1981	76	935	-
Apr 1981	84	944	-
May 1981	59	957	-
Jun 1981	84	950	-
Jul 1981	108	1,060	-
Aug 1981	52	1,060	-
Sep 1981	88	925	-
Oct 1981	108	688	-
Nov 1981	83	667	-
Dec 1981	45	655	-
Jan 1982	41	583	-
Feb 1982	43	581	-
Mar 1982	61	589	-
Apr 1982	814	588	-
May 1982	495	830	-
Jun 1982	241	665	-
Jul 1982	165	694	-
Aug 1982	108	878	-
Sep 1982	64	980	-
Oct 1982	162	1,010	-
Nov 1982	104	1,010	-
Dec 1982	91	991	-
Jan 1983	67	934	-
Feb 1983	64	660	-
Mar 1983	350	555	-
Apr 1983	788	543	-
May 1983	334	814	-
Jun 1983	266	843	-
Jul 1983	272	912	-
Aug 1983	116	907	-
Sep 1983	124	916	-
Oct 1983	121	971	-
Nov 1983	121	1,000	-
Dec 1983	69	987	-
Jan 1984	61	955	-
Feb 1984	56	939	-
Mar 1984	91	937	-
Apr 1984	644	1,050	-
May 1984	173	1,120	-
Jun 1984	406	1,110	-
Jul 1984	156	1,060	-
Aug 1984	61	967	-
Sep 1984	43	789	-
Oct 1984	75	835	-
Nov 1984	88	956	-
Dec 1984	60	989	-
Jan 1985	56	987	-
Feb 1985	53	994	-
Mar 1985	267	950	-
Apr 1985	470	845	-
May 1985	377	1,040	-
Jun 1985	342	1,080	-
Jul 1985	266	1,040	-
Aug 1985	285	1,060	-
Sep 1985	240	934	-
Oct 1985	179	894	-
Nov 1985	117	943	-
Dec 1985	90	913	-
Jan 1986	87	840	-
Feb 1986	78	782	-
Mar 1986	275	718	-
Apr 1986	1,190	707	-

Date	Red River Flows (cms)	Burntwood River Flows (cms)	Limestone Flows (cms)	Date	Red River Flows (cms)	Burntwood River Flows (cms)	Limestone Flows (cms)
May 1986	986	935	-	Nov 1990	36	752	2,863
Jun 1986	331	772	-	Dec 1990	22	657	2,985
Jul 1986	209	728	-	Jan 1991	20	624	2,731
Aug 1986	101	734	-	Feb 1991	23	683	2,514
Sep 1986	94	922	-	Mar 1991	33	569	2,378
Oct 1986	131	1,100	-	Apr 1991	137	503	2,207
Nov 1986	84	1,040	-	May 1991	120	695	2,784
Dec 1986	75	954	-	Jun 1991	107	702	2,224
Jan 1987	75	948	-	Jul 1991	234	771	2,210
Feb 1987	67	933	-	Aug 1991	71	960	2,416
Mar 1987	189	910	-	Sep 1991	72	1,040	2,070
Apr 1987	1,140	907	-	Oct 1991	65	1,060	2,501
May 1987	206	912	-	Nov 1991	56	1,030	2,627
Jun 1987	154	971	-	Dec 1991	48	1,030	2,580
Jul 1987	115	1,070	-	Jan 1992	41	990	2,792
Aug 1987	116	934	-	Feb 1992	39	913	2,768
Sep 1987	52	767	-	Mar 1992	217	877	2,621
Oct 1987	47	754	-	Apr 1992	807	725	2,466
Nov 1987	36	932	-	May 1992	316	866	2,803
Dec 1987	32	1,030	-	Jun 1992	134	936	2,701
Jan 1988	24	1,020	-	Jul 1992	122	931	2,365
Feb 1988	21	985	-	Aug 1992	53	870	2,305
Mar 1988	68	882	-	Sep 1992	106	767	2,521
Apr 1988	264	759	-	Oct 1992	66	826	3,709
May 1988	105	957	-	Nov 1992	42	853	3,768
Jun 1988	86	841	-	Dec 1992	41	925	3,425
Jul 1988	49	760	-	Jan 1993	42	937	3,287
Aug 1988	22	832	-	Feb 1993	45	795	3,491
Sep 1988	23	926	-	Mar 1993	59	568	3,329
Oct 1988	26	946	-	Apr 1993	605	536	2,362
Nov 1988	16	875	-	May 1993	165	583	2,079
Dec 1988	15	834	-	Jun 1993	164	554	1,699
Jan 1989	14	771	-	Jul 1993	424	562	1,965
Feb 1989	19	767	-	Aug 1993	1,060	514	2,574
Mar 1989	26	765	-	Sep 1993	387	491	4,223
Apr 1989	653	745	-	Oct 1993	174	503	3,735
May 1989	323	869	-	Nov 1993	124	665	2,810
Jun 1989	102	794	-	Dec 1993	81	757	3,503
Jul 1989	61	840	-	Jan 1994	70	687	3,628
Aug 1989	22	972	-	Feb 1994	66	589	3,299
Sep 1989	43	956	-	Mar 1994	182	544	3,140
Oct 1989	31	773	-	Apr 1994	625	514	2,699
Nov 1989	20	905	-	May 1994	301	642	3,128
Dec 1989	17	961	-	Jun 1994	228	658	2,734
Jan 1990	15	969	0	Jul 1994	441	867	2,722
Feb 1990	16	986	0	Aug 1994	172	831	2,673
Mar 1990	56	803	0	Sep 1994	204	733	2,629
Apr 1990	281	712	0	Oct 1994	292	724	2,786
May 1990	116	874	0	Nov 1994	223	708	3,115
Jun 1990	143	1,100	0	Dec 1994	137	678	2,950
Jul 1990	83	868	0	Jan 1995	90	621	3,301
Aug 1990	37	734	0	Feb 1995	74	603	3,153
Sep 1990	25	689	2,477	Mar 1995	619	549	3,178
Oct 1990	36	695	2,750	Apr 1995	1,390	605	3,088

Date	Red River Flows (cms)	Burntwood River Flows (cms)	Limestone Flows (cms)
May 1995	749	718	3,016
Jun 1995	404	716	2,877
Jul 1995	330	591	2,508
Aug 1995	185	567	2,936
Sep 1995	141	555	3,070
Oct 1995	146	638	3,358
Nov 1995	127	749	3,123
Dec 1995	104	789	3,068
Jan 1996	92	887	3,163
Feb 1996	86	916	3,045
Mar 1996	134	895	2,979
Apr 1996	1,100	848	2,975
May 1996	1,920	782	3,411
Jun 1996	816	783	4,957
Jul 1996	278	653	5,312
Aug 1996	175	625	4,624
Sep 1996	97	704	3,397
Oct 1996	95	729	3,425
Nov 1996	109	809	3,464
Dec 1996	96	872	3,671
Jan 1997	78	938	3,589
Feb 1997	78	1,020	3,470
Mar 1997	92	1,090	3,624
Apr 1997	1,240	1,080	3,809
May 1997	2,940	817	4,477
Jun 1997	605	715	5,570
Jul 1997	725	665	5,525
Aug 1997	179	836	4,963
Sep 1997	115	1,080	3,903
Oct 1997	170	1,090	3,708
Nov 1997	132	1,100	3,897
Dec 1997	101	1,100	3,942
Jan 1998	86	1,100	3,990
Feb 1998	95	1,100	3,770
Mar 1998	759	1,170	3,768
Apr 1998	990	1,180	3,612
May 1998	638	1,220	3,902
Jun 1998	442	1,360	3,947
Jul 1998	650	1,390	4,213
Aug 1998	173	1,150	3,809
Sep 1998	99	1,070	2,740
Oct 1998	131	1,030	2,798
Nov 1998	152	933	2,806
Dec 1998	153	936	2,845
Jan 1999	92	842	2,806
Feb 1999	83	692	2,807
Mar 1999	198	556	2,655
Apr 1999	1,440	556	2,802
May 1999	942	569	2,428
Jun 1999	748	710	2,853
Jul 1999	571	649	2,774
Aug 1999	287	597	2,625
Sep 1999	423	605	2,780
Oct 1999	205	623	3,183
Nov 1999	145	835	3,080
Dec 1999	109	994	3,205
Jan 2000	96	1,000	3,251
Feb 2000	90	1,030	3,413
Mar 2000	434	1,000	3,445
Apr 2000	238	974	3,152
May 2000	184	857	3,197
Jun 2000	455	1,110	2,846
Jul 2000	804	1,110	3,388
Aug 2000	197	1,060	3,575
Sep 2000	196	1,080	3,539
Oct 2000	132	1,070	3,745
Nov 2000	624	1,100	3,579
Dec 2000	206	1,080	3,552
Jan 2001	119	1,040	3,740
Feb 2001	106	1,010	3,829
Mar 2001	125	997	3,829
Apr 2001	1,570	878	3,496
May 2001	1,390	876	4,482
Jun 2001	599	764	4,833
Jul 2001	394	726	5,204
Aug 2001	461	739	4,581
Sep 2001	128	763	3,627
Oct 2001	103	786	3,493
Nov 2001	144	937	3,537
Dec 2001	106	973	3,320
Jan 2002	77	973	3,563
Feb 2002	68	967	3,059
Mar 2002	81	792	2,923
Apr 2002	318	826	2,693
May 2002	252	864	2,835
Jun 2002	897	959	3,242
Jul 2002	931	788	3,220
Aug 2002	310	618	3,329
Sep 2002	371	601	3,256
Oct 2002	115	601	3,313
Nov 2002	80	863	2,990
Dec 2002	55	975	3,214
Jan 2003	48	978	3,397
Feb 2003	39	924	2,897
Mar 2003	102	900	2,725
Apr 2003	361	719	2,414
May 2003	338	589	2,355
Jun 2003	304	616	1,932
Jul 2003	310	615	2,058
Aug 2003	81	600	1,761
Sep 2003	44	598	1,519
Oct 2003	43	615	1,439
Nov 2003	37	793	1,579
Dec 2003	22	869	1,866
Jan 2004	29	834	1,859
Feb 2004	28	818	1,853
Mar 2004	137	684	2,058
Apr 2004	1,320	605	1,795

Date	Red River Flows (cms)	Burntwood River Flows (cms)	Limestone Flows (cms)
May 2004	465	544	2,224
Jun 2004	741	579	2,979
Jul 2004	300	576	3,365
Aug 2004	153	569	3,394
Sep 2004	237	729	3,319
Oct 2004	239	959	3,528
Nov 2004	461	1,030	3,849
Dec 2004	127	1,010	3,587
Jan 2005	91	996	3,994
Feb 2005	89	987	4,053
Mar 2005	106	979	4,029
Apr 2005		949	4,270
May 2005	516	714	5,184
Jun 2005	1,070	917	5,783
Jul 2005	1,600	760	6,303
Aug 2005	456	766	6,644
Sep 2005	264	810	6,784
Oct 2005	185	855	6,237
Nov 2005	174	1,090	4,627
Dec 2005	160	1,050	3,988
Jan 2006		1,000	4,212
Feb 2006		985	4,069
Mar 2006		981	4,471
Apr 2006		1,170	4,283
May 2006		957	5,194
Jun 2006		960	5,279
Jul 2006		1,080	4,489
Aug 2006		1,080	4,263
Sep 2006		1,090	3,404

Date	Red River Flows (cms)	Burntwood River Flows (cms)	Limestone Flows (cms)
Oct 2006		1,090	2,586
Nov 2006		1,050	2,681
Dec 2006		999	3,262
Jan 2007	49	997	3,445
Feb 2007	46	996	3,072
Mar 2007	172	988	3,051
Apr 2007	1,070	1,090	2,989
May 2007	479	1,260	3,670
Jun 2007	818	1,110	3,686
Jul 2007	582	985	4,326
Aug 2007	122	940	4,722
Sep 2007	65	1,030	3,868
Oct 2007	87	1,080	3,954
Nov 2007	106	1,090	4,355
Dec 2007	68	1,060	3,685
Jan 2008	56	1,030	3,984
Feb 2008	45	1,000	3,955
Mar 2008	64	988	3,709
Apr 2008	422	1,120	3,770
May 2008		1,180	3,538
Jun 2008		1,070	3,357
Jul 2008		837	4,296
Aug 2008		687	5,274
Sep 2008		928	4,681
Oct 2008		1,050	4,335
Nov 2008		1,030	4,286
Dec 2008		1,020	3,772

<u>PUB/MH I-76</u>

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8 – Energy Supply (Page 15)**

a) **Please provide seasonal precipitation data on an average watershed basis for the winter (October to February), spring (March/April), and summer (May to September) periods for the period from 1978-2009.**

<u>ANSWER</u>:

The weighted average precipitation (mm) by basin for the period 1978 to 2009, given the above defined seasons are:

	Winter	Spring	Summer
Chruchill River Basin	123	47	314
Nelson River Basin	129	49	321
Saskatchewan River Basin	99	51	318
Winnipeg River Basin	179	71	442

Please note that March and April are generally both winter months except for the southern portions of Manitoba Hydro's watersheds.

PUB/MH I-76

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8 – Energy Supply (Page 15)**

b) **Please provide seasonal runoff (inches) on an average watershed basis for the April to July period and the August to October period for the 1978 to 2009 time frame.**

ANSWER:

Manitoba Hydro does not have seasonal runoff values as requested.

However, the weighted average precipitation (inches) by basin for the period 1978 to 2009, given the above defined periods are:

	Apr.-Jul	Aug.-Oct.
Churchill River Basin	8.5	6.2
Nelson River Basin	8.8	6.4
Saskatchewan River Basin	9.4	5.3
Winnipeg River Basin	12.4	9.1

As a result of hydrologic losses such as evaporation, infiltration and evaporation; only a portion of the above precipitation was available to Manitoba Hydro hydraulic generation as inflows from runoff.

<u>PUB/MH I-77</u>

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8, Energy Supply, Page 17 of 20, Figure 8.6.2**

a) Please confirm that in February of most years, MH commits to summer peak export energy sales , but only if energy in storage is above 8,000 GWh. Explain what other factors (e.g. actual winter precipitation) are employed.

<u>ANSWER</u>:

Manitoba Hydro may commit to export sales in February for the subsequent spring and summer season, but has no specific requirement related to 8,000 GWh of energy in reservoir storage. The main factor that enables these sales is that under worst case conditions Manitoba Hydro has surplus energy available to serve the sale. The determination of this surplus includes energy-in-storage levels, and basin snow pack conditions. For example in the springs of 2005, 2008 and 2009, near record flood forecasts were issued for the Red River, which meant that MH could with confidence predict that inflows to Manitoba Hydro's reservoirs in those years would be above dependable inflow conditions.

PUB/MH I-77

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8, Energy Supply, Page 17 of 20, Figure 8.6.2**

b) **Please confirm that MH maximizes peak and off-peak export sales in most years, but not if energy in storage is below 14,000 GWh and spring energy inflows are less than about 130 GWh/month. If not, please explain and define what other factors (actual winter and spring precipitation/timing of runoff/etc.) are employed.**

ANSWER:

No. Manitoba Hydro does not enter into export sales as described in this Information Request. Please refer to PUB/MH I-77(a).

PUB/MH I-77

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8, Energy Supply, Page 17 of 20, Figure 8.6.2**

c) Please confirm that MH assumes long-term average energy inflows of 50 GWh/month for the second half of the fiscal year and anticipates drawing about 6,000 GWh from energy in storage. If not, please explain what other factors are employed.

ANSWER:

Manitoba Hydro can confirm that the referenced Figure 8.6.2, entitled "Daily Gross Energy from Inflow Indicator" indicates that on average, the daily inflow is around 50 GWh/day or 1,500 GWh/month for the second half of the fiscal year.

In addition, Manitoba Hydro can confirm that Figure 8.6.3 entitled "Total Energy in Reservoir Storage" indicates that there is an average storage draw down of almost 7,000 GWh for the period of October 1 to April 1.

However, Manitoba Hydro does not use either of these numbers in planning its power system operations.

PUB/MH I-77

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8, Energy Supply, Page 17 of 20, Figure 8.6.2**

d) Please explain how MH recognizes and adjusts for the potential summer reduction of energy in storage due to net evaporation losses in high flow years/median flow years/low flow years/severe droughts.

ANSWER:

Manitoba Hydro's historic flow record includes the effects of evaporation in all years regardless of the magnitude of the overall inflows. The standard method of calculating inflows available for outflow captures all sources of inputs as well as losses such as evaporation.

PUB/MH I-78

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8, Energy Supply, Page 17 of 20, Lines 7 and 8**

a) Please confirm that the reference to 3,000 GWh above April average refers to 3,000 GWh above 8,000 GWh (and not the pre-2003/04 average of 10,000 GWh).

ANSWER:

The reference to 3,000 GWh above April average (Tab 8, Energy Supply, Page 17 of 20, Lines 7 and 8) refers to 3,000 GWh above 8,000 GWh (and not the pre-2003/04 average of 10,000 GWh).

PUB/MH I-78

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8, Energy Supply, Page 17 of 20, Lines 7 and 8**

b) **Why does MH no longer consider the 10,000 GWh as of April as a constraint benchmark for increased export sales? Was the energy in storage calculation revised after 2003/04?**

ANSWER:

Manitoba Hydro is not aware of a reference to 10,000 GWh in April as a constraint for export sales. Interruptible export sales are predominantly a function of the spring and summer water supply. Also, refer to PUB/MH I-82(d).

PUB/MH I-78

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8, Energy Supply, Page 17 of 20, Lines 7 and 8**

c) **Please confirm that in 2006/07 (mini-drought year), MH perhaps belatedly limited the October to April withdrawal of energy from storage to about 6,000 GWh by reducing export sales to about 400 GWh/month for the last six months of the year.**

ANSWER:

Manitoba Hydro did not limit exports in the last six months of 2006/07 by restructuring withdrawals of energy from storage. To the contrary, Manitoba Hydro maintained near maximum outflows from its reservoirs, maximizing storage withdrawals. However, upstream water and storage conditions in the Winnipeg River basin (not under the control of MH) were well below average, resulting in reduced water supplies from Ontario. This resulted in reduced hydraulic generation and thus reduced surplus energy for export.

PUB/MH I-79

Subject: Tab 8: Energy Supply
Reference: 2008/09 Power Resource Plan and Tab 8 (Pages 16/17/18 of 20)

a) What specific parameters does MH consider throughout the year in deciding to make export sales over and above dependable energy?

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-77.

PUB/MH I-79

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan and Tab 8 (Pages 16/17/18 of 20)**

b) **Explain what specific weighting is given to the spring flow conditions and energy-in-storage in each watershed.**

- **Winnipeg River.**
- **Red River.**
- **Saskatchewan River.**
- **Burntwood River.**
- **Other inflow.**

ANSWER:

Manitoba Hydro does not apply weights to spring flow conditions nor to energy in storage in its various watersheds.

PUB/MH I-79

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan and Tab 8 (Pages 16/17/18 of 20)**

c) Does MH regularly monitor or define on a watershed basis the following:

- **Precipitation (October to February)?**
- **Spring precipitation (March/April)?**
- **Summer precipitation (May to September)?**
- **Summer evaporation from reservoirs (May to September)?**

ANSWER:

Manitoba Hydro generally monitors precipitation on a business-day basis. Each week Manitoba Hydro reviews the system and basin weighted average precipitation reports for varying durations:

1. the past week;
2. the past 60 days; and
3. seasonal cumulative values (April 1st through October 31st or November 1st through March 31st).

Evaporation is implicitly monitored through a lake local inflow which is calculated using measured inflow, outflow and water level.

PUB/MH I-79

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan and Tab 8 (Pages 16/17/18 of 20)**

d) For each component, to the extent that this information is readily available, please provide a tabular summary for the post-LWR/CRD period.

ANSWER:

The system weighted average precipitation for the periods specified in PUB/MH I-79(c) are shown for each year since 1978 in the table below. As explained in part (c), evaporation is not recorded in this manner nor is it disaggregated from lake local inflow records.

OVERALL WEIGHTED AVERAGE PRECIPITATION IN mm

Year	March to April	May to September	October to February
1978	60.3	382.3	133.1
1979	80.7	297.1	150.3
1980	32.7	365.4	114.6
1981	52.9	324.3	150.7
1982	59.3	368.3	147.9
1983	54.2	347.2	142.5
1984	48.0	332.7	180.9
1985	68.6	416.1	135.1
1986	85.9	375.6	116.8
1987	39.6	318.9	104.5
1988	61.1	363.7	144.2
1989	44.3	344.9	130.5
1990	71.2	329.6	140.5
1991	69.2	413.4	155.5
1992	55.6	378.3	100.3
1993	48.6	413.9	108.1
1994	47.6	344.7	160.0
1995	48.9	349.5	165.9
1996	54.0	357.0	183.5
1997	55.4	339.2	146.4
1998	36.2	326.7	150.9
1999	36.2	430.5	118.1
2000	55.1	400.1	127.6
2001	69.5	340.1	117.0
2002	70.1	380.6	91.7
2003	58.8	338.8	123.9
2004	62.5	394.6	173.3
2005	54.1	468.5	154.6
2006	48.8	319.0	134.3
2007	63.5	387.0	162.1
2008	59.3	371.1	149.6
2009	72.7	348.5	***112.2***

Note: 2009 ‘October to February’ is to February 14, 2010

<u>PUB/MH I-80</u>

Subject: Tab 8: Energy Supply
Reference: 2008/09 Power Resource Plan, Table A-1(a)

a) Please define MH's existing power resources:

- **Dependable hydro plant output:**
  - **Minimum inflow.**
  - **Use of energy in storage.**
- **Mean hydro plan output:**
  - **Average inflow.**
  - **Use of energy in storage.**

<u>ANSWER</u>:

The dependable energy of 21,110 GW.h/year from the existing hydroelectric power resources is determined by a computer simulation of system operation utilizing a chronological series of inflows for several years preceding 1940/41, the lowest flow year on record. The maximum dependable energy that the Manitoba Hydro system can generate over the period of a year corresponds to the utilization of energy from inflows for flow year 1940/41 combined with maximum utilization of energy from storage. The inflow at the lower Nelson River corresponding to flow year 1940/41 is about 53,000 cubic feet per second (cfs) and this has the capability of producing approximately 14,700 GW.h of annual energy. The annual dependable energy of 21,110 GW.h is achieved through the maximum withdrawal from storage which increases the average annual flow at the lower Nelson River to about 70,000 cfs. The maximum withdrawal from storage is influenced by the monthly distribution of load demands and the physical characteristics of the generating system which includes the impact of ice in the winter months.

The mean hydroelectric power output corresponds to an average annual system flow of about 113,000 cfs. This flow is capable of producing about 29,250 GW.h/year of energy. It is assumed that water is not withdrawn form storage or placed into storage in an average flow year.

PUB/MH I-80

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table A-1(a)**

b) Discuss MH's rationale for not now using 18,500 GWh as the dependable hydraulic output.

ANSWER:

Please refer to the response to PUB/MH I-80 (a) for information relating to the determination of dependable energy. In that response it is stated that the dependable energy is determined by making maximum use of storage over the period of a year. This is achieved by maintaining reservoir levels as near to full supply level as possible at the start of the dependable year and drawing them down as much as possible and still meeting all load demands in that year. In 2003/04 it was not necessary to have high storage levels at the start of the year since the generating system had excess capacity relative to the firm load demands. If the generating system had reservoir levels near the upper end of the range, it could have produced significantly more than 18,500 GW.h in that year. Therefore, it is not appropriate to utilize 18,500 GW.h as the dependable hydraulic output since dependable energy is defined as the maximum energy that the system can produce in a low flow year.

<u>PUB/MH I-80</u>

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table A-1(a)**

c) How much higher could 2003/04 hydraulic output have been if Lake Winnipeg had been drawn down to 712.0?

<u>ANSWER</u>:

The wind eliminated level of Lake Winnipeg on April 1, 2004 was approximately 712.1 ft. If the levels were at 712.0 ft on April 1, approximately 206 GWh of additional hydraulic generation could have been achieved in 2003/04.

PUB/MH I-81

Subject: **Tab 8: Energy Supply**
Reference: **2008 GRA PUB/MH I-30(b), 2008 GRA PUB/MH I- 3(f)**

a) Please re-file an updated version of 2008 GRA PUB/MH I-30b) showing annual system inflows/MH hydraulic energy/net revenue/etc.

ANSWER:

It is noted that the reference from the 2008 GRA should be PUB/MH II-30(b) from Round II and not Round I of the proceeding. The 2008 GRA response was derived from an estimate for load year 2010/11 and the current update is derived for load year 2011/12. The flow record currently utilized by Manitoba Hydro in its generation estimates is based on a 94 year flow record that extends up to the year 2005/06 inclusive. It has been the practice in Manitoba Hydro to update the flow record about every five years, and therefore the same flow record is currently being utilized as that in the 2008 GRA. The updated table for 2009 conditions is provided on the following page. This update is based on the 2009 Load Forecast and the 2009 forecast of export and import prices as well as all other updates for the 2009 IFF.

Flow Year	Annual System Inflow	MH Hydraulic Energy	Net Revenue	Variation of Net Revenue from Average	Flow Year	Annual System Inflow	MH Hydraulic Energy	Net Revenue	Variation of Net Revenue from Average
	Kcfs	(GWh/yr)	(M $Cdn)	(M $Cdn)		Kcfs	(GWh/yr)	(M $Cdn)	(M $Cdn)
1912	111	35202	424	222	1961	75	20539	-459	-661
1913	118	31970	330	128	1962	119	31024	288	86
1914	98	27839	160	-42	1963	111	30866	284	82
1915	104	29382	236	34	1964	115	31380	306	104
1916	135	34704	430	228	1965	159	36853	470	268
1917	118	33198	377	175	1966	153	36455	443	241
1918	105	29278	226	24	1967	114	33827	364	162
1919	98	26433	74	-128	1968	138	33335	380	178
1920	102	28144	168	-34	1969	150	36494	455	253
1921	113	30457	269	67	1970	148	36617	457	255
1922	105	28860	209	7	1971	140	35044	419	217
1923	111	30032	248	46	1972	125	33842	371	170
1924	98	25802	28	-174	1973	116	30842	292	90
1925	119	31260	307	105	1974	165	36643	451	249
1926	110	30500	277	75	1975	138	36328	455	253
1927	154	36649	462	260	1976	94	26867	6	-196
1928	113	33282	375	173	1977	100	25698	22	-180
1929	86	24379	-83	-285	1978	121	31927	329	127
1930	89	23391	-172	-374	1979	136	33632	362	160
1931	86	22960	-215	-417	1980	95	25825	34	-168
1932	95	25443	3	-199	1981	85	22798	-229	-431
1933	100	26855	105	-97	1982	116	30392	267	65
1934	118	31577	313	111	1983	111	29677	240	38
1935	117	31484	310	108	1984	100	26734	91	-111
1936	96	26018	43	-159	1985	139	33347	380	178
1937	98	26951	104	-98	1986	131	34508	392	190
1938	88	24939	-36	-238	1987	83	22950	-217	-419
1939	79	21512	-356	-558	1988	72	19445	-542	-744
1940	54	19389	-545	-747	1989	90	24863	-43	-245
1941	92	21497	-355	-557	1990	87	24732	-52	-254
1942	101	28406	182	-20	1991	91	25243	-14	-216
1943	107	29753	243	41	1992	116	30307	260	58
1944	106	29542	234	32	1993	105	29548	228	26
1945	118	31437	314	112	1994	101	28200	149	-53
1946	113	31209	302	100	1995	105	29479	227	25
1947	125	33054	373	171	1996	141	34459	400	198
1948	113	32367	312	111	1997	153	36215	452	250
1949	115	30074	258	56	1998	106	30012	172	-30
1950	147	34610	404	202	1999	111	30039	253	51
1951	132	35442	439	237	2000	128	32517	350	148
1952	106	31097	297	95	2001	128	32908	318	116
1953	124	32858	371	169	2002	107	28990	196	-6
1954	144	36475	463	262	2003	72	20182	-496	-698
1955	132	35240	416	214	2004	140	33577	392	190
1956	119	32632	336	134	2005	171	37646	484	282
1957	112	30890	287	85					
1958	95	26326	66	-136	**Average**	**113**	**30067**	**202**	**0**
1959	137	33574	389	187					
1960	102	29106	201	0					

PUB/MH I-81

Subject: Tab 8: Energy Supply
Reference: 2008 GRA PUB/MH I-30(b), 2008 GRA PUB/MH I- 3(f)

b) For the period 2000 to 2009, please explain how these annual system inflows were derived to form a significant input to MH's annual hydraulic generation forecasts. Please reconcile with PUB/MH I-3 f) from the prior GRA.

ANSWER:

The inflows in the response to PUB/MH I-81(a) represent the annual system inflows that result when the effects of regulation by Manitoba Hydro are removed. The inflows from the various drainage basins contributing to the Manitoba Hydro system are summed, and these inflows represent the total annual water supply at the at the Lower Nelson River if there were no reservoirs under the control of Manitoba Hydro. Please refer to the response to PUB/MH I-3(e) in the 2008 GRA for a further description of the determination of present-use flows that are used in planning studies. The forecast of annual hydraulic generation under future development plans is developed through use of a computer model which simulates the operation of the hydroelectric system of reservoirs and generating stations in the most efficient manner. The sequence of annual system inflows in the response to PUB/MH I-81(a) is used as input into the computer simulation model.

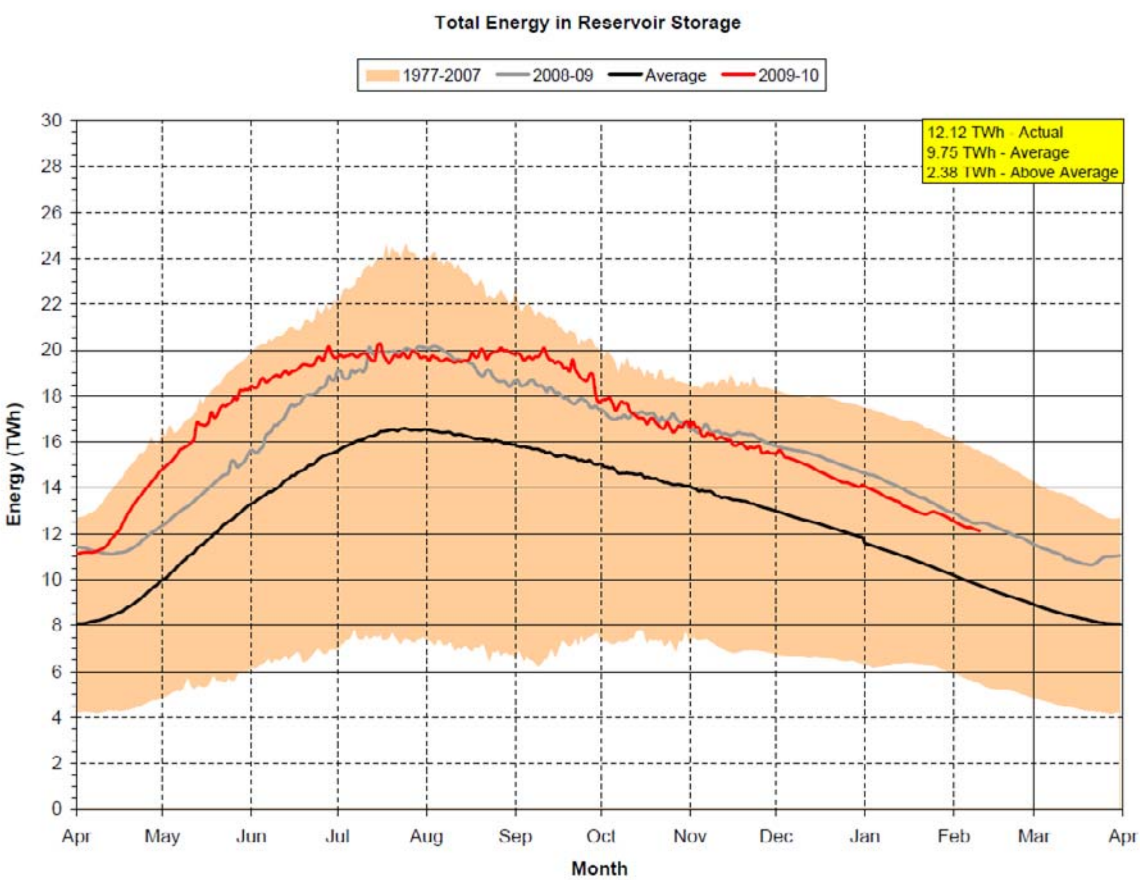
The flows in the response to PUB/MH I-3(f) in the 2008 GRA are actual historic outflows that include the operations of Manitoba Hydro. The annual outflows at the Limestone G.S. in that response include the effect of regulation of reservoirs at Cedar Lake, Lake Winnipeg and Southern Indian Lake and reflect withdrawal from storage or increase in storage over the period of a year. Therefore, these outflows can be higher or lower than unregulated inflows on an annual basis because of storage effects.

PUB/MH I-82

Subject: Tab 8: Energy Supply
Reference: Exhibit #17 (2007/03/11) Tab 8 – Energy Supply

a) **Please re-file Exhibit #17 (2007/03/11) Nelson-Churchill drainage basin's energy and reservoir storage chart.**

ANSWER:



<u>PUB/MH I-82</u>

Subject: **Tab 8: Energy Supply**
Reference: **Exhibit #17 (2007/03/11) Tab 8 – Energy Supply**

b) Please explain the role that energy in storage plays as a significant input to MH's annual hydraulic generation forecasts.

<u>ANSWER</u>:

Illustrating and tracking storage in terms of energy is meaningful to monitor aggregate storage conditions for a system of reservoirs used for hydro-electric production.

Energy in storage is not an explicit input to the annual hydraulic generation forecast. Instead, energy in storage is modeled by using current water levels, consistent with actual conditions at the time of the forecast. To this water supply is added the forecast of inflows to the system, which in combination is the available water supply used to produce hydraulic generation forecasts.

PUB/MH I-82

Subject: **Tab 8: Energy Supply**
Reference: **Exhibit #17 (2007/03/11) Tab 8 – Energy Supply**

c) **Please confirm that the shaded area on Exhibit #17 reflects the range of recorded annual energy-in-storage from 1977 to date.**

ANSWER:

Confirmed. Manitoba Hydro assumes the reference to Exhibit #17 is incorrect and that the correct reference is Figure 8.6.3 on page 18 of Tab 8 of the Filing.

PUB/MH I-82

Subject: **Tab 8: Energy Supply**
Reference: **Exhibit #17 (2007/03/11) Tab 8 – Energy Supply**

d) **Please confirm that the average energy-in-storage curve was moved downward by about 2,000 GWh following the 2003/04 drought. Explain**

ANSWER:

Following the 2003/04 drought, Manitoba Hydro updated the chart in question to include recent history. Manitoba Hydro also revisited the assumed minimum operating levels for the reservoirs accounted for in this chart. Both of these changes would have affected the extremes and historic average values shown on this chart.

PUB/MH I-82

Subject: **Tab 8: Energy Supply**
Reference: **Exhibit #17 (2007/03/11) Tab 8 – Energy Supply**

e) **Please provide a tabulation of annual April energy-in-storage/maximum level of energy in storage and year-end energy in storage (as available) for the post-Limestone G.S. conditions.**

ANSWER:

April 1st and annual maximum energy in reservoir storage (EIS) for the Nelson-Churchill Drainage Basin is provided in the table below. These figures are based on historic lake levels since 1978 and Manitoba Hydro's current hydroelectric generation capability. March 31st is considered to be year end for both the fiscal and hydrologic year; hence year-end energy in storage is virtually identical to the April 1st level of the subsequent year shown in the table.

Fiscal Year Beginning	April 1st EIS	Maximum Annual EIS
	TWh	TWh
1978	6.5	19.0
1979	9.2	20.8
1980	9.8	13.6
1981	6.0	12.8
1982	3.7	16.7
1983	7.6	16.5
1984	7.0	15.4
1985	5.6	19.1
1986	10.7	19.1
1987	8.7	14.2
1988	4.8	10.1
1989	4.6	13.5
1990	4.5	16.3
1991	3.8	12.6
1992	6.8	17.6
1993	8.1	17.4
1994	8.3	15.9
1995	8.6	15.8
1996	8.3	20.3
1997	11.1	20.7
1998	12.3	18.2
1999	7.2	16.8
2000	9.2	17.3
2001	9.3	18.7
2002	6.3	15.2
2003	4.2	7.5
2004	6.0	18.0
2005	11.8	24.0
2006	12.4	18.5
2007	8.3	20.8
2008	11.4	20.2
2009	11.1	20.2

<u>PUB/MH I-83</u>

Subject: **Tab 8: Energy Supply**
Reference: **Exhibit #17 27/03/11**

a) Does MH contemplate a zero energy in storage scenario during

- **i. A one-year drought? Explain.**
- **ii. A two-year drought? Explain.**
- **iii. A five-year drought? Explain.**
- **iv. A seven-year drought? Explain.**

<u>ANSWER</u>:

Manitoba Hydro does not contemplate a zero energy in storage situation either from a planning or operating perspective regardless of the extent of drought. Without water in storage, Manitoba Hydro could not operate its hydraulic system.

<u>PUB/MH I-83</u>

Subject: Tab 8: Energy Supply
Reference: Exhibit #17 27/03/11

b) In the design of LWR, what outflow from Lake Winnipeg did MH expect to achieve with a 711.0 lake levels under summer and or winter conditions?

<u>ANSWER</u>:

Source: "Comparison of Maximum Lake Winnipeg Discharge Open Water and Winter Conditions", drawing number 0510-B-9729, dated April 3, 1975

	Maximum Discharge (cfs) *(Elevation = 711 feet)*	**Notes**
Open water	84,300	May to October
November	57,000	Combined curve based on monthly average of open water conditions, reduced discharges for ice cover formation, and early winter ice conditions.
Least severe December	62,000	Rating curve is based upon minimum ice cover theoretically derived from historical meteorological data.
Average January-February	50,500	
Average March-April	44,000	

Lake Winnipeg elevation is given for Berens River, 1968 GS of C Datum (1970 Revision). Elevation includes all Manitoba Hydro datum adjustments to the end of year 1971.

PUB/MH I-83

Subject: **Tab 8: Energy Supply**
Reference: **Exhibit #17 27/03/11**

c) What minimum energy in storage level April 1, May 1, and June 1 would MH look for in contemplating the annual achievement of:

i. 33,000 GWh of hydraulic generation?
ii. 29,000 GWh of hydraulic generation?
iii. 25,000 GWh of hydraulic generation?

ANSWER:

The amount of hydro-electric energy Manitoba Hydro can produce in a year is largely dependent on the amount of precipitation and resulting runoff (or inflow) occurring in that year. It is therefore not possible to respond to this question without defining the inflow conditions.

In general, Manitoba Hydro does not contemplate a specific annual achievement of hydraulic generation in any given year. However, Manitoba Hydro does plan its operations to ensure storage levels are, at minimum, sufficient to supply firm domestic and export load under the most severe drought of record inflow condition. For a single year worst drought commencing on April 1st, the minimum useable energy storage amount is approximately 3 TWh.

<u>PUB/MH I-84</u>

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan**

a) Please file the 2009/10 Power Resource Plan.

<u>ANSWER</u>:

Excerpts from the 2009 Power Resource Plan have been used to create an external version of power resource plan. This external version of the 2009/10 power resource plan is provided as Appendix 47.

PUB/MH I-84

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan**

b) Below what cumulative GW.h level of MH energy supply, is MH released from its legal obligations to deliver pursuant to its export contracts?

ANSWER:

Manitoba Hydro's export contracts do not specify a certain cumulative energy supply level, below which Manitoba Hydro is released from its legal obligations to deliver pursuant to its contracts.

PUB/MH I-84

Subject: Tab 8: Energy Supply
Reference: 2008/09 Power Resource Plan

c) IF MH's GW.h of supply from hydraulic sources falls below the dependable level, is MH legally obligated to deliver the full output from its (a) thermal and (b) contracted import capabilities? Please explain.

ANSWER:

The answer to this question is dependent on the contract terms in each contract, which can vary from contract to contract. Further, in order to answer this question Manitoba Hydro would be required to provide a legal opinion on its contractual obligations to various third parties, which it respectfully declines to disclose.

PUB/MH I-85

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table A-1(a)**

a) Please define the specific roles, operational constraints, and current unit operating costs (fuel and variable OM&A) for:

i. Brandon Unit 5 (coal)
ii. Selkirk thermal (natural gas)
iii. Brandon SCCT units (natural gas)

ANSWER:

The Role of Manitoba Hydro's Thermal Generation

As a primarily hydroelectric utility, Manitoba Hydro is dependent on river flows for over 95 per cent of its electricity, on average, and is, therefore, exposed to low river flows or droughts. To protect customers from the impacts of low water flows and meet demand during times of peak usage, Manitoba Hydro operates a fleet of thermal generating units that are not dependent on river flows: four natural gas-fired generating units and one coal-fired generating unit. The thermal units can also be used to help manage the variability associated with the wind energy that Manitoba Hydro has added to its portfolio of generating resources.

In addition to providing an alternative source of electricity, the thermal units also offset the concentration of hydroelectric generation and HVDC transmission in the north. While the majority of Manitoba Hydro's electricity is generated in the north, the majority of the utility's customers are in the south. In the event of a major transmission or generation failure, the thermal fleet can provide electricity for a significant portion of Manitoba Hydro's customers in the south. This important back-up capability is also an asset for enhancing Manitoba Hydro's electricity exports.

Due to the abundance of water in most years, the thermal generating units are typically operated well below their maximum capability. In addition to variations in river flows, system operation is dependent on many dynamic factors that include: generation and transmission constraints, generation and transmission outages and failures, variations in anticipated demand and demand peaks, export market opportunities, Midwest Independent

Transmission System Operator (MISO) system support requirements, and variations in ambient temperatures from anticipated conditions.

Operational Constraints

Each of Manitoba Hydro's thermal generating stations is governed by individual Manitoba Environment Act Licences. The licences specify terms and conditions under which operation is permitted to occur. Operation and maintenance of Manitoba Hydro's thermal facilities is also governed by industrial legislation such as the Steam and Pressure Plants Act.
In addition to the general references for operational limits, terms and conditions discussed above, Brandon G.S. Unit 5 is also subject to operational restrictions under the recently enacted Climate Change and Emissions Reductions Act and its associated regulation 186/2009, which is discussed in more detail in PUB/MH I – 85 (b). For reference, the links to each facility's Environment Act Licence are provided below:

i. The terms and conditions of Environment Act Licence No. 1703R constrain the operation of Brandon Unit 5 (coal). The licence may be viewed at: http://www.gov.mb.ca/conservation/eal/registries/3252brandon_gs_5/vol_1_2_3/vol2_appendix_a.pdf

ii. The terms and conditions of Environment Act Licence No. 1645R5 constrain the operation of the Selkirk Generating Station (natural gas). The licence may be viewed at: http://www.gov.mb.ca/conservation/eal/archive/older/licences/1645r5.pdf

iii. The terms and conditions of Environment Act Licence No. 2497R constrain the operation of Brandon SCCT units (natural gas). The licence may be viewed at: http://www.gov.mb.ca/conservation/eal/archive/2001/licences/2497r.html

Current Fuel and O&M Costs

The specific operating costs of Manitoba Hydro's thermal units are not fixed. They vary according to the real-time cost of inputs, which are dominated by the fuel component in all cases. The delivered cost of either coal or natural gas varies according to the prevailing commodity price, Manitoba Hydro's contractual arrangements for supply, transportation costs, and other charges. Generally, however, assuming a price of $9 - $11US/ton Powder River Basin coal (at the mine mouth), Manitoba Hydro's cost to operate Brandon Unit 5 is in the order of $40/MW.h. The components of this cost break down as approximately: $25/MW.h for fuel, $10/MW.h for GHG carbon tax paid to province, $5/MW.h O&M.

Selkirk and Brandon 6&7 have similar operating cost structures and assuming a \$7.00US/mmBtu natural gas price, operating costs are in the order of \$90/MW.h. Specific cost components are in the order of \$85/MW.h for fuel and \$5/ MW.h for O&M. All costs are estimated and rounded.

PUB/MH I-85

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table A-1(a)**

b) File Regulation 186/2009 and explain its financial impact to MH.

ANSWER:

Regulation 186/2009 is attached. It can also be found at:
http://web2.gov.mb.ca/laws/regs/pdf/c135-186.09.pdf

A comprehensive financial evaluation of restricted operations at Brandon Unit 5 in the future has not been evaluated as an isolated issue. Restricted operation has been imposed as a regulatory constraint and is not an option for Manitoba Hydro. However, the financial impacts of the regulatory change have been incorporated into the overall generation costs and interchange revenue estimates that are utilized in the preparation of the IFF.

An approximate estimate has been made of the financial impact by estimating the lost opportunity for export revenue and the increased thermal generation cost if restrictions had been in effect in the past several years. It is estimated that the financial impact of regulatory restrictions may have been in the order of $7 to $15 million per year in the non-drought years. The legislation allows for use of Brandon Unit 5 in a drought year and would have very little impact in a drought year such as 2003/04.

THE CLIMATE CHANGE AND EMISSIONS REDUCTIONS ACT
(C.C.S.M. c. C135)

Coal-Fired Emergency Operations Regulation

Regulation 186/2009
Registered November 18, 2009

Emergency operations defined

1(1) In section 16 of *The Climate Change and Emissions Reductions Act*, "**emergency operations**" means operations using coal to generate or prepare to generate power in Manitoba that, in the opinion of Manitoba Hydro, are necessary to

(a) prevent or minimize the impact of a system or local emergency or any other condition that may

(i) jeopardize the continuous supply of power, at acceptable voltage and frequency, or

LOI SUR LES CHANGEMENTS CLIMATIQUES ET LA RÉDUCTION DES ÉMISSIONS DE GAZ À EFFET DE SERRE
(c. C135 de la C.P.L.M.)

Règlement sur l'utilisation du charbon en cas d'opérations d'urgence

Règlement 186/2009
Date d'enregistrement : le 18 novembre 2009

Définition

1(1) À l'article 16 de la *Loi sur les changements climatiques et la réduction des émissions de gaz à effet de serre*, « **opérations d'urgence** » s'entend des opérations où l'on utilise du charbon pour produire ou se préparer à produire de l'énergie au Manitoba et qui, selon Hydro-Manitoba, sont nécessaires aux fins suivantes :

a) prévenir une situation d'urgence ou autre qui se produit localement ou à l'échelle du réseau, ou en atténuer les répercussions, laquelle situation pourrait avoir dans la province ou un réseau régional de distribution l'une des conséquences suivantes :

(i) menacer l'alimentation sans interruption en énergie, à un voltage et à une fréquence acceptables,

(ii) cause or contribute to instability, uncontrolled separation or cascading failures, or to uncontrolled electricity flows,

within Manitoba or an integrated regional power grid;

(b) provide power if, due to forecasted water supply conditions in Manitoba, demand for power is expected to exceed aggregate supply; or

(c) maintain coal-fired generating facilities in a state of readiness to respond to an emergency or other condition.

1(2) Manitoba Hydro must, in assessing the potential for an emergency or other condition under clause (1)(a) or in making a forecast under clause (1)(b), consider

(a) any interconnection or other binding agreement under which Manitoba Hydro is obligated to provide a reliable and continuous supply of power; and

(b) any standards, rules, terms, conditions, guidelines or schedules established by a standards authority which relate to the planning, design or operation of power generation or transmission facilities or systems within an integrated regional power grid.

1(3) In clause (2)(b), "**standards authority**" means any agency, industry organization or body that makes or approves standards or criteria that apply both in and outside Manitoba relating to the operation or reliability of power generation or transmission facilities or systems.

Minister must be notified — coal operations

2(1) Manitoba Hydro must give the minister notice as soon as reasonably practicable if it uses coal to generate power in Manitoba for any reason other than for maintaining coal-fired generating facilities in a state of readiness to respond to an emergency or other condition.

(ii) causer des cas d'instabilité, des séparations non contrôlées, des défaillances en cascade ou des flux électriques non contrôlés ou y contribuer;

b) fournir de l'énergie si, en raison de conditions prévues au chapitre de l'approvisionnement en eau, l'on prévoit que la demande d'énergie sera supérieure à l'alimentation globale;

c) veiller à ce que les centrales alimentées au charbon soient prêtes à fonctionner si une situation d'urgence ou autre survient.

1(2) Au moment d'évaluer si une situation d'urgence ou autre visée à l'alinéa (1)a) pourrait survenir ou de faire des prévisions conformément à l'alinéa (1)b), Hydro-Manitoba tient compte des facteurs suivants :

a) l'existence d'une convention d'interconnexion ou autre liant les parties et en vertu de laquelle elle est tenue de fournir un approvisionnement fiable et constant en énergie;

b) l'existence de normes, de règles, de modalités, de conditions, de lignes directrices ou de programmes établis par un organisme de normalisation et ayant trait à la planification, à la conception ou à l'exploitation d'installations ou de réseaux de production ou de transport d'énergie au sein d'un réseau régional de distribution.

1(3) À l'alinéa (2)b), « **organisme de normalisation** » s'entend d'un organisme, d'une organisation représentant l'industrie ou d'une entité qui établit ou approuve des normes ou des critères applicables au Manitoba et ailleurs à l'égard de l'exploitation ou de la fiabilité des installations ou des réseaux de production ou de transport d'énergie.

Obligation d'aviser le ministre en cas d'utilisation de charbon

2(1) Hydro-Manitoba est tenue d'aviser le ministre dès que possible si elle utilise du charbon pour produire de l'énergie au Manitoba, à moins que cette mesure ne serve à garder des centrales alimentées au charbon prêtes à fonctionner en cas de situation d'urgence ou autre.

2(2) Manitoba Hydro must give the minister notice if, due to forecasted water supply conditions, it is of the opinion that it may be necessary to use coal to generate power in Manitoba. The notice must include Manitoba Hydro's rationale for its opinion.

2(3) After giving notice under subsection (2), Manitoba Hydro must notify the minister when water supply conditions improve to the point that it no longer expects to use coal to generate power in Manitoba.

Annual coal operations emergency preparedness plan

3 Manitoba Hydro must prepare and submit to the minister an annual coal operations emergency preparedness plan for the 12-month period beginning April 1 of each year. The plan must be submitted to the minister on or before the date specified by the minister.

Reporting

4(1) Within 30 days after the end of each quarter, Manitoba Hydro must submit a report to the minister setting out the following in respect of each time in the quarter it used coal under subsection 1(1):

(a) the reason or reasons for the use;

(b) the start and end date of the use;

(c) the gross power generated;

(d) an estimate of the resulting emissions.

4(2) In subsection (1), "**quarter**" means the consecutive three-month periods of January to March, April to June, July to September and October to December.

Coming into force

5 This regulation comes into force on January 1, 2010.

The Queen's Printer
for the Province of Manitoba

2(2) Hydro-Manitoba est tenue de remettre un avis motivé au ministre si elle juge, en raison des conditions prévues au chapitre de l'approvisionnement en eau, qu'elle pourrait devoir utiliser du charbon pour produire de l'énergie au Manitoba.

2(3) Après avoir donné l'avis, Hydro-Manitoba est tenue d'aviser le ministre de nouveau lorsque les conditions au chapitre de l'approvisionnement en eau s'améliorent à un point tel qu'elle ne s'attend plus à devoir utiliser du charbon pour produire de l'énergie au Manitoba.

Plan annuel de préparatifs d'urgence sur l'utilisation du charbon

3 Hydro-Manitoba dresse et soumet au ministre, au plus tard à la date limite qu'il fixe, un plan annuel de préparatifs d'urgence sur l'utilisation du charbon visant la période de 12 mois commençant le 1er avril.

Rapport

4(1) Dans les 30 jours suivant la fin d'un trimestre, Hydro-Manitoba soumet au ministre un rapport précisant, à l'égard de chaque utilisation de charbon visée au paragraphe 1(1) au cours de cette période, les renseignements suivants :

a) les raisons de l'utilisation;

b) la date où l'utilisation a commencé et pris fin;

c) l'énergie brute produite;

d) une évaluation des émissions de gaz à effet de serre produites.

4(2) Au paragraphe (1), « **trimestre** » s'entend des périodes consécutives de trois mois allant de janvier à mars, d'avril à juin, de juillet à septembre et d'octobre à décembre.

Entrée en vigueur

5 Le présent règlement entre en vigueur le 1er janvier 2010.

L'Imprimeur de la Reine
du Manitoba

<u>PUB/MH I-85</u>

Subject: Tab 8: Energy Supply
Reference: 2008/09 Power Resource Plan, Table A-1(a)

c) Would the Brandon Coal G.S. be available for:

i. Support for firm summer export sales (in advance of a drought)?
ii. Support of firm winter export sales (during a drought)?
iii. To displace Brandon SCCT units (natural gas) in a drought?

<u>ANSWER</u>:

i. The operating restrictions on Brandon Coal G.S. associated with Regulation 186/2009 permit operation of Unit 5 to supply system energy, in any month of the year, according to the specific terms, including in anticipation of, and during drought in order to support firm export sales existing at December 31, 2009. However, it is noted that after December 31, 2009 Manitoba Hydro will not negotiate new forward firm export sales that require the use of dependable energy from Unit 5. From the overall perspective, this reduces reliance on operation of the Brandon Coal G.S., while still allowing for its operation to maintain system reliability and to reduce the financial impacts of drought. Please refer to the response to PUB/MH I-85(c)(ii), (c)(iii), (d) and (e) for additional information.

ii. After December 31, 2009 Manitoba Hydro will not negotiate new forward firm export sales that require the use of dependable energy from Unit 5. Please refer to the response to PUB/MH I-85(c)(i) and (c)(iii), (d) and (e) for additional information.

iii. It should be noted that droughts occur in varying degrees of duration and intensity. In a severe drought Brandon coal-fired Unit 5, as well as Brandon gas-fired Units 6 and 7, may be required to meet firm load requirements. In less severe drought periods, Brandon gas-fired Units 6 and 7 may be operated before Brandon coal-fired Unit 5. Actual day to day operation of Unit 5 under drought conditions will occur according to specific real-time load requirements including energy commitments, the availability of alternative sources of supply including import energy, and the need for Brandon area generation to support the transmission system.

PUB/MH I-85

Subject: Tab 8: Energy Supply
Reference: 2008/09 Power Resource Plan, Table A-1(a)

d) With unit costs typically in excess of import and export prices, would the Selkirk and Brandon Natural Gas G.S. be employed in the first summer of a drought?

ANSWER:

A number of factors are indicative of the start of a drought condition including how rapidly water conditions deteriorate leading up to the recognition of the drought. It is only at some later time after a downturn in streamflows that it is clear that the system is in fact in a drought period, but even then the severity and duration are not known until there is a recovery in streamflows.

As discussed in the response to PUB/MH I-138, imports are typically a lower cost option than running Manitoba Hydro gas-fired generation. Imports for drought support will typically be maximized prior to running Manitoba Hydro gas-fired generation. The specific timing of gas-fired operations prior to or during a drought will depend on the prevailing circumstances at the time. In general, it is possible but not certain that gas-fired generation could be required in the first or any month or year of a drought.

<u>PUB/MH I-85</u>

Subject: Tab 8: Energy Supply
Reference: 2008/09 Power Resource Plan, Table A-1(a)

e) **Has MH considered the possibility that its thermal plant outputs would not be active for the first six months of a drought; and should possibly be downgraded when defining dependable energy?**

<u>ANSWER</u>:

Manitoba Hydro has not considered downgrading dependable energy due to the possibility that thermal plants would not be active in the first six months of a drought. Manitoba Hydro maintains its thermal resources in a state of readiness to enable not only emergency response but also to contribute energy to the system for extended periods should that be necessary. As long as units are available, they are considered capable of supplying dependable energy to the system during severe drought. Aside from short periods where units are out of service for maintenance, units are considered as available to contribute to dependable energy to the system. There is no reason to assume that Manitoba Hydro's thermal resources would not be available during the onset of a drought, except for short intervals to perform necessary maintenance. Please refer to the response to PUB/MH I-85(c) and (d) for further information.

<u>PUB/MH I-86</u>

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table 1(a)**

a) **Please confirm that MH wind resources currently are indentified at 320 GW.h/year and are still forecast to reach 1,229 GW.h/year by 2013/14.**

<u>ANSWER</u>:

The existing St. Leon wind resource is expected to provide 320 GW.h/year of dependable energy. As shown in Tab 8 Table 2 of the 2010/11 & 2011/12 GRA, the addition of a 300 MW wind farm at St. Joseph was expected to increase the total dependable energy from wind generation to 1,254 GW.h/year as early as 2011/12.

Subsequent to the preparation of the 2009/10 power resource plan the scale of the St. Joseph wind farm has been reduced and current indications are that a total addition at this wind farm will be 138 MW instead of 300 MW. The corresponding dependable energy from the St. Joseph wind farm can be expected to be reduced on a proportional basis.

PUB/MH I-86

Subject: Tab 8: Energy Supply
Reference: 2008/09 Power Resource Plan, Table 1(a)

b) **Please confirm that these outputs assume a 40% on-line factor and a 90% reliability factor.**

ANSWER:

Manitoba Hydro does not use the terms on-line factor or reliability factor for wind generation. The terms used by Manitoba Hydro are the average annual capacity factor and the dependable energy factor. The average annual capacity factor is the expected average annual wind generation, expressed as a percentage of maximum possible wind farm generation based on operation at maximum rating 100% of the time. For example, a wind farm rated at 100 MW with an expected annual generation of 350,000 MW.h would have an average annual capacity factor of 40% [350,000 MW.h / (100 MW x 8760 hours per year)].

The dependable energy factor is defined as the minimum generation that could be expected from a wind farm over the period of a year compared to the long-term average. Dependable wind energy corresponds to an extreme year in which wind speed is consistently below average. The dependable energy factor is expressed as a percent of the expected average annual wind generation and Manitoba Hydro uses 85% for this factor.

The power resource plan assumes a 39% average annual capacity factor and a 85% dependable energy factor for the St. Leon wind farm and assumes a 38% average annual capacity factor and a 85% dependable energy factor for the additional 300 MW of wind generation. The dependable energy capability in the power resource plan supply/demand table is further adjusted to account for transmission losses.

PUB/MH I-86

Subject: Tab 8: Energy Supply
Reference: 2008/09 Power Resource Plan, Table 1(a)

c) **Please define the percentage of time that the wind is expected to be unavailable and the percentage of time that the wind turbines are down due to inclement conditions and/or maintenance.**

ANSWER:

Please see the response to PUB/MH I-86(b) for a description of the planning assumptions regarding wind generation.

The average annual capacity factor is the expected average annual wind generation, expressed as a percentage of maximum possible wind farm generation. Based on actual wind metrological data and actual wind farm output to date, Manitoba Hydro expects average annual capacity factors in the 38% to 40% range for the St. Leon and St. Joseph areas. Note that this capacity factor is the expectation of actual wind farm generation performance and is net of all effects from maintenance and weather related outages.

Manitoba Hydro purchases energy as available from St. Leon Wind Energy LP at the point of interconnection. Maintenance and weather related outages are internal operational issues to the wind farm operator. There are 63 wind turbine generators at St. Leon each with a nameplate capacity of 1.65 MW. At any given time, one or two wind turbines generators are likely to be out of service for maintenance. Overall, it is expected that any particular wind turbine generator unit would not be available to generate for about 3% of the time due to maintenance outages.

PUB/MH I-86

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table 1(a)**

d) Please provide the St. Leon wind farm monthly performance data for the in-service years to date.

ANSWER:

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.

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.

<u>PUB/MH I-86</u>

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table 1(a)**

e) **Please confirm that MH regards the wind input as being of similar dependability on an energy supply basis as the minimum potential hydraulic generation experienced in the last 90 years?**

<u>ANSWER</u>:

It is confirmed that Manitoba Hydro considers that the dependable energy capability of wind generation over the period of a year is of similar dependability as the dependable energy capability of hydroelectric generation over a year.

PUB/MH I-86

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table 1(a)**

f) **Please provide a graphical illustration of MH's potential annual wind generation and its expected variability over the same 90-year period.**

ANSWER:

Manitoba Hydro does not have 90 years of potential annual wind generation data corresponding to the water flow record. Please see the response to PUB/MH I-86(b) for a description of how Manitoba Hydro determines annual wind dependable energy.

PUB/MH I-87

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table A-1a, Table A-1b**

a) Please define the specific DSM resources that MH employs in the dependable energy and capacity determination.

ANSWER:

Please refer to the 2009 Power Smart Plan which can be found in Appendix 9.1 of this Application. The majority of the programs and initiatives outlined in Appendices A.1 and A.2 of the Power Smart Plan are included as DSM resources in the dependable energy and capacity resources of the Power Resource Plan. The following are not included in the Power Resource Plan.

Energy	Capacity
Codes and standards savings	Codes and standards savings Customer self-generation savings Curtailable rates savings

Codes and standards savings are included in the load forecast so they are not included as part of DSM in the Power Resource Plan. Both customer self-generation and curtailable rates capacity savings are not considered dependable and long term commitments, so they are not included as a resource in the Power Resource Plan.

PUB/MH I-87

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table A-1a, Table A-1b**

b) Please clarify the degree of dependability of these resources in light of MH's CRP rationale that suggests DSM is not as readily dispatchable as a SCCT (only 40%).

ANSWER:

The capacity associated with the Curtailable Rates Program is not included as part of the Demand Side Management dependable capacity used in the power resource plan. From the planning perspective Manitoba Hydro does not count on curtailable loads to meet capacity requirements in the long term because there is no assurance that the Curtailable Rates Program will exist one or two decades into the future. An additional reason for not including curtailable capacity in long-term resource planning is that the limitations of CRP may result in it not being available when required during critical peak load demand periods.

PUB/MH I-87

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table A-1a, Table A-1b**

c) Please clarify the role of the Kelsey G.S. rerunnering with respect to:

- **Dependable energy.**
- **Average energy.**
- **Maximum energy.**
- **Winter capacity.**
- **Summer capacity.**

ANSWER:

In general, the Kelsey Improvements and Upgrades Project is expected to increase power production from Kelsey G.S. by adding 77 MW of capacity and about 350 GW.h of average annual system energy production, primarily through a substantial reduction in the frequency of spill from 70% down to 35%. This increases the average annual energy surplus to Manitoba Hydro's integrated system, thereby providing additional benefits through increased opportunities for export sales or reduced thermal generation and imports.

The specific contributions as outlined above are as follows:

1. Dependable energy: no significant gain in dependable energy is expected since the majority of energy gained by rerunnering is achieved at higher river flows, whereas dependable energy is derived from the lowest flows on record.

2. Average energy: the gain in the plant energy output over all flow conditions is expected to be approximately 350 GW.h of average annual energy for an overall increase of about 20%.

3. Maximum energy; the maximum energy output of the plant is expected to increase by about 20% relative to the maximum output of the plant before rerunnering.

4. Winter capacity; the winter capacity of the plant is expected to increase by about 75 MW for an overall increase of about 30% in the winter capacity rating of the plant.

5. Summer capacity; the summer capacity of the plant is expected to increase by about 77 MW for an overall increase of about 30% in the summer capacity rating of the plant.

PUB/MH I-87

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan, Table A-1a, Table A-1b**

d) Please clarify the role of the Pointe du Bois G.S. update with respect to:

- **Dependable energy.**
- **Average energy.**
- **Maximum energy.**
- **Winter capacity.**
- **Summer capacity.**

ANSWER:

The existing Pointe du Bois Plant provides the following:

473 GW.h of dependable energy
525 GW.h of average energy
685 GW.h of maximum energy
77 MW of winter capacity
78 MW of summer capacity

As a result of the change in the economic climate and rising construction costs, the decision was made that the Pointe du Bois Modernization Project will now take the form of a new spillway and new concrete and earth dams. The existing powerhouse can continue to operate, and the decision to rebuild, renew or decommission it is being deferred to a later period.

The decision to not upgrade the Pointe du Bois Generating Station powerhouse at this time will result in the existing capabilities being maintained into the future.

PUB/MH I-88

Subject: **Tab 8: Energy Supply**
Reference: **2007/08 Power Resources Plan, Table A1-1a, Table A1-1b**

a) What is the role that contracted (scheduled) imports play in defining MH's export sales during:

- **Low flow years?**
- **Mean flow years?**
- **High flow years?**

ANSWER:

Contract imports occur during low flow conditions to secure the energy supply for serving firm commitments (Manitoba Load and firm export contracts) and to lock in the price.

In general, Manitoba Hydro does not contract for purchases during mean and high flow conditions, but will buy them on the spot market as required.

<u>PUB/MH I-88</u>

Subject: **Tab 8: Energy Supply**
Reference: **2007/08 Power Resources Plan, Table A1-1a, Table A1-1b**

b) Are these imports contracted on a firm price take or pay basis, or some other level of firmness? Explain.

<u>ANSWER</u>:

Manitoba Hydro does not have any long-term firm take or pay power purchase contracts. During drought periods, Manitoba Hydro may contract for fixed price energy depending on the requirements at that time.

PUB/MH I-88

Subject: **Tab 8: Energy Supply**
Reference: **2007/08 Power Resources Plan, Table A1-1a, Table A1-1b**

c) Are these imports scheduled as peak or off-peak? Explain.

ANSWER:

Scheduled imports, for servicing firm requirements during drought, are initially scheduled as off-peak purchases to minimize the cost. However, as drought severity increases, eventually on-peak imports are purchased in spite of increased cost as tie-line limits are reached in the off peak.

PUB/MH I-88

Subject: **Tab 8: Energy Supply**
Reference: **2007/08 Power Resources Plan, Table A1-1a, Table A1-1b**

d) How do these contracted imports relate to the imports available via diversity agreements?

ANSWER:

Energy available includes the Seasonal Diversity agreements as well as additional energy available under those contracts during adverse water conditions.

PUB/MH I-89

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-82 (2004/04/19)**

Please confirm on an order of magnitude basis that for the 1977-2009 period, the following annual hydrologic generation (GWh) would have been derived from post-Limestone plants.

	Minimum	Average	Maximum
Burntwood River	**3,300**	**5,100**	**7,000**
Saskatchewan River	**2,000**	**4,100**	**7,400**
Red River	**500**	**1,700**	**3,600**
Winnipeg River	**6,500**	**11,300**	**16,900**
Other Local Inflows	**1,500**	**6,600**	**11,600**
Total		**28,800**	

ANSWER:

The methodology used to derive the hydroelectric generation in the information request is not known to Manitoba Hydro. The average generation can be confirmed on an order of magnitude basis. The generation for the minimum case appears to be low and may not include withdrawals from storage that normally occurs in the lowest flow year. The generation for the maximum flow year is significantly overestimated and this may be due to failure to recognize the maximum capability of hydro plant and the spill of water. The response to PUB/MH I-81(a) contains a summary of total hydraulic generation for all flow years. It is noted that the maximum annual generation in that response is 37,646 GW.h in the year 2005/06 which is significantly lower than the 46,500 total for the maximum in the information request.

PUB/MH I-90

Subject: Tab 8: Energy Supply
Reference: PUB/MH I-3(f)

a) Please confirm that in 2003/04, MH's hydraulic resources generated a total of 18, 500 GWh approximately comprised of

i. 6,500 GWh from Winnipeg River flows.
ii. 3,300 GWh from Saskatchewan River flows
iii. 1,000 GWh from Red River flows
iv. 4,000 GWh from Burntwood River flows.
v. 1,700 GWh from other local inflows.
vi. 2,000 GWh from energy –in-storage.

ANSWER:

In 2003/04, Manitoba Hydro's hydraulic resources generated ~18,500 GWh. On a river specific basis, hydraulic generation can be attributed to river flows as follows:

i. 8,000 GWh from Winnipeg River flows.
ii. 3,000 GWh from Saskatchewan River flows.
iii. 1,000 GWh from Red River flows.
iv. 5,000 GWh from Burntwod River flows.
v. 1,500 GWh from other local inflows.
vi. 0 GWh from energy-in-storage.

Note that the above figures are based on an approximate allocation of flows. The actual 2003/04 inflows were enough to generate 18,500 GWh of hydraulic generation and store approximately 1,500 GWh (primarily into Cedar Lake from Saskatchewan River flows).

PUB/MH I-90

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-3(f)**

b) **Please provide a similar tabulation employing post-Limestone G.S. resources for other" low flow" years**

i. **1988/89.**
ii. **1987/88.**
iii. **1981/82.**
iv. **1989/90.**
v. **1980/81.**
vi. **1990/91.**
vii. **1991/92.**
viii. **1977/78.**

ANSWER:

The following tabulates estimates of generation from hydraulic resources assuming post-Limestone G.S. resources were in service in each of the listed "low flow" years.

1. In 1988/89, Manitoba Hydro's post-Limestone hydraulic resources potentially would have generated 18,850 GWh comprised of:

   i. 7,634 GWh from Winnipeg River flows.
   ii. 3,230 GWh from Saskatchewan River flows.
   iii. 1,272 GWh from Red River flows.
   iv. 3,702 GWh from Burntwood River flows.
   v. 1,979 GWh from other local inflows.
   vi. 1,033 GWh from energy-in-storage.

2. In 1987/88, Manitoba Hydro's post-Limestone hydraulic resources potentially would have generated 22,353 GWh comprised of:

   i. 8,220 GWh from Winnipeg River flows.
   ii. 4,255 GWh from Saskatchewan River flows.
   iii. 1,585 GWh from Red River flows.

iv. 4.543 GWh from Burntwood River flows.
v. 3,752 GWh from other local inflows.
vi. 0 GWh from energy-in-storage.

3. In 1981/82, Manitoba Hydro's post-Limestone hydraulic resources potentially would have generated 22,201 GWh comprised of:

   i. 8,397 GWh from Winnipeg River flows.
   ii. 4,397 GWh from Saskatchewan River flows.
   iii. 1,515 GWh from Red River flows.
   iv. 4,304 GWh from Burntwood River flows.
   v. 2,524 GWh from other local inflows.
   vi. 1,014 GWh from energy-in-storage.

4. In 1989/90, Manitoba Hydro's post-Limestone hydraulic resources potentially would have generated 24274 GWh comprised of:

   i. 10,071 GWh from Winnipeg River flows.
   ii. 4,217 GWh from Saskatchewan River flows.
   iii. 1,612 GWh from Red River flows.
   iv. 4,556 GWh from Burntwood River flows.
   v. 3,748 GWh from other local inflows.
   vi. 70 GWh from energy-in-storage.

5. In 1980/81, Manitoba Hydro's post-Limestone hydraulic resources potentially would have generated 25,210 GWh comprised of:

   i. 9,487 GWh from Winnipeg River flows.
   ii. 4,778 GWh from Saskatchewan River flows.
   iii. 1,753 GWh from Red River flows.
   iv. 5,042 GWh from Burntwood River flows.
   v. 4,151 GWh from other local inflows.
   vi. 0 GWh from energy-in-storage.

6. In 1990/91, Manitoba Hydro's post-Limestone hydraulic resources potentially would have generated 24,162 GWh comprised of:

   i. 9,533 GWh from Winnipeg River flows.

ii. 4,783 GWh from Saskatchewan River flows.
iii. 1,603 GWh from Red River flows.
iv. 4,448 GWh from Burntwood River flows.
v. 3,796 GWh from other local inflows.
vi. 0 GWh from energy-in-storage.

7. In 1991/92, Manitoba Hydro's post-Limestone hydraulic resources potentially would have generated 24,658 GWh comprised of:

i. 9,830 GWh from Winnipeg River flows.
ii. 4,735 GWh from Saskatchewan River flows.
iii. 1,629 GWh from Red River flows.
iv. 4,606 GWh from Burntwood River flows.
v. 3,858 GWh from other local inflows.
vi. 0 GWh from energy-in-storage.

8. In 1977/78, Manitoba Hydro's post-Limestone hydraulic resources potentially would have generated 25,097 GWh comprised of:

i. 9,497 GWh from Winnipeg River flows.
ii. 4,588 GWh from Saskatchewan River flows.
iii. 1,765 GWh from Red River flows.
iv. 5,069 GWh from Burntwood River flows.
v. 4,179 GWh from other local inflows.
vi. 0 GWh from energy-in-storage.

PUB/MH I-90

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-3(f)**

c) Can MH confirm that spring runoff (due to winter and spring precipitation) in the Winnipeg River and Red River watersheds was significantly below average in each of the above "low flow" years.

ANSWER:

Spring runoff (due to winter and spring precipitation) in the Winnipeg River and Red River watersheds were below average for all of the "low flow" years in PUB/MH I-90 (a) and (b).

PUB/MH I-90

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-3(f)**

d) Can MH confirm that above average Winnipeg River and Red River spring runoff would typically ensure average or above average overall hydraulic output? Explain.

ANSWER:

No. Above average spring runoff does not guarantee above average hydraulic output for the year. Other significant factors include: spring precipitation, summer precipitation, fall precipitation, and carry over reservoir storage from the previous year. Moreover, the Winnipeg and Red River basins only make up a portion of the larger Nelson / Churchill River Basin that supplies Manitoba Hydro’s hydraulic generation stations.

<u>PUB/MH I-90</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-3(f)**

e) **Please confirm that, on average, the Saskatchewan River flows account for about 14% of MH's total hydraulic generation.**

<u>ANSWER</u>:

Saskatchewan River flows account for approximately 20% of Manitoba Hydro's total hydraulic generation.

<u>PUB/MH I-90</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-3(f)**

f) **Please confirm that, on average, that Winnipeg River, Red River, and local inflow account for 68% of MH's hydraulic generation.**

<u>ANSWER</u>:

Water from the Winnipeg River and the Red River basins account for approximately 61% of Manitoba Hydro's hydraulic generation.

<u>PUB/MH I-90</u>

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-3(f)**

g) **Please confirm that, on average, the Burntwood River flows account for about 18% of MH's total hydraulic generation.**

<u>ANSWER</u>:

The Upper Churchill River basin supplies the majority of flow on the Burntwood River via the Churchill River Diversion Project. In total, the flow in the Burntwood River accounts for approximately 19% of Manitoba Hydro's total hydraulic generation.

<u>PUB/MH I-91</u>

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8 – Energy Supply Page 17/18.**

Please confirm that MH's operational decision process relies on:

i. **Actual flows (unweighted) within the major stream system (Winnipeg River, Red River, Saskatchewan River, and Burntwood River).**

ii. **Spring and summer peak flow hydrographs that are of a predictable shape so that by reference to a peak discharge, the upcoming fall and winter hydraulic generation can be predicted.**

iii. **Local inflows (other than four major streams) being more than sufficient to counter evaporation losses from reservoirs (e.g., Lake Winnipeg).**

iv. **Limiting the size of the individual export sales commitments that can be made without reference to the Division Manager.**

v. **Please provide any additional factors.**

<u>ANSWER</u>:

i. Confirmed. Actual river flows within the major stream system (*that includes* Winnipeg River, Red River, Saskatchewan River, and Burntwood River) are a key input to the operations planning process.

ii. No. Upcoming fall and winter hydraulic generation is not predicted by reference to a peak discharge experienced in the spring and summer periods. Refer to 2010 GRA PUB/MH I-81 for further explanation.

iii. No. The operations planning process relies on a water supply forecasting technique utilizing regression analysis that accounts for all the inputs and losses in the hydrologic cycle.

iv. No. Operations planning decisions are separate from management controls that limit export sales commitments. The operations planning process does require that all export sale and purchase commitments be included.

v. There are numerous other non-technical factors and technical factors that are considered in the operations planning process. These 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 exercise of professional judgment and experience,
c. Current storage levels, near term weather forecasts, equipment maintenance schedules, domestic load forecasts, ice conditions, availability of extra-provincial tie-line capacity and short term market trends and needs.

PUB/MH I-92

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8 – Energy Supply (Page 17, Figure 8.6.2)**

a) **Please confirm that MH’s annual hydraulic generation is derived in the larger part from winter and spring precipitation and that summer and fall precipitation play a somewhat lesser part.**

ANSWER:

No. Manitoba Hydro’s annual hydraulic generation is derived in the larger part from spring and summer precipitation.

<u>PUB/MH I-92</u>

Subject: Tab 8: Energy Supply
Reference: Tab 8 – Energy Supply (Page 17, Figure 8.6.2)

b) Please confirm that MH tracks water shed precipitation on a monthly basis.

<u>ANSWER</u>:

Manitoba Hydro tracks water shed precipitation more frequently than monthly. In general, precipitation data is tracked on a business-day basis.

PUB/MH I-92

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8 – Energy Supply (Page 17, Figure 8.6.2)**

c) **Is winter and spring precipitation directly employed as an input into MH's operational modelling? Explain.**

ANSWER:

No. Precipitation is not a direct input into Manitoba Hydro's operations planning models. Precipitation is implicitly included in Manitoba Hydro's modeling in the form of observed stream flows. Very recent precipitation information is used qualitatively to monitor overall basin conditions.

PUB/MH I-92

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8 – Energy Supply (Page 17, Figure 8.6.2)**

d) **Is summer precipitation and/or evaporation directly employed as an input into MH's operational modelling? Explain.**

ANSWER:

No. Please see Manitoba Hydro's responses to PUB/MH I-92(c) and PUB/MH I-77(d).

PUB/MH I-93

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan (Page 18)**

a) Please confirm MH's current assessment of feasible head/capacity/energy output of future hydraulic stations is based on the "run-of-the-river" approach.

ANSWER:

The estimates of head/capacity/energy output generally assume a run-of-river approach (where inflows and outflows are matched on a daily basis) for use in the resource screening studies particularly for the second tier of projects (not including Keeyask, Conawapa, Pointe du Bois and Kelsey rerunnering). The projects that are part of the immediate development plan (Keeyask, Conawapa, Pointe du Bois and Kelsey re-runnering) undergo detailed mode of operation studies for use in a multitude of applications. Keeyask will take the regulated flows from LWR and CRD and is expected to operate in both a run-of-river approach as well as in a pondage approach where more water is shifted to peak time periods. Conawapa is expected to operate as a run-of-river project and will follow the flow pattern established by Kettle. Pointe du Bois and Kelsey are assumed to operate as a run of river plants. The remaining options have not been studied to such a detail, and different configurations are possible. The project parameters and the known hydraulics are used to estimate the plant capacity and energy potential. The nominal capacity shown in Table 3 Column 2 (Page 18) is not sustainable continuously. Estimates are made of how much energy each option may produce for a range of inflow conditions. These estimates are based on a rough understanding of the reservoir size and basic run of river modes of operation. Generally, average monthly flows and average head conditions are used to estimate average energy. At the early stages of the planning process alternative concepts are developed for each site using one or both modes of operation.

PUB/MH I-93

Subject: **Tab 8: Energy Supply**
Reference: **2008/09 Power Resource Plan (Page 18)**

b) i. CRD/Burntwood River stations – 525 MW (three plants not including Wuskwatim):

- **Will these plants require similar downscaling for environmental considerations as Wuskwatim did?**

ii. Lower Nelson River stations – 1,280 MW:

- **Is Birthday Rapids G.S. still viable when Keeyask is built?**
- **Is Gilliam Island G.S. still viable with its potential environmental issues?**

iii. Upper Nelson River stations – 55 MW:

- **Are both Whitemud G.S. and Red Rock G.S. likely to be built?**

iv. Upper Churchill River stations – 245 MW:

- **Do these involve extensive forebays?**

ANSWER:

i. Each plant will undergo an optimization process that balances economic, environmental and social considerations during their individual planning processes.

ii. Birthday Rapids G.S. will be technically viable after Keeyask is built. It would not be as economic. Also Birthday Rapids G.S. would have undesirable effects upstream on Split Lake.

Gillam Island G.S. will be viable. Any environmental issues will be addressed during the planning process.

iii. The Whitemud and Red Rock plants are potential sites that could be built individually or together. No commitment has been made to build them.

iv. Both Bonald G.S. and Granville G.S. sites have forebays but comparatively would not be as extensive as the Keeyask G.S. Manitoba Hydro has not conducted detailed engineering studies on these sites and currently does not have information on the flooded areas of the projects.

PUB/MH I-93

Subject: Tab 8: Energy Supply
Reference: 2008/09 Power Resource Plan (Page 18)

c) Reconcile the Generating stations listed in the 2009 Power Resource Plan with those listed in MH's March 31, 1999 Annual Report.

ANSWER:

It is assumed that the information request intended to refer to the 2008 and not the 2009 power resource plan. A summary of the 1999 and the 2008 plant capacities is provided on the next page. The capacity values stated in various annual reports are the result of specific tests undertaken at the generating stations each year, and are adjusted to reflect average operating conditions during the peak load hours for each month. As a result of differences in testing and different operating conditions, the results change modestly from year to year. The values used in the power resource plans are not intended to change from year to year, unless warranted by system changes.

Significant differences between the 1999 Annual Report, and the values used in the 2008 power resource plan, include:

Jenpeg G.S. – The resource plan output is 38 MW greater than the 1999 Annual Report. Jenpeg is generally operated to provide maximum outflows from Lake Winnipeg over the winter period, which draws the forebay down and reduces the available generation. The output of Jenpeg varies considerably over the year, and from year to year, due to varying outflow requirements from Lake Winnipeg.

Long Spruce G.S. – The resource plan is 13 MW less than the 1999 Annual Report. Although Long Spruce is capable of higher generation capacity, typical operation at time of peak in January is restricted to about 1007 MW.

Limestone G.S. – This plant had some operating restrictions in 1999 that have since been resolved, and this is the reason for the lower rating in the 1999 Annual Report.

Pointe du Bois and Slave Falls Generating Stations – These plants were added to the Manitoba Hydro system in 2002 after the purchase of Winnipeg Hydro and therefore were not part of Manitoba Hydro's 1999 Annual Report.

Brandon Units 6&7 – These are new 165 MW natural gas-fired combustion turbines installed in 2002 and therefore were not part of Manitoba Hydro's 1999 Annual Report. The combined output has been adjusted to 298 MW to reflect winter conditions.

In summary, of the 480 MW difference between the 1999 Annual Report and the 2008 power resource plan, 423 MW is due to additional generating equipment while the remaining 57 MW is due to changes in plant ratings.

		Winter Capability (MWs)	
Interconnected Capabilities:		**1999 Annual Report**	**2008 Power Resource Plan**
Hydraulic	Great Falls	129	127
	Seven Sisters	155	156
	Pine Falls	88	88
	McArthur	54	57
	Grand Rapids	480	480
	Kelsey	215	208
	Kettle	1224	1220
	Jenpeg	97	135
	Long Spruce	1020	1007
	Limestone	1294	1335
	Laurie River	11	10
	Pointe du Bois*		64
	Slave Falls*		61
		4767	4948
Thermal	Brandon Unit 5	97	105
	Selkirk	139	132
	Brandon Unit 6 & 7		298
		236	535
Total Interconnected Capabilities		**5003**	**5483**

* acquired from Winnipeg Hydro in 2002
** In-service date 2002

<u>PUB/MH I-94</u>

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8, Energy Supply, Page 11 – Lines 26 and 27, Table 8.5.1**

Please confirm that annual average prices of export energy have:

i. **Markedly declined since 2005/06.**
ii. **Not shown a significant upward trend since prior to 2003/04.**

<u>ANSWER</u>:

Annual US dollar prices have varied from approximately 77.35 to 64.25 per MW.h, throughout the 2005/06 - 2008/09 period. For a listing of actual prices represented in Figure 8.5.1, please see Manitoba Hydro's response to CAC/MSOS/MH I-65(b).

<u>PUB/MH I-95</u>

Subject: **Tab 8: Energy Supply**
Reference: **Tab 8, Energy Supply, Page 11, 12 and 13, Table 8.5.2**

Please confirm that MH's dependable sales prices (including demand charges) were less than the average of on peak opportunity sales in:

i. **2005/06.**
ii. **2006/07.**
iii. **2007/08**

but were greater in 2008/09 and 2009/10. Tab 9: Demand Side Management

<u>ANSWER</u>:

On average Manitoba Hydro's dependable sales prices were less than on peak opportunity sales prices from 2005/06 to 2007/08. However, average dependable sale prices were greater than in the ten years prior to 2005/06 and in the years 2008/09 to date.

In addition, Manitoba Hydro dependable sales contracts have provided Manitoba Hydro with reliability, energy security, market access and revenue stability benefits not reflected in the sale revenues.

PUB/MH I-96

Subject: Tab 9: Demand Side Management
Reference: DSM Deferred Charge

Please provide details of the actual DSM expenditures being deferred by electric program for 2008/09, 2009/10, 2010/11 and 2011/12 breaking out the costs between internal and external costs.

ANSWER:

	Expenditure Breakdown (1000s)											
	2008/09 - Actual			2009/10 - Forecast			2010/11 - Forecast			2011/12 - Forecast		
	Total	Internal	External	Total	Internal	External	Total	Internal	External	Total	Internal	External
RESIDENTIAL												
Residential CFL	$1,271	$288	$983	$1,631	$272	$1,359	$1,701	$272	$1,429	$1,668	$272	$1,396
Home Insulation	$1,590	$160	$1,430	$1,429	$204	$1,225	$1,335	$204	$1,131	$1,246	$204	$1,042
Appliances	$1,719	$343	$1,376	$198	$93	$106	$136	$64	$73			
EE Light Fixtures	$380	$101	$279	$400	$114	$286	$477	$153	$324	$598	$180	$418
New Homes	$635	$251	$384	$538	$216	$322	$583	$221	$362	$665	$231	$433
Seasonal LED Lighting	$339	$102	$237									
Lower Income Energy Efficiency	$209	$111	$99	$651	$74	$577	$756	$67	$689			
Water & Energy Saver	$78	$72	$7	$451	$146	$305	$909	$247	$661	$1,057	$326	$731
Fridge Recycling				$3,637	$110	$3,527	$3,215	$92	$3,123	$3,215	$92	$3,123
	$6,222	*$1,427*	*$4,795*	*$8,935*	*$1,228*	*$7,707*	*$9,113*	*$1,320*	*$7,792*	*$8,449*	*$1,305*	*$7,144*
COMMERCIAL												
Commercial Lighting	$7,723	$1,775	$5,948	$8,687	$1,769	$6,917	$6,684	$1,769	$4,915	$6,273	$1,769	$4,504
Building Envelope	$678	$138	$540	$1,491	$897	$594	$1,388	$897	$491	$1,386	$897	$489
Agricultural Heat Pads	$42	$17	$25	$123	$25	$98	$117	$19	$98			
Parking Lot Controllers	$377	$136	$242	$451	$140	$311	$92	$32	$61	$5	$5	
Spray Valves	$21	$4	$17	$31	$9	$22						
Internal Retrofit	$4,311	$230	$4,081	$1,735	$553	$1,182	$3,802	$1,212	$2,590	$1,573	$501	$1,072
Commercial Geothermal	$221	$125	$96	$522	$170	$352	$538	$174	$365	$543	$177	$366
Commercial Refrigeration	$174	$88	$86	$188	$76	$111	$205	$75	$130	$216	$76	$140
HVAC - Chillers	$212	$13	$199	$229	$11	$218	$227	$10	$217	$232	$9	$223
Custom	$238	$200	$38	$205	$76	$128	$201	$76	$125	$201	$76	$125
Commercial Building Optimization	$28	$20	$7	$146	$67	$79	$146	$67	$79	$159	$67	$93
City of Winnipeg Agreement	$63	$29	$34	$36	$1	$35	$23	$1	$22	$17	$1	$16
Commercial Kitchen Appliances	$90	$39	$51	$73	$14	$59	$86	$12	$74	$98	$12	$86
Commercial Clothes Washers	$43	$30	$13	$112	$34	$79	$57	$23	$33	$59	$22	$38
New Construction	$95	$94	$1	$522	$342	$180	$847	$308	$539	$970	$274	$696
Power Smart Energy Manager	$115	$92	$23	$163	$129	$34	$182	$129	$53	$169	$121	$48
Network Energy Manager	$20	$17	$3	$548	$57	$490	$539	$57	$482	$483	$57	$426
Power Smart Shops	$60	$60		$348	$242	$106	$310	$207	$104	$311	$207	$104
CO2 Sensors				$8	$3	$5	$8	$3	$5	$8	$2	$5
	$14,514	*$3,108*	*$11,405*	*$15,617*	*$4,615*	*$11,002*	*$15,451*	*$5,069*	*$10,382*	*$12,702*	*$4,271*	*$8,431*
INDUSTRIAL												
Performance Optimization	$2,504	$503	$2,001	$2,555	$780	$1,775	$2,602	$780	$1,822	$2,649	$780	$1,869
Emergency Preparedness	$81	$81		$150	$150		$3,100	$175	$2,925	$4,825	$100	$4,725
	$2,585	*$584*	*$2,001*	*$2,705*	*$930*	*$1,775*	*$5,702*	*$955*	*$4,747*	*$7,474*	*$880*	*$6,594*
CUSTOMER SELF-GENERATION												
Bioenergy Optimization	$1,718	$70	$1,649	$2,675	$948	$1,727	$2,338	$248	$2,090	$2,573	$447	$2,126
RATE/LOAD MANAGEMENT												
Curtailable Rates	$6,382	$5	$6,377	$6,363	$4	$6,359	$6,363	$4	$6,359	$6,363	$4	$6,359
DISCONTINUED	$10	$4	$7	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Option 1 & CSI	$1,877	$1,675	$202	$3,259	$2,597	$661	$3,204	$2,570	$634	$3,044	$2,513	$531
Support Activity	$1,870	$714	$1,156	$776	$296	$480	$820	$313	$507	$890	$340	$550
Contingency	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Utility Cost - Electric	***$35,178***	***$7,586***	***$27,592***	***$40,329***	***$10,619***	***$29,710***	***$42,989***	***$10,480***	***$32,510***	***$41,494***	***$9,759***	***$31,735***

PUB/MH I-97

Subject: **Tab 9: Demand Side Management**
Reference: **DSM Accounting Treatment Comparison**

a) **Please provide the accounting treatment followed by other Canadian electric utilities related to DSM program costs and compare them with the accounting policies followed by MH.**

ANSWER:

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

PUB/MH I-97

Subject: **Tab 9: Demand Side Management**
Reference: **DSM Accounting Treatment Comparison**

b) Please provide a continuity schedule showing spending, amortization expense, amortization rates and balances for planning studies and demand side management for the years 2004/05 through 2011/12.

ANSWER:

Please see the following planning studies and DSM continuity schedules.

Planning Studies Continuity Schedule **($000's)**

	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast	2012 Forecast
Opening Balance	37 101	45 458	63 099	28 476	25 265	25 171	-	-
Additions	12 977	23 153	9 491	3 682	2 605	-	-	-
Amortization Expense	(4 621)	(5 485)	(2 437)	(2 366)	(2 539)	-	-	-
Transfers	-	(27)	(41 676)	(4 527)	(160)	-	-	-
Transfer to Retained Earnings						(25 171)		
Ending Balance	$ 45 458	$ 63 099	$ 28 476	$ 25 265	$ 25 171	$ -	$ -	$ -

Demand Side Management Continuity Schedule **($000's)**

	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast	2012 Forecast
Opening Balance	61 187	76 383	95 917	122 948	148 700	163 776	182 162	200 321
Additions	21 153	28 153	36 128	37 109	35 178	40 329	42 989	42 544
Amortization Expense	(5 957)	(7 247)	(9 098)	(11 357)	(20 102)	(21 943)	(24 829)	(28 703)
Transfers	-	(1 373)	-	-	-	-	-	-
Ending Balance	$ 76 383	$ 95 917	$ 122 948	$ 148 700	$ 163 776	$ 182 162	$ 200 321	$ 214 162

PUB/MH I-98

Subject: Tab 9: Demand Side Management
Reference: Appendix 9-1 GHG Reductions, CCX Trading

a) **Please provide a full description of MH participation in the Chicago Climate Exchange in particular phase 2.**

ANSWER:

Prior to 2002 Manitoba Hydro participated in the design and discussions leading up to the formation of the Chicago Climate Exchange (CCX). In 2002 Manitoba Hydro became a founding member, committing to participate for a four year period (2003-2006). Over the initial period the CCX grew considerably and subsequently extended its operations to a second four year period from 2007 until 2010 (Phase II). Manitoba Hydro committed to participate in this second phase of the exchange.

The CCX system requires that its participants reduce emissions relative to a historic baseline. Each participant is provided an annual allowance of CCX units which decreases each year from the historic baseline. If a participant's emissions exceed their allowance level they are required to buy additional units through the exchange. Conversely, if their emissions are below their allowance level they are able to sell surplus units.

Manitoba Hydro's emission baseline is based on the average emission level realized during the years 1998-2001; this is equivalent to 758,900 tonnes of CO_2. The annual reduction schedule is as follows:

2003: 1% below baseline
2004: 2% below baseline
2005: 3% below baseline
2006: 4% below baseline
2007: 4.25% below baseline
2008: 4.5% below baseline
2009: 5% below baseline
2010: 6% below baseline

To date, Manitoba Hydro's annual emission reductions have exceeded its annual allocation of units in each year of participation. This has resulted in surpluses that Manitoba Hydro has sold on the CCX's exchange.

Manitoba Hydro has been an active member of CCX and is involved in the administration of the CCX through its committee structure. Through participation in the CCX, Manitoba Hydro gained experience in the measurement, reporting, and trading of emissions.

<u>PUB/MH I-98</u>

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9-1 GHG Reductions, CCX Trading**

b) Please provide details of all transactions made by MH on the CCX.

<u>ANSWER</u>:

A summary of transactions is provided on the following page. The reference to CFI in the tables below relates to a CCX carbon financial instrument. One CFI = 100 metric tonnes of carbon dioxide (CO_2).

Chicago Climate Exchange Transactions

CCX Trading Activity

sales shown as +ve
purchases shown as -ve

	No. of CFIs sold and vintage						Price per tonne (US$)					
	2003	2004	2005	2006	2007	2008	2003	2004	2005	2006	2007	2008
Trading Date:												
9/29/2003	-40	0	0	0	0	0	$1.50	$0.00	$0.00	$0.00	$0.00	$0.00
9/29/2003	-40	0	0	0	0	0	$1.00	$0.00	$0.00	$0.00	$0.00	$0.00
9/29/2003	-100	0	0	0	0	0	$0.98	$0.00	$0.00	$0.00	$0.00	$0.00
2/6/2004	-5	0	0	0	0	0	$0.90	$0.00	$0.00	$0.00	$0.00	$0.00
2/19/2004	-1	0	0	0	0	0	$0.91	$0.00	$0.00	$0.00	$0.00	$0.00
2/19/2004	-5	0	0	0	0	0	$0.90	$0.00	$0.00	$0.00	$0.00	$0.00
2/19/2004	-5	0	0	0	0	0	$0.90	$0.00	$0.00	$0.00	$0.00	$0.00
2/19/2004	-5	0	0	0	0	0	$0.91	$0.00	$0.00	$0.00	$0.00	$0.00
2/19/2004	-10	0	0	0	0	0	$0.91	$0.00	$0.00	$0.00	$0.00	$0.00
2/19/2004	-19	0	0	0	0	0	$0.91	$0.00	$0.00	$0.00	$0.00	$0.00
4/18/2006	50	5	50	0	0	0	$4.40	$4.45	$4.40	$0.00	$0.00	$0.00
4/18/2006	25	15	0	0	0	0	$4.40	$4.45	$0.00	$0.00	$0.00	$0.00
4/21/2006	10	10	0	0	0	0	$4.70	$4.70	$0.00	$0.00	$0.00	$0.00
6/2/2006	0	15	15	0	0	0	$0.00	$4.00	$4.00	$0.00	$0.00	$0.00
6/12/2006	10	10	0	0	0	0	$4.00	$4.05	$0.00	$0.00	$0.00	$0.00
6/12/2006	10	0	0	0	0	0	$4.10	$0.00	$0.00	$0.00	$0.00	$0.00
6/12/2006	10	0	0	0	0	0	$4.10	$0.00	$0.00	$0.00	$0.00	$0.00
6/14/2006	10	0	0	0	0	0	$4.10	$0.00	$0.00	$0.00	$0.00	$0.00
6/14/2006	10	0	0	0	0	0	$4.10	$0.00	$0.00	$0.00	$0.00	$0.00
6/14/2006	10	0	0	0	0	0	$4.10	$0.00	$0.00	$0.00	$0.00	$0.00
6/15/2006	10	0	0	0	0	0	$4.05	$0.00	$0.00	$0.00	$0.00	$0.00
6/15/2006	10	0	0	0	0	0	$4.05	$0.00	$0.00	$0.00	$0.00	$0.00
6/15/2006	10	0	0	0	0	0	$4.05	$0.00	$0.00	$0.00	$0.00	$0.00
6/15/2006	10	0	0	0	0	0	$4.05	$0.00	$0.00	$0.00	$0.00	$0.00
6/15/2006	20	0	0	0	0	0	$4.05	$0.00	$0.00	$0.00	$0.00	$0.00
6/15/2006	0	10	0	0	0	0	$0.00	$4.05	$0.00	$0.00	$0.00	$0.00
6/15/2006	0	10	0	0	0	0	$0.00	$4.05	$0.00	$0.00	$0.00	$0.00
6/15/2006	0	10	0	0	0	0	$0.00	$4.05	$0.00	$0.00	$0.00	$0.00
6/15/2006	0	10	0	0	0	0	$0.00	$4.05	$0.00	$0.00	$0.00	$0.00
6/16/2006	15	0	10	0	0	0	$4.30	$0.00	$4.30	$0.00	$0.00	$0.00
6/16/2006	15	0	15	0	0	0	$4.30	$0.00	$4.30	$0.00	$0.00	$0.00
6/16/2006	0	0	20	0	0	0	$0.00	$0.00	$4.35	$0.00	$0.00	$0.00
6/23/2006	0	0	5	0	0	0	$0.00	$0.00	$4.55	$0.00	$0.00	$0.00
6/23/2006	0	0	15	0	0	0	$0.00	$0.00	$4.55	$0.00	$0.00	$0.00
6/23/2006	0	0	10	0	0	0	$0.00	$0.00	$4.55	$0.00	$0.00	$0.00
6/23/2006	0	0	10	0	0	0	$0.00	$0.00	$4.55	$0.00	$0.00	$0.00
6/26/2006	0	0	10	0	0	0	$0.00	$0.00	$4.60	$0.00	$0.00	$0.00
6/26/2006	0	0	15	0	0	0	$0.00	$0.00	$4.60	$0.00	$0.00	$0.00
6/26/2006	0	0	15	0	0	0	$0.00	$0.00	$4.60	$0.00	$0.00	$0.00
6/26/2006	0	0	15	0	0	0	$0.00	$0.00	$4.60	$0.00	$0.00	$0.00
6/26/2006	0	0	15	0	0	0	$0.00	$0.00	$4.60	$0.00	$0.00	$0.00
6/26/2006	0	0	15	0	0	0	$0.00	$0.00	$4.60	$0.00	$0.00	$0.00
6/27/2006	0	25	15	0	0	0	$0.00	$4.55	$4.55	$0.00	$0.00	$0.00
6/27/2006	0	0	1	0	0	0	$0.00	$0.00	$4.55	$0.00	$0.00	$0.00
6/27/2006	0	0	10	0	0	0	$0.00	$0.00	$4.55	$0.00	$0.00	$0.00
6/28/2006	0	10	15	0	0	0	$0.00	$4.55	$4.60	$0.00	$0.00	$0.00
6/28/2006	0	10	20	0	0	0	$0.00	$4.55	$4.55	$0.00	$0.00	$0.00
6/28/2006	0	5	15	0	0	0	$0.00	$4.55	$4.55	$0.00	$0.00	$0.00
6/28/2006	0	5	15	0	0	0	$0.00	$4.55	$4.55	$0.00	$0.00	$0.00
7/5/2006	0	10	0	0	0	0	$0.00	$4.55	$0.00	$0.00	$0.00	$0.00
7/5/2006	0	10	0	0	0	0	$0.00	$4.50	$0.00	$0.00	$0.00	$0.00
7/5/2006	0	10	0	0	0	0	$0.00	$4.50	$0.00	$0.00	$0.00	$0.00
7/6/2006	0	10	10	0	0	0	$0.00	$4.50	$4.50	$0.00	$0.00	$0.00
7/6/2006	0	10	10	0	0	0	$0.00	$4.50	$4.50	$0.00	$0.00	$0.00
7/6/2006	0	10	10	0	0	0	$0.00	$4.50	$4.50	$0.00	$0.00	$0.00
7/6/2006	0	10	10	0	0	0	$0.00	$4.50	$4.50	$0.00	$0.00	$0.00
7/6/2006	0	10	0	0	0	0	$0.00	$4.50	$0.00	$0.00	$0.00	$0.00
7/7/2006	0	0	1	0	0	0	$0.00	$0.00	$4.60	$0.00	$0.00	$0.00
7/7/2006	0	15	15	0	0	0	$0.00	$4.50	$4.55	$0.00	$0.00	$0.00
7/7/2006	0	0	15	0	0	0	$0.00	$0.00	$4.50	$0.00	$0.00	$0.00
7/7/2006	0	0	15	0	0	0	$0.00	$0.00	$4.50	$0.00	$0.00	$0.00
7/7/2006	0	0	10	0	0	0	$0.00	$0.00	$4.50	$0.00	$0.00	$0.00
7/10/2006	0	0	10	0	0	0	$0.00	$0.00	$4.50	$0.00	$0.00	$0.00
7/10/2006	0	0	10	0	0	0	$0.00	$0.00	$4.50	$0.00	$0.00	$0.00
7/10/2006	0	0	10	0	0	0	$0.00	$0.00	$4.50	$0.00	$0.00	$0.00
7/10/2006	0	10	0	0	0	0	$0.00	$4.50	$0.00	$0.00	$0.00	$0.00
7/11/2006	0	10	0	0	0	0	$0.00	$4.55	$0.00	$0.00	$0.00	$0.00
7/11/2006	0	10	0	0	0	0	$0.00	$4.55	$0.00	$0.00	$0.00	$0.00
7/13/2006	0	10	3	0	0	0	$0.00	$4.55	$4.55	$0.00	$0.00	$0.00
7/13/2006	0	19	0	0	0	0	$0.00	$4.55	$0.00	$0.00	$0.00	$0.00
7/20/2006	10	0	0	0	0	0	$4.45	$0.00	$0.00	$0.00	$0.00	$0.00

Chicago Climate Exchange Transactions

CCX Trading Activity

sales shown as +ve
purchases shown as -ve

	No. of CFIs sold and vintage						Price per tonne (US$)					
	2003	2004	2005	2006	2007	2008	2003	2004	2005	2006	2007	2008
7/28/2006	15	0	0	0	0	0	$4.45	$0.00	$0.00	$0.00	$0.00	$0.00
7/28/2006	20	0	0	0	0	0	$4.45	$0.00	$0.00	$0.00	$0.00	$0.00
7/28/2006	10	0	0	0	0	0	$4.45	$0.00	$0.00	$0.00	$0.00	$0.00
7/28/2006	20	0	0	0	0	0	$4.50	$0.00	$0.00	$0.00	$0.00	$0.00
7/31/2006	20	0	0	0	0	0	$4.45	$0.00	$0.00	$0.00	$0.00	$0.00
7/31/2006	20	0	0	0	0	0	$4.45	$0.00	$0.00	$0.00	$0.00	$0.00
7/31/2006	20	0	0	0	0	0	$4.45	$0.00	$0.00	$0.00	$0.00	$0.00
7/31/2006	20	0	0	0	0	0	$4.40	$0.00	$0.00	$0.00	$0.00	$0.00
7/31/2006	10	0	0	0	0	0	$4.40	$0.00	$0.00	$0.00	$0.00	$0.00
7/31/2006	10	0	0	0	0	0	$4.40	$0.00	$0.00	$0.00	$0.00	$0.00
7/31/2006	20	0	0	0	0	0	$4.40	$0.00	$0.00	$0.00	$0.00	$0.00
8/1/2006	10	0	0	0	0	0	$4.35	$0.00	$0.00	$0.00	$0.00	$0.00
8/1/2006	8	0	0	0	0	0	$4.35	$0.00	$0.00	$0.00	$0.00	$0.00
8/1/2006	10	0	0	0	0	0	$4.35	$0.00	$0.00	$0.00	$0.00	$0.00
8/30/2007	-10	0	0	0	0	0	$3.15	$0.00	$0.00	$0.00	$0.00	$0.00
8/30/2007	-20	0	0	0	0	0	$3.15	$0.00	$0.00	$0.00	$0.00	$0.00
9/4/2007	-5	0	0	0	0	0	$3.05	$0.00	$0.00	$0.00	$0.00	$0.00
9/4/2007	-5	0	0	0	0	0	$3.05	$0.00	$0.00	$0.00	$0.00	$0.00
9/4/2007	-5	0	0	0	0	0	$3.05	$0.00	$0.00	$0.00	$0.00	$0.00
9/4/2007	-35	0	0	0	0	0	$3.05	$0.00	$0.00	$0.00	$0.00	$0.00
9/4/2007	-5	0	0	0	0	0	$3.05	$0.00	$0.00	$0.00	$0.00	$0.00
9/4/2007	-17	0	0	0	0	0	$3.05	$0.00	$0.00	$0.00	$0.00	$0.00
9/6/2007	0	0	0	45	0	0	$0.00	$0.00	$0.00	$3.05	$0.00	$0.00
9/12/2007	0	0	0	50	0	0	$0.00	$0.00	$0.00	$3.05	$0.00	$0.00
9/26/2007	0	0	0	25	0	0	$0.00	$0.00	$0.00	$3.00	$0.00	$0.00
10/2/2007	0	0	0	50	0	0	$0.00	$0.00	$0.00	$3.00	$0.00	$0.00
10/10/2007	0	0	0	150	0	0	$0.00	$0.00	$0.00	$2.50	$0.00	$0.00
10/12/2007	0	0	0	100	0	0	$0.00	$0.00	$0.00	$2.40	$0.00	$0.00
10/18/2007	0	0	0	100	0	0	$0.00	$0.00	$0.00	$2.25	$0.00	$0.00
10/18/2007	0	0	0	1	0	0	$0.00	$0.00	$0.00	$2.20	$0.00	$0.00
10/19/2007	0	0	0	10	0	0	$0.00	$0.00	$0.00	$2.25	$0.00	$0.00
3/20/2008	0	0	0	0	10	0	$0.00	$0.00	$0.00	$0.00	$5.75	$0.00
3/20/2008	0	0	0	0	10	0	$0.00	$0.00	$0.00	$0.00	$5.75	$0.00
3/20/2008	0	0	0	0	10	0	$0.00	$0.00	$0.00	$0.00	$5.75	$0.00
3/20/2008	0	0	0	0	10	0	$0.00	$0.00	$0.00	$0.00	$5.75	$0.00
3/20/2008	0	0	0	0	5	0	$0.00	$0.00	$0.00	$0.00	$5.75	$0.00
3/20/2008	0	0	0	0	5	0	$0.00	$0.00	$0.00	$0.00	$5.75	$0.00
3/24/2008	0	0	0	0	17	0	$0.00	$0.00	$0.00	$0.00	$5.70	$0.00
4/1/2008	0	0	0	0	25	0	$0.00	$0.00	$0.00	$0.00	$5.65	$0.00
4/9/2008	0	0	0	0	25	0	$0.00	$0.00	$0.00	$0.00	$6.00	$0.00
4/14/2008	0	0	0	0	25	0	$0.00	$0.00	$0.00	$0.00	$6.00	$0.00
4/252008	0	0	0	0	25	0	$0.00	$0.00	$0.00	$0.00	$6.40	$0.00
4/252008	0	0	0	0	15	0	$0.00	$0.00	$0.00	$0.00	$6.30	$0.00
4/252008	0	0	0	0	10	0	$0.00	$0.00	$0.00	$0.00	$6.30	$0.00
5/7/2008	0	0	0	0	20	0	$0.00	$0.00	$0.00	$0.00	$6.45	$0.00
5/16/2008	0	0	0	0	20	0	$0.00	$0.00	$0.00	$0.00	$7.00	$0.00
5/22/2008	0	0	0	0	20	0	$0.00	$0.00	$0.00	$0.00	$7.25	$0.00
5/23/2008	0	0	0	0	25	0	$0.00	$0.00	$0.00	$0.00	$7.30	$0.00
10/26/2009	0	0	0	0	50	0	$0.00	$0.00	$0.00	$0.00	$0.10	$0.00
10/26/2009	0	0	0	0	100	0	$0.00	$0.00	$0.00	$0.00	$0.10	$0.00
10/26/2009	0	0	0	0	50	0	$0.00	$0.00	$0.00	$0.00	$0.10	$0.00
10/27/2009	0	0	0	0	73	0	$0.00	$0.00	$0.00	$0.00	$0.10	$0.00
10/13/2009	0	0	0	0	0	100	$0.00	$0.00	$0.00	$0.00	$0.00	$0.10
10/13/2009	0	0	0	0	0	50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.10
10/13/2009	0	0	0	0	0	100	$0.00	$0.00	$0.00	$0.00	$0.00	$0.10
10/13/2009	0	0	0	0	0	35	$0.00	$0.00	$0.00	$0.00	$0.00	$0.10
10/13/2009	0	0	0	0	0	65	$0.00	$0.00	$0.00	$0.00	$0.00	$0.10
10/26/2009	0	0	0	0	0	100	$0.00	$0.00	$0.00	$0.00	$0.00	$0.10
10/26/2009	0	0	0	0	0	50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.10
10/27/2009	0	0	0	0	0	69	$0.00	$0.00	$0.00	$0.00	$0.00	$0.10

PUB/MH I-98

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9-1 GHG Reductions, CCX Trading**

c) Please summarize the annual net revenue due to trading on CCX .

ANSWER:

Annual net revenue (CAD $) from CCX trading is summarized below. The net revenue reflects the revenue due to the sale of CCX units less the costs of any purchases and fees. The 2003/04 amount reflects CCX units that were purchased in that year and held and sold in later years when they were determined to be surplus.

2003/04	-$27,367
2004/05	0
2005/06	0
2006/07	$595,279
2007/08	$90,538
2008/09	$112,645

<u>PUB/MH I-98</u>

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9-1 GHG Reductions, CCX Trading**

d) Please provide the forecasted CCX revenues for 2009/10, 2010/11 and 2011/12.

<u>ANSWER</u>:

Manitoba Hydro has committed to Phase II of the CCX which ends December 31, 2010. Therefore, revenue from CCX is forecasted for only 2009/10 and 2010/11.

CCX carbon prices dropped dramatically during 2009. Potential reasons for this decrease include the economic downturn and the growing expectation that CCX CFI's are unlikely to be eligible under mandatory GHG systems. Based on median flows, current market and forecast carbon price per tonne on the CCX at US$0.10/tonne, projected annual revenue from CCX is less than $5,000 CAD for both 2009/10 and 2010/11.

PUB/MH I-99

Subject: **Tab 9: Demand Side Management**
Reference: **DSM Federal Government Funding**

Please describe the impact of the Federal Eco- Energy Program and the extent to which it is reflected in the 2009 power Smart Plan via LIEEP, Energy Audits etc.

ANSWER:

Manitoba Hydro integrates the Federal ecoENERGY Program into its overall Power Smart initiative and the influence of the Federal ecoENERGY Program on program participation is fully reflected in the 2009 Power Smart Plan. Program participation for each program was estimated based on a combined and fully integrated basis.

PUB/MH I-100

Subject: **Tab 9: Demand Side Management**
Reference: **DSM Customer Consumption**

a) Please provide schedules of the actual and forecast customer numbers and average consumption by electric Customer Class for the years 2008/09 through 2018/19

ANSWER:

See Appendix 7.1 of this Application. The actual and forecast customers and average consumption for the basic Residential rate is provided in the Electric Load Forecast, Table 6, page 18 and the General Service is available in Table 8, page 27.

PUB/MH I-100

Subject: **Tab 9: Demand Side Management**
Reference: **DSM Customer Consumption**

b) Please provide a breakdown of the DSM savings [GWh,MW,GHG] from each of the customer rate classes in a. for Residential, Commercial, and Industrial customer groups.

ANSWER:

The following tables provide a breakdown of forecast incentive-based savings from the 2009 Power Smart Plan into customer rate classes. Energy and demand savings are at meter.

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	77	160	232	247	262	226	188	155	158	158
GS Small (Non-Demand)	20	40	55	68	80	89	97	107	116	125
GS Small (Demand)	17	37	51	65	76	86	96	108	119	130
GS Medium	37	64	86	110	130	147	150	168	184	200
GS Large <30 kV	25	38	51	67	81	93	91	102	112	122
GS Large 30-100 kV	5	7	9	11	13	15	13	15	16	17
GS Large >100 kV	37	44	53	69	83	92	71	78	84	89
Total	**217**	**389**	**536**	**636**	**725**	**747**	**707**	**732**	**789**	**841**

MW 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	15	35	53	59	62	54	47	38	39	38
GS Small (Non-Demand)	4	9	12	16	19	21	24	26	28	30
GS Small (Demand)	3	8	12	15	18	20	24	26	29	31
GS Medium	7	14	20	26	31	35	37	41	45	48
GS Large <30 kV	5	8	12	16	19	22	23	25	27	29
GS Large 30-100 kV	19	19	20	20	21	21	21	21	21	22
GS Large >100 kV	166	169	171	176	179	181	177	178	180	181
Total	**218**	**262**	**299**	**328**	**349**	**354**	**352**	**356**	**369**	**379**

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	74	155	230	251	273	245	218	185	192	195
GS Small (Non-Demand)	19	39	54	69	83	96	113	128	141	154
GS Small (Demand)	16	36	51	66	79	94	112	129	145	160
GS Medium	35	62	85	112	135	159	174	201	223	247
GS Large <30 kV	24	37	50	68	85	101	106	122	136	150
GS Large 30-100 kV	5	7	9	11	14	16	16	18	19	20
GS Large >100 kV	36	43	53	70	86	100	82	93	102	110
Total	**210**	**379**	**531**	**647**	**756**	**811**	**820**	**876**	**957**	**1,038**

NOTE: GS = General Service

<u>PUB/MH I-101</u>

Subject: **Tab 9: Demand Side Management**
Reference: **Tab 9 Page 2 of 5**

The application states that the energy savings realized during 2008/09 is currently being evaluated with the report expected to be finalized in late 2009. Please file the 2008/09 Annual Power Smart Review.

<u>ANSWER</u>:

Please see Appendix 40.

PUB/MH I-102

Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9 -1 Pages 3 & 4, Power Smart Plan electric DSM Target Differences/Utility Cost**

a) Please provide a table with the corresponding data points in support of the graphs.

ANSWER:

Forecast Winter Capacity Savings (MW @ Generation)			Forecast Electric Energy Savings (GW.h @ Generation)			Forecast DSM Utility Costs (thousands)		
	2009 LRP *Data Points*	**2008 LRP** *Data Points*		**2009 LRP** *Data Points*	**2008 LRP** *Data Points*		**2009 LRP** *Data Points*	**2008 LRP** *Data Points*
2009	253	225	2009	311	166	2009	$ 316,104	$ 328,564
2010	313	264	2010	561	330	2010	$ 359,093	$ 361,901
2011	367	301	2011	787	494	2011	$ 401,588	$ 393,713
2012	411	337	2012	959	655	2012	$ 439,944	$ 423,160
2013	446	366	2013	1120	778	2013	$ 473,856	$ 449,180
2014	463	394	2014	1202	897	2014	$ 503,761	$ 475,782
2015	471	421	2015	1216	1005	2015	$ 532,739	$ 501,193
2016	487	448	2016	1298	1115	2016	$ 559,794	$ 526,402
2017	512	475	2017	1418	1235	2017	$ 585,360	$ 551,183
2018	534	499	2018	1537	1325	2018	$ 610,446	$ 571,523
2019	554	522	2019	1636	1405	2019	$ 632,271	$ 587,212
2020	574	544	2020	1732	1484	2020	$ 653,836	$ 602,650
2021	594	565	2021	1829	1563	2021	$ 675,328	$ 618,004
2022	612	586	2022	1912	1640	2022	$ 696,768	$ 633,250
2023	630	605	2023	1997	1696	2023	$ 717,327	$ 648,219
2024	644	-	2024	2053	-	2024	$ 733,329	$ -

PUB/MH I-102

Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9 -1 Pages 3 & 4, Power Smart Plan electric DSM Target Differences/Utility Cost**

b) Please explain the change in winter capacity savings from 2008 to 2009.

ANSWER:

Winter capacity savings are expected to increase from those outlined in the 2008 Power Smart Plan due to the addition of new programs and adjustments to existing and future programs based on updated market information. New programs added to the 2009 Power Smart Plan include Solar Water Heating, Fridge Recycling and Emergency Preparedness. Adjustments were made to a number of programs that increased the winter capacity savings including Compact Fluorescent Lighting, Water and Energy Saver, Lower Income Energy Efficiency, Commercial Lighting and Commercial Rinse and Save.

PUB/MH I-103

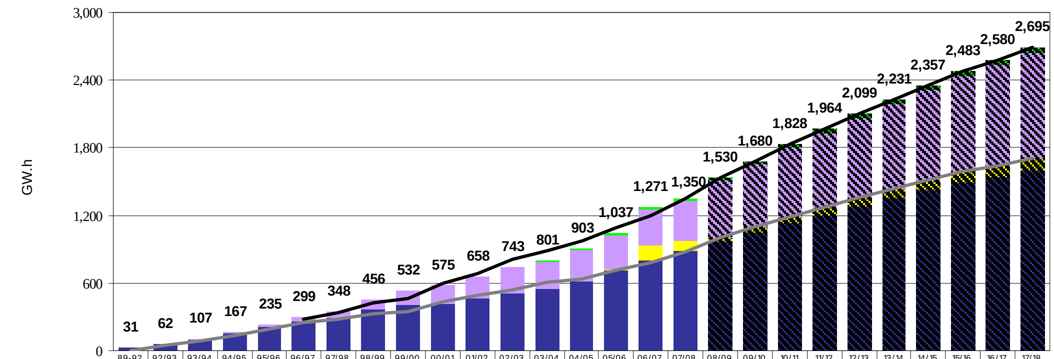
Subject: Tab 9: Demand Side Management

Reference: Tab 9 figures 9.3.1, 9.3.2, Appendix 9.1 Pages 29-30

a) **Please re-file the graphs with forecasted detail of the components of total savings at generation energy and demand savings plan for the years 2008/09 through 2017/18.**

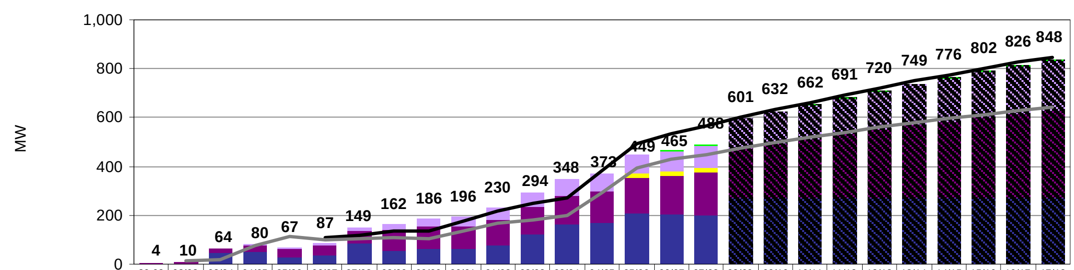
ANSWER:

Exhibit 4.4.2-C
Electric Energy Savings - Power Smart Portfolio
Total Savings Achieved vs. Plan
at generation



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Customer Service Initiatives											2	4	7	11	13	16	20	17	24	27	31	34	38	41	43	47	49
Codes and Standards	-	2	8	16	25	40	63	93	125	156	189	228	248	274	298	323	352	510	560	611	660	708	756	803	851	897	943
Incentive-based - Customer Self Gen															11	132	93	30	43	55	65	71	78	83	88	93	99
Incentive-based - Efficiency	31	59	99	151	209	259	285	363	407	419	467	511	546	619	714	800	886	973	1,054	1,135	1,209	1,286	1,360	1,429	1,500	1,543	1,605
Total Achieved	31	62	107	167	235	299	348	456	532	575	658	743	801	903	1,037	1,271	1,350	1,530	1,680	1,828	1,964	2,099	2,231	2,357	2,483	2,580	2,695
Plan (incentive-based programs only)	-	50	86	138	195	252	279	327	350	435	491	544	603	634	713	782	879	1,002	1,098	1,191	1,274	1,358	1,438	1,514	1,590	1,638	1,705
Plan						281	336	422	466	602	686	810	891	970	1,088	1,199	1,350	1,530	1,680	1,828	1,964	2,099	2,231	2,357	2,483	2,580	2,695

Exhibit 4.4.2-D
Average Winter Demand Savings - Power Smart Portfolio
Total Savings Achieved vs. Plan
at generation



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Customer Service Initiatives											1	1	2	3	3	4	6	1	2	2	2	3	3	3	3	3	3
Codes and Standards	-	1	2	4	6	10	15	23	32	40	49	59	64	70	76	82	89	122	130	141	149	158	167	177	186	194	203
Incentive-based - Customer Self Gen															16	16	16										
Incentive-based - Efficiency	4	10	17	26	34	41	46	86	91	93	105	113	119	131	146	161	179	204	225	243	263	280	300	316	332	347	359
Incentive-based - Rate/Load	-	-	45	51	27	36	88	53	64	63	75	121	163	169	208	202	199	270	270	270	270	270	270	270	270	270	270
Total Achieved	4	10	64	80	67	87	149	162	186	196	230	294	348	373	449	465	488	601	632	662	691	720	749	776	802	826	848
Plan (incentive-based programs only)		12	18	75	114	101	104	110	105	136	166	183	200	296	394	429	449	477	499	520	539	559	579	596	613	628	641
Plan						108	118	134	135	178	216	249	273	385	491	535	564	601	632	662	691	720	749	776	802	826	848

PUB/MH I-103

Subject: **Tab 9: Demand Side Management**
Reference: **Tab 9 figures 9.3.1, 9.3.2, Appendix 9.1 Pages 29-30**

b) Please describe how Electric Demand Savings and Average Winter Demand Savings due to Codes and Standards were determined. Provide illustrative calculations for the levels of saving in 2007/08 and 2008/09.

ANSWER:

The determination of energy savings due to Codes and Standards is similar to the methodology used for other Power Smart programs. Energy savings are calculated by determining the energy consumption difference between the inefficient technology and the efficient technology.

The following steps are taken when estimating the impact of codes and standards:

1. Estimate energy savings associated with new codes and standards:

    a. Determine current baseline energy usage associated with the technology.
    b. Determine energy usage of the technology once code is enacted.
    c. Determine per unit energy savings ((a)-(b): baseline minus post-code enactment usage).
    d. Determine number of technologies installed during evaluation period.
    e. Multiply (d) number of technologies by (c) per unit energy impact = annual energy savings associated with the code.
    f. Continue savings for the life of the product.

2. Codes and Standards are evaluated, based on the methodology above, annually in the Power Smart Annual review.

PUB/MH I-104

Subject: Tab 9: Demand Side Management
Reference: Appendix 9-1 2009 Power Smart Plan page 10

Please provide a Tabular comparison of MH's DSM spending efforts with other Canadian utilities [B.C/ Sask/Ont/Qc] with respect to:

- **% of annual domestic rates revenue.**
- **% of annual domestic energy (GWh)**
- **% of domestic System Demand (MW)**

If discrete funding is identified by other utilities for low income DSM programming, please compare MH's funding to that of other Canadian utilities.

ANSWER:

The following table outlines the 2009/10 planned electric DSM expenditures as a percent of various factors:

	Manitoba Hydro	**BC Hydro**	**Ontario Power Authority**	**Hydro Quebec**	**SaskPower***
Spending as % of Annual Domestic Rates Revenue	**3.5%**	**4.2%**	Not available	**2.4%**	Not available
Spending as % of Annual Domestic Energy (GW.h)	**0.2%**	**0.2%**	**0.1%**	**0.1%**	Not available
Spending as % of Domestic System Demand (MW)	**0.9%**	**1.2%**	**0.6%**	**0.7%**	Not available
Planned Low Income Budget	**$3.9 million**	**$ 6.0 million**	Not available	**$9.8 million**	Not available

*Note: SaskPower does not have an approved DSM plan at this time.

PUB/MH I-105

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 2009 Power Smart Plan Page 20, Codes & Standards**

a) **Please describe any actual and impending changes that may be made in the national or provincial building codes related to improving energy & demand efficiency that have occurred since 2007.**

ANSWER:

i. National:

In July 2008, the Council of the Federation committed to the following:

- Enhance the Model National Energy Code for Buildings by 25% by 2011
- Add energy efficiency as the fifth core objective into the National Building Code of Canada

Work is currently underway on an updated version of the Model National Energy Code, which is expected to be complete by 2011.

ii. Provincial:

In 2008, the Building Standards Board of Manitoba (BSB) formed two sub-committees to develop recommendations for incorporating measures related to energy and water efficiency into the Part 3 (Commercial) and Part 9 (Residential) Manitoba Building Code (MBC).

As a result of the committees' work, water efficiency and energy efficiency have now been added as core objectives to the MBC. In addition, specific water efficiency recommendations have been presented and passed by the BSB for both Part 3 and Part 9 building construction. Energy efficiency recommendations have been presented and passed by the BSB for Part 9 building construction and are expected to be presented in Spring 2010 for Part 3 building construction.

All recommendations currently passed by the BSB have been submitted for review by the Minister of Labour.

PUB/MH I-105

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 2009 Power Smart Plan Page 20, Codes & Standards**

b) To what extent has the changes in Codes and Standards described in (a) and have been factored into the 2009 Power Smart Plan.

ANSWER:

The changes to the Manitoba Building Code could affect two programs within Manitoba Hydro's Power Smart portfolio; the Power Smart New Homes Program and the Commercial New Buildings Program. At the time of the development of the 2009 Power Smart Plan, there were no details about the levels of efficiency that would be proposed and therefore, code changes would not have been factored into the planning process for those two programs.

PUB/MH I-105

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 2009 Power Smart Plan Page 20, Codes & Standards**

c) Please list the details of the Power Smart natural gas, electric and geothermal home standards.

ANSWER:

Please see the following tables which outline the details of the Power Smart New Home Program for gas, electric and geothermal heated homes.

Power Smart New Home - Natural Gas		
	Required	Optional
R-50 attic insulation with raised heel truss	*	
R-24 foundation insulation	*	
Air tightness 1.5 Air Exchanges/hour (ACH)	*	
Heat Recovery Ventilation System (HRV)	*	
Low flow shower head (2.5 GPM)	*	
Hot water tank - min. 2" insulation	*	
Permanently wired car plug timer	*	
Energy Efficient lighting in living room, kitchen and one other area		or select one from option A
Gas fireplace with electronic ignition		or select one from option B
Option A		
Electronically commuted motor (ECM)		
Upgrade HRV efficiency		
Option B		
Electronically commuted motor (ECM)		
Upgrade HRV efficiency		
Energy Efficient lighting in every room of the home		

Power Smart New Home - Electric GOLD		
	Required	Optional
R-50 attic insulation with raised heel truss	*	
R-26 above grade exterior wall insulation	*	
R-24 foundation insulation	*	
Heat Recovery Ventilation System (HRV)	*	
Air tightness 1.5 Air Exchanges/hour (ACH)	*	
Low flow shower head (2.5 GPM)	*	
Hot water tank - min. 2" insulation	*	
Permanently wired car plug timer	*	
Energy Star® programmable thermostat	*	
Energy Efficient lighting in living room, kitchen and one other area	Preferred	or select one from option A
Gas fireplace with electronic ignition	Preferred	or select one from option B
Option A		
ECM motor		
Upgrade HRV efficiency		
Option B		
ECM motor		
Upgrade HRV efficiency		
Energy Efficient lighting in every room of the home		

Power Smart New Home - Geothermal GOLD		
	Required	Optional
R-50 attic insulation with raised heel truss	*	
R-24 foundation insulation	*	
Air tightness 1.5 Air Exchanges/hour (ACH)	*	
Heat Recovery Ventilation System (HRV)	*	
Geothermal heat pump system must meet CSA standard C-448.2	*	
Low flow shower head (2.5 GPM)	*	
Hot water tank - min. 2" insulation	*	
Permanently wired car plug timer	*	
Energy Efficient lighting in living room, kitchen and one other area	Preferred	or select one from option A
Gas fireplace with electronic ignition	Preferred	or select one from option B
Option A		
Electronically commuted motor (ECM)		
Upgrade HRV efficiency		
Option B		
Electronically commuted motor (ECM)		
Upgrade HRV efficiency		
Energy Efficient lighting in every room of the home		

PUB/MH I-106

Subject: Tab 9: Demand Side Management
Reference: Appendix 9.1 Page 28 Brand Awareness

Please file a copy of the January 2009 survey which supports the views expressed on the Power Smart Brand.

ANSWER:

Power Smart brand awareness and perception data was based on a series of questions fielded by telephone to 500 randomly selected Manitoba households during January 2009. Percentages quoted refer to the percent who reported a 7 or higher on a 10-point scale where 1 is strongly disagree and 10 is strongly agree.

Statement 1: *94% of all Manitoba Hydro customers are aware of the Manitoba Hydro Power Smart brand.* This is determined by adding the percentage of respondents who answered "Power Smart" to question 1 below (25.6%) and the percentage of respondents who answered "yes" to question 1(b) below (68.1%).

Statement 2: *88% of all Manitoba Hydro customers believe Power Smart encourages or strongly encourages energy efficiency*. This is determined by adding the percentage of respondents that reported a score of 7 to 10 in question 2 (a) below.

Statement 3: *77% of all Manitoba Hydro customers agree or strongly agree Power Smart helps customer save money on their energy bills*. This is determined by adding the percentage of respondents that reported a score of 7 to 10 in question 2 (b) below.

Statement 4: *79% of all Manitoba Hydro customers agree or strongly agree Power Smart programs help conserve the environment.* This is determined by adding the percentage of respondents that reported a score of 7 to 10 in question 2 (c) below.

Statement 5: *73% of all Manitoba Hydro customers agree or strongly agree Power Smart programs mean there will be electricity available for Manitobans in the future*. This is determined by adding the percentage of respondents that reported a score of 7 to 10 in question 2 (d) below.

Survey questions and responses:

Question 1. Some companies use phrases or names to describe a particular program or service to its customers. Do you recall the name Manitoba Hydro uses to promote its ENERGY EFFICIENCY programs and services? (PROMPT: What is it? -- DO NOT READ CATEGORIES)

Power Smart	**25.6%**	=> go to question 2
Other (Incorrect)	5.6%	
Don't Know	65.8%	
No Response	3.0%	

Question 1(b). Have you heard of the brand name Power Smart?

Yes	**68.1%**	
No	5.8%	=> Go to end
Don't Know	0.4%	=> Go to end
No Response	-	=> Go to end

Question 2. Now I will read a few statements about Power Smart to you. Using a scale of 1 to 10 where 1 is strongly disagree and 10 is strongly agree, please indicate to what extent you agree or disagree with each statement.

	Strongly Disagree 01	02	03	04	05	06	07	08	09	Strongly Agree 10	Do Not Know	Refuse
a. Power Smart programs encourage customers to be more energy efficient. *	1%	1%	-	1%	4%	4%	**11%**	**28%**	**16%**	**32%**	2%	-
b. Power Smart programs help customers save money on their energy bills.	2%	1%	1%	2%	6%	7%	**12%**	**22%**	**15%**	**28%**	5%	-
c. Power Smart programs help conserve the environment. (**IF NECESSARY, SAY** "To help reduce the impact on the environment.")	2%	1%	1%	-	5%	9%	**15%**	**22%**	**12%**	**30%**	2%	-
d. Power Smart programs mean there will be electricity available for Manitobans in the future.	1%	3%	1%	2%	12%	7%	**13%**	**24%**	**12%**	**24%**	2%	-

* The percentage rating this statement a 7 or higher does not add to 88% as reported in Appendix 9.1, page 28 due to rounding error.

PUB/MH I-107

Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9.1 2009 Power Smart Plan Pages 39-41 Section 6.1.2. Power Smart Residential –Targets**

a) Please file a schedule that compares the Residential Incentive Based Programs, the Energy and Demand Savings (2023/24), Cumulative Utility Costs ($2009) and annual C02 Reductions for comparative periods with the 2008 Power Smart Plan and explain any material differences.

ANSWER:

The table below provides a comparison of the 2008 and 2009 Power Smart Plans for 2008/09 to 2023/24. The actual savings and expenditures for 2008/09 were included in the 2009 Power Smart Plan totals to allow a comparison of the same timeframe.

RESIDENTIAL Incentive Based	*2009 Power Smart Plan*				*2008 Power Smart Plan*				*Difference*			
	Energy Savings - GW.h @ meter	Demand Savings - MW @ meter	Annual CO2 Reductions (tonnes)	Cumulative Utility Costs (thousands) $2009	Energy Savings - GW.h @ meter	Demand Savings - MW @ meter	Annual CO2 Reductions (tonnes)	Cumulative Utility Costs (thousands) $2009	Energy Savings - GW.h @ meter	Demand Savings - MW @ meter	Annual CO2 Reductions (tonnes)	Cumulative Utility Costs (thousands) $2009
	2023/24	2023/24	2023/24	2023/24	2023/24	2023/24	2023/24	2023/24	2023/24	2023/24	2023/24	2023/24
New Home Program	24.4	4.4	18,160	$ 2,434	24.7	4.4	19,007	$ 2,865	(0.3)	0.0	(846)	$ (431)
Home Insulation Program	31.2	15.2	19,699	$ 10,785	34.1	16.5	26,240	$ 13,193	(2.9)	(1.3)	(6,541)	$ (2,408)
Water and Energy Saver Program	27.8	4.5	21,392	$ 4,368	14.4	1.1	11,081	$ 1,715	13.4	3.4	10,311	$ 2,653
Residential CFL Program	0	0	-	$ 6,296	0	0	0	$ 2,859	0.0	0.0	0	$ 3,437
Residential Appliance Program	8.5	1.3	3,078	$ 2,088	6.1	1.1	4,694	$ 2,264	2.4	0.2	(1,616)	$ (176)
Lower Income Energy Efficiency Program	11.9	3.1	8,772	$ 2,568	4.9	2.3	3,771	$ 975	7.0	0.8	5,002	$ 1,593
EE Light Fixtures	0.9	0.2	616	$ 1,864	9.1	1.8	7,002	$ 3,182	(8.2)	(1.6)	(6,387)	$ (1,319)
Residential HE Furnace & Boiler Program	0.6	0.2	462	$ -	0	0	0	$ -	0.6	0.2	462	$ -
Fridge Recycling Program	15.2	1.3	11,696	$ 10,068	0	0	0	$ -	15.2	1.3	11,696	$ 10,068
Seasonal LED	0.8	0	-	$ 346	1.8	0.1	1,385	$ 2,301	(1.0)	(0.1)	(1,385)	$ (1,955)
TOTAL	***121.3***	***30.2***	***83,876***	***$ 40,816***	***95.1***	***27.3***	***73,179***	***$ 29,355***	***26.2***	***2.9***	***10,696***	***$ 11,461***

Home Insulation Program - The 2009 Plan reflects a reduction in both energy savings and costs compared to the 2008 Plan as a result of lower expected participation estimates.

Water and Energy Saver Program - The 2009 Plan reflects increased energy savings and costs compared to the 2008 Plan as a result of changes to the proposed program design. The program design submitted for the 2008 Plan consisted of mail-out water saver kits to residential customers. The program design submitted for the 2009 Plan consists of a combined approach that incorporated mail-out kits and direct installation of kits in a customer's home. This approach, although being more costly to implement, is expected to result in higher energy savings as a result of a much higher likelihood that the water saving devices will be installed in residences.

Residential CFL Program - The 2008 Plan contained a program design that incorporated mail-in rebates. For the 2009 Plan the program delivery model was changed to a point-of-purchase instant rebate which effectively tripled participation. The resulting energy savings are not reflected in the milestone year of 2023/24 as the product life is only 4.5 years and the program is scheduled to end in 2011/12 due to pending federal lighting efficiency regulation scheduled to take effect in 2012. The energy savings at the scheduled end date of the program in 2011/12 are 131 GW.h in the 2009 Plan as compared to 40 GW.h in the 2008 Plan.

Lower Income Energy Efficiency Program - The 2009 Plan includes an updated plan for achieving energy savings in the Lower Income market. Both expected energy savings and utility costs increased over the 2008 Plan to reflect increased program efforts and resulting energy savings.

EE Light Fixtures - The 2008 Plan energy savings were calculated based on a product life of 20 years. The 2009 Plan energy savings were modified to reflect a product life of 8 years, as it was recognized that the energy savings for fixtures are a result of the bulbs that are used and energy savings could not be claimed past the year 2012 when lighting efficiency regulations are expected to take effect. Utility costs budgeted in the 2009 Plan were reduced as compared to the 2008 Plan to reflect lower expected program spending.

Fridge Recycling Program - There was no formal program design submitted for a Refrigerator Recycling Program in the 2008 Plan.

PUB/MH I-107

Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9.1 2009 Power Smart Plan Pages 39-41 Section 6.1.2. Power Smart Residential –Targets**

b) Please provide a similar comparison and analysis as in part b) for comparative periods with the 2006 Power Smart Plan filed at the last MH GRA.

ANSWER:

The table below provides a comparison of the 2006 and 2009 Power Smart Plans for 2006/07 to 2017/18. The actual savings and expenditures for 2006/07 to 2008/09 were included in the 2009 Power Smart Plan totals to allow a comparison of the same timeframe.

RESIDENTIAL Incentive Based	*2009 Power Smart Plan*				*2006 Power Smart Plan*				*Difference*			
	Energy Savings - GW.h @ meter	Demand Savings - MW @ meter	Annual CO2 Reductions (tonnes)	Cumulative Utility Costs (thousands) $2009	Energy Savings - GW.h @ meter	Demand Savings - MW @ meter	Annual CO2 Reductions (tonnes)	Cumulative Utility Costs (thousands) $2009	Energy Savings - GW.h @ meter	Demand Savings - MW @ meter	Annual CO2 Reductions (tonnes)	Cumulative Utility Costs (thousands) $2009
	2017/18	2017/18	2017/18	2017/18	2017/18	2017/18	2017/18	2017/18	2017/18	2017/18	2017/18	2017/18
New Home Program	26.62	4.96	20,484	$ 3,931	46.66	10.79	35,905	$ 13,543	(20.0)	(5.8)	(15420.8)	$ (9,612)
Home Insulation Program	43.4	21.13	33,396	$ 14,240	21.08	10.28	16,221	$ 10,474	22.3	10.9	17175.2	$ 3,766
Water and Energy Saver Program	27.8	4.5	21,392	$ 5,307	1.70	0.25	1,308	$ 775	26.1	4.3	20084.0	$ 4,532
Residential CFL Program	0	0	-	$ 9,086	76.27	15.31	58,690	$ 4,095	(76.3)	(15.3)	(58689.8)	$ 4,991
Residential Appliance Program	14.63	2.08	11,258	$ 3,799	19.14	2.57	14,728	$ 5,841	(4.5)	(0.5)	(3470.4)	$ (2,042)
Lower Income Energy Efficiency Program	14.8	3.4	11,389	$ 3,068	10.19	6.22	7,841	$ 6,760	4.6	(2.8)	3547.4	$ (3,692)
EE Light Fixtures	3.7	0.74	2,847	$ 1,864	0.00	0.00	-	$ 437	3.7	0.7	2847.2	$ 1,426
Residential HE Furnace & Boiler Program	0.6	0.2	462	$ -	0.00	0.00	-	$ -	0.6	0.2	461.7	$ -
Fridge Recycling Program	37.9	3.3	29,164	$ 10,162	11.27	1.14	8,672	$ 3,839	26.6	2.2	20491.8	$ 6,323
Seasonal LED	3.07	0.06	2,362	$ 1,102	5.18	0.25	3,986	$ 908	(2.1)	(0.2)	(1623.6)	$ 194
Residential Geothermal (Incentive)	0	0	-	$ -	7.14	2.86	5,494	$ 6,920	(7.1)	(2.9)	(5494.2)	$ (6,920)
Res Thermostat	0.33	0	254	$ 105	8.32	2.60	6,402	$ 4,164	(8.0)	(2.6)	(6148.3)	$ (4,059)
ECM	0	0	-	$ -	2.16	0.43	1,662	$ 1,541	(2.2)	(0.4)	(1662.1)	$ (1,541)
TOTAL	***172.9***	***40.4***	***133,008***	***$ 52,665***	***209.11***	***52.7***	***160,910***	***$ 59,298***	***(36.3)***	***(12.3)***	***(27,902)***	***$ (6,633)***

New Homes Program - The 2009 Plan reflects a decrease in both energy savings and costs compared to the 2006 Plan as a result of a decrease in forecasted participants and a decrease in savings per home as a result of a Manitoba Building Code amendment requiring increased basement insulation levels.

Home Insulation Program - The increase in energy savings and costs for the 2009 Plan resulted from a large increase in projected participants which reflected experience gained running the program.

Water and Energy Saver Program - The 2009 Plan reflects increased expected energy savings and costs compared to the 2006 plan as a result of changes to the proposed program design.

Residential CFL Program - For the 2009 Plan the program delivery model was changed to a point-of-purchase instant rebate, which effectively tripled participation and increased incentive costs. The resulting energy savings are not reflected in the year of 2017/18 as the product life is only 4.5 years and the program is scheduled to end in 2011/12 due to pending federal lighting efficiency regulation scheduled to take effect in 2012. The energy savings at the scheduled end date of the program in 2011/12 are 131 GW.h in the 2009 Plan compared to 42 GW.h in the 2006 Plan.

Lower Income Energy Efficiency Program - The 2006 Plan included a preliminary plan for a future Lower Income program. The 2009 Plan reflects a complete revision to the preliminary plan with higher expected energy savings and program costs.

Fridge Recycling Program - The Refrigerator Recycling Program underwent a redesign between the time that the 2006 and the 2009 Plans were developed. The proposed new program delivery approach reaches a much larger target market, resulting in increased expected participation, energy savings and costs.

Residential Geothermal Program - An incentive based concept for residential geothermal was contemplated for the 2006 Plan but not implemented.

Residential Thermostat Program - The Thermostat Program submitted for the 2006 Plan was based on a program term of ten years. The numbers reported in the 2009 Plan are the results from a reduced, two-year program ending in 2008, thus resulting in lower energy savings and costs.

PUB/MH I-107

Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9.1 2009 Power Smart Plan Pages 39-41 Section 6.1.2. Power Smart Residential –Targets**

c) **Please provide the supporting data points in a table for the DSM Savings as a % of Forecast Growth Graph [page 40].**

ANSWER:

III. Forecast Cummulative DSM Savings	II. Forecast Energy Demand Growth	V. % of Energy Demand Growth
89	91	98%
186	177	105%
268	263	102%
286	347	82%
302	430	70%
259	511	51%
214	591	36%
176	673	26%
180	756	24%
180	839	21%
179	922	19%
179	1,006	18%
180	1,091	16%
167	1,176	14%
154	1,262	12%
139	1,348	10%

PUB/MH I-108

Subject: Tab 9: Demand Side Management

Reference: Appendix 9.1, 2009 Power Smart Plan Overall Cost Effectiveness

a) Please provide a table with the comparable measures of TRC, RIM, LUC, from the 2008 Power Smart Plan by each Electric DSM program and compare with the current targets. Please explain any differences

ANSWER:

The following table provides a comparison of the 2008 and 2009 Power Smart Plan metrics.

	2009 Plan TRC	*2008 Plan TRC*	*2009 Plan RIM*	*2008 Plan RIM*	*2009 Plan LUC (¢/kW.h)*	*2008 Plan LUC (¢/kW.h)*
RESIDENTIAL						
New Home Program	1.9	1.7	1.4	1.2	0.6	0.9
Home Insulation Program	4.4	3.9	1.6	1.5	2.2	2.3
Water and Energy Saver Program	9.6	9.4	1.1	1.0	1.3	0.8
Residential CFL Program	15.3	5.4	1.3	1.2	0.8	1.2
Residential Appliance Program	4.0	1.1	1.2	0.9	0.7	3.1
Lower Income Energy Efficiency Program*	1.9	1.2	1.0	0.7	3.7	9.7
Residential SLED Program	n/a	3.9	n/a	0.8	n/a	2.0
EE Light Fixtures	1.8	2.9	0.7	1.0	5.3	2.5
HE Furnace & Boiler Program (ECM motors)	0.8	n/a	1.9	n/a	0.0	n/a
Fridge Recycling Program	1.6	n/a	0.8	n/a	2.5	n/a
COMMERCIAL						
Commercial Lighting Program	2.5	3.3	1.4	1.4	1.7	1.8
Commercial Custom Measures Program	2.5	1.5	1.2	1.1	2.5	2.8
Commercial Windows Program	2.3	3.6	1.2	1.5	4.5	2.3
Commercial HVAC Program - Chiller	1.7	3.2	1.1	1.1	1.0	1.5
Commercial Parking Lot Controller Program	3.7	3.3	1.7	1.5	0.5	0.4
City of Winnipeg Power Smart Agreement	8.2	6.5	1.5	1.5	1.1	0.6
Commercial Rinse & Save Program	62.6	16.6	1.4	1.1	0.3	0.3
Commercial Refrigeration Program	5.8	4.1	1.4	1.2	0.6	1.4
Commercial Insulation Program	3.2	2.1	1.6	1.2	2.5	1.6
Commercial Earth Power Program	2.7	2.9	1.6	1.7	2.3	1.9
Commercial New Construction Program	1.5	1.5	1.1	1.1	3.2	3.0
Commercial Building Optimization Program	5.0	4.8	1.7	1.7	1.4	1.3
Internal Retrofit Program	1.1	3.2	1.1	3.2	2.2	2.9
Agricultural Heat Pad Program	143.9	9.0	1.8	1.8	0.2	0.2
Power Smart Energy Manager Program	3.1	2.4	1.5	1.7	0.6	0.4
Commercial Kitchen Appliance Program	3.5	1.8	1.3	1.2	2.6	3.3
Commercial Clothes Washers Program	2.0	1.4	1.6	1.6	3.1	3.4
Network Energy Management Program	3.5	2.9	1.1	1.1	1.4	0.7
Power Smart Shops	1.9	1.6	1.0	1.0	2.1	1.9
CO2 Sensors	4.9	n/a	1.4	n/a	0.7	n/a
INDUSTRIAL						
Performance Optimization Program	3.8	3.4	1.4	1.4	1.6	1.1
Emergency Preparedness Program	2.4	n/a	1.1	n/a	6.3	n/a
CUSTOMER SELF-GENERATION						
Bioenergy Optimization Program	1.6	3.4	1.3	1.3	1.6	1.3
TOTAL	***2.6***	***2.8***	***1.3***	***1.4***	***1.7***	***1.6***

* Includes funds from AEF

Residential CFL Program - The 2008 Plan was based on a program delivery model of mail-in coupons. The 2009 Plan is based on point-of-sale rebates which have resulted in increased participation and a reduction in costs associated with eliminating rebate paperwork. The increased participation and associated energy savings result in a higher TRC. The reduction in administrative costs results in a higher RIM and lower LUC.

Residential Appliance Program - The 2009 Plan includes energy savings associated with the market transformation effects of the incentive-based program that ended on March 31, 2009. Incentives and application processing costs are not included in this plan and these reduced costs result in a higher TRC and RIM calculation, and a lower LUC than the previous plan.

Lower Income Energy Efficiency Program - The 2009 Plan includes revisions to the program design included with the 2008 Plan. The revised design and estimated outcomes include higher energy savings estimates which results in a higher TRC and RIM and a lower LUC.

Energy Efficient Light Fixtures - The 2008 Plan included energy savings for the estimated 20-year life of an energy efficient light fixture. In the 2009 Plan, energy savings were expected for only 8 years to reflect energy efficient lighting regulations scheduled to take effect in 2012. The reduction in energy savings resulted in a lower TRC and RIM, and a higher LUC.

Commercial Windows Program - The TRC decrease in the 2009 Plan is attributed to an increase in program administrative costs. The LUC increase is attributed to an increase in the administrative costs.

Commercial HVAC Program (Chiller) - The TRC decrease in the 2009 Plan is due to an increase in the incremental cost (cost per ton of chiller capacity) and a decrease in demand savings per ton of chiller capacity. The incremental cost was increased based on actual customer invoice costs. The LUC decreased due to a reduction in the incentives paid per ton.

Commercial Rinse & Save Program - The 2009 Plan included water savings benefits which resulted in a higher TRC. Water saving benefits were not included in the 2008 plan.

Commercial Refrigeration Program - The TRC increase in the 2009 Plan is due to an increase in the number of expected participants and an increase in energy savings per participant. The LUC has decreased due to an increase in the number of expected participants and an increase in energy savings per participant.

Commercial Insulation Program - The TRC increase in the 2009 Plan is attributed to a decrease in the incremental product cost. The LUC increase is attributed to a decrease in expected energy savings.

Internal Retrofit Program - The TRC and RIM decreased in the 2009 Plan due to an increase in the incentives for the Downtown Office Project. Additionally, the number of projects were reduced in the 2009 Plan which reduced expected energy savings.

Agricultural Heat Pad Program - The TRC increase in the 2009 Plan is due to a reduction in the price of heat pads as a result of the recent downturn in the hog industry.

Commercial Kitchen Appliance Program - The 2009 Plan included water savings benefits which resulted in a higher TRC. Water saving benefits were not included in the 2008 Plan.

Network Energy Management Program - The TRC in the 2009 Plan increased due to an increase in planned participation and a decrease in the incremental product cost. The incremental product cost decreased due to additional software being added to the eligible products with significantly lower cost than the other available software programs. The LUC increased due to increased administration costs related to increased participation.

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Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9.1, 2009 Power Smart Plan Overall Cost Effectiveness**

b) Please provide a similar comparison in a) between the 2006 Power Smart Plan and current plan.

ANSWER:

The following table provides a comparison of the 2006 and 2009 Power Smart Plan metrics.

	2009 TRC	2006 TRC	2009 RIM	2006 RIM	2009 LUC (¢/kW.h)	2006 LUC (¢/kW.h)
RESIDENTIAL						
New Home Program	1.9	1.5	1.4	1.2	0.6	1.9
Home Insulation Program	4.4	3.4	1.6	1.5	2.2	2.9
Water and Energy Saver Program	9.6	1.9	1.1	0.8	1.3	4.0
Residential CFL Program	15.3	7.1	1.3	1.4	0.8	0.6
Residential Appliance Program	4.0	1.1	1.2	0.9	0.7	3.4
Residential Thermostats	n/a	1.9	n/a	1.2	n/a	3.4
Lower Income Energy Efficiency Program	1.9	1.8	1.0	0.8	3.7	3.2
Residential SLED Program	n/a	7.2	n/a	1.0	n/a	1.2
EE Light Fixtures	1.8	1.4	0.7	0.8	5.3	4.4
HE Furnace & Boiler Program (ECM motors)	0.8	1.1	1.9	0.9	0.0	4.9
Fridge Recycling Program	1.6	3.4	0.8	0.8	2.5	3.2
Residential Geothermal (Incentive) Program	n/a	1.3	n/a	1.0	n/a	6.4
Aboriginal Residential Program	n/a	1.8	n/a	0.8	n/a	8.4
COMMERCIAL						
Commercial Lighting Program	2.5	2.5	1.4	1.5	1.7	1.8
Commercial Custom Measures Program	2.5	2.6	1.2	1.2	2.5	1.6
Commercial Windows Program	2.3	3.9	1.2	1.6	4.5	2.4
Commercial HVAC Program - Chiller	1.7	1.7	1.1	1.0	1.0	1.6
Commercial Parking Lot Controller Program	3.7	2.1	1.7	1.1	0.5	1.6
City of Winnipeg Power Smart Agreement	8.2	4.3	1.5	1.4	1.1	1.9
Commercial Rinse & Save Program	62.6	17.4	1.4	1.4	0.3	0.4
Commercial Refrigeration Program	5.8	2.3	1.4	1.1	0.6	2.4
Commercial Insulation Program	3.2	4.9	1.6	1.9	2.5	1.5
Commercial Earth Power Program	2.7	3.0	1.6	2.1	2.3	1.3
Commercial New Construction Program	1.5	9.7	1.1	1.7	3.2	1.0
Commercial Building Optimization Program	5.0	2.7	1.7	1.6	1.4	2.1
Internal Retrofit Program	1.1	1.9	1.1	1.9	2.2	4.9
Agricultural Heat Pad Program	143.9	34.3	1.8	1.7	0.2	0.5
Power Smart Energy Manager Program	3.1	n/a	1.5	n/a	0.6	n/a
Commercial Kitchen Appliance Program	3.5	n/a	1.3	n/a	2.6	n/a
Commercial Clothes Washers Program	2.0	n/a	1.6	n/a	3.1	n/a
Network Energy Management Program	3.5	n/a	1.1	n/a	1.4	n/a
Power Smart Shops	1.9	n/a	1.0	n/a	2.1	n/a
CO2 Sensors	4.9	n/a	1.4	n/a	0.7	n/a
Commercial Air Conditioners	n/a	3.3	n/a	1.0	n/a	1.7
Aboriginal Commercial	n/a	1.7	n/a	1.1	n/a	5.2
INDUSTRIAL						
Performance Optimization Program	3.8	3.1	1.4	1.4	1.6	1.2
Quality Motor Repair	n/a	1.5	n/a	1.0	n/a	3.5
Emergency Preparedness Program	2.4	n/a	1.1	n/a	6.3	n/a
CUSTOMER SELF-GENERATION						
Bioenergy Optimization Program	1.6	2.4	1.3	1.6	1.6	0.6
TOTAL	***2.6***	***2.7***	***1.3***	***1.4***	***1.7***	***1.9***

Water and Energy Saver Program – The 2009 Plan includes water savings benefits which results in a higher TRC. Water savings benefits were not included in the 2006 Plan. The 2009 Plan also incorporates a modified program design that includes a direct installation component that increases program energy savings and decreases the LUC.

Residential CFL Program – The 2006 Plan was based on a delivery model of mail-in coupons. The 2009 Plan is based on point-of-sale rebates which have resulted in increased participation and a reduction in costs associated with eliminating the paperwork associated with rebates. This increase in participation and reduction in costs increased the TRC.

Residential Appliance Program – The 2009 Plan documents energy savings associated with the market transformation effects of the Program that ended March 31, 2009. Incentives are not included in this plan. This results in an increase in the TRC and a decrease in the LUC.

HE Furnace and Boiler Program (ECM motors) – The 2006 Plan was based on offering a standalone program to encourage the use of ECM motors in heating equipment. The 2009 Plan is based on ECM motors being added as a technical requirement for customers to receive a rebate under the Natural Gas High Efficiency Furnace and Boiler Program. All program costs are allocated to the natural gas furnace program. Energy savings levels were adjusted to reflect changes in assumptions regarding furnace fan operation.

Fridge Recycling Program – The program design in the 2009 Plan takes into account the likelihood that refrigerators removed from service would be replaced by customers, thereby reducing the total energy savings achieved. This results in a decrease in the TRC.

Commercial Windows Program – The TRC and RIM decrease, and LUC increase are attributed to an increase in the expected total program administrative and incentive costs.

Commercial Parking Lot Controller Program – The TRC and RIM increase, and LUC decrease in the 2009 Plan are attributed to a decrease in the expected total program administrative and incentive costs. This is the result of the program ending sooner than anticipated, due to market transformation and a higher level of expected participation.

Commercial Rinse & Save Program – The TRC has increased because the 2009 TRC includes water savings benefits in the TRC calculation. Water saving benefits had not been included in the 2006 plan.

Commercial Refrigeration Program – The TRC has increased, and LUC has decreased due to an increase in the number of planned participants and an increase in savings per participant.

Commercial Insulation Program – The TRC decrease and LUC increase are attributed to an increase in the expected total program administrative and incentive costs.

Commercial New Construction Program – The TRC decrease and LUC increase are due to incremental product cost increases, reduced participation forecast and increased customer incentive per participant.

Commercial Building Optimization Program – The TRC increased and LUC decreased in the 2009 Plan due to a decrease in the expected program administration and incentive costs.

Agricultural Heat Pad Program – The TRC increase is due to a reduction in the price of heat pads due to the recent downturn in the hog industry.

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Subject: Tab 9: Demand Side Management

Reference: Appendix 9.1, 2009 Power Smart Plan Overall Cost Effectiveness

c) Please provide forecast participation rates for each incentive based program

ANSWER:

PROGRAM	***2009***	***2010***	***2011***	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***2023***	***2024***
RESIDENTIAL																
New Home Program	90	114	157													
Home Insulation Program	1,153	1,054	960	872	789	711	638	568								
Water and Energy Saver	5,082	13,017	15,969	14,423	14,662											
Residential CFL Program	63,775	68,127	71,099													
Lower Income Energy Efficiency	804	963														
EE Light Fixtures	4,378	6,578	12,001													
HE Furnace & Boiler (ECM motors)	3,600															
Fridge Recycling Program	15,250	15,250	15,250													
COMMERCIAL																
Commercial Lighting	1,043	867	787	757	728	686	648	612	576	544	513	484	457	431	407	325
Commercial Custom Measures	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Commercial Windows	120	120	120	119	119	119	119	119	118	118	118	118	117	117	117	117
Commercial HVAC - Chiller	7	7	7	7	7	7	8	8	8							
Commercial Parking Lot Controller	108	42														
City of Winnipeg Agreement																
Commercial Rinse & Save	172															
Commercial Refrigeration	27	32	35	39	41	45	47	51	55	58	63	67	73	79	87	96
Commercial Insulation	145	150	150	150	150	151	151	151	152	152	152	152	152	153	153	153
Commercial Earth Power	27	28	28	29	29	30	30	31	32							
Commercial New Construction		9	12	19	19	25	32	39	42	46						
Commercial Building Optimization	8	8	10	16	16	15	16	27	13	16	16	17	17	19	23	
Internal Retrofit	79	84	81													
Agricultural Heat Pad	11	12														
Power Smart Energy Manager	2	6	5	4												
Commercial Kitchen Appliance	23	28	33	39	46	52	58	64	70							
Commercial Clothes Washers	115	46	55	64	74	83	94	115	126							
Network Energy Management	39	38	34	25	22											
Power Smart Shops	330	292	297	298	297	292	285	276	264	252						
CO2 Sensors	4	4	5	5	6	6	7	8	8	9						
INDUSTRIAL																
Performance Optimization	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45
Emergency Preparedness	0	30	50	70	25	10	5	5	5	5	5	5	5	5	5	5
Customer Self Generation																
Bioenergy Optimization	1	3	6	10	11	10	9	6	3	3	3					

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Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1, 2009 Power Smart Plan Overall Cost Effectiveness**

d) Please provide the free rider assumptions for each Electric Incentive Based Program.

ANSWER:

	Assumed Free Riders (%)
Residential Programs:	
New Home Program	1%
Home Insulation Program	12%
Water and Energy Saver Program	1%
Residential CFL Program	78%
Residential Appliance Program	Not applicable
Lower Income Energy Efficiency Program	0%
Residential SLED Program	60%
Energy Efficient Light Fixtures	2%
Fridge Recycling Program	10%
HE Furnace & Boiler Program (ECM Motors)	56%
Commercial Programs:	
Commercial Lighting Program	4%
Commercial Custom Measures Program	14%
Commercial Windows Program	1%
Commercial HVAC Program	9%
Commercial Parking Lot Controller Program	8%
Commercial Rinse & Save Program	10%
Commercial Refrigeration Program	15%
Commercial Insulation Program	3%
Commercial Earth Power Program	26%
Commercial New Construction Program	22%
Commercial Building Optimization Program	0%
Internal Retrofit Program	0%
Agricultural Heat Pad Program	11%

Power Smart Energy Manager Program	0%
Commercial Kitchen Appliance Program	4%
Commercial Clothes Washers Program	8%
Network Energy Management Program	9%
Power Smart Shops	0%
CO2 Sensors	57%
Industrial Programs:	
Performance Optimization Program	0%

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Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 LIEEP**

a) **Please provide demographic data on Low income households broken down by dwelling type and ownership [actual numbers and % of total]**

ANSWER:

The following two tables are based on data obtained from the 2003 survey.

	LICO-Standard		
DWELLING TYPE	**OWN**	**RENT**	**TOTAL**
Single Detached	45,467	5,344	50,811
Multiplex	3,961	2,876	6,836
Rowhouse	1,410	3,066	4,476
Mobile Home	2,613	507	3,120
Apartment Suite	2,145	14,762	16,907
TOTAL	55,596	26,555	82,151
Single Detached	81.8%	20.1%	61.9%
Multiplex	7.1%	10.8%	8.3%
Rowhouse	2.5%	11.6%	5.4%
Mobile Home	4.7%	1.9%	3.8%
Apartment Suite	3.9%	55.5%	20.6%
TOTAL	100.0%	100.0%	100.0%

	LICO-125		
DWELLING TYPE	**OWN**	**RENT**	**TOTAL**
Single Detached	54,426	5,696	60,122
Multiplex	4,704	3,001	7,706
Rowhouse	1,510	3,066	4,577
Mobile Home	2,993	507	3,500
Apartment Suite	2,145	15,147	17,292
TOTAL	65,779	27,417	93,197
Single Detached	82.7%	20.8%	64.5%
Multiplex	7.1%	11.0%	8.3%
Rowhouse	2.3%	3.3%	4.9%
Mobile Home	3.5%	0.5%	3.8%
Apartment Suite	4.5%	16.3%	18.5%
TOTAL	100.0%	100.0%	100.0%

The following two tables are based on data obtained from the 2009 survey.

LICO-Standard			
DWELLING TYPE	**OWN**	**RENT**	**TOTAL**
Single Detached	44,200	3,908	48,108
Multiplex	2,809	1,194	4,003
Rowhouse	1,327	1,438	2,765
Mobile Home	1,787	55	1,842
Apartment Suite	4,205	14,015	18,220
TOTAL	54,328	20,610	74,938
Single Detached	81.4%	19.0%	64.2%
Multiplex	5.2%	5.8%	5.3%
Rowhouse	2.4%	7.0%	3.7%
Mobile Home	3.3%	0.3%	2.5%
Apartment Suite	7.7%	68.0%	24.3%
TOTAL	100.0%	100.0%	100.0%

LICO-125			
DWELLING TYPE	**OWN**	**RENT**	**TOTAL**
Single Detached	64,024	4,720	68,744
Multiplex	5,164	1,822	6,986
Rowhouse	1,735	1,654	3,389
Mobile Home	2,777	102	2,879
Apartment Suite	5,156	18,630	23,786
TOTAL	78,856	26,928	105,784
Single Detached	81.2%	17.5%	65.0%
Multiplex	6.5%	6.8%	6.6%
Rowhouse	2.2%	6.1%	3.2%
Mobile Home	3.5%	0.4%	2.7%
Apartment Suite	6.5%	69.2%	22.5%
TOTAL	100.0%	100.0%	100.0%

<u>PUB/MH I-109</u>

Subject: Tab 9: Demand Side Management
Reference: Appendix 9.1 LIEEP

b) Please provide similar data on customers in Manitoba Social Housing Sector.

<u>ANSWER</u>:

Manitoba Hydro does not identify accounts as Social Housing on its billing system, and this information was not obtained from the Residential Survey. As such, Manitoba Hydro does not have this data.

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Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 2009 Power Smart Plan, LIEEP Page 55**

a) With respect to low income tenants, please fully describe the qualification criteria used to determine how tenants receive the benefits including how the program operates when payment arrangements have been made.

ANSWER:

One of Manitoba Hydro's objectives underlying the LIEEP is to ensure that the financial benefits associated with implementing energy efficient up-grades will be realized by low income consumers. For a participating building involving low income tenants, the tenant will benefit directly provided the energy bills are being paid by the tenant. For those buildings where the landlord pays the energy bills, the building is not eligible for participation in the LIEEP as the landlord would be realizing the benefits of lower energy bills rather than the low income tenant.

Payment arrangements have been made between Manitoba Housing and Manitoba Hydro, whereby Manitoba Housing will effectively pay the AEF portion of the cost of the upgrades in cases where the tenant is not directly paying the energy bill. The result of this arrangement ensures more homes are retrofitted, facilitates the administration of the program and ensures no financial impact for Manitoba Hydro and the utilities ratepayers. Manitoba Housing continues to receive Power Smart funding for all housing units including those where the tenant is not paying the utility bill.

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Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 2009 Power Smart Plan, LIEEP Page 55**

b) **Please indicate the number of instances where benefits have not been provided due to tenants not paying their utility bills.**

ANSWER:

Manitoba Housing and not for profit landlords are made aware of the criteria that tenants need to pay the utility bill prior to commencement of the process. As a result of this, Manitoba Hydro has not formally declined an application due to tenants not paying their utility bill.

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Subject: Tab 9: Demand Side Management
Reference: Appendix 9.1 2009 Power Smart Plan, LIEEP Page 55

c) Please provide an annual breakdown of program participation by low income homeowners and tenants.

ANSWER:

The following table provides the actual participation up to the end of 2008/09 and the projected participation for electric homes for 2009/10 and 2010/11.

Item	Actual Participants			
	2006-07	**2007-08**	**2008-09**	**Total**
Homeowner	0	0	2	2
Tenant	27	84	95	206
Total	**27**	**84**	**97**	**208**

Item	Forecasted Participants		
	2009/10	**20010/11**	**Total**
Homeowner	608	686	1,294
Tenant	196	277	473
Total	**804**	**963**	**1,767**

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Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 2009 Power Smart Plan, LIEEP Page 55**

d) Please provide the level of participation in the program, spending and number of households addressed by each of the Non-Profit social housing organizations and Manitoba Housing Authority.

ANSWER:

The following table provides the participation and spending for BUILD (Building Urban Industries for Local Development) and BEEP (Brandon Energy Efficiency Program). All electric homes completed were MHA (Manitoba Housing Authority) units.

Participation of by Not-for-Profit Organizations and MH (Manitoba Housing) Electric up to 2008/09			
ITEM	**# households**	**Total Cost**	**Average/Home**
BUILD	76	$324,197	$4,266
BEEP	130	$383,826	$2,953
Subtotal MHA	206	$708,022	$3,437

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Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 2009 Power Smart Plan, LIEEP Page 55**

e) **Please indicate the number of Community Energy Efficiency Business Plans that MH has received and describe MH's involvement in the development and management of the plans, and in particular does MH provide guidance on goals and targets in those plans. If not why not? Please also describe the management oversight provided by MH to ensure that the business plan targets are achieved.**

ANSWER:

Manitoba Hydro receives annual Community Energy Efficiency Business Plans from B.U.I.L.D. and B.E.E.P. through Green Manitoba. B.U.I.L.D. and B.E.E.P. submit their annual plans to Green Manitoba, which are subsequently distributed to members of an Interdepartmental Working Group set up by the Provincial Government. Manitoba Hydro is a non-officio member of this Interdepartment Working Group. As a result, Manitoba Hydro is included with this group of stakeholders who review and provide feedback to both B.U.I.L.D. and B.E.E.P. in regards to both goals and targets.

Both B.U.I.L.D. and B.E.E.P. have their own respective Board of Directors. While Manitoba Hydro is in on-going communications with both groups and works with them to help them meet their business plans, formal management oversight would be provided by their Board of Directors.

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Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 2009 Power Smart Plan, LIEEP Page 55**

f) **Please provide an update on the development efforts to expand the LIEEP to allow private landlords to participate. Please file a copy of any studies or position papers prepared by MH or on its behalf on this matter.**

ANSWER:

Manitoba Hydro is currently assessing options for allowing private landlords to participate in LIEEP.

<u>**PUB/MH I-111**</u>

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 , 2009 Power Smart Plan, Page 56-59- LIEEP**

a) **Please provide details of the spending by program and number of households addressed through the Community based approach, Individual Approach and First Nations Community by year since the launch of the LIEEP program**

<u>ANSWER</u>:

The following table provides the spending for electric heated homes in the Community based approach, Individual approach and First Nations Community by year for the LIEEP program.

LIEEP Electric Spending			
	2005-06		
Category	**PS**	**Bill 11**	**Total**
Community	$ -	$ -	$ -
Individual	$ -	$ -	$ -
First Nations[2]	$ 5,000	$ -	$ 5,000
Total 2005-06[1]	**$ 5,000**	**$ -**	**$ 5,000**
	2006-07		
Category	**PS**	**Bill 11**	**Total**
Community	$ 38,453	$ 61,067	$ 99,520
Individual	$ 58,523	$ -	$ 58,523
First Nations[2]	$ 12,897	$ 161,622	$ 174,519
Total 2006-07[1]	**$ 109,873**	**$ 222,690**	**$ 332,563**
	2007-08		
Category	**PS**	**Bill 11**	**Total**
Community	$ 158,947	$ 177,922	$ 336,869
Individual	$ 62,705	$ 7,811	$ 70,516
First Nations[2]	$ 2,107	$ (18,217)	$ (16,110)
Total 2007-08[1]	**$ 223,758**	**$ 167,517**	**$ 391,275**
	2008-09		
Category	**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[1]	**$ 209,410**	**$ 429,458**	**$ 638,868**
	TOTAL SPENDING FROM 2005-06 TO 2008-09		
Category	**PS**	**Bill 11**	**Total**
Community	$ 307,631	$ 387,368	$ 694,999
Individual	$ 214,573	$ 253,601	$ 468,174
First Nations	$ 25,838	$ 178,695	$ 204,533
Grand Total All[1]	**$ 548,041**	**$ 819,664**	**$ 1,367,706**

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	2006-07 to 2008-09 TOTAL
Community	27	84	95	**206**
Individual	0	0	2	**2**
First Nations[1]	0	0	0	**0**
Grand Total All	**27**	**84**	**97**	**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 I-111

Subject: Tab 9: Demand Side Management
Reference: Appendix 9.1 , 2009 Power Smart Plan, Page 56-59- LIEEP

b) Please provide details by measure on the forecasted spending on Electric LIEEP for the years 2009/10 and 2010/11.

ANSWER:

The following table provides details by measure on the forecast spending related to the Electric LIEEP during the years 2009/10 and 2010/11.

Forecasted Spending for Electric LIEEP - Power Smart Plan

Spending by Measure	Costs		
	2009/10	**20010/11**	**Total**
Power Smart			
Basic Energy Efficiency Items & Draft Proofing	$ 14,148	$ 14,855	$ 29,003
Insulation - Attic	$ 222,694	$ 267,243	$ 489,936
Insulation - Basement/Crawl	$ 99,713	$ 123,644	$ 223,357
Insulation - Wall	$ 143,898	$ 172,480	$ 316,378
Fridges	$ -	$ -	$ -
Total Incentives	**$ 480,452**	**$ 578,222**	**$ 1,058,674**
Total Administration	**$ 170,453**	**$ 177,742**	**$ 348,195**
Total Power Smart	**$ 649,966**	**$ 755,073**	**$ 1,405,039**
AEF			
Basic Energy Efficiency Items & Draft Proofing	$ 187,158	$ 208,815	$ 395,974
Insulation - Attic	$ 153,544	$ 173,635	$ 327,179
Insulation - Basement/Crawl	$ 1,322,788	$ 1,515,552	$ 2,838,341
Insulation - Wall	$ 192,482	$ 210,364	$ 402,846
Fridges	$ 467,611	$ 494,122	$ 961,733
Total Incentives	**$ 2,323,584**	**$ 2,602,488**	**$ 4,926,072**
Total Administration	**$ 892,272**	**$ 892,272**	**$ 1,784,544**
Total AEF	**$ 3,215,856**	**$ 3,494,760**	**$ 6,710,616**
Total Power Smart & AEF	**$ 3,865,821**	**$ 4,249,833**	**$ 8,115,655**

PUB/MH I-111

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 , 2009 Power Smart Plan, Page 56-59- LIEEP**

c) Please provide a full description of the efforts currently being undertaken and delivered under the LIEEP on First Nations Communities.

ANSWER:

Manitoba Hydro uses a dedicated team and partnership approach to pursue opportunities on First Nation Communities. Through this approach, Manitoba Hydro works with the community and assists in developing plans for pursuing energy efficient opportunities.

The following describes the general approach taken with each community:

– Manitoba Hydro staff first meet with the First Nation community and during this first meeting, the First Nations community is informed and educated on the Corporation's LIEEP;

– Manitoba Hydro's staff then work with the First Nation Community to select an initial group of ten homes to be retrofitted;

– Manitoba Hydro's staff arranges for home audits to be performed;

– Manitoba Hydro works with the community to secure the eligible material required for retrofitting the ten homes;

– Manitoba Hydro provides the First Nation Community with training, as required;

– the First Nation Community install the retrofit measures utilizing First Nation resources;

– Manitoba Hydro assists the First Nation Community in obtaining any eligible funds available through the Federal Government's ecoENERGY Grant program where applicable; and

- Upon completion of the initial 10 homes, a plan is developed to up-grade additional eligible housing within the community.

The following describes the current status with activities involving First Nation Communities:

Brochet: Plans are in place to visit the community in the spring

Crane River First Nation: 10 homes were identified in the community and work has been completed. Upon completion of the work a community presentation was conducted regarding moisture problems, heat recovery ventilator operation/maintenance, and basic energy efficiency measures such as insulated pipe wrap. Manitoba Hydro is working with the community to identify another 10 homes that might qualify for the program.

Cross Lake First Nation: Homes have been identified in the community, training has been provided by Manitoba Hydro and work currently has been completed on 16 homes. Manitoba Hydro is working with the community to identify additional homes that might qualify for the program.

Ebb & Flow First Nation: 10 homes have been identified in the community and work has been completed. Manitoba Hydro is working with the community to identify an additional 10 homes that might qualify for the program.

Fisher River First Nation: Homes have been identified in the community and Manitoba Hydro has provided training. The community has begun doing work on the homes and is near completion.

Island Lake First Nation: Manitoba Hydro has provided energy efficient materials to retrofit 101 homes in the community. Materials were shipped to the communities in March 2007. Manitoba Hydro has provided on-site training for the community. The community has indicated that all material has been used and verification of the work, numbers of houses completed and potential savings is taking place.

Lac Brochet First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Lake Manitoba First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Moose Lake First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Nelson House First Nation: Discussions have begun with the community with a visit to the community scheduled for the near future

Peguis First Nation: 10 homes have been indentified in the community and work has been completed. Manitoba Hydro is working with the community to identify additional homes that might qualify for the program.

Pine Creek First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Pukatawagan First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Opaskwayak Cree Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Sagkeeng First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Shamattawa First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

South Indian Lake First Nation: Homes have been identified in the community and Manitoba Hydro is working with the community to put a plan in place to do the work.

Tadoule Lake: Plans are in place to visit the community in the spring

PUB/MH I-111

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 , 2009 Power Smart Plan, Page 56-59- LIEEP**

d) Please provide details on the source of external funding for the LIEEP.

ANSWER:

Manitoba Hydro does not administer external funding for the community initiatives in LIEEP and as such, does not have all the details associated with the funding. As a partner in the community initiatives, Manitoba Hydro is however aware of the general principles and the following information.

External funding for Community approach includes funding from the provincial government for administration, training and labour for B.U.I.L.D. and B.E.E.P. This funding is sourced from Competitiveness Training and Trade, Green Manitoba Efficiency Fund, and Water Stewardship. Funding may also be received from municipal governments or other non-government organizations.

In addition, external funding for both the Individual and Community approach includes:

- participating social housing landlords who pay for their ecoENERGY evaluations, which currently consists of Manitoba Housing (MH) and Dakota Ojibway First Nations Housing Authority (DOFNHA);
- provincial government subsidies of $50 per ecoENERGY D and E evaluations (total of $100 per home with both D and E evaluations); and
- federal government ecoENERGY grants that will be received from the federal government for qualifying retrofits performed.

PUB/MH I-111

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 , 2009 Power Smart Plan, Page 56-59- LIEEP**

e) Please update the table on page 59 providing the RIM and levelized unit cost for the LIEEP including Power Smart, AEF and external funding.

ANSWER:

The electric RIM for the LIEEP including Power Smart and the Affordable Energy Fund dollars supporting electric measures is 1.0. Since external funding is not paid by Manitoba Hydro, these funds are not included in the RIM calculation.

The electric levelized utility cost (LUC) for the LIEEP including Power Smart and the Affordable Energy Fund dollars supporting electric measures is 3.7 cents per kilowatt hour. Since external funding is not paid by Manitoba Hydro, these funds are not included in the electric LUC calculation.

PUB/MH I-112

Subject: **Tab 9: Demand Side Management**
Reference: **LIEEP**

a) **Please file the base LICO table utilized by MH in the determination of eligibility criteria in part (a), as well as a table that shows 125% of the LICO amounts.**

ANSWER:

The base LICO table and the 125% LICO table utilized by Manitoba Hydro in the determination of current eligibility criteria are shown below.

	LICO BEFORE TAX 2008				
		Urban			
Household Size	Rural	Less than 30,000	Between 30,000 - 99,999	Between 100,000 - 499,999	500000 + over
1 person	$ 15,261	$ 17,363	$ 18,986	$ 19,094	$ 22,171
2	$ 19,000	$ 21,615	$ 23,622	$ 23,769	$ 27,600
3	$ 23,358	$ 26,573	$ 29,040	$ 29,221	$ 33,932
4	$ 28,360	$ 32,264	$ 35,260	$ 35,479	$ 41,197
5	$ 32,164	$ 36,593	$ 39,992	$ 40,238	$ 46,726
6	$ 36,278	$ 41,271	$ 45,104	$ 45,383	$ 52,698
7 or more	$ 40,390	$ 45,949	$ 50,216	$ 50,527	$ 58,672

LICO BEFORE TAX 2008 x 125%					
	LICO BEFORE TAX				
		Urban			
Household Size	Rural	Less than 30,000	Between 30,000 - 99,999	Between 100,000 - 499,999	500,000 + over
1 person	$ 19,077	$ 21,704	$ 23,733	$ 23,867	$ 27,714
2	$ 23,750	$ 27,019	$ 29,527	$ 29,712	$ 34,501
3	$ 29,197	$ 33,216	$ 36,300	$ 36,527	$ 42,415
4	$ 35,450	$ 40,330	$ 44,075	$ 44,349	$ 51,496
5	$ 40,205	$ 45,742	$ 49,989	$ 50,298	$ 58,407
6	$ 45,348	$ 51,588	$ 56,380	$ 56,729	$ 65,872
7 or more	$ 50,487	$ 57,437	$ 62,771	$ 63,159	$ 73,340

<u>PUB/MH I-112</u>

Subject: **Tab 9: Demand Side Management**
Reference: **LIEEP**

b) Please describe how the low income demographic information has been determined.

<u>ANSWER</u>:

Lower Income demographic information was extrapolated using data obtained from an internal 2003 residential energy use survey. Responses to the household income and people per household questions were cross tabulated to estimate the number of residential customers fitting into the lower income category as defined by 125% of LICO criteria.

<u>PUB/MH I-112</u>

Subject: Tab 9: Demand Side Management
Reference: LIEEP

c) Please indicate the total number of residential households in Manitoba

<u>ANSWER</u>:

Based on the 2009 residential survey, there are 439,096 accounts that are billed as residential rate class customers. These are residential households in Manitoba that directly receive an electricity bill from Manitoba Hydro. Bulk-metered apartments and other bulk-metered multi-family dwellings, as well as the residential seasonal and residential diesel rate class customers are not included in this figure.

<u>PUB/MH I-112</u>

Subject: **Tab 9: Demand Side Management**
Reference: **LIEEP**

d) Please provide a breakdown of the estimated number of low income customers.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH I-109(a).

PUB/MH I-112

Subject: **Tab 9: Demand Side Management**
Reference: **LIEEP**

e) Please detail the number of EFT's dedicated to the low income program and the breakdown between labour and overhead for each of the years 2008/09 through 2011/12.

ANSWER:

The number of EFT's dedicated to the low income program has fluctuated since the program began. There are approximately 10 EFT's currently dedicated to the low income program with additional support provided by various other areas within the Corporation. Contributions from these other functional areas (e.g. legal, business communications, business engineering, etc.) varies throughout the year with the assistance provided on as required basis.

Below is a breakdown of actual labour and overhead for 2008/09 and forecast for the years 2009/10 and 2010/11.

Item	2008/09 Actual	2009/10 Budget	2010/11 Budget	Total
Labour	$615,800	$713,400	$751,600	$2,080,800
O/H	$167,100	$192,800	$203,200	$563,100
Total	**$782,900**	**$906,200**	**$954,800**	**$2,643,900**

PUB/MH I-113

Subject: **Tab 9: Demand Side Management**
Reference: **Affordable Energy Fund**

a) Please provide a table which includes actual and forecast spending by program since the inception of the AEF

ANSWER:

	Actual Expenditures (millions)			Forecast Expenditures (millions)						
Initiative	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Lower Income Program	0.3	0.2	0.9	8.5	9.0	0.0	0.0	0.0	0.0	0.0
Geothermal Support	0.6	0.3	0.1	0.4	0.5	1.4	1.4	0.4	0.3	0.1
Community Energy Development	0.0	0.0	0.0	0.2	1.5	1.5	1.5	1.5	1.8	0.0
Community Support and Outreach	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.0	0.0
Oil and Propane Heated Homes	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Special Projects										
Residential ecoEnergy Audits	0.0	0.1	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Oil and Propane Furnace Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Water Heaters	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Residential Loan	0.0	0.0	0.0	0.6	0.2	0.1	0.1	0.0	0.0	0.0
ANNUAL EXPENDITURES	$0.9	$0.6	$1.4	$10.1	$11.7	$3.2	$3.2	$2.1	$2.1	$0.1

	Forecast Expenditures (millions)									
Initiative	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Lower Income Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.0
Geothermal Support	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	6.0
Community Energy Development	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0
Community Support and Outreach	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
Oil and Propane Heated Homes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Special Projects										
Residential ecoEnergy Audits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Oil and Propane Furnace Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Solar Water Heaters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Residential Loan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
ANNUAL EXPENDITURES	$0.1	$0.1	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$36.2

PUB/MH I-113

Subject: Tab 9: Demand Side Management
Reference: Affordable Energy Fund

b) Please detailed expenditures by year since the establishment of the AEF on electric DSM programs and forecasted to 2024/25

ANSWER:

The following table outlines the actual and planned Affordable Energy Fund expenditures that support all or partial electric energy efficiency programs. Manitoba Hydro does not allocate the Affordable Energy Fund budget to electric and natural gas, rather the Affordable Energy Fund supports the program and both electric and natural gas heated customers can participate. The table below outlines the total funding for the initiatives.

	Actual Expenditures (millions)			Forecast Expenditures (millions)						
Initiative	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Lower Income Program	0.3	0.2	0.9	8.5	9.0	0.0	0.0	0.0	0.0	0.0
Geothermal Support	0.6	0.3	0.1	0.4	0.5	1.4	1.4	0.4	0.3	0.1
Community Support and Outreach	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.0	0.0
Special Projects										
Residential ecoEnergy Audits	0.0	0.1	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Solar Water Heaters	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Residential Loan	0.0	0.0	0.0	0.6	0.2	0.1	0.1	0.0	0.0	0.0
ANNUAL EXPENDITURES	$0.9	$0.6	$1.4	$9.8	$10.1	$1.7	$1.7	$0.6	$0.3	$0.1

	Forecast Expenditures (millions)									
Initiative	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Lower Income Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.0
Geothermal Support	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	6.0
Community Support and Outreach	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
Special Projects										
Residential ecoEnergy Audits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Solar Water Heaters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Residential Loan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
ANNUAL EXPENDITURES	$0.1	$0.1	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$27.8

PUB/MH I-113

Subject: Tab 9: Demand Side Management
Reference: Affordable Energy Fund

c) Of the funds that are available for electric programs, please detailed the percentage that has been spent to date.

ANSWER:

The following table outlines the spending to date for funds available for all or partial electric programs.

	Actual Expenditures			Total Spent	Total Planned	Percent Spent
Initiative	2006/07	2007/08	2008/09	to 2008/09	to 2024/25	to Date
Lower Income Program	0.3	0.2	0.9	1.4	19.0	7%
Geothermal Support	0.6	0.3	0.1	1.0	6.0	16%
Community Support and Outreach	0.0	0.0	0.0	0.0	0.8	5%
Special Projects						
Residential ecoEnergy Audits	0.0	0.1	0.2	0.3	0.5	55%
Solar Water Heaters	0.0	0.0	0.1	0.1	0.3	29%
Residential Loan	0.0	0.0	0.0	0.0	1.2	0%
ANNUAL EXPENDITURES	$0.9	$0.6	$1.4	$2.8	$27.8	10%

PUB/MH I-114

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9.1 Fridge Recycling Program**

Please provide details on the number of refrigerators recycled by year, and the amount of incentives paid to customers.

ANSWER:

A Fridge Recycling Program has not been launched by Manitoba Hydro and therefore, no refrigerators have been recycled and no incentives have been paid.

PUB/MH I-115

Subject: Tab 9: Demand Side Management
Reference: Tab 13.5 [18]

Please file all reports and/or documents generated internally & externally since the 2007/08 GRA with respect to:

- **Residential DSM initiatives;**
- **Low Income DSM [LIEEP/ Diesel Communities];**
- **Bill Assistance**
- **Affordable Energy Program; and**
- **Furnace & Refrigerator Replacement Programs.**

ANSWER:

The following reports were produced related to Residential DSM Initiatives since the 2007/2008 GRA:

- 2007-2008 Power Smart Annual Review (see Appendix 9.2 of this Application).
- 2008-2009 Power Smart Annual Review (see Appendix 40).
- The 2009 Power Smart Plan (see Appendix 9.1 of this Application).
- The Dunsky Consulting Report "Leadership in Energy Efficiency: Comparing Manitoba Hydro's Power Smart with Leading North American Strategies" (see Appendix 25).
- Performance of Ground Source Heat Pumps in Manitoba. The report has customer specific information and therefore can not be shared with third parties. To provide some insight into the content of the report, attached is an article which was published in the Canadian GeoExchange Coalition magazine. The article outlines the study objectives, results and conclusions of the study (see Appendix 44, Attachment 5).

The following reports were produced related to Low Income DSM, Bill Assistance and the Affordable Energy Program, since the 2007/08 GRA:

- High Efficient Furnace Replacement Program for Lower Income Manitobans November 2008 (see Appendix 44, Attachment 4).
- Bill Assistance Report (see Appendix 44, Attachment 2).
- Manitoba Hydro Affordable Energy Program (see Appendix 44, Attachment 1).

- Affordable Energy Program Marketing Plan (see Appendix 44, Attachment 3).
- Dunsky Consulting Report "Leadership in Energy Efficiency: Comparing Manitoba Hydro's Power Smart with Leading North American Strategies" (see Appendix 25).

Manitoba Hydro has no reports on Diesel DSM that can be provided. Please see Manitoba Hydro's response to CAC/MSOS/MH I-95(a).

The Furnace Replacement Program is for natural gas heating systems and therefore, is outside the scope of this hearing.

There have been no reports produced for the Refrigerator Replacement Program since the 2007/2008 GRA.

PUB/MH I-116

Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9.1 2009 Power Smart Plan Pages 64-66 Section 6.2.2. Power Smart Commercial - Targets**

a) Please file a schedule that compares for each Commercial Incentive Based Programs, the Energy and Demand Savings (2023/24), Cumulative Utility Costs ($2009) and annual C02 Reductions for comparative periods with the 2008 power smart plan and explain any differences.

ANSWER:

The table below provides a comparison of the 2008 and 2009 Power Smart Plans for 2008/09 to 2023/24. The actual savings and expenditures for 2008/09 were included in the 2009 Power Smart Plan totals to allow a comparison of the same timeframe.

	2009 Power Smart Plan				2008 Power Smart Plan				Difference			
	Winter Demand MW @ meter 2023/24	Energy Savings GW.h @ meter 2023/24	Annual CO2 Reduction (tonnes)	Cumulative Utility Costs (thousands) $2009 2023/24	Winter Demand MW @ meter 2023/24	Energy Savings GW.h @ meter 2023/24	Annual CO2 Reduction (tonnes)	Cumulative Utility Costs (thousands) $2009 2023/24	Winter Demand MW @ meter 2023/24	Energy Savings GW.h @ meter 2023/24	Annual CO2 Reduction (tonnes)	Cumulative Utility Costs (thousands) $2009 2023/24
COMMERCIAL												
Commercial Lighting Program	77.9	310.0	238,507	$ 91,394	64.7	263.8	203,031	$ 75,658	13.3	46.1	35,476	$ 15,736
Commercial Custom Measures Program	1.4	9.2	7,076	$ 3,264	0.5	7.0	5,417	$ 3,050	0.9	2.2	1,658	$ 214
Commercial Windows Program	6.4	15.9	12,200	$ 10,472	7.6	18.8	14,439	$ 6,333	(1.2)	(2.9)	(2,239)	$ 4,138
Commercial HVAC Program - Chiller	0.0	19.0	14,635	$ 2,389	0.2	18.3	14,077	$ 3,119	(0.2)	0.7	559	$ (730)
Commercial Parking Lot Controller Program	0.0	12.0	9,197	$ 933	0.0	46.9	36,121	$ 2,063	0.0	(35.0)	(26,924)	$ (1,130)
City of Winnipeg Power Smart Agreement	0.0	0.0	0	$ 140	1.1	3.7	2,825	$ 207	(1.1)	(3.7)	(2,825)	$ (67)
Commercial Rinse & Save Program	0.0	0.0	0	$ 52	0.0	0.0	0	$ 32	0.0	0.0	0	$ 20
Commercial Refrigeration Program	6.1	51.4	39,516	$ 4,453	2.8	25.3	19,441	$ 4,702	3.3	26.1	20,075	$ (249)
Commercial Insulation Program	15.4	31.2	23,980	$ 10,815	2.4	47.0	36,146	$ 11,099	13.1	(15.8)	(12,166)	$ (285)
Commercial Earth Power Program	7.4	17.9	13,737	$ 5,329	14.0	26.5	20,426	$ 5,658	(6.7)	(8.7)	(6,689)	$ (329)
Commercial New Construction Program	5.9	30.6	23,530	$ 14,666	6.4	42.5	32,733	$ 19,740	(0.6)	(12.0)	(9,202)	$ (5,074)
Commercial Building Optimization Program	5.8	17.4	13,371	$ 2,920	14.8	44.4	34,142	$ 6,424	(9.0)	(27.0)	(20,771)	$ (3,503)
Internal Retrofit Program	7.3	21.9	16,883	$ 11,507	6.6	24.5	18,824	$ 12,657	0.7	(2.5)	(1,941)	$ (1,150)
Agricultural Heat Pad Program	0.6	6.8	5,240	$ 283	2.8	28.7	22,111	$ 571	(2.2)	(21.9)	(16,871)	$ (288)
Power Smart Energy Manager Program	0.2	3.9	3,000	$ 1,195	0.4	7.0	5,368	$ 1,751	(0.2)	(3.1)	(2,368)	$ (556)
Commercial Kitchen Appliance Program	1.1	3.3	2,568	$ 1,250	0.8	2.5	1,922	$ 820	0.3	0.8	646	$ 431
Commercial Clothes Washers Program	1.8	2.3	1,780	$ 823	1.9	2.4	1,865	$ 772	(0.1)	(0.1)	(85)	$ 51
Network Energy Management Program	2.4	15.0	11,514	$ 2,298	1.2	22.8	17,520	$ 2,399	1.2	(7.8)	(6,006)	$ (101)
Power Smart Shops	1.2	9.6	7,414	$ 2,813	0.8	7.0	5,422	$ 2,089	0.3	2.6	1,992	$ 725
CO2 Sensors	0.0	1.1	827	$ 80	0.0	0.0	0	$ -	0.0	1.1	827	$ 80
TOTAL	*140.9*	*578.3*	*444,975*	*$ 167,077*	*129.1*	*639.2*	*491,830*	*$ 159,143*	*11.8*	*(60.9)*	*(46,855)*	*$ 7,934*

Commercial Lighting Program - forecast participation increased from the 2008 to the 2009 Plan. This resulted in an increase in energy and demand savings, CO2 reductions and utility costs.

Commercial Windows Program - forecast participation decreased from the 2008 to the 2009 Plan to better reflect actual results. This resulted in a decrease in energy and demand savings and CO_2 reductions. Utility costs increased due to an increase in program administrative costs based on actual results.

Commercial Parking Lot Controller Program – forecast energy savings per participant decreased from the 2008 to the 2009 Plan to better reflect actual results experienced. This resulted in a decrease in energy savings, CO_2 reductions and utility costs.

Commercial Refrigeration Program - forecast participants and energy savings per participant increased from the 2008 to the 2009 Plan to better reflect actual results experienced. This resulted in an increase in energy and demand savings and CO_2 reductions.

Commercial Insulation Program - forecast participation decreased from the 2008 to the 2009 Plan to better reflect actual results experienced. This resulted in a decrease in energy savings, CO_2 reductions and utility costs. Demand savings of 2.4 MW shown in the 2008 Plan are incorrect; the correct demand savings are 23.6 MW. Thus the demand savings also decreased in 2009 for the same reasons as mentioned previously.

Commercial New Construction Program - forecast participation decreased from the 2008 to the 2009 Plan. This resulted in a decrease in energy and demand savings, CO_2 reductions and utility costs. These revisions were based on the most current information available regarding the commercial building construction industry.

Commercial Building Optimization Program - forecast participation decreased from the 2008 to the 2009 Plan. This resulted in a decrease in energy and demand savings, CO_2 reductions and utility costs. Participation was reduced to more closely reflect actual results experienced and to take into consideration the length of time to complete each project.

Agricultural Heat Pad Program - forecast participation decreased from the 2008 to the 2009 Plan. This resulted in a decrease in energy and demand savings, CO_2 reductions and utility costs. The decrease in savings and program costs is a reflection of the strong downturn in the hog market.

PUB/MH I-116

Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9.1 2009 Power Smart Plan Pages 64-66 Section 6.2.2. Power Smart Commercial - Targets**

b) Please provide a similar comparison and analysis as in part a) for comparative periods with the 2006 Power Smart Plan.

ANSWER:

The table below provides a comparison of the 2006 and 2009 Power Smart Plans for 2006/07 to 2017/18. The actual savings and expenditures for 2006/07 to 2008/09 were included in the 2009 Power Smart Plan totals to allow a comparison of the same timeframe.

	2009 Power Smart Plan				2006 Power Smart Plan				Differences			
	Winter Demand MW @ meter 2017/18	Energy Savings GW.h @ meter 2017/18	Annual CO2 Reduction (tonnes)	Cumulative Utility Costs (thousands) $2009 2017/18	Winter Demand MW @ meter 2017/18	Energy Savings GW.h @ meter 2017/18	Annual CO2 Reduction (tonnes)	Cumulative Utility Costs (thousands) $2009 2017/18	Winter Demand MW @ meter 2017/18	Energy Savings GW.h @ meter 2017/18	Annual CO2 Reduction (tonnes)	Cumulative Utility Costs (thousands) $2009 2017/18
COMMERCIAL												
Commercial Lighting Program	63.1	268.6	206,657	$78,367	67.2	259.4	199,572	$80,967	(4.1)	9.2	7,085	$ (2,600)
Commercial Custom Measures Program	1.3	8.9	6,841	$2,368	1.1	21.9	16,865	$5,733	0.2	(13.0)	(10,024)	$ (3,365)
Commercial Windows Program	4.4	11.4	8,742	$7,304	2.4	6.0	4,652	$2,400	1.9	5.3	4,089	$ 4,904
Commercial HVAC Program - Chiller	0.2	9.7	7,495	$2,667	0.0	8.3	6,423	$2,546	0.2	1.4	1,072	$ 121
Commercial Parking Lot Controller Program	0.0	21.1	16,221	$2,452	0.0	12.8	9,861	$2,534	0.0	8.3	6,360	$ (82)
City of Winnipeg Power Smart Agreement	0.7	4.9	3,763	$1,951	1.0	5.3	4,055	$1,146	(0.3)	(0.4)	(292)	$ 805
Commercial Rinse & Save Program	0.4	3.3	2,539	$119	0.0	0.0	0	$260	0.4	3.3	2,539	$ (140)
Commercial Refrigeration Program	3.3	26.4	20,330	$2,955	2.5	19.4	14,941	$6,532	0.9	7.0	5,389	$ (3,577)
Commercial Insulation Program	10.8	22.1	17,006	$7,146	14.1	29.5	22,686	$7,776	(3.3)	(7.4)	(5,680)	$ (630)
Commercial Earth Power Program	10.7	25.4	19,530	$6,322	13.2	27.3	21,041	$5,560	(2.5)	(2.0)	(1,511)	$ 762
Commercial New Construction Program	4.9	21.0	16,160	$12,466	2.3	10.0	7,695	$1,393	2.6	11.0	8,465	$ 11,074
Commercial Building Optimization Program	4.4	13.7	10,542	$1,886	7.0	21.1	16,227	$4,948	(2.6)	(7.4)	(5,685)	$ (3,062)
Internal Retrofit Program	7.9	25.5	19,653	$28,039	6.7	25.1	19,287	$18,871	1.2	0.5	366	$ 9,167
Agricultural Heat Pad Program	1.4	13.8	10,650	$411	1.2	10.6	8,191	$941	0.2	3.2	2,459	$ (530)
Power Smart Energy Manager Program	0.7	16.6	12,774	$1,275	0.0	0.0	0	$0	0.7	16.6	12,774	$ 1,275
Commercial Kitchen Appliance Program	1.0	3.0	2,309	$1,251	0.0	0.0	0	$0	1.0	3.0	2,309	$ 1,251
Commercial Clothes Washers Program	1.1	1.5	1,154	$782	0.0	0.0	0	$0	1.1	1.5	1,154	$ 782
Network Energy Management Program	1.5	9.4	7,233	$2,300	0.0	0.0	0	$0	1.5	9.4	7,233	$ 2,300
Power Smart Shops	0.9	7.5	5,771	$2,603	0.0	0.0	0	$0	0.9	7.5	5,771	$ 2,603
CO2 Sensors	0.0	0.9	693	$70	0.0	0.0	0	$0	0.0	0.9	693	$ 70
Commercial Air Conditioning	0.0	0.0	0	$0	0.0	4.0	3,074	$916	0.0	(4.0)	(3,074)	$ (916)
Comm 80+	0.0	0.0	0	$0	0.0	0.0	0	$255	0.0	0.0	0	$ (255)
Commercial Aboriginal Program	0.0	0.0	0	$0	0.5	1.5	1,161	$1,196	(0.5)	(1.5)	(1,161)	$ (1,196)
TOTAL	***118.6***	***514.7***	***396,062***	***$162,735***	***119.2***	***462.3***	***355,733***	***$143,975***	***(0.5)***	***52.4***	***40,329***	***$ 18,760***

Commercial Custom Measures Program - Forecast per participant savings decreased from the 2006 to the 2009 Plan based on actual energy savings data experienced. This resulted in a decrease in energy savings, CO2 reductions and utility costs. Forecast demand savings increased in the 2009 Plan based on actual program savings achieved.

Commercial Windows - Forecast participation increased from the 2006 to the 2009 Plan. This resulted in an increase in energy and demand savings, CO_2 reductions and utility costs.

Commercial Refrigeration Program - Forecast participation and energy savings per participant increased from the 2006 to the 2009 Plan based on actual results experienced. This resulted in an increase in energy and demand savings and CO_2 reductions. Utility costs decreased based on actual program administrative costs.

Commercial New Construction Program - Forecast participation increased from the 2006 to the 2009 Plan. This resulted in an increase in energy and demand savings, CO_2 reductions and utility costs. These revisions were based on the most current information available regarding the commercial building construction industry.

Commercial Building Optimization Program - Forecast participation decreased from the 2006 to the 2009 Plan. This resulted in a decrease in energy and demand savings, CO_2 reductions and utility costs. Participation was reduced to more closely reflect actual results experienced and to take into consideration the length of time to complete each project. Utility costs decreased from the 2006 plan due to less staff being required for the program and less training dollars being required due to funding being provided by the Federal government.

<u>PUB/MH I-117</u>

Subject: Tab 9: Demand Side Management
Reference: Appendix 9.1 2009 Power Smart Plan

a) **Please provide a comparison of the DSM savings and GHG reduction targets set for 2016/17 in the 2006 Power Smart Plan with the level of savings and reduction now forecast in the 2009 Power Smart Plan for that year and explain any differences.**

<u>ANSWER</u>:

The following table provides a comparison of the 2006 and 2009 Power Smart Plans for 2006/07 to 2016/17. The actual savings for 2006/07 to 2008/09 were included in the 2009 Power Smart Plan totals to allow for a comparison over the same timeline.

	2006 Plan 2016/17 GW.h Savings (@ meter)	2006 Plan CO2 Reduction (tonnes)	2009 Plan 2016/17 GW.h Savings (@ meter)	2009 Plan CO2 Reduction (tonnes)	*GW.h Differences*	*CO2 Reduction Differences (tonnes)*
Residential	194	149,206	174	134,178	-20	-15,028
Customer Service Initiatives	41	31,165	27	20,777	-14	-10,388
Commercial	431	331,962	482	370,653	50	38,690
Industrial	151	112,762	200	149,820	49	37,058
Rates	0	0	0	0	0	0
Self-Generation	85	63,611	69	51,548	-16	-12,063
Option 1 - Supp Codes and Standards	471	362,435	493	379,056	22	16,621
2016/17 Impacts	**1,372**	**1,055,908**	**1,444**	**1,106,031**	**72**	**50,123**

The energy savings in the 2009 Plan are higher than those in the 2006 Plan. Energy savings from the residential sector in the 2009 Plan is lower due mainly to revisions to projected energy savings for the CFL program with the revised projections being updated to reflect updated and more current market information.

Energy savings from Customer Service Initiatives in the 2009 Plan is lower due to reductions to planned savings in the ecoENERGY and Residential Earth Power Programs based on updated market information.

Energy savings from the commercial sector are higher in the 2009 Plan due mainly to the addition of six programs to the portfolio.

Energy savings from the industrial sector are higher in the 2009 Plan due mainly to the addition of the Emergency Preparedness Program and an increase in projected energy savings from the Performance Optimization Program. The revised estimates were based on updated and more current market information.

Energy savings from self-generation in the 2009 Plan are lower due to revisions to energy savings from the Bioenergy Optimization Program which was based on more updated information related to customers participating in the program.

Energy savings from codes and standards are higher in the 2009 Plan due to revisions to estimated code impacts from technologies based on updated and more current market information.

PUB/MH I-117

Subject: Tab 9: Demand Side Management
Reference: Appendix 9.1 2009 Power Smart Plan

b) Please provide a similar analysis in a) of DSM savings and GHG reductions set for 2022/23 in the 2009 Power Smart Plan with the 2008 Power Smart Plan

ANSWER:

The following table provides a comparison of the 2008 and 2009 Power Smart Plans for 2008/09 to 2022/23. The actual energy savings for 2008/09 were included in the 2009 Power Smart Plan totals to allow a comparison over the same timeline.

	2008 Plan 2022/23 GW.h Savings (@ meter)	2008 Plan CO2 Reduction (tonnes)	2009 Plan 2022/23 GW.h Savings (@ meter)	2009 Plan CO2 Reduction (tonnes)	GW.h Differences	CO2 Reduction Differences (tonnes)
Residential	98	75,488	134	102,805	36	27,317
Customer Service Initiatives	30	22,777	27	20,846	-3	-1,931
Commercial	619	476,551	557	428,765	-62	-47,786
Industrial	200	149,850	266	199,076	66	49,226
Rates	0	0	0	0	0	0
Self-Generation	78	58,292	75	56,044	-3	-2,248
Option 1 - Supp Codes and Standards	580	446,310	726	558,744	146	112,434
2022/23 Impacts	**1,605**	**1,229,268**	**1,785**	**1,373,175**	**180**	**143,907**

Overall the energy savings in the 2009 Plan are higher than those in the 2008 Plan. Energy savings from the residential sector are higher due mainly to the addition of the Fridge Recycling Program.

Energy savings from the commercial sector are lower in the 2009 Plan due to reductions in projected energy savings from a number of programs which were based on updated and more current market information.

Energy savings from the industrial sector are higher in the 2009 Plan due to the addition of the Emergency Preparedness Program and an increase in projected energy savings from the Performance Optimization program.

Energy savings from codes and standards are higher in the 2009 Plan due to revisions to estimated code impacts from technologies based on updated and more current market information.

PUB/MH I-118

Subject: Tab 9: Demand Side Management

Reference: Appendix 9-1 Page 109, 2009 Power Smart Plan detailed savings and costs

Please provide a tabulation of the Levelized Utility Cost [¢/kW.h] and the corresponding revenue gains [difference between export sales and foregone domestic revenue] for each incentive program.

ANSWER:

	2009 LUC (c/kW.h)	*Revenue Gain (c/kW.h)*
RESIDENTIAL		
Incentive Based		
New Home Program	0.57	0.93
Home Insulation Program	2.22	3.65
Water and Energy Saver Program	1.33	-0.01
Lower Income Energy Efficiency Program	0.64	-0.97
Residential HE Furnace & Boiler Program	0.00	2.29
EE Light Fixtures	5.30	0.64
Residential CFL Program	0.75	0.59
Fridge Recycling Program	2.46	-0.93
Residential Appliance Program	0.68	0.28
COMMERCIAL		
Commercial Lighting Program	1.71	2.03
Commercial Custom Measures Program	2.46	1.92
Commercial Windows Program	4.54	3.67
Commercial HVAC Program - Chiller	0.99	0.24
Commercial Parking Lot Controller Progran	0.49	1.64
City of Winnipeg Power Smart Agreement	1.11	1.88
Commercial Rinse & Save Program	0.25	0.34
Commercial Refrigeration Program	0.60	0.82
Commercial Insulation Program	2.50	4.37
Commercial Earth Power Program	2.31	4.03
Commercial New Construction Program	3.15	1.62
Commercial Building Optimization Prograr	1.42	3.04
Internal Retrofit Program	2.17	7.58
Agricultural Heat Pad Program	0.24	1.67
Power Smart Energy Manager Program	0.60	1.06
Commercial Kitchen Appliance Program	2.57	2.48
Commercial Clothes Washers Program	3.07	5.31
Network Energy Management Program	1.38	0.27
Power Smart Shops	2.12	0.17
CO2 Sensors	0.70	0.99
INDUSTRIAL		
Performance Optimization Program	1.58	1.77
Emergency Preparedness Program	6.26	3.23
CUSTOMER SELF-GENERATION		
Bioenergy Optimization Program	1.63	1.88
LOAD MANAGEMENT		
Curtailable Rate Program	n/a	n/a

PUB/MH I-119

Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9-1 Executive Summary Page 4, Page 113, 7.1.2 Electric DSM Utility Investment**

a) Please provide the corresponding data points for the chart on page 4 of the executive summary.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-102(a).

PUB/MH I-119

Subject: Tab 9: Demand Side Management

Reference: Appendix 9-1 Executive Summary Page 4, Page 113, 7.1.2 Electric DSM Utility Investment

b) For each of the years 2009/10 through 2023/24 please provide a schedule which compares the electric Power Smart utility budget in the 2009 plan versus the 2008 plan including an explanation for any material differences.

ANSWER:

	Utility Costs (Millions, 2009 $)		
	2009	**2008**	**Difference**
2009/10	$40.3	$35.3	$5.0
2010/11	$43.0	$34.0	$9.0
2011/12	$42.5	$32.4	$10.0
2012/13	$38.4	$30.0	$8.3
2013/14	$33.9	$26.5	$7.4
2014/15	$29.9	$27.1	$2.8
2015/16	$29.0	$25.9	$3.1
2016/17	$27.1	$25.7	$1.3
2017/18	$25.6	$25.3	$0.3
2018/19	$25.1	$20.7	$4.3
2019/20	$21.8	$16.0	$5.8
2020/21	$21.6	$15.7	$5.8
2021/22	$21.5	$15.7	$5.8
2022/23	$21.4	$15.6	$5.9
2023/24	$20.6	$15.3	$5.3
Totals	$441.6	$361.3	$80.2

The 2009 Power Smart Plan total utility budget increased over the budget outlined in the 2008 Plan for a variety of reasons. New programs were added to the portfolio (Refrigerator Recycling Program, Emergency Preparedness Programs), revisions were made to existing programs based on updated market information resulting in higher planned costs (Performance Optimization Program, Bioenergy Optimization Program) and the contingency budget was increased.

PUB/MH I-119

Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9-1 Executive Summary Page 4, Page 113, 7.1.2 Electric DSM Utility Investment**

c) Please provide a similar comparison to part a of the Electric power Smart utility budget in the 2009 plan with the 2006 plan.

ANSWER:

The following table provides a comparison of the 2009 and 2006 Power Smart Plans up to 2017/18 which is the final year included within the 2006 Power Smart Plan.

	Total Utility Costs (Millions, 2009 $)		
	2009	**2006**	**Difference**
2009/10	$40.3	$40.2	$0.1
2010/11	$43.0	$34.6	$8.4
2011/12	$42.5	$34.4	$8.1
2012/13	$38.4	$34.4	$4.0
2013/14	$33.9	$33.9	$0.0
2014/15	$29.9	$31.2	-$1.2
2015/16	$29.0	$30.6	-$1.6
2016/17	$27.1	$26.0	$1.0
2017/18	$25.6	$25.3	$0.2
Totals	$309.6	$290.5	$19.1

Overall the 2009 Power Smart Plan total utility budget increased over the budget outlined in the 2006 Plan. The 2009 budget was higher that the 2006 budget in some years and lower in other years due to a variety of factors. New programs were added to the portfolio (Commercial Kitchen Appliances, Network Energy Management, Emergency Preparedness), programs were removed from the portfolio (Residential Incentive-based Geothermal, Commercial 80 Plus), revisions were made to existing programs based on updated market information that both increased and decreased expenditures (Water and Energy Saver, Fridge Recycling, Performance Optimization, New Homes, Lower Income) and the contingency budget was decreased.

<u>PUB/MH I-120</u>

Subject: **Tab 9: Demand Side Management**

Reference: **Appendix 9-1 , Page 109, Customer Service Initiatives, Appendix A.1 Winter Capacity Savings**

Please provide supporting calculations with narrative on how the Winter Capacity Savings for the Residential Earth Power Program and the Power Smart Residential Loan Program for 2009/10 and 2010/11 was determined.

<u>ANSWER</u>:

<u>Residential Earth Power</u>

Winter Capacity Savings:

2009/10	0.5 MW
2010/11	1.0 MW

Winter capacity savings are calculated by forecasting the number of system installations and multiplying this number by the average capacity savings per system.

The average capacity savings per system is calculated by forecasting the percentage of homes with a natural gas heating baseline and those with an electric heating baseline. From this, a weighted average calculation is performed to determine the net effects of the increased demand from geothermal systems replacing natural gas systems and the decreased demand from geothermal systems replacing traditional all-electric systems.

It is forecast that in 2009/10, 200 customers will participate in the program with a weighted average demand savings of 2.5 kW per unit resulting in total demand savings of 0.5 MW. It is forecast that in 2010/11, 200 additional customers will participate for additional savings of 0.5 MW plus 0.5 MW of persisting savings from customers who participated in 2009/10 for total demand savings of 1.0 MW.

Power Smart Residential Loan

Winter Capacity Savings:	
2009/10	0.34 MW
2010/11	0.68 MW

Winter capacity savings are calculated by forecasting the expected number of participants and multiplying this number by the average capacity savings per customer.

The average winter capacity savings are based on actual savings from past program activity.

It is forecast that in 2009/10, 6 500 customers will participate in the program with an average demand savings of 0.0523 kW per customer resulting in demand savings of 0.34 MW. It is forecast that in 2010/11, 6 500 additional customers will participate for additional savings of 0.34 MW plus 0.34 MW of persisting savings from customers who participated in 2009/10 for total demand savings of 0.68 MW.

<u>PUB/MH I-121</u>

Subject: **Tab 9: Demand Side Management**
Reference: **City of Winnipeg Power Smart Agreement**

a) **Please provide a summary of the terms of the agreement with the City of Winnipeg on DSM programs and the financial implications of the program to Manitoba Hydro**

<u>ANSWER</u>:

Manitoba Hydro and the City of Winnipeg entered into a Power Smart Agreement on September 3, 2002 with an objective to capture energy efficient opportunities within the City's facilities, with a minimum target of reducing the City's energy bill by $800,000 annually. The program has spent $10.6 million to date, which includes $3.2 million in commitment payments, $6.4 million in energy efficiency project costs, and $1.0 million in program administration and management fees. In addition, Manitoba Hydro realizes the benefits associated with increased electricity export revenues.

PUB/MH I-121

Subject: Tab 9: Demand Side Management
Reference: City of Winnipeg Power Smart Agreement

b) **Please indicate the amount of savings realized in each of the years 2002 through 2009 and that forecast for 2010, 2011 and 2012.**

ANSWER:

Project Year	Annual Savings	
2002/03	$13,529	
2003/04	$55,921	
2004/05	$140,147	
2005/06	$626,229	
2006/07	$770,906	
2007/08	$757,792	
2008/09	$874,859	
2009/10	$900,000	forecast
2010/11	$920,000	forecast
2011/12	$940,000	forecast

PUB/MH I-121

Subject: **Tab 9: Demand Side Management**
Reference: **City of Winnipeg Power Smart Agreement**

c) Please provide a continuity schedule of spending for each commercial program for the fiscal years 2000/01 to the present and explain the increase in the program.

ANSWER:

Manitoba Hydro would require authorization from the City of Winnipeg to release information specific to its programs. However, to provide some insight, the City of Winnipeg initiative involves projects associated with the following energy efficiency technologies and programs:

- Building Envelope
- Lighting
- Parking Lot Controllers
- HVAC Upgrades
- Elevator Upgrades
- Compressed Air
- Building Retrofit
- Washroom Fixtures
- Traffic Signals
- Street Lighting
- Solar Wall

The increase in program spending is related to a higher number of completed projects.

PUB/MH I-122

Subject: **Tab 9: Demand Side Management**
Reference: **DSM GHG Impact**

a) Please confirm that MH allocated all export to coal generation displacement prior to 2001.

ANSWER:

For the purposes of estimating the impacts of electricity-based DSM programs, prior to 2001 Manitoba Hydro assumed that exports displaced primarily coal generation.

PUB/MH I-122

Subject: **Tab 9: Demand Side Management**
Reference: **DSM GHG Impact**

b) **Please provide the calculation MH uses to calculate GHG emissions savings per unit of KW.h saved.**

ANSWER:

GHG emission savings in kilograms are calculated by multiplying the displacement factor [currently 0.75 kg/kW.h as discussed in response to PUB/MH I-122(c)] and the kW.h of energy saved through DSM initiatives (referred to the southern system bus).

<u>PUB/MH I-122</u>

Subject: **Tab 9: Demand Side Management**
Reference: **DSM GHG Impact**

c) **Please describe how MH currently allocates exports to coal generation reduction and natural gas generation reduction and the reflective savings.**

<u>ANSWER</u>:

As stated in the response to PUB/MH I-122(a), prior to 2001 Manitoba Hydro assumed that exports displaced primarily coal generation which corresponds to emissions of approximately 1.0 kg/kW.h.

Today a more conservative estimate of 0.75 kg/kW.h is assumed. This reflects the displacement of a mixture of fossil-fuel resources and a variety of technologies and efficiencies.

PUB/MH I-122

Subject: **Tab 9: Demand Side Management**
Reference: **DSM GHG Impact**

d) Please provide unit consumption (GWh/ customer) levels for the last five years in Saskatchewan and BC for residential [standard & all electric], commercial and industrial customers.

ANSWER:

The unit consumption levels for SaskPower and BC Hydro were derived from their annual reports. SaskPower and BC Hydro include small industrials in the commercial sector. The usage figures are in kW.h per customer. Neither utility provides a residential breakdown by standard and all electric.

Sask Power	**Average Use (kW.h/Customer) by Calendar Year**				
Class	**2008**	**2007**	**2006**	**2005**	**2004**
Residential	10,288	10,328	10,022	10,219	10,231
Commercial & Small Industrial	89,101	86,634	85,410	84,367	82,354
Large Industrial	114,787,500	99,280,488	97,060,976	96,518,519	89,229,885

BC Hydro	**Average Use (kW.h/Customer) by Calendar Year**				
Class	**2008**	**2007**	**2006**	**2005**	**2004**
Residential	11,191	10,811	10,759	10,654	10,701
Commercial & Small Industrial	94,457	94,619	94,396	93,208	92,805
Large Industrial	96,125,000	109,513,699	112,520,548	117,224,638	114,007,353

<u>PUB/MH I-122</u>

Subject: **Tab 9: Demand Side Management**
Reference: **DSM GHG Impact**

e) **Please compare and explain the different growth levels [in unit consumption levels] in the context of DSM activities within these jurisdictions listed in d) and Manitoba.**

<u>ANSWER</u>:

The following tables outline the 4-year growth levels from 2004 to 2008 for each sector.

Manitoba Hydro	
Class	**4-year growth**
All Residential	2.3%
Residential - Standard only	3.7%
Residential - All Electric	-1.7%
General Service Mass Market	0.5%
Top Consumers	6.7%

B.C. Hydro	
Class	**4-year growth**
Residential	4.6%
Commercial & Small Industrial	1.8%
Large Industrial	-15.7%

SaskPower	
Class	**4-year growth**
Residential	0.6%
Commercial & Small Industrial	8.2%
Power	28.6%

There are major regional and load reporting differences between Saskatchewan and Manitoba which make direct comparisons challenging and therefore, any comparisons should be interpreted with caution. DSM activities are only one of a number of factors that affect these growth rates. Other factors include provincial differences in the economic growth, specific customer and industry growth, electricity and gas prices, use of electricity for heating and ongoing fuel switching. In addition, customer classification differences, method of weather adjustment and year-to-year random effects can significantly affect the growth rate. As a result, it is impossible to identify the specific reasons why the growth rates differ and to assess accurately how the respective growth rates relate to DSM activities within each region.

PUB/MH I-123

Subject: **Tab 9: Demand Side Management**
Reference: **Manitoba GHG Emissions**

Please provide the most current data on the major sources of GHG emissions in Manitoba including amount and percentage.

ANSWER:

Table A11-14: 1990-2007 GHG Emission Summary for Manitoba from page 557 of the National Inventory Report 1990-2007 below provides the most current overview of major sources of GHG emissions in Manitoba. The complete National Inventory Report 1990-2007 is obtainable at the following website:
http://www.ec.gc.ca/pdb/ghg/inventory_report/2007/full_inv_2007_eng.cfm

Electricity & Heat Generation values are not provided in the National Inventory Report since Environment Canada deemed it to be confidential data based on the limited number of data providers. Manitoba Hydro's electricity generation emissions for 2007 were 492 kilotonnes (kt) CO2e (for Brandon Units 5, 6 & 7 and Selkirk Units 1 & 2).

Table A11-14: 1990–2007 GHG Emission Summary for Manitoba

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007
					kt CO_2 equivalent					
TOTAL	18 600	19 800	21 200	19 600	20 400	21 100	21 200	20 800	20 900	21 300
ENERGY	12 200	12 500	12 900	11 700	12 100	12 300	12 300	12 500	12 100	12 800
a. **Stationary Combustion Sources**	4 820	4 190	5 320	4 540	4 860	4 930	4 660	4 560	4 200	4 560
Electricity and Heat Generation	569	219	992	X	X	X	X	X	X	X
Fossil Fuel Industries	0.14	0.04	0.03	0.03	0.33	0.01	0.01	0.01	0.05	0.01
Mining & Oil and Gas Extraction	73.5	12.5	29.2	X	X	X	X	X	X	X
Manufacturing Industries	1 040	818	1 130	1 050	1 210	1080	1 200	1 240	1 320	1 330
Construction	63.1	33.6	61.7	60.9	68.0	78.3	82.1	84.9	90.9	102
Commercial & Institutional	1400	1 580	1 670	1 580	1 700	1580	1 580	1 450	1 290	1 410
Residential	1 600	1 400	1 400	1 200	1 300	1200	1 200	1 100	960	1 100
Agriculture & Forestry	41.9	76.4	62.7	X	X	X	X	X	X	X
b. **Transport**[1]	6 990	7 820	7 000	6 610	6 690	6790	7 070	7 280	7 220	7 570
Civil Aviation (Domestic Aviation)	330	360	360	350	360	390	340	330	330	410
Road Transportation	3920	4 330	4 400	4 440	4 520	4580	4 790	4 650	4 930	5 240
Light-duty Gasoline Vehicles	1630	1 560	1 290	1 260	1 260	1 240	1 230	1 110	1 200	1 240
Light-duty Gasoline Trucks	859	1 150	1 470	1 470	1 530	1 590	1 670	1 600	1 740	1 800
Heavy-duty Gasoline Vehicles	439	227	218	248	239	239	253	233	254	263
Motorcycles	6.80	6.01	4.21	4.80	7.30	7.90	8.43	7.92	8.67	8.96
Light-duty Diesel Vehicles	10.7	9.18	7.82	7.78	8.09	8.23	8.87	8.08	8.91	9.34
Light-duty Diesel Trucks	40.2	71.2	88.7	90.4	94.9	98.9	105	106	119	125
Heavy-duty Diesel Vehicles	868	1 210	1 290	1 330	1 360	1 380	1 490	1 560	1 590	1 780
Propane & Natural Gas Vehicles	61	97	36	31	20	22	21	14	15	18
Railways	600	600	300	200	80	200	300	300	200	200
Navigation (Domestic Marine)	0.02	–	–	–	–	0.29	0.11	–	–	0.32
Other Transportation	2 100	2 600	1 900	1 600	1 700	1600	1 700	2 000	1 700	1 700
off-Road Gasoline	340	510	430	390	370	390	400	370	330	360
off-Road Diesel	960	780	690	660	700	800	850	1 100	830	860
Pipelines	841	1 290	822	539	654	447	429	596	535	472
c. **Fugitive Sources**[2]	421	476	563	569	584	593	593	614	668	681
Coal Mining[3]	–	–	–	–	–	–	X	X	X	X
Oil and Natural Gas	421	476	563	569	584	593	X	X	X	X
INDUSTRIAL PROCESSES[4]	504	330	549	538	481	463	482	545	532	547
a. **Mineral Products**	200	69	69	61	63	58	62	59	54	53
Cement Production	140	–	–	–	–	–	–	–	–	–
Lime Production	58	69	69	61	63	58	62	59	54	53
b. **Chemical Industry**	20	29	44	48	43	42	50	54	50	50
Nitric Acid Production	20.1	29.1	44.2	48.1	43.4	41.6	50.4	53.7	50.2	50.2
Adipic Acid Production	–	–	–	–	–	–	–	–	–	–
c. **Metal Production**	–	–	–	–	–	–	–	–	–	–
Iron and Steel Production	–	–	–	–	–	–	–	–	–	–
Aluminium Production	–	–	–	–	–	–	–	–	–	–
SF_6 Used in Magnesium Smelters and Casters	–	–	–	–	–	–	–	–	–	–
d. **Other & Undifferentiated Production**[5]	280	230	440	430	370	360	370	430	430	440
SOLVENT & OTHER PRODUCT USE	7.0	8.0	9.0	7.9	6.1	8.1	7.7	6.5	12	12
AGRICULTURE	5 300	6 200	7 000	6 600	7 000	7500	7 600	7 000	7 500	7 100
a. **Enteric Fermentation**	1 400	1 800	2 000	2 000	2 100	2200	2 400	2 400	2 400	2 200
b. **Manure Management**	520	660	750	800	850	880	910	920	930	880
c. **Agriculture Soils**	3 300	3 800	4 200	3 800	4 100	4400	4 200	3 600	4 100	4 000
Direct Sources	1 900	2 100	2 300	2 000	2 100	2 300	2 200	1 800	2 100	2 000
Pasture, Range and Paddock Manure	230	300	340	360	370	390	420	430	420	390
Indirect Sources	1 000	1 000	2 000	1 000	2 000	2000	2 000	1 000	2 000	2 000
WASTE	600	690	760	770	790	800	810	820	840	850
a. **Solid Waste Disposal on Land**	570	660	730	740	750	760	780	790	800	810
b. **Wastewater Handling**	31	32	33	34	34	33	34	33	33	34
c. **Waste Incineration**	–	–	–	–	–	–	–	–	–	–

Notes:

1. Emissions from fuel ethanol are reported within the gasoline transportation subcategories.
2. Fugitive emissions from refineries and the bitumen industry are only reported at the national level.
3. Fugitive emissions from coal mining activities for 2002 and 2003 have been extrapolated based on publicly available data.
4. Emissions associated with the use of mineral products, production and consumption of halocarbons & SF_6 are only reported at the national level.
5. Emissions coming from ammonia production are included in the category Other & Undifferentiated Production at provincial levels.

X Indicates confidential data.

– Indicates no emissions.

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Subject: **Tab 9: Demand Side Management**
Reference: **Load Saving Profile**

Please provide an overall monthly DSM load savings profile separately defining peak, shoulder, and off-peak load.

ANSWER:

The following tables provide the monthly energy savings during on and off peak hours. Shoulder savings are not measured for DSM initiatives.

Monthly On Peak Energy Distribution (GW.h @ generation)

	April	May	June	July	August	September	October	November	December	January	February	March	Program On Peak Annual Energy
2009	11	11	11	12	12	12	12	13	16	15	14	13	152
2010	21	21	21	22	22	22	22	25	31	28	25	24	283
2011	29	29	29	30	30	30	31	34	43	39	35	33	392
2012	34	34	35	36	36	36	36	40	50	46	41	39	464
2013	39	39	40	41	41	41	41	46	56	52	47	45	527
2014	41	41	42	43	43	42	43	46	55	53	48	46	542
2015	40	40	41	42	42	41	41	44	51	51	46	45	522
2016	42	41	43	44	44	42	42	45	50	52	47	46	540
2017	45	45	46	47	47	45	45	49	54	57	51	50	582
2018	48	48	50	50	50	48	48	52	58	60	54	53	621
2019	51	50	52	53	53	51	51	55	60	63	57	56	651
2020	53	53	54	56	56	53	53	57	62	65	59	58	680
2021	55	55	57	58	58	55	56	60	65	68	62	61	710
2022	57	57	58	60	60	57	57	61	67	70	63	63	732
2023	59	59	61	63	62	59	59	63	69	72	65	65	757
2024	60	60	61	63	63	59	60	64	69	73	66	65	762

Monthly Off Peak Energy Distribution (GW.h @ generation)

	April	May	June	July	August	September	October	November	December	January	February	March	Program Off Peak Annual Energy
2009	7	7	7	7	7	7	7	8	10	9	8	8	92
2010	13	12	11	11	11	11	12	14	17	16	14	14	157
2011	17	16	15	15	15	15	16	19	24	23	19	19	214
2012	20	19	18	18	18	18	20	23	28	27	23	22	255
2013	23	22	20	20	21	21	22	26	32	31	27	26	291
2014	24	23	21	21	22	21	23	27	32	32	28	27	300
2015	22	20	19	19	19	20	21	25	29	30	26	25	276
2016	23	21	20	20	20	20	22	26	29	31	27	26	286
2017	25	23	21	21	21	22	24	28	32	34	29	28	308
2018	26	24	23	22	23	23	26	30	34	36	31	30	328
2019	27	25	24	24	24	24	27	31	35	37	32	31	342
2020	29	27	25	25	25	26	28	32	36	38	33	33	357
2021	30	28	26	26	27	27	29	33	38	40	35	34	372
2022	31	29	27	27	28	27	30	34	39	41	35	35	382
2023	32	30	28	28	28	28	31	35	40	42	36	36	394
2024	32	30	28	28	29	29	31	35	40	42	37	36	396

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Subject: **Tab 9: Demand Side Management**
Reference: **DSM Program Spending**

Under what circumstances would a Residential or Commercial program with the RIM score of less than 1.0 proceed?

ANSWER:

As a guideline, Manitoba Hydro attempts to design electricity based DSM programs that have a RIM of 1.0 or greater. If a preliminary program design has a RIM of less than 1.0, alternative program designs are assessed to determine if acceptable energy savings can be achieved through a different approach. Program designs with a RIM of less than 1.0 may still proceed if the program design is judged to provide benefits to the Corporation's overall Power Smart Initiative and will assist in achieving the Corporation's strategic goals.

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Subject: **Tab 9: Demand Side Management**
Reference: **Appendix 9-2 Pages c & d, Exhibit E.1**

Please explain what factors led to savings related Codes and Standards being 28 GWh, 22 GW.h less than the 50 GW.h plan for 2007/08.

ANSWER:

The planned energy savings which were included in the 2006 Power Smart Plan were too optimistic and have since been revised to lower targets.

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Subject: **Tab 9: Demand Side Management**
Reference: **DSM Spending & Allocation**

a) **Please provide a schedule which shows the DSM program spending and relative proportion of total DSM program spending by customer type for each of the years 2006/07 through 2011/12.**

ANSWER:

The following table outlines the DSM spending by customer type.

DSM SPENDING BY SECTOR						
	Actual 2006/07	Actual 2007/08	Actual 2008/09	Forecast 2009/10	Forecast 2010/2011	Forecast 2011/12
Residential	$6,003,285	$7,158,353	$7,947,670	$10,806,498	$10,979,745	$10,639,167
Commercial	$19,664,838	$17,568,466	$14,836,241	$16,209,263	$16,074,474	$13,673,140
Industrial	$10,475,698	$12,382,006	$12,394,251	$13,312,929	$15,934,632	$18,182,086
Total	**$36,143,821**	**$37,108,826**	**$35,178,161**	**$40,328,689**	**$42,988,851**	**$42,494,393**

The following table outlines the relative proportion of DSM spending by customer type.

DSM SPENDING BY SECTOR						
	Actual 2006/07	Actual 2007/08	Actual 2008/09	Forecast 2009/10	Forecast 2010/2011	Forecast 2011/12
Residential	17%	19%	23%	27%	26%	25%
Commercial	54%	47%	42%	40%	37%	32%
Industrial	29%	33%	35%	33%	37%	43%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

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Subject: **Tab 9: Demand Side Management**
Reference: **DSM Spending & Allocation**

b) Please provide a schedule which reflects the allocation of DSM expenditures and relative proportion by Customer Class for each of the years 2006/07 through 2011/12.

ANSWER:

Annual DSM expenditures are forecast and tracked on an aggregate basis by sector and program in the Power Smart Annual Review and Plan. DSM expenditures are not tracked by customer class; rather Power Smart spending is capitalized based on expenditures by program.

The amortization and interest costs related to the DSM expenditures are only allocated to the customer classes during the preparation of a Prospective Cost of Service Study (PCOSS). For the 2010 PCOSS forecast amortization and interest costs were calculated on the unamortized balance of all DSM programs completed to 2007/08, as well as the forecast spending to the end of 2009/10, and then assigned to the customer classes.

In the 2010 PCOSS the cost of DSM allocated to each customer class, as well as the relative proportion allocated to each class, are as follows:

Forecast DSM Costs in PCOSS10
($ 000's)

	Interest	Depreciation	Total	Relative Proportion
Residential	2,565	3,959	6,524	17%
GSS ND	1,913	2,848	4,761	12%
GSS Demand	2,174	3,513	5,687	15%
GSM	2,657	4,000	6,657	17%
GSL 0-30 kV	1,306	1,970	3,276	9%
GSL 30-100 kV	455	793	1,248	3%
GSL >100 kV	3,610	6,388	9,998	26%
Street Lights	2	6	8	0%
	14,682	23,477	38,159	100%

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Subject: Tab 9: Demand Side Management
Reference: Tab 10 Residential Rate Increases

Please quantify and explain the impact of the proposed lower Basic Monthly Charge and higher second block energy rates on the full spectrum of low income customers including those with electric heat.

ANSWER:

The impact of the proposed lower Basic Charge and higher second block energy rate will be the same for bills of low-income customers as it is for non low-income customers.

Based on the proposed residential rates filed in Appendix 10.3 of the Application, customers who consume less than an average 835 kW.h per month (10,020 kW.h annually) will experience a rate decrease. Those consuming more than 835 kW.h per month will experience bill increases which rise as usage increases, as shown in the following table.

RESIDENTIAL 200 AMP & LESS

KW.h	April 1, 2009 $/MONTH	April 1, 2010 $/MONTH	DIFF. $/MONTH	% Chg.
0	$6.85	$5.85	($1.00)	-14.60%
10	$7.48	$6.49	($0.99)	-13.24%
20	$8.10	$7.12	($0.98)	-12.10%
40	$9.35	$8.40	($0.95)	-10.16%
60	$10.60	$9.67	($0.93)	-8.77%
75	$11.54	$10.63	($0.91)	-7.89%
80	$11.85	$10.95	($0.90)	-7.59%
100	$13.10	$12.22	($0.88)	-6.72%
125	$14.66	$13.81	($0.85)	-5.80%
150	$16.23	$15.41	($0.82)	-5.05%
175	$17.79	$17.00	($0.79)	-4.44%
185	$18.41	$17.63	($0.78)	-4.24%
200	$19.35	$18.59	($0.76)	-3.93%

KW.h	April 1, 2009 $/MONTH	April 1, 2010 $/MONTH	DIFF. $/MONTH	% Chg.
250	$22.48	$21.78	($0.70)	-3.11%
300	$25.60	$24.96	($0.64)	-2.50%
350	$28.73	$28.15	($0.58)	-2.02%
375	$30.29	$29.74	($0.55)	-1.82%
400	$31.85	$31.33	($0.52)	-1.63%
500	$38.10	$37.70	($0.40)	-1.05%
600	$44.35	$44.07	($0.28)	-0.63%
700	$50.60	$50.44	($0.16)	-0.32%
750	$53.73	$53.63	($0.10)	-0.19%
835	$59.04	$59.04	$0.00	0.00%
900	$63.10	$63.18	$0.08	0.13%
1000	$69.40	$69.93	$0.53	0.76%
1100	$75.70	$76.68	$0.98	1.29%
1200	$82.00	$83.43	$1.43	1.74%
1300	$88.30	$90.18	$1.88	2.13%
1400	$94.60	$96.93	$2.33	2.46%
1500	$100.90	$103.68	$2.78	2.76%
1750	$116.65	$120.56	$3.91	3.35%
2000	$132.40	$137.43	$5.03	3.80%
2500	$163.90	$171.18	$7.28	4.44%
3000	$195.40	$204.93	$9.53	4.88%
4000	$258.40	$272.43	$14.03	5.43%
5000	$321.40	$339.93	$18.53	5.77%

PUB/MH I-129

Subject: **Tab 9: Demand Side Management**
Reference: **2007/08 Power Smart Review exhibits 4.3.2.1B, 4.3.2.2B**

a) Please explain the substantial inferred online percentage [G.WH divided by MW x 8760] for power savings with respect to:

- **i. Customer self generation to 2006/07;**
- **ii. Commercial lighting to 2007/08;**
- **iii. Internal retrofits to 2007/08;**
- **iv. Commercial Heat Pads to 2007/08;**
- **v. Other high winter demand ventures to 2007/08.**

ANSWER:

i. The Customer Load Displacement Pilot is a customer self generation initiative. When operational, the generator operates 24 hours a day, seven days a week. As such, the energy savings relative to the capacity results in a high online percentage, similar to capacity factor.

ii. The Commercial Lighting program results in relatively high inferred online percentage due to the high usage rate associated with commercial lighting applications.

iii. The majority of the Internal Retrofit Program energy savings are related to lighting and as such, the inferred online percentage is high for this initiative.

iv. The high inferred online percentage associated with agricultural heat pads is due to the high usage of these units and to a lesser extent, due to the energy savings being higher during the summer relative to the winter. Winter demand savings are reported in exhibit 4.3.2.2B of the Power Smart Annual Review. Using the higher energy savings which are achieved during the summer in combination with the lower winter capacity results in a high inferred online percentage.

v. The Seasonal LED Program has a high inferred online percentage due to the technology's hours of operation which is predominantly at night. As demand savings during off-peak hours are not coincident with system peaks, there is virtual no value associated with the demand savings. Peak demand savings are relatively small and as a result, the technology results in a high inferred online percentage.

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Subject: Tab 9: Demand Side Management

Reference: 2007/08 Power Smart Review exhibits 4.3.2.1B, 4.3.2.2B

b) **Please identify the efficiency programs that provide higher summer than winter MW savings.**

ANSWER:

	2007/08	
Program	**Average Winter MW**	**Summer MW**
Appliances	0.5	0.6
Agricultural Heat Pads	0.5	0.6
Commercial Chillers	0.0	0.1
Commercial Lighting	2.9	4.1
Commerical Custom	0.2	0.2
Commerical Windows	0.1	0.1

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Subject: **Tab 9: Demand Side Management**
Reference: **2007/08 Power Smart Review exhibits 4.3.2.1B, 4.3.2.2B**

c) Do MH's efficiency programs attach equal value to winter & summer MW savings, to Peak and Off – Peak MW savings? Explain the economic and GHG emissions rationale that supports MH's approach.

<u>ANSWER</u>:

Manitoba Hydro attaches a higher value to winter demand savings and on-peak demand savings because this is the period of peak demand for the Manitoba Hydro generation and transmission system. Winter capacity is more valuable to Manitoba Hydro due to a combination of electricity market values, system operating constraints and transmission and distribution limitations. Demand savings during off-peak hours are valued at zero as these savings are not coincident with system peaks.

The value associated with potential green house gas emission reductions is captured within the electricity export prices.

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Subject: **Tab 9: Demand Side Management**
Reference: **2007/08 Power Smart Review exhibits 4.3.2.1B, 4.3.2.2B**

a) Please explain how the energy savings and the demand savings for each of the following DSM programs were determined:

i. Seasonal LED Lighting;
ii. Parking Lot Controllers;
iii. Custom; and
iv. Spray Valves.

ANSWER:

i. Seasonal LED Lighting

- Per unit energy savings were determined by calculating the average energy use of LED light strings versus inefficient incandescent light strings. This energy savings estimate was then multiplied by the number of rebated participants for the 2007/08 year.
- Total energy savings were then adjusted to take into account free riders.
- The total figure found in the 2007/08 Power Smart Review in exhibits 4.3.2.1B, 4.3.2.2B (see Appendix 9.2 of this Application), includes the energy savings achieved during 2007/08 and the energy savings persisting from participation during previous years.

ii. Parking Lot Controllers

- Energy savings per controller were based on an estimate of plug in hours over the year and weather history. Given that a controlled parking plug restricts power to the plug during periods of warmer temperatures, the weather history allowed for an estimate of how much off time, and therefore energy savings, a controlled plug would experience versus an uncontrolled plug which would be drawing power 100 per cent of the time. The per unit energy savings were then multiplied by the number units installed by the rebated participants for the 2007/08 year.
- 2007/08 program savings were adjusted to take into account free riders.

- The total figure provided in the 2007/08 Power Smart Review exhibits 4.3.2.1B, 4.3.2.2B (see Appendix 9.2 of this Application), takes the energy savings from 2007/08 year participants and adds the energy savings from past years' participants that are still be realized in 2007/08.

iii. Custom

- Energy savings were determined through an analysis of the actual work performed by the rebated participants for the 2007/08 year. Program participation requires the completion of an engineering feasibility study which provides detailed energy savings associated with the projects and technologies.
- The total figure found in the 2007/08 Power Smart Review exhibits 4.3.2.1B, 4.3.2.2B (see Appendix 9.2 of this Application), takes the energy savings from 2007/08 year participants and adds the energy savings from past years' participants that are still be achieved in 2007/08.

iv. Spray Valves

- Per unit energy savings were determined by calculating the energy use of the energy efficient low flow spray valve at 4.7 litres per minutes versus the existing installed valve which was deemed to have an average flow rate of 10.6 litres per minute. The per unit savings were then multiplied by the number units installed by the rebated participants for the 2007/08 year.
- The 2007/08 program energy savings were adjusted to take into account free ridership.
- The total figure found in the 2007/08 Power Smart Review exhibits 4.3.2.1B, 4.3.2.2B (see Appendix 9.2 of this Application), takes the energy savings from 2007/08 year participants and adds the energy savings from past years' participants that are still be realized in 2007/08.

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Subject: **Tab 9: Demand Side Management**
Reference: **2007/08 Power Smart Review exhibits 4.3.2.1B, 4.3.2.2B**

b) **Please identify the period of time in a year over which MH estimates the energy and demand savings experience for each of the programs listed in [a]. Please explain how 1.0 GWh of energy were saved with the Seasonal LED Lighting Program, yet negligible demand savings were achieved.**

ANSWER:

i. Seasonal LED Lighting

Holiday lights are typically used in the evening for a few weeks during the winter. These lights are typically used during off peak hours and as a result, the Seasonal LED Lighting Program achieves a significantly higher level of energy savings relative to demand savings.

ii. Parking Lot Controllers

All electricity savings were achieved during the winter in 2007/08.

iii. Custom

For 2007/08, 53% of the electricity savings were achieved during the winter and 47% during the summer.

iv. Spray Valves

For 2007/08, 50% of the electricity savings were achieved during the winter and 50% during the summer.

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Subject: **Tab 9: Demand Side Management**
Reference: **2007/08 Power Smart Review exhibits 4.3.2.1B, 4.3.2.2B**

c) **Please provide a tabulation of the on – line hours in a year employed in each of the energy savings programs identified by MH.**

ANSWER:

Energy saving technologies are evaluated using the method most appropriate to the specific technology under assessment. In the case of appliances, third-party data from Energy Star regarding annual consumption is utilized to define energy savings between inefficient and efficient technologies. In the case of technologies such as building envelope measures and thermostats, the technologies themselves do not consume energy however result in energy savings through impacts on heating system consumption. Accordingly, on-line hours is not a measure that is applicable for all programs. A tabulation of the on-line hours used for each applicable program using this metric is provided in the following table:

Program	On Line Hours
RESIDENTIAL	
Compact Fluorescent Lighting	1500 hrs
New Homes: Car Timer EE Lighting Showerhead	 300 hrs 1500 hrs 90 hrs
Seasonal LED Lighting	252 hrs
Energy Efficient Light Fixtures	1500 hrs
Water Saver Package: Showerhead Kitchen faucet aerator Bathroom faucet aerator	 90 hrs 9 hrs 9 hrs
Residential Geothermal	1000 hrs
ECM	6425 hrs

Program	**On Line Hours**
COMMERCIAL	
Commercial Lighting:	
T8	3000 hrs
T5	3000 hrs
Occupancy sensors,	3000 hrs
High performance luminaries	3000 hrs
High pressure sodium interior	3500 hrs
Probe start metal halite	3500 hrs
Pulse start quartz metal halite	3500 hrs
Pulse start ceramic metal halite	4000 hrs
High pressure sodium exterior	4380 hrs
LED backlit signs	4400 hrs
Compact fluorescent lamps	4476 hrs
LED exit signs	8760 hrs
Agricultural Heat Pads	5625 hrs
Commercial Geothermal	2000 hrs
Parking Lot Controller:	
Multi-residential	560 hrs
Industrial and institutional	960 hrs
Offices	320 hrs
Commercial Refrigeration	4960 hrs
Spray Valves	730 hrs

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Subject: **Tab 9: Demand Side Management**
Reference: **2009 Power Smart Plan Appendix A.1-A.3 Power Smart Targets**

a) Please explain how the energy savings and the demand savings for each of the following DSM programs were estimated:

i. Fridge Recycling;
ii. HVAC- Chiller;
iii. Parking Lot Controller;
iv. Agriculture Heat Pad;
v. Power Smart Energy Manager; and
vi. C02 Sensors.

ANSWER:

i. Fridge Recycling

- The average energy savings per removed unit was calculated by determining the estimated energy consumption of the unit removed. This was determined through research undertaken which included assessing assumptions used with other utility programs, published NRCan EnerGuide data, and conversations with existing fridge recycling service providers delivering programs in the market.
- Average energy savings per unit removed were then discounted by estimating that 55% of these units would remain off the system permanently, and 45% of the removed units would be replaced with a new model.
- The expected remaining useful life of the removed appliance was estimated and energy savings per unit were multiplied by this number.
- Interactive effects with heating and cooling equipment were taken into account and incorporated into the net average energy savings per unit.
- Total participants were estimated by determining the number of units that could reasonably be expected to be collected. This was determined through research undertaken which included assessing assumptions used with other utility programs and contact with existing fridge recycling service providers. The net energy savings per unit were then multiplied by the expected number of participants to estimate total program energy savings.

- The total program energy savings were adjusted to take into account free ridership.

ii. HVAC - Chiller

- Annual per unit energy savings were based on the difference in energy usage between standard air-cooled chillers versus efficient water-cooled chillers and the energy savings were calculated using the customer's full load operating hours and equipment capacity in tons.
- The per unit energy savings were then multiplied by the program participation forecast.
- The total program energy savings were then adjusted to take into account free ridership.

iii. Parking Lot Controller

- Energy savings per controller were based on an estimate of plug in hours over the year and weather history. Given that a controlled parking plug restricts power to the plug during periods of warmer weather temperatures, the weather history allowed for an estimate of how much off time, and therefore energy savings, a controlled plug would experience versus an uncontrolled plug which would be drawing power 100 per cent of the time while being plugged in.
- The per unit energy savings were then multiplied by the program participation forecast.
- The total program energy savings were adjusted to take into account free ridership.

iv. Agriculture Heat Pad

- Per unit electricity energy savings were calculated through an analysis of the difference in electricity consumption between standard heating lamps and energy efficient heat pads, multiplied by the annual hours of operation.
- The per unit energy savings were then multiplied by the program participation forecast.
- The total program energy savings were then adjusted to take into account free ridership.

v. Power Smart Energy Manager

- Per participant annual electricity savings were estimated by reviewing the energy savings achieved through Manitoba Hydro's pilot Energy Manager Program delivered in the Pembina Trails School Division in 2001 through 2005.
- The per participant energy savings were then multiplied by a program participation forecast.

vi. CO2 Sensors

- Annual energy savings were estimated based on average target building operating hours, occupancy rates, and heating and cooling system efficiencies. These sensors measure actual CO2 levels and reduce ventilation frequency based on observed CO2 levels, therefore, energy savings are achieved through the reduced amount of outside air needing heating or cooling as compared to a building that does not have a sensor.
- The per participant energy savings were then multiplied by a program participation forecast.
- The total program energy savings were then adjusted to take into account free ridership.

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Subject: **Tab 9: Demand Side Management**
Reference: **2009 Power Smart Plan Appendix A.1-A.3 Power Smart Targets**

b) Please identify the period of time in a year over which MH estimates the energy and demand savings are experienced for each of the programs listed in [a]. Please explain how in 2009/10 1.9 GWh of energy are estimated to be saved attributable to the Power Smart Energy Manager program, yet demand savings of only 0.1 MW are expected. Also explain how in 2024/25 CO2 Sensors are expected to save 1.1 GWh, yet negligible demand savings are expected.

ANSWER:

i. Fridge Recycling

It is estimated that 45% of the electricity savings will be achieved during the winter and 55% during the summer.

ii. HVAC - Chiller

It is estimated that all electricity savings will be achieved during the summer.

iii. Parking Lot Controller

It is estimated that all electricity savings will be achieved during the winter.

iv. Agriculture Heat Pad

It is estimated that 52% of the electricity savings will be achieved during the winter and 48% during the summer.

v. Power Smart Energy Manager

It is estimated that 40% of the electricity savings will be achieved during the winter and 60% during the summer.

In 2009/10, the Power Smart Energy Manager Program is expected to achieve 1.9 GWh of energy and 0.1 MW of demand. There is only a small demand savings as the majority of electricity savings occur during off peak electric load periods. Equipment, air exchangers and lighting in school buildings are generally required to be on during peak times for student, staff, maintenance and cleaning purposes.

vi. CO2 Sensors

It is estimated that virtually all of the electricity savings will be achieved during the summer.

By 2024/25, CO2 sensors are expected to save 1.1 GWh with negligible demand savings. CO2 sensors save energy when buildings are not fully occupied which typically occurs during off peak electric load periods. As such, it is estimated that there is virtually no demand savings achieved through the CO2 Sensor Program.

PUB/MH I-132

Subject: **Tab 9: Demand Side Management**
Reference: **2009 Power Smart Plan Section 4.3 – Economic Effectiveness Ratios**

a) The 2009 Power Smart Plan provides the results of the TRC, RIM, and LUC cost-effectiveness measures, but does not provide the inputs to undertake the calculation of the ratios for these measures. Please provide the following for each of the Incentive – based electric DSM program:

- **i. The revenue realized by MH from conserved electricity sold in the export market;**
- **ii. The avoided cost of new infrastructure;**
- **iii. The total program administration costs, and utility program administration costs [if different];**
- **iv. The incremental product costs;**
- **v. The revenue loss resulting from reduced consumption;**
- **vi. The cost of incentives; and**
- **vii. The energy saved.**

ANSWER:

The following table outlines the inputs for the various cost-effectiveness measures of each incentive-based program in the 2009 Power Smart Plan. One marginal benefit value is provided for (i) and (ii) as these values are not independently calculated. As a proxy, it is estimated that 75% of the marginal value is from export revenue and 25% of the marginal value is from the avoided cost of new infrastructure.

	Marginal Benefits		Program Admin Costs		Incremental Product Cost	Revenue Loss	Incentives		Energy Saved
	INPUT i & ii		INPUT iii		INPUT iv	INPUT v	INPUT vi		INPUT vii
	PV of Marginal Benefit	***PV of Non-Energy (Water) Benefits***	***PV of Utility Program Admin Costs***	***PV of AEF Program Admin Costs***	***PV of Incremental Product Costs***	***PV of Revenue Loss***	***PV of Utility Incentives***	***PV of AEF Incentives***	***PV of Energy Saved @ Gen (kW.h)***
RESIDENTIAL									
New Home	$27,465,817	$0	$1,179,447	$0	$13,268,399	$17,841,851	$498,404	$0	295,615,532
Home Insulation	$44,139,657	$0	$2,303,238	$0	$7,717,119	$20,585,204	$5,303,602	$0	343,077,994
Water and Energy Saver	$21,799,156	$14,389,900	$2,523,149	$0	$1,228,992	$16,375,333	$1,245,158	$0	283,586,906
Lower Income	$19,820,833	$2,510,036	$337,976	$1,733,245	$11,398,668	$12,528,866	$1,025,270	$4,775,902	213,886,387
HE Furnace & Boiler	$1,031,475	$0	$0	$0	$1,340,677	$555,091	$0	$0	9,526,204
EE Light Fixtures	$1,983,289	$0	$1,013,293	$0	$62,403	$1,320,823	$368,489	$0	26,086,831
Residential CFL	$50,860,299	$0	$1,709,685	$0	$1,612,649	$34,415,732	$3,005,910	$0	627,476,240
Fridge Recycling	$24,527,762	$0	$7,329,721	$0	$8,102,463	$22,014,257	$2,193,891	$0	387,605,783
Appliances	$3,834,486	$8,437,540	$326,824	$0	$2,721,431	$2,741,979	$0	$0	48,027,994
COMMERCIAL									
Lighting	$347,400,207	$0	$18,719,997	$0	$120,922,999	$189,859,470	$40,935,892	$0	3,488,418,075
Custom Measures	$6,702,125	$0	$825,977	$0	$1,836,503	$3,409,991	$1,237,406	$0	83,999,761
Windows	$18,886,559	$0	$4,827,354	$0	$3,247,172	$8,380,272	$2,320,877	$0	157,555,226
HVAC - Chiller	$7,876,706	$0	$72,663	$0	$4,500,017	$5,492,316	$1,649,427	$0	173,096,889
Parking Lot Controller	$7,876,418	$0	$181,073	$0	$1,955,936	$4,106,607	$361,404	$0	109,875,846
City of Winnipeg Agreement	$642,251	$0	$5,662	$0	$72,568	$358,018	$66,906	$0	6,566,394
Rinse & Save	$789,893	$1,014,745	$12,291	$0	$16,540	$551,210	$18,354	$0	12,044,790
Refrigeration	$38,098,408	$0	$1,038,279	$0	$5,487,109	$24,601,577	$1,900,401	$0	486,802,139
Insulation	$42,030,068	$0	$4,827,354	$0	$8,470,339	$18,355,272	$2,705,037	$0	301,643,229
Earth Power	$21,908,731	$0	$1,613,844	$0	$6,634,094	$9,368,813	$2,429,589	$0	175,206,593
New Construction	$31,251,333	$0	$2,602,627	$0	$18,389,714	$17,980,300	$7,980,897	$0	335,927,288
Building Optimization	$14,887,954	$0	$595,513	$0	$2,364,756	$7,011,829	$1,349,792	$0	136,823,103
Internal Retrofit	$31,277,686	$0	$6,715,467	$0	$20,791,677	$0		$0	309,398,949
Agricultural Heat Pad	$7,123,948	$0	$49,510	$0	$0	$3,706,116	$183,776	$0	98,139,001
Power Smart Energy Manager	$8,117,762	$0	$828,698	$0	$1,787,000	$4,490,749	$73,849	$0	150,886,092
Kitchen Appliances	$3,884,549	$3,145,983	$101,053	$0	$1,921,803	$2,057,453	$783,472	$0	34,460,247
Clothes Washers	$3,596,898	$1,664,163	$184,420	$0	$2,413,318	$1,656,657	$416,347	$0	19,589,824
Network Energy Management	$10,973,062	$0	$292,332	$0	$2,868,248	$7,819,628	$1,768,838	$0	149,354,594
Power Smart Shops	$8,040,354	$1,453,679	$1,497,172	$0	$3,486,023	$5,859,049	$695,483	$0	103,463,120
CO2 Sensors	$453,820	$0	$18,171	$0	$73,995	$253,540	$43,323	$0	8,766,464
INDUSTRIAL									
Performance Optimization	$146,211,813	$0	$9,930,423	$0	$28,960,435	$76,602,313	$19,696,471	$0	1,869,852,327
Emergency Preparedness	$50,562,529	$0	$2,149,227	$0	$19,127,566	$29,094,777	$14,982,101	$0	273,600,739
Customer Self Generation									
Bioenergy Optimization	$93,377,793	$0	$2,478,727	$0	$54,528,780	$46,946,422	$17,549,580	$0	1,229,772,822

PUB/MH I-132

Subject: **Tab 9: Demand Side Management**
Reference: **2009 Power Smart Plan Section 4.3 – Economic Effectiveness Ratios**

b) **Please explain the methodology for determining the Present Value of each of these inputs in the cost-effectiveness ratios including the various required input factors such as discount rate used. Tab 10: Proposed Rates And Customer Impacts**

ANSWER:

The Present Value of each input in the cost-effectiveness ratios used Manitoba Hydro's real weighted average cost of capital at the time the 2009 Power Smart Plan was created (6.1%) discounted over a 30 year period.

PUB/MH I-133

Subject: Tab 10: Proposed Rates And Customer Impacts
Reference: Tab 10 Page 3 of 10 Basic Monthly Charge

a) **Please discuss and quantify the costs (both fixed and variable) that are theoretically to be recovered from the electric BMC.**

ANSWER:

Currently, the electric BMC for residential customers is $6.85, which recovers approximately 34% of the fixed customer related costs as determined in PCOSS10. If all fixed customer related costs were recovered through the BMC, Manitoba Hydro would need to increase its BMC to approximately $20 per customer per month (as per Appendix 11.1, page 16 of the Application). From a theoretical perspective a basic monthly charge is put in place to recover only fixed customer costs; those costs which can be identified to vary exclusively with the number of customers regardless of whether the customer imposes any demand or energy requirements on the system. The costs recoverable through the BMC include some of the costs associated with distribution circuits as well as the costs associated with customer service lines, meters, meter reading, billing and general customer service.

It is arguable that customer hook-up and usage is much less influenced by the level of the Basic Monthly Charge than the level of the Demand or Energy charges. Consequently, in a situation such as Manitoba Hydro's in which embedded costs are significantly lower than marginal costs, it is not unreasonable for fixed charges to under-recover relative to fixed costs, to assist in maintaining flexibility to move the more price elastic part of the rate structure, the energy charge, closer to marginal cost. A lower fixed charge and therefore a higher variable rate also assists in allowing the customer greater control over the level of their bill. Additionally, basic monthly charges are typically not well understood or accepted by customers. It is therefore not uncommon for utilities to set the level of the charge below the fully embedded customer costs, a trade off between establishing strictly cost based rates and the practical realities of providing customers with service.

PUB/MH I-133

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

b) What percentage of the theoretical costs are currently being recovered in the residential BMC?

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-133(a).

PUB/MH I-133

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

c) What percentage of the costs will be recovered under the proposed reductions to the electric BMC in this application?

ANSWER:

The proposed residential BMC of $5.85 would recover 29% of the $20.38 fixed customer related costs as determined in PCOSS10 (Appendix 11.1, page 16).

PUB/MH I-133

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

d) **Please quantify the costs both fixed and variable that are theoretically to be recovered from Gas operations and the percentage of those costs currently recovered in the Gas BMC.**

ANSWER:

The $14.00 Gas BMC for the SGS class that will be implemented on May 1, 2010 will recover 50.2% of fixed customer related costs. If all fixed customer related costs were recovered through the BMC, Centra’s BMC would have to increase to approximately $28.00 for SGS customers. From a theoretical perspective a basic monthly charge in place to recover only fixed customer costs; those costs which can be identified to vary exclusively with the number of customers regardless of whether the customer imposes any demand or energy requirements on the system. Such costs include service lines, meters, meter reading, billing, general customer service and distribution system costs deemed to be customer related.

PUB/MH I-133

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

e) **Please provide the detailed rationale that MH has relied upon in making the request to reduce the BMC.**

ANSWER:

The rationale for a reduction to the basic charge is two fold. First it eliminates the difficulty associated with establishing and monitoring income screening for low income consumers which is also intrusive to their privacy. Second, the reduction to the basic charge also accelerates the inverted rate objectives that will encourage all Manitobans to conserve energy.

For additional information please see Manitoba Hydro's response to CAC/MSOS/MH I-1(c).

PUB/MH I-133

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

f) **Confirm and discuss that higher volume residential customers will be cross subsidizing the customer service and fixed distribution costs of low volume residential customer.**

ANSWER:

It is true that the revenue shortfall attributed to a lower monthly Basic Charge (BMC) would be recovered through a higher tail block energy rate thereby impacting higher volume residential customers more. As discussed in parts (a) and (b) of this same question the BMC currently charged only recovers 34% of the calculated customer charge in the Cost of Service Study (PCOSS10) which is $20.38/month. Thus, from a strictly embedded cost perspective, there is apparent subsidization of fixed distribution cost of the low volume residential customer.

To the extent that there is cross-subsidization of low volume users and to the extent that low volume equates to low income, such cross-subsidization is consistent with the objectives of low income assistance programs.

PUB/MH I-133

Reference: Tab 10 page 3 of 10 basic monthly charge

g) Discuss the impact on a typical residential customer utilizing electric heat and provide supporting calculations.

ANSWER:

Higher usage electric customers will pay higher energy bills with the proposed reduction in the basic monthly charge (BMC). The primary reason is that the revenue loss in the reduction of the BMC must still be recovered in some other manner. As detailed in Tab 10 of the Application, the proposed energy rates are to increase 1.9% in the first energy block (up to 900 kW.h/month) and 7.1% in the second, or tail block, portion for all monthly consumption in excess 900 kW.h/month.

The following bill comparison from Appendix 10.5 from the Application outlines the impact. All-Electric Residential customers average approximately 2,300 kW.h/month over the year.

Bill Comparison

Residential

Forecast Customers: 445,517

kW.h	April 1, 2009 $ / Month	April 1, 2010 $ / Month	Difference in $ / Month	Percent Change
250	$22.48	$21.78	($0.70)	(3.11%)
750	$53.73	$53.63	($0.10)	(0.19%)
1 000	$69.40	$69.93	$0.53	0.76%
2 000	$132.40	$137.43	$5.03	3.80%
5 000	$321.40	$339.93	$18.53	5.77%

On February 9, 2010 Manitoba Hydro received Order 18/10 which granted interim approval of Manitoba Hydro’s proposed 2.9% general rate increase for April 1, 2010. However in this Order the PUB directed that the current BMC not be reduced.

<u>PUB/MH I-133</u>

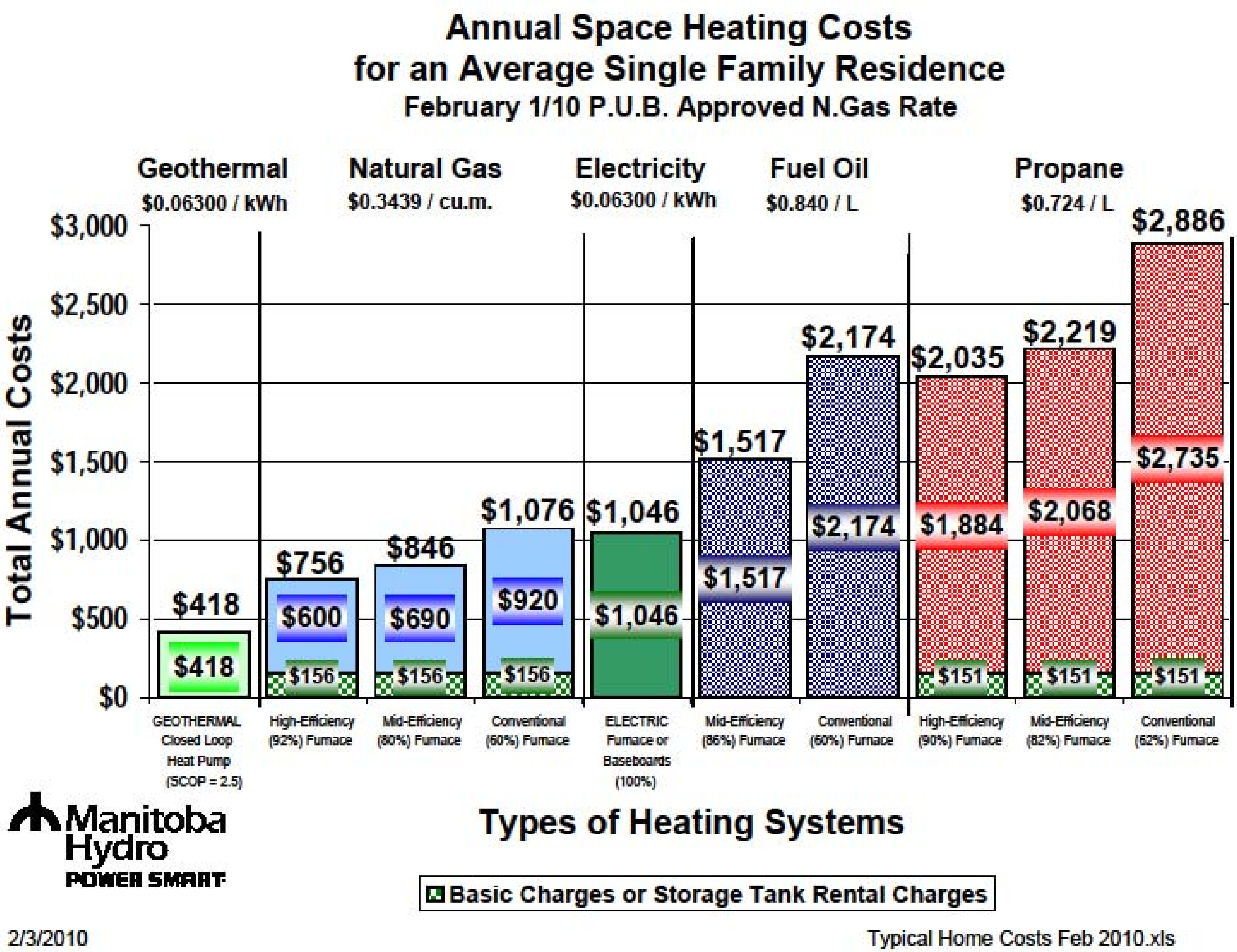
Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Tab 10 Page 3 of 10 Basic Monthly Charge**

h) Provide a comparison to home heating cost between gas and electricity and at what electricity price are the heating sources equal.

<u>ANSWER</u>:

See attached for a comparison of typical heating costs using various fuels and efficiencies. For the heating cost to be the same as using natural gas, the following electricity prices would be required for each respective efficiency type of natural gas furnace:

Conventional Furnace -	\$0.065 per kWh.
Mid-Efficiency Furnace -	\$0.051 per kWh.
High-Efficiency Furnace -	\$0.046 per kWh.


Annual Space Heating Costs
for an Average Single Family Residence
February 1/10 P.U.B. Approved N.Gas Rate
Geothermal
$0.06300 / kWh
Natural Gas
$0.3439 / cu.m.
Electricity
$0.06300 / kWh
Fuel Oil
$0.840 / L
Propane
$0.724 / L
Total Annual Costs
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
$418
$418
$756
$600
$156
$846
$690
$156
$1,076
$920
$156
$1,046
$1,046
$1,517
$1,517
$2,174
$2,174
$2,035
$1,884
$151
$2,219
$2,068
$151
$2,886
$2,735
$151
GEOTHERMAL Closed Loop Heat Pump (SCOP = 2.5)
High-Efficiency (92%) Furnace
Mid-Efficiency (80%) Furnace
Conventional (60%) Furnace
ELECTRIC Furnace or Baseboards (100%)
Mid-Efficiency (86%) Furnace
Conventional (60%) Furnace
High-Efficiency (90%) Furnace
Mid-Efficiency (82%) Furnace
Conventional (62%) Furnace
Manitoba Hydro
POWER SMART
Types of Heating Systems
Basic Charges or Storage Tank Rental Charges
2/3/2010
Typical Home Costs Feb 2010.xls

<u>PUB/MH I-134</u>

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **CRP Report April 1/08 – March 31/09 CRP Report April 1/07 – March 31/08**

a) **Please clarify the role of CRP in supporting export sales during:**

- **i.** **Winter months.**
- **ii.** **Summer months.**

<u>ANSWER</u>:

Manitoba Hydro can avoid curtailing firm exports during an emergency through curtailment of certain CRP loads. The CRP provides this role in both the winter and summer months, however the maximum duration of CRP curtailments is less in the winter months (for Option ‘A’ CRP).

PUB/MH I-134

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **CRP Report April 1/08 – March 31/09 CRP Report April 1/07 – March 31/08**

b) **Please confirm that the 230 MW of CRP is currently adequate to satisfy the MISO reserve requirements.**

ANSWER:

The maximum amount of CRP Option 'A' and Option 'C' is currently set at 230 MW. The maximum amount of CRP Option 'R' is currently set at 100 MW. These limits are adequate to meet Manitoba Hydro's obligations to the MISO-MBHydro Contingency Reserve Sharing Group (CRSG).

PUB/MH I-134

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **CRP Report April 1/08 – March 31/09 CRP Report April 1/07 – March 31/08**

c) Does MH contemplate having the increase the CRP to meet:

i. MISO's evolving requirements?
ii. MH's expanding generation capacity (e.g., Wuskwatim, Keeyask, and Conawapa)? If so, please quantify.

ANSWER:

i. Yes, Manitoba Hydro may pursue increasing the CRP as a result of MISO's evolving capacity requirements.

ii. No. The development of new hydraulic generation will not increase the need for curtailable load in Manitoba.

PUB/MH I-135

Subject: **Tab 10: Proposed Rates And Customer Impacts**
Reference: **Power Resource Plan 2008/09**

a) Please define the further capacity (MW) resource that MH anticipates coming from the CRP

ANSWER:

At this time, Manitoba Hydro does not anticipate any further capacity resource coming from the CRP.

PUB/MH I-135

Subject: Tab 10: Proposed Rates And Customer Impacts
Reference: Power Resource Plan 2008/09

b) What percentage of the CRP capacity is dispatchable?

ANSWER:

The minimum notice to curtail Option 'A' and Option 'R' loads is 5 minutes, hence it can be considered dispatchable for the allowed uses defined in the CRP. The total of Option 'A' and Option 'R' load makes up approximately 88 % of the total CRP load under contract.

PUB/MH I-136

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 7)**

a) Please explain why thermal generation would continue to be deducted from exports in defining export shares of G&T costs, when thermal does not generally support export?

ANSWER:

The direct assignment of a portion of the fuel and variable maintenance costs from Brandon Unit #5 necessitated that the associated thermal energy be deducted from the energy used in the allocation of non-thermal Generation costs. If not for this deduction, the Export class would effectively attract costs twice for the same kilowatt-hour; once by direct assignment of thermal costs and again via allocation of generation costs (net of thermal costs).

PUB/MH I-136

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 7)**

b) **Is it now MH's position that in the absence of thermal generation, there would still be sufficient dependable energy to allow current levels of firm export contracts? Please illustrate how this would play out for the next eight years.**

ANSWER:

Under the Climate Change and Emissions Reductions Act, Brandon coal-fired generation may be used to support firm export contracts that existed prior to this legislation being enacted. Should severe drought conditions occur within the next eight years, it is anticipated that coal-fired operations would be required.

Manitoba Hydro also has the ability to support firm export contracts with generation from Brandon combustion turbines (Units 6 & 7) and Selkirk gas-fired steam turbines (Units 1 & 2).

PUB/MH I-136

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 7)**

c) Would it also be true that MH's domestic load has "almost never used" the thermal plants for normal energy supply in non-emergency situations?

ANSWER:

Under normal energy supply and non-emergency conditions Manitoba Hydro does not require the thermal plants for energy supply purposes. This has been the case since Manitoba Hydro became strongly interconnected with the US market, from which alternate supplies of energy and capacity were available. However, Brandon and Selkirk coal fired generation have historically been economic supplies of electricity at times and have been operated to improve Manitoba Hydro net export revenues especially in the last 15 years as market prices have risen relative to Manitoba Hydro's cost of coal fired generation.

During periods of extensive shutdown, the thermal plants at Brandon and Selkirk operate routinely to maintain proficiency and reliability of service such that the plants could operate to meet Manitoba load should system conditions require.

<u>PUB/MH I-136</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 7)**

d) **Please define the specific times that thermal generation was on-line over the last eight years to meet:**

i. **Domestic load and firm contract exports.**
ii. **Domestic load only.**

<u>ANSWER</u>:

Table 1 provides annual thermal generation for the period 2001/02 through 2008/09. Manitoba Hydro does not have the operating records to disaggregate this information as requested. However, for example, in the drought of 2003/04, thermal generation was used to support reservoir storages to ensure reliable and secure supply of energy to serve domestic load.

Table 1. Annual thermal generation.

Fiscal Year	Thermal Generation (GWh)
2001/02	481
2002/03	601
2003/04	853
2004/05	414
2005/06	401
2006/07	522
2007/08	457
2008/09	335

PUB/MH I-136

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 7)**

e) **Does MH currently make available the thermal generation capacity in respect to ancillary services/other export needs? Explain.**

ANSWER:

Manitoba Hydro currently makes available gas-fired thermal generation for export energy needs (i.e. Brandon combustion turbines and Selkirk gas fired steam turbines). Since restrictions under the Climate Change and Emissions Reductions Act became effective on January 1, 2010, Brandon coal-fired generation is not considered available for export energy needs unless, during drought conditions, such generation is necessary to support firm export contracts that existed prior to this legislation being enacted (see response for PUB/Manitoba Hydro I-136(b)).

At times, Manitoba Hydro uses thermal generation capacity for its own domestic ancillary services requirements. Thermal generation capacity is not made available for export of ancillary services.

PUB/MH I-136

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 7)**

f) Does MH currently rely primarily on energy from the Lower Nelson G.S. to serve its firm export contracts and opportunity sales?

ANSWER:

In general, Manitoba Hydro's export sales are supported from the Manitoba Hydro system as a whole and not from any specific plant or set of plants. To the extent that the Lower Nelson River generating stations supply on average about 75% of Manitoba Hydro's energy supply, Manitoba Hydro does rely on these stations to serve its export sales activities.

PUB/MH I-137

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 8)**

a) Does MH intend to treat the AEF as a second deduction on export revenue (similar to uniform rates) or as first call on net export credits?

ANSWER:

Manitoba Hydro has included AEF in the PCOSS as a deduction on Export revenue similar to the treatment for Uniform Rates, and other costs directly assigned to the Export class such as purchased power, ‘Trading Desk’ or applicable thermal costs.

<u>PUB/MH I-137</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 8)**

b) **Please clarify the requirements/restrictions on programs for that might qualify under the AEF.**

<u>ANSWER</u>:

Funding to support projects through the Affordable Energy Fund shall require consultation with the Minister responsible for Manitoba Hydro and project funding must be for one of the following objectives as outlined with The Winter Heating Cost Control Act:

1) Encourage energy efficiency and conservation, whereby programs and services created for this purpose must be designed and delivered to ensure:

   i. that people living in rural or northern Manitoba, those with low incomes, and seniors have access to those programs and services; and

   ii. that Manitoba Hydro's residential customers have access to comparable programs and services, regardless of the energy source they use to heat their homes.

2) Encourage the use of alternative energy sources, including earth energy.

3) Facilitate research and development of alternative energy sources and innovative energy technologies.

Projects that encourage energy efficiency and conservation (under "1" above) and which target commercial and industrial customers are not eligible for support from the Fund.

Projects and funds must be incremental to expenditures which would normally be made through Manitoba Hydro's Power Smart, R&D or supply-side initiatives. These projects can be new projects, enhanced projects or projects which can no longer be supported through the Power Smart, R&D or supply-side initiatives.

<u>PUB/MH I-137</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 8)**

c) Does MH have a finite annual budget for the AEF, or will this involve variable annual funding?

<u>ANSWER</u>:

Manitoba Hydro has a forecast for annual expenditures that are to be drawn against the Affordable Energy Fund.

<u>PUB/MH I-137</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 8)**

d) Please confirm that the AEF credit essentially only benefits the residential RCC's.

<u>ANSWER</u>:

Confirmed. In PCOSS10 all energy savings from AEF programs, as well as the associated reduction in revenue, were assigned to the residential class.

PUB/MH I-138

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Pages 8 and 9)**

a) Is it MH’s position that it is more cost effective to purchase power than use its current thermal generation to maximize export sales? Explain.

ANSWER:

Manitoba Hydro’s gas-fired generation is inefficient relative to the marginal supply from the import markets. In other words, its ‘heat rate’ is high as compared to the ‘implied heat rate’ in neighbouring markets. For example, the heat rate for the Brandon CT is approximately 13.0 mmbtu/MWh versus an average implied heat rate in Manitoba Hydro’s on-peak export market of between 7.5 and 10.0 mmbtu/MWh. Therefore, given the market is an equivalent alternative supply source, market purchased energy will typically achieve a savings of roughly 25 to 40 percent over Manitoba Hydro gas-fired generation. This savings increases when considering other non-fuel costs of operating gas-fired generation (e.g., maintenance).

PUB/MH I-138 (REVISED)

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Pages 8 and 9)**

b) **Would this suggest that in IFF 08-1, MH was planning to import about 3,000 to 4,000 GWh/year (and avoid thermal generation) in support of its mean flow forecasts?**

ANSWER:

Manitoba Hydro assumed imports of 1,974 GWh in the PCOSS10 and all of the associated costs have been assigned to exports. Under the median flow assumption of the PCOSS10 these imports were required to optimize export revenues. In addition, 475 GWh of thermal generation was required to optimize net export revenues and to meet training and proficiency needs. Additional purchases and thermal above these amounts were not forecast as they were uneconomic. Less amounts of thermal generation were not forecast as that would have resulted in lost opportunity costs.

PUB/MH I-138

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Pages 8 and 9)**

c) As such, would this not suggest that in a mean flow scenario, all transactions, power purchases, as well as exports be considered as export costs?

ANSWER:

Manitoba Hydro is unable to find context for this question from either part (a) or (b) of this Information Request or the reference given.

However, if the Information Request is in reference to the treatment of power purchases in the PCOSS, which is based on median water conditions, Manitoba Hydro can confirm that all power purchases have been assigned as costs to the Export class.

Please also see Manitoba Hydro's response to PUB/MH I-138(d).

PUB/MH I-138

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Pages 8 and 9)**

d) Is MH in effect advocating that all exports be assigned only incremental costs?

ANSWER:

Manitoba Hydro is interpreting the Reference above to be to subsection c) in the "Methodology Used in PCOSS10" section of PCOSS10. This subsection begins on the middle of page 8 and continues to page 9. It deals with the following costs:

– Purchased Power costs;
– US transmission costs;
– Trading desk related costs;
– MAPP and MISO costs.

PCOSS10 assigns these categories of cost between Export Class and domestic customers as follows:

Treatment of Costs in PCOSS10 ($ 000's)

	Export Class	Domestic Classes	Total
'Trading Desk' Costs	4,992	6,988	11,980
Purchased Power	153,650	-	153,650
PSO Transmission	20,400	-	20,400
MISO/MAPP	1,641	2,298	3,939
	180,683	9,286	189,969

As shown in the table, Purchased Power and Transmission costs, which account for over 90% of the costs discussed in subsection c), are fully assigned to the Export class, so this is not a case of assigning incremental cost only.

With respect to the Trading Desk and MAPP/MISO costs, Manitoba Hydro has assigned directly to the Export class only those costs that would not have been incurred if Manitoba

Hydro did not have an export business. An argument could be made that these are "incremental" costs, that is, incremental to what would be required only to serve domestic costs. On the other hand, these are embedded costs in PCOSS10 and any other obvious method of allocation (e.g. on the basis of energy) would assign more cost to the domestic classes. In either case, Manitoba Hydro believes that this method of assigning costs is fully consistent with cost causation. Please see also Manitoba Hydro's response to MIPUG/MH I-22(c) for further elaboration.

Manitoba Hydro intends to commission a complete review of its Cost of Service Study methodology, including the treatment of export sales, and the treatment of these cost categories could be considered in that review.

PUB/MH I-139

Subject: Tab 11: Cost Of Service Study
Reference: PCOSS-10 Methodology Used (Page 9)

a) **Please confirm MH 2009/10 revenue forecast reflects export volumes of 7,707 GWh. The volume is the same as in PCOSS-08, but with a revised price of 5.45¢/kW.h.**

ANSWER:

The forecast Export energy volume used in PCOSS10 is 7,901 GWh. The Metered Energy shown in Schedule B2 is in error. The corrected schedule is shown below.

Please note that the 5.45¢/kW.h shown in Schedule B2 of PCOSS10, and the 5.32¢/kW.h shown in the amended Schedule B2 below, represents the calculated unit cost of exports, not unit revenue.

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2010
Customer, Demand, Energy Cost Analysis

SUMMARY

	CUSTOMER			DEMAND					ENERGY			
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	114,124	466,759	20.38	195,045	0%	n/a	n/a		197,601	6,811,218	5.76	**
GS Small - Non Demand	21,469	52,716	33.94	37,531	0%	n/a	n/a		46,052	1,478,206	5.65	**
GS Small - Demand	6,951	11,260	51.44	44,560	38%	2,203	7.74		60,304	1,983,393	4.43	
General Service - Medium	5,523	1,859	247.59	61,751	100%	7,008	8.81		89,384	3,032,155	2.95	
General Service - Large <30kV	2,773	259	n/a	27,043	100%	3,452	8.64	*	44,383	1,533,322	2.89	
General Service - Large 30-100kV	1,739	30	n/a	9,991	100%	2,455	4.78	*	29,741	1,151,746	2.58	
General Service - Large >100kV	2,014	14	n/a	29,355	100%	9,476	3.31	*	143,770	5,626,174	2.56	
SEP	356	25	1,187.66	242	0%	n/a	n/a		915	22,550	5.13	**
Area & Roadway Lighting	15,217	153,710	8.25	2,375	0%	n/a	n/a		2,252	99,432	4.65	**
Total General Consumers	170,168	686,631		407,892		24,594			614,402	21,738,196		
Diesel	251	732	28.55	376	0%	n/a	n/a		10,660	12,820	86.08	**
Export	n/a	n/a	n/a	52,345	0%	n/a	n/a		367,777	7,901,000	5.32	***
Total System	170,419	687,363		460,613		24,594			992,839	29,652,016		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

PUB/MH I-139

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 9)**

b) Please confirm MH's actual export price in 2008/09 was 5.0¢/kW.h for 9,600 GWh sold.

ANSWER:

Manitoba Hydro's average export price for 2008/09 was $51.63/MWh.

The 9,600 GWh amount referenced is the Net Metered Interchange (i.e. exports – imports). Manitoba Hydro's total exports for 2008/09 were 10,576 GWh.

PUB/MH I-139

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS-10 Methodology Used (Page 9)**

c) **Please provide MH's actual export volumes (GWh) and average unit prices in the first three quarters of 2009/10.**

ANSWER:

First three quarters of 2009/10	**EXPORTS**	
	GWh	**Avg Price**
Dependable	2,613	56.41
Opportunity	6,554	20.77

PUB/MH I-140

Subject: Tab 11: Cost Of Service Study
Reference: PCOSS 10 – Schedule D-2 (Page 54)

a) **Please provide tabular illustration of 12 period SEP price variations for the full period used.**

ANSWER:

2008
Hour Weighted Average Price (Cdn$ per kW.h)

	Peak	Shoulder	Off-Peak
Spring	0.0657	0.0627	0.0418
Summer	0.0678	0.0404	0.0134
Fall	0.0497	0.0411	0.0160
Winter	0.0740	0.0597	0.0391

2004
Hour Weighted Average Price (Cdn$ per kW.h)

	Peak	Shoulder	Off-Peak
Spring	0.0589	0.0430	0.0403
Summer	0.0726	0.0498	0.0493
Fall	0.0515	0.0492	0.0494
Winter	0.0823	0.0546	0.0540

2007
Hour Weighted Average Price (Cdn$ per kW.h)

	Peak	Shoulder	Off-Peak
Spring	0.0427	0.0411	0.0074
Summer	0.0672	0.0476	0.0216
Fall	0.0741	0.0688	0.0668
Winter	0.0833	0.0674	0.0597

2003
Hour Weighted Average Price (Cdn$ per kW.h)

	Peak	Shoulder	Off-Peak
Spring	0.0474	0.0382	0.0271
Summer	0.0598	0.0397	0.0205
Fall	0.0509	0.0388	0.0232
Winter	0.0933	0.0659	0.0593

2006
Hour Weighted Average Price (Cdn$ per kW.h)

	Peak	Shoulder	Off-Peak
Spring	0.0534	0.0517	0.0341
Summer	0.0905	0.0720	0.0098
Fall	0.0695	0.0589	0.0168
Winter	0.0657	0.0565	0.0400

2002
Hour Weighted Average Price (Cdn$ per kW.h)

	Peak	Shoulder	Off-Peak
Spring	0.0691	0.0564	0.0211
Summer	0.0703	0.0408	0.0124
Fall	0.0421	0.0304	0.0200
Winter	0.0452	0.0295	0.0253

2005
Hour Weighted Average Price (Cdn$ per kW.h)

	Peak	Shoulder	Off-Peak
Spring	0.0603	0.0476	0.0318
Summer	0.0513	0.0371	0.0195
Fall	0.0498	0.0412	0.0223
Winter	0.0676	0.0483	0.0356

2001
Hour Weighted Average Price (Cdn$ per kW.h)

	Peak	Shoulder	Off-Peak
Spring	0.0384	0.0368	0.0189
Summer	0.0716	0.0700	0.0138
Fall	0.0617	0.0437	0.0183
Winter	0.1121	0.0519	0.0303

Years indicated above are fiscal years ending March 31.

<u>PUB/MH I-140</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10 – Schedule D-2 (Page 54)**

b) Please provide a graphical illustration of annual domestic energy use profiles for 2002/03 to 2007/08 to show the variability between domestic load and exports.

<u>ANSWER</u>:

Please refer to 72 energy use load shape graphs for various rate classes, domestic load, exports and total system for years 2002/03 to 2007/08 in Appendix 41.

PUB/MH I-141

Subject: **Tab 11: Cost Of Service Study**
Reference: **Schedule E-1, Page 63, Classified Costs by Allocation Table**

a) **Please provide the breakdown of domestic and export costs under Codes E12 and D14 covering each of interest, depreciation, and operation.**

ANSWER:

PCOSS10 Generation Costs as Allocated by E12 - 12 Period Weighted Energy
($ 000's)

	Interest	Depreciation	Operating	Total
Residential	85,606	32,261	68,805	186,672
General Service Small ND	18,499	6,971	14,868	40,339
General Service Small D	24,470	9,222	19,667	53,358
General Service Medium	37,063	13,967	29,789	80,820
General Service Large 0-30 KV	18,417	6,941	14,803	40,160
General Service Large 30-100 KV	13,023	4,908	10,467	28,399
General Service Large >100KV	62,539	23,568	50,266	136,373
Area & Roadway Lighting	1,005	379	808	2,192
Export	68,744	25,907	55,253	149,904
Total System	$ 329,367	$ 124,124	$ 264,727	$ 718,218

PCOSS10 Transmission Costs as Allocated by D14 - 2CP Demand
($ 000's)

	Interest	Depreciation	Operating	Total
Residential	23,273	13,980	13,545	50,798
General Service Small ND	5,384	3,234	3,133	11,751
General Service Small D	6,614	3,973	3,850	14,437
General Service Medium	9,988	5,999	5,813	21,800
General Service Large 0-30 KV	4,910	2,949	2,857	10,716
General Service Large 30-100 KV	3,172	1,905	1,846	6,924
General Service Large >100KV	14,609	8,775	8,502	31,887
Area & Roadway Lighting	189	113	110	411
Export	23,230	13,954	13,520	50,703
Total System	$ 91,369	$ 54,883	$ 53,176	$ 199,428

PUB/MH I-141

Subject: **Tab 11: Cost Of Service Study**
Reference: **Schedule E-1, Page 63, Classified Costs by Allocation Table**

b) Please provide a detailed listing of those costs in Schedule E-1 allocated to export covering each of interest, depreciation and operation; also include a listing of direct costs not included in Schedule E-1.

ANSWER:

The allocated and directly assigned Interest, Depreciation and Operating costs for the Export class in PCOSS10 are as follows:

Export Costs in PCOSS10 ($ 000's)

	Interest	Depreciation	Operating	Total
Uniform Rates Reduction	19,438			19,438
Affordable Energy Fund		3,867		3,867
'Trading Desk' Costs		327	4,665	4,992
NEB Costs			1,752	1,752
Purchased Power			153,650	153,650
PSO Transmission			20,400	20,400
Brandon Unit 5 Fuel and Variable O&M			13,863	13,863
Directly Assigned Generation	**19,438**	**4,194**	**194,330**	**217,961**
MISO/MAPP Costs			1,641	1,641
Directly Assigned Transmission	**-**	**-**	**1,641**	**1,641**
E12 Generation - Export Share	**68,744**	**25,907**	**55,253**	**149,904**
D14 Transmission - Export Share	**23,230**	**13,954**	**13,520**	**50,703**
Total Costs Assigned to Exports	**$ 111,412**	**$ 44,055**	**$ 264,744**	**$ 420,210**

All costs that are directly assigned to the Export class have been included in Schedule E-1, and are shown in summary for Generation and Transmission in the direct costs shown on page two of Schedule E-1.

PUB/MH I-141

Subject: **Tab 11: Cost Of Service Study**
Reference: **Schedule E-1, Page 63, Classified Costs by Allocation Table**

c) Please provide a detailed analysis of MH's domestic/export cost allocation of HVDC facilities

- **i. Northern AC collectors.**
- **ii. Northern AC/DC converter.**
- **iii. Bipoles I and II.**
- **iv. Southern DC/AC converter.**
- **v. AC lines to U.S.**

ANSWER:

Northern AC collector circuits, Bipoles I and II, as well as the Radisson and Henday convertor stations, are functionalized as Generation in the PCOSS. The costs are allocated 79.1% to domestic customers and 20.9% to the Export class, based on the "Energy (MW.h) Weighted by Marginal Cost" (Table E12).

Dorsey convertor station and AC lines to the U.S. are functionalized as Transmission in the PCOSS. The costs are allocated 74.6% to the domestic customer classes and 25.4% to the Export class, based on the "Average Winter and Summer Coincident Peak Demand" (Table D14).

<u>PUB/MH I-142</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule B-2 (Page 16)**

a) Please confirm that the Dorsey Station is the primary dispatch point for exports to the U.S.

<u>ANSWER</u>:

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. 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. This HVdc power is converted into AC power and is utilized for both domestic load requirements and export opportunities. The Dorsey complex is the location of a major AC substation which is 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. In summary the Dorsey complex is an important component of the Manitoba Hydro system for both domestic and export customers.

PUB/MH I-142

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule B-2 (Page 16)**

b) Please confirm that Bipole I and II deliver all the power from the Lower Nelson G.S. to the Dorsey Station approximating:

i. 13,800 GWh in Dependable flow years;
ii. 20,400 GWh in Mean flow years;
iii. 20,500 GWh in Median flow years; and
iv. 26,700 GWh High flow years.

ANSWER:

It is not confirmed that all power from the Lower Nelson G.S is delivered through Bipole I and II of the HVDC transmission system as a relatively small portion of the Lower Nelson G.S generation (up to two units of output from the Kettle G.S.) can be delivered on the AC transmission system. The annual energy estimates for power from the Lower Nelson G.S. to the Dorsey Station that are summarized in the information request are generally in a reasonable range with the exception of dependable energy which should be higher at approximately 15,000 GW.h.

<u>PUB/MH I-142</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule B-2 (Page 16)**

c) Please confirm that current gross exports to the U.S. typically consume:

i. 25% Dependable flow years.
ii. 38% Mean flow years.
iii. 43% Median flow years.
iv. 55% High flow years. of the Lower Nelson generation.

<u>ANSWER</u>:

There are many factors that can influence the annual quantity of export to the U.S. and Manitoba Hydro is unable to infer the assumptions that may have been used to determine the information presented in this information request. It is not known if the intent was to concentrate on U.S. exports as opposed to Canadian exports. The estimates appear to be representative of what Manitoba Hydro may estimate to the export market as a whole except that the 55% for high flow years appears to be too high. A more reasonable estimate would result in a ratio of 45%.

PUB/MH I-142

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule B-2 (Page 16)**

d) Please confirm that actual Canadian exports are typically made from the AC transmission system.

ANSWER:

It is not confirmed that exports to Canadian extraprovincial customers typically are made from generation sources connected only to the AC transmission system as opposed to the Lower Nelson generation that is connected to the HVDC system. Manitoba Hydro operates a networked transmission system into which generation is injected at various locations. Domestic and export loads are served from the network and it is not possible to track the source of the power. Please see Manitoba Hydro's response to PUB/MH I-143(a) for further information.

PUB/MH I-143

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule B-3/ PCOSS 08, Schedule D-1**

a) **Please confirm that AC transmitted generation flows primarily to domestic customers.**

ANSWER:

In a networked transmission system such as the one Manitoba Hydro operates, generation is injected into the transmission system, and all loads connected to the transmission system are supplied. Because the generation resources in the networked system are dispatched anywhere between minimum and maximum values, there is no source specific generation supplying source specific loads for long periods of time. Manitoba Hydro does have a few instances of local AC generation supplying loads either not connected to the transmission system, or AC generation connected to the subtransmission system supplying a small portion of the local area load.

All AC generation is connected to the Manitoba Hydro Transmission System. Power transmitted through the HVdc transmission system, is injected into the MH AC Transmission System at Dorsey station. All domestic loads are served by the AC and HVdc generation connected to the Transmission System. How power injections mingle to supply load cannot be determined or tracked.

At different times of day and different times of the year, the amount of HVdc power injected into the AC system at Dorsey varies widely, as does the load. The system's assets are operated as a single system.

PUB/MH I-143

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule B-3/ PCOSS 08, Schedule D-1**

b) Please define the typical percentage of domestic load served from AC-transmitted generation in:

i. Northern Manitoba
ii. Western Manitoba
iii. Interlake
iv. Eastern Manitoba

ANSWER:

All domestic loads are served by generation that is ultimately transmitted as alternating current. The typical percentage of load by operating regional peak load is:

i.	Northern Manitoba	11%
ii.	Western Manitoba	37%
iii.	Interlake	5%
iv.	Eastern Manitoba	10%
v.	Winnipeg	37%

Definitions:

i. Northern Load - calculated from loads north of a line through Ashern and Dauphin.

ii. Western Load - calculated from loads south of the northern load line and west a line bounded by Red River excluding suburban Winnipeg and Selkirk areas and south to the US border and west to the Saskatchewan border.

iii. Interlake Load - calculated from loads between Lakes Manitoba and Winnipeg, north of suburban Winnipeg and Selkirk and south of the northern load line.

iv. Eastern Load – calculated from loads south of the northern line, east of the Red River to the Ontario boundary and south to the USA border. Excluding Winnipeg.

It should be noted that the above domestic load is served by both the generation connected to the AC transmission system and the generation transmitted by HVdc to Dorsey, where it is converted to alternating current, and transmitted to the domestic load.

<u>PUB/MH I-143</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule B-3/ PCOSS 08, Schedule D-1**

c) **Please confirm that HVDC transmission in its current form or as expanded does not substantially improve service reliability for the above regions. Provide calculations and explain.**

<u>ANSWER</u>:

The HVdc transmission system is a vital link needed to supply domestic load in all regions of the province including northern Manitoba, Western Manitoba, the Interlake and Eastern Manitoba. Currently, more than 70% of the generation in Manitoba is transmitted to the Dorsey converter station over the existing Bipole 1 and Bipole II HVdc lines, which are located on a common Interlake transmission corridor. This supply is vulnerable to extended outages due to catastrophic events effecting the corridor or Dorsey Station. Manitoba Hydro is planning to expand the HVdc transmission system with the addition of a western routed Bipole III line and a new converter station at Conawapa in the north and Riel in the south to help mitigate this vulnerability to catastrophic events. For example, the probability of a Bipole I and II outage due to a tornado hitting the Bipole I and II Interlake corridor is 1 in 16 years. The probability of a three bipole outage with a western routed Bipole III line improves to 1 in 3650 years. The addition of Bipole III will significantly improve service reliability.

PUB/MH I-143

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule B-3/ PCOSS 08, Schedule D-1**

d) In the absence of Bi-pole I and II, please quantify what the capacity shortfall is for current domestic load with/and without current firm export contract sales. Provide calculations.

ANSWER:

- Capacity Shortfall With Export Sales = Domestic Load – AC Generation Capacity + Reserves - Import Capacity + Export Sales
- Capacity Shortfall Without Export Sales = Domestic Load – AC Generation Capacity + Reserves - Import Capacity
- AC Generation Capacity = Sum of Capacity at Generating Stations (Grand Rapids, Great Falls, Jenpeg, Laurie River, Kelsey, McArthur Falls, Pine Falls, Seven Sisters, Brandon, Selkirk, Slave Falls, Point Du Bois and one Kettle AC Unit)
- Immediate Import Capacity = 850 MW
- Within 24 hours Import Capacity = Sum of Import Capacity on USA, SPC and ONT interfaces
- Reserves = Sum of Regulation Reserve + Contingency Reserves less Curtailable Load

Immediate Shortfall - After Loss of Bi-pole I and II

	Monthly Domestic Peak Load	**AC Generation Capacity**	**Reserves**	**Import Capacity**	**Export Contracts**	**Capacity Shortfall with Export Sales**	**Capacity Shortfall Without Export Sales**
Winter Peak Jan -2010	4290	1509	160	850	630	2721	2091
Summer Peak - Aug 2009	3108	1509	160	850	1130	2039	909

** All values in MW.

Shortfall Within 24 hours - After Loss of Bi-pole I and II

	Monthly Domestic Peak Load	AC Generation Capacity	Reserves	Import Capacity	Export Contracts	Capacity Shortfall with Export Sales	Capacity Shortfall Without Export Sales
Winter Peak Jan -2010	4290	2028	160	1050	630	2003	1373
Summer Peak - Aug 2009	3108	2028	160	1027	1130	1344	214

- AC generation increases within 24 hours since Manitoba Hydro Thermal Generation will be brought on line.
- Import Capacity increases within 24 hours since Manitoba Hydro will make arrangements to purchase energy from outside the province.

** All values in MW.

<u>PUB/MH I-143</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule B-3/ PCOSS 08, Schedule D-1**

e) **In the absence of Bipole I and II, what is the capacity shortfall in 2023/24 when firm export sales and domestic load exploit the full 5x16 hydraulic generation with Bipole III and both Keeyask and Conawapa G.S. in place? Provide a quantified discussion.**

<u>ANSWER</u>:

In the event that Bipoles I and II simultaneously fail in 2023/24, any potential capacity shortfall would depend on a number of factors including the Manitoba load at the time of the event, the nature of the failure and its impact on the bulk transmission system, future generation and transmission development within and in close electrical proximity to Manitoba, generation and transmission outages and available operating reserve on the interconnected system. In order to provide an answer, the following assumptions were made:

- Resources and commitments are consistent with the recommended development plan in the 2009/10 power resource plan as provided in the Attachment to PUB/MH I-84(a).
- Failure occurs during the Manitoba peak winter load (net of DSM) of 5034 MW
- No generation or transmission outages other the Bipoles I and II.
- Manitoba Hydro would not be required to deliver on its export capacity commitments should there be a loss of Bipole I and II.
- The transmission grid is stable following the failure, and external assistance would be immediately available.

Immediate Shortfall - After Loss of Bi-pole I and II

in MW

	Monthly Domestic Peak Load	AC Generating Capacity	Operating Reserves	Northern Generation delivered on Bipole III	Import Capacity	Export Contracts (to be curtailed after loss)	Capacity Shortfall
Winter Peak Jan -2010	4290	1509	160	0	850	630	2091
Winter Peak Jan - 2024	5034	1709	160	2000	1950	1200	None

Capacity Shortfall = Domestic Load - AC Generation Capacity + Reserves - Import Capacity

In the absence of Bipole I and II, the electricity supply situation in 2023/24 is considerably improved in terms of ability to supply Manitoba load compared to the 2010/11 case. In 2023/24, even though the peak load is about 740 MW higher, there is 2000 MW of additional supply available from Bipole III, plus 1100 MW of supply from additional import capability.

PUB/MH I-144

Subject: **Tab 11: Cost Of Service Study**
Reference: **Schedule C-2, Page 29, Functionalization of Gross Investment**

a) **Please identify the major components of the $127,815,329 gross investment allocation of transmission to export.**

ANSWER:

Major components of the Transmission investment shown as Export in Schedule C-2 are:

D602-F - Dorsey-Forbes 500kv Trans. Line
G82-R - Glenboro-Rugby 230kV T/L
K21-W, K22-W - Kenora-Whiteshell 230 kV AC T/L
P58-C - Rall's Island- Cliff Lake 230 kV AC T/L
R49-R - Ridgeway-Richer 230 kV AC T/L
R50-M - Richer-Moranville Minn. 230 kV AC T/L
HS15 - Herblet L. - Mile 13 115 kV AC T/L
SK-1 - Seven Sisters-Ontario 115 kV AC T/L

PUB/MH I-144

Subject: **Tab 11: Cost Of Service Study**
Reference: **Schedule C-2, Page 29, Functionalization of Gross Investment**

b) Please confirm that the HVDC Dorsey Converter is included in the $639,039,576 gross investment domestic allocation and not allocated to export.

ANSWER:

The Dorsey Converter Station is included in the $639,039,576 gross investment functionalized as Domestic Transmission; however, transmission costs are allocated to both domestic and export customers based on Average Winter and Summer Coincident Peak Demand (table D14).

<u>PUB/MH I-144</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **Schedule C-2, Page 29, Functionalization of Gross Investment**

c) Are the full investment costs of the Dorsey to U.S. border transmission line and stations allocated to export? Explain.

<u>ANSWER</u>:

The depreciation and interest costs related to the entire investment in Dorsey Convertor station, as well as the Dorsey-Forbes transmission line, are allocated 74.6% to the domestic customer classes and 25.4% to the Export class, based on the “Average Winter and Summer Coincident Peak Demand” (Table D14).

PUB/MH I-144

Subject: **Tab 11: Cost Of Service Study**
Reference: **Schedule C-2, Page 29, Functionalization of Gross Investment**

d) Please confirm that the gross investment for transmission has about 15% allocated to export.

ANSWER:

Transmission costs are allocated based on Average Winter and Summer Coincident Peak Demand (Table D14). The share of Transmission costs allocated to export is approximately 25%.

PUB/MH I-144

Subject: **Tab 11: Cost Of Service Study**
Reference: **Schedule C-2, Page 29, Functionalization of Gross Investment**

e) Please explain why in export cost allocation:

- **i. There is no direct allocation of transmission depreciation?**
- **ii. There is about a 15% direct allocation of interest and reserve contribution?**
- **iii. There is only a 3% direct allocation of operating costs?**

ANSWER:

i. It is important to note that any lines that cross provincial boundaries are designated as Export Transmission on Schedule C-2; this designation is not intended to imply that these assets are used only by the Export customer class. These interconnection lines serve a dual role in facilitating both export sales, as well as the import purchases necessary to ensure domestic reliability.

Furthermore, there are taps off some of the interconnection lines referenced as "Export Transmission" in the Schedule C-2. In these cases the interconnection lines provide the most efficient route to serve domestic load, as well as having the capability to provide extra-provincial loads. The benefit of these lines to domestic reliability is important -- should any upstream interruption of service occur from a domestic tap the ability to import power ensures that the load will continue to be served despite the interruption on the domestic supply side.

Like other shared resources, including all transmission, the costs of these interconnection lines are allocated between both the domestic and Export classes that utilize the transmission assets.

ii. For the reasons noted in part (i) there is no direct allocation to the Export class of any interest, which also includes capital tax and reserve contribution, for Transmission assets. The interest costs related to Manitoba Hydro's entire Transmission system have allocated to the domestic and Export classes. The allocated costs by class are shown in the response to PUB/MH I-141(a).

iii. For the reasons noted in part (i) there is no direct allocation to the Export class of any operating costs related to Transmission assets. The operating costs related to Manitoba Hydro's entire Transmission system have been allocated to the domestic and Export classes. The allocated costs by class are shown in the response to PUB/MH I-141(a).

A portion of the MISO/MAPP costs have been directly assigned to the Export class as shown in the response to PUB/MH I-141(b).

PUB/MH I-145

Subject: **Tab 11: Cost Of Service Study**

Reference: **PCOSS 10, Schedule D-2 (Page 54)/PCOSS 08 Schedule D-2 (Page 61)**

a) Please confirm the following energy loads at generation:

	2009/10	**2007/08**
Domestic (Hydraulic)	**24,665 GWh**	**23,741 GWh**
(Thermal)	**158 GWh**	**(incl. in above)**
	25,823 GWh	**23,741 GWh**
Export	**6,424 GWh**	**4,524 GWh**
	32,247 GWh	**28,265 GWh**

ANSWER:

Please note there appears to be an arithmetic error in the table included in the Information Request above. The domestic hydraulic and thermal energy for 2009/10 totals 24,823 GWh for 2009/10.

It should be noted that the energy shown in Schedule D-2 is used to calculate the E12 Weighted Energy allocator, and does not include energy for resources whose costs have been directly assigned to a customer class. SEP customers are directly assigned Generation costs, and are excluded from the Domestic energy shown in Schedule D-2. The Export customer class is directly assigned the costs of Purchased Power, a share of Thermal Generation, and, in PCOSS08, DSM savings realized to date. As the cost of these directly assigned resources is not allocated using this allocator, the associated energy is not included in its calculation.

Total energy at generation for the domestic and export classes are as follows:

Comparison of Forecast Energy at Generation
PCOSS10 vs PCOSS08 (GWh)

		PCOSS10	PCOSS08
Domestic	Hydraulic	24,665	23,741
	Thermal	158	
	SEP	26	27
		24,849	23,768
Export	Hydraulic	6,424	4,524
	Thermal	317	560
	Purchased Power	1,974	2,028
	DSM Savings to Date	-	1,350
		8,715	8,462
Total Energy @ Gen GWh		33,564	32,230

<u>PUB/MH I-145</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule D-2 (Page 54)/PCOSS 08 Schedule D-2 (Page 61)**

b) **Please confirm that the 2,082 GWh increase in domestic load indicates an 8.8% growth over a two-year period (almost double MH's long-term forecast rate). Explain.**

<u>ANSWER</u>:

As per the response to PUB/MH I-145(a) the increase in domestic load is 1,081 GWh, which would indicate a 4.6% growth over a two year period.

<u>PUB/MH I-145</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule D-2 (Page 54)/PCOSS 08 Schedule D-2 (Page 61)**

c) Please confirm that the export share of generation load/costs is:

	2009/10	2007/08
Unweighted	**20%**	**16%**
Weighted	**21%**	**16%**

<u>ANSWER</u>:

The export share of generation load/costs in the table above is confirmed subject to slight rounding differences.

<u>PUB/MH I-145</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule D-2 (Page 54)/PCOSS 08 Schedule D-2 (Page 61)**

d) Please explain the increase in export share from 2007/08.

<u>ANSWER</u>:

In PCOSS08 Export energy in Schedule D-2 was adjusted by DSM savings-to-date of 1,350 GWh, which reduced their relative share of energy in the schedule. Without this adjustment the export share would have been 20% unweighted and 19% weighted.

PUB/MH I-145

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule D-2 (Page 54)/PCOSS 08 Schedule D-2 (Page 61)**

e) Please confirm that the annual export loads consisted of:

	2009/10	2007/08
Peak (5x8)	29%	23%
Shoulder	47%	46%
Off-Peak (7x8)	24%	31%

ANSWER:

The annual export loads in the table above are confirmed subject to slight rounding differences.

PUB/MH I-145

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule D-2 (Page 54)/PCOSS 08 Schedule D-2 (Page 61)**

f) Please explain the increase in peak load share.

ANSWER:

For PCOSS08, the energy consumption patterns from 2005/06, a year of very high water flows, were used to distribute forecast energy consumption into twelve time periods.

For PCOSS10, a six year average energy use profile was used to distribute the forecast energy into twelve time periods to reflect Order 116/08. This modification minimizes year-to-year variation in the energy profiles, which in the case of exports sales were largely caused by differing water conditions in the year upon which the energy consumption profiles were based.

PUB/MH I-145

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule D-2 (Page 54)/PCOSS 08 Schedule D-2 (Page 61)**

g) Please confirm that in the four summer months, export load consisted of:

	2009/10	2007/08
Peak (5x8)	30%	24%
Shoulder	47%	45%
Off-Peak (7x8)	23%	31%

ANSWER:

Confirmed.

PUB/MH I-145

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule D-2 (Page 54)/PCOSS 08 Schedule D-2 (Page 61)**

h) Please explain the difference in peak load shares.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-145(f).

PUB/MH I-145

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10, Schedule D-2 (Page 54)/PCOSS 08 Schedule D-2 (Page 61)**

i) **Given that MH's apparent objective is to maximize summer peak sales, why are there any off-peak (overnight) sales when total sales fall below tie-line capacity in peak and shoulder hours?**

ANSWER:

Manitoba Hydro's objective is to maximize export revenues. Under the flow, reservoir and market conditions assumed in PCOSS 10, net export revenue is maximized by scheduling export sales in non peak hours due to the limitation on hydraulic generating capacity.

<u>PUB/MH I-146</u>

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10 – Schedule D-2**

a) Please define the process of modifying the export profile, when deducting the imports from exports and adding transmission losses.

<u>ANSWER</u>:

As discussed in the response to PUB/MH-I 145(a), the class energy included in Schedule D-2 does not include energy deemed provided by a resource whose costs have been directly assigned to a customer class.

To determine the Export profile, transmission losses are first added to Export sales to determine energy at generation. The Export energy at generation is then reduced for any energy provided by thermal generation or power purchases as these costs have also been directly assigned to the Export class. The resulting energy is allocated amongst the twelve periods using the unadjusted export profile as determined using the average over the past five years of load research data.

PUB/MH I-146

Subject: **Tab 11: Cost Of Service Study**
Reference: **PCOSS 10 – Schedule D-2**

b) Please confirm that the deduction of imports were primarily applied to the summer 5x16 exports. Explain.

ANSWER:

Not confirmed. The import energy has been used to reduce Export energy at generation prior to its allocation between the twelve periods, and is therefore applied in the same proportions as given for Export sales in the response to PUB/MH I-145(e).

PUB/MH I-147

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter III (Page 13 – 17)**

a) Please provide MH's:

i. Drought Preparedness Plan.
ii. System Operation Priorities.

ANSWER:

i. Manitoba Hydro is in the process of developing a Drought Preparedness Plan and is unable to provide it at this time.

ii. Please see attached System Operation Priorities.

SYSTEM OPERATION PRIORITIES

The following priorities are to be followed by the Reservoir and Energy Resources Department in planning system operations of the Manitoba power system.

PRIORITY 1 ENERGY SUPPLY

Maintaining the firm energy supply is the highest priority objective of operations. The consequences of running short are more serious in the winter than in the summer. To ensure that the winter energy demand can be met under all circumstances resources should be in place to meet the forecast load given the most severe winter weather conditions.

PRIORITY 2 ENERGY RESERVES

Adequate energy reserves in reservoir storage will be maintained as normal operating practice if available resources allow. These reserves must be sufficient to meet firm load requirements given a repeat of the worst historic flow conditions coincident with firm load demands associated with severe winter weather conditions recognizing the availability of thermal and import energy supplies.

On a contingency basis energy reserves can be used to meet firm load requirements when no alternative resources are available.

PRIORITY 3 RELIABILITY

The operation of the system will be planned to minimize the risk of a system shutdown or blackout. The consequences of a shut down are more serious in the winter than in the summer. Given this situation preference will generally be given to minimizing winter risk compared to that in the summer.

PRIORITY 4 CITIZENSHIP CONCERNS

The operation of the system will be planned in a manner that minimizes significant adverse impacts of operations on other resource users and the environment. If adverse impacts can not be avoided notice to affected parties will be given. How the power system is operated must be tempered with respect for the priorities of others.

PRIORITY 5 ECONOMIC OPERATION

The operation of the system will be planned in a manner that maximizes the financial and economic benefits to the customers of Manitoba Hydro.

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PUB/MH I-147

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter III (Page 13 – 17)**

b) Please provide volume and price quantification of how these documents would work to define a (circa 2010) reoccurrence of drought scenarios such as:

i. 2006/07
ii. 2002/03
iii. 2003/04
iv. 5-year drought
v. 7-year drought

ANSWER:

Manitoba Hydro's operating priorities and drought management strategy has not changed from the drought of 2003/04. However since that time the MISO market has developed and Manitoba Hydro has a full set of financial instruments available to help manage the financial risk of drought.

Fundamental to managing droughts and the associated financial risks are eight important considerations:

1. normal customer service will be maintained during droughts and that the societal costs of having insufficient electricity supplies are orders of magnitude greater than the cost of purchased power
2. the severity and duration of drought is not known in advance
3. the severity of winter in Manitoba cannot be predicted in advance
4. the historic record of water flows is no guarantee of future water flows
5. water flows are mean reverting in nature over time
6. Manitoba has limited import and thermal capability which may be insufficient to offset shortfalls in hydraulic generation from inflows
7. Manitoba Hydro can fulfill the majority of its export obligations with purchased energy
8. reservoir storage does not create energy it only shifts it from one period to the next

Based upon these considerations, Manitoba Hydro operates the power system in a conservative fashion as follows:

1. Reservoir storages are maintained such that sufficient reserves are available at all times to meet

   a. the forecast domestic demand (assuming a winter with a 1 in 10 severity), and
   b. those firm export demands that cannot be settled financially

   under an assumption of water supply conditions

   c. in the current year at the lower 90% confidence interval, and
   d. in the second year with a repeat of the 1940/41 flow conditions.

   To the extent that forecast supply conditions are insufficient to meet forecast demand conditions, reserves in reservoir storage will be utilized to the extent necessary to balance supply and demand, but will be re-established at the earliest time.

2. Energy planning will rely on firm resources only, including base load operation of Brandon coal unit #5. To the extent non-firm resources become available in real time, these will be used to achieve cost savings if possible.

3. Manitoba Hydro's fuel and purchase power and hedging activities will be gradual and mechanistic recognizing the mean reverting nature of the water supply based upon a production plan for the power system that is updated weekly.

4. To the extent that Manitoba Hydro is exposed to short term price and market volatility associated with its fuel and power purchases, Manitoba Hydro may hedge away a portion or all of that risk. Any hedging strategies will be approved by the Export Power Risk Management Committee.

The financial impact of these drought management activities are included in the IFF for every low flow year in MH's 94 year hydraulic record where additional costs are required. Please note that in fiscal 2006/07 hydraulic generation (as indicated in Figure 8.6.4 of the Application) was above average and that Manitoba Hydro does not consider that year to be a drought or mini-drought event.

The cost of a 5-year drought and a 7year drought are outlined in PUB/MH I-150(a).

PUB/MH I-148

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report

a) Please provide a detailed monthly quantification of diversity sales and purchases for 2002/03, 2003/04, and 2006/07.

ANSWER:

Monthly quantities of diversity sales and purchases are listed below for 2002/03, 2003/04 and 2006/07.

	Diversity Sales MWh	Diversity Purchases MWh
Apr-02	0	156,369
May-02	6,470	28,570
Jun-02	48,400	22,358
Jul-02	49,150	33,436
Aug-02	38,250	25,800
Sep-02	55,285	25,841
Oct-02	21,750	32,276
Nov-02	0	62,795
Dec-02	0	52,749
Jan-03	0	54,154
Feb-03	0	62,729
Mar-03	0	76,677
Apr-03	0	44,380
May-03	0	0
Jun-03	66,445	300
Jul-03	166,627	0
Aug-03	139,891	0
Sep-03	26,930	0
Oct-03	0	0
Nov-03	0	0
Dec-03	0	8,250

	Diversity Sales MWh	Diversity Purchases MWh
Jan-04	0	9,445
Feb-04	0	10,025
Mar-04	0	0
Apr-06	0	0
May-06	10,250	0
Jun-06	43,600	0
Jul-06	106,544	0
Aug-06	130,750	0
Sep-06	28,320	0
Oct-06	0	0
Nov-06	0	700
Dec-06	0	5,625
Jan-07	0	4,650
Feb-07	0	10,200
Mar-07	0	1,125

PUB/MH I-148

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report**

b) Please reconcile these with prices and volumes as defined by NEB permit/licence exports.

ANSWER:

Canadian exports are not reported to the NEB. Therefore the difference between the ICF numbers and those reported to the NEB are attributable to exports to Canadian markets and financial sales to the US.

PUB/MH I-149

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, Chapter IV (Page 18)

a) Please provide specific example (s) of MH's arbitrage merchant trading transaction (e.g., MISO purchase/Ontario sale) to illustrate how this differs from non-arbitrage merchant trading.

ANSWER:

Arbitrage is the practice of taking advantage of a price differential between two or more markets: striking a combination of matching deals that capitalize upon the imbalance, the profit being the difference between the market prices. An arbitrage transaction(s) is entered into with the expectation of profit.

Example of an arbitrage merchant transaction:
Manitoba Hydro submits an offer to sell the Ontario market (IESO) 50 MW for the hour ending 7:00 a.m. at a price of C$50/MWh. The IESO accepts the energy offer at 4:00 a.m. (two hours prior to the delivery hour). Given the commitment to sell to the IESO, at 5:10 a.m., Manitoba Hydro purchases power from the MISO Real Time market to be delivered to the IESO Real Time market via firm transmission capacity. Market participants are unable to specify a purchase price in the MISO Real Time market but, in this example, the MISO market has recently been trading in the US$30-US$35/MWh range for hour ending 7:00 a.m. The MISO market ends up settling at US$30/MWh for hour ending 7:00 a.m. In this example, with a US/Cdn exchange rate of 1.02, Manitoba Hydro would realize a profit of C$1,029.41 (C$50 – (US$30/1.02)) x 50 MW).

Example of a non-arbitrage merchant transaction:
A company sells energy forward at the forward market price in the California market for the upcoming summer period with an expectation that it will purchase the power at a favorable price at a later date. In this case, the seller is betting against the market. There exists a significant risk that the seller's expectations will not be realized and a loss will occur.

<u>PUB/MH I-149</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter IV (Page 18)**

b) Discuss in detail the risks associated with both.

<u>ANSWER</u>:

In the arbitrage example given in a), Manitoba Hydro knows the current market conditions in both the Ontario and MISO markets and only enters into the transaction when there is an expectation of profit. There is some risk that the MISO real time price will be above the sell price. However, the risk is limited as the transaction is only one hour in duration.

In the second case, the hypothetical trading company is speculating that the market price will move favorably (i.e. the company is betting against the market).

PUB/MH I-150

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter IV (Page 19)**

a) Please provide a detailed quantification of volumes and prices that support MH's representations of

i. A 5-year drought.
ii. A 7-year drought.

ANSWER:

The following drought impact summary is consistent with assumptions utilized in IFF09-1. With an onset of the 5-year drought beginning in fiscal year 2011/12, the impact on revenues and volumes is provided in the table below as the difference between the average condition and the 5-year drought. Specific information on export prices is not provided because this is commercially sensitive information.

	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	223	483	80	114	89	990
Net Revenue (Excluding Finance Expense)	-419	-742	-249	-320	-271	-2003
Impact of 5-Year Drought on Energy (GWh/yr)						
Extra-Provincial Sales	-3542	-4190	-3162	-3408	-3016	-17318
Hydro Generation	-7117	-10707	-5060	-5584	-4779	-33246
Fuel & Power Purchase	3021	5658	1515	1748	1396	13338

With an onset of the 7-year drought beginning in fiscal year 2011/12, the impact on revenues and volumes is provided in the table below as the difference between the average condition and the 7-year drought.

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Total
Impact of 7-Year Drought on Revenues (millions of $ Cdn)								
Revenue								
Extra-Provincial Sales	-134	-104	-193	-272	-369	-297	-80	-1450
Expense								
Water Rental	-14	-11	-18	-29	-37	-29	-6	-142
Fuel & Power Purchase	39	12	89	366	619	438	-20	1543
Net Revenue (Excluding Finance Expense)	-159	-106	-264	-609	-951	-707	-54	-2851
Impact of 7-Year Drought on Energy (GWh/yr)								
Extra-Provincial Sales	-2639	-2291	-3230	-3831	-4237	-3675	-1616	-21519
Hydro Generation	-4049	-3158	-5260	-8534	-11121	-8548	-1928	-42596
Fuel & Power Purchase	1103	619	1636	4020	5998	4180	154	17711

PUB/MH I-150

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, Chapter IV (Page 19)

b) Please modify these to reflect shortage prices (e.g., import costs reflect high on-peak values).

ANSWER:

Manitoba Hydro is not able to undertake the analysis as requested in the time frame available for response to information requests. The analysis of the requested cost of drought is a complex exercise which requires two sets of new computer simulations, each with a new definition of import prices. Such an analysis of an alternative prices scenario would require a clear definition of the pricing of import energy. The modeling inputs utilize a pricing structure for import energy that results in higher prices as the volume of required energy increases. A further complication in modeling is that a procedure would be required to implement a transition to shortage pricing as the severity of a drought increases.

As an approximation it suggested that the off-peak import power costs in the response to PUB/MH I-206(a) be increased by a percentage as high as 100% to reflect a possible scenario of shortage pricing in order to obtain an order of magnitude estimate. The off-peak import costs of $523 million in that response for a five-year drought would double to $1,046 million. This would increase the cost of a five-year drought from $2.0 to $2.5 billion.

Please refer to the 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.

PUB/MH I-150

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter IV (Page 19)**

c) Please review and explain why other potential risks should not be partially added if there are coincidental possibilities.

ANSWER:

As noted in Section 4.2, Risk factors on page 55 of the ICF report:

> "The key risks affecting Manitoba Hydro's export sales can be classified into the following broad categories:
>
> - Hydrology Risks
> - Evolving Power Industry and Wholesale Power Market Price Risks
> - Environmental Regulatory Risks
> - Risks related to Long-Term Contract Terms and Conditions
> - Manitoba's Domestic Electricity Demand Risks
> - Construction Costs, Infrastructure Damage and Other Volume Risks
> - Transmission Risks
> - Financial Risks"

As stated on page 21 of the ICF report:

> "We observe that some other financial stress tests involve more than one risk factor changing simultaneously while Manitoba Hydro's does not. However, these organizations examine more common events than extended droughts, for example, recessions. Hence, they need to examine a broader range of events, including simultaneous changes in more than one variable in order, to reach the confidence levels that Manitoba Hydro reaches when varying only one variable, i.e., is there an extended drought or not. Hence, as a general matter, Manitoba Hydro does not need to simultaneously examine multiple risk events."

PUB/MH I-151

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Page 41, Exhibit 2-14**

a) **Please define the net export revenue (gross revenues minus fuel and power purchases) for the 2003/04 to 2008/09 period (as per Exhibit 4.4).**

ANSWER:

Net Export Revenue is defined as Extraprovincial Revenues from power sales less all fuel expenses, power purchases and water rental expenses allocated to extraprovincial power sales.

NET EXPORT REVENUE ($ millions)

2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual
388	652	339	453	414

PUB/MH I-151

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Page 41, Exhibit 2-14**

b) **Please confirm that on a net basis, MH's exports account for about 25% of total net revenues.**

ANSWER:

Net Export Revenue as a % of Total Revenue

2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual
26%	36%	21%	27%	23%

PUB/MH I-152

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 3.0, Exhibits 3-1 and 3-2 (Pages 48 and 49).**

Please indentify separately MH's:

- **i.** **MISO export sales as reported by NEB.**
- **ii.** **Direct sales to Saskatchewan.**
- **iii.** **Direct sales to Ontario.**
- **iv.** **Merchant sales from MISO to Ontario.**

ANSWER:

There were no sales to MISO prior to 2005 (MISO market opened Apr 1, 2005).
The sales to MISO are included under NEB Permit #269, NEB does not report MISO sales separately.

Merchant sales did not commence until 2004.

Direct Sales to Ontario and Saskatchewan have not been provided separately due to commercial sensitivity. However combined sales data has been provided from 2002 to 2007, data prior to that is not available on a calendar year.

	Sales to US as reported to NEB Permit 269		Merchant Sales		Sales to Canada	
	MWh	CDN $	MWh	CDN $	MWh	CDN $
2000	0	0	0	0		
2001	0	0	0	0		
2002	0	0	0	0	2,105,481	77,226,495
2003	0	0	0	0	1,449,202	63,322,707
2004	0	0	195,440	5,613,316	1,340,022	59,251,121
2005	1,123,259	58,640,254	702,971	40,601,828	1,659,841	114,463,424
2006	7,054,083	310,708,976	1,210,985	52,918,302	771,927	40,193,276
2007	6,352,819	286,311,792	1,202,912	53,343,085	557,922	34,851,387

PUB/MH I-153

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 3.0 (Page 49).**

a) Please provide the existing actual export contract documents (in confidence if necessary).

ANSWER:

Manitoba Hydro is attaching copies of the following two long term export contracts:

1) 500 MW System Participation Power Sales Agreement, made between Northern States Power Company and Manitoba Hydro effective August 1, 2002; and

2) 150 MW Diversity Power Sales Agreement made between United Power Agency and The Manitoba Hydro-Electric Board effective February 1, 1991.

These contracts are typical of the arrangements Manitoba Hydro has with its export customers for the sale of the energy products known as System Participation Power and Seasonal Diversity Power. Confidential information has been redacted and is indicated by the words “TRADE SECRET AND CONFIDENTIAL”.

Since the signing of the UPA Agreement, UPA has entered into a Management Service Agreement with Great River Energy (GRE) under which GRE manages the assets of UPA including the Diversity Agreement. Manitoba Hydro and GRE have supplemented the Diversity Agreement from time to time primarily to change pricing terms. The terms and conditions of these supplementary agreements are subject to confidentiality obligations which prohibit disclosure.

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Northern States Power - Manitoba Hydro

500 MW System Participation Power Sale Agreement

This SYSTEM PARTICIPATION POWER SALE AGREEMENT ("Agreement") is entered into effective as of August 1 2002, by and between Northern States Power Company ("NSP" or "Buyer"), a Minnesota corporation in the United States and The Manitoba Hydro-Electric Board ("MH" or "Seller"), a Manitoba Crown Corporation incorporated pursuant to the provisions of *The Manitoba Hydro Act* (R.S.M. 1987, c.H190), each of the foregoing entities being sometimes referred to individually as "Party" or collectively referred to as "Parties".

RECITALS

0.01 WHEREAS, the Parties entered into a 500 kV Coordination Agreement (the "Coordination Agreement") effective February 1, 1991 for the interconnected operation of the Parties' 500 kV transmission line and for the provision of various services pursuant to the Service Schedules of said Coordination Agreement; and

0.02 WHEREAS, Section 4.01(b) of the Coordination Agreement provides for other transactions to be executed by the Parties from time to time; and

0.03 WHEREAS, NSP issued a Request for Proposals dated August 2, 1999 in response to which MH submitted an offer to sell System Participation Power which was accepted by NSP; and

0.04 WHEREAS, MH is capable of providing System Participation Power to NSP as provided hereunder from its existing resources, including those under construction; and

0.05 WHEREAS, NSP desires to purchase and MH desires to sell System Participation Power pursuant to the terms and conditions set forth in this Agreement; and

0.06 WHEREAS MH recognizes that NSP is relying on the reliable and consistent availability of System Participation Power in accordance with the terms and conditions of this Agreement; and

0.07 WHEREAS, NSP and MH are each party to the Restated MAPP Agreement; and

0.08 WHEREAS, the Parties require governmental permits and approvals for the import and export of electric energy.

NOW, THEREFORE, in consideration of the mutual promises and covenants of each Party to the other contained in this Agreement and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties covenant and agree as follows:

ARTICLE 1

DEFINITIONS

Section 1.01 Unless otherwise specified in this Agreement, the following terms as used in this Agreement shall have the meanings set forth below:

Accreditable Capacity – shall mean capacity that meets the characteristics and is eligible to constitute "accredited capacity" as defined in the Restated MAPP Agreement, or, in the event such term is no longer contained in the Restated MAPP Agreement or the Restated MAPP Agreement no longer applies, a substantially comparable capacity product consistent with the requirements of the relevant RRO.

Affiliate - shall mean any person or entity that directly or indirectly, through one or more intermediaries, controls, is controlled by or is under common control with NSP or MH.

Border Accommodation Power Sales – shall mean those power or energy sales to customers located in Provinces and States adjacent to the Province of Manitoba whereby electric service to those locations is not otherwise readily available from other power suppliers. In all cases, these sales are made over transmission systems lower than 115 kV.

Business Day – shall mean Monday through Friday, excluding holidays recognized by the North American Electric Reliability Council, or its successor reliability organization.

CPT - shall mean Central Prevailing Time.

Contract Term - shall mean May 1, 2005, through April 30, 2015.

Contract Year - shall mean a twelve month period, May 1 through April 30 of the following calendar year, whether or not within the Contract Term.

Coordination Agreement – shall mean the 500 kV Coordination Agreement between the Parties dated February 1, 1991 as amended from time to time, provided that if such contract is terminated prior to the termination of this Agreement then the terms of such contract as they existed immediately prior to such termination shall be deemed to apply for purposes of this Agreement.

End-Use Load - shall mean the load of persons or other entities that purchase or produce electric energy for their own consumption and not for resale.

Energy – shall mean Guaranteed Energy and Supplemental Energy.

Firm Power - shall mean generating capacity and associated energy intended to be available at all times, except as agreed otherwise by MH and the Firm Power purchaser, and for which MH maintains generation reserves in accordance with standards and requirements established by the RRO to which the Firm Power purchaser belongs, or with respect to

Firm Power sales to the City of Winnipeg (if applicable), the RRO to which MH belongs.

Firm Transmission Service – shall include firm point-to-point and network integration transmission service provided pursuant to the OATT (or subsequent transmission service as allowed by this Agreement) of either Party's Transmission Provider and/or transmission service to bundled native load customers, or other service for delivery of Energy as allowed by this Agreement.

Force Majeure - shall mean an event or circumstances, excluding those set forth in Section 3.06(b)(1), (2) and (3) and Section 3.07(a)(1), which prevents one Party from performing its obligations under this Agreement, which event or circumstance was not anticipated as of the date of this Agreement, which is not within the reasonable control of, or the result of the negligence of, the claiming Party, and which, by the exercise of due diligence, the claiming Party is unable to overcome or avoid or cause to be avoided. For greater certainty, Force Majeure shall not be based on (i) the loss of Buyer's markets; (ii) Buyer's inability economically to use or resell the Accreditable Capacity and Energy governed by this Agreement; or (iii) Seller's ability to sell the Accreditable Capacity and Energy governed by this Agreement at a price greater than the prices determined by this Agreement.

Good Utility Practice – shall mean, at any particular time, any of the practices, methods and acts engaged in or approved by a significant portion of the hydro-electric utilities located in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could be expected to produce the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a range of acceptable practices, methods or acts.

Guaranteed Energy – shall have the meaning set forth in Section 2.03.

MAPP Reliability Council - shall mean the Mid-Continent Area Power Pool Reliability Council or successor regional reliability organization to which NSP belongs, if any, or any committee or subcommittee thereof.

OATT – shall mean an Open Access Transmission Tariff that (i) in the case of NSP, has been filed with and accepted by FERC as complying with FERC's then current open access, comparability and nondiscrimination requirements, (ii) in the case of MH, provides reciprocal open access transmission service on a sufficiently comparable and nondiscriminatory terms so as to entitle MH to use the OATTs of transmission providers in the United States, and (iii) in the case of a third party, has been filed with and accepted by FERC as complying with FERC's then current open access, comparability and nondiscrimination requirements, or provides reciprocal open access transmission service so as to entitle such entity to transmit electricity with entities whose OATT has been filed with and accepted by FERC as an OATT.

Performance Assurance – shall mean collateral in the form of cash, letter(s) of credit or other security reasonably acceptable to the Requesting Party.

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Point of Delivery - shall mean the location, as set forth in Section 3.03 of this Agreement, at which MH delivers Energy to NSP and title to the Energy transfers to NSP.

Point of Interconnection - shall mean the point or points where MH's high voltage transmission facilities, which are physically connected with the high voltage transmission facilities owned by NSP, cross the international boundary between the Province of Manitoba and the United States of America.

Real Power Losses - shall have the same meaning as provided in the transmission tariff (or rules) of the applicable Transmission Provider.

Requesting Party – shall have the meaning set forth in Section 9.02.

Restated MAPP Agreement - shall mean the agreement among MAPP participants governing their relationship dated January 12, 1996, as amended from time to time.

RRO - shall mean a regional reliability organization, including the MAPP Reliability Council, if applicable.

Schedule or Scheduling - shall mean the actions of Seller, Buyer and their designated representatives, of notifying, requesting and confirming to each other the quantity of Energy to be delivered on any given day or days during the Contract Term.

Supplementary Agreement - shall mean an instrument in writing duly authorized and executed by the Parties which amends, alters, varies, modifies or waives any provision of this Agreement.

Supplemental Energy – shall have the meaning set forth in Section 2.04.

System Participation Power - shall mean generating capacity and associated energy intended to be available at all times, and which excludes any generation reserves established or required by the RRO to which the purchaser belongs, which capacity shall constitute Accreditable Capacity.

Third Party Claim – shall mean a claim by any person or entity other than the Parties or their Affiliates.

TLR - shall mean those procedures which enable any Transmission Provider, pursuant to its OATT, to curtail transactions that contribute to an overload on the electric system in order to preserve system reliability, including any instruction or requirement under such procedures that (i) MH reduce, curtail or suspend Energy Schedules or deliveries to NSP under this Agreement, or (ii) NSP reduce or cease Scheduling or accepting deliveries of Energy from MH under this Agreement. For purposes of this Agreement, TLR shall be deemed to include Transmission Loading Relief under the NERC procedures or other process administered pursuant to an applicable OATT.

Transmission Provider – shall mean any entity or entities transmitting or transporting the Energy under an OATT (or subsequent transmission service as allowed by this Agreement) and as governed by this Agreement.

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Section 1.02 Unless the context otherwise requires:

(1) Words singular and plural in number shall be deemed to include the other and pronouns having masculine or feminine gender shall be deemed to include the other.

(2) Any reference in this Agreement to any person or entity includes its successors and assigns and, in the case of any governmental authority, any person or entity succeeding to its functions and capacities.

(3) Any reference in this Agreement to any Section or Appendix means and refers to the Section contained in, or Appendix attached to, this Agreement.

(4) Other grammatical forms of defined words or phrases have corresponding meanings.

(5) A reference to writing includes typewriting, printing, lithography, photography and any other mode of representing or reproducing words, figures or symbols in a lasting and visible form, including electronic mail.

(6) A reference to a Party to this Agreement includes that Party's successors and permitted assigns.

(7) A reference to a document or agreement, including this Agreement, includes a reference to that document or agreement as amended from time to time.

Section 1.03

Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings.

ARTICLE 2

SUPPLY AND PURCHASE OBLIGATIONS

Section 2.01 Except as specified in Section 2.04 and 3.06, at all times during the Contract Term, MH shall make available to NSP 500 MW of System Participation Power.

Section 2.02 MH shall maintain sufficient resources to meet MH's commitment under this Agreement. Said resources shall be Accreditable Capacity pursuant to the RRO to which MH belongs. MH shall comply with all relevant RRO procedures in connection with accreditation of the resources required to supply the Accreditable Capacity that is the subject of this Agreement and throughout the Contract Term shall maintain its Reserve Capacity Obligation in accordance with the higher of the levels required by: (a) Sections 6.4.2 and 3.53 of the Restated MAPP Agreement as such sections require as of the date of execution of this Agreement, or (b) the Reserve Capacity Obligation or substantially-equivalent planning reserve requirement of any RRO to which MH belongs. In the event MH is not a member of an RRO, MH agrees to maintain Reserve Capacity Obligation or substantially-equivalent planning reserve on its system in the same amount and of the same quality as if sections 6.4.2 and 3.53 of the Restated MAPP Agreement (as in effect on the date of execution of this Agreement) were still in effect.

Section 2.03 Except as specified in Section 3.06 and 3.07, at all times during the Contract Term, MH shall make available for delivery to the Point of Delivery and NSP shall Schedule and accept delivery at the Point of Delivery or pay (i.e. “take or pay”) for 160,000 MWh of energy during each rolling consecutive twenty-eight (28) calendar day period, meaning each and every rolling twenty-eight (28) day period terminating at hour ending 24:00 of each calendar day (“Guaranteed Energy”).

Section 2.04 In addition to the Guaranteed Energy specified in Section 2.03, MH may, at its sole discretion, offer to supply additional energy ("Supplemental Energy") associated with the 500 MW of Accreditable Capacity made available pursuant to this Agreement. The price associated with the supply of Supplemental Energy shall be as mutually agreed by the Parties and MH shall have the unfettered discretion to propose any price for Supplemental Energy. Except as provided herein, all other terms and conditions of this Agreement shall apply to the sale and purchase of Supplemental Energy. In the event that this provision precludes or impedes obtaining accreditation of this Agreement by the MAPP Reliability Council, for 500 MW of Accreditable Capacity, MH shall agree to amend this provision sufficient to allow such accreditation to be obtained.

Section 2.05 Notwithstanding the fact that delivery of Guaranteed Energy is subject to curtailment by MH in accordance with Sections 3.06 and 3.08, in conducting its energy planning, MH recognizes that NSP is relying on the reliable and consistent availability of Guaranteed Energy hereunder. MH covenants and agrees to use commercially reasonable efforts to have sufficient energy available at all times to reliably and consistently provide NSP Guaranteed Energy under this Agreement.

a. The Parties agree that MH's energy supply planning under this Section 2.05 is for the purpose of planning for the availability of sufficient energy, taking into account the hydraulic nature of the majority of MH's generation resources, in order to provide NSP Guaranteed Energy hereunder consistently and reliably.

b. MH agrees that it will undertake long term and season-ahead energy supply planning, including the marketing of surplus energy and the purchase of energy to offset projected energy needs, in a manner that includes the following:

(1) MH will plan to have sufficient energy available to meet MH’s needs, including serving NSP’s purchase of Guaranteed Energy hereunder and all of MH's other wholesale power and energy sales of equal or greater priority to NSP's purchase hereunder, under normal operating circumstances, and in spite of the recurrence of the lowest river flows in Manitoba on record between 1912 and the date of execution of this Agreement as the worst case scenario. In the event that during the Contract Term actual Manitoba river flows are lower than said worst case scenario, MH shall not be obligated to plan additional resources to supply NSP under this Agreement until such time as

MH changes its planning criteria for all of MH's firm transactions.

(2) MH’s energy supply planning process will take into account future load growth forecasts provided for in MH's formal load forecast, which is reviewed and updated annually.

(3) MH will conduct its energy supply planning in accordance with Good Utility Practice.

ARTICLE 3

SCHEDULING, AVAILABILITY AND DELIVERY

<u>Section 3.01</u>

a. MH acknowledges that its Transmission Provider currently has in place an OATT that governs the provision of transmission service for delivery to the Point of Delivery of Energy purchased by NSP under this Agreement. MH shall be solely responsible for arranging and paying for Firm Transmission Service (or if such service does not exist in the future, the highest priority delivery service available) for delivery of Energy to the Point of Delivery at its sole cost. Attached as Appendix 1 hereto is a copy of OASIS transmission reservation Number 155212, which is the transmission service reservation purchased by MH for the purposes of this Agreement. NSP shall be responsible for arranging and paying for Firm Transmission Service (or substantially comparable transmission service) with its Transmission Provider(s) to transmit the Energy from the Point of Delivery.

(1) Nothing in this Agreement shall obligate MH or its Transmission Provider to maintain an OATT in effect during the Contract Term.

(2) In the event that MH or its Transmission Provider cease to maintain an OATT in effect MH shall allocate sufficient transmission capacity for delivery of Energy to the Point of Delivery.

b. MH acknowledges that the transmission service reserved for the purposes of this Agreement is reserved through an exercising of MH’s right of first refusal arising under the the reservation priority right described in Section 2.3 of MH's Transmission Provider's OATT upon expiration of the firm transmission service rights granted by the 500 MW Power Sale Agreement between the Parties dated June 14, 1984. If NSP is able to obtain firm transmission service under the applicable OATT for delivery from and after the Point of Delivery of Energy purchased hereunder without (i) it or its Transmission Provider or the Mid-West Independent System Operator incurring expenses associated with infrastructure or interconnection improvements to accommodate such Firm Transmission Service, and (ii) without needing to exercise any right of first refusal it or its Transmission Provider may have under the applicable OATT, then NSP hereby waives any right of first refusal it may have arising under the OATT of NSP’s Transmission Provider (or the OATT of any regional transmission organization with authority over

NSP's Transmission Provider's system) upon expiration of the firm transmission service rights granted by the 500 MW Power Sale Agreement between the Parties dated June 14, 1984. To the extent NSP is unable to obtain such firm transmission service under the applicable OATT NSP shall retain any rights it may have to utilize any such right of first refusal.

Section 3.02 NSP shall be responsible for Scheduling the Energy for delivery by MH to the Point of Delivery.

Section 3.03

a. The Point of Delivery shall be at the Point of Interconnection unless agreed otherwise by the Parties.

b. MH may provide Scheduled Energy to a Point of Delivery within NSP’s transmission system other than the Point of Interconnection, provided (i) NSP agrees in its sole discretion that such delivery will not result in any adverse economic or reliability impact on NSP in light of all circumstances (including the effect such request has on NSP's Energy Schedule under this Agreement), and (ii) MH shall agree to pay all transmission service costs, including congestion management fees, associated with delivery of Guaranteed Energy to a Point of Delivery other than the Point of Interconnection. NSP shall respond to a request for a Point of Delivery other than the Point of Interconnection within a reasonable period of time.

Section 3.04 As between the Parties, title to and risk of loss of the Energy shall pass from MH to NSP at the Point of Delivery.

Section 3.05 Unless otherwise mutually agreed, all Scheduling of the Energy to the Point of Delivery shall occur by 9:00 AM CPT on the Business Day prior to delivery. The maximum Schedule for Energy during any hour shall be 500 MW. With the exception of Schedules that are curtailed pursuant to the terms of this Agreement, all Schedules associated with Guaranteed Energy shall provide for continuous 16 consecutive-hour delivery at 500 MW per hour, unless otherwise mutually agreed. During periods of curtailment, Schedules for delivery of Guaranteed Energy for durations less than 16 hours and at rates of less than 500 MW per hour are permitted to the extent required by the factor(s) giving rise to the curtailment. Subject to the requirements of this Section, Sections 2.03, 3.06 and 3.07, NSP in its sole discretion shall determine the hours of Guaranteed Energy delivery.

Section 3.06

a. MH shall not have the right to withhold, reduce or curtail the amount of Accreditable Capacity made available to NSP through this Agreement for any reason, including Force Majeure, except to the extent allowed pursuant to Section 7.02 hereof.

b. MH’s curtailment of Energy shall be allowed only in the circumstances and to the extent set forth below in paragraphs (1), (2), (3) and (4):

(1) In the event that, in order to maintain the reliable operation of the interconnected AC transmission system, MH is required to reduce or curtail NSP's

Schedule, the transaction curtailment priority used by MH relative to all uses of such AC transmission system at the time shall be implemented exclusively under MH's Transmission Provider's OATT, excepting that (i) MH shall redispatch its generation system to the full extent possible to alleviate such event or condition without curtailing deliveries under this Agreement and (ii) curtailment of NSP's Schedule hereunder shall be allowed to the extent and for the period that absent such curtailment, outage to End-Use Load in Canada or Border Accommodation Power Sales (up to the limits imposed pursuant to Section 3.08(1)) would have been required, consistent with Good Utility Practice.

(2) In the event MH or its Transmission Provider ceases to have an OATT, curtailment or reduction of NSP's Schedule hereunder in order to maintain the reliable operation of the interconnected AC transmission system, shall be implemented exclusively in accordance with this clause (2). Curtailment of energy deliveries under this paragraph to accommodate such events shall be implemented as follows, in the order specified, until the required amount of loading relief has been obtained: a) MH shall first curtail all transmission service or transactions, that are lower than the highest priority delivery service available as allowed by Section 3.01(a) above, which contribute to the condition requiring curtailment; b) MH shall redispatch its generation system to continue the Energy Schedule hereunder consistent with producing the desired loading mitigation upon the congested facility(s); c) to the extent all transactions identified in clause (a) of this paragraph are curtailed and system redispatch is not sufficient to produce the necessary mitigation that would avoid curtailment of the NSP's Schedule, the transaction curtailment priority used by MH relative to all uses of such AC transmission system at the time shall be implemented in a comparable and non-discriminatory manner, provided that (i) MH shall redispatch its generation system to the full extent possible to alleviate such event or condition without curtailing deliveries under this Agreement and (ii) curtailment of NSP's Schedule hereunder shall be limited to the extent and for the period that absent such curtailment, outage to End-Use Load in Canada or Border Accommodation Power Sales (up to the limits imposed pursuant to Section 3.08(1)) would have been required, consistent with Good Utility Practice.

(3) In the event that all or a portion of MH’s generation capacity is unavailable due to (i) forced outages of generating unit(s), (ii) derates of generating unit(s) caused by low water flow or other reason, (iii) the unavailability of generation outlet capacity caused by a forced outage or derate of MH's high voltage DC (“HVDC”) system, or (iv) scheduled

outages of generating unit(s) or MH's HVDC system, to the extent that such scheduled outages are reasonably necessary to avoid equipment damage to facilities or to avoid the deferral of normal or scheduled maintenance beyond that consistent with Good Utility Practice, and to the extent that such outages as referenced in any of clauses (i), (ii), (iii) or (iv) cause MH to have insufficient energy to serve the total load requirements of MH's End-Use Load in Canada and Border Accommodation Power Sales (up to the limits imposed pursuant to Section 3.08(1)), Firm Power sales and System Participation Power sales to any person or entity other than sales to an Affiliate of MH which are for the purpose of serving End-Use Load outside Canada, Energy deliveries to NSP may be reduced in an amount equal to the lesser of the amount necessary to respond to such circumstance or the amount necessary to make pro rata reductions of all energy deliveries in the order specified pursuant to Section 3.08.

(4) To the extent a Force Majeure actually precludes MH’s ability to make, or to continue to make available Energy under this Agreement, MH may restrict, limit or discontinue deliveries to NSP only to the extent that the Force Majeure actually causes MH to have an actual inability to deliver Energy sufficient to fulfill a Schedule under this Agreement. In such circumstance, deliveries to NSP may be reduced in an amount equal to the lesser of the amount necessary to respond to the Force Majeure or the amount necessary to make pro rata reductions of all deliveries in the order specified pursuant to Section 3.08.

c. MH shall give NSP reasonable notice of any known or anticipated event expected to give rise to the right of curtailment under Section 3.06(b)(3) and (4), including the anticipated duration of such event. MH shall provide daily updates thereafter throughout the duration of such an event.

(1) In the event that curtailment events are expected to last more than one day, NSP shall be deemed to have Scheduled deliveries of a 16-hour block at 500 MW per hour for each Monday through Friday during such event.

(2) In the event of an MH curtailment during any period in which NSP has Scheduled or is deemed to have Scheduled deliveries under clause (1) above, NSP shall not thereafter be obligated to accept delivery of the quantity of Energy subject to the curtailment for the remainder of the expected duration of the curtailment, as communicated by MH pursuant to clause (c) above, provided that if deliveries from MH become available again prior to the expiration of such period, MH shall first offer to resume deliveries to NSP prior to attempting to sell such available Energy to any other person or entity.

(3) In the event that circumstances give MH the right to curtail pursuant to Section 3.06(b), MH shall use due diligence to overcome or avoid such circumstances. The Parties acknowledge and agree that "due diligence" does not obligate Manitoba Hydro to purchase energy from a third party. Notwithstanding the provisions of the preceding sentence and subject to the limitations contained in Sections 3.06(c) and 3.06(d), MH retains the right to deliver Energy under conditions which give rise to the right to curtail.

(4) MH agrees that it will not reduce or suspend deliveries under this Agreement in an amount greater than necessary to respond to the circumstance giving rise to the right of curtailment and will only reduce or suspend deliveries under this Agreement, in a maximum amount, pro rata in accordance with the priorities set forth in Sections 3.06(b)(1) and (2), and 3.08. In no event may MH curtail deliveries (i) for End Use Load outside Canada, or to serve Border Accommodation Power Sales beyond the limits set forth in Section 3.08, (ii) for the purpose of supplying Firm Power to an Affiliate which results in the serving of End-Use Load outside Canada or for making any non-Firm Power sale to any person or entity.

d. If curtailment events are expected to last one calendar week or greater, MH agrees that absent NSP's consent, MH shall curtail deliveries of Energy uniformly on each hour of each day of such curtailment. For example, if MH reasonably believes an event will cause it to be able to curtail deliveries to the level of 300 MW per hour for some portion of one week, MH shall deliver 300 MW per hour during all hours of such curtailment event. During such an event MH shall offer to NSP any additional Energy (up to a total of 500 MW per hour) it can deliver, specifying the quantity and hours such Energy is available. NSP shall have the right but not the obligation to take such additional Energy.

<u>Section 3.07</u>

a. NSP shall have the right to curtail, reduce, cancel or suspend a Schedule specified in Article 2 or otherwise refuse to accept deliveries in accordance with the following provisions:

(1) In the event that NSP is directed by a Transmission Provider to implement TLR or otherwise curtail Firm Transmission Service required for delivery of any Energy Scheduled under this Agreement, in order to maintain the reliable operation of the interconnected transmission system, NSP's purchase of Energy (and corresponding take or pay obligation) may be curtailed by NSP under this paragraph up to the limitation imposed by a Transmission Provider.

(2) To the extent a Force Majeure actually precludes NSP's ability to take, or to continue to accept Energy under this Agreement.

b. NSP's obligation to pay for Guaranteed Energy pursuant to Section 2.03 shall only be reduced:

(1) by the amount of Guaranteed Energy Scheduled (or deemed to have been Scheduled pursuant to Section 3.06(c) by NSP during hour ending 6:00 through hour ending 24:00, Monday through Friday, that (i) is not delivered by MH for the reasons set forth in Section 3.06(b) or 3.06(c); or (ii) is not received by NSP for reasons set forth in Section 3.07(a).

For the purpose of this subsection 3.07(b), said reduction shall be equal to 500 MWh per hour, less any amount able to be Scheduled by NSP and delivered by MH for no more than 16 hours per day, Monday through Friday. Said reduction shall apply to any rolling 28 day period that includes the calendar day upon which the failure to deliver or inability to Schedule occurs. In no event shall the reduction applicable to any given calendar day exceed 8,000 MWh less the total Guaranteed Energy delivered to NSP on said calendar day.

<u>Section 3.08</u>

a. In the event of curtailment by MH pursuant to Section 3.06(b)(3) and (4), then the following priority criteria shall be used to determine the amount of Energy that shall be subject to curtailment:

(1) Unless otherwise specified through contractual arrangements with MH's End-Use Load customers, Manitoba wholesale requirements customers or Border Accommodation Power Sales customers, all Firm Power supplied to said customers shall take priority over all other power and energy sales, provided however that the priority of Border Accommodation Power Sales, shall be limited to a maximum aggregate load of 40 MW;

(2) Other than Firm Power sales to an Affiliate of MH for the purpose of, or resulting in, the serving of End-Use Load outside Canada, Firm Power sales shall take priority over all System Participation Power sales;

(3) System Participation Power sales shall take priority over all other power and energy sales;

(4) In the event that more than one System Participation Power sale exists, contracts with terms greater than six months shall take priority over contracts with terms less than or equal to six months;

(5) In the event that more than one System Participation Power sale exists in the time frames specified in (4) of this section, curtailment with respect to such power sales shall be made on a pro rata basis.

b. Notwithstanding the foregoing curtailment priorities, MH agrees that the curtailment priority for the deliveries of Energy under this Agreement shall never be subordinate to or lower in priority than the highest priority accorded to any sale made by MH or any Affiliate for End-Use Load in the United States.

c. Notwithstanding Section 3.08 a., in the circumstances where a curtailment by MH is necessitated only by the events described in Section 3.06(b)(3)(i), (iii) and (iv), MH reserves the right to curtail higher priority sales over lower priority sales to the extent that curtailment of such lower priority sales can be avoided by MH purchasing energy from third parties.

Section 3.09 Each Party shall provide as much notice and as many details as practicable to the other Party regarding Schedule curtailment, inability to Schedule, refusal to deliver, refusal to accept delivery or the unavailability of Guaranteed Energy pursuant to Sections 3.06 and 3.07, including the anticipated duration of curtailment or inability to Schedule or accept delivery of Energy. The Party unable to perform its obligations shall provide daily updates to the other Party.

Section 3.10 If during a period of curtailment pursuant to this Agreement, MH arranges for the supply of emergency replacement energy to NSP from a third party, in accordance with policies and/or procedures in place within an RRO to which both Parties belong, such Energy shall not be considered Guaranteed Energy. All obligations to take or pay for such emergency replacement energy shall be governed by the Parties' contract with the RRO to which both Parties belong or in the absence of such payment provisions, NSP shall pay MH for all costs incurred by MH arising from such supply.

ARTICLE 4

CAPACITY PRICING

Section 4.01 The monthly rate for Accreditable Capacity required to be made available pursuant to Section 2.01 shall be as follows and shall be changed on an annual basis effective May 1 using the following formula:

TRADE SECRET – CONFIDENTIAL

ARTICLE 5

ENERGY PRICING

Section 5.01 The rate for Guaranteed Energy shall be as follows and changed on an annual basis effective May 1 using the following formula:

TRADE SECRET – CONFIDENTIAL

ARTICLE 6

BILLING AND COST RESPONSIBILITY

Section 6.01 Sections 8.01 through and including Section 8.08 of the Coordination Agreement, excluding Section 8.02, are incorporated by reference into this Agreement and shall apply as if this Agreement was a Service Schedule to the Coordination Agreement.

TRADE SECRET & CONFIDENTIAL

Section 6.02 The amount payable by NSP to MH in each month shall be the sum of:

(1) the Monthly Capacity Rate (in dollars per MW-month) determined in accordance with Section 4.01, multiplied by the lesser of 500 MW or the amount of Accreditable Capacity provided pursuant to Section 7.02 as adjusted; plus

(2) the Energy Rate (in dollars per MWh) as determined in accordance with Section 5.01, multiplied by the quantity of Guaranteed Energy Scheduled by NSP; plus

(3) the rate for Supplemental Energy (in dollars per MWh) as agreed to in accordance with Section 2.04, multiplied by the quantity of Supplemental Energy Scheduled by NSP; minus

(4) the Energy Rate (in dollars per MWh) as determined in accordance with Section 5.01 multiplied by the quantity of Guaranteed Energy Scheduled but not delivered due to the provisions of Sections 3.06 or 3.07; minus

(5) the rate for Supplemental Energy (in dollars per MWh) as agreed to in accordance with Section 2.04 multiplied by the quantity of Supplemental Energy Scheduled but not delivered due to the provisions of Sections 3.06 and 3.07; plus

(6) the amount owing, if any, ("Take or Pay Payment") due to the Minimum Guaranteed Energy that was not reduced or curtailed pursuant to Sections 3.06 or 3.07 and not Scheduled or otherwise purchased by NSP during the billing month between hour ending 6:00 through hour ending 24:00, Monday through Friday, and calculated as follows:

Minimum Guaranteed Energy = D-C

Take or Pay Payment = ((D-C)-E) x Energy Rate if (D-C) > E

Or

Take or Pay Payment = $0.00 if (D-C) = or < E

where,

- D shall be equal to (A x 16) x 500 MW per hour, where "A" is the number of Monday through Friday days in the billing month; and
- C shall be the reduction in NSP's obligation to Schedule and/or pay for (in MWh) Guaranteed Energy, as calculated pursuant to Sections 3.06 and 3.07;
- E shall be the quantity of Guaranteed Energy delivered to NSP during the billing month, which was delivered during hour ending 6:00 through hour ending 24:00, Monday through Friday and with a maximum quantity of 8,000 MWh on each of those days;

plus

(7) reimbursement to MH for any extra transmission costs incurred pursuant to Section 6.04; and minus

(8) any reimbursement to NSP for extra transmission costs incurred pursuant to Section 3.03(b).

Section 6.03 MH is responsible for all costs as a result of making Accreditable Capacity available pursuant to this Agreement, as well as any transmission service charges, including replacement of or payment for Real Power Losses and other expenses incurred in order to deliver Energy to the Point of Delivery. NSP shall be responsible for any costs including transmission service charges and replacement of or payment for Real Power Losses and other charges associated with the Accreditable Capacity and Energy, or its receipt, of and from the Point of Delivery.

Section 6.04 In the event that (1) the Parties do not agree to Point of Delivery other than the Point of Interconnection; and (2) MH's Transmission Provider adopts an OATT (or subsequent transmission service as allowed by this Agreement), that does not permit MH to reserve transmission service solely within Canada for the delivery of Energy to NSP at the Point of Delivery; and (3) MH is required to modify the transmission service arranged for the purposes of this Agreement, then: MH shall be responsible for reserving alternate transmission service for Delivery of the Energy to NSP. In that circumstance, the Parties shall cooperate in good faith to allocate such transmission costs equitably to conform with the cost allocation provided in Section 6.03 (ie. based on costs incurred north versus south of the Point of Interconnection). If the Parties cannot reasonably agree on such allocation, the matter shall be resolved pursuant to Section 10.09.

Section 6.05

TRADE SECRET – CONFIDENTIAL

(3) Notwithstanding the foregoing, nothing in this Section 6.05 shall preclude or limit NSP's right to designate the resources purchased under this Agreement as "renewable resources" or to apply any portion of this purchase to applicable portfolio standards or other regulatory requirements related to renewable resources, provided that such designation or application by NSP shall not obligate MH to manage the supply of Energy purchased pursuant to this Agreement in any particular manner, nor restrict MH from the particular type of generating resources used to supply the Energy purchased pursuant to this Agreement (including energy obtained from third party purchases, regardless of the generation type used by the third party), nor shall anything in this Section 6.05 constitute a representation by MH that the Energy supplied by MH pursuant to this Agreement is supplied from renewable resources.

ARTICLE 7

CONDITIONS OF SALE AND PURCHASE

Section 7.01

(1) This Agreement shall be conditional upon the Parties receiving by July 31, 2003, and maintaining in effect the listed approvals:

- the final non-appealable approvals of the National Energy Board of Canada, the US Department of Energy, the US Securities Exchange Commission, the Minnesota Public Utilities Commission, accreditation by the MAPP Reliability Council for the 500 MW of Accreditable Capacity purchased pursuant to this Agreement, the Lieutenant Governor in Council of Manitoba, the board of directors of MH and any other approvals required by law.

(2) MH shall seek approval from the National Energy Board and the Lieutenant Governor in Council of Manitoba, the board of directors of MH and any other approvals required in Canadian law for this transaction. NSP shall seek approval from the US Department of Energy, the US Securities Exchange Commission, the Minnesota Public Utilities Commission, MAPP Reliability Council accreditation, and any other United States or Minnesota approvals required by law.

(3) Both Parties shall use commercially reasonable efforts to secure these approvals, including providing reasonable assistance to the other Party, if requested.

(4) Each Party shall notify the other Party as soon as practicable following the failure to obtain a required approval.

(5) If any of the referenced approvals are denied, conditionally approved or revoked, the Parties shall negotiate in good faith to implement amendments to this Agreement that overcome the denial, or revocation or to satisfy the conditions imposed. In the event that any denials cannot be overcome or conditions cannot be satisfied through such good faith negotiations, this Agreement shall terminate as of the earlier of July 31, 2003 or written notice of one Party advising the other Party that the impediment cannot be reasonably solved. In the event that any of the above referenced approvals is obtained, but later revoked, this Agreement shall terminate as of the date of revocation.

Section 7.02 NSP shall seek accreditation from MAPP for 500 MW of Accreditable Capacity purchased pursuant to this Agreement. If, after receiving accreditation, at any time during the Contract Term, MAPP accreditation of the Accreditable Capacity purchased pursuant to this Agreement is reduced below 500 MW, then MH and NSP’s obligations under this Agreement shall be reduced pro rata based on a percentage derived from the reduced accreditation divided by 500 MW. Said reduction of obligations shall be considered NSP's sole and exclusive remedy for failure by MH to make Accreditable Capacity available to NSP.

ARTICLE 8

FORCE MAJEURE

Section 8.01 Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement to the extent such performance is prevented or delayed due to a Force Majeure, provided that:

(1) the non-performing Party shall give the other Party notice promptly (and within 48 hours if possible) after the non-performing Party’s knowledge of the commencement of the Force Majeure, with written confirmation to be supplied within 10 days after the

commencement of the Force Majeure further describing the particulars of the occurrence of the Force Majeure;

(2) the delay in performance shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure;

(3) the Party whose performance is delayed or prevented shall proceed with reasonable efforts to overcome the Force Majeure which is preventing or delaying performance and shall provide weekly written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure, the schedule for such actions and the expected date by which performance shall no longer be affected by the Force Majeure;

(4) when the performance of the Party claiming the Force Majeure is no longer being delayed or prevented, that Party shall give the other Party notice to that effect.

ARTICLE 9

CREDITWORTHINESS

Section 9.01 For the purpose of determining whether a Party is able to meet its obligations pursuant to this Agreement, a Party may require reasonable credit review procedures. If requested by a Party, the other Party shall deliver (i) within 120 days following the end of each fiscal year, a copy of such Party's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of such Party's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles or such other principles then in effect, provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such Party shall diligently pursue the preparation, certification and delivery of the statements.

Section 9.02 If a Party ("Requesting Party") has reasonable grounds to believe that the other Party's creditworthiness or performance under this Agreement has become unsatisfactory, the Requesting Party shall provide the other Party with written notice requesting Performance Assurance in an amount determined by the Requesting Party in a commercially reasonable manner. For the purposes of this Article, unsatisfactory creditworthiness shall mean that the credit rating for senior unsecured debt of the affected Party, as determined by the applicable credit rating agencies, has fallen below investment grade. Upon receipt of such notice the other Party shall have fourteen (14) Business Days to remedy the situation by providing Performance Assurance to the Requesting Party in an amount reasonably determined by the Requesting Party. In the event that the other Party fails to provide such Performance Assurance, or a guarantee or other credit assurance acceptable to the Requesting Party within three (3) Business Days of receipt of notice, then the Requesting Party may terminate this Agreement upon thirty (30) days notice.

ARTICLE 10

REMEDIES/ARBITRATION

Section 10.01 If for reasons provided in Section 3.06, but excluding any curtailments or inability to deliver arising from or related to circumstances or events occurring in the United States that are not caused by MH, MH fails to deliver at least **TRADE SECRET – CONFIDENTIAL** of Guaranteed Energy Scheduled by NSP in a month for twelve months, whether consecutive or not, in any thirty-six consecutive month period, NSP shall be entitled to terminate this Agreement by notifying MH in writing of its decision to terminate and the effective date of termination. Notwithstanding the foregoing, NSP's entitlement to terminate must be exercised within six (6) calendar months of the date when such right first arose.

Section 10.02 Failure by MH to deliver Guaranteed Energy, except where such failure is excused by the terms and conditions of this Agreement, shall constitute an Event of Default. Failure by NSP to make payments for undisputed amounts due under this Agreement to MH within 30 days after notice from MH that such payment is due shall constitute an Event of Default.

Section 10.03 In the event the defaulting Party fails to cure the Event of Default, or upon the occurrence of an incurable Event of Default, the non-defaulting Party may terminate the Agreement by notifying the defaulting Party in writing of the decision to terminate and the effective date of the termination. Such termination shall be cumulative of and not in lieu of any other remedies set forth in this Agreement.

Section 10.04 Upon termination of the Agreement by MH or NSP due to an Event of Default or pursuant to Section 10.01, Section 10.03 or Section 7.01(5): (1) NSP shall have no future or further obligation to purchase the Accreditable Capacity or Energy under this Agreement or to make any payment whatsoever under this Agreement, except for payments for obligations arising or accruing prior to the effective date of termination; and (2) MH shall have no future or further obligation to provide the Accreditable Capacity or deliver the Energy to NSP under this Agreement or to satisfy any other obligation of this Agreement, except for payments or other obligations arising or accruing prior to the effective date of termination.

Section 10.05 Except as otherwise specifically provided in this Agreement, neither Party shall be liable to the other under this Agreement for any indirect, punitive, exemplary, special or consequential damages, including but not limited to, loss of use, loss of revenue, loss of profit, loss of tax benefits, or interest charges. The Parties recognize and agree that the cost to NSP of procuring energy or capacity to replace any Energy or Accreditable Capacity provided in accordance with Section 2.02 and in the amounts allowed in Section 7.02 that MH fails to make available or deliver to the Point of Delivery and for which MH's failure is not excused, shall be deemed to be a direct and recoverable damage and not an indirect or consequential damage.

Section 10.06 Each Party recognizes that NSP is relying upon the availability of the Accreditable Capacity provided in accordance with Section 2.02 and in the amounts allowed in Section 7.02 and Energy provided from the System Participation Power and that this Agreement is a significant asset of MH. Each Party further agrees that, if it defaults under this Agreement, and if the other Party thereafter brings an action seeking specific performance of this Agreement, the defaulting Party shall not defend against such action on the basis of the non-defaulting Party having an adequate remedy at law.

Section 10.07

(1) MH shall indemnify NSP from, any damages or injury NSP may suffer or incur as a result of Third Party Claims arising from MH's failure to perform or negligent performance of its obligations under this Agreement, except to the extent such damages or injury were caused by the misconduct of NSP. NSP shall indemnify MH from, any damages or injury MH may suffer or incur as a result of Third Party Claims arising from NSP's failure to perform or negligent performance of its obligations under this Agreement, except to the extent such damages or injury were caused by the misconduct of MH. For the purposes of this section:

(a) "misconduct" includes negligent acts or omissions by a Party, and

(b) "damages or injury" includes indirect, incidental and consequential damages suffered by a third party, and without restricting the generality of the foregoing, expenses or liabilities associated with the interruption of power, energy or related services to any third party, excepting damage or injury where said interruption is contemplated and authorized pursuant to the terms of this Agreement, including Sections 3.06 and 3.07.

(2) Each Party shall promptly notify the other Party of claims, demands or actions that may result in a claim for indemnity. Failure to notify shall not relieve a Party from liability unless, and then only to the extent that, such failure results in the forfeiture by such Party of a substantial right or defense. No settlement of any claim that may result in a claim for indemnity may be made by either Party without the prior written consent of the other Party, which consent may not be unreasonably withheld. Neither Party shall be liable under this Agreement in respect of any settlement of a claim unless it has consented in writing to such settlement.

Section 10.08 Any claim, counterclaim, demand, cause of action, dispute or controversy arising out of or relating to this Agreement shall be resolved in accordance with the terms of Article 10 of the Coordination Agreement, which terms are hereby incorporated by reference. The provisions of this Article shall survive beyond the Contract Term.

ARTICLE 11

GENERAL

Section 11.01 This Agreement shall be effective upon execution by the Parties, subject to satisfaction of the requirements of Section 7.01, and shall continue until the later of April 30, 2015, or such other effective date of termination if terminated earlier pursuant to Sections 7.01, 10.01 or 10.03, and the date upon which all obligations under this Agreement are discharged.

TRADE SECRET & CONFIDENTIAL

Section 11.02

(1) The rights and obligations of this Agreement may not be assigned by either Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld. Any purported assignment of this Agreement in the absence of the required consent shall be void.

(2) Notwithstanding Section 11.02(1) above, the Parties may, without the other Party's consent, assign this Agreement to a wholly owned subsidiary or corporate successor or as security in any financing provided that such assignment shall not relieve the assignor of its liability hereunder.

(3) Notwithstanding Section 11.02(1) above, NSP may, at its sole option and without MH's consent or approval, sell, transfer or assign all or any part of the Energy and associated Accreditable Capacity delivered to it under this Agreement to another electric utility or other buyer(s); provided, however, that such transfer or assignment shall not affect MH's obligations or rights under this Agreement.

Section 11.03 This Agreement does not confer any exclusive rights on either Party with respect to the sale or purchase of capacity, energy or related services. Neither Party has actual, apparent, or inherent authority to bind the other Party as agent, and this Agreement is not intended to and does not create the relationship between the Parties of employer-employee, principal-servant, franchise, association, joint venture or partnership.

Section 11.04 Any notices other than those required by Sections 3.09, 3.06(c), 8.01(1) and 8.01(4), demands or requests required or authorized by this Agreement shall be in writing to the "Executive Officers" as follows:

Vice-President
Power Supply
Manitoba Hydro
Post Office Box 815
Station Main
Winnipeg, Manitoba R3C 2P4

if to the Manitoba Hydro-Electric Board;

and to:

Manager, Purchased Power
Xcel Energy Services
1099 18th Street
Suite 3000
Denver, CO 80202

if to Northern States Power Company,

and shall be effective upon actual receipt by the Party to whom addressed. The designation of the persons to be notified or the address of such persons may be changed at any time by similar notice.

TRADE SECRET & CONFIDENTIAL

Section 11.05 Each Party shall keep complete and accurate records and memoranda of its operations and transactions under this Agreement and shall maintain such data as may be necessary to determine with reasonable accuracy information required by this Agreement. With respect to invoice records, each Party shall maintain such records, memoranda and data for the current calendar year plus a minimum of six previous calendar years. The Parties, or their respective designees, shall each have the right upon reasonable prior notice to inspect, review and take copies of each other's records and data as reasonably necessary to resolve issues, verify costs and ascertain the reasonableness and accuracy of any statements of cost relating to transactions hereunder. The Parties or their designees shall have the right upon reasonable prior notice to inspect, review and take copies of the other Party's records as far as such records concern curtailments required by this Agreement. Each Party shall treat such information as confidential and shall not disclose the information on the same conditions set forth in Section 11.14.

Section 11.06 Each Party hereby grants its consent to the other Party to record Scheduling telephone calls and electronic communications for the purpose of this Agreement. All written records and recordings of such telephone calls and electronic communications that are not subject to any legal privilege, regardless of form, shall be admissible in any arbitration or other legal proceeding between the Parties arising out of this Agreement.

Section 11.07 Unless otherwise specifically provided herein, this Agreement may be altered, modified, varied or waived, in whole or in part, only by written Supplementary Agreement.

Section 11.08 This Agreement represents the entire agreement between the Parties with respect to the subject matter hereof and terminates and supersedes all prior oral and written proposals, including the document entitled, "500 MW Agreement Negotiation Points" executed by the Parties on November 21, 2001, and communications pertaining hereto. There are no representations, conditions, warranties or agreements, expressed or implied, statutory or otherwise, with respect to or collateral to this entire Agreement other than those contained herein or expressly incorporated herein.

Section 11.09 Each of the Parties are parties to existing agreements with other parties which may include providing for interconnection, pooling and interchange of electrical services. This Agreement shall not affect the obligations and rights of a Party with respect to such existing agreements.

Section 11.10 MH irrevocably agrees to waive the protections of the Foreign Sovereign Immunities Act, 28 U.S.C. § 1602, et seq., in connection with this Agreement.

Section 11.11 This Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

Section 11.12 It is acknowledged and agreed that Accreditable Capacity, Energy and related services are inherently dangerous, and MH offers no warranty, express or implied, that the Accreditable Capacity, Energy or related services will not cause injury to person or property.

Section 11.13 This Agreement shall be subject to the present and future local, state, provincial and federal laws of Canada and the United States, regulations or orders of lawful authorities and may be suspended by or as a result of an order of competent authority in case of war, but this Agreement shall become effective again as soon as such order is rescinded or the approval for the transfer of Accreditable Capacity and Energy is again secured.

Section 11.14 Neither Party shall disclose any of the terms or conditions of this Agreement to a third party (other than the Party's and its Affiliates' employees, lenders, counsel, or accountants who have a need to know such information and have agreed to keep such terms confidential), except to satisfy the conditions of sale and purchase identified in Section 7.01 or in order to comply with any applicable law, order, regulatory requirement or request, or exchange rule; provided, each Party shall notify the other Party of any proceeding of which it is aware which may result in disclosure and use reasonable efforts to prevent or to limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation.

THE MANITOBA HYDRO-ELECTRIC BOARD	***NORTHERN STATES POWER COMPANY***
A. D. Cormie	Paul Bonavia
Division Manager	Vice President
DATE: August 1, 2002	DATE: 7-30-02

APPROVED

L... ...VICES

Manitoba Hydro

from the Office of the Vice-President

2002 08 14

Ms. K. (Karen) Hyde
Manager, Purchased Power
Xcel Energy Services
1099 18th Street
Suite 3000
Denver, CO 80202

Dear Ms. Hyde:

I am writing to provide notice of a change to the *Northern States Power - Manitoba Hydro 500 MW System Participation Power Sale Agreement* signed by Manitoba Hydro on August 1, 2002.

The OASIS reservation number referenced in Section 3.01 of the Power Sale Agreement has been changed. OASIS transmission reservation number **75003362**, located on the Manitoba Hydro page of the MISO OASIS has replaced transmission reservation number 155212 found on the Manitoba Hydro page of the MAPP OASIS.

Attached for your records are OASIS transmission reservation request 155212 and request 75003362.

Yours truly,

K.R.F. Adams, P. Eng.
Vice-President
Power Supply

KRFA/lo

P.O. Box 815 • Winnipeg, Manitoba • CANADA R3C 2P4 • kradams@hydro.mb.ca
Telephone / *N° de téléphone* : (204) 474-3923 • Fax / *N° de télécopieur* : (204) 474-4114

Manitoba Hydro

Transmission Request #155212 Details

Goto:

Refresh

Customer Information

Renewal Deferral Redirect New Req

Name
Judy A. Clendenan

Company	**DUNS**
MHEM	253893713

Affiliated with Provider
No

Phone	**Fax**
204-474-4558	204-453-5359

E-mail
jaclendenan@hydro.mb.ca

Comments Update Comments
Multiple Member Service Request with NSP

Status Notification
mailto:jaclendenan@hydro.mb.ca

Seller/Provider Information

Name
Jake Unrau

Company	**DUNS**
MHEB	205689045

Phone	**Fax**
204-487-5357	204-487-5368

E-mail
junrau@hydro.mb.ca

Comments Update Comments
MAPP to alter POD(Shercogen) due to NSP network service.

Provider Comments

Path and POR/POD Information

POR	**POD**
DORSEY230	MH.NSP

Path Name

Source	**Sink**
MHEB	NSP

Transmission Service

Increment	**Type**	**Class**
YEARLY	POINT_TO_POINT	FIRM
Period	**Window**	**Sub Class**
FULL_PERIOD	FIXED	

NERC Curtailment Priority
7

Other Curtailment Priority
10

Dates and Times

Start Date and Time
05/01/2005 00:00:00 CD

Stop Date and Time
05/01/2015 00:00:00 CD

Queued Date and Time
03/10/1999 11:51:18 CS

Approval Date and Time
08/04/1999 15:04:30 CD

Confirmation Date and Time
01/13/2000 15:38:39 CS

Rebid Date and Time

Time Of Last Status Change

Request Information

Capacity Requested
500 MW

Capacity Granted
500 MW

Bid Price	**Offer Price**	**Price Units**

Ceiling Price

Negotiated Price

Status	**Preconfirmed**
CONFIRMED	No

Status Comments

Transmission Request #75003362 Details

Goto:

Refresh

Customer Information

Renewal Deferral Redirect New Req

Name
Dwight S Evans

Company MHEM
DUNS 253893713

Affiliated with Provider
No

Phone 204-474-3042
Fax 204-453-5359

E-mail
dsevans@hydro.mb.ca

Comments Update Comments

Status Notification

Seller/Provider Information

Name
Blain A Poff

Company MHEB
DUNS 205689045

Phone 204-487-5302
Fax 204-487-5368

E-mail
bapoff@hydro.mb.ca

Comments Update Comments
Replaces reservation number 73155212

Provider Comments

Path and POR/POD Information

POR MHEB
POD NSP

Path Name
_/MHEB/MHEB-NSP//

Source MHEB
Sink NSP

Transmission Service

Increment YEARLY
Type POINT_TO_POINT
Class FIRM

Period FULL_PERIOD
Window FIXED
Sub Class

NERC Curtailment Priority
7

Other Curtailment Priority
9

Dates and Times

Start Date and Time
05/01/2005 00:00:00 ES

Stop Date and Time
05/01/2015 00:00:00 ES

Queued Date and Time
01/30/2002 07:54:04 ES

Approval Date and Time
01/30/2002 07:54:05 ES

Confirmation Date and Time
01/30/2002 07:54:05 ES

Rebid Date and Time

Time Of Last Status Change
01/30/2002 07:54:05 ES

Request Information

Capacity Requested
529 MW

Capacity Granted
529 MW

Bid Price 0.0000
Offer Price 0.0000
Price Units $/MW-Year

Ceiling Price
99999.0000

Negotiated Price

Status CONFIRMED
Preconfirmed No

Status Comments

UPA DIVERSITY EXCHANGE AGREEMENT

between

THE MANITOBA HYDRO - ELECTRIC BOARD

and

UNITED POWER ASSOCIATION

FEBRUARY 1, 1991

UPA DIVERSITY EXCHANGE AGREEMENT
(1995 - 2015)

THIS UPA DIVERSITY EXCHANGE AGREEMENT ("Agreement") is entered into effective as of February 1, 1991, by and between United Power Association ("UPA"), a Minnesota cooperative corporation, and The Manitoba Hydro-Electric Board ("MH"), a Manitoba Crown corporation, (each of the foregoing entities being sometimes referred to individually as "Party" or collectively referred to as "Parties").

RECITALS

0.01 WHEREAS, UPA is the owner and operator of electric generation and transmission facilities in the United States of America, and MH is the owner and operator of electric generation and transmission facilities in Canada, and each Party is engaged in the generation, transmission, distribution and sale of electric energy; and

0.02 WHEREAS, UPA, among others, is a party to the Mid-Continent Area Power Pool ("MAPP") Agreement, dated March 31, 1972, and amendments thereto; and

0.03 WHEREAS, the Parties require governmental permits and approvals for the import and export of electric energy; and

0.04 WHEREAS, Northern States Power Company ("NSP"), a Minnesota Corporation, UPA and MH shall concurrently execute an agreement (the Tri-Party Coordination Agreement) for the purpose of providing UPA with the capability to schedule power and energy transactions with MH via the Facilities; and

0.05 WHEREAS, NSP and MH shall concurrently execute an agreement (the 500 KV Upgrade Facilities Agreement) for the purpose of increasing the capability of the existing facilities; and

0.06 WHEREAS, NSP and MH shall concurrently execute an agreement (the 500 KV Coordination Agreement) which shall amend and restate the Coordination Agreement dated July 21, 1976, and shall be for the purpose of conducting power and energy transactions and operating and maintaining the Facilities; and

0.07 WHEREAS, NSP and UPA shall concurrently execute an agreement (the Resolution Agreement) for the purpose of providing UPA with the rights to 200 MW of transmission capability with MH during the twenty (20) year period starting May 1, 1995 and ending April 30, 2015; and

0.08 WHEREAS, MH will have capacity available during the Summer Seasons and UPA will have capacity available during the Winter Seasons.

NOW THEREFORE, in consideration of the mutual promises and covenants of each Party to the other contained in this Agreement and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties covenant and agree as follows:

ARTICLE 1
DEFINITIONS

Section 1.01 Unless otherwise specified in this Agreement, all definitions and references to and use of terms and their abbreviations, shall have the meanings which are set out in the Tri-Party Coordination Agreement, or if not specified therein, then in the MAPP Agreement as amended as at May 1, 1985, ("MAPP Agreement").

Contract Year - shall mean any twelve (12) month period from May 1 through the following April 30. A Contract Year shall consist of 8 760 hours except in years when February 29 occurs when it shall consist of 8 784 hours.

Seasonal Diversity Power - shall mean capacity and associated energy which is exchanged between power systems on a seasonal basis pursuant to this Agreement. The supplying system will provide reserve capacity for this power.

Summer Season - shall mean the period from May 1 through the following October 31.

Winter Season - shall mean the period from November 1 through the following April 30.

Coordinating Committee - shall mean the committee established in Section 6.04 of this Agreement.

Section 1.02 When required by the context of this Agreement, the singular shall include the plural, and the plural shall include the singular.

ARTICLE 2
SERVICE TO BE PROVIDED

<u>Section 2.01</u> During the period May 1, 1995 through April 30, 2015, MH shall make available to UPA at all times during each Summer Season, and UPA shall make available to MH at all times during each Winter Season, at the Point of Interconnection, 150 MW of Seasonal Diversity Power.

<u>Section 2.02</u> During the Summer Season or the Winter Season the supplying Party may, at its option, limit the energy associated with the Seasonal Diversity Power to an amount which will result in an average of the Monthly Capacity Factors over that season of twenty (20) percent.

ARTICLE 3
SCHEDULING

<u>Section 3.01</u> The following procedures shall apply for scheduling deliveries of Seasonal Diversity Power:

(a) Seasonal:

(i) On or before each February 1, UPA shall provide MH with an estimate of UPA's anticipated energy usage for each month of the Summer Season commencing May 1 of the forthcoming Contract Year.

(ii) On or before each August 1, of each Contract Year, MH shall provide UPA with an estimate of MH's anticipated energy usage for each month of the Winter Season commencing November 1 of the same Contract Year.

(b) Weekly:

On or before 1500 hours central time on Thursday of each Week of each Contract Year, the receiving Party shall provide the supplying Party with a proposed schedule of deliveries for each clock hour of the following Week.

(c) Daily:

On or before 1500 hours central time of each day of the Contract Year, the receiving Party may modify the hourly schedule, proposed in (b) above, by providing the supplying Party with a schedule of deliveries for each clock hour of the following day. No further modification shall be permitted without the mutual agreement of the Parties.

Section 3.02 Notwithstanding the provisions of Section 3.01, additions, modifications and deletions to the above schedules may be made by the Parties in accordance with criteria established by the Coordinating Committee.

Section 3.03 Each Party shall operate and maintain its electric system so as to minimize to the extent practicable, differences between net actual deliveries and net scheduled deliveries. The difference between the net scheduled deliveries and the net actual deliveries shall be balanced out in kind in accordance with procedures established by the Coordinating Committee.

ARTICLE 4
PRICING

Section 4.01 There shall be no charge for the capacity associated with the Seasonal Diversity Power exchanged pursuant to this Agreement.

Section 4.02 The rate for energy delivered to UPA during each of the twenty (20) Summer Season periods is the greater of:

(a) a rate calculated as follows:

$$\text{Rate} = \$16.5/\text{MWh} \times \frac{E_{T(n)}}{E_{T(f)}}$$

where:

$E_{T(n)}$ is the total dollars per MWh expense for the nth Contract Year calculated in accordance with Appendix A to this Agreement,

$E_{T(f)}$ is the total dollars per MWh expense for the twelve (12) month period ending April 30, 1988, calculated in accordance with Appendix A to this Agreement, or

(b) MH's Incremental Cost plus ten (10) percent, provided however there shall be no allowance for the storage value of water.

Section 4.03 The rate for energy delivered to MH during each of the twenty (20) Winter Season periods shall be determined in accordance with (a) or (b) below, whichever is applicable:

(a) For energy delivered prior to 0800 hours central time or after 2000 hours central time each weekday (Monday through Friday), or during all hours of Saturday, Sunday or Designated Holidays, the rate shall be the weighted average price paid by UPA in accordance with Section 4.02 for the Summer Season of the same Contract Year.

(b) For energy delivered during periods other than those described in Section 4.03 (a), the rate shall be the greater of:

(i) the rate calculated in accordance with Section 4.03 (a), or

(ii) UPA's Incremental Cost plus ten (10) percent.

Section 4.04 The amount payable to the supplying Party for Seasonal Diversity Power shall be equal to the product calculated by multiplying the appropriate rate described in this Article 4 by the amount of energy scheduled for delivery pursuant to Article 3 of this Agreement.

Section 4.05 All rates stated and all rates calculated shall be in lawful money of the United States of America.

ARTICLE 5
ENERGY EXCHANGE

Section 5.01 During a period of Adverse Water Conditions, UPA shall deliver energy to MH upon MH's request. Such energy shall be that energy which is available to UPA after UPA has made provision to comply with any applicable governmental emission standards, and to supply its firm energy commitments, now or hereafter created, including firm sales to other utilities. The maximum amount of energy which UPA is obligated to deliver under this section, in any twelve (12) month period, is the lesser of that required to enable MH to meet its firm commitments or 660 GWh.

Section 5.02 MH shall pay UPA for energy delivered under the provisions of Section 5.01, an amount equal to UPA's Incremental Cost plus ten (10) percent multiplied by the amount of energy delivered. The Incremental Cost for such energy will be determined after providing for firm and nonfirm sales which UPA is making at the time when such energy is delivered.

Section 5.03 If MH receives energy in accordance with Section 5.01, MH shall offer to return to UPA an amount or amounts of energy totalling that received from UPA, within five years of the delivery of such energy. The price for energy returned to UPA shall be the weighted average price paid by MH for the energy received from UPA in the preceding five years under Section 5.01, after adjusting the price MH paid in each Contract Year by a factor equivalent to the ratio of:

(a) The factor $E_{T(n)}$, from Section 4.02 (a), for the Contract Year in which the energy is returned to UPA divided by;

(b) The factor $E_{T(n)}$, from Section 4.02 (a), for the Contract Year in which the energy was delivered by UPA to MH.

ARTICLE 6
GENERAL

Section 6.01 Except as otherwise provided herein, the provisions of Articles 4, 5 and 6 of the Tri-Party Coordination Agreement shall apply to this UPA Diversity Exchange Agreement and are hereby incorporated by reference.

Section 6.02 This Agreement shall become effective upon execution by the Parties and shall be conditional upon receiving the approvals, duly accepted and acknowledged as hereinafter provided by both Parties to this Agreement. The approvals shall be the following:

a) the Administrator of the Rural Electrification Administration, or the designee of the Administrator;

b) The Manitoba Energy Authority approval for the export of electricity;

c) an Order-in-Council issued by the Province of Manitoba in Canada;

d) an Export Licence issued by the United States, Department of Energy;

e) A Presidential Permit issued by the President of the United States or delegate;

f) approval of the Federal Energy Regulatory Commission;

g) the license(s) or permit(s) to export power and energy issued by the National Energy Board of Canada; and

h) MAPP approval for the accreditation of the Seasonal Diversity Power.

Both Parties shall expend their best efforts to secure the approvals on or before May 1, 1992. If all approvals are not received on or before May 1, 1993, this Agreement shall terminate and neither Party shall be liable to the other Party.

The Party seeking each approval shall send to the other Party a copy of each approval as issued within thirty (30) days of receipt. The Party seeking the approval shall within ninety (90) days notify the other Party in writing either that it accepts the approval or that it does not accept such approval. If a Party fails to notify the other Party of its non-acceptance within ninety (90) days of receipt of the approval, that Party shall be deemed to have accepted the approval.

Section 6.03 This Agreement represents the entire agreement between the Parties with respect to the subject matter hereof and terminates and supersedes all prior oral and written proposals and communications pertaining hereto including the UPA Diversity Exchange Agreement entered into on November 20, 1989. There are no representations, conditions, warranties or agreements, express or implied, statutory or otherwise, with respect to or collateral to this Agreement other than contained herein or expressly incorporated herein. Unless otherwise specifically provided herein, this Agreement may be altered, modified or varied, in whole or in part, only by Supplementary Agreement.

Section 6.04 A committee, known as the "Coordinating Committee", is hereby established and has the authority to determine:

(a) interchange accounting and billing procedures;

(b) procedures for carrying out the transactions referred to in Article 2 of the Tri-Party Coordination Agreement; and

(c) such other matters as provided herein.

The Coordinating Committee shall be comprised of two members: one member representing MH and one member representing UPA. The Coordinating Committee shall meet at the request of either member within two weeks of receipt of such request. Members shall be named and changed by appropriate notice.

ARTICLE 7
DEFAULTS AND REMEDIES

Section 7.01 If a Party fails, for any reasons other than those for which performance is excused herein, to make Seasonal Diversity Power available pursuant to this UPA Diversity Exchange Agreement and such default continues for ten (10) days after receipt of written notice of such default, the defaulting Party, notwithstanding Section 5.09 of the Tri-Party Coordination Agreement, shall reimburse the receiving Party within twenty (20) days of receipt of invoice for its reasonable cost of any purchases of replacement capacity and energy, less the amount payable to the defaulting Party had it not defaulted. If the default continues for ninety (90) days after receipt of notice of default, the receiving Party may terminate this Agreement but is not obligated to do so. A Party shall not be considered in default of its obligation to perform a transaction hereunder if the transaction can be accomplished through the use of other interconnections between the Parties.

Section 7.02 If a Party fails to make payment under the terms of this Agreement and such default continues for ten (10) business days after receipt of written notice of the default, the supplying Party may suspend deliveries of Seasonal Diversity Power, but is not obligated to do so. When deliveries are suspended, the Seasonal Diversity Power may be utilized or sold to entities other than the defaulting Party on an interruptible basis until all amounts in default are paid together with interest at the Agreed Interest Rate.

Section 7.03 If a Party is in default for failure to make payments under the terms of this Agreement and such default continues for a period of ninety (90) days after receipt of written notice of default, the supplying Party may terminate this Agreement and/or take whatever other remedies it has at law or under this Agreement.

Section 7.04 The Parties agree to use their best efforts to mitigate any damages which they might suffer by reason of the occurrence of any default or any other event giving rise to a remedy under this Agreement.

ARTICLE 8
CONTRACT TERM

<u>Section 8.01</u> Subject to Article 6 of this Agreement, this UPA Diversity Exchange Agreement shall become effective as of February 1, 1991, and shall continue until April 30, 2015.

IN WITNESS WHEREOF, the Parties have caused this UPA Diversity Exchange Agreement to be executed by their duly authorized representatives as of the day and year first above written.

UNITED POWER ASSOCIATION:

DATE: March 5, 1991

Phillip Tideman
President

Philip O. Martin
General Manager

THE MANITOBA HYDRO-ELECTRIC BOARD:

DATE: March 5, 1991

R.B. Brennan
President and
Chief Executive Officer

R.O. Lambert
Executive Vice-President

APPENDIX A
DOLLARS PER MWH EXPENSE CALCULATION

The steam power production expenses for the three lignite plants, Coal Creek, Milton R. Young unit number 2 ("Square Butte"), and Coyote shall be those which are recorded as a production expense in accordance with the FERC or REA accounts which are numbered at the execution of this Agreement as 500 to 507 inclusive and 510 to 514 inclusive. The items covered by reference to the FERC/REA accounts fall under the general heading of Power Production Expenses - Steam Power Generation, and are composed of:

Operation Supervision and Engineering (500)
Fuel (501)
Steam Expenses (502)
Steam from Other Sources (503)
(less) Steam Transferred - Cr. (504)
Electric Expenses (505)
Maintenance Supervision and Engineering (506)
Rents (507)
Miscellaneous Steam Power Expenses (510)
Maintenance of Structures (511)
Maintenance of Boiler Plant (512)
Maintenance of Electric Plant (513)
Maintenance of Miscellaneous Steam Plant (514)

The dollars per MWh expense for a plant shall be determined by dividing these steam power production expenses for the plant by the plant's total net generation produced during the corresponding period.

For each Contract Year throughout the contract term, the total dollars per MWh expense shall be determined as indicated under (a), (b) or (c), whichever is applicable:

a) If each of the three lignite plants, Coal Creek, Square Butte, and Coyote operated at a capacity factor of sixty (60) percent or more during the twelve (12) month period preceding the Contract Year, the total dollars per MWh expense for the Contract Year shall be calculated as follows:

$$E_{T(n)} = 0.50\ E_{CC(n)} + 0.25\ E_{SB(n)} + 0.25\ E_{C(n)}$$

where:

n is the nth Contract Year of the contract term,

$E_{T(n)}$ is the total dollars per MWh expense to be calculated for the nth Contract Year,

$E_{CC(n}$ is the dollars per MWh expense for Coal Creek during the twelve (12) month period preceding the nth Contract Year,

$E_{SB(n)}$ is the dollars per MWh expense for Square Butte during the twelve (12) month period preceding the nth Contract Year, and

$E_{C(n)}$ is the dollars per MWh expense for Coyote during the twelve (12) month period preceding the nth Contract Year.

b) If only one of the three lignite plants, Coal Creek, Square Butte, and Coyote operated at a capacity factor of less than sixty (60) percent during the twelve (12) month period preceding the Contract Year, the total dollars per MWh expense for the Contract Year shall be calculated as follows:

The total dollars per MWh expense to be utilized shall be calculated as shown in the following example where it has been assumed that Coyote is the plant which operated at a capacity factor of less than sixty (60) percent;

$$E_{T(k)} = 0.50E_{CC(k)} + 0.25E_{SB(k)} + 0.25E_{C(m)} \frac{0.50E_{CC(k)} + 0.25E_{SB(k)}}{0.50E_{CC(m)} + 0.25E_{SB(m)}}$$

where:

k is the kth Contract Year during the contract term where the Coyote capacity factor during the twelve (12) month period preceding the kth Contract Year was less than sixty (60) percent,

$E_{T(k)}$ is the total dollars per MWh expense to be calculated for the kth Contract Year,

$E_{C(k)}$ is the dollars per MWh expense for Coal Creek during the twelve (12) month period preceding the kth Contract Year,

$E_{SB(k)}$ is the dollars per MWh expense for Square Butte during the twelve (12) month period preceding the kth Contract Year, m is the last month preceding the kth Contract Year and a month in the preceding Contract Year where all three plants, Coal Creek, Square Butte, and Coyote operated during the twelve (12) month period preceding the mth month at a capacity factor of sixty (60) percent or more, and

$E_{CC(m)}$, $E_{SB(m)}$, $E_{C(m)}$ are the dollars per MWh expense for the three (3) plants, Coal Creek, Square Butte, and Coyote respectively, during the twelve (12) month period preceding the mth month.

The total dollars per MWh expense for Contract Years when Coal Creek or Square Butte operated at a capacity factor of less than sixty (60) percent during the twelve (12) month period preceding the Contract Year shall be calculated in a similar manner.

(c) If more than one (1) of the plants, Coal Creek, Square Butte, and Coyote operated at a capacity factor of less than sixty (60) percent during the twelve (12) month period preceding the Contract Year, or if there does not exist a month, m, as described in (b) above in the preceding Contract Year, the total dollars per MWh expense for the Contract Year shall be calculated by multiplying the total dollars per MWh expense for the preceding Contract Year by the ratio of the United States Consumer Price Index as of May 1 of the Contract Year and the United States Consumer Price Index as of May 1 of the preceding Contract Year.

PUB/MH I-153

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 3.0 (Page 49).**

b) Please confirm that the capacity (demand) component of MH's firm export contract can equate to about a third of the total unit price per KW.h.

ANSWER:

Confirmed.

<u>PUB/MH I-154</u>

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, Chapter 4.0 (Page 55), Exhibit 4-1

a) Please provide a frequency analysis of MH's low flow years for the entire period of record and for the post-regulation period.

<u>ANSWER</u>:

Manitoba Hydro does not have a frequency analysis of low flow years. There are several factors that make it impractical to determine the frequency of low flow periods. One of the most important factors is that it is necessary to have a large sample size to undertake a meaningful statistical analysis. The history of the last 100 years indicates that there was a period of below average flows that lasted seven years ending in 1941. A second extended five-year drought period occurred between 1987 and 1992. The 100 years of recorded water flow history with two extended low flow periods is not a large sample size for statistical analysis.

A second factor that complicates the frequency analysis of low flow periods is the persistence in water flows in that low flow periods tend to occur over more than one year. Consequently, drought events are not all of equal duration or severity. This complicates the analysis because statistical techniques require distinct events.

In summary, statistical analysis of frequency of low flows would not be meaningful because of the short period of recorded flows and the tendency for low flow periods to span several years. Furthermore, it would be even less meaningful to attempt to undertake such an analysis for a shorter period such as the post-regulation period.

Please refer to the response to CAC/MSOS/MH I-62(i) for a discussion of an approximate approach for determining the probability of the two extended drought periods referenced above.

<u>PUB/MH I-154</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 4.0 (Page 55), Exhibit 4-1**

b) **Please discuss and qualify the frequency analyses in the context of what could be expected over a period of several centuries.**

<u>ANSWER</u>:

As discussed in the response to PUB/MH I-154(a) a statistical analysis of the frequency of low flow periods cannot be expected to be meaningful because of the small sample size of 100 years of recorded flows and the tendency for low flow to span several years. Because a statistical analysis of low flows in the historic period is not meaningful, it is not appropriate to draw any inferences as to the frequency of low flow events over a period of several centuries.

PUB/MH I-154

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, Chapter 4.0 (Page 55), Exhibit 4-1

c) Please discuss and qualify the capacity factors in Exhibit 4-1. Are these factors actual historical occurrences or have these been modified to remove transmission constraints or include the 1992 addition of Limestone G.S.

ANSWER:

These factors represent actual historical occurrences. For the purpose of the referenced Exhibit 4-1, the on-peak period comprised 57% of the year (16 hours, Monday through Saturday) and the off-peak period comprised 43% of the year (8 hours overnight and all day Sunday). The capacity factors were calculated as:

> Capacity Factor = average hydraulic generation during respective period [MW] ÷ peak hydraulic generation level that occurred in that year [MW]

There were no modifications to remove effects of transmission constraints or the addition of Limestone G.S.

PUB/MH I-154

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 4.0 (Page 55), Exhibit 4-1**

d) Do the capacity factors reflect available water flows or do load demands play a role as well?

ANSWER:

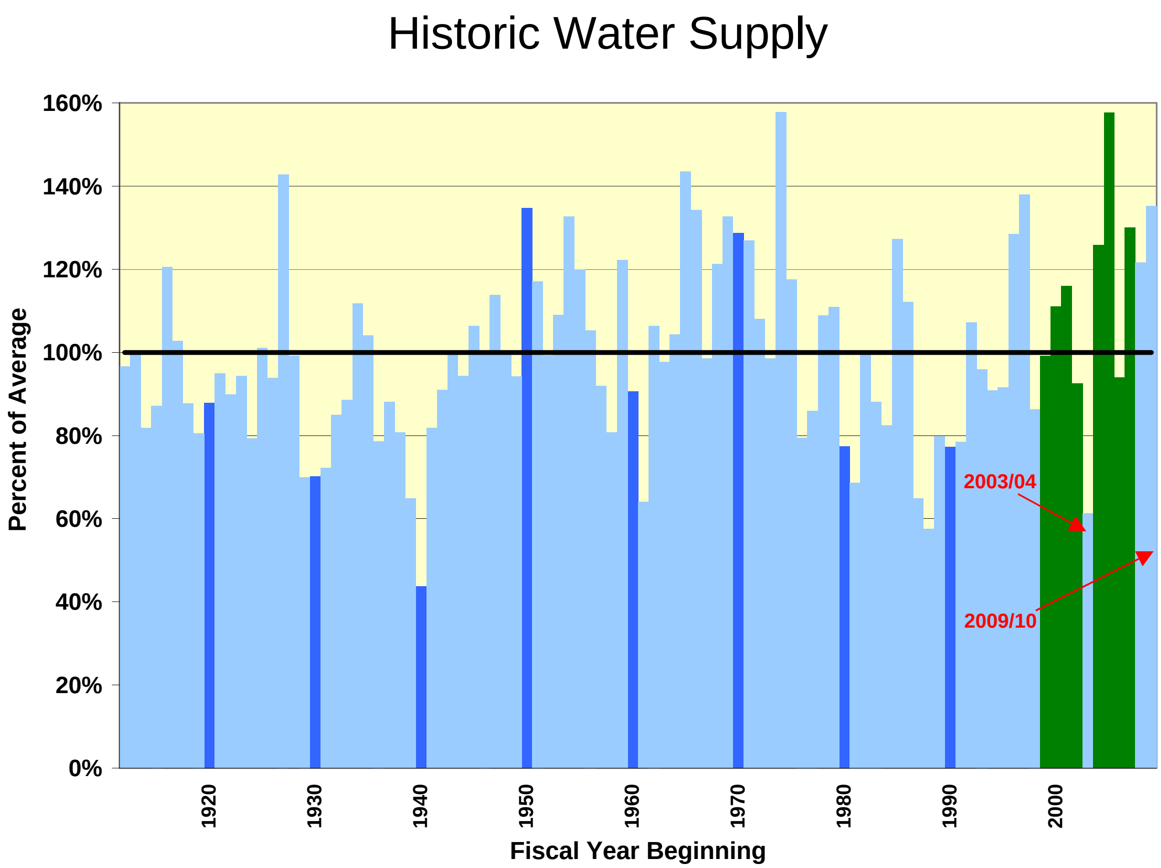
Annual capacity factors mainly reflect changing available water flows. To the extent that generation spillage is necessary as a result of insufficient demand (which may be limited by tie-line limits) the capacity factors will be reduced.

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, (Page 57), Exhibit 4-2

a) **Please confirm that the 1999-2007 period (minus 2003/04) reflects a relatively high flow period and does not represent a normal/average situation.**

ANSWER:

In five out of 8 years between the 1999/00 to 2007/08 (excluding 2003/04) Manitoba Hydro experienced above average inflow conditions. The period in question is shaded green in the figure below.



PUB/MH I-155

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, (Page 57), Exhibit 4-2**

b) Please define the Exhibit 4-2 inter-regional transfers and reconcile the energy supply/demand values with MH's Annual Report data and NEB data.

ANSWER:

The inter-regional transfers as per the ICF report in Exhibit 4-2 represents the MW.h delivered to and from other provinces on a calendar year basis.

The Operating Statistics in Manitoba Hydro's Annual Report identifies energy supply and demand values based on net metered data since 2005/06 and on a fiscal year basis.

The NEB data identifies energy scheduled for delivery to and from Canada (exports and imports) on a monthly and calendar year basis. Due to NEB reporting deadlines, Manitoba Hydro may provide preliminary values to NEB and provide updates at a later date. It is at NEB's discretion whether to use updated values or incorporate all changes in the December report. Statistics Canada also references NEB export and import data; however, it is uncertain whether they include subsequent updates from Manitoba Hydro.

PUB/MH I-156

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, Page 60

a) **Please confirm that ICF and Consensus Group forecasts of export-prices include CO_2 premiums. What price level per tonne was assumed?**

ANSWER:

It is confirmed that export prices that are forecasted by ICF and other consultants that comprise the consensus forecast include CO_2 premiums. Manitoba Hydro's electricity export price forecast is prepared using information from several external price forecast consultants who each have their own electricity price forecast models and assumptions. For 2008, information from five external price forecast consultants was used to prepare the Manitoba Hydro electricity export price forecast. Manitoba Hydro's forecast which is based on a consensus of the five consultants is referred to as the Consensus Price Forecast in the ICF Report. 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, SO_x, NO_x, and mercury and renewable portfolio standard requirements, and characteristics of the existing generation fleet. Hence, any CO_2 premium is but one of many pricing factors considered in developing the electricity export price forecast. This forecast contains an Expected forecast scenario, as well as a Low forecast scenario and a High forecast scenario.

The specific details of Manitoba Hydro's electricity export price forecast, including details on specific pricing factors such as the assumptions regarding CO_2 premiums, are commercially sensitive information, and therefore are confidential since public release could harm the Corporation in negotiation of contracts for export sales.

As a general comment, all five of the price forecast consultants forecast some level of CO_2 premiums in their forecasts. The specific level of CO_2 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.

PUB/MH I-156

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, Page 60

b) Please define the specific aspects that MH relies on in selecting IFF 09-1 export price levels well above the ICF (et.al.) forecasts.

ANSWER:

The specific details of Manitoba Hydro's electricity export price forecast contain commercially sensitive information and therefore are confidential since public release could harm the Corporation in negotiation of contracts for export sales. Please refer to the response to PUB/MH I-156(a) for a general description of the factors utilized to develop the export price forecast.

As a general comment, it is incorrect to assume that the export prices utilized in IFF09-1 are well above the consensus of ICF and other forecasters that are used to formulate Manitoba Hydro's electricity export price forecast. The export revenues in IFF09-1 were derived by utilizing the Manitoba Hydro's electricity export price forecast for export sales.

PUB/MH I-156

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Page 60**

c) Please explain the changing role of MH's exports within a renewable focused MISO market.

ANSWER:

As noted on page 60 of the ICF report, "While on the one hand Manitoba Hydro is expected to benefit from U.S. carbon regulation (through high resultant power pricing in the U.S.), on the other hand, regulations that impose significant renewable capacity expansion may negatively impact the Corporation's revenues from its net exports. Given the recent push for renewable generation, MISO, having great potential for wind generation, may witness substantial growth in wind capacity. It has greater access to wind than almost any other U.S. regional power market."

Among other risks, a purchaser considering future new supply options faces U.S. carbon regulation risk for future supply options that utilize natural gas or coal. Most renewable supply options have minimal carbon regulation risk and hence this aspect makes renewable supply options more attractive to the purchaser. Since carbon regulation will tend to increase U.S. power prices in real terms, Manitoba Hydro low carbon supply options are expected to benefit from U.S. carbon regulation. Manitoba Hydro has already seen a shift from a power market focused solely on lowest cost to one which considers the carbon footprint of the generation.

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.

PUB/MH I-157

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Page 60**

a) Please provide an analysis of MH's projected import capacity requirement for a 5-year and 7-year drought in the following periods:

i. 2012-2018.
ii. 2018-2024.
iii. 2024-2030.

ANSWER:

Part i: Drought Begins in 2011/12

With an onset of the 5-year drought beginning in fiscal year 2011/12, the impact on import purchase costs and energy follows:

	2011/12	2012/13	2013/14	2014/15	2015/16	Total
Import Energy Purchases (millions of $ Cdn)						
Average	66	67	71	76	86	367
Drought	187	234	171	189	181	961
Impact of 5-year Drought	**-120**	**-167**	**-100**	**-113**	**-94**	**-594**
Import Energy Requirements (GWh/yr)						
Average	1275	1235	1227	1267	1322	6325
Drought	3324	3763	2927	3011	2789	15813
Impact of 5-year Drought	**-2049**	**-2528**	**-1699**	**-1744**	**-1467**	**-9488**

Notes: **Average** Represents the average cost or energy over the entire historic flow range (1912/13 to 2005/06, inclusive).

Drought Represents the cost and energy data for the 5-year drought chronology (1987/88 to 1991/92, inclusive)

Impact Represents the deviation from average.

With an onset of the 7-year drought beginning in fiscal year 2011/12, the impact on import purchase costs and energy follows:

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Total
Import Energy Purchases (millions of $ Cdn)								
Average	66	67	71	76	86	95	105	567
Drought	131	105	188	214	340	240	115	1332
Impact of 7-year Drought	**-65**	**-38**	**-116**	**-138**	**-254**	**-144**	**-10**	**-764**
Import Energy Requirements (GWh/yr)								
Average	1275	1235	1227	1267	1322	1375	1453	9153
Drought	2621	2101	3112	3302	4073	3228	1843	20281
Impact of 7-year Drought	**-1346**	**-867**	**-1885**	**-2035**	**-2751**	**-1853**	**-390**	**-11127**

Notes: **Average** Represents the average cost or energy over the entire historic flow range (1912/13 to 2005/06, inclusive).

Drought Represents the cost and energy data for the 7-year drought chronology (1936/37 to 1942/43, inclusive)

Impact Represents the deviation from average.

Part ii: Drought Begins in 2017/18

With an onset of the 5-year drought beginning in fiscal year 2017/18, the impact on import purchase costs and energy follows:

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Import Energy Purchases (millions of $ Cdn)						
Average	105	175	149	149	161	739
Drought	232	550	305	399	347	1832
Impact of 5-year Drought	**-126**	**-374**	**-157**	**-250**	**-186**	**-1093**
Import Energy Requirements (GWh/yr)						
Average	1453	2448	2118	2018	2096	10131
Drought	3112	6501	4405	4905	4758	23681
Impact of 5-year Drought	**-1659**	**-4053**	**-2288**	**-2888**	**-2662**	**-13549**

With an onset of the 7-year drought beginning in fiscal year 2017/18, the impact on import purchase costs and energy follows:

	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Import Energy Purchases (millions of $ Cdn)								
Average	105	175	149	149	161	156	156	1052
Drought	197	267	327	509	720	626	191	2836
Impact of 7-year Drought	**-92**	**-91**	**-178**	**-360**	**-560**	**-469**	**-35**	**-1785**
Import Energy Requirements (GWh/yr)								
Average	1453	2448	2118	2018	2096	1892	1837	13860
Drought	2768	3950	4602	6244	7562	6394	2719	34239
Impact of 7-year Drought	**-1315**	**-1503**	**-2485**	**-4227**	**-5466**	**-4502**	**-882**	**-20379**

Part iii: Drought Begins in 2023/24

With an onset of the 5-year drought beginning in fiscal year 2023/24, the impact on import purchase costs and energy follows:

	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Import Energy Purchases (millions of $ Cdn)						
Average	156	182	142	145	154	778
Drought	632	858	403	411	374	2678
Impact of 5-year Drought	**-476**	**-676**	**-261**	**-267**	**-220**	**-1899**
Import Energy Requirements (GWh/yr)						
Average	1837	2039	1682	1684	1727	8969
Drought	6620	7880	4690	4214	4363	27767
Impact of 5-year Drought	**-4783**	**-5841**	**-3008**	**-2530**	**-2636**	**36736**

With an onset of the 7-year drought beginning in fiscal year 2023/24, the impact on import purchase costs and energy follows:

	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	Total
Import Energy Purchases (millions of $ Cdn)								
Average	156	182	142	145	154	163	174	1116
Drought	323	216	372	537	620	628	184	2879
Impact of 7-year Drought	**-166**	**-34**	**-230**	**-392**	**-466**	**-465**	**-10**	**-1763**
Import Energy Requirements (GWh/yr)								
Average	1837	2039	1682	1684	1727	1765	1819	12553
Drought	3857	2938	4248	5601	6024	5910	2370	30948
Impact of 7-year Drought	**-2020**	**-898**	**-2566**	**-3917**	**-4297**	**-4145**	**-551**	**-18395**

It is noted that all of the above information is based on assumptions that are consistent with IFF09-1.

PUB/MH I-157

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Page 60**

b) Please confirm that for an even more severe drought, MH would be able to curtail export obligations and not require greater import capability.

ANSWER:

It is confirmed that Manitoba Hydro has the right to curtail firm export obligations for the new firm sales defined by the term sheets if drought flows lower than the current lowest on record were to occur. It is also confirmed that Manitoba Hydro would not require greater import capability since it could curtail its export obligations if a more severe drought than any on record were to occur. The degree to which export obligations would be curtailed would depend on the severity of such a drought.

PUB/MH I-158

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 5.0 (Pages 68 and 69) Exhibit 5-1**

a) Please provide a comparison of MH's summer sales contract prices and the SPOT market prices on a monthly basis for the same period as Exhibit 5-1.

ANSWER:

The Spot market prices are effective as of April 2005 with the opening of the MISO market and have been provided for the June to August period to represent Summer sales contract prices.

Opportunity Bilateral combines both the Short Term Firm and Short Term Energy categories.

	Opportunity Bilateral		**MISO Spot**	
	On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
Jun-05	73.22	21.21	75.46	24.41
Jul-05	93.86	40.29	91.02	36.32
Aug-05	92.53	30.10	86.92	19.73
Jun-06	64.03	40.33	58.01	18.13
Jul-06	82.82	63.52	94.85	35.60
Aug-06	77.66	52.68	71.32	27.17
Jun-07	72.49	31.95	62.77	22.21
Jul-07	86.31	36.32	70.49	24.51
Aug-07	80.64	39.93	65.02	21.65
Jun-08	80.83	31.94	57.19	16.45
Jul-08	95.12	42.66	78.97	19.99
Aug-08	98.51	43.67	65.54	21.43
Jun-09	30.10	13.36	26.55	10.86
Jul-09	26.30	10.60	24.96	10.44
Aug-09	29.06	11.85	27.91	11.48

<u>PUB/MH I-158</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 5.0 (Pages 68 and 69) Exhibit 5-1**

b) Please provide a similar comparison of MH's winter energy purchase prices and the above summer sales contract prices on a monthly basis.

<u>ANSWER</u>:

The Spot market prices are effective as of April 2005 with the opening of the MISO market and have been provided for the June to August period to represent Summer sales contract prices and December to March to represent the Winter period. Opportunity Bilateral combines both the Short Term Firm and Short Term Energy categories.

	Summer Sales Opportunity Bilateral			Winter Energy Purchase Opportunity	
	On-Peak	**Off-Peak**		**On-Peak**	**Off-Peak**
Jun-05	73.22	21.21	**Dec-05**	123.28	58.46
Jul-05	93.86	40.29	**Jan-06**	68.03	28.42
Aug-05	92.53	30.10	**Feb-06**	61.15	29.15
Jun-06	64.03	40.33	**Mar-06**	65.78	23.28
Jul-06	82.82	63.52	**Dec-06**	102.09	40.29
Aug-06	77.66	52.68	**Jan-07**	102.41	43.77
Jun-07	72.49	31.95	**Feb-07**	100.43	51.02
Jul-07	86.31	36.32	**Mar-07**	126.58	38.98
Aug-07	80.64	39.93	**Dec-07**	58.06	29.67
Jun-08	80.83	31.94	**Jan-08**	55.67	36.57
Jul-08	95.12	42.66	**Feb-08**	65.26	38.89
Aug-08	98.51	43.67	**Mar-08**	67.64	37.49
Jun-09	30.10	13.36	**Dec-08**	61.25	33.21
Jul-09	26.30	10.60	**Jan-09**	56.07	33.83
Aug-09	29.06	11.85	**Feb-09**	48.95	31.23
			Mar-09	46.99	16.93

PUB/MH I-159

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 5.0 (Page 70 and 71)**

a) **Please provide an analysis of MH's proposed 2024 contract commitments (with new G&T in place) and define potential import requirements for the 1977 to 2009 post-regulation flow scenarios.**

ANSWER:

The analysis of potential export contracts is not being provided because it is confidential information that could harm Manitoba Hydro since counterparties to the contracts could use this information to their advantage while terms and conditions are being negotiated. The analysis of export contracts will be subject to a full examination when the "needs for and alternatives to" process is initiated.

The specific import requirement for each of the requested flow years is also commercially sensitive information which, if made publicly available, could harm the Corporation in its participation in the competitive electricity market.

PUB/MH I-159

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 5.0 (Page 70 and 71)**

b) Please quantify the net export revenues that would accrue to MH in the above scenario assuming that all non-scheduled imports would command peak (5x16) prices.

ANSWER:

Please see Manitoba Hydro’s response to PUB/MH I-159(a) which states that Manitoba Hydro considers its analysis of potential export contracts to be commercially sensitive information and is therefore confidential. The net export revenues being requested for the specific scenario outlined above is considered to be confidential information that Manitoba Hydro is not prepared to make available publicly.

PUB/MH I-160

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 6.0 (Page 77)**

a) Please file MH's term sheets with Wisconsin Public Service, Minnesota Power and Xcel Energy [in confidence with the Board]

ANSWER:

Manitoba Hydro respectfully declines to file the requested term sheets. It should be recognized that the term sheets form the basis for further negotiations which are currently underway.

PUB/MH I-160

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 6.0 (Page 77)**

b) **Please confirm that MH's current and pending export costs include a capacity (demand) charge.**

ANSWER:

As indicated in the ICF report, when capacity is included in an agreement, a fixed capacity (demand) charge is applied unless the agreement is a seasonal diversity exchange where the parties swap capacity at no cost. A small number of agreements are for energy only in which case, there is no obligation to make capacity available and in those instances, a capacity (demand) charge would not apply.

PUB/MH I-160

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 6.0 (Page 77)**

c) What percentage of the average contract revenue is derived from this demand charge?

ANSWER:

The demand charge provides approximately one third of the average contract revenue for existing export agreements that include a demand charge.

PUB/MH I-161

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 6.0 (Pages 85 to 88) IFF 09-1**

a) Please provide (in confidence if necessary), an annual breakdown of MH's IFF 09-1 export revenue (volumes and prices) into:

i. 5x16 firm contract peak
ii. 5x16 opportunity peak.
iii. 2x16 weekend off-peak.
iv. 7x8 overnight off-peak.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-209 for a summary of the annual volumes and prices for the total of all export sales to the year 2029/30. The breakdown of export sales that is requested is commercially sensitive information that could harm the Corporation in its participation in the competitive electricity export market.

PUB/MH I-161

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 6.0 (Pages 85 to 88) IFF 09-1**

b) Please provide similar data breakdowns for the 2019/20 to 2028/29 period.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-161(a).

PUB/MH I-162

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, Chapter 9.0 (Page 113)

a) Please provide a comparative tabulation of SEP peak/shoulder/off-peak prices and MH’s import prices for the following three years:

i. 2002/03.
ii. 2003/04.
iii. 2006/07.

ANSWER:

The table below compares the average annual SEP Peak, Shoulder and Off-Peak prices to Manitoba Hydro’s import prices for the three fiscal years.

Fiscal Year	SEP General Service Large > 100 kV (¢/kW.h)			Manitoba Hydro’s Import Price (¢/kW.h)
	Peak	Shoulder	Off Peak	
2002/03	5.643	4.069	3.045	3.910
2003/04	8.544	6.789	6.731	5.259
2006/07	7.565	5.154	3.616	5.119

PUB/MH I-162

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, Chapter 9.0 (Page 113)

b) Please indicate the months that the three period prices were nearly the same in these three years.

ANSWER:

In responding to this question Manitoba Hydro assumed a differential of $0.002 as a basis for determining if the three period prices were "nearly the same". For example, the following week would have been included:

	Peak	Shoulder	Off Peak
August 18 - 24, 2003:	$0.10299	$0.10145	$0.10200

	# of Weeks		
	2002/03	**2003/04**	**2006/07**
April	0	0	1
May	0	0	0
June	0	0	0
July	0	0	0
August	0	1	0
September	0	1	0
October	0	1	0
November	0	4	0
December	0	5	0
January	0	4	0
February	0	1	0
March	3	0	0
Total	3	17	1

Note: Number of weeks based on a SEP week which are Monday to Sunday.

<u>PUB/MH I-162</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 9.0 (Page 113)**

c) Please confirm that in the other 7 of 10 years that off-peak prices remained significantly below peak and shoulder prices.

<u>ANSWER</u>:

Confirmed. The average annual SEP Off-Peak prices (based on fiscal year) remained below SEP peak and shoulder prices.

PUB/MH I-163

Subject: Tab 12: Corporate Risk Management
Reference: ICF Report, Chapter 9.0 (Pages 118 to 120)

a) Please provide an overview of MH's planning approach to defining system constraints in drought years, average years, and high flow years.

ANSWER:

Manitoba Hydro's planning approach is to ensure that there is sufficient energy and capacity supplies available at all times to meet its firm load and reserve obligations. To the extent that Manitoba Hydro has surplus supplies available, these surpluses are scheduled for sale to the various external markets in a manner such that Manitoba Hydro's net revenues are maximized. In scheduling the production of electricity, Manitoba Hydro recognizes all the constraints of its generating, transmission and export systems including; safety, reliability, legal and licenses as well as the physical characteristics of the reservoirs, rivers and water control structures.

In drought years, Manitoba Hydro is faced with the uncertainty of the magnitude and duration of the drought as there is no guarantee that the historic flow record includes the worst drought possible. To maintain the highest level of supply security, Manitoba Hydro adopts a conservation strategy which preserves reservoir storages to the extent possible given the availability of alternate supplies. Specifically, reservoir releases are managed on the assumption that forecast inflows will be at the lower 90% confidence level in the current year, that 1940/41 inflows will occur in the second year, that winter weather and electricity demand will be at the upper 90% confidence level and that imports will be relied on only to the extent there is firm transmission available.

In non drought years, energy security is not an issue as Manitoba Hydro is not in an energy short situation and the power system can be operated normally.

<u>PUB/MH I-163</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 9.0 (Pages 118 to 120)**

b) **Please provide a detailed process outline of MH operational modelling to define surplus energy at various times of the years, e.g.:**

i. **February (precipitation/energy in storage).**
ii. **April (precipitation/energy in storage).**
iii. **July (runoff/energy in storage).**
iv. **October (runoff/energy in storage).**

<u>ANSWER</u>:

On a weekly basis, Manitoba Hydro prepares a production forecast for the generating system for a period as long as 16 months into the future. This forecast indicates the generation plans for each of Manitoba Hydro’s facilities and any import and export transactions necessary to serve Manitoba Hydro’s load obligations. Inputs into this forecast are Manitoba Hydro’s reservoir storages plus its current water supply forecast for the planning period. Should Manitoba Hydro have surplus energy supplies available, these are scheduled for sale into the external markets in a manner that maximizes Manitoba Hydro’s net export revenue. This process is updated weekly, adjusting on a continuous basis for current water, market and other conditions. The production plan also consists of a set of reservoir releases that reflect those necessary to accommodate Manitoba Hydro’s various stakeholders, anticipated releases from upstream reservoir operators, and license requirements as well as those needed for economic power system operation.

PUB/MH I-164

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 10.0 (Page 122) 2008/09 Power Resource Plan.**

a) Please define on a comparative basis the level of obligation (GWh) that MH would have to purchase and/or thermally generate energy in the first year of a drought for hydraulic generation levels of:

i. 2014/15 22,000 GWh/15,000 GWh.
ii. 2019/20 25,000 GWh/18,000 GWh.
iii. 2024/25 30,000 GWh/23,000 GWh.

ANSWER:

Manitoba Hydro is unable to respond to this request because of difficulty in understanding the intent of the request. As discussed in the response to PUB/MH I-85(d) the first year of a drought is difficult to identify since drought consists of several years of low flows and the severity and duration are known only after a recovery in water flows has occurred. Manitoba Hydro is not able to understand the meaning of "in the first year of a drought". Furthermore, it is not known what the intent was in providing the pairs of different hydraulic generation levels.

<u>PUB/MH I-164</u>

Subject: **Tab 12: Corporate Risk Management**
Reference: **ICF Report, Chapter 10.0 (Page 122) 2008/09 Power Resource Plan.**

b) Please identify the nature of the export load reduction in each of the above cases.

<u>ANSWER</u>:

As discussed in the response to PUB/MH I-164(a), Manitoba Hydro is unable to respond because of difficulty in understanding the intent of the request.

PUB/MH I-165

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.1 (2) Demand Billing Concessions**

a) **Provide an update to the tables provided under PUB/MH 1XP-6 monthly energy consumption and average cost information.**

ANSWER:

Updated tables attached for information as requested.

Monthly Energy Consumption and Average Cost Information

Chemical Sector - Demand Deferral

Serv Month	Bill Days	Energy kW.h	Rec Dmd (kVA)	Bill Dmd (kVA)	Curr Rate Bill Dem	Bill LF (%)	Curr Rate Revenue	Curr Rate Unit Cost	Concession Threshold	Calc Billing Concession	Demand Concession
					Rate Class:		GSL - >100 kV		+ 10%	Rev Check	0.0%
2009 NOV	**30**	**49,716,080**	**78,888**	**78,888**	**78,888**	**0.000**	**$ 1,678,840.40**	**$ 0.03377**	**$ 0.03637**	**$ -**	**-**
2009 OCT	**31**	**53,594,711**	**76,551**	**76,551**	**76,551**	**0.000**	**$ 1,763,962.10**	**$ 0.03291**	**$ 0.03637**	**$ -**	**-**
2009 SEP	**30**	**51,905,430**	**76,484**	**76,484**	**76,484**	**0.000**	**$ 1,721,030.40**	**$ 0.03316**	**$ 0.03637**	**$ -**	**-**
2009 AUG	**31**	**53,435,671**	**76,819**	**76,819**	**76,819**	**0.000**	**$ 1,761,401.50**	**$ 0.03296**	**$ 0.03637**	**$ -**	**-**
2009 JUL	**31**	**52,064,232**	**76,487**	**76,487**	**76,487**	**0.915**	**$ 1,725,048.40**	**$ 0.03313**	**$ 0.03637**	**$ -**	**-**
2009, JUN	**30**	**49,682,418**	**69,652**	**69,652**	**69,652**	**0.991**	**$ 1,628,117.70**	**$ 0.03277**	**$ 0.03637**	**$ -**	**-**
2009, MAY	31	37,816,177	64,055	64,055	64,055	0.794	$ 1,298,864.70	$ 0.03435	$ 0.03637	$ -	-
2009, APR	30	42,879,242	64,368	64,368	64,368	0.925	$ 1,428,144.10	$ 0.03331	$ 0.03637	$ -	-
2009, MAR	31	53,768,110	78,862	78,862	78,862	0.916	$ 1,780,811.20	$ 0.03312	$ 0.03637	$ -	-
2009, FEB	28	46,854,826	79,260	79,260	79,260	0.880	$ 1,608,745.60	$ 0.03433	$ 0.03637	$ -	-
2009, JAN	31	55,616,754	78,842	78,842	78,842	0.948	$ 1,827,289.00	$ 0.03286	$ 0.03637	$ -	-
24 Mth Analysis	**Bill Days**	**Energy kW.h**	**Rec Dmd (kVA)**	**Bill Dmd (kVA)**	**Curr Rate Bill Dem**	**Bill LF (%)**	**Curr Rate Revenue**	**Curr Rate Unit Cost**	**Concession Threshold**	**Calc Billing Concession**	**Demand Concession**
24 Mth Tot	731.0	1,179,713,232	1,718,214	1,718,214	1,718,214		$ 39,007,126.88				
24 Mth Avg	30.5	49,154,718	71,592	71,592	71,592	0.939	$ 1,625,296.95	**$ 0.03306**			

Deferral Summary	**Unit Cost Concession Threshold**	**$ 0.03637**	**Jun 09 - Nov 09**	
	Average Monthly Deferral		**$ -**	**-**
	Six Month Deferral		**$ -**	**-**

Monthly Energy Consumption and Average Cost Information

Petroleum Transportation Sector - Demand Deferral

Serv Month	Bill Days	Energy kW.h	Rec Dmd (kVA)	Bill Dmd (kVA)	Curr Rate Bill Dem	Bill LF (%)	Curr Rate Revenue	Curr Rate Unit Cost	Concession Threshold	Calc Billing Concession	Demand Concession
					Rate Class:		GSL - >100 kV		+ 10%	Rev Check	0.0%
2009 NOV	**30**	**10,138,840**	**24,554**	**24,554**	**24,554**	**0.000**	**$ 388,090.40**	**$ 0.03828**	**$ 0.03854**	**$ -**	**-**
2009 OCT	**31**	**10,725,070**	**24,207**	**24,207**	**24,207**	**0.000**	**$ 400,989.60**	**$ 0.03739**	**$ 0.03854**	**$ -**	**-**
2009 SEP	**30**	**10,391,771**	**23,839**	**23,839**	**23,839**	**0.000**	**$ 390,603.20**	**$ 0.03759**	**$ 0.03854**	**$ -**	**-**
2009 AUG	**31**	**10,270,544**	**24,087**	**24,087**	**24,087**	**0.000**	**$ 388,887.50**	**$ 0.03786**	**$ 0.03854**	**$ -**	**-**
2009 JUL	**31**	**14,222,786**	**24,934**	**24,934**	**24,934**	**0.767**	**$ 493,057.80**	**$ 0.03467**	**$ 0.03854**	**$ -**	**-**
2009, JUN	**30**	**14,708,006**	**24,747**	**24,747**	**24,747**	**0.825**	**$ 504,275.50**	**$ 0.03429**	**$ 0.03854**	**$ -**	**-**
2009, MAY	31	10,821,304	24,341	24,341	24,341	0.598	$ 404,138.30	$ 0.03735	$ 0.03854	$ -	-
2009, APR	30	13,739,783	25,019	25,019	25,019	0.763	$ 481,345.10	$ 0.03503	$ 0.03854	$ -	-
2009, MAR	31	15,907,264	25,039	25,039	25,039	0.854	$ 536,073.70	$ 0.03370	$ 0.03854	$ -	-
2009, FEB	28	13,246,848	24,677	24,677	24,677	0.799	$ 467,076.40	$ 0.03526	$ 0.03854	$ -	-
2009, JAN	31	14,800,053	24,721	24,721	24,721	0.805	$ 506,454.70	$ 0.03422	$ 0.03854	$ -	-
24 Mth Analysis	**Bill Days**	**Energy kW.h**	**Rec Dmd (kVA)**	**Bill Dmd (kVA)**	**Curr Rate Bill Dem**	**Bill LF (%)**	**Curr Rate Revenue**	**Curr Rate Unit Cost**	**Concession Threshold**	**Calc Billing Concession**	**Demand Concession**
24 Mth Tot	731.0	317,699,580	578,799	578,799	578,799		$ 11,131,545.10				
24 Mth Avg	30.5	13,237,483	24,117	24,117	24,117	0.751	$ 463,814.38	**$ 0.03504**			

Deferral Summary	**Unit Cost Concession Threshold**	**$ 0.03854**	**Jun 09 - Nov 09**
	Average Monthly Deferral		**$ - -**
	Six Month Deferral		**$ - -**

Monthly Energy Consumption and Average Cost Information

Primary Metals Sector - Demand Deferral

Serv Month	Bill Days	Energy kW.h	Rec Dmd (kVA)	Bill Dmd (kVA)	Curr Rate Bill Dem	Bill LF (%)	Curr Rate Revenue	Curr Rate Unit Cost	Concession Threshold	Calc Billing Concession	Demand Concession
					Rate Class:		GSL - >100 kV		+ 10%	Rev Check	0.0%
2009 NOV	**30**	**508,332**	**930**	**15,100**	**15,100**	**0.000**	**$ 94,350.00**	**$ 0.18561**	**$ 0.04813**	**$ 69,885.48**	**12,942**
2009 OCT	**31**	**660,059**	**2,329**	**15,100**	**15,100**	**0.000**	**$ 98,173.50**	**$ 0.14873**	**$ 0.04813**	**$ 66,401.94**	**12,297**
2009 SEP	**30**	**5,814,001**	**21,594**	**21,594**	**21,594**	**0.000**	**$ 263,120.40**	**$ 0.04526**	**$ 0.04813**	**$ -**	**-**
2009 AUG	**31**	**4,285,324**	**21,510**	**21,510**	**21,510**	**0.000**	**$ 224,144.20**	**$ 0.05231**	**$ 0.04813**	**$ 17,912.65**	**3,317**
2009 JUL	**31**	**744,594**	**9,976**	**15,100**	**15,100**	**0.066**	**$ 100,303.80**	**$ 0.13471**	**$ 0.04813**	**$ 64,466.95**	**11,938**
2009, JUN	**30**	**4,521,439**	**21,543**	**21,543**	**21,543**	**0.291**	**$ 230,272.50**	**$ 0.05093**	**$ 0.04813**	**$ 12,660.03**	**2,344**
2009, MAY	31	5,207,395	23,813	23,813	23,813	0.294	$ 259,816.60	$ 0.04989	$ 0.04813	$ 9,165.02	1,697
2009, APR	30	5,224,351	21,890	21,890	21,890	0.331	$ 249,859.60	$ 0.04783	$ 0.04813	$ -	-
2009, MAR	31	6,372,353	21,562	21,562	21,562	0.397	$ 277,018.10	$ 0.04347	$ 0.04813	$ -	-
2009, FEB	28	3,240,119	21,335	21,335	21,335	0.226	$ 196,860.00	$ 0.06076	$ 0.04813	$ 40,922.70	7,578
2009, JAN	31	4,084,347	21,558	21,558	21,558	0.255	$ 219,338.70	$ 0.05370	$ 0.04813	$ 22,749.81	4,213
24 Mth Analysis	**Bill Days**	**Energy kW.h**	**Rec Dmd (kVA)**	**Bill Dmd (kVA)**	**Curr Rate Bill Dem**	**Bill LF (%)**	**Curr Rate Revenue**	**Curr Rate Unit Cost**	**Concession Threshold**	**Calc Billing Concession**	**Demand Concession**
24 Mth Tot	731.0	159,209,154	546,836	546,836	546,836		$ 6,964,985.08				
24 Mth Avg	30.5	6,633,715	22,785	22,785	22,785	0.398	$ 290,207.71	**$ 0.04375**			
Deferral Summary								**Unit Cost Concession Threshold**	**$ 0.04813**	**Jun 09 - Nov 09**	
								Average Monthly Deferral		**$ 38,554.51**	**7,140**
								Six Month Deferral		**$ 231,327.05**	**42,838**

Monthly Energy Consumption and Average Cost Information

Pulp & Paper Sector - Demand Deferral

Serv Month	Bill Days	Energy kW.h	Rec Dmd (kVA)	Bill Dmd (kVA)	Curr Rate Bill Dem	Bill LF (%)	Curr Rate Revenue	Curr Rate Unit Cost	Concession Threshold	Calc Billing Concession	Demand Concession
					Rate Class:		GSL - >100 kV		+ 10%	Rev Check	0.0%
2009 NOV	**30**	**1,517,620**	**3,522**	**37,515**	**37,515**	**0.000**	**$ 240,825.00**	**$ 0.15869**	**$ 0.03716**	**$ 184,436.40**	**34,155**
2009 OCT	**31**	**1,607,643**	**3,550**	**37,515**	**37,515**	**0.000**	**$ 243,093.60**	**$ 0.15121**	**$ 0.03716**	**$ 183,351.64**	**33,954**
2009 SEP	**30**	**1,587,911**	**3,589**	**37,515**	**37,515**	**0.000**	**$ 242,596.40**	**$ 0.15278**	**$ 0.03716**	**$ 183,594.27**	**33,999**
2009 AUG	**31**	**19,034,826**	**52,871**	**52,871**	**52,871**	**0.000**	**$ 765,181.00**	**$ 0.04020**	**$ 0.03716**	**$ 57,865.87**	**10,716**
2009 JUL	**31**	**4,660,170**	**50,877**	**50,877**	**50,877**	**0.123**	**$ 392,172.10**	**$ 0.08415**	**$ 0.03716**	**$ 218,981.38**	**40,552**
2009, JUN	**30**	**19,065,480**	**53,508**	**53,508**	**53,508**	**0.495**	**$ 769,393.30**	**$ 0.04036**	**$ 0.03716**	**$ 61,009.54**	**11,298**
2009, MAY	31	35,508,671	53,019	53,019	53,019	0.900	$ 1,181,121.10	$ 0.03326	$ 0.03716	$ -	-
2009, APR	30	32,901,638	52,430	52,430	52,430	0.872	$ 1,112,243.30	$ 0.03381	$ 0.03716	$ -	-
2009, MAR	31	35,559,251	53,639	53,639	53,639	0.891	$ 1,185,743.70	$ 0.03335	$ 0.03716	$ -	-
2009, FEB	28	16,558,017	53,593	53,593	53,593	0.460	$ 706,664.20	$ 0.04268	$ 0.03716	$ 91,400.25	16,926
2009, JAN	31	31,324,104	53,575	53,575	53,575	0.786	$ 1,078,672.40	$ 0.03444	$ 0.03716	$ -	-

24 Mth Analysis	Bill Days	Energy kW.h	Rec Dmd (kVA)	Bill Dmd (kVA)	Curr Rate Bill Dem	Bill LF (%)	Curr Rate Revenue	Curr Rate Unit Cost	Concession Threshold	Calc Billing Concession	Demand Concession
24 Mth Tot	731.0	801,633,237	1,274,650	1,273,322	1,273,322		$ 27,077,097.24				
24 Mth Avg	30.5	33,401,385	53,110	53,055	53,055	0.861	$ 1,128,212.38	**$ 0.03378**			

Deferral Summary			
Unit Cost Concession Threshold	**$ 0.03716**	**Jun 09 - Nov 09**	
Average Monthly Deferral		**$ 148,206.52**	**27,446**
Six Month Deferral		**$ 889,239.10**	**164,674**

Monthly Energy Consumption and Average Cost Information

Institutional Sector - Demand Deferral

Serv Month	Bill Days	Energy kW.h	Rec Dmd (kVA)	Bill Dmd (kVA)	Curr Rate Bill Dem	Bill LF (%)	Curr Rate Revenue	Curr Rate Unit Cost	Concession Threshold	Calc Billing Concession	Demand Concession
					Rate Class:		GSL - 750 to 30 kV		+ 10%	Rev Check	0.0%
2009 NOV	**30**	**2,600,362**	**5,071**	**4,474**	**4,474**	**0.000**	**$ 102,665.80**	**$ 0.03948**	**$ 0.04468**	**$ -**	**-**
2009 OCT	**31**	**2,673,481**	**4,957**	**4,447**	**4,447**	**0.000**	**$ 104,470.80**	**$ 0.03908**	**$ 0.04468**	**$ -**	**-**
2009 SEP	**30**	**3,532,982**	**6,787**	**6,787**	**6,787**	**0.000**	**$ 144,502.40**	**$ 0.04090**	**$ 0.04468**	**$ -**	**-**
2009 AUG	**31**	**3,612,854**	**6,696**	**6,696**	**6,696**	**0.000**	**$ 146,038.60**	**$ 0.04042**	**$ 0.04468**	**$ -**	**-**
2009 JUL	**31**	**3,572,110**	**6,526**	**6,526**	**6,526**	**0.736**	**$ 143,722.70**	**$ 0.04023**	**$ 0.04468**	**$ -**	**-**
2009, JUN	**30**	**3,308,716**	**6,749**	**6,749**	**6,749**	**0.681**	**$ 138,110.90**	**$ 0.04174**	**$ 0.04468**	**$ -**	**-**
2009, MAY	31	2,804,040	5,509	5,509	5,509	0.684	$ 115,554.00	$ 0.04121	$ 0.04468	$ -	-
2009, APR	30	2,582,614	4,864	4,864	4,864	0.737	$ 104,942.50	$ 0.04063	$ 0.04468	$ -	-
2009, MAR	31	2,741,020	4,721	4,721	4,721	0.780	$ 108,254.50	$ 0.03949	$ 0.04468	$ -	-
2009, FEB	28	2,521,473	4,687	4,687	4,687	0.801	$ 102,020.20	$ 0.04046	$ 0.04468	$ -	-
2009, JAN	31	2,809,120	4,713	4,713	4,713	0.801	$ 110,057.00	$ 0.03918	$ 0.04468	$ -	-
24 Mth Analysis	**Bill Days**	**Energy kW.h**	**Rec Dmd (kVA)**	**Bill Dmd (kVA)**	**Curr Rate Bill Dem**	**Bill LF (%)**	**Curr Rate Revenue**	**Curr Rate Unit Cost**	**Concession Threshold**	**Calc Billing Concession**	**Demand Concession**
24 Mth Tot	731.0	68,659,296	129,189	129,189	129,189		$ 2,789,056.90				
24 Mth Avg	30.5	2,860,804	5,383	5,383	5,383	0.727	$ 116,210.70	**$ 0.04062**			
Deferral Summary								**Unit Cost Concession Threshold**	**$ 0.04468**	**Jun 09 - Nov 09**	
								Average Monthly Deferral		**$ -**	**-**
								Six Month Deferral		**$ -**	**-**

Monthly Energy Consumption and Average Cost Information

Commercial Sector - Demand Deferral

Serv Month	Bill Days	Energy kW.h	Rec Dmd (kVA)	Bill Dmd (kVA)	Curr Rate Bill Dem	Bill LF (%)	Curr Rate Revenue	Curr Rate Unit Cost	Concession Threshold	Calc Billing Concession	Demand Concession
					Rate Class:		GSL - 750 to 30 kV		+ 10%	Rev Check	0.0%
2009 NOV	**32**	**2,385,362**	**4,785**	**4,785**	**4,785**	**0.000**	**$ 98,998.20**	**$ 0.04150**	**$ 0.04753**	**$ -**	**-**
2009 OCT	**28**	**2,061,998**	**4,592**	**4,592**	**4,592**	**0.000**	**$ 88,803.90**	**$ 0.04307**	**$ 0.04753**	**$ -**	**-**
2009 SEP	**30**	**2,367,308**	**5,168**	**5,168**	**5,168**	**0.000**	**$ 101,216.90**	**$ 0.04276**	**$ 0.04753**	**$ -**	**-**
2009 AUG	**33**	**2,623,625**	**5,411**	**5,411**	**5,411**	**0.000**	**$ 109,934.80**	**$ 0.04190**	**$ 0.04753**	**$ -**	**-**
2009 JUL	**29**	**2,274,263**	**5,181**	**5,181**	**5,181**	**0.631**	**$ 98,768.90**	**$ 0.04343**	**$ 0.04753**	**$ -**	**-**
2009, JUN	**33**	**2,569,161**	**5,392**	**5,392**	**5,392**	**0.602**	**$ 108,313.50**	**$ 0.04216**	**$ 0.04753**	**$ -**	**-**
2009, MAY	28	2,082,113	4,906	4,906	4,906	0.632	$ 91,576.20	$ 0.04398	$ 0.04753	$ -	-
2009, APR	31	2,271,448	5,123	5,123	5,123	0.596	$ 98,281.40	$ 0.04327	$ 0.04753	$ -	-
2009, MAR	32	2,380,551	4,967	4,967	4,967	0.624	$ 100,155.40	$ 0.04207	$ 0.04753	$ -	-
2009, FEB	30	2,212,769	4,900	4,900	4,900	0.627	$ 95,100.60	$ 0.04298	$ 0.04753	$ -	-
2009, JAN	28	2,068,617	4,827	4,827	4,827	0.638	$ 90,648.40	$ 0.04382	$ 0.04753	$ -	-

24 Mth Analysis	Bill Days	Energy kW.h	Rec Dmd (kVA)	Bill Dmd (kVA)	Curr Rate Bill Dem	Bill LF (%)	Curr Rate Revenue	Curr Rate Unit Cost	Concession Threshold	Calc Billing Concession	Demand Concession
24 Mth Tot	729.0	55,922,791	125,705	125,705	125,705		$ 2,416,683.59				
24 Mth Avg	30.4	2,330,116	5,238	5,238	5,238	0.610	$ 100,695.15	**$ 0.04321**			

Deferral Summary				
	Unit Cost Concession Threshold	**$ 0.04753**	**Jun 09 - Nov 09**	
	Average Monthly Deferral		**$ -**	**-**
	Six Month Deferral		**$ -**	**-**

<u>PUB/MH I-165</u>

Subject: Tab 13: PUB Directives
Reference: Tab 13.1 (2) Demand Billing Concessions

b) Provide an update to PUB/MH 1XP-2 and PUB/MH 1XP-3.

<u>ANSWER</u>:

Update to PUB/MH IXP-2 and PUB/MH IXP-3

Per Manitoba Hydro's response to Questions (d,e) in the PUB's letter of Nov 26, 2009

The 131 customers referenced in Manitoba Hydro's revised response to PUB/MH IXP-3 were identified based on a preliminary analysis of customer consumption during the Jan - Jun 2009 billing period, relative to the historic period of Sep 2006 - Aug 2008. Customers were identified based on application of the concession formula alone, with minimal consideration given to other factors such as rate class changes, seasonal behavior, plant closures, production/process changes, etc. This initial assessment was intended to be a conservative evaluation based on unit energy costs, which did not pre-judge customer eligibility for other less discrete factors.

A more detailed analysis of the 131 customers selected through this process was undertaken to identify those customers experiencing rate changes, seasonal operations consistent with past behavior, plant closures, process changes, etc. This examination reduced the number of customer that subsequently received letters informing them of eligibility for the concession deferral to 76. The lower number reflects customers moving from a GSM/GSL rate class to GSM/GSL Limited Use, or GSS rate class, customers experiencing consistent seasonal behavior, including those customer historically impacted by the 70 percent winter ratchet, and customers experiencing abnormal consumption patterns due to facility improvements, renovations, relocations, process changes, etc.

An examination of energy consumption during the Jun - Nov 09 period for the 76 customer issued letters identified 13 customers that were no longer eligible for demand concessions due to reductions in unit energy costs resulting from an increase in energy consumption (kWh) or an improved ability to curtail, or reduce, demand recorded (kVA) during these billing periods. As a result, these customers were no longer eligible for demand concessions, reducing the total of eligible customers to 63. This reduction was offset by identification of additional customers that were not determined to be eligible based on behavior during the Jan - Jun 09 period, but became eligible based on consumption behavior during the Jun 09 - Nov 09 period. The addition of these customers increased the pool of eligible customers to 81 accounts.

The results reported in the table below are based on an analysis of consumption and demand experienced by this pool of 81 customers during the Jun - Nov 2009 billing periods.

Rate Class (Subclass)	**Qty**	**Historic GWh/Mth Usage (Jun - Nov)**	**Actual GWh/Mth Usage (Jun - Nov**	**Percentage Reduction**
GS Large >100 KV	6	82.7	35.6	57.0%
GS Large 30-100 KV	2	6.9	3.4	50.7%
GS Large 750 V-30 KV	13	10.6	6.3	40.6%
GS Medium	60	6.9	5.2	24.6%
Totals	**81**	**107.1**	**50.5**	**52.8%**
Rate Class (Subclass)	**Qty**	**Historic MW/Mth Billed (Jun – Nov)**	**Actual MW/Mth Billed (Jun – Nov**	**Percentage Reduction**
GS Large >100 kV	6	162.3	148.7	8.4%
GS Large 30-100 kV	2	11.9	10.2	14.3%
GS Large 750 V-30 kV	13	32.1	28.8	10.3%
GS Medium	60	23.9	23.1	3.3%
Totals	**81**	**230.2**	**210.8**	**8.4%**
Rate Class (Subclass)	**Qty**	**Historic MW/Mth Record (Jun – Nov)**	**Actual MW/Mth Record (Jun – Nov**	**Percentage Reduction**
GS Large >100 kV	6	162.4	116.2	28.4%
GS Large 30-100 kV	2	12.0	9.1	24.2%
GS Large 750 V-30 kV	13	31.6	28.6	9.4%
GS Medium	60	24.0	22.1	7.9%
Totals	**81**	**230.0**	**176.0**	**23.5%**

Rate Class (Subclass)	Qty	Concessions Available ($)	Concession Applications ($)	Percentage Applied
GS Large >100 kV	6	$ 1,047,197	$ 982,014	93.8%
GS Large 30-100 kV	2	$ 96,794	$ 96,794	100.0%
GS Large 750 V-30 kV	13	$ 255,750	$ 171,316	70.0%
GS Medium	60	$ 155,540	$ 41,065	26.4%
Totals	**81**	**$ 1,555,281**	**$ 1,291,189**	**83.0%**

Note: The table above has been updated to reflect the final results of the Distress Industry Billing Demand Deferral Program

"Concessions Available" amounts shown in the table above do not include corrections for maintenance shutdowns, and other similar non-economic events. The indicated "Concession Application" amounts include corrections for such non-economic events and are based on amounts confirmed by Manitoba Hydro as being deferred to the conclusion of the application period, which ended January 15th, 2010.

The 151 customers flagged by Manitoba Hydro as having "apparent" eligibility in one month of the Jan - Jun 2009 analysis period were further evaluated to determine continued eligibility during the Jun - Nov 2009 eligibility period. Such analysis revealed that instances of customers demonstrating continuing eligibility during the concession period were minimal. There was very poor correlation between those customers that were identified as showing "apparent" eligibility in the analysis period with those customers that demonstrated similar "apparent" eligibility during the concession period.

Instances where "apparent" eligibility transitioned into "demonstrated" eligibility were included in the table above.

Instances of customers demonstrating "apparent" eligibility during one month of the concession period has been determined to be generally related to events such as maintenance shutdowns, facility improvements, renovations, process changes, or other normal interruptions to regular business operations, rather than for reasons of the global economic downturn.

Additional to Manitoba Hydro's earlier response:

An analysis of behavior during the six month period ending in the November 2009 billing period shows energy consumption in the pool of 81 eligible customers to be down by 52.8 percent over historic levels, with billable demand and recordable demand down by 8.4 percent and 23.5 percent over historic levels during the same period. Total revenues provided by the 81 eligible customers have declined by approximately 38 percent over historic levels.

PUB/MH I-166

Subject: **Tab 13: PUB Directives**
Reference: **Order 126/09 Demand Billing Concessions**

Please explain the factors being reviewed by MH to determine whether the deferral for one GSL> 100kV. customer complies with… "the spirit and intent of the deferral approved by the PUB in its Order 126/09".

ANSWER:

The primary factors reviewed by Manitoba Hydro in determining whether customers comply with… "the spirit and intent of the deferral approved by the PUB in its Order 126/09...." are outlined in Manitoba Hydro's Application for Interim Ex Parte Approval of the Implementation of Temporary Billing Demand Concessions and related PUB Board Order 126/09, which states:

"…MH seeks to provide temporary relief to such large customers to assist the firms and their workers..." and "…short term assistance to GSL and GSM customers that are reducing production as a result of the global economic downturn that will assist in ensuring that MH's electricity rate structure does not contribute to the financial distress of these large customers." In evaluating whether a company complied with the "spirit and intent of the deferral, Manitoba Hydro would review whether any customer stopped production without a return to work strategy rather than simply reducing production and whether the company continued to assist their workers during that period of time.

PUB/MH I-167

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.1 (2) Demand Billing Concessions**

a) Please detail the reasons MH now seeks "forgiveness" of the demand billing deferrals.

ANSWER:

It is Manitoba Hydro's opinion that billing demand concessions were necessary to retain operations in Manitoba, at a time when companies with facilities in multiple jurisdictions, were closing the facilities with higher cost of operations in an effort to reduce costs and match inventories with global demand for their products. Retention of these operating facilities in Manitoba enables facilities to return to normal operation as market conditions improve, protecting Manitoba Hydro's investment in the infrastructure already deployed to service these customers. Additionally, opportunities for employment and provincial economic activity are retained maintaining the benefit to the Province.

In reviewing Manitoba Hydro's initial application, the PUB expressed considerable concern about the unpredictable aspect of the total value of concessions that Manitoba Hydro might provide under the program. With the conclusion of the program in November 2009, Manitoba Hydro has clearly established its liabilities as they relate to the deferrals provided to eligible customers. These liabilities are well within the range of estimates provided by Manitoba Hydro in its initial application and subsequent supporting information, providing known impacts on revenues. As a result, impact on rates is less than originally anticipated.

Customers have indicated that simply deferring payments of portions of their bills does not meet their need of relief from higher unit energy costs, as expense is simply transferred to other periods via the deferral. In fact, costs are further increased by the application of interest to these outstanding amounts. As such, these liabilities must be maintained in the evaluation of operating costs for future production activities. Converting deferrals into concessions provides customers with the ability to maintain competitive energy costs on a going-forward basis as markets strengthen and operations return to normal.

PUB/MH I-167

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.1 (2) Demand Billing Concessions**

b) **In addition to MH's response to (a), please provide detailed information in response to the possible additional information listed in items (a) through (n) [both inclusive] on pages 14 through 24 of Order 126/09.**

ANSWER:

Possible additional information referenced in items (a) through (i) on pages 14 through 24 of Order 126/09 are addressed in the responses below:

a) The Distressed Industry Billing Demand Deferral Program was intended to address potentially negative impacts of Manitoba Hydro's billing structure on unit energy costs in instances where operations were curtailed for the specific purpose of matching output to market demand. Customers able to mitigate this impact by reducing electrical demand in relation to energy consumption were not negatively impacted by Manitoba Hydro's rate structure and therefore not harmed by increasing unit energy costs. The capability to match electrical demand to energy consumption does not exist in all industry sectors due to process requirements that establish electrical demand levels irrespective of production volume.

The intent of Manitoba Hydro's application was to address the negative cost implications of its rate structure on companies striving to maintain competitiveness in their markets. A company's profitability may be impacted by additional factors beyond energy costs. Manitoba Hydro's products and/or services may not directly relate to those factors. The Corporation's objective in providing for relief was to ensure that energy costs, which are universal to operations in all jurisdictions, not contribute negatively to the competitiveness of a Manitoba-based operation.

There was therefore, no requirement for a qualifying customer to file, or have reviewed, its financial information.

b) Manitoba Hydro concluded the Distressed Industry Billing Demand Deferral program with the Nov 09 billing period. Based on applications received and approved for deferral, it is known that the Corporation's liability for outstanding deferrals totals $1,291,190.

The total amount of deferral is distributed by rate type and subclass as follows:

Rate Type (subclass)	Deferral ($)
GSM	$ 41,064
GSL 750 V - 30 kV	$ 171,317
GSL 30 - 100 kV	$ 96,794
GSL > 100 kV	$ 982,015

Reductions in consumption and revenues were evaluated based on analysis of participating customers' energy consumption and revenues (at 2009 rates w/o taxes) during previous fiscal periods relative to the Jun 09 - Nov 09 period during which the billing demand deferral program was available. Combined reduction in energy consumption were estimated at 339,868,443 kWh, with a corresponding decline in revenues (at 2009 rates) of $ 9,352,471,

The approximate reductions in consumption and revenues by rate class for the period during which the billing demand deferral program operated are provided in the table below:

Rate Type (subclass)	kWh Reduction	Revenue Reduction
GSM	10,661,780	$ 350,000
GSL 750 V - 30 kV	25,572,023	$ 835,000
GSL 30 - 100 kV	20,557,997	$ 593,000
GSL > 100 kV	283,076,643	$ 7,575,000

In its Order 126/09, the PUB noted the financial cost or benefit of energy sold on the domestic market versus that sold on the export market as a result of the economic downturn.

The value of energy not sold to domestic customers participating in the billing demand deferral program was examined using surplus energy rates posted by the Corporation on a weekly basis, as approved by the PUB. An estimation of this impact, indicates that approximately $6.7 million in revenue would be received had this energy been sold on the export spot market using SEP prices for the period, compared to the $9.4 million noted above as total energy and revenue loss.

The accompanying table provides a summary of this analysis by rate class:

Rate Type (subclass)	**SEP ($)**
GSM	$ 243,000
GSL 750 V - 30 kV	$ 536,000
GSL 30 - 100 kV	$ 415,000
GSL > 100 kV	$ 5,573,000

c) The duration and impact of the current economic recession on Manitoba Hydro’s customers varies depending on the industry sector and general trends within specific markets. No general statement covers the entire experience of a diverse group of companies and industrial sectors.

Conditions within the pulp and paper sector remain difficult, with no near-term relief anticipated through increased market demand and strengthening prices. Some companies within the metals and mining sectors are experiencing slow and gradual recovery in demand for their products as global inventories of raw materials and finished products stabilize, resulting in increased production of products incorporating metal components. Several companies within the mining sector are moving forward with plans to expand product capacity in anticipation of strengthened global demand for their products. Many manufacturing companies are indicating expectations of recovering markets in the second quarter of 2010 with continued improvement through year-end, although such expectations are not universal. In all cases, recognition exists that recovery is fragile and rate of improvement susceptible to significant variation.

d) Manitoba Hydro has offered technical assistance to customers participating in the billing demand deferral program, in order to assist these companies in evaluating alternate technologies and processes that will improve the competitiveness of these companies as they ramp up production in response to improvements in market conditions.

Manitoba Hydro is not aware of the specific nature of assistance provided to resource-based companies in Northern Manitoba.

e) Manitoba Hydro is only aware of one other utility that has offered some form of rate relief to customers during the economic recession. The Quebec government authorized industrial customers whose power demand exceeded 50 MW to benefit, once, from an exceptional reduction in contract power during the period April 1, 2009 to March 31, 2010. Hydro Quebec also offers a Load Retention Rate (in place since 1993) to large customers (5000 kW or more) that are experiencing financial difficulties and who can demonstrate that they are obtaining nonrefundable reductions from their other suppliers.

Manitoba Hydro’s GSL and GSM rate structures are designed around typical load factors that have historical basis for customers in these rate classes. These load factors have proven to be relatively stable under normal market conditions. Manitoba Hydro’s rates are among the lowest in North America under these conditions.

The global economic downturn created abnormal market conditions that forced companies to significantly curtail production in attempts to reduce inventories and match output to market demand. In some cases, implementing these curtailments resulted in significant reductions in load factor due to the “fixed” nature of electrical demand levels, which remained relatively static despite significant reductions in energy consumption. The structure of Manitoba Hydro’s GSL and GSM rates under these conditions resulted in higher unit energy costs. Manitoba Hydro adopted a minimum requirement of a 10 percent increase in unit energy costs to attain eligibility for the program in order to filter out variations resulting from normal fluctuations in load factor.

Examples of normal (historic), actual, and billed (after deferral) unit energy costs are provided in the table below:

Rate Type (subclass)	Actual ($/kWh)	Normal ($/kWh)	Billed ($/kWh)
GSL > 100 kV	$ 0.0458	$ 0.0364	$ 0.0400
GSL 30 - 100 kV	$ 0.0574	$ 0.0361	$ 0.0397
GSL 750 V - 30 kV	$ 0.0637	$ 0.0554	$ 0.0610
GSM	$ 0.0683	$ 0.0527	$ 0.0580

The implementation of the EIIR was not a consideration in the design of the Distressed Industry Billing Demand Deferral Program as the potential growth targeted by that initiative was not evident among during the period in which the program was available.

f) All reports with respect to Low Income have been filed, or will be filed, during the course of the current proceeding. As noted in response to CAC/MSOS/Manitoba Hydro I-88 no further diesel reports have been filed other than those from November 16, 2009 as an application for revised rates in the Diesel Zone is currently being reviewed internally prior to making application to the PUB.

g) Manitoba Hydro granted the following concessions to customers participating in the billing demand deferral program:

Concession Type	Amount	Value (before taxes)	Rationale
Demand	426 kVA	$2,300.99	Equipment Testing

Any bill reduction or concession granted by MH was accounted for prior to the determination of the billing demand deferral amount available under the program.

h) Manitoba Hydro is aware that some industries faced the consequences of the global recession earlier than others. The Jun 09 - Nov 09 period during which billing demand deferrals were provided was determined by the timing of customer-initiated communication requesting relief from anticipated higher unit energy costs that would arise as operations were curtailed in an attempt to match inventories with demand.

i) Manitoba Hydro has no additional submissions from interested parties, which were unknown during the Ex Parte proceeding.

PUB/MH I-168

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.1(2) Demand Billing Concessions, Order 126/09**

a) **Please file a copy of the "form letter" sent by MH to customers, notifying them of the deferral program.**

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-193(a).

<u>PUB/MH I-168</u>

Subject: Tab 13: PUB Directives
Reference: Tab 13.1(2) Demand Billing Concessions, Order 126/09

b) Please also file the form of application utilized by customers applying for deferral of demand charges.

<u>ANSWER</u>:

No specific "form of application" was utilized by customers applying for deferrals under the Distressed Industry Billing Demand Deferral Program. Customers typically provided the following information in support of their application:

1. General description of the company's business activities,

2. General description of current operational status

3. General description of economic factors impacting customer's business sector,

4. Description of measures implemented at Manitoba-based operations to mitigate the impacts of the economic downturn, including measures taken to reduce demand and energy consumption,

5. An estimate of the duration of current operational changes, along with justification for the estimate of duration, and

6. A position on future outlook and possible actions - positive/negative.

PUB/MH I-169

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.1(2) Demand Billing Concessions Eligibility**

Please confirm MH's determination of eligibility was exactly as MH proposed in its initial application.

ANSWER:

Manitoba Hydro confirms that the process outlined in its initial application was used in the determination of eligibility for billing demand deferrals under the program approved by the PUB in Board Order 126/09.

PUB/MH I-170

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.1(2) Demand Billing Concessions Correspondence**

Please file a copy of the following correspondence related to the Demand Billing Concession matter:

a) MH's letter to the Board dated November 18, 2009;

ANSWER:

Please see the following attachment.

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor – 360 Portage Avenue
Telephone / N° de téléphone : (204) 360-3946 • Fax / N° de télécopieur : (204) 360-6147
pjramage@hydro.mb.ca

November 18, 2009

DELIVERED

Mr. G. Gaudreau
THE PUBLIC UTILITIES BOARD
400 - 330 Portage Avenue
WINNIPEG, Manitoba R3C 0C4

Dear Mr. Gaudreau:

RE: DIRECTIVE 3, ORDER 126/09

As discussed on Monday, November 16, 2009, Manitoba Hydro is writing in order to report to the Public Utilities Board, pursuant to Order 126/09, Directive 3, on the status of customer uptake and Demand Billing Deferrals approved and expected to be approved to November 30, 2009.

Manitoba Hydro advised all customers who may qualify for the Demand Billing Deferral by letters issued in late September. Key Account, Major Account and Retail Operations staff followed up with each eligible customer.

To date, nine customers, involving ten accounts, have requested the demand billing deferral and the first bills incorporating that deferral will issue on or about the end of November, 2009. Manitoba Hydro estimates that the total of deferrals to November 30, 2009 will be approximately $2.0 million. Further details are provided in the attachment to this letter.

Manitoba Hydro has not yet determined whether or not it will extend this program beyond November 30, 2009, but will make this determination prior to that date and will advise the Public Utilities Board of its decision. If the program is extended, Manitoba Hydro's best current estimate of Demand Billing Deferrals for the period December 1, 2009 through March 31, 2010, is $1.0 - $1.25 million.

Manitoba Hydro would like to take this opportunity to advise the Public Utilities Board, that a number of customers have expressed concern that the program has been approved for billing deferral only and not for a full Concession. These customers indicate that deferral does not allow them to incorporate the cost reduction into their bidding on new orders, since it remains a liability on their books. Some customers have indicated that, while they may be eligible for the program, they are opting not to apply because of the uncertainty regarding the concession.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT
Per:

PATRICIA J. RAMAGE
Barrister & Solicitor

PJR/
encl.

Manitoba Hydro Demand Billing Deferrals Pursuant to Order 126/09
General Service Large and Medium Demand Billing Deferrals Estimated to November 30, 2009

Manitoba Hydro Rate Class	# of Accounts	Demand Billing Deferrals by Customer Class (actuals) June	July	August	September	October	Total to 30-Oct	November estimated	Total to 30-Nov
General Service Medium	0	$ -	$ -	$ -	$ -	$ -	**$ -**		**$ -**
General Service Large <30 kV	4	$ 20,816	$ 26,358	$ 35,181	$ 24,653	$ 26,971	**$ 133,979**	$ 34,000	**$ 167,979**
General Service Large 30 - 100 kV	1	$ -	$ 28,328	$ 23,244	$ 2,900	$ 5,551	**$ 60,023**	$ 6,500	**$ 66,523**
General Service Large > 100 kV	5	$ 190,750	$ 466,168	$ 141,946	$ 272,790	$ 335,862	**$ 1,407,516**	$ 380,000	**$ 1,787,516**
Total Demand Billing Deferrals	**10**	**$ 211,566**	**$ 520,854**	**$ 200,371**	**$ 300,343**	**$ 368,384**	**$ 1,601,518**	**$ 420,500**	**$ 2,022,018**

PUB/MH I-170

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.1(2) Demand Billing Concessions Correspondence**

Please file a copy of the following correspondence related to the Demand Billing Concession matter:

b) The Board's letter to MH dated November 26, 2009; and

ANSWER:

Please see the following attachment.

Manitoba

Family Services and Consumer Affairs

The Public Utilities Board
400 – 330 Portage Avenue
Winnipeg, Manitoba, Canada R3C 0C4
T 204-945-2638 / 1-866-854-3698
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November 26, 2009

Ms. Patricia J. Ramage
Law Department
Manitoba Hydro
22 – 360 Portage Avenue
Winnipeg, MB R3C 0G8

Dear Ms. Ramage:

Re: Demand Billing Deferrals for GSM and GSL Customers and Board Order 126/09

Thank you for your letter of November 18, 2009, by which MH advises the Board that:

- the estimated total Demand Billing deferrals to November 30, 2009 approximate $2.0M;
- a determination as to whether to extend the current program through to March 31, 2010 will be made by MH by November 30, 2009;
- MH will notify the Board prior to the end of this month as to whether an extension will be provided; and
- in MH's opinion, some eligible industrial customers are opting not to apply for the concession program because of the uncertainty regarding the concession, i.e. whether the concession will be payment deferral or absolute forgiveness.

Recognizing MH's intention to communicate to the Board, prior to the end of this month, its decision on whether it will extend the program, it would be appreciated if MH would include in its communication:

a) MH's advice as to whether it will extend the deferral period to March 31, 2010;
b) if available, a revised update of the amounts anticipated to be deferred between June 1, 2009 and November 30, 2009;
c) if available, the amounts that either are or would have been (would have been in the case MH decides not to extend the program) anticipated to be deferred between December 1, 2009 and March 31, 2010 (as required by Directive 3);

d) MH's revised response to PUB/MH IXP-3, including another column containing actual June-October and forecast November 2009 reductions in demand and energy consumption and the dollar value of the demand concessions, for the 131 GSM and GSL customers that MH has determined would have been eligible in approximately 50-60% of the six month billing demand concession period had the Board approved MH's Application as filed;
e) MH's revised response to PUB/MH IXP-3, including yet another column for actual June-October and forecast November 2009, reductions in demand and energy consumption, and the value of demand concessions, for the additional 151 GSM and GSL customers that MH has flagged as having "apparent" eligibility in one month of the six month period, had MH's Application been approved as filed;
f) MH's detailed estimate of the reductions in demand and energy consumption, and the value of demand concessions, for all eligible customers for the period of December 1, 2009 to March 31, 2010, had MH's Application been approved as filed, and extended until March 31, 2010; and
g) advice, pursuant to Directive 4, as to whether the Utility will seek to 'review and vary' Order 126/09 in light of the customer concerns as mentioned in your November 18, 2009 letter, or, alternatively, whether MH intends to apply to finalize or confirm Order 126/09, as part of, or concurrent with, the General Rate Application scheduled to be filed November 30, 2009.

Thank you for your attention to this matter.

Yours very truly,

"ORIGINAL SIGNED BY"
Gerry Gaudreau, CMA
Secretary and Executive Director

c.c. R. F. Peters, Board Counsel

PUB/MH I-170

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.1(2) Demand Billing Concessions Correspondence**

Please file a copy of the following correspondence related to the Demand Billing Concession matter:

c) MH's reply to the Board in its letter dated December 18, 2009.

ANSWER:

Please see the following attachment.

Manitoba Hydro

P.O. Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor – 360 Portage Avenue
Telephone / N° de téléphone : (204) 360-3946• Fax / N° de télécopieur : (204) 360-6147
pjramage@hydro.mb.ca

December 18, 2009

Mr. G. Gaudreau
The Public Utilities Board
400 - 330 Portage Avenue
WINNIPEG, Manitoba R3C 0C4

Dear Mr. Gaudreau:

RE: MANITOBA HYDRO'S APPLICATION FOR APPROVAL OF THE IMPLEMENTATION OF TEMPORARY BILLING DEMAND CONCESSIONS

I am enclosing Manitoba Hydro's responses to the questions included in your letter of November 26, 2009, regarding Manitoba Hydro's partial bill deferral program, which was approved in your Order 126/09.

I can advise that Manitoba Hydro will not be extending the program beyond November 30, 2009. As you are aware, Manitoba Hydro applied for confirmation of Order 126/09, with deferrals to be made permanent concessions, in its General Rate Application which was filed December 1, 2009.

As the attached responses indicate, total confirmed deferrals to November 30 are $0.74 million. Deferrals which have been requested, but are still under review, total $1.23 million. Had Manitoba Hydro continued the program to March 31, 2010, it is estimated that additional deferrals totaling $0.85 million would have been sought.

Please contact the writer if you have further questions on this matter.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT

Per:

PATRICIA J. RAMAGE
Barrister and Solicitor

PJR/sc
encls.

Responses to Questions
PUB - Letter of Nov 26, 2009

Question:

a) MH's advice as to whether it will extend the deferral period to March 31, 2010

Answer:

Manitoba Hydro will not extend the deferral period beyond November 30, 2009.

Question:

b) If available, a revised update of the amounts anticipated to be deferred between June 1, 2009 and November 30, 2009.

Answer:

The accompanying table identifies the deferral amounts confirmed and pending to the end of November 2009 in the amount of $1,971,528. Deferrals in the amount of $621,875 were credited to customer billings during the November billing period. An additional $114,413 is confirmed for credit during the December billing period pending Executive approval.

A significant potential variance in the total amount of $1,971,528 is an amount for one customer that may vary from $469,407 - $1,235,240 (shown in the accompanying table as pending). Due to the circumstances of this application, MH is conducting a review of this customer's request to determine whether it complies with the spirit and intend of the deferral approved by the PUB in its Order 126/09.

It is anticipated that an additional amount, not exceeding $75,000 - $100,000, may be included beyond the amount specified in the accompanying table to account for General Service Medium customers that have not yet confirmed their intentions to apply for the deferrals. Many of these customers have indicated that they do not feel that a deferral provides the required benefit to their operating costs as the amounts remain as a liability on their financials.

See accompanying table (Confirmed Billing Demand Concession Deferrals) illustrating confirmed deferrals by month through the Jun - Nov 2009 period.

Response to Question b)

Confirmed Billing Demand Concession Deferrals by Rate Class

(confirmed through November 30th, 2009)

MH Rate Class	Customers (qty)	Approved Concession Amounts by Customer Class (actuals) June	July	August	September	October	November	Total to 30-Nov
General Service Medium	**0**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
General Service Large <30 kV	**4**	**$ 20,816**	**$ 26,358**	**$ 35,180**	**$ 24,392**	**$ 26,665**	**$ 19,354**	**$ 152,765**
General Service Large 30 - 100 kV	**1**	**$ -**	**$ 28,328**	**$ 23,244**	**$ 2,900**	**$ 5,551**	**$ 10,893**	**$ 70,916**
General Service Large > 100 kV	**4**	**$ 106,007**	**$ 161,971**	**$ 61,478**	**$ 17,793**	**$ 81,192**	**$ 84,166**	**$ 512,607**
Pending Consideration/Approval	1	$ 84,742	$ 304,196	$ 80,469	$ 254,998	$ 254,670	$ 256,165	$ 1,235,240
		$ 190,749	$ 466,167	$ 141,947	$ 272,791	$ 335,862	$ 340,331	**$ 1,747,847**
Approved Concessions	**9**	**$ 126,823**	**$ 216,657**	**$ 119,902**	**$ 45,085**	**$ 113,408**	**$ 114,413**	**$ 736,288**
Including Pending Consideration	10	$ 211,565	$ 520,853	$ 200,371	$ 300,083	$ 368,078	$ 370,578	$ 1,971,528

Question:

c) If available, the amounts that either are or would have been (would have been in the case MH decides not to extend the program) anticipated to be deferred between December 1, 2009 and March 31, 2010 (as required by Directive 3)

Answer:

The accompanying table identifies the anticipated deferral amounts to the end of March 2010 if MH had decided to extend the program as approved by Board Order 126/09 beyond November 31, 2009. The amounts were determined from an analysis of customer behavior during the Jun - Nov 09 period, discussions with customer regarding operations during this period, and an analysis of the impact on customer billings (and corresponding impact on unit energy costs) resulting from the removal of the 70 percent winter ratchet clause in Manitoba Hydro's General Service rate tariffs.

See accompanying table (Estimated Billing Demand Concession Deferrals) illustrating estimated deferrals by month through the Dec 2009 - March 2010 period.

Response to Question c)

Estimated Billing Demand Concession Deferrals by Rate Class

(for the period of December 1, 2009 - March 31, 2010)

MH Rate Class	Customers (qty)	Estimated Concession Amounts by Customer Class December	January	February	March	Estimated to Mar 31
General Service Medium	5	$ 25,000	$ 20,000	$ 20,000	$ 20,000	$ 85,000
General Service Large <30 kV	4	$ 42,165	$ 28,781	$ 28,781	$ 28,781	$ 128,508
General Service Large 30 - 100 kV	1	$ 28,102	$ 24,633	$ 21,163	$ 21,163	$ 95,061
General Service Large > 100 kV	5	$ 138,304	$ 123,517	$ 137,557	$ 137,557	$ 536,935
Total Anticipated Deferrals	15	$ 233,571	$ 196,931	$ 207,501	$ 207,501	$ 845,504

Question:

d) MH's revised response to PUB/MH IXP-3, including another column containing actual June - October and forecast November 2009 reductions in demand and energy consumption and the dollar value of the demand concessions, for the 131 GSM and GSL customers that MH has determined would have been eligible in approximately 50 - 60 percent of the six month billing demand concession period had the Board approved MH's Application as filed:

Answer:

The 131 customers referenced in MH's revised response to PUB/MH IXP-3 were selected based on a preliminary analysis of customer consumption behavior during the Jan - Jun 2009 billing period, relative to the historic period of Sep 2006 - Aug 2008. Customers were selected based on application of the concession formula alone, with minimal consideration given to other factors such as rate class changes, seasonal behavior, plant closures, production/process changes, etc. This initial assessment was intended to be a conservative evaluation based on unit energy costs, which did not pre-judge customer eligibility for other less discrete factors.

A more detailed analysis of the 131 customers selected through this process was undertaken to identify those customers experiencing rate changes, seasonal operations consistent with past behavior, plant closures, process changes, etc. This examination reduced the number of customer that subsequently received letters informing them of eligibility for the concession deferral to 76. The lower number reflects customers moving from a GSM/GSL rate class to GSM/GSL Limited Use, or GSS rate class, customers experiencing consistent seasonal behavior, including those customer historically impacted by the 70 percent winter ratchet, and customers experiencing abnormal consumption patterns due to facility improvements, renovations, relocations, process changes, etc.

An examination of energy consumption during the Jun - Nov 09 period for the 76 customer issued letters identified 13 customers that were no longer eligible for demand concessions due to reductions in unit energy costs resulting from an increase in energy consumption (kWh) or an improved ability to curtail, or reduce, demand recorded (kVA) during these billing periods. As a result, these customers are no longer eligible for demand concessions, reducing the total of eligible customers to 63. This reduction was offset by identification of additional customers that were not determined to be eligible based on behavior during the Jan - Jun 09 period, but became eligible based on consumption behavior during the Jun 09 - Nov 09 period. The addition of these customers increased the pool of eligible customers to 81 accounts.

The results reported in the table below are based on an analysis of consumption and demand experienced by this pool of 81 customers during the Jun - Nov 2009 billing periods.

Rate Class (Sub-Class)	Qty	Historic GWh/Mth Usage (Jun - Nov)	Actual GWh/Mth Usage (Jun - Nov	Percentage Reduction
GS Large >100KV	6	82.7	35.6	57.0%
GS Large 30-100KV	2	6.9	3.4	50.7%
GS Large 750V-30KV	13	10.6	6.3	40.6%
GS Medium	60	6.9	5.2	24.6%
Totals	**81**	**107.1**	**50.5**	**52.8%**
Rate Class (Sub-Class)	**Qty**	**Historic MW/Mth Billed (Jun - Nov)**	**Actual MW/Mth Billed (Jun - Nov**	**Percentage Reduction**
GS Large >100KV	6	162.3	148.7	8.4%
GS Large 30-100KV	2	11.9	10.2	14.3%
GS Large 750V-30KV	13	32.1	28.8	10.3%
GS Medium	60	23.9	23.1	3.3%
Totals	**81**	**230.2**	**210.8**	**8.4%**
Rate Class (Sub-Class)	**Qty**	**Historic MW/Mth Record (Jun - Nov)**	**Actual MW/Mth Record (Jun - Nov**	**Percentage Reduction**
GS Large >100KV	6	162.4	116.2	28.4%
GS Large 30-100KV	2	12.0	9.1	24.2%
GS Large 750V-30KV	13	31.6	28.6	9.4%
GS Medium	60	24.0	22.1	7.9%
Totals	**81**	**230.0**	**176.0**	**23.5%**
Rate Class (Sub-Class)	**Qty**	**Concessions Available ($)**	**Concession Applications ($)**	**Percentage Applied**
GS Large >100KV	6	$ 1,813,030	$ 1,747,847	96.4%
GS Large 30-100KV	2	$ 96,794	$ 70,916	73.3%
GS Large 750V-30KV	13	$ 255,750	$ 152,765	59.7%
GS Medium	60	$ 155,540	$ 0	0.0%
Totals	**81**	**$ 2,321,114**	**$ 1, 971,528**	**84.9%**

Concessions Available amounts do not include corrections for maintenance shutdowns, and other similar non-economic events. Concession Application amounts include corrections for such non-economic events and are based on amounts confirmed by MH.

Question:

e) MH's revised response to PUB/MH IXP-3, including another column containing actual June - October and forecast November 2009 reductions in demand and energy consumption and the dollar value of the demand concessions, for the 151 GSM and GSL customers that MH has flagged as having "apparent" eligibility in one month of the six month period, had MH's application been approved as filed.

Answer:

The 151 customers flagged by MH as having "apparent" eligibility in one month of the Jan - Jun 2009 analysis period were further evaluated to determine continued eligibility during the Jun - Nov 2009 eligibility period. Such analysis revealed that instances of customers demonstrating continuing eligibility during the concession period were minimal. There was very poor correlation between those customers that were identified as showing "apparent" eligibility in the analysis period with those customers that demonstrated similar "apparent" eligibility during the concession period.

Instances where "apparent" eligibility transitioned into "demonstrated" eligibility were included in the response to Questions d) above.

Instances of customer demonstrating "apparent" eligibility during one month of the concession period has been determined to be generally related to events such as maintenance shutdowns, facility improvements, renovations, process changes, or other normal interruptions to regular business operations, rather than for reasons of the global economic downturn. For this reason, MH determined that it was preferable to include those customers that transitioned to "demonstrated" eligibility into the response to Question d) above.

Question:

f) MH's detailed estimate of the reductions in demand and energy consumption, and the value of demand concessions, for all eligible customers for the period of December 1, 2009 to March 31, 2010, had MH's Application been approved as filed, and extended until March 31, 2010.

Answer:

It is anticipated that some additional take-up of available concession amounts would have occurred during the Jun - Nov 2009 billing period had the PUB approved MH's initial Application as filed. The deferral aspect of the program approved by the PUB in its Order 126/09 appears to have been a point of contention with many eligible customers, resulting in a lower than anticipated subscription rates in the GSM and GSL 750 - 30 kV rate classes. As such, approval of MH's Application as filed will require a revision to estimates for demand concessions in the Dec 09 - Mar 10 billing period, particular for those rate classes with a lower than anticipated take-up.

The primary variable in the lower levels of projected demand concession deferrals provided for the Dec 09 - Mar 10 billing periods in response to Question c), is the removal of the 70 percent winter ratchet, which will result in reduced billable demands during periods of low recorded demands. This reduction is particularly evident where customer operations are curtailed throughout an entire billing period, resulting in artificially low, recorded demands being established.

The high subscription rate in the GSL >100 kV rate class under the deferral program approved by PUB in its Order 126/09 indicates that there would be minimal change in estimates for this rate class had the PUB approved Manitoba Hydro's Application as filed. Therefore, estimates for concessions will not change from those provided in response to Question c). Energy costs generally represent a greater portion of overall operating costs for customers in this rate class. Although wary of the deferral aspect of the program, these customers felt that the short-term benefit in terms of cash-flow offset the risk of future repayment, resulting in a higher subscription rate.

Assuming a subscription rate of 85 - 95 percent in the remaining GSL and GSM rate classes would indicate an increase in the amount of concessions applied relative to the response provided in Question c). These estimates for concession amounts have been revised based on this assumption as illustrated in the accompanying table. It is important to recognize that increases in concession amounts in these rate classes were not assumed as a result of changes in operational behavior, but rather the result of a higher subscription rates due to the concession being treated as a "forgivable" credit rather than a deferral subject to future repayment.

There is no compelling reason to suggest that monthly demand and energy reductions will differ significantly from the values provided for energy and recorded demand in response to Question d). Please refer to the values provided in the response to Question d) for these amounts.

Response to Question f)

Estimated Billing Demand Concession Deferrals by Rate Class (as Filed)

(for the period of December 1, 2009 - March 31, 2010)

MH Rate Class	Customers (qty)	Estimated Concession Amounts by Customer Class December	January	February	March	Estimated to Mar 31
General Service Medium	50	$ 42,500	$ 34,000	$ 34,000	$ 34,000	$ 144,500
General Service Large <30 kV	12	$ 63,248	$ 43,172	$ 43,172	$ 43,172	$ 192,762
General Service Large 30 - 100 kV	2	$ 35,596	$ 31,202	$ 26,806	$ 26,806	$ 120,411
General Service Large > 100 kV	6	$ 138,304	$ 123,517	$ 137,557	$ 137,557	$ 536,935
Total Anticipated Deferrals	70	$ 279,647	$ 231,890	$ 241,535	$ 241,535	$ 994,608

Question:

g) Advice, pursuant to Directive 4, as to whether the Utility will seek to 'review and vary' Order 126/09 in light of the customer as mentioned in your November 18, 2009 letter, or, alternatively, whether MJ intends to apply to finalize or confirm Order 126/09, as part of, or concurrent with, the General Rate Application scheduled to be filed November 30, 2009.

Answer:

Contained within Manitoba Hydro's General Rate Application is the application to finalize Order 126/09 but to make permanent, ie, non-repayable by the customer, the partial billing deferrals approved by Manitoba Hydro pursuant to Order 126/09. Specifically, in Tab 1 of the General Rate Application Manitoba Hydro has requested:

" e) Final approval of Order 126/09, which order resulted from Manitoba Hydro's Application for Temporary Billing Demand Concessions for General Service Medium and Large customers related to impacts of the economic downturn. In Order 126/09, the PUB approved this Application, in the form of "a partial bill payment deferral program". Manitoba Hydro is requesting that the PUB's final approval of Order 126/09 include making permanent, billing concessions granted under such program."

<u>PUB/MH I-171</u>

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.3 (2) B.O. 57/09 SEP Extension 2008 GRA, PUB (MH II-30(b))**

a) Please confirm that MH's hydraulic generation [with post- Limestone capacity] would have over the last 31 years produced:

- **< 22,000 GW hours in three years;**
- **< 25,000 GWh in 8 years;**
- **< 28,000 GWh in 12 years;**
- **< 29,000 GWh in 17 years;**
- **more than 32,000 GWh in 7 years; and**
- **more than 34,000 GWh in 2 years.**

<u>ANSWER</u>:

The source of the hydraulic generation estimates with post-Limestone capacity in the information request is not known to Manitoba Hydro. Manitoba Hydro's estimate utilizing information from PUB/MH II-30(b) of the 2008 GRA with updates from the historic record after 2005/06 is provided below for the period 1978 to 2008, inclusive.

- < 22,000 GWh in 3 years;
- < 25,000 GWh in 8 years;
- < 28,000 GWh in 12 years;
- < 29,000 GWh in 15 years;
- > 32,000 GWh in 10 years; and
- > 34,000 GWh in 4 years.

PUB/MH I-171

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.3 (2) B.O. 57/09 SEP Extension 2008 GRA, PUB (MH II-30(b))**

b) Please confirm that in those 31 years, Lake Winnipeg's maximum summer water levels were:

- **715.0 in 5 years [high flow years].**
- **714.5 in 19 years.**
- **714.0 in 25 years.**

ANSWER:

Lake Winnipeg wind eliminated lake levels exceeded 715.0 ft in seven years (1979, 1986, 1993, 1997, 2005, 2007, 2008), exceeded 714.5 ft in 17 years, and exceeded 714.0 ft in 22 years.

PUB/MH I-172

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.3 (3) B.O. 57/09 SEP Extension 2008 GRA**

a) **Please confirm that with hydraulic generation below 29,000 GWh/year, MH is able to meet current domestic load and committed long-term export contracts. What additional higher value sales are possible in:**

- **5x16 peak period?**
- **Off – peak periods?**

ANSWER:

Manitoba Hydro can confirm that it is always capable of meeting its firm export and domestic load obligations regardless of the hydraulic generation amount (barring catastrophic or unforeseen circumstances).

To the extent that hydraulic generation is limiting the amount of export sales, Manitoba Hydro will purchase energy to serve its load, store water in its reservoirs and release that water for generation in higher value periods to the extent that such transactions are economic. Generally, that means buying off peak energy for sale in the on-peak. To the extent that Manitoba Hydro has unused thermal generation available, this supply source will be used to supplement export sales, again only to the extent that such activities are economic.

At times there are lucrative opportunities in the off peak market where hourly prices exceed prices in the on peak. Manitoba Hydro will engage in these activities to the extent they are economic.

PUB/MH I-172

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.3 (3) B.O. 57/09 SEP Extension 2008 GRA**

b) Please confirm that with hydraulic generation below 25,000 GWh/year, MH is able to meet current domestic load and long-term export contracts. What additional higher value sales are possible:

- **5x16 peak period?**
- **Off – peak periods?**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-172(a).

With 25,000 GWh/year of hydraulic generation rather than 29,000 GWh/yr, there will be increased opportunities for purchases to serve Manitoba load, for resale or for sale of surplus Manitoba Hydro thermal generation when it is economical whether in the on or off peak periods.

PUB/MH I-172

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.3 (3) B.O. 57/09 SEP Extension 2008 GRA**

c) Please confirm that summer off – peak overnight sales provide the lowest revenue price and would in low flow periods be eliminated.

ANSWER:

The summer off-peak prices provide the lowest prices due to the lowest overall demand in the hourly electricity markets. Under median or lower inflow conditions Manitoba Hydro generally does not engage in off-peak sales due to a lack of surplus energy.

<u>PUB/MH I-173</u>

Subject: **Tab 13: PUB Directives**
Reference: **Off - Peak Sales B.O. 57/09 SEP Extension**

Please confirm on an order of magnitude basis annual sales/purchases:

Year	Annual Exports	Summer Off-peak Exports (SEP Prices)	Winter Imports
2000/01	12,065 GWh	1,600 GWh	600 (2.5-5.0¢/KWh)
2001/02	12,091 GWh	2,500 GWh (1 .0-2.5¢ KWh)	1,000 GWh (2.0-3.0¢/KWh)
2002/03	9,463 GWh	700 GWh (2.0-3.00¢/KWh)	2,300 GWh (2.5-6.0¢/KWh)
2003104	4,389 GWh	Nil (4.0-9.5¢/KWh)	7,000 GWh (4.0-5.50/Kwh)
2004/05	10,700 GWh	1,400 GWh (4.0-4.5¢/KWh)	1,300 GWh (3.5-4.0¢/KWh)
2005/06	16,000 GWh	2,900 GWh (2.0-3.5¢/KWh)	2,300 GWh (4.0-4.5¢/KWh)
2006/07	10,100 GWh	2,800 GWh (1 .0-3.5¢/KWh)	1,200 GWh (4.0-6.0¢/KWh)
2007/08	11,800 GWh	3,100 GWh (1.5-3.5¢/KWh)	10 GWh (6.0-10.0¢/KWh)
2008/09	9,700 GWh	2,100 GWh (1 .0-4.0¢/KWh)	100 GWh (3.5-7.0¢KWh)
2009/10	-	1,700 GWh (1¢/KWh)	-

<u>ANSWER</u>:

Manitoba Hydro is unable to confirm the data in the table provided above. The table below provides accurate values:

- Total export GW.h sales - as provided in response to CAC/MSOS/MH I-13(d).

- Summer off-peak exports (April to November inclusive). The price per kW.h shown below the volumes indicates the minimum and maximum average monthly weighted price for the fiscal year.
- Total winter imports (December to March inclusive). The price per kW.h shown below the volumes indicates the minimum and maximum average monthly weighted price for the fiscal year.
- SEP summer off-peak prices. These values are based on the minimum and maximum SEP prices approved by the PUB each week for the summer (April to November) off-peak period for the Large >100 kV customer class. These prices do not distinguish between export and import prices.

Year	**Annual Export Sales (GW.h)**	**Summer Off-Peak Exports GW.h (¢ / kW.h)**	**Winter (total) Imports GW.h (¢ / kW.h)**	**SEP Summer Off-Peak Prices**
2000/01	12,153 GW.h			n/a
2001/02	12,299 GW.h			1.1 - 2.9 ¢/kW.h
2002/03	9,735 GW.h			1.7 - 2.8 ¢/kW.h
2003/04	6.977 GW.h			2.5 - 11.8 ¢/kW.h
2004/05	10,746 GW.h			1.4 - 5.2 ¢/kW.h
2005/06	15,266 GW.h	4,528 GW.h (2.4 - 4.1¢/kW.h)	268 GW.h (3.5 - 7.2¢/kW.h)	0.7 - 4.1 ¢/kW.h
2006/07	11,110 GW.h	3,365 GW.h (2.3 - 4.6¢/kW.h)	942 GW.h (5.4 - 6.2¢/kW.h)	0.6 - 9.3 ¢/kW.h
2007/08	12,997 GW.h	3,686 GW.h (2.0 - 5.0¢/kW.h)	291 GW.h (4.5 - 5.4¢/kW.h)	0.7 - 5.8 ¢/kW.h
2008/09	12,174 GW.h	3,350 GW.h (2.1 - 3.6¢/kW.h)	468 GW.h (3.7 - 5.0¢/kW.h)	1.1 - 4.2 ¢/kW.h
2009/10	9,708 GW.h	n/a	n/a	0.6 - 1.8 ¢/kW.h

Note: The On/Off peak split for data prior to fiscal 2005/06 is not available as a different reporting system was used prior to this date.

PUB/MH I-174

Subject: Tab 13: PUB Directives

Reference: Appendix 13.3 Fixed Vs. Floating Debt Page 23-27

a) **Please provide the graphs in figures 5 & 6 with MH's floating rate mix and comment on how MH compares with the Peer group.**

ANSWER:

The following response was provided by National Bank Financial:

"*The following information was utilized for the requested graphs:*

Table 17: Peer Group – Historical Floating Rate Debt[1]

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Manitoba Hydro		**18%**	**15%**	**18%**	**18%**	**22%**	**19%**	**17%**	**19%**	**20%**
BC Hydro	38%	30%	19%	26%	38%	29%	29%	36%	38%	37%
SaskPower	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Hydro Québec	26%	26%	26%	24%	25%	26%	20%	8%	8%	11%
NB Power	4%	5%	3%	0%	9%	14%	11%	8%	0%	8%
Nfld. Hydro		20%	17%	13%	11%	11%	10%	4%	1%	n/a
Emera Inc.	20%	18%	27%	16%	7%	8%	5%	7%	2%	6%
Fortis Inc.	14%	4%	14%	14%	9%	9%	6%	13%	18%	12%
Canadian Utilities Limited	5%	9%	7%	4%	1%	1%	1%	2%	2%	3%
Peer Group Average *(Excl. Manitoba Hydro)*	**16%**	**14%**	**14%**	**12%**	**12%**	**12%**	**10%**	**10%**	**9%**	**11%**

[1] Historical financial data as per company reports, rounded to the nearest percentage point. NBF files this revision to Table 17 of its report, based on historical Manitoba Hydro data revised as per company information. This adjustment is for consistency purposes only and does not affect NBF's findings in the report.

Figure 5: Term Spread vs. Average Peer Group Floating Rate Debt %[2]

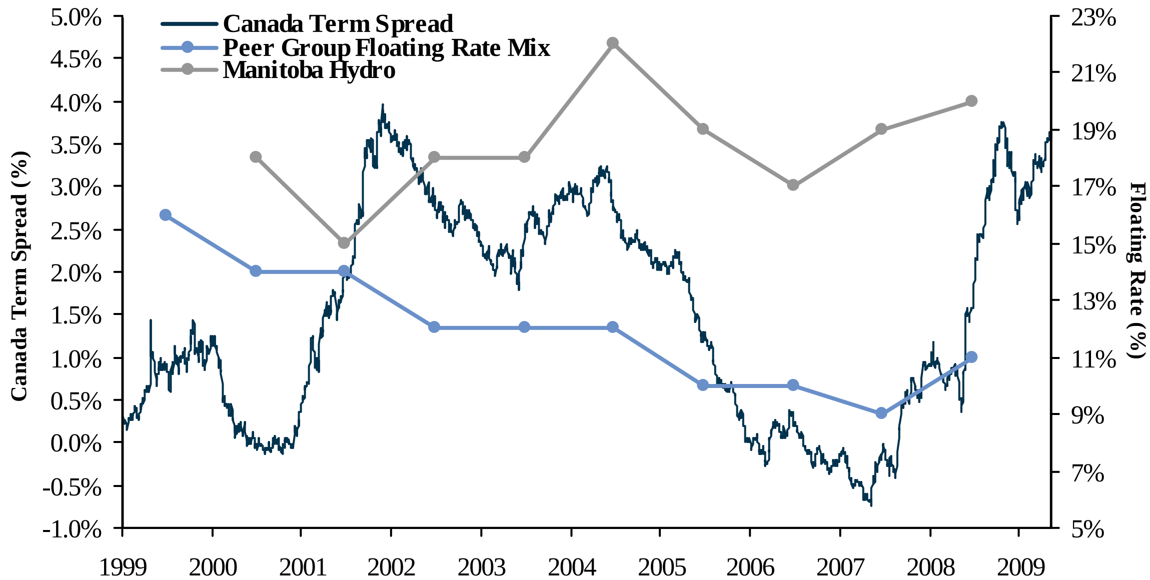
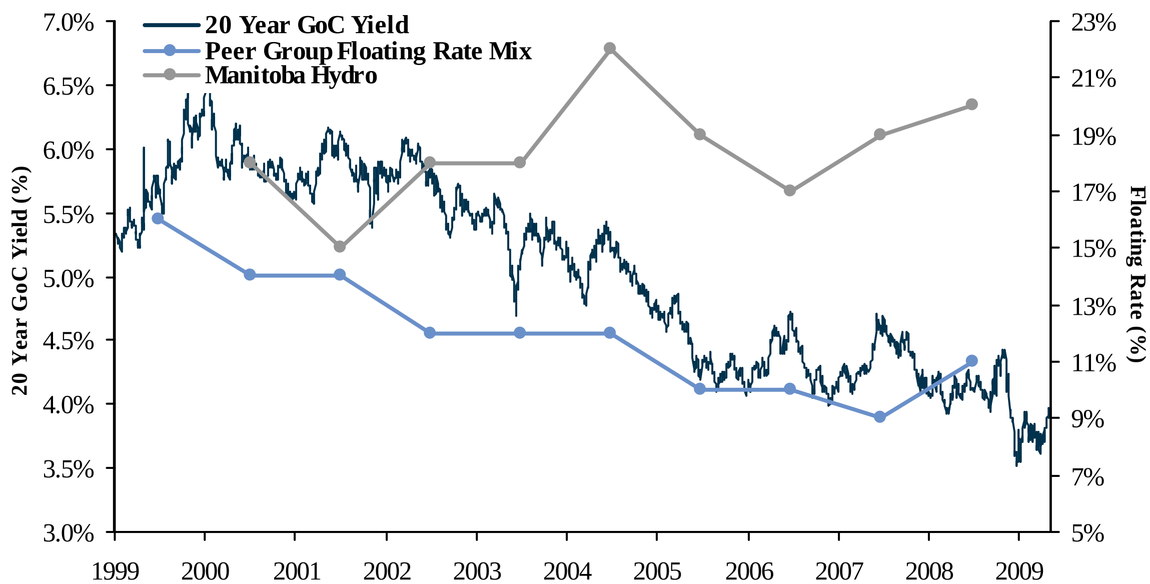


Figure 6: 20 Year Government of Canada vs. Average Peer Group Floating Rate Debt %[3]



[2] Historical interest rate data as per Bloomberg, peer group floating rate mix as per peer group company reports, rounded to the nearest percentage point. The peer group average was adjusted to exclude TransAlta to be consistent with the peer group as defined on page 23 of the report. It also excludes Manitoba Hydro. The adjustment is for consistency purposes only and does not affect NBF's findings in the report.

[3] Historical interest rate data as per Bloomberg, peer group floating rate mix as per peer group company reports, rounded to the nearest percentage point. The peer group average was adjusted to exclude TransAlta to be consistent with the peer group as defined on page 23 of the report. It also excludes Manitoba Hydro. The adjustment is for consistency purposes only and does not affect NBF's findings in the report.

NBF observes that Manitoba Hydro's floating rate debt percentages have remained within the targeted range at the end of each fiscal year. Also, Manitoba Hydro's floating rate debt percentages have remained above the peer group average, and has tended to follow changes in term spreads over time."

PUB/MH I-174

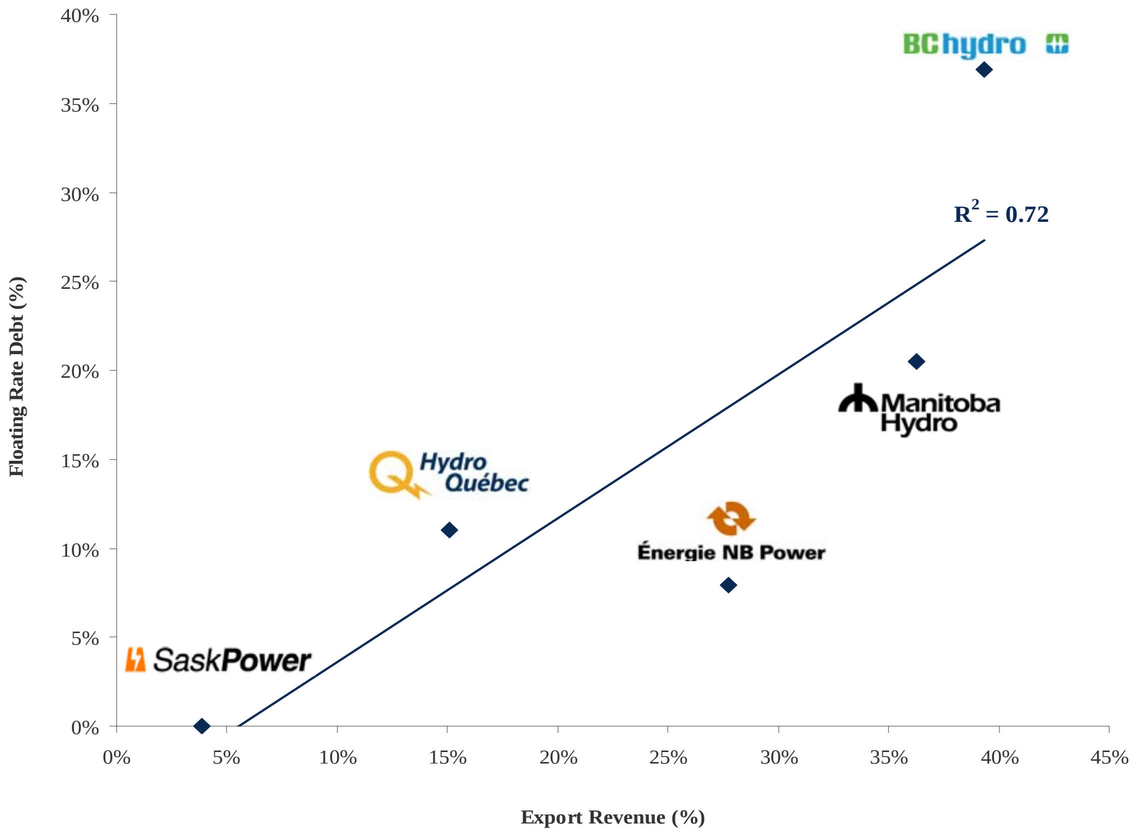
Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.3 Fixed Vs. Floating Debt Page 23-27**

b) Please refile figure 8 placing MH relative floating rate % of export revenue comparing with the Peer Group.

ANSWER:

The following response was provided by National Bank Financial (please see the graph included below):

Figure 8: Peer Group Floating Rate Debt % (2008) vs. Export Revenue % (Crown Utilities)[1]



[1] Data as per Manitoba Hydro and peer group company reports, rounded to the nearest percentage point. Figure excludes Nlfd. Hydro data previously based on 2007 information (2008 figures unavailable at the time of report drafting). This revision is for consistency purposes only and does not affect NBF's findings in the report.

PUB/MH I-175

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.3 Fixed Vs. Floating Debt Page 23-27**

Reference: **Appendix 13.4 IFRS**

a) **Please file a copy of any reports prepared during the detailed design phase of the project, including those that provide a detailed review of the accounting differences between Canadian GAAP and IFRS and the impact of those differences on net income, customer rates, and implications for conversion of key business and IT processes and their related costs for the change.**

ANSWER:

Please see Appendix 32 for a copy of the IFRS report which provides the status of the detailed design phase of the project.

<u>PUB/MH I-175</u>

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.3 Fixed Vs. Floating Debt Page 23-27**

Reference: **Appendix 13.4 IFRS**

b) Please provide a project progress chart detailing the current status on the IFRS project.

<u>ANSWER</u>:

Please see Appendix 32.

PUB/MH I-175

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.3 Fixed Vs. Floating Debt Page 23-27**

Reference: **Appendix 13.4 IFRS**

c) **Please provide an estimate of the external and internal costs incurred by MH related to IFRS conversion the accounting treatment and the proposed recovery of such costs in rates.**

ANSWER:

The following table provides costs incurred to date.

	2008/09	**2009/10 (to Feb/10)**
Internal Labour	$597,000	$898,000
External Consulting	49,000	291,000
Other	2,000	6,000
Total	**$748,000**	**$1,195,000**

Project costs are expensed as incurred and charged to OM&A.

<u>PUB/MH I-176</u>

Subject: **Tab 13: PUB Directives**

Reference: **Appendix 13.4, Tab 5 Page 4 of 9, Appendix 5.2 IFF09-1 Pages 34 to 36, Appendix 4.4 page 10 of 36**

a) Please provide a schedule which details and supports the net adjustments to IFF09-1 by specific IFRS accounting impacts, similar to that provided at the status update PUB/MH -1 (c). Include on the IFF09-1 for Electric operations the debt to equity ratio.

<u>ANSWER</u>:

Please see Manitoba Hydro's responses to PUB/MH I-16(b) for IFRS accounting impacts and PUB/MH I 1(b)(ii) for the debt/equity ratio for Electric Operations.

<u>PUB/MH I-176</u>

Subject: **Tab 13: PUB Directives**

Reference: **Appendix 13.4, Tab 5 Page 4 of 9, Appendix 5.2 IFF09-1 Pages 34 to 36, Appendix 4.4 page 10 of 36**

b) Please discuss the implications on MH's accounting for regulatory assets and liabilities if current IFRS standards do not change.

<u>ANSWER</u>:

As noted in the IFRS Status Update Report, Section 4.1.2 page 14 (Appendix 32), the application of the IFRS framework in other countries has not typically resulted in the recognition of regulatory assets and liabilities. If the IASB Rate-regulated Activities Exposure Draft does not pass, these costs may need to be adjusted to retained earnings upon transition and may be expensed in the year incurred on a go forward basis.

<u>PUB/MH I-176</u>

Subject: **Tab 13: PUB Directives**

Reference: **Appendix 13.4, Tab 5 Page 4 of 9, Appendix 5.2 IFF09-1 Pages 34 to 36, Appendix 4.4 page 10 of 36**

c) Please discuss the implication on MH's accounting for regulatory assets and liabilities If the current proposed standard set out in the IASB exposure draft Rate-Regulated Activities is adopted as drafted and describe how the financial position forecast in IFF09-1 will change. Please re-file a revised IFF09-1(pages 34 to 36) for electric operations reflecting the draft standards in the ED. Please include the debt to equity ratio on the schedule.

<u>ANSWER</u>:

Under the proposed IASB Rate-regulated Activities Exposure Draft, Manitoba Hydro would continue to recognize rate-regulated assets and liabilities. Please see Section 4.1.2 of the IFRS Status Update Report (Appendix 32), for a discussion of the provisions of the Exposure Draft.

IFF09 and the 20 year Financial Outlook were prepared based upon the understanding that rate regulated accounting would likely prevail. Given that there are still substantial uncertainties with respect to the Exposure Draft, it is not possible to update IFF09 and the 20 year Financial Outlook, at this time, to provide a conclusive indication of the impacts on Manitoba Hydro.

PUB/MH I-176

Subject: **Tab 13: PUB Directives**

Reference: **Appendix 13.4, Tab 5 Page 4 of 9, Appendix 5.2 IFF09-1 Pages 34 to 36, Appendix 4.4 page 10 of 36**

d) **Please file a revised 20 years IFF for Electric operations reflecting the draft standard in the Exposure Draft . Please include the debt to equity ratio on the schedule.**

ANSWER:

Please see part c of this response.

PUB/MH I-177

Subject: **Tab 13: PUB Directives**
Reference: **IFRS Consultations**

a) **Please indicate whether MH provided any commentary in response to the IASB exposure draft, if so please file**

ANSWER:

Manitoba Hydro has provided commentary to the IASB on the exposure draft related to Rate-regulated Activities. Manitoba Hydro also provided input into the CEA, CGA and CEPA joint response. These are provided in Appendices 2 and 3 of the IFRS Status Update Report.

<u>PUB/MH I-177</u>

Subject: **Tab 13: PUB Directives**
Reference: **IFRS Consultations**

b) Please indicate what discussions MH has had with other regulatory jurisdictions in Canada and concerns raised associated with the conversion to IFRS

<u>ANSWER</u>:

Manitoba Hydro has participated in the CEA IFRS/Finance subcommittee meetings and discussions. Other Canadian utilities have generally expressed similar concerns as outlined in Manitoba Hydro's IFRS Status Update Report.

<u>**PUB/MH I-178**</u>

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 Head Office**

a) Please provide a schedule detailing the all in cost of operating the new head office building including depreciation and interest costs.

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

Please see the following table for the information requested for the 2010/11 forecast year.

	Cost(in thousands of $)	Cost/sqft
Service Type		
Security	$ 435	$ 0.62
Janitorial	1,340	1.92
Manitoba Hydro internal labour	404	0.58
Maintenance & Repair	501	0.72
Operations	291	0.42
Utilities	230	0.33
Total Operating & Maintenance	$ 3,201	$ 4.59
Depreciation	3,093	4.43
Interest	15,990	22.92
Property & Business Tax (estimated)	4,863	6.97
Total 360 Portage Operating costs	$ 27,147	$ 38.91
360 Portage gross area	697,609	

PUB/MH I-178

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 Head Office**

b) Please indicate the lease cost per square foot related to the new building based on the all in operating cost set out in a).

ANSWER:

Manitoba Hydro leases surplus space in the new building at prevailing market rates.

<u>PUB/MH I-178</u>

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 Head Office**

c) Please indicate the estimated annual costs for heating and cooling the new head office and compare that cost with the annual average weather normalized heating and cooling costs incurred at 820 Taylor

<u>ANSWER</u>:

All energy consumption is considered internal heat gain, contributing to the heating and cooling of the building and it is more appropriate to consider total energy consumption in a comparison.

The estimated annual energy requirement for the new head office is 5.7 million kWh for an energy cost of approximately $156 thousand. On a square meter basis, the estimated annual energy requirement is 88 kWh/m^2/year.

The estimated annual energy requirement for 820 Taylor is 9.3 million kWh for an energy cost of approximately $253 thousand. On a square meter basis, the estimated annual energy requirement is 487 kWh/m^2/year.

PUB/MH I-178

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 Head Office**

d) Please provide the notice of assessment for the Property & Business Tax totaling $6.75 million.

ANSWER:

The $6.7 million was a previous estimate. A notice of assessment was not received to support this estimate. The current estimated property and business tax is $4.9 million, as per PUB/MH I-178(a).

PUB/MH I-178

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 Head Office**

e) Please provide a breakdown of the $3.95 million Operating and Maintenance costs of the new head office in both dollar terms and on a per square foot basis.

ANSWER:

Detailed OM&A costs for the new head office are forecasted to be $3.2 million for 2010/11. Please refer to part a of this response for the requested breakdown.

PUB/MH I-178

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 Head Office**

f) Please provide a breakdown of the Operating and Maintenance costs at 820 Taylor in both dollar terms and on a per square foot basis.

ANSWER:

Please see the following table for the OM&A costs for 820 Taylor.

Service Type	Cost (in thousand of $)		Cost/sqft	
Security	$	172	$	0.84
Janitorial		244		1.19
Manitoba Hydro internal labour		545		2.66
Maintenance & Repair		183		0.89
Operations		301		1.47
Utilities		61		0.30
Total Operating & Maintenance	**$**	**1,507**	**$**	**7.35**
Taylor Gross Area Square Footage		205,000		

PUB/MH I-179

Subject: Tab 13: PUB Directives
Reference: Cost Savings Attributable to Head Office

a) Please provide a breakdown of the lease reductions by facility.

ANSWER:

Please see the following tables for the lease reductions by facility.

in thousands of $

Location	Annual Rent	Annual Common Area Maintenance	Operations	Business & Property Taxes	Total lease facility savings
1080 WAVERLEY	$ 27	$ 3	$ 25	$ 11	**$ 65**
1090 WAVERLEY	292	33	128	138	**591**
1100 WAVERLEY Bay 2 to 11	260	-	-	91	**351**
1100 WAVERLEY Bay 12 to 15	82	-	-	30	**112**
1100 WAVERLEY bay 16 to 17	56	-	-	20	**76**
1120 WAVERLEY	141	6	35	57	**240**
1140 WAVERLEY	250	22	103	93	**468**
1146 WAVERLEY Bay 1 to 4	97	29	81	27	**234**
1146 WAVERLEY Bay 5 to 8	102	-	-	27	**129**
1146 WAVERLEY Bay 9 & 10	48	-	-	13	**61**
1146 WAVERLEY Bat 11 to 13	63	-	-	18	**81**
1146 WAVERLEY Bay 14	37	-	-	10	**47**
1150 WAVERLEY B & C	214	41	83	19	**357**
1461 CHEVRIER	110	43	2	10	**166**
1565 WILLSON PLACE/ 900 Waverley	591	-	187	152	**931**
1664 SEEL AVE	23	-	-	-	**23**
185 KING STREET	118	78	84	44	**324**
444 ST. MARY	1,064	724	36	235	**2,060**
693 TAYLOR	118	34	114	54	**319**
756 PEMBINA HIGHWAY	10	-	-	-	**10**
Total	**$ 3,704**	**$ 1,013**	**$ 878**	**$ 1,049**	**$ 6,645**

Address	Exterior Gross Square Footage	Lease Term
185 King St.	7,230	2009 05 25
185 King St.	5,723	2009 05 25
444 St. Mary Ave.	2,084	2009 01 31
444 St. Mary Ave.	15,129	2009 02 28
444 St. Mary Ave.	15,129	2009 01 31
444 St. Mary Ave.	15,129	2009 01 31
444 St. Mary Ave.	15,129	2009 01 31
444 St. Mary Ave.	2,692	2009 01 31
444 St. Mary Ave.	15,129	2009 01 31
444 St. Mary Ave.	2,301	2009 01 31
693 Taylor Ave.	15,220	2009 03 31
1080 Waverley St.	2,013	2009 03 31
1090 Waverley St.	7,538	2009 03 31
1090 Waverley St.	13,912	2009 03 31
1120 Waverley St.	19,671	2009 12 31
1100 Waverley St.	51,136	2010 01 31
Total area released to date	**205,164**	

Address	Exterior Gross Square Footage	Lease Term
1140 Waverley St.	32,110	2010 07 30
1146 Waverley St.	35,693	2010 04 30
1461 Chevrier Blvd.	9,992	2010 03 31
1565 Willson Pl.	16,461	2011 10 31
1565 Willson Pl.	16,692	2011 10 31
1565 Willson Pl.	16,606	2011 10 31
1150 Waverley St.	12,260	2013 06 30
1150 Waverley St.	5,090	2012 09 30
Balance to be released	**144,904**	

PUB/MH I-179

Subject: Tab 13: PUB Directives
Reference: Cost Savings Attributable to Head Office

b) Please provide a breakdown of the estimated $1 million in savings for avoided rent for additional space requirements.

ANSWER:

The $1 million in savings represented in Appendix 13.5 used 444 St Mary Ave costs as a basis and was estimated as follows:

444 St. Mary Projected Costs		
Rent @ $12 / sq ft		$850,000
Common Area Maintenance @ $12 / sq ft		850,000
Parking		300,000
Electric Utility		50,000
Other Operating & Maintenance		50,000
Projected 2009/10 annual facility cost for 444 St. Mary	**$**	**2,100,000**
Number of Employees that Occupied 444 St. Mary		330
Total cost per Employee at 444 St. Mary	$	6,364
Number of additional Employees for 360 Portage		150
Number of additional Employees for 360 Portage X Total cost per Employee at the 444 St. Mary Rate	$	954,545

PUB/MH I-179

Subject: Tab 13: PUB Directives
Reference: Cost Savings Attributable to Head Office

c) Please provide a breakdown by division of the estimated 150 additional EFTs .

ANSWER:

The increased requirement was primarily due to growth in the Power Supply business unit. The EFT growth by division within Power Supply from 2004/05 to 2011/12 is provided in PUB/MH I-34(b).

<u>PUB/MH I-179</u>

Subject: **Tab 13: PUB Directives**
Reference: **Cost Savings Attributable to Head Office**

d) **Please indicate the total square footage of leased space and provide a summary of the lease arrangements for that space.**

<u>ANSWER</u>:

There is 20,672 square feet of space currently being leased. The lease arrangements for these tenants are confidential as agreed to in the lease agreements.

PUB/MH I-179

Subject: **Tab 13: PUB Directives**
Reference: **Cost Savings Attributable to Head Office**

e) Please provide a quantification of the estimated 10% to 15% productivity savings

ANSWER:

Manitoba Hydro cannot provide a specific quantification of the productivity savings attributed specifically to the new head office as these productivity savings will take time to materialize and the head office component will be intermixed with other factors also contributing to productivity gains. Manitoba Hydro has committed to maximizing the opportunities and savings associated with the new head office but maintains that it is most appropriate to review the costs and savings of the utility from an overall perspective to ensure that costs are fair and reasonable.

Manitoba Hydro understands that companies have experienced savings in the order of 10% - 15% when centralizing their facilities. For illustrative purposes, Manitoba Hydro applied a 10% productivity factor to the salary, benefit and support costs of approximately 2,000 employees that will be located at the new head office, equating to $20 million.

PUB/MH I-179

Subject: **Tab 13: PUB Directives**
Reference: **Cost Savings Attributable to Head Office**

f) Please file a reference list of literature cited in MH claiming the expected productivity savings.

ANSWER:

The following literature was referenced by Manitoba Hydro with respect to potential productivity savings:

- *User Effective Buildings* - book by Aardex Corporation
- *Building Green on Brown Fields* - article from Darwin Magazine
- *The Costs and Financial Benefits of Green Buildings* - A report to California's Sustainable Building Task Force

This information is copyrighted, however, permission is being sought to publish excerpts from these references.

In summary, the literature references above indicate improvements in organizational and individual productivity, reductions in absenteeism, and an increase in worker health, comfort and satisfaction. These improvements are attributed to the various features of high quality green buildings, such as: improved indoor air quality, lighting design, and ergonomic workstations. Productivity savings in the order of 10 - 20% were referenced.

<u>PUB/MH I-179</u>

Subject: **Tab 13: PUB Directives**

Reference: **Cost Savings Attributable to Head Office**

g) **Please provide a schedule detailing the savings from facility lease costs, property and business taxes, common area maintenance and the avoidance of cost escalation as a result of terminating existing leases by facility which is no longer occupied by MH.**

<u>ANSWER</u>:

Please see part a) of this response.

PUB/MH I-179

Subject: Tab 13: PUB Directives
Reference: Cost Savings Attributable to Head Office

h) Please indicate the current occupancy levels of the new head office and 820 Taylor and the relative capacity of each facility.

ANSWER:

Please see the following table as of March 1, 2010.

360 Portage	occupancy	1,698
360 Portage	fitted capacity	2,274
820 Taylor	occupancy	571
820 Taylor following renovation*	fitted capacity	852

In addition to current occupancy, the buildings are required to meet seasonal, temporary and future growth needs, and must be designed to have proper adjacencies for working groups.

* 80% of the renovation has been completed to date. The entire renovation is expected to be completed by the summer of 2010.

PUB/MH I-180

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (24) Rebalancing of Demand and Energy Charges**

a) **Will MH be also dealing with as yet, unresolved issues related to a possible need for higher customer charges?**

ANSWER:

Manitoba Hydro does not propose to increase customer charges for demand-billed customers. The only exception is the need to increase the Basic Charge for the General Service Small customer class in order to consolidate it with the Basic Charge of the Medium customer class.

Although the unit customer costs presented in PCOSS10 (filed as Appendix 11.1 of the Application) indicate under-recovery of Customer costs, these costs do not significantly impact the results presented in Tab 13.5 pertaining to Demand / Energy rebalancing.

PUB/MH I-180

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (24) Rebalancing of Demand and Energy Charges**

b) Please update the July 31, 2009 filing to reflect Winter Ratchet removal.

ANSWER:

Although the winter ratchet was removed as of December 1, 2009, the actual demand and energy rates charged to customers did not change, thereby not affecting the rates shown in the report. The total cost allocated to each class will not change, however the allocated cost per kV.A of billable demand will certainly change with the elimination of the winter ratchet. Table 5 in Appendix 13.7 of the Application has been revised, as provided below, to show the impact on Allocated Demand Cost if the winter ratchet kV.A had been eliminated at that time.

General Service Demand and Energy Rates vs. Allocated Cost at April 1, 2009
Revised to reflect elimination of Winter Ratchet kV.A

	Apr 1/09 Rate (Demand)	2008 Allocated Cost	Rev/Cost %	Apr 1/09 Rate (Energy)	2008 Allocated Cost	Rev/Cost %
GSS	8.34	7.40	113%	2.86	2.52	113%
GSM	8.35	8.24	101%	2.86	2.52	113%
GSL <30	7.08	9.04	78%	2.73	2.45	111%
GSL 30-100	6.06	4.99	121%	2.58	2.23	116%
GSL >100	5.40	3.51	154%	2.52	2.22	114%

PUB/MH I-180

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (24) Rebalancing of Demand and Energy Charges**

c) Please update July 31, 2009 filing to explain possible rate impacts as a result of the elimination of the Winter Ratchet.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-180(b).

<u>PUB/MH I-180</u>

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (24) Rebalancing of Demand and Energy Charges**

d) What are the subclass revenue implications associated with the proposed rate adjustments to 2013?

<u>ANSWER</u>:

The Proof of Revenues filed as Appendices 10.1 and 10.2 of the Application detail the revenue implications for each subclass associated with the proposed rate increases for 2010/11 and 2011/12 only. In the absence of any further rate changes in 2013 the revenue implications would be similar to these years and change only due to forecasted consumption levels.

PUB/MH I-180

Subject: Tab 13: PUB Directives
Reference: Tab 13.5 (24) Rebalancing of Demand and Energy Charges

e) Is it MH's intention to initiate a differential rate increase within this GRA for 2010/11 and 2011/12?

ANSWER:

Assuming the question pertains to a differential rate increase between demand and energy charges, the answer is yes, as noted on pages 4 and 5 of Tab 10 of Manitoba Hydro's Application. All of the proposed increase in revenue for demand billed accounts will be derived from the energy portion of the rate.

Manitoba Hydro did not propose differential rate increases between customer classes.

Please also see Manitoba Hydro's response to RCM/TREE/MH I-7(a).

PUB/MH I-181

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.7, MH Report to PUB – July 2009**

a) Please explain what GSL <30 subclass characteristics contribute to the continued under billing of demand.

ANSWER:

The allocated Demand unit costs for the GSL <30 kV class in the PCOSS, and shown in Table 5 of Appendix 13.7, differs from unit cost for the GSM class for the following two principal reasons.

1) Unlike the GSM class, the GSL <30 kV class does not pay a monthly basic charge, so the calculated Demand unit costs in the PCOSS includes all Customer related costs allocated to that class. Customer costs in PCOSS08 represented 69 cents of the $8.96/kVA Demand cost calculated for the GSL <30 kV class; the equivalent cost is not included in the calculated GSM Demand cost.

2) Diversity of billable demand with respect to class coincident demand is less for GSL <30 kV (13.2 units of billing demand for each unit of coincident peak demand) than for GSM (13.9 units of billable demand per unit of coincident peak demand). Unit costs are calculated in the PCOSS by dividing total Demand costs (which are allocated among classes largely on the basis of class coincident demand) by billable demand. GSM has more units of billable demand per unit of class coincident demand, and therefore has a lower cost per unit of billable demand. At least some of this additional diversity is due to the fact that GSM customers have typically been more affected by the winter ratchet. With the elimination of the winter ratchet provision effective December 1, 2009, at least some of this diversity difference will be eliminated and the cost per unit of billable demand will increase for the GSM class relative to the GSL<30.

Were the GSL<30 group to have the same ratio of billable demand to class coincident peak demand as the GSM class in the 2008 PCOSS, its billable demand would increase by 5.3% and its unit cost would decrease by 44 cents per kV.A. In summary, if GSL<30 kV diversity characteristics and costs included in the unit demand cost determination were the same as the

GSM class, its unit costs would be reduced to $7.83 per kV.A, which is very similar to that of the GSM class. See calculation below:

	Diversity factor	Demand -related costs
GSM	13.9	$7.97 per billable kV.A
GSL < 30 kV	13.2	$8.96 per billable kV.A
Eliminate Customer related costs		($0.69)
Adjust for diversity (exclude Cust costs) [(13.2-13.9)/13.2] * 8.27		($0.44)
GSL <30 kV for comparability to GSM		$7.83 per billable kV.A

There are also two principal factors affecting a comparison of unit costs of the GSL < 30 kV class with GSL 30-100.

1) The most significant factor is that the GSL <30 kV class, like GSM, is assigned costs for its usage of Distribution stations, poles and wires. The GSL 30-100kV class, and other classes who receive service at the Transmission or Subtransmission level, do not share in any of these Distribution costs. Including the portion of these costs classified as Demand adds another $3.76 to the Demand unit costs calculated for GSL <30 kV in PCOSS08; the equivalent costs are not included in the calculated GSL 30-100kV Demand cost.

2) A less important factor affecting the comparison of these two groups is that GSL 30 – 100 kV also has greater relative diversity of billing demand than GSL <30 kV (13.6 versus 13.2). Correcting for this factor would reduce the unit cost for GSL < 30 kV from $8.96 to $8.69. The difference between this diversity-adjusted unit cost, and the unit cost for GSL 30-100 kV of $4.99 is $3.70, an amount which is entirely accounted for by the Demand related Distribution costs, discussed in the previous paragraph.

The gap between the rates per kV.A for the two GSL classes is only $ 1.02 which is significantly less than the gap between the allocated unit costs. The difference between the rate gap and the embedded allocated unit cost gap results from the need to consider more than just embedded cost in designing demand rates for customers served at different voltages.

While it would be desirable to increase revenue from the GSL <30 kV class based on its allocated Revenue Requirement, a demand charge difference of $3.76 per kV.A would not be appropriate. This is because, while the overall distribution system below 30 kV shows an embedded cost differential of $3.76 per kV.A, the marginal cost of connecting a customer at below 30 kV compared to connecting at above 30 kV is considerably less, and probably closer to the current $1.02 gap between the demand charges for the two voltages. Incorporating the full embedded cost gap into the rate structure could encourage customers to seek connections at a higher voltage than is required to serve their load.

Practice in this regard at other Canadian utilities varies. SaskPower for example has a rate differential of $2.79 per kV.A between customers served at 25 kV and those served at 72 kV. However, Hydro-Quebec maintains a differential of only $0.34 per kW between customers served between 15 and 50 kV and those served at between 5 and 15 kV.

Further, Manitoba Hydro is of the view that significant changes to the demand rate for GSL < 30 kV based on these results should not be considered as the PCOSS has been prepared using a variety of methodologies over the past ten years, all of which produce differing results (as evidenced by comparing Tables 4 and 5, Appendix 13.7). Going forward, the elimination of the winter ratchet will also cause changes to RCC's, the results of which have yet to be determined. Finally, as indicated elsewhere, Manitoba Hydro is in the process of seeking a complete independent evaluation of appropriate cost allocation methodology.

PUB/MH I-181

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.7, MH Report to PUB – July 2009**

b) **Has MH given consideration to the impact of shortfalls with respect to basic customer charges on the demand-energy balancing? Explain.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-180(a).

PUB/MH I-181

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.7, MH Report to PUB – July 2009**

c) Has MH given consideration to reducing or increasing the current demand charge of individual subclasses [e.g., GSL >100 and GSL < 30] given their persistent over recovery or under recovery of demand charges?

ANSWER:

Manitoba Hydro notes that the Revenue Cost Coverage for Demand and Energy components of the various subclasses are premised on the existing Cost of Service methodology which Manitoba Hydro is proposing to have extensively and independently reviewed. Should the ratios be confirmed subsequent to this review, Manitoba Hydro would consider whether changes to Demand Charges or some other mechanism, would be appropriate to address the Demand and Energy component ratios.

PUB/MH I-181

Subject: Tab 13: PUB Directives
Reference: Appendix 13.7, MH Report to PUB – July 2009

d) Please provide a listing of current and projected subclass demand charges expressed as average ¢ per kW.h.

ANSWER:

The table below provides demand revenue expressed as a price per kW.h based on the projected demand revenue divided by the forecasted kW.h's for each major demand subclass.

Subclass	Total Fcst kW.h 2010/11	Total Fcst kW.h 2011/12
Small Demand	1,916,696,065	1,947,611,375
Medium	3,074,694,283	3,123,931,051
Large <30	1,574,302,879	1,590,819,485
Large 30-100	853,454,110	867,984,670
Large >100	5,354,440,000	5,635,200,000

Subclass	Demand Revenue at Proposed Rates	
	April 2010 Rates	April 2011 Rates
	2010/11	2011/12
Small Demand	$ 18,359,951	$ 18,656,085
Medium	$ 52,041,884	$ 50,784,729
Large <30	$ 26,215,541	$ 26,201,895
Large 30-100	$ 10,293,734	$ 10,433,860
Large >100	$ 48,806,842	$ 51,315,448

Subclass	Demand Price per kW.h 2010/11	Demand Price per kW.h 2011/12
Small Demand	$ 0.00958	$ 0.00958
Medium	$ 0.01693	$ 0.01626
Large <30	$ 0.01665	$ 0.01647
Large 30-100	$ 0.01206	$ 0.01202
Large >100	$ 0.00912	$ 0.00911

PUB/MH I-182

Subject: Tab 13: PUB Directives
Reference: Small and Medium Class Consolidation Report page 1 of 3

a) Did MH consider reducing the energy rate differential between first, second, and third blocks as a conservation measure? Explain.

ANSWER:

Achieving the targeted revenue requirement for the Small Non-Demand, Small Demand and Medium Demand customer classes, while staying within bill impact limitations, requires a delicate balancing act when setting blocked energy rates for these customers. The three groups represent very diverse load characteristics, as indicated by the percentage of kW.h consumed in each block shown in the table below.

	Small Non-Demand	Small Demand	Medium Demand
First 11,000 kW.h	74.1%	6.0%	0.1%
Next 8,500 kW.h	18.7%	15.5%	0.4%
Balance of kW.h	7.2%	78.5%	99.5%

As this table indicates, increasing or decreasing the first block energy rate will have a significant impact on the revenue received from Small Non-Demand customers, but will have minimal impact on Small Demand and Medium Demand customers. Conversely, increasing the tail block rate would have little impact on Small Non-Demand customers but will greatly impact the Small Demand and Medium Demand customers.

Two other important considerations when determining the blocked energy rates for these customers is the role the Basic Charge and Demand Charge play on each subclass. The majority of customers are Small Non-Demand, hence increasing the Basic Charge, even minimally, will generate more revenue from this group of customers than the other two groups. With respect to Demand Charges, Small Non-Demand customers do not pay a Demand Charge; therefore the first block energy rate is higher to compensate for this. Medium customers, on the other hand, generate roughly 34% of their total revenue from demand charges, much higher than the 16% demand revenue received from Small Demand customers. The tail block energy rate is therefore lower to account for this.

As a price signal, the first block is more important to the Small Non-Demand class, while the last block is more important to the Small Demand and Medium classes. Manitoba Hydro already places significant emphasis on these blocks, within the constraints outlined above.

PUB/MH I-182

Subject: **Tab 13: PUB Directives**
Reference: **Small and Medium Class Consolidation Report page 1 of 3**

b) Please provide an alternative revenue neutral scenario that employs:

- **only two rate blocks.**
- **Limit the differential between first and third blocks to 2 ¢ /kW.h**

ANSWER:

Assuming the proposed Basic Charges and Demand Charges remain the same as filed in the Application, the following three scenarios (which each assume a different block amount) show the impact on each customer class of having only two rate blocks with a 2¢ differential, while still achieving the overall increase of 2.9% above current rates.

Scenario 1:

			Overall % Change
First 6,000	6.1 ¢ per kW.h	Small Non-Demand	-11.2%
Balance @	4.1 ¢ per kW.h	Small Demand	- 3.0%
		Medium	+17.8%
		Overall	+ 2.9%

Scenario 2:

			Overall % Change
First 11,000	5.9 ¢ per kW.h	Small Non-Demand	-10.0%
Balance @	3.9 ¢ per kW.h	Small Demand	- 0.7%
		Medium	+15.2%
		Overall	+ 2.9%

Scenario 3:

			Overall % Change
First 20,000	5.53 ¢ per kW.h	Small Non-Demand	- 8.4%
Balance @	3.53 ¢ per kW.h	Small Demand	+ 2.0%
		Medium	+12.3%
		Overall	+ 2.9%

<u>PUB/MH I-182</u>

Subject: **Tab 13: PUB Directives**
Reference: **Small and Medium Class Consolidation Report page 1 of 3**

c) **Please confirm that the July 2009 report actually reflects billing status consistent with the current PCOSS-March 31, 2010.**

<u>ANSWER</u>:

The July 2009 Small and Medium Class Consolidation report was based on the May 2008 System Load Forecast projections and proposed rate increases for 2010/11 to 2013/14 as noted on Page 2 of 3 of the report.

PCOSS10 is based is also based on the May 2008 System Load Forecast but only at approved April 1, 2009 rates.

PUB/MH I-183

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (27) SEP**

a) Please provide an extended analysis of the overnight summer sales issue for the 2000/01 to 2007/08 period.

ANSWER:

Overnight off peak SEP prices are set

a) Under low river flow conditions by MH's energy costs, firstly from purchases in off peak hours, and as the drought intensifies and more purchased energy is required, in the on peak hours. Fiscal year 2003/04 was a good example of these conditions.

b) Under normal river flows in the summer by MH's off peak export market sale prices. The summers of 2002 and 2004 were good examples of these conditions.

c) Under normal river flows in the winter by MH's off peak import purchase costs. In the winter outflows from Lake Winnipeg are restricted by ice conditions which limit the flows on the Nelson River at the outlet of Lake Winnipeg. As a result off peak purchases are the most economic source of incremental energy supply and will set the price of SEP energy. The winter of 2008/09 was a good example of this situation.

d) Under high summer river flow conditions by MH's off peak export market as long as there is room on the export transmission lines. Most of the summers of 2007 and 2008 were good examples of this situation. High river flows were the result of above average inflows to reservoirs and reservoirs filling to capacity precluding storage of additional water.

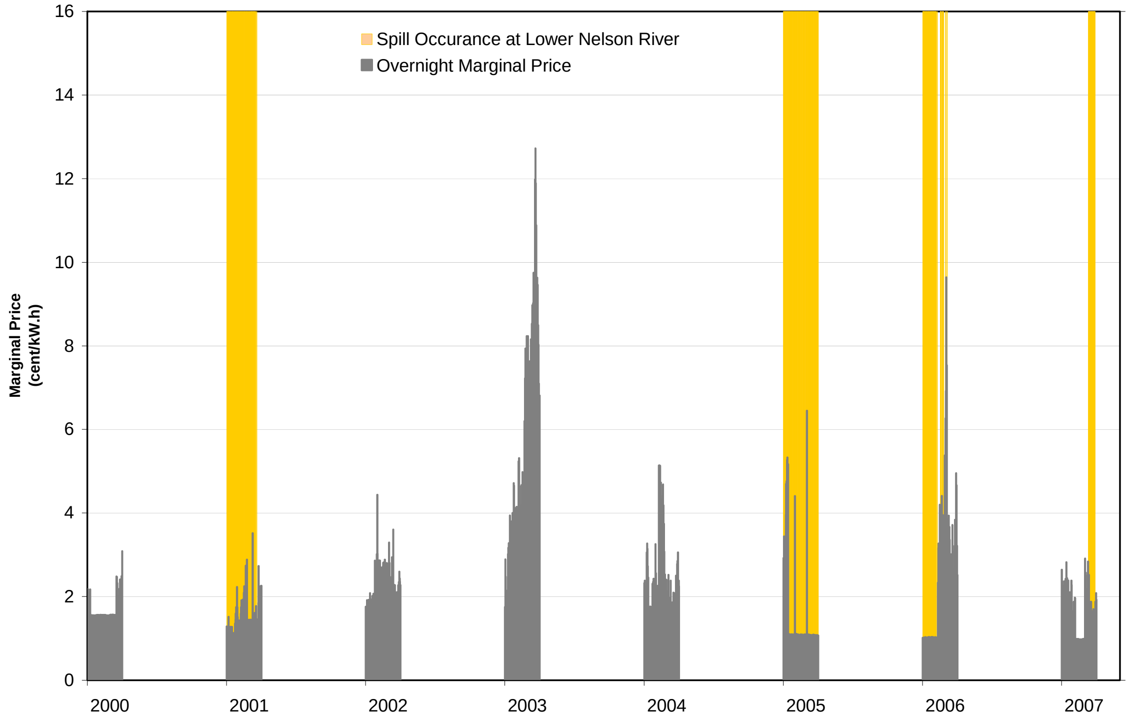
e) Under high summer river flow conditions when the transmission export lines are fully loaded and there is more water available than needed for hydraulic generation, spillage would be required. The summers of 2005 and 2006 are good examples of these conditions. In these circumstances, additional load in Manitoba from SEP customers would be served by MH from incremental hydraulic generation at MH's marginal cost of generation. The summers of 2005, 2006 were good examples of

f) Under high winter river flow conditions by MH's off peak export market or off peak import market depending on the severity of weather at the time. During warm weeks when Manitoba load demand is reduced MH will have surplus off peak energy for sale and the price of this energy will set the off peak SEP price. During cold weeks when Manitoba load demand is high, MH will cease off peak energy exports and may have to buy to serve incremental load demand. In these circumstances purchased energy will set the off peak SEP price. The winters of 2005/06 and 2008/09 were good examples of these conditions.

High water conditions are characterized by spillage at the Lower Nelson generating stations. Figure A illustrates the coincidence of Lower Nelson River spill conditions and Surplus Energy Program (SEP) prices for summer overnight periods.

Under all conditions Manitoba Hydro sets the prices offered to SEP customers to fully recover all its incremental costs including water rentals, incremental O&M and purchased energy costs. In the circumstances when SEP load displaces exports sales, Manitoba Hydro sets the SEP price so that it is no better off or worse off selling to the SEP customer than selling on the export market.

Figure A: Summer (Jun 01 - Aug 31) Overnight Marginal Prices and Lower Nelson River Spill (2000/01 through 2007/08)



PUB/MH I-183

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 (27) SEP**

b) Please provide an overview of this issue for the 1977 to 2008 flows under 2006/07 load and export conditions

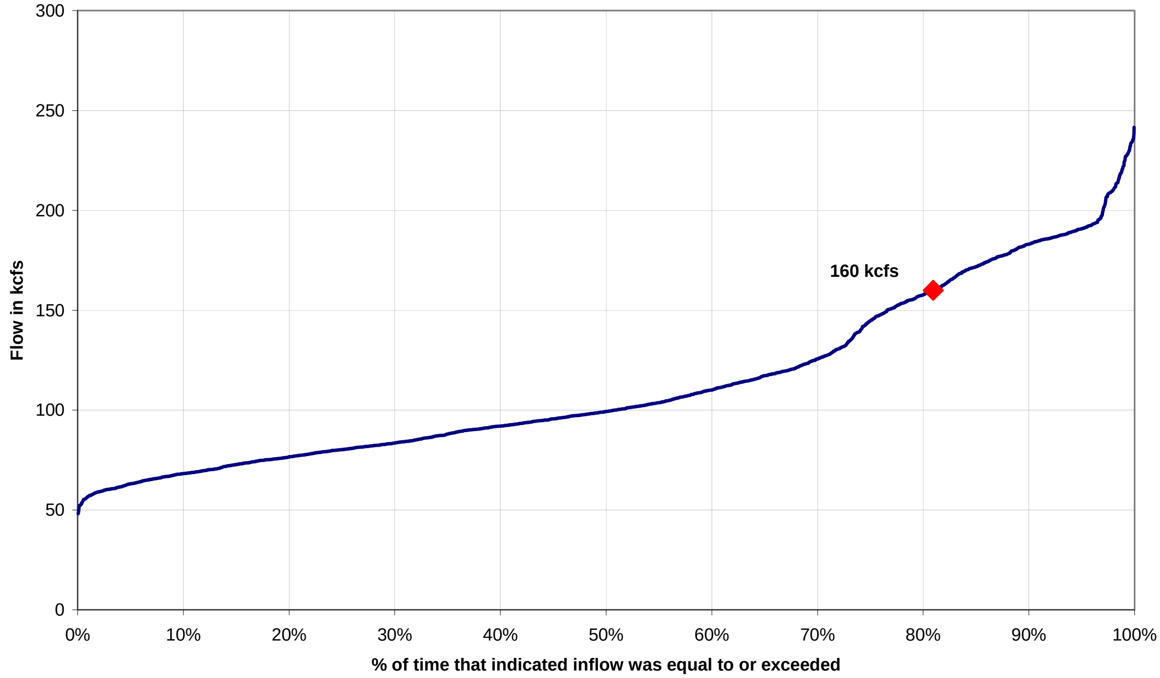
ANSWER:

The answer to PUB/MH I-183(a) illustrated the coincident relationship between Lower Nelson River (LNR) spill and low summer off-peak Surplus Energy Program (SEP) rates. This relationship can be used to approximate the frequency that low off-peak SEP prices would occur for the 1977 to 2008 flow record under 2006/07 load and export conditions.

A review of SEP rates and Lower Nelson River flows from summer 2006 showed that overnight SEP rates collapsed to the hydraulic variable cost when flows exceeded roughly 160 thousand cubic feet per second (kcfs).

For the June 01 to August 31 period in years 1977 to 2008, inflows to the LNR exceeded this threshold approximately 20% of the time, as illustrated in Figure B. One can therefore estimate that off-peak prices for the SEP customers would be at a level of the hydro variable cost approximately 20% of the time.

Figure B: Summer (Jun 01 - Aug 31)
Lower Nelson River Flow Duration Curve (1977 to 2008)



PUB/MH I-184

Subject: Tab 13: PUB Directives
Reference: Appendix 13.9, MH report eliminating use of diesel fuel, Pages 3 and 4

a) **Please provide the detailed experience of the various community electrical energy consumptions for five years prior to the North Central project and the entire subsequent period of grid supply.**

ANSWER:

Shown below is the energy consumption of each of the North Central project communities. Usage following connection is shown in yellow.

	Total GW.h	A GW.h	B GW.h	C GW.h	D GW.h	E GW.h	F GW.h	G GW.h
1992/93	19.0	3.6	3.1	0.9	1.2	3.7	4.8	1.9
1993/94	20.5	3.6	3.2	1.0	1.3	4.0	5.3	2.1
1994/95	21.5	3.7	3.4	1.0	1.4	4.2	5.7	2.2
1995/96	23.4	3.6	3.9	1.1	1.8	4.6	5.9	2.4
1996/97	25.0	4.2	4.2	1.4	1.9	4.7	6.1	2.4
1997/98	29.6	6.1	5.3	2.0	1.9	5.0	6.6	2.8
1998/99	36.3	6.6	9.1	3.4	1.9	5.1	7.1	3.0
1999/00	47.1	9.4	10.4	4.3	3.0	7.6	9.2	3.4
2000/01	58.4	10.7	11.5	5.2	3.8	9.5	13.5	4.3
2001/02	69.1	14.0	12.1	5.3	4.4	10.6	16.7	5.9
2002/03	77.4	12.0	14.3	6.1	4.9	12.6	20.1	7.6
2003/04	78.9	14.5	13.6	5.6	5.5	13.0	19.5	7.3
2004/05	91.3	17.2	15.4	6.6	6.6	16.1	21.2	8.3
2005/06	88.2	16.5	14.8	6.2	6.4	15.2	20.8	8.3
2006/07est	92.7	18.4	15.2	6.4	6.6	17.0	20.4	8.7
2007/08	97.3	20.4	15.6	6.7	6.8	18.7	20.0	9.0
2008/09	100.8	21.1	15.1	6.7	6.9	19.7	21.8	9.5

A = Oxford House
B = God's Lake Narrows
C = God's River
D = Red Sucker Lake
E = St. Theresa Point
F = Garden Hill
G = Wasagamack

PUB/MH I-184

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, MH report eliminating use of diesel fuel, Pages 3 and 4**

b) Please provide an annual comparison of total fossil fuels used by these communities and GHG emissions for the years prior and post-North Central project.

ANSWER:

An estimate of annual fuel used for generating electricity and associated GHG emissions, in aggregate, of the North Central communities is as follows:

		Total Diesel Used (litres)		GHG emissions (tonnes)	
	Total Diesel GW.h	Low efficiency	High efficiency	Low efficiency	High efficiency
1992/93	19	5,956,113	5,191,257	13,659	11,905
1993/94	20.5	6,426,332	5,601,093	14,737	12,844
1994/95	21.5	6,739,812	5,874,317	15,456	13,471
1995/96	23.4	7,335,423	6,393,443	16,822	14,661
1996/97	25	7,836,991	6,830,601	17,972	15,664
1997/98	16.3	5,109,718	4,453,552	11,718	10,213
1998/99	17.1	5,360,502	4,672,131	12,293	10,714

Manitoba Hydro does not have or can not locate records regarding the fuel used to generate electricity by diesel generation in the communities that were connected to the provincial electrical grid by the North Central Project. Manitoba Hydro also does not have any records related to the use of fossil fuels in these communities for purposes other than generating electricity.

As answered in part a) of this question, Manitoba Hydro does have some estimates of electricity generated in these communities by diesel generators prior to their connection to the grid.

In order to provide the estimates of the annual fuel usage and associated emissions, the following assumptions were used in the calculations:

A fuel efficiency range of 3.19 to 3.66 kWh per litre of fuel. Fuel efficiency data is not available, so the range of the Canadian Off-Grid Utility Association members' corporate averages for fuel efficiency is used to represent the potential range of efficiencies for these communities.

2.73 tonnes of CO_2 per tonne of diesel fuel burned. This is consistent with the Generation Resource Screening Studies in Appendix 13.9.

PUB/MH I-185

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, MH report on eliminating use of diesel fuel, Pages 1, 2, and 3**

a) Please provide insight to the risks and costs associated with nonperforming winter roads on diesel fuel supply and heating oil supply.

ANSWER:

Manitoba Hydro stores approximately two years supply of fuel at each of the four diesel generating sites to minimize the risks associated with nonperforming winter roads.

If Manitoba Hydro was unable to haul a fuel supply over two consecutive winter road seasons fuel would be transported by air. Only the minimum amount of fuel would be flown in until such time as the winter roads were open to facilitate restocking of the storage tanks.

For 2009/2010 the difference in fuel hauling cost between ground and air for Tadoule Lake would have been approximately 54¢ per liter.

PUB/MH I-185

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, MH report on eliminating use of diesel fuel, Pages 1, 2, and 3**

b) Please provide insight to the outage risks associated with long remote transmission lines from ice storms, forest fires, etc.

ANSWER:

The majority of faults on power systems occur on the transmission lines. Because this system covers a large area and is generally exposed to the effects of the weather, faults occur at frequent intervals. The worst times are during the summer storm season where a single lightning storm may cause a number of relay and breaker operations on lines over the whole system. Sleet storms with icing and high winds can also cause considerable trouble.

Most faults that occur on transmission lines are of a transient nature. That is, they occur as an arcing fault between a conductor and ground or between conductors. Once the line is cleared from the system the arc extinguishes and the line may be re-energized almost immediately. Some lines are equipped with automatic re-closers to minimize outage time and restore service as quickly as possible.

Following the current Corporate Risk assessment method, the outage risks associated with long remote northern transmission lines (100 kV and above) are as follows:

Event Type	Ice Storms	Forest Fires	Thunderstorms
Event probability	Very Rare	1 in 10 years	4-5 a year
Event impact	Medium - short term in duration, but creates inconvenience	High - short term to several months depending on time of year	Low- momentary in duration

The outage risks associated with long remote northern transmission lines (66 kV and below) are as follows:

Event Type	Ice Storms	Forest Fires	Thunderstorms
Event probability	1 in 10 years	1 in 10 years	8-10 a year
Event impact	High - short term to several months depending on time of year	High - short term to several months depending on time of year	Low- momentary in duration

PUB/MH I-186

Subject: **Tab 13: PUB Directives**

Reference: **Appendix 13-9 Page 4, Diesel Communities- Wind Generation "These installations do not come without problems; however experience to date has been that any issues encountered have been manageable."**

a) Please elaborate on the problems that have been encountered in the wind – diesel installations and how the problems have been addressed.

ANSWER:

Based on publicly available information from the Arctic Pembina Institute and the National Renewable Energy Laboratory, the following is a brief summary of problems that have been encountered or can be expected in wind-diesel installations and how the problems have been or can be addressed.

There have been issues which are common to new wind installations regardless of where they are located, such as component failure, and low capacity factors during commissioning and early service years while operators learn how to optimize the system. Improved component monitoring and increased operator experience help reduce these problems.

Construction issues related to the remote locations of these installations have included foundation concerns, high construction costs, and road access for transporting the required equipment. Improved foundations for installation in permafrost regions have increased stability but have high associated costs. Construction costs and road access issues for transporting equipment can be reduced with tower designs that do not require cranes, with packaged designs that enable assembly prior to arrival on-site, and with thorough project planning which builds on past experiences.

Operating challenges include limited service capabilities, harsh climates and expensive travel costs, all contributing to higher maintenance expenses and increased system or component downtime. To address concerns stemming from the harsh climates within which these installations are expected to operate, turbine manufacturers have been developing suitable arctic climate packages. Advances in remote monitoring, adaptive system control and condition monitoring, and local wind technician training can assist to reduce costs.

Where there are heating loads served by extracting heat from the diesel generators, that load must still be served if the diesel generators are used less due to the offset from wind power generation. Available alternate heating solutions can vary depending on location, economics and environmental concerns.

Excess energy generation at times when wind generation exceeds load demand can be addressed by curtailing wind turbine generation during such periods. As an alternative it may be possible to dispatch this energy for new loads such as space or water heating, air conditioning, water purification/desalination systems, pumping water, or making ice.

PUB/MH I-186

Subject: **Tab 13: PUB Directives**

Reference: **Appendix 13-9 Page 4, Diesel Communities- Wind Generation**
"These installations do not come without problems; however experience to date has been that any issues encountered have been manageable."

b) **Please indicate where remote wind – diesel generation facilities are currently installed and the size of the wind generation capacity at those facilities**

ANSWER:

Based on information obtained from the Arctic Pembina Institute and the National Renewable Energy Laboratory, Manitoba Hydro has compiled the list below of existing wind-diesel generation facilities in Canada and the United States:

Location	**Wind Turbine Capacity (kW)**
Ramea Island, Newfoundland	625
Rankin Inlet, Nunavut	50
Savoonga, Alaska	200
Gambell, Alaska	300
Toksook Bay, Alaska	400
Hooper Bay, Alaska	300
Kasigluk, Alaska	300
Quinhagek, Alaska	300
Kotzebue, Alaska	1025
St. Paul Island, Alaska	225
Chevak, Alaska	400
Mekoryuk, Alaska	200

<u>PUB/MH I-186</u>

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13-9 Page 4, Diesel Communities- Wind Generation**
"These installations do not come without problems; however experience to date has been that any issues encountered have been manageable."

c) **Have any studies been undertaken to determine the suitability of wind generation in any of the four diesel communities? If so, please file a summary of the results from the studies.**

<u>ANSWER</u>:

Manitoba Hydro contracted a consultant to perform an evaluation of technical issues with integrating wind turbines at the diesel generating stations located in Brochet, Lac Brochet, Shamattawa, and Tadoule Lake. The evaluation included low, medium and high-penetration systems.

The final report recommends that, if Manitoba Hydro proceeds with developing wind generation in the four diesel communities, low-penetration options offer the lowest risk with respect to potential operating challenges, cost, and required modifications to the existing generating stations. Low-penetration systems would allow Manitoba Hydro and the communities to gain operating experience, and protect the option to expand to a medium-penetration system depending on the low-penetration system performance.

<u>PUB/MH I-187</u>

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9 Page 7**

a) **Please elaborate on the environmental and technical issues encountered which precluded a study of small Hydro generation for the Shamattawa and Tadoule Lake communities.**

<u>ANSWER</u>:

The small hydro development option was screened out of this study due to a number of issues including: the need to identify an appropriate site for small hydro applications, limited local hydrometric data, the need for a feasible station design and associated cost estimates, limited water storage, unknown environmental impacts, reliability, minimal long-term employment opportunities, and the Heritage River designation of the Seal River and the Hayes River.

Further discussion of the environmental and technical issues which screened out small hydro generation from study for Shamattawa and Tadoule Lake is provided in "Appendix A - Technical & Environmental Screening of Potential Supply Options" of the Generation Resource Screening Study for each community, included in Appendix 2 of Appendix 13.9 of the general rate application.

PUB/MH I-187

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9 Page 7**

b) **Please explain how it was determined that the capital costs estimate for a small generation facility which provides 200A service would be 6 to 8% higher than the cost construct a facility which provided a 60A service.**

ANSWER:

The 6 to 8% difference in capital cost between 60A and 200A small hydro options results from the following differences in the requirement for ongoing diesel support and the requirement for a different transformer station:

- Both small hydro options require maintaining diesel generation for peaking requirements and back-up generation during low water years or when hydro units may be unavailable. However, the 200A option requires maintenance of both communities' existing diesel sites, with an increase in capacity required during the study period, while the 60A option requires maintaining only one existing diesel site with no required capacity additions during the study period.
- The 200A option requires incremental upgrades to the transformer station compared to the 60A option.

The following factors are common between the options and do not result in a difference in capital:

- The 60A and 200A service small hydro options assume the same small hydro facility design, making the small hydro facility capital costs equal. The small hydro facility capital cost contributes to the majority of capital costs for each option.
- Both options require identical transmission lines to connect the small hydro facility to the communities.

PUB/MH I-188

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, Page 42 to 191**

a) **Please provide the 2006 fuel price forecast and the most recent update to that forecast.**

ANSWER:

The table below provides the 2006 diesel fuel price forecast and the most recent update to the diesel fuel price forecast. These forecasted rates are an average of the all-in delivered cost to each of the communities of Tadoule, Lac Brochet, Brochet and Shamattawa.

	Diesel Fuel Price Forecast, cents/litre	
	2006 Forecast (2006 Constant $)	**2009 Forecast (2008 Constant $)**
2006/07	105.3	na
2007/08	101.5	na
2008/09	97.3	na
2009/10	93.3	70.2
2010/11	91.8	73.6
2011/12	91.3	75.6
2012/13	91.3	77.0
2013/14	91.3	77.9
2014/15	91.5	78.2
2015/16	91.5	78.5
2016/17	91.5	78.5
2017/18	91.5	78.5
2018/19	91.8	78.5
2019/20	91.8	78.5
2020/21	91.8	78.5
2021/22	92.0	78.5
2022/23	92.3	78.5
2023/24	92.3	78.5
2024/25	92.3	78.5
2025/26	92.3	78.5
2026/27	92.3	78.5
2027/28	92.3	78.5
2028/29	92.3	78.5

PUB/MH I-188

Subject: Tab 13: PUB Directives
Reference: Appendix 13.9, Page 42 to 191

b) Please provide the 2000 to date annual fuel price history.

ANSWER:

The following table was provided in the 2006 Diesel Hearing and has been updated to incorporate more recent information.

	Brochet		Lac Brochet		Shamattawa		Tadoule Lake	
Year	Rack[1]	On Site[2]	Rack[1]	On Site[2]	Rack[1]	On Site[2]	Rack[1]	On Site[2]
2009/10								
2008/09	0.525	0.822	0.557	0.95	0.513	0.791	0.568	0.985
2007/08	0.874	1.132	0.886	1.275	0.772	1.107	0.871	1.291
2006/07	0.680	0.941	0.626	1.013	0.693	1.029	0.657	1.053
2005/06	0.569	0.711	0.536	0.820	0.536	0.752	0.536	0.840
2004/05	0.411	0.547	0.352	0.610	0.352	0.551	0.352	0.629
2003/04	0.412	0.545	0.386	0.604	0.412	0.545	0.386	0.619
2002/03	0.288	0.411	0.309	0.504	0.288	0.411	0.309	0.519
2001/02	0.379	0.473	0.409	0.589	0.390	0.486	0.409	0.601

1- equals rack terminal price at either Winnipeg or Thompson
2 - delivered price to site including transportation and other fees

PUB/MH I-189

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, Page 167 of 191**

Please provide up-to-date estimates for converting a home from 60A to 200A, and for installing an electric-forced air furnace. Please do the same for electric baseboard heaters.

ANSWER:

It is estimated that upgrading a home from 60A to 200A would cost between $3000 to $3500. Installing an electric-forced air furnace or an electric baseboard heating system would cost between $2200 and $3200. The prices are for urban areas and exclude taxes, duct work and any associated travel costs. A range of prices are provided as prices vary considerably in the marketplace due to various factors including individual contractor bidding practices and marketing strategies.

PUB/MH I-190

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, Page 8 of 191**

a) **What is the experience with upgrades to 200A service in communities formerly served by diesel power? Please detail the percentage of customers in each class that have a) upgraded to 200A service, and b) installed electric heat.**

ANSWER:

Manitoba Hydro does not have the requested information readily available. To provide some insight into the energy usage within these communities, the following table provides the total annual energy use, the number of customers and the average use for residential and commercial customers located within these communities.

The data suggests most customers have converted to 200 amp service and these customers are using electricity to heat their facilities.

	Residential			General Service		
	GW.h	**customers**	**kW.h/cust**	**GW.h**	**customers**	**kW.h/cust**
1992/93	9.5	1,487	6,369	9.1	364	25,061
1993/94	9.9	1,535	6,455	10.1	392	25,799
1994/95	10.3	1,646	6,252	10.9	430	25,341
1995/96	10.9	1,690	6,427	12.2	462	26,386
1996/97	11.6	1,758	6,583	13.1	502	26,066
1997/98	14.7	1,873	7,837	14.6	462	31,647
1998/99	18.7	1,945	9,620	17.3	474	36,428
1999/00	23.8	2,061	11,561	22.9	444	51,645
2000/01	28.9	2,151	13,456	29.0	455	63,826
2001/02	33.5	2,201	15,198	35.2	456	77,304
2002/03	41.4	2,222	18,613	35.7	440	81,162
2003/04	41.5	2,214	18,729	37.1	451	82,224
2004/05	49.2	2,204	22,329	41.7	447	93,128
2005/06	49.3	2,244	21,957	38.5	453	84,961
2006/07est	53.1	2,222	23,906	39.2	424	92,454
2007/08	57.0	2,200	25,894	39.9	395	101,050
2008/09	61.2	2,293	26,690	39.2	393	99,677

<u>PUB/MH I-190</u>

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, Page 8 of 191**

b) Please also give the number of customers that have upgraded to 200A service, the numbers of customers that have installed electric heat, and the total number of customers in each class.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH I-190(a).

<u>PUB/MH I-191</u>

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, Page 32 of 191**

Please confirm that the 200A options include the cost to upgrade the service up to the point of customer-owned wiring, including any required upgrades to customer's meters.

<u>ANSWER</u>:

The cost estimates used for 200A options include upgrades to the distribution system for the communities, not individual services. Costs that vary depending on individual customer decisions to switch from 60A to 200A, such as the cost of any required upgrades to customer's meters, are not included.

PUB/MH I-192

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, Page 62 of 191**

Please explain why an efficiency of 95% is given for electric baseboard heat.

ANSWER:

An efficiency of 95% for electric baseboard heat was assumed in order to be conservative in comparing annual fuel costs between different heating technologies serving the same residential heating load.

<u>PUB/MH I-193</u>

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, Pages 40, 84, and 122 of 191**

a) **Please confirm whether new diesel generators from established manufacturers exceed the efficiency of the currently installed diesel generators.**

<u>ANSWER</u>:

Current manufacturer generator set efficiencies provide negligible improvements over Manitoba Hydro's current prime power inventory of generator sets. Manitoba Hydro only tracks overall station efficiency and not individual generator set efficiency.

<u>PUB/MH I-193</u>

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, Pages 40, 84, and 122 of 191**

b) **Please list the efficiencies of new diesel generating sets that could directly replace the existing installed generator sets. That is, please list the efficiency of new 425 kW, 600 kW, 855 kW, and 1,015 kW generating sets and compare that with the efficiencies of MH's existing units.**

<u>ANSWER</u>:

Manitoba Hydro tracks total station efficiency rather than individual unit efficiency. Station efficiency is represented by kWh/ L and is calculated by dividing the total annual generation from the station, in kWh, by the total annual volume, in litres, of diesel fuel consumed for generation at the station.

The most current information on each station as of March 2009 is:

Brochet	3.11 kWh/L
Lac Brochet	4.13 kWh/L
Shamattawa	3.59 kWh/L
Tadoule Lake	3.34 kWh/L
Average	3.49 kWh/L

Manitoba Hydro's average fuel efficiency is in line with the Canadian Off-Grid Utility Association members' corporate averages which range from 3.19 kWh/L to 3.66 kWh/L.

Comparison of current Caterpillar prime power generator set specifications:

455 ekW - 3.36 kWh/L @ 75% load - C15 ACERT Engine, EPA Tier 2
591 ekW - 3.34 kWh/L @ 75% load, C27 ACERT Engine, EPA Tier 2
910 ekW - 3.48 kWh/L @ 75% load, C32 ACERT Engine, EPA Tier 2
1000 ekW - 3.57 kWh/L @ 75% load, 3512 TA Engine

Note: Fuel efficiency value calculated using 75% of rated loading divided by manufacturer published fuel consumption in litres/hr.

PUB/MH I-194

Subject: **Tab 13: PUB Directives**
Reference: **Appendix 13.9, Page 12 of 191**

Please explain the steps MH would take to reduce or eliminate the risk of damage to the wind turbines due to cold weather, ice conditions, and vandalism.

ANSWER:

These issues were not included at this level of study, and would need to be addressed if wind turbines were pursued further as a power supply option for off-grid communities.

PUB/MH I-195

Subject: Tab 13: PUB Directives
Reference: Appendix 13.9, Pages 102 to 105 and 141-144 of 191

Please confirm whether MH has implemented hydrometric data collection and/or review on any rivers near Tadoule Lake or Shamattawa with the aim of evaluating potential small hydro.

ANSWER:

Manitoba Hydro has not implemented data collection on any rivers near Tadoule Lake or Shamattawa with the aim of evaluating small hydro.

As further background information, Manitoba Hydro reviewed stream flow data available from the Environment Canada HYDAT database for the nearest hydrometric measurement station to each community, as described in "Appendix A - Technical & Environmental Screening of Potential Supply Options" of the Generation Resource Screening Study for each community, included in Appendix 2 of Appendix 13.9 of the General Rate Application.

PUB/MH I-196

Subject: **Tab 13: PUB Directives**
Reference: **Response to Order 150/08 Directive #25 Elimination of the Winter Ratchet**

a) Please indicate the basic rationale which justifies elimination of the Winter Ratchet for GSM in the class consolidation process.

ANSWER:

To fully consolidate the General Service Small and Medium rate classes requires that they be charged identical rates and the same application of those rates. As indicated in the Small / Medium Class Consolidation report filed with the PUB in July 2009 (included as Appendix 13.8 of this Application), the only differences between the rates of Small and Medium customers was the Monthly Basic Charge, first block Energy Charge and application of the 70% winter ratchet.

With the rates proposed in this Application only the monthly Basic Charge differs between the two classes, which, depending on future rate proposals, could take one or two more rate changes to fully consolidate. The Energy rates proposed are now the same for both classes and the 70% winter ratchet has been eliminated as of December 1, 2009. Prior to its elimination, only a Medium Demand customer was subject to the 70% ratchet provision.

PUB/MH I-196

Subject: **Tab 13: PUB Directives**

Reference: **Response to Order 150/08 Directive #25 Elimination of the Winter Ratchet**

b) What are the anticipated RCC impacts going forward to 2013:

i. With the 70% Winter Ratchet still in place?

ii. Without the Winter Ratchet?

ANSWER:

Manitoba Hydro collected approximately $2.5 million annually from the winter ratchet, of which over 80% was from the GSM class. In the absence of this revenue Manitoba Hydro would have to increase other charges to collect this revenue when designing rates and the revenue requirement of each class. Typically this recovery would be in a higher energy charge. In this Application, as discussed in Tab 10, Manitoba Hydro has replaced the revenue through higher proposed energy charges; as a result there is no impact to the class RCC.

PUB/MH I-196

Subject: **Tab 13: PUB Directives**
Reference: **Response to Order 150/08 Directive #25 Elimination of the Winter Ratchet**

c) Please provide the rationale and justification that would support a PUB approval of the elimination of the 70% winter ratchet.

ANSWER:

Manitoba Hydro eliminated the 70% winter ratchet in response to Order 116/08 wherein it stated at page 355: *"Unless MH provides an acceptable TOU implementation process, the ratchet is to be removed ahead of the winter of 2009/10"*.

PUB/MH I-197

Reference: Tab 14, 13.4 (3) 20 year - Year Financial Outlook Page 3 – Major Capital

Please provide the incremental revenue requirement impacts for the first year beyond in-service for Bipole III , Keeyask G.S. and Conawapa G.S.

ANSWER:

The incremental revenue requirement impacts are estimated below for the first full year of operation of each of the facilities above.

Revenue is estimated based upon Keeyask and Conawapa generation and Bipole III line loss savings at calculated average export prices (per PUB/MH I-45(b)). Finance expense is estimated based upon the incremental revenue net of expenses plus the initial capital outlay of the project at the projected Manitoba Hydro Canadian long term debt rate.

The incremental revenue requirements estimated for one year would not imply that rate increases are required in those years. Over the long term, generation benefits offset initial capitalization costs (see the Alternative Development Sequence in Appendix 15). Bipole III is a non-discretionary facility required for reliability purposes and related benefits in addition to the line loss savings have not been quantified for the purposes of estimating the incremental revenue requirements. Bipole III allows for the export benefits derived from Keeyask and Conawapa.

	Millions of $		
	Bipole III 2019	**Keeyask** 2021	**Conawapa** 2025
Revenue	$ 26	$ 294	$ 543
Expenses			
OM&A, Depreciation, Capital Tax and Water Rentals	68	101	158
Finance expense	158	283	412
Total Expenses	225	383	570
Estimated Incremental Revenue Requirement	$ 199	$ 89	$ 27

PUB/MH I-198

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook, Figure 1

Please provide a table of corresponding data points for the graph.

ANSWER:

Please refer to the attached table.

Projected Capital Expenditures - Major Categories
(in Millions of Dollars)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Base Capital	365	435	440	392	453	382	381	406	375	351
Gas Capital	37	38	41	45	37	36	37	37	38	39
New Major Generation	702	612	555	588	996	1347	1738	1722	1304	1262

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Base Capital	314	387	460	507	541	603	580	598	588	623
Gas Capital	39	39	40	41	42	41	41	42	43	44
New Major Generation	938	1046	888	1020	271	37	32	42	96	74

<u>PUB/MH I-199</u>

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 8, 9, 10, and 11

a) Please re-file the 20-Year IFF that reflects only electric operations and include the financial ratios

<u>ANSWER</u>:

Please refer to the attached schedules.

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
20 YEAR FINANCIAL OUTLOOK
(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 (Before Corp Allocation)	423	419	474	532	533	551	536	552	594	680	885
Finance Expense	417	413	468	525	527	544	529	545	587	674	878
Depreciation and Amortization	368	386	407	435	446	466	476	481	501	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	1,505	1,723	1,824	1,860	1,922	1,963	2,046	2,156	2,370	2,617
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	78	87	72	125	113	248	263	235	244	276
*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%
Financial Ratios											
Debt	74%	75%	76%	76%	78%	79%	80%	80%	80%	80%	80%
Interest Coverage	1.24	1.14	1.14	1.11	1.19	1.15	1.30	1.28	1.23	1.22	1.22
Capital Coverage (excl Major Gen.)	1.37	1.11	1.14	1.31	1.25	1.53	1.89	1.87	1.96	2.21	2.71

PUB-MH-I-199 (a)

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
20 YEAR FINANCIAL OUTLOOK
(In Millions of Dollars)

For the year ended March 31

	2021	2022	2023	2024	2025	2026	2027	2028	2029
REVENUES									
General Consumers									
at approved rates	1,312	1,327	1,342	1,357	1,374	1,393	1,413	1,433	1,450
additional *	550	594	639	687	736	789	844	901	959
Extraprovincial	1,201	1,223	1,379	1,758	1,940	1,908	1,903	1,928	1,950
Other	9	9	10	10	10	10	10	11	11
	3,073	3,153	3,370	3,812	4,060	4,100	4,170	4,273	4,370
EXPENSES									
Operating and Administrative	509	519	536	547	558	569	580	592	603
Finance Expense (Before Corp Allocation)	965	858	897	1,078	1,173	1,133	1,101	1,044	986
Finance Expense	958	851	890	1,071	1,166	1,126	1,094	1,037	980
Depreciation and Amortization	592	598	626	687	731	747	764	767	777
Water Rentals and Assessments	129	130	136	150	154	155	155	156	157
Fuel and Power Purchased	435	460	474	460	492	420	396	425	446
Capital and Other Taxes	117	121	126	128	128	129	129	130	131
Corporate Allocation	9	9	9	9	9	9	9	9	9
	2,750	2,688	2,798	3,051	3,239	3,156	3,127	3,116	3,103
Non-controlling Interest	(25)	(27)	(28)	(29)	(30)	(34)	(38)	(41)	(43)
Net Income	299	439	544	732	791	911	1,005	1,116	1,224
*Additional General Consumers Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	42.22%	45.06%	47.96%	50.92%	53.94%	57.02%	60.16%	63.36%	66.63%
Financial Ratios									
Debt	79%	78%	76%	74%	70%	66%	62%	57%	51%
Interest Coverage	1.24	1.36	1.45	1.59	1.66	1.79	1.90	2.05	2.22
Capital Coverage (excl Major Gen.)	2.32	2.26	2.30	2.59	2.50	2.81	2.95	3.19	3.19

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
20 YEAR FINANCIAL OUTLOOK
(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	15,075	15,566	15,982	16,691	17,127	17,837	20,301	21,599	25,001
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,010)	(8,514)	(9,052)
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	13,085	15,950
Construction in Progress	1,947	2,458	1,341	1,818	2,838	3,854	5,532	6,948	6,159	6,446	4,168
Current and Other Assets	2,767	2,735	2,871	2,926	2,708	2,860	3,047	3,259	3,564	3,348	3,683
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,546	15,353	16,798	18,656	20,545	22,057	22,922	23,843
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,054	8,769	10,349	11,505	13,123	14,412	15,346	16,429	14,147
Current and Other Liabilities	2,156	1,926	2,119	2,916	2,106	2,306	2,333	2,692	3,045	2,586	5,514
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,261	2,331	2,403	2,528	2,641	2,889	3,153	3,388	3,632	3,908
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,546	15,353	16,798	18,656	20,545	22,057	22,922	23,843

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
20 YEAR FINANCIAL OUTLOOK
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
ASSETS									
Plant in Service	26,067	26,505	30,392	33,459	34,732	35,524	36,105	36,821	37,414
Accumulated Depreciation	(9,616)	(10,190)	(10,793)	(11,461)	(12,177)	(12,911)	(13,663)	(14,420)	(15,188)
Net Plant in Service	16,451	16,316	19,599	21,998	22,556	22,613	22,441	22,401	22,226
Construction in Progress	4,523	5,453	3,111	877	270	119	207	205	338
Current and Other Assets	3,886	3,422	3,704	4,315	5,201	5,650	6,794	8,013	9,284
Goodwill	42	42	42	42	42	42	42	42	42
	24,902	25,233	26,456	27,232	28,068	28,424	29,484	30,661	31,890
LIABILITIES AND EQUITY									
Long-Term Debt	17,406	17,838	18,640	18,642	18,044	18,047	18,049	17,991	17,743
Current and Other Liabilities	3,015	2,476	2,354	2,394	3,036	2,477	2,527	2,642	2,891
Contributions in Aid of Construction	272	272	273	274	276	277	280	283	287
Retained Earnings	4,207	4,645	5,190	5,922	6,713	7,623	8,629	9,745	10,969
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0
	24,902	25,233	26,456	27,232	28,068	28,424	29,484	30,661	31,890

PUB-MH-I-199 (a)

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
20 YEAR FINANCIAL OUTLOOK
(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	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)	(423)	(479)	(541)	(550)	(549)	(554)	(566)	(634)	(725)	(915)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	493	516	524	579	596	734	769	746	786	859
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	600	540	1,600	1,400	1,800	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	1,220	1,288	1,528	1,585	1,255	961	835
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(1,113)	(1,079)	(1,004)	(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)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,243)	(1,198)	(1,118)	(1,123)	(1,648)	(1,876)	(2,355)	(2,334)	(1,954)	(1,846)	(1,543)
Net Increase (Decrease) in Cash	(114)	8	17	(86)	151	9	(92)	21	47	(98)	151
Cash at Beginning of Year	66	(48)	(40)	(23)	(109)	41	51	(41)	(21)	26	(72)
Cash at End of Year	(48)	(40)	(23)	(109)	41	51	(41)	(21)	26	(72)	79

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ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
20 YEAR FINANCIAL OUTLOOK
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
OPERATING ACTIVITIES									
Cash Receipts from Customers	3,073	3,153	3,370	3,812	4,060	4,100	4,170	4,273	4,370
Cash Paid to Suppliers and Employees	(1,194)	(1,234)	(1,277)	(1,289)	(1,337)	(1,279)	(1,266)	(1,308)	(1,343)
Interest Paid	(1,000)	(894)	(908)	(1,099)	(1,206)	(1,178)	(1,137)	(1,092)	(1,046)
Interest Received	30	27	4	3	11	15	10	18	27
	909	1,052	1,189	1,426	1,528	1,659	1,777	1,891	2,009
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	1,000	600	800	-	-	-	-	-	-
Sinking Fund Withdrawals	285	741	171	-	-	341	-	-	60
Retirement of Long-Term Debt	(285)	(744)	(171)	-	-	(600)	-	-	(60)
Other	11	(26)	(23)	(24)	(24)	(25)	(27)	(29)	(30)
	1,011	571	777	(24)	(24)	(284)	(27)	(29)	(30)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contribution	(1,443)	(1,359)	(1,536)	(820)	(651)	(622)	(651)	(695)	(706)
Sinking Fund Payment	(292)	(349)	(208)	(183)	(188)	(193)	(179)	(183)	(188)
Other	(33)	(38)	(28)	(32)	(29)	(30)	(33)	(31)	(31)
	(1,768)	(1,746)	(1,772)	(1,035)	(868)	(845)	(862)	(909)	(925)
Net Increase (Decrease) in Cash	152	(124)	194	367	636	529	887	953	1,053
Cash at Beginning of Year	79	231	107	301	669	1,305	1,834	2,721	3,674
Cash at End of Year	231	107	301	669	1,305	1,834	2,721	3,674	4,727

PUB/MH I-199

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 8, 9, 10, and 11

b) For each 20- Year forecast scenario provided please include the financial ratios.

ANSWER:

Please refer to Appendix 15 which contains the financial projections and financial ratios for each of the 20-Year Forecast Scenarios.

PUB/MH I-199

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 8, 9, 10, and 11

c) Please include the projected cash flow statement for electric operations only.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-199(a).

PUB/MH I-199

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 8, 9, 10, and 11

d) Please file the related 20-year consolidated cash flow statement.

ANSWER:

Please refer to the attached schedule.

PUB-MH-I-199 (d)

CONSOLIDATED PROJECTED CASH FLOW STATEMENT
20 YEAR FINANCIAL OUTLOOK
(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	2,171	2,159	2,401	2,495	2,590	2,649	2,836	2,938	3,029	3,261	3,540
Cash Paid to Suppliers and Employees	(1,175)	(1,227)	(1,364)	(1,382)	(1,414)	(1,441)	(1,493)	(1,561)	(1,613)	(1,712)	(1,726)
Interest Paid	(474)	(445)	(504)	(568)	(578)	(577)	(582)	(594)	(662)	(753)	(943)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	551	510	547	561	613	636	777	810	790	834	904
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	900	800	600	600	1,600	1,400	1,800	1,800	1,800	1,400	1,000
Sinking Fund Withdrawals	262	227	27	103	483	-	3	-	-	456	171
Retirement of Long-Term Debt	(448)	(304)	(27)	(183)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(36)	(12)	19	(10)	(13)	(11)	(13)	(14)	(14)	(26)	(15)
	678	712	619	509	1,220	1,289	1,529	1,585	1,255	961	835
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1,151)	(1,117)	(1,046)	(1,035)	(1,495)	(1,774)	(2,163)	(2,173)	(1,723)	(1,658)	(1,299)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(107)	(201)	(159)	(242)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(17)	(31)	(29)	(41)	(28)	(27)	(27)
	(1,281)	(1,236)	(1,160)	(1,168)	(1,687)	(1,912)	(2,393)	(2,372)	(1,993)	(1,885)	(1,582)
Net Increase (Decrease) in Cash	(52)	(15)	6	(98)	146	12	(87)	23	52	(90)	157
Cash at Beginning of Year	(32)	(84)	(99)	(92)	(190)	(44)	(32)	(119)	(96)	(44)	(133)
Cash at End of Year	(84)	(99)	(92)	(190)	(44)	(32)	(119)	(96)	(44)	(133)	24

CONSOLIDATED PROJECTED CASH FLOW STATEMENT
20 YEAR FINANCIAL OUTLOOK
(In Millions of Dollars)

For the year ended March 31	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
OPERATING ACTIVITIES									
Cash Receipts from Customers	3,704	3,789	4,005	4,451	4,705	4,744	4,819	4,920	5,023
Cash Paid to Suppliers and Employees	(1,753)	(1,795)	(1,840)	(1,853)	(1,904)	(1,846)	(1,836)	(1,879)	(1,916)
Interest Paid	(1,029)	(923)	(937)	(1,128)	(1,236)	(1,208)	(1,167)	(1,122)	(1,077)
Interest Received	30	27	4	3	11	15	10	18	27
	952	1,098	1,232	1,472	1,577	1,705	1,825	1,936	2,057
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	1,000	600	800	-	-	-	-	-	-
Sinking Fund Withdrawals	285	741	171	-	-	341	-	-	60
Retirement of Long-Term Debt	(285)	(744)	(171)	-	-	(600)	-	-	(60)
Other	11	(26)	(23)	(24)	(24)	(25)	(27)	(29)	(30)
	1,011	571	777	(24)	(24)	(284)	(27)	(29)	(30)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(1,483)	(1,400)	(1,577)	(863)	(692)	(665)	(694)	(739)	(750)
Sinking Fund Payment	(292)	(349)	(208)	(183)	(188)	(193)	(179)	(183)	(188)
Other	(33)	(38)	(29)	(32)	(29)	(30)	(33)	(31)	(31)
	(1,808)	(1,788)	(1,813)	(1,078)	(909)	(888)	(905)	(953)	(970)
Net Increase (Decrease) in Cash	155	(119)	196	371	644	533	893	955	1,057
Cash at Beginning of Year	24	179	60	255	626	1,270	1,802	2,695	3,650
Cash at End of Year	179	60	255	626	1,270	1,802	2,695	3,650	4,707

PUB/MH I-200

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook , Order 32/0 Directive #3

Please respond to Directive #3 of Order 32/09 by filing a series of alternative 20-year scenarios containing the Electric IFF (including financial ratios) and Power Resource Plan and Capital Plan, to reflect:

a) A pessimistic view of exports prices; assume $5 Gj natural gas pricing and zero US C02 pricing.

ANSWER:

Similar to the response to PUB/MH I-51 (a), the IFF09 Low Price scenario can be used to show the directional impact of lower prices as requested. Please see Appendix 15 for the projections supporting the Low Export Price scenario.

PUB/MH I-200

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook , Order 32/0 Directive #3

Please respond to Directive #3 of Order 32/09 by filing a series of alternative 20-year scenarios containing the Electric IFF (including financial ratios) and Power Resource Plan and Capital Plan, to reflect:

b) A periodic one-year drought (e.g. 2003-04 severity) every five years with the first interval drought commencing in 2011/12.

ANSWER:

The base export revenue forecast assumed in IFF09-1 inherently incorporates the effects of drought. The revenue forecast is developed by averaging the revenues corresponding to all 94 years of historic flow conditions on record in each year of the forecast. This method captures the asymmetric relationship between higher costs of low flows which are greater than the benefits of high flows. This produces a revenue forecast that is lower than would otherwise be calculated if the historic flows were simply averaged to then calculate revenue.

For comparative purposes in this analysis, a median flow scenario has been developed as the base case. Evaluating a periodic low flow scenario against an average of all flow revenues scenario has the effect of "double counting" the low flow revenues. The median flow scenario removes both high and low flows to eliminate the effects of this double counting. The corresponding projected electric operating statement is found in the attached.

The periodic one-year drought analysis substitutes low flow revenues in every fifth year of the median flow forecast. The impacts on the projected electric operating statement to 2028/29 can be seen in the attached.

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
MEDIAN FLOW
(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	572	601	635	616	733	765	785	926	1,104
Other	7	7	8	8	8	8	8	9	9	9	9
	1,581	1,584	1,826	1,914	2,007	2,065	2,252	2,355	2,446	2,660	2,919
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	417	413	466	520	516	527	506	513	545	621	814
Depreciation and Amortization	368	386	407	435	446	466	476	481	501	532	566
Water Rentals and Assessments	120	110	112	115	116	116	116	117	116	116	127
Fuel and Power Purchased	103	132	196	197	205	214	240	278	303	365	311
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	1,505	1,670	1,768	1,796	1,852	1,884	1,952	2,056	2,243	2,448
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	78	157	147	209	208	359	392	378	403	457
*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%
Financial Ratios											
Debt	74%	75%	75%	75%	76%	77%	77%	77%	77%	76%	75%
Interest Coverage	1.24	1.14	1.26	1.23	1.32	1.28	1.44	1.42	1.38	1.38	1.39
Capital Coverage (excl Major Gen.)	1.37	1.11	1.30	1.50	1.44	1.78	2.19	2.17	2.35	2.66	3.27

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
MEDIAN FLOW
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
REVENUES									
General Consumers									
at approved rates	1,312	1,327	1,342	1,357	1,374	1,393	1,413	1,433	1,450
additional *	550	594	639	687	736	789	844	901	959
Extraprovincial	1,215	1,241	1,376	1,776	1,965	1,972	1,968	1,994	2,020
Other	9	9	10	10	10	10	10	11	11
	3,086	3,171	3,367	3,830	4,086	4,164	4,236	4,339	4,440
EXPENSES									
Operating and Administrative	509	519	536	547	558	569	580	592	603
Finance Expense	882	758	778	940	1,020	963	914	840	763
Depreciation and Amortization	592	598	626	687	731	747	764	767	777
Water Rentals and Assessments	132	133	140	154	159	161	160	161	161
Fuel and Power Purchased	302	320	296	265	289	258	231	253	272
Capital and Other Taxes	117	121	126	128	129	129	129	130	131
Corporate Allocation	9	9	9	9	9	9	9	9	9
	2,543	2,457	2,511	2,730	2,895	2,836	2,788	2,752	2,717
Non-controlling Interest	(25)	(27)	(28)	(29)	(30)	(34)	(38)	(41)	(43)
Net Income	518	687	828	1,071	1,161	1,294	1,410	1,546	1,680
*Additional General Consumers Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	42.22%	45.06%	47.96%	50.92%	53.94%	57.02%	60.16%	63.36%	66.63%
Financial Ratios									
Debt	73%	71%	69%	64%	59%	54%	47%	41%	33%
Interest Coverage	1.44	1.62	1.75	1.97	2.10	2.30	2.51	2.79	3.12
Capital Coverage (excl Major Gen.)	2.90	2.79	2.86	3.21	3.11	3.48	3.63	3.92	3.93

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
MEDIAN FLOW
(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	15,075	15,566	15,982	16,691	17,127	17,837	20,301	21,599	25,001
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,010)	(8,514)	(9,052)
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	13,085	15,950
Construction in Progress	1,947	2,458	1,341	1,818	2,838	3,854	5,532	6,948	6,159	6,446	4,168
Current and Other Assets	2,767	2,735	2,871	2,925	2,666	2,807	3,047	3,259	3,538	3,348	3,730
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,546	15,312	16,745	18,656	20,545	22,030	22,922	23,889
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	8,854	8,569	9,949	11,105	12,723	13,812	14,546	15,629	13,147
Current and Other Liabilities	2,156	1,926	2,248	2,971	2,235	2,328	2,297	2,727	3,111	2,521	5,514
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,261	2,402	2,548	2,758	2,966	3,325	3,717	4,095	4,498	4,954
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,546	15,312	16,745	18,656	20,545	22,030	22,922	23,889
Debt Ratio	74%	75%	75%	75%	76%	77%	77%	77%	77%	76%	75%

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
MEDIAN FLOW
(In Millions of Dollars)

For the year ended March 31	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
ASSETS									
Plant in Service	26,067	26,505	30,392	33,459	34,732	35,524	36,105	36,821	37,414
Accumulated Depreciation	(9,616)	(10,190)	(10,793)	(11,461)	(12,177)	(12,911)	(13,663)	(14,420)	(15,188)
Net Plant in Service	16,451	16,316	19,599	21,998	22,556	22,613	22,441	22,401	22,226
Construction in Progress	4,523	5,453	3,111	877	270	119	207	205	338
Current and Other Assets	3,954	3,335	3,698	4,648	5,903	6,736	8,285	9,934	11,661
Goodwill	42	42	42	42	42	42	42	42	42
	24,970	25,146	26,450	27,564	28,770	29,510	30,975	32,582	34,266
LIABILITIES AND EQUITY									
Long-Term Debt	16,206	16,238	16,840	16,842	16,244	16,247	16,249	16,191	15,943
Current and Other Liabilities	3,018	2,476	2,350	2,390	3,032	2,473	2,524	2,638	2,887
Contributions in Aid of Construction	272	272	273	274	276	277	280	283	287
Retained Earnings	5,472	6,159	6,987	8,058	9,219	10,513	11,923	13,469	15,149
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0
	24,970	25,146	26,450	27,564	28,770	29,510	30,975	32,582	34,266
Debt Ratio	73%	71%	69%	64%	59%	54%	47%	41%	33%

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
MEDIAN FLOW
(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	1,581	1,584	1,826	1,914	2,007	2,065	2,252	2,355	2,446	2,660	2,919
Cash Paid to Suppliers and Employees	(646)	(690)	(776)	(794)	(818)	(845)	(891)	(949)	(1,001)	(1,082)	(1,062)
Interest Paid	(453)	(423)	(480)	(535)	(540)	(530)	(527)	(539)	(588)	(672)	(854)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	493	584	601	664	694	848	893	893	945	1,036
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	400	540	1,400	1,400	1,800	1,600	1,600	1,400	800
Sinking Fund Withdrawals	262	227	27	103	482	-	1	-	-	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	419	512	1,019	1,288	1,526	1,385	1,055	961	635
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(1,113)	(1,079)	(1,004)	(989)	(1,457)	(1,737)	(2,125)	(2,135)	(1,685)	(1,619)	(1,259)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(105)	(201)	(159)	(242)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,243)	(1,198)	(1,118)	(1,122)	(1,648)	(1,873)	(2,355)	(2,334)	(1,954)	(1,846)	(1,543)
Net Increase (Decrease) in Cash	(114)	8	(115)	(10)	35	109	19	(55)	(6)	61	129
Cash at Beginning of Year	66	(48)	(40)	(155)	(165)	(130)	(21)	(2)	(57)	(63)	(3)
Cash at End of Year	(48)	(40)	(155)	(165)	(130)	(21)	(2)	(57)	(63)	(3)	126

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
MEDIAN FLOW
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
OPERATING ACTIVITIES									
Cash Receipts from Customers	3,086	3,171	3,367	3,830	4,086	4,164	4,236	4,339	4,440
Cash Paid to Suppliers and Employees	(1,063)	(1,097)	(1,103)	(1,099)	(1,139)	(1,122)	(1,106)	(1,142)	(1,174)
Interest Paid	(922)	(804)	(799)	(968)	(1,059)	(1,014)	(956)	(892)	(826)
Interest Received	30	27	4	3	10	14	9	16	23
	1,131	1,297	1,469	1,766	1,898	2,042	2,182	2,321	2,464
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	800	200	600	-	-	-	-	-	-
Sinking Fund Withdrawals	285	741	171	-	-	304	-	-	60
Retirement of Long-Term Debt	(285)	(744)	(171)	-	-	(600)	-	-	(60)
Other	11	(26)	(23)	(24)	(24)	(25)	(27)	(29)	(30)
	811	171	577	(24)	(24)	(321)	(27)	(29)	(30)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contribution	(1,443)	(1,359)	(1,536)	(820)	(651)	(622)	(651)	(695)	(706)
Sinking Fund Payment	(292)	(349)	(208)	(165)	(169)	(174)	(160)	(164)	(168)
Other	(33)	(38)	(28)	(32)	(29)	(30)	(33)	(31)	(31)
	(1,768)	(1,746)	(1,772)	(1,017)	(849)	(826)	(844)	(890)	(905)
Net Increase (Decrease) in Cash	173	(279)	274	724	1,025	896	1,311	1,403	1,529
Cash at Beginning of Year	126	299	21	295	1,019	2,044	2,939	4,250	5,653
Cash at End of Year	299	21	295	1,019	2,044	2,939	4,250	5,653	7,181

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
Periodic Low Water Flow Scenario (Median Flow Base Case)
(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	482	601	635	616	733	587	785	926	1,104
Other	7	7	8	8	8	8	8	9	9	9	9
	1,581	1,584	1,736	1,914	2,007	2,065	2,252	2,177	2,446	2,660	2,919
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	417	413	474	542	540	553	532	555	612	692	892
Depreciation and Amortization	368	386	407	435	446	466	476	481	501	532	566
Water Rentals and Assessments	120	110	106	115	116	116	116	109	116	116	127
Fuel and Power Purchased	103	132	457	197	205	214	240	593	303	365	311
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	1,505	1,932	1,790	1,819	1,877	1,911	2,300	2,122	2,314	2,525
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	78	(195)	124	186	183	332	(133)	311	331	379
*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%
Financial Ratios											
Debt	74%	75%	78%	78%	79%	80%	80%	83%	82%	82%	80%
Interest Coverage	1.24	1.14	0.68	1.19	1.27	1.24	1.40	0.86	1.29	1.29	1.30
Capital Coverage (excl Major Gen.)	1.37	1.11	0.51	1.44	1.39	1.72	2.12	0.90	2.17	2.47	3.04

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
Periodic Low Water Flow Scenario (Median Flow Base Case)
(In Millions of Dollars)

For the year ended March 31

	2021	2022	2023	2024	2025	2026	2027	2028	2029
REVENUES									
General Consumers									
at approved rates	1,312	1,327	1,342	1,357	1,374	1,393	1,413	1,433	1,450
additional *	550	594	639	687	736	789	844	901	959
Extraprovincial	1,215	1,151	1,376	1,776	1,965	1,972	1,643	1,994	2,020
Other	9	9	10	10	10	10	10	11	11
	3,086	3,081	3,367	3,830	4,086	4,164	3,910	4,339	4,440
EXPENSES									
Operating and Administrative	509	519	536	547	558	569	580	592	603
Finance Expense	964	863	931	1,104	1,192	1,143	1,121	1,086	1,020
Depreciation and Amortization	592	598	626	687	731	747	764	767	777
Water Rentals and Assessments	132	117	140	154	159	161	136	161	161
Fuel and Power Purchased	302	1,021	296	265	289	258	1,056	253	272
Capital and Other Taxes	117	121	126	128	128	129	129	130	131
Corporate Allocation	9	9	9	9	9	9	9	9	9
	2,625	3,247	2,664	2,893	3,067	3,015	3,795	2,998	2,974
Non-controlling Interest	(25)	(27)	(28)	(29)	(30)	(34)	(38)	(41)	(43)
Net Income	436	(193)	675	908	989	1,115	77	1,300	1,423
*Additional General Consumers Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	42.22%	45.06%	47.96%	50.92%	53.94%	57.02%	60.16%	63.36%	66.63%
Financial Ratios									
Debt	79%	81%	79%	75%	71%	66%	65%	59%	53%
Interest Coverage	1.34	0.84	1.53	1.72	1.81	1.95	1.07	2.17	2.36
Capital Coverage (excl Major Gen.)	2.68	0.90	2.56	2.92	2.82	3.17	1.40	3.50	3.51

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
Periodic Low Water Flow Scenario (Median Flow Base Case)
(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	15,075	15,566	15,982	16,691	17,127	17,837	20,301	21,599	25,001
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,010)	(8,514)	(9,052)
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	13,085	15,950
Construction in Progress	1,947	2,458	1,341	1,818	2,838	3,854	5,532	6,948	6,159	6,446	4,168
Current and Other Assets	2,767	2,735	2,871	2,929	2,666	2,811	3,047	3,259	3,538	3,448	3,760
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,549	15,312	16,749	18,656	20,545	22,030	23,022	23,920
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,254	8,969	10,349	11,505	13,123	14,812	15,546	16,829	14,347
Current and Other Liabilities	2,156	1,926	2,201	2,949	2,233	2,356	2,347	2,703	3,154	2,535	5,536
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,261	2,050	2,174	2,360	2,543	2,875	2,742	3,053	3,384	3,763
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,549	15,312	16,749	18,656	20,545	22,030	23,022	23,920

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
Periodic Low Water Flow Scenario (Median Flow Base Case)
(In Millions of Dollars)

For the year ended March 31	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
ASSETS									
Plant in Service	26,067	26,505	30,392	33,459	34,732	35,524	36,105	36,821	37,414
Accumulated Depreciation	(9,616)	(10,190)	(10,793)	(11,461)	(12,177)	(12,911)	(13,663)	(14,420)	(15,188)
Net Plant in Service	16,451	16,316	19,599	21,998	22,556	22,613	22,441	22,401	22,226
Construction in Progress	4,523	5,453	3,111	877	270	119	207	205	338
Current and Other Assets	3,903	3,416	3,629	4,621	5,704	6,358	6,574	7,977	9,447
Goodwill	42	42	42	42	42	42	42	42	42
	24,918	25,227	26,381	27,538	28,572	29,132	29,264	30,625	32,053
LIABILITIES AND EQUITY									
Long-Term Debt	17,406	18,438	19,040	19,242	18,644	18,647	18,649	18,591	18,343
Current and Other Liabilities	3,040	2,510	2,387	2,432	3,074	2,515	2,566	2,680	2,929
Contributions in Aid of Construction	272	272	273	274	276	277	280	283	287
Retained Earnings	4,199	4,006	4,682	5,589	6,578	7,693	7,770	9,070	10,493
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0
	24,918	25,227	26,381	27,538	28,572	29,132	29,264	30,625	32,053

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
Periodic Low Water Flow Scenario (Median Flow Base Case)
(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	1,581	1,584	1,736	1,914	2,007	2,065	2,252	2,177	2,446	2,660	2,919
Cash Paid to Suppliers and Employees	(646)	(690)	(1,030)	(794)	(818)	(845)	(891)	(1,255)	(1,001)	(1,082)	(1,062)
Interest Paid	(453)	(423)	(483)	(559)	(563)	(555)	(554)	(570)	(655)	(741)	(927)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	493	236	577	640	669	822	378	826	877	964
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	800	540	1,400	1,400	1,800	2,200	1,600	1,600	800
Sinking Fund Withdrawals	262	227	27	103	486	-	5	-	-	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	819	512	1,023	1,288	1,530	1,985	1,055	1,161	635
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(1,113)	(1,079)	(1,004)	(989)	(1,457)	(1,737)	(2,125)	(2,135)	(1,685)	(1,619)	(1,259)
Sinking Fund Payment	(94)	(99)	(98)	(119)	(176)	(109)	(201)	(159)	(242)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,243)	(1,198)	(1,118)	(1,125)	(1,648)	(1,877)	(2,355)	(2,334)	(1,954)	(1,846)	(1,543)
Net Increase (Decrease) in Cash	(114)	8	(63)	(37)	14	81	(3)	29	(73)	192	56
Cash at Beginning of Year	66	(48)	(40)	(103)	(140)	(126)	(45)	(48)	(19)	(92)	100
Cash at End of Year	(48)	(40)	(103)	(140)	(126)	(45)	(48)	(19)	(92)	100	157

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
Periodic Low Water Flow Scenario (Median Flow Base Case)
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
OPERATING ACTIVITIES									
Cash Receipts from Customers	3,086	3,081	3,367	3,830	4,086	4,164	3,910	4,339	4,440
Cash Paid to Suppliers and Employees	(1,063)	(1,781)	(1,103)	(1,098)	(1,139)	(1,121)	(1,907)	(1,141)	(1,173)
Interest Paid	(1,004)	(897)	(948)	(1,127)	(1,232)	(1,196)	(1,165)	(1,142)	(1,087)
Interest Received	30	27	4	3	11	16	10	19	28
	1,049	430	1,320	1,607	1,726	1,863	849	2,075	2,207
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	800	1,200	600	200	-	-	-	-	-
Sinking Fund Withdrawals	285	741	171	-	-	352	-	-	60
Retirement of Long-Term Debt	(285)	(744)	(171)	-	-	(600)	-	-	(60)
Other	11	(26)	(23)	(24)	(24)	(25)	(27)	(29)	(30)
	811	1,171	577	176	(24)	(274)	(27)	(29)	(30)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contribution	(1,443)	(1,359)	(1,536)	(820)	(651)	(622)	(651)	(695)	(706)
Sinking Fund Payment	(292)	(349)	(208)	(188)	(194)	(199)	(185)	(190)	(195)
Other	(33)	(38)	(28)	(32)	(29)	(30)	(33)	(31)	(31)
	(1,768)	(1,746)	(1,772)	(1,040)	(874)	(851)	(869)	(916)	(932)
Net Increase (Decrease) in Cash	91	(146)	125	743	828	738	(47)	1,130	1,245
Cash at Beginning of Year	157	248	102	226	970	1,798	2,536	2,488	3,619
Cash at End of Year	248	102	226	970	1,798	2,536	2,488	3,619	4,864

PUB/MH I-200

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook , Order 32/0 Directive #3

Please respond to Directive #3 of Order 32/09 by filing a series of alternative 20-year scenarios containing the Electric IFF (including financial ratios) and Power Resource Plan and Capital Plan, to reflect:

c) A periodic 5-year drought (e.g. 1980's severity) commencing in 2011/12 and reoccurring in 2021/22.

ANSWER:

It is extremely unlikely that two five year droughts of this severity and duration would occur within a twenty year forecast period. Projected electric financial statements are provided here to show the impacts.

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
FIVE YEAR DROUGHT FROM 2012 TO 2016 AND 2022 TO 2026
(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	334	288	429	365	502	729	742	894	1,093
Other	7	7	8	8	8	8	8	9	9	9	9
	1,581	1,584	1,588	1,600	1,801	1,814	2,021	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	413	477	571	615	659	674	713	766	865	1,084
Depreciation and Amortization	368	386	407	435	446	466	476	481	501	532	566
Water Rentals and Assessments	120	110	87	77	97	95	99	115	115	115	124
Fuel and Power Purchased	103	132	472	733	340	383	386	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	1,505	1,932	2,317	2,011	2,131	2,180	2,213	2,335	2,560	2,823
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	78	(342)	(716)	(212)	(322)	(168)	96	56	53	70
*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%
Financial Ratios											
Debt	74%	75%	80%	86%	90%	93%	95%	95%	95%	95%	95%
Interest Coverage	1.24	1.14	0.45	(0.05)	0.72	0.63	0.83	1.09	1.05	1.04	1.05
Capital Coverage (excl Major Gen.)	1.37	1.11	0.17	(0.68)	0.52	0.41	0.83	1.47	1.49	1.68	2.06

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
FIVE YEAR DROUGHT FROM 2012 TO 2016 AND 2022 TO 2026
(In Millions of Dollars)

For the year ended March 31

	2021	2022	2023	2024	2025	2026	2027	2028	2029
REVENUES									
General Consumers									
at approved rates	1,312	1,327	1,342	1,357	1,374	1,393	1,413	1,433	1,450
additional *	550	594	639	687	736	789	844	901	959
Extraprovincial	1,201	930	1,093	1,497	1,755	1,643	1,903	1,928	1,950
Other	9	9	10	10	10	10	10	11	11
	3,073	2,860	3,084	3,551	3,876	3,835	4,170	4,273	4,370
EXPENSES									
Operating and Administrative	509	519	536	547	558	569	580	592	603
Finance Expense	1,180	1,111	1,238	1,510	1,678	1,706	1,720	1,692	1,662
Depreciation and Amortization	592	598	626	687	731	747	764	767	777
Water Rentals and Assessments	129	98	100	123	130	134	155	156	157
Fuel and Power Purchased	435	1,073	1,355	901	1,087	580	396	425	446
Capital and Other Taxes	117	120	126	127	128	128	129	129	130
Corporate Allocation	9	9	9	9	9	9	9	9	9
	2,971	3,528	3,990	3,904	4,320	3,873	3,753	3,770	3,784
Non-controlling Interest	(25)	(27)	(28)	(29)	(30)	(34)	(38)	(41)	(43)
Net Income	77	(695)	(933)	(382)	(474)	(72)	379	462	542
*Additional General Consumers Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	42.22%	45.06%	47.96%	50.92%	53.94%	57.02%	60.16%	63.36%	66.63%
Financial Ratios									
Debt	95%	98%	100%	100%	100%	100%	100%	100%	100%
Interest Coverage	1.05	0.53	0.41	0.77	0.72	0.96	1.22	1.27	1.32
Capital Coverage (excl Major Gen.)	1.76	(0.17)	(0.58)	0.54	0.41	1.13	1.91	2.07	2.10

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
FIVE YEAR DROUGHT FROM 2012 TO 2016 AND 2022 TO 2026
(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	15,075	15,566	15,982	16,691	17,127	17,837	20,301	21,599	25,001
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,010)	(8,514)	(9,052)
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	13,085	15,950
Construction in Progress	1,947	2,458	1,341	1,818	2,838	3,854	5,532	6,948	6,159	6,446	4,168
Current and Other Assets	2,767	2,735	2,871	2,930	2,666	2,825	3,047	3,304	3,538	3,378	3,781
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,551	15,312	16,762	18,656	20,590	22,030	22,951	23,941
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,454	9,969	11,749	13,305	15,523	17,012	17,946	19,429	17,347
Current and Other Liabilities	2,156	1,926	2,148	2,937	2,218	2,460	2,338	2,709	3,169	2,558	5,560
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,261	1,902	1,187	974	652	484	581	637	690	760
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,551	15,312	16,762	18,656	20,590	22,030	22,951	23,941

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
FIVE YEAR DROUGHT FROM 2012 TO 2016 AND 2022 TO 2026
(In Millions of Dollars)

For the year ended March 31	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
ASSETS									
Plant in Service	26,067	26,505	30,392	33,459	34,732	35,524	36,105	36,821	37,414
Accumulated Depreciation	(9,616)	(10,190)	(10,793)	(11,461)	(12,177)	(12,911)	(13,663)	(14,420)	(15,188)
Net Plant in Service	16,451	16,316	19,599	21,998	22,556	22,613	22,441	22,401	22,226
Construction in Progress	4,523	5,453	3,111	877	270	119	207	205	338
Current and Other Assets	3,966	3,387	3,607	3,913	4,341	4,213	4,936	5,501	6,090
Goodwill	42	42	42	42	42	42	42	42	42
	24,982	25,198	26,360	26,829	27,209	26,987	27,626	28,148	28,696
LIABILITIES AND EQUITY									
Long-Term Debt	20,806	22,238	24,440	25,242	25,444	25,847	26,049	25,991	25,743
Current and Other Liabilities	3,065	2,544	2,438	2,486	3,136	2,582	2,638	2,753	3,001
Contributions in Aid of Construction	272	272	273	274	276	277	280	283	287
Retained Earnings	837	142	(791)	(1,173)	(1,647)	(1,719)	(1,340)	(878)	(336)
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0
	24,982	25,198	26,360	26,829	27,209	26,987	27,626	28,148	28,696

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
FIVE YEAR DROUGHT FROM 2012 TO 2016 AND 2022 TO 2026
(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	1,581	1,584	1,588	1,600	1,801	1,814	2,021	2,320	2,404	2,628	2,907
Cash Paid to Suppliers and Employees	(646)	(690)	(1,027)	(1,292)	(935)	(993)	(1,019)	(1,010)	(1,059)	(1,155)	(1,167)
Interest Paid	(453)	(423)	(485)	(577)	(636)	(656)	(690)	(729)	(812)	(913)	(1,119)
Interest Received	29	22	14	16	14	4	15	26	37	39	34
	511	493	91	(253)	245	170	328	606	569	599	655
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	1,000	1,340	1,800	1,800	2,400	2,000	1,800	1,800	1,200
Sinking Fund Withdrawals	262	227	27	103	487	-	18	-	13	456	189
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	1,019	1,312	1,424	1,688	2,144	1,785	1,268	1,361	1,053
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(1,113)	(1,079)	(1,004)	(989)	(1,457)	(1,737)	(2,125)	(2,135)	(1,685)	(1,619)	(1,259)
Sinking Fund Payment	(94)	(99)	(98)	(121)	(176)	(123)	(201)	(172)	(242)	(218)	(256)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,243)	(1,198)	(1,118)	(1,127)	(1,648)	(1,891)	(2,355)	(2,348)	(1,954)	(1,864)	(1,543)
Net Increase (Decrease) in Cash	(114)	8	(9)	(68)	21	(33)	117	44	(116)	96	166
Cash at Beginning of Year	66	(48)	(40)	(48)	(116)	(96)	(129)	(12)	32	(84)	11
Cash at End of Year	(48)	(40)	(48)	(116)	(96)	(129)	(12)	32	(84)	11	178

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
FIVE YEAR DROUGHT FROM 2012 TO 2016 AND 2022 TO 2026
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
OPERATING ACTIVITIES									
Cash Receipts from Customers	3,073	2,860	3,084	3,551	3,876	3,835	4,170	4,273	4,370
Cash Paid to Suppliers and Employees	(1,193)	(1,814)	(2,121)	(1,702)	(1,907)	(1,416)	(1,265)	(1,307)	(1,342)
Interest Paid	(1,218)	(1,136)	(1,240)	(1,531)	(1,714)	(1,759)	(1,764)	(1,757)	(1,743)
Interest Received	30	27	4	3	16	22	14	28	42
	691	(63)	(273)	321	271	681	1,156	1,237	1,327
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	1,200	1,600	2,200	800	800	400	200	-	-
Sinking Fund Withdrawals	285	741	171	-	-	486	-	-	60
Retirement of Long-Term Debt	(285)	(744)	(171)	-	-	(600)	-	-	(60)
Other	11	(26)	(23)	(24)	(24)	(25)	(27)	(29)	(30)
	1,211	1,571	2,177	776	776	261	173	(29)	(30)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contribution	(1,443)	(1,359)	(1,536)	(820)	(651)	(622)	(651)	(695)	(706)
Sinking Fund Payment	(292)	(349)	(223)	(243)	(258)	(273)	(260)	(270)	(278)
Other	(33)	(38)	(28)	(32)	(29)	(30)	(33)	(31)	(31)
	(1,768)	(1,746)	(1,787)	(1,095)	(938)	(925)	(944)	(996)	(1,015)
Net Increase (Decrease) in Cash	134	(239)	117	2	109	17	384	212	281
Cash at Beginning of Year	178	312	72	189	191	300	317	701	913
Cash at End of Year	312	72	189	191	300	317	701	913	1,194

PUB/MH I-200

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook , Order 32/0 Directive #3

Please respond to Directive #3 of Order 32/09 by filing a series of alternative 20-year scenarios containing the Electric IFF (including financial ratios) and Power Resource Plan and Capital Plan, to reflect:

d) Zero long-term contract commitments beyond 2015;

ANSWER:

The financial analysis of a scenario with no long-term contract commitments beyond 2015 is not being provided because it is commercially sensitive since it would contain information that can be used to determine the benefit of specific export contracts. This information could be detrimental to Manitoba Hydro in negotiations of the terms and conditions of export contracts with various counterparties. A full evaluation of the benefits, including financial analyses, of new export sales will be provided at a later time when a full "needs for and alternatives to" process is undertaken.

<u>PUB/MH I-200</u>

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook , Order 32/0 Directive #3

Please respond to Directive #3 of Order 32/09 by filing a series of alternative 20-year scenarios containing the Electric IFF (including financial ratios) and Power Resource Plan and Capital Plan, to reflect:

e) A strong movement to domestic electric heating – assume a 20% switch over during the forecast period.

<u>ANSWER</u>:

A 20% switch over from gas to electrically heated homes during the forecast would result in additional load implications of approximately 1200 GW.h in net firm energy and 400 MW in net total peak by the end of the 20 year period. Manitoba Hydro has provided a medium high load forecast sensitivity in IFF09-1 (Appendix 5.2, p.20) which includes additional load of 2470 GW.h in net firm energy and 572 MW in net total peak by 2028/29 which are greater than a scenario with 20% conversion to electric heat. The medium-high load forecast sensitivity included in IFF09-1 has been extended for the 20 year forecast period and electric operations projections are attached.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(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	1,217	1,236	1,254	1,284	1,304	1,324	1,341	1,356	1,375
additional *	-	33	71	118	167	222	279	339	402	468	539
Extraprovincial	414	383	521	543	555	550	633	653	662	818	986
Other	7	7	8	8	8	8	8	9	9	9	9
	1,581	1,584	1,817	1,905	1,985	2,064	2,224	2,324	2,414	2,652	2,909
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	417	413	467	525	526	544	529	546	588	673	878
Depreciation and Amortization	368	386	407	435	446	466	476	481	501	532	566
Water Rentals and Assessments	120	110	111	113	113	114	115	116	115	116	125
Fuel and Power Purchased	103	132	245	256	273	294	309	355	376	447	427
Capital and Other Taxes	73	76	77	80	85	92	100	109	115	122	126
Corporate Allocation	8	9	9	9	9	9	9	9	9	9	9
	1,460	1,505	1,718	1,829	1,872	1,946	1,975	2,060	2,171	2,377	2,626
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	78	100	77	111	113	241	254	230	260	268
*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%
Financial Ratios											
Debt	74%	75%	76%	76%	78%	79%	80%	80%	81%	81%	80%
Interest Coverage	1.24	1.14	1.16	1.12	1.17	1.15	1.29	1.27	1.22	1.23	1.21
Capital Coverage (excl Major Gen.)	1.37	1.11	1.17	1.32	1.22	1.54	1.89	1.85	1.95	2.26	2.69

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
REVENUES											
General Consumers											
at approved rates	1,394	1,413	1,433	1,453	1,474	1,496	1,520	1,544	1,566	1,588	1,612
additional *	585	632	682	734	789	847	907	970	1,035	1,049	1,065
Extraprovincial	1,091	1,098	1,243	1,615	1,795	1,741	1,728	1,732	1,735	1,729	1,736
Other	9	9	10	10	10	10	10	11	11	11	11
	3,080	3,153	3,368	3,811	4,068	4,094	4,166	4,257	4,346	4,378	4,424
EXPENSES											
Operating and Administrative	511	523	547	558	569	580	592	603	615	628	640
Finance Expense	977	878	922	1,108	1,208	1,170	1,141	1,088	1,035	973	895
Depreciation and Amortization	598	606	634	695	739	755	772	775	785	792	802
Water Rentals and Assessments	129	130	137	150	155	156	156	157	157	158	158
Fuel and Power Purchased	449	485	485	474	496	423	413	449	475	492	489
Capital and Other Taxes	119	122	128	129	130	130	131	131	132	133	136
Corporate Allocation	9	9	9	9	9	9	9	9	9	9	9
	2,792	2,753	2,862	3,124	3,306	3,224	3,213	3,213	3,209	3,185	3,128
Non-controlling Interest	(25)	(27)	(28)	(29)	(30)	(34)	(38)	(41)	(43)	(46)	(51)
Net Income	263	374	479	659	731	836	914	1,003	1,094	1,146	1,245
*Additional General Consumers Revenue											
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	0.00%	0.00%
Cumulative Percent Increase	42.22%	45.06%	47.96%	50.92%	53.94%	57.02%	60.16%	63.36%	66.63%	66.63%	66.63%
Financial Ratios											
Debt	80%	79%	78%	75%	72%	68%	64%	60%	55%	50%	46%
Interest Coverage	1.20	1.30	1.38	1.52	1.59	1.70	1.79	1.90	2.03	2.14	2.31
Capital Coverage (excl Major Gen.)	2.25	2.13	2.19	2.48	2.41	2.70	2.81	3.01	3.00	2.92	3.61

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
(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	15,075	15,566	15,982	16,691	17,127	17,837	20,301	21,599	25,001
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,010)	(8,514)	(9,052)
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	13,085	15,950
Construction in Progress	1,947	2,458	1,341	1,818	2,838	3,854	5,532	6,948	6,181	6,578	4,452
Current and Other Assets	2,767	2,735	2,871	2,926	2,666	2,809	3,047	3,259	3,538	3,353	3,802
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,546	15,312	16,747	18,656	20,545	22,052	23,058	24,246
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,054	8,769	10,149	11,305	13,123	14,412	15,346	16,629	14,547
Current and Other Liabilities	2,156	1,926	2,106	2,898	2,260	2,451	2,335	2,704	3,057	2,524	5,526
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,261	2,344	2,421	2,532	2,646	2,887	3,141	3,371	3,631	3,899
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,546	15,312	16,747	18,656	20,545	22,052	23,058	24,246

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ASSETS											
Plant in Service	26,319	26,843	30,730	33,796	35,070	35,861	36,443	37,159	37,752	38,363	39,076
Accumulated Depreciation	(9,622)	(10,204)	(10,816)	(11,492)	(12,216)	(12,959)	(13,720)	(14,485)	(15,262)	(16,047)	(16,841)
Net Plant in Service	16,697	16,639	19,914	22,305	22,854	22,903	22,723	22,674	22,491	22,316	22,235
Construction in Progress	4,605	5,453	3,111	877	270	119	207	205	338	579	1,036
Current and Other Assets	3,925	3,402	3,629	4,380	5,214	5,598	6,659	7,774	8,923	9,807	10,757
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	25,269	25,536	26,696	27,604	28,380	28,662	29,631	30,694	31,794	32,745	34,070
LIABILITIES AND EQUITY											
Long-Term Debt	17,806	18,238	19,040	19,242	18,644	18,647	18,649	18,591	18,343	18,345	18,335
Current and Other Liabilities	3,028	2,489	2,368	2,413	3,055	2,497	2,547	2,662	2,911	2,709	2,793
Contributions in Aid of Construction	272	272	273	274	276	277	280	283	287	292	298
Retained Earnings	4,162	4,536	5,015	5,674	6,405	7,241	8,155	9,159	10,253	11,399	12,644
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0	0	0
	25,269	25,536	26,696	27,603	28,380	28,662	29,631	30,694	31,794	32,745	34,070

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
(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	1,581	1,584	1,817	1,905	1,985	2,064	2,224	2,324	2,414	2,652	2,909
Cash Paid to Suppliers and Employees	(646)	(690)	(824)	(850)	(884)	(922)	(959)	(1,024)	(1,074)	(1,163)	(1,177)
Interest Paid	(453)	(423)	(481)	(541)	(550)	(544)	(548)	(566)	(635)	(723)	(912)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	493	526	529	565	602	732	760	741	804	854
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	600	540	1,400	1,400	2,000	1,800	1,800	1,600	1,200
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	1,161	1,035
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(1,113)	(1,079)	(1,004)	(989)	(1,457)	(1,737)	(2,125)	(2,135)	(1,706)	(1,729)	(1,412)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(107)	(201)	(159)	(242)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,243)	(1,198)	(1,118)	(1,122)	(1,648)	(1,876)	(2,355)	(2,334)	(1,976)	(1,955)	(1,695)
Net Increase (Decrease) in Cash	(114)	8	27	(81)	(64)	15	106	11	20	10	193
Cash at Beginning of Year	66	(48)	(40)	(12)	(94)	(157)	(142)	(37)	(25)	(5)	5
Cash at End of Year	(48)	(40)	(12)	(94)	(157)	(142)	(37)	(25)	(5)	5	199

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

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
OPERATING ACTIVITIES											
Cash Receipts from Customers	3,080	3,153	3,368	3,811	4,068	4,094	4,166	4,257	4,346	4,378	4,424
Cash Paid to Suppliers and Employees	(1,212)	(1,263)	(1,301)	(1,316)	(1,355)	(1,295)	(1,297)	(1,346)	(1,385)	(1,417)	(1,429)
Interest Paid	(1,018)	(921)	(937)	(1,131)	(1,248)	(1,223)	(1,185)	(1,144)	(1,103)	(1,046)	(946)
Interest Received	30	27	4	3	11	16	10	19	28	27	30
	880	996	1,134	1,367	1,477	1,593	1,694	1,786	1,887	1,942	2,078
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	1,000	600	800	200	-	-	-	-	-	-	-
Sinking Fund Withdrawals	285	741	171	-	-	352	-	-	60	250	-
Retirement of Long-Term Debt	(285)	(744)	(171)	-	-	(600)	-	-	(60)	(250)	30
Other	11	(26)	(23)	(24)	(24)	(25)	(27)	(29)	(30)	(43)	(73)
	1,011	571	777	176	(24)	(274)	(27)	(29)	(30)	(43)	(43)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(1,493)	(1,363)	(1,536)	(820)	(651)	(622)	(651)	(695)	(706)	(830)	(1,148)
Sinking Fund Payment	(292)	(349)	(208)	(188)	(194)	(199)	(185)	(190)	(195)	(197)	(190)
Other	(33)	(38)	(28)	(32)	(29)	(30)	(33)	(31)	(31)	(32)	(32)
	(1,818)	(1,750)	(1,772)	(1,040)	(874)	(851)	(869)	(916)	(932)	(1,059)	(1,370)
Net Increase (Decrease) in Cash	72	(183)	139	503	579	468	798	842	925	839	666
Cash at Beginning of Year	199	271	87	226	729	1,308	1,775	2,573	3,415	4,340	5,179
Cash at End of Year	271	87	226	729	1,308	1,775	2,573	3,415	4,340	5,179	5,845

PUB/MH I-200

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook , Order 32/0 Directive #3

Please respond to Directive #3 of Order 32/09 by filing a series of alternative 20-year scenarios containing the Electric IFF (including financial ratios) and Power Resource Plan and Capital Plan, to reflect:

f) A ten percent increase in domestic consumption over the twenty-year period due to the take up of electric motor vehicles. Please estimate the number of vehicles this would equate to in the scenario.

ANSWER:

Manitoba Hydro completed a preliminary plug-in electric vehicle (PEV) adoption scenario for Manitoba which estimates (medium adoption scenario) that approximately 271,000 PEV (about 32% of the vehicles) will be in service by 2030. Energy consumption estimates for this number of vehicles, based on 125 Wh/km average vehicle efficiency, amount to approximately 720 GWh or 2.16% of MH estimated total load for 2030. Peak contribution is less given these cars are plugged in during off-peak hours.

In order for PEV to attain 10% of MH's load by 2030, approximately 1.37 million electric vehicles would need to be on the road in Manitoba, more than 5 times Manitoba Hydro's estimate and 1.62 times the number of estimated total vehicles on the road at that time.

The response to PUB/MH I-200(e) provides the electric operations projections for the medium-high load forecast sensitivity which has additional load implications of 2470 GW.h in net firm energy and 572 MW in net total peak by 2028/29.

PUB/MH I-200

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook , Order 32/0 Directive #3

Please respond to Directive #3 of Order 32/09 by filing a series of alternative 20-year scenarios containing the Electric IFF (including financial ratios) and Power Resource Plan and Capital Plan, to reflect:

g) Existing transmission tie-line constraints.

ANSWER:

For the purposes of this response, Manitoba Hydro interprets existing transmission tie-line constraints to mean no new development of interconnections outside the province. IFF09-1 assumes an incremental 500 kV interconnection to the US necessary for the construction of Keeyask and Conawapa to support planned export contracts with Northern States Power, Wisconsin Public Service and Minnesota Power. Interconnections provide access to the export market, and constraining Manitoba Hydro to existing interconnections would limit surplus energy from being exported. In addition, in the absence of new interconnections Manitoba Hydro's import capability would be limited in times of low water flow conditions.

Manitoba Hydro does not have a specific scenario with no new interconnections. However, an alternate development plan required to meet Manitoba demand has been prepared which includes Conawapa in 2021 (one year earlier than IFF09) and a combined cycle gas turbine in 2033. This scenario excludes the incremental 500 kV interconnection to the US mentioned above and consequently also excludes the construction of Keeyask and the sales to Wisconsin Public Service and Minnesota Power. The projected consolidated financial statements for the Alternative Development Sequence can be seen in Appendix 15.

PUB/MH I-200

Reference: **Tab 13, 13.4 (3) 20 -Year Financial Outlook , Order 32/0 Directive #3**

Please respond to Directive #3 of Order 32/09 by filing a series of alternative 20-year scenarios containing the Electric IFF (including financial ratios) and Power Resource Plan and Capital Plan, to reflect:

h) Potential carbon tax on MH's imports and a doubling of water rental rates.

ANSWER:

The expected export price forecast in IFF09-1 assumes a carbon tax on imports that is consistent with that of exports. No additional carbon tax has been included. The following electric financial projections show the additional impact of doubling water rental rates.

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
Water Rentals Doubled
(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	421	483	549	559	586	582	609	662	761	980
Depreciation and Amortization	368	386	407	435	446	466	476	481	501	532	566
Water Rentals and Assessments	231	213	211	216	218	217	218	219	218	218	236
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
	1,571	1,616	1,838	1,950	1,996	2,067	2,118	2,213	2,334	2,560	2,831
Non-controlling Interest	-	-	2	3	(0)	(3)	(7)	(9)	(11)	(13)	(13)
Net Income	10	(32)	(28)	(52)	(9)	(30)	94	98	59	56	64
*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%
Financial Ratios											
Debt	75%	77%	79%	80%	82%	84%	85%	86%	87%	88%	88%
Interest Coverage	1.02	0.94	0.95	0.92	0.99	0.96	1.11	1.10	1.05	1.05	1.05
Capital Coverage (excl Major Gen.)	1.07	0.86	0.89	1.00	0.96	1.17	1.50	1.47	1.50	1.68	2.04

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
Water Rentals Doubled
(In Millions of Dollars)

For the year ended March 31	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
REVENUES									
General Consumers									
at approved rates	1,312	1,327	1,342	1,357	1,374	1,393	1,413	1,433	1,450
additional *	550	594	639	687	736	789	844	901	959
Extraprovincial	1,201	1,223	1,379	1,758	1,940	1,908	1,903	1,928	1,950
Other	9	9	10	10	10	10	10	11	11
	3,073	3,153	3,370	3,812	4,060	4,100	4,170	4,273	4,370
EXPENSES									
Operating and Administrative	509	519	536	547	558	569	580	592	603
Finance Expense	1,076	983	1,041	1,240	1,349	1,323	1,306	1,264	1,222
Depreciation and Amortization	592	598	626	687	731	747	764	767	777
Water Rentals and Assessments	246	247	259	285	294	296	296	297	297
Fuel and Power Purchased	435	460	474	460	492	420	396	425	446
Capital and Other Taxes	117	120	126	128	128	128	129	129	130
Corporate Allocation	9	9	9	9	9	9	9	9	9
	2,984	2,936	3,072	3,355	3,562	3,493	3,479	3,483	3,485
Non-controlling Interest	(23)	(25)	(26)	(27)	(29)	(33)	(36)	(39)	(42)
Net Income	66	192	272	429	470	575	655	751	844
*Additional General Consumers Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	42.22%	45.06%	47.96%	50.92%	53.94%	57.02%	60.16%	63.36%	66.63%
Financial Ratios									
Debt	88%	87%	87%	85%	83%	80%	77%	74%	70%
Interest Coverage	1.05	1.14	1.20	1.31	1.34	1.42	1.49	1.58	1.68
Capital Coverage (excl Major Gen.)	1.73	1.72	1.77	2.03	1.96	2.23	2.35	2.56	2.57

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
Water Rentals Doubled
(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	15,075	15,566	15,982	16,691	17,127	17,837	20,301	21,599	25,001
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,010)	(8,514)	(9,052)
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	13,085	15,949
Construction in Progress	1,947	2,458	1,341	1,818	2,838	3,854	5,532	6,948	6,159	6,446	4,168
Current and Other Assets	2,767	2,736	2,875	2,929	2,668	2,821	3,053	3,267	3,568	3,363	3,698
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,252	13,935	14,550	15,314	16,759	18,662	20,553	22,060	22,937	23,857
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,796	9,254	9,169	10,749	12,105	13,923	15,412	16,546	17,829	15,747
Current and Other Liabilities	2,268	1,949	2,260	2,982	2,262	2,406	2,432	2,758	3,083	2,625	5,563
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,071	2,039	1,994	1,942	1,932	1,902	1,996	2,094	2,153	2,209	2,273
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,252	13,935	14,550	15,314	16,759	18,662	20,553	22,060	22,937	23,857

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
Water Rentals Doubled
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
ASSETS									
Plant in Service	26,067	26,505	30,392	33,458	34,732	35,523	36,105	36,821	37,414
Accumulated Depreciation	(9,616)	(10,190)	(10,793)	(11,461)	(12,177)	(12,911)	(13,663)	(14,420)	(15,188)
Net Plant in Service	16,451	16,315	19,599	21,998	22,556	22,613	22,441	22,401	22,226
Construction in Progress	4,523	5,453	3,111	877	270	119	207	205	338
Current and Other Assets	3,873	3,367	3,584	4,098	4,662	4,777	5,570	6,424	7,315
Goodwill	42	42	42	42	42	42	42	42	42
	24,889	25,178	26,336	27,014	27,530	27,550	28,261	29,072	29,921
LIABILITIES AND EQUITY									
Long-Term Debt	19,206	19,838	20,840	21,042	20,444	20,447	20,449	20,391	20,143
Current and Other Liabilities	3,070	2,536	2,421	2,466	3,108	2,549	2,599	2,714	2,963
Contributions in Aid of Construction	272	272	273	274	276	277	280	283	287
Retained Earnings	2,339	2,531	2,803	3,232	3,702	4,277	4,933	5,684	6,528
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0
	24,889	25,178	26,336	27,014	27,530	27,550	28,261	29,072	29,921

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
Water Rentals Doubled
(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	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	(757)	(793)	(928)	(948)	(975)	(1,001)	(1,049)	(1,114)	(1,162)	(1,258)	(1,280)
Interest Paid	(453)	(429)	(490)	(560)	(582)	(582)	(600)	(626)	(703)	(808)	(1,012)
Interest Received	29	22	14	16	14	4	15	26	36	39	34
	400	385	404	403	444	460	585	606	575	600	650
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	1,000	600	740	1,600	1,600	2,000	2,000	2,000	1,600	1,200
Sinking Fund Withdrawals	262	227	27	106	486	-	9	-	-	456	174
Retirement of Long-Term Debt	(355)	(304)	(27)	(121)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(35)	(10)	19	(10)	(14)	(12)	(12)	(13)	(14)	(26)	(14)
	618	913	619	715	1,223	1,488	1,735	1,786	1,456	1,162	1,039
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contribution	(1,113)	(1,079)	(1,004)	(989)	(1,457)	(1,737)	(2,125)	(2,135)	(1,685)	(1,619)	(1,259)
Sinking Fund Payment	(94)	(100)	(100)	(120)	(176)	(113)	(201)	(159)	(242)	(203)	(256)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,243)	(1,199)	(1,120)	(1,126)	(1,648)	(1,881)	(2,355)	(2,334)	(1,954)	(1,849)	(1,542)
Net Increase (Decrease) in Cash	(226)	99	(97)	(8)	19	67	(34)	57	76	(87)	146
Cash at Beginning of Year	66	(160)	(61)	(158)	(166)	(147)	(79)	(114)	(56)	20	(67)
Cash at End of Year	(160)	(61)	(158)	(166)	(147)	(79)	(114)	(56)	20	(67)	80

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
Water Rentals Doubled
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
OPERATING ACTIVITIES									
Cash Receipts from Customers	3,073	3,153	3,370	3,812	4,060	4,100	4,170	4,273	4,370
Cash Paid to Suppliers and Employees	(1,310)	(1,350)	(1,400)	(1,424)	(1,477)	(1,419)	(1,406)	(1,448)	(1,483)
Interest Paid	(1,114)	(1,023)	(1,054)	(1,265)	(1,393)	(1,381)	(1,354)	(1,326)	(1,297)
Interest Received	30	27	4	3	13	17	11	21	31
	679	807	920	1,125	1,203	1,318	1,422	1,520	1,622
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	1,200	800	1,000	200	-	-	-	-	-
Sinking Fund Withdrawals	285	741	171	-	-	389	-	-	60
Retirement of Long-Term Debt	(285)	(744)	(171)	-	-	(600)	-	-	(60)
Other	11	(25)	(23)	(23)	(24)	(25)	(27)	(28)	(30)
	1,211	771	978	177	(24)	(236)	(27)	(28)	(30)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contribution	(1,443)	(1,359)	(1,536)	(820)	(651)	(622)	(651)	(695)	(706)
Sinking Fund Payment	(292)	(349)	(208)	(207)	(213)	(219)	(204)	(209)	(215)
Other	(33)	(38)	(28)	(32)	(29)	(30)	(33)	(31)	(31)
	(1,768)	(1,746)	(1,772)	(1,058)	(893)	(871)	(888)	(935)	(952)
Net Increase (Decrease) in Cash	122	(169)	126	243	287	212	507	557	640
Cash at Beginning of Year	80	202	33	159	402	689	900	1,408	1,964
Cash at End of Year	202	33	159	402	689	900	1,408	1,964	2,604

PUB/MH I-201

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 8 & 9

a) Please explain what export market circumstances support an increase in extra-provincial revenue from IFF 08-1 of about:

- **i. 14% in F2012.**
- **ii. 5% in F2016.**
- **iii. 7% in F2020.**
- **iv. 5% in F2024.**
- **v. 2% in F2028.**

ANSWER:

i. In 2012, increased energy is available for export due firstly to change in demand from domestic sales to the export markets and secondly from net energy supply increases from increased wind energy and hydraulic generation. The increased sales volumes are partially offset by decreased Ancillary Services Market sales and lower average export prices.

ii.-v. In 2016, 2020, 2024 and 2028, increased net energy is available for export due to a change in demand from domestic sales to the export markets. This is partially offset by decreased generation and imports and by lower projected average export prices and decreased Ancillary Services Market sales.

Below is a table comparing IFF09-1 to the IFF08-1 20 Year Financial Outlook for extra-provincial revenue and domestic sales.

Total Export Sales Variance (in Millions $)	2012	2016	2020	2024	2028
IFF09-1	554	701	1,093	1,758	1,928
IFF08-1	481	665	1,024	1,686	1,899
Variance	73	36	69	72	29
Total Variance	15.1%	6.7%	7.7%	4.9%	2.1%

Export Sales Avg Price ($Cdn/MW.h)	2012	2016	2020	2024	2028
IFF09-1	65.92	90.88	105.58	114.91	130.44
IFF08-1	69.99	93.67	110.44	117.64	134.82
Variance	(4.07)	(2.79)	(4.86)	(2.73)	(4.39)

Export Sales Energy (Net of Line Losses in GW.h)	2012	2016	2020	2024	2028
IFF09-1	7,295	6,712	8,928	13,372	12,913
IFF08-1	6,105	6,266	8,253	12,786	12,558
Variance	1,190	446	675	586	356

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	62.39	61.97	61.82
Variance	(0.84)	0.36	3.91	9.41	15.42

Domestic Sales Energy (GW.h)	2012	2016	2020	2024	2028
IFF09-1	24,728	26,439	27,229	28,638	30,215
IFF08-1	26,050	27,296	28,167	29,517	30,761
Variance	(1,322)	(857)	(939)	(879)	(545)

PUB/MH I-201

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 8 & 9

b) Please explain the circumstances that required fuel and power purchase cost increases of about:

i. 50% in F2012.
ii. 20% in F2016.
iii. 35% in F2020.
iv. 35% in F2024.

ANSWER:

i. In 2012, increased wind energy purchases and transmission charges on increased exports are partially offset by decreased thermal generation and imported energy.

iii. In 2016, decreases in thermal generation and imported energy volumes are partially offset by increased wind energy purchases and transmission charges on increased exports.

iii. In 2020, transmission charges on the increased exports and unfavourable exchange rate variances are partially offset by lower imports.

iv. I 2024, transmission charges on the increased exports and unfavourable exchange rate variances are partially offset by lower imports.

Below is a table comparing IFF09-1 to the IFF08-1 20 Year Financial Outlook for fuel and power purchased.

Fuel and Power Purchased Variance (in Millions of $)	2012	2016	2020	2024
IFF09-1	248	297	419	460
IFF08-1	227	316	406	447
Variance	22	-19	12	13
% Variance	9.6%	-6.2%	3.0%	2.9%

Fuel and Power Purchased Avg Price ($Cdn/MW.h)	2012	2016	2020	2024
IFF09-1	69.63	79.10	85.50	99.26
IFF08-1	66.95	78.57	85.18	101.30
Variance	2.69	0.53	0.32	(2.04)

Fuel and Power Purchased Energy ($Cdn/MW.h)	2012	2016	2020	2024
IFF09-1	3047	3160	3980	3775
IFF08-1	3025	3494	4192	3885
Variance	23	-335	-213	-110

<u>PUB/MH I-202</u>

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 10 & 11

a) Please explain the low level of construction in progress [$200 million/year] after 2024.

<u>ANSWER</u>:

The low level of construction in progress after 2024 is due to the fact that the major projects (i.e. Bipole III, Keeyask and Conawapa) are forecast to be completed and placed into service. No additional new major generation or transmission projects are planned subsequent to Conawapa in-service. The capital expenditures forecasted between 2024 and 2029 consist primarily of domestic projects and other amounts that are intended to represent regular system expansion and/or replacement projects. These projects typically have shorter construction time frames (1 to 5 years) and as a result are placed into service frequently.

PUB/MH I-202

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 10 & 11

b) With respect to the response to PUB/MH I 197, please explain the relationship between ongoing Base Capital expenditures and the level of plant in-service and explain how ongoing Base Capital expenditure changes after the construction of Keeyask, Bipole III and Conawapa?

ANSWER:

During construction, Base Capital expenditures accumulate in work in progress until they are placed in service at which point the costs are transferred into plant in-service. Base Capital expenditures have construction time frames that typically do not exceed five years, therefore these expenditures move quickly out of work in progress into plant in-service.

Base Capital expenditures are planned using factors such as projected domestic load growth and known cycles of asset replacement. These assumptions are used throughout the forecast and are unrelated to the timing of new major generation and transmission projects such as Keeyask, Bipole III and Conawapa.

PUB/MH I-202

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 10 & 11

c) Please discuss MH's anticipated replacement of current plant in service, which from 2010 to 2018 is being depreciated at approximately $400 million per year.

ANSWER:

Manitoba Hydro expects to replace and/or refurbish current plant in-service in accordance with estimated service lives of existing assets.

PUB/MH I-202

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 10 & 11

d) Please provide a table, which indicates since 1990 the level of annual Base Capital Expenditures, Major Generation and Transmission Expenditures and the relative percentage of Base Capital Expenditure to Net Plant in Service in each year.

ANSWER:

Please see the attached table.

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**
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%**
2011	558	433	991	8,015	**5.4%**
2012	510	441	951	9,677	**4.6%**
2013	549	394	943	9,761	**4.0%**
2014	962	456	1,418	9,765	**4.7%**
2015	1,317	385	1,702	10,042	**3.8%**
2016	1,709	384	2,093	10,035	**3.8%**
2017	1,695	409	2,104	10,297	**4.0%**
2018	1,278	378	1,656	12,292	**3.1%**
2019	1,237	354	1,590	13,085	**2.7%**
2020	917	317	1,233	15,950	**2.0%**
2021	1,025	387	1,412	16,451	**2.4%**
2022	866	460	1,326	16,316	**2.8%**
2023	998	507	1,505	19,599	**2.6%**
2024	250	541	791	21,998	**2.5%**
2025	21	603	624	22,556	**2.7%**
2026	15	580	596	22,613	**2.6%**
2027	26	598	624	22,441	**2.7%**
2028	79	588	668	22,401	**2.6%**
2029	57	623	679	22,226	**2.8%**

<u>PUB/MH I-203</u>

Reference: Tab 14, 13.4 (3) 20 year - Year Financial Outlook Page 3 – Major Capital

Please provide the incremental revenue requirement impacts for the first year beyond in-service for Bipole III, Keeyask G.S. and Conawapa G.S.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH I-197.

PUB/MH I-204 (REVISED)

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook Pages 10 & 11

Please provide a schedule indicating the level of capitalized OM&A and Finance Expense for each of the years 1999 through 2029.

ANSWER:

(000's)		
	Capitalized OM&A *	**Finance Expense allocated to Construction**
2003/04	207,593	31,564
2004/05	215,904	32,683
2005/06	232,487	34,496
2006/07	238,879	47,071
2007/08	259,627	60,015
2008/09	271,373	74,493
2009/10	299,037	91,505
2010/11	304,061	130,789
2011/12	310,188	137,126
2012/13	N/A	110,061
2013/14	N/A	144,108
2014/15	N/A	208,376
2015/16	N/A	306,070
2016/17	N/A	408,036
2017/18	N/A	449,275
2018/19	N/A	430,042
2019/20	N/A	365,023
2020/21	N/A	300,298
2021/22	N/A	352,971
2022/23	N/A	329,902
2023/24	N/A	159,756
2024/25	N/A	30,714
2025/26	N/A	29,672
2026/27	N/A	17,854
2027/28	N/A	22,687
2028/29	N/A	24,875

*Capitalized OM&A is specifically forecast to 2011/12. In subsequent forecasts, net OM&A is escalated at 2% with no corresponding forecast for capitalized OM&A.

PUB/MH I-205

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook

Please indicate the required rate change required in each year to maintain a 75:25 debt to equity ratio in each year of the 20 year forecast.

ANSWER:

For illustrative purposes only, the attached table provides the annual rate adjustments required to maintain 75:25 debt/equity in each year of the forecast. Manitoba Hydro expects to manage rate change requirements to avoid abnormally large increases, or decreases, to ratepayers.

Electric Rate Changes Required to Maintain a 75:25 Debt to Equity Ratio

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Increase	0.0%	2.9%	10.1%	-0.9%	16.3%	2.8%	0.0%	0.5%	-3.1%	1.0%	-4.4%
Debt Ratio	74%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%

	2021	2022	2023	2024	2025	2026	2027	2028	2029
Rate Increase	3.3%	-6.0%	-0.6%	-18.8%	-1.8%	-2.5%	1.4%	0.6%	0.5%
Debt Ratio	75%	75%	75%	75%	75%	75%	75%	75%	75%

PUB/MH I-206

**Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook
Pages 14 & 15 - Five Year Drought**

a) Please provide the assumptions (GWh, ¢/kW.h, carbon adder, natural gas prices) with respect to revenue and costs employed to define a 5-year drought impact.

ANSWER:

The impact of the 5-year drought beginning in 2011/12 is defined as the differential between 5-year drought chronology (1987/88 to 1991/92) and the expected financial consequences (i.e. average of all flow cases). The attached table summarizes the impact of the 5-year drought in terms of the difference in revenues and energy supply. Specific information on export price forecast, carbon adders or natural gas prices is not provided because this is commercially sensitive information.

			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 Expense)			-419	-742	-249	-320	-271	-2003
Impact of 5-Year Drought on Energy (GWh/yr)								
Extra-Provincial Sales			-3542	-4190	-3162	-3408	-3016	-17318
Hydro Generation			-7117	-10707	-5060	-5584	-4779	-33246
Fuel & Power Purchase								
	Thermal		972	3130	-184	3	-71	3850
	Import	On-Peak	208	521	94	90	76	990
		Off-Peak	1841	2007	1605	1654	1391	8498
	Total		3021	5658	1515	1748	1396	13338

PUB/MH I-206

**Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook
Pages 14 & 15 - Five Year Drought**

b) What specific peak and off-peak demands and prices did MH employ for imports and/or thermal generation during the 5-year drought?

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-206(a) for a summary of the annual on-peak and off-peak volumes and costs for imports and for the thermal generation during the 5-year drought. It should be noted that the revenues and energy volumes for the import component are for the differential in import requirement between the expected case and the drought case. The unit prices for import energy are commercially sensitive information which cannot be provided since they are related to the export price forecast which is confidential.

<u>PUB/MH I-207</u>

Reference: **Tab 13, 13.4 (3) 20-Year Financial Outlook**
Pages 14 & 15 - Median Flow Revenues

a) **What specific peak and off-peak prices and demands did MH employ to define the revenues and costs in each of the 94 years?**

<u>ANSWER</u>:

The specific volumes and prices of export, import and thermal generation are not being provided because they are confidential. The information that Manitoba Hydro determines through computer simulation analysis of 94 years of water conditions is commercially sensitive information that could be used to the disadvantage of the Corporation because of the competitive market in which it operates.

PUB/MH I-207

Reference: Tab 13, 13.4 (3) 20-Year Financial Outlook
Pages 14 & 15 - Median Flow Revenues

b) In analyzing the 1921, 1926, and 1982 representative median flow scenarios, what peak and off-peak prices and demands did MH employ to define revenues and costs?

ANSWER:

The table on the next page contains the revenues, energy volumes and associated prices for median flow condition. It is noted that the median is represented by averaging specific results from three flow cases which have flow volumes near the 50^{th} percentile. The prices for on-peak and off-peak periods for specific products is not being provided because it is commercially sensitive information.

EXPORT REVENUE ASSUMPTIONS FOR MEDIAN FLOW CONDITIONS (EXPECTED PRICES)

(in GWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	30,450	31,239	31,477	31,422	31,427	31,593	31,225	31,225	34,157
MH Thermal Generation	189	189	189	204	239	252	282	326	301
Import Energy (Incl Wind Purchase)	2,202	2,108	2,103	2,179	2,328	2,412	2,646	3,440	2,593
Manitoba Domestic Energy Sales	24,718	25,075	25,413	26,030	26,439	26,790	26,743	26,929	27,229
Total Export Sales	7,553	7,866	7,770	7,246	7,057	6,982	6,943	7,576	9,135

(in Millions of Dollars)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	102	104	105	105	105	106	104	104	114
MH Thermal Generation	15	15	16	18	24	27	32	40	46
Import Energy (Incl Wind Purchase)	145	146	150	156	169	177	195	249	186
Manitoba Domestic Energy Sales									
Total Export Sales	535	564	595	575	685	690	708	848	1,025

Average Price ($/MWh)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	3.34	3.34	3.34	3.34	3.34	3.34	3.34	3.34	3.34
MH Thermal Generation	81.92	81.10	85.73	90.55	100.76	106.67	113.14	121.26	153.07
Import Energy (Incl Wind Purchase)	65.71	69.12	71.34	71.75	72.74	73.48	73.89	72.32	71.92
Manitoba Domestic Energy Sales									
Total Export Sales	70.82	71.67	76.62	79.35	97.02	98.77	101.94	111.90	112.17

EXPORT REVENUE ASSUMPTIONS FOR MEDIAN FLOW CONDITIONS (EXPECTED PRICES) (Cont'd)

(in GWh)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
MH Hydraulic Generation	35,804	35,944	37,869	41,910	43,385	43,630	43,399	43,441	43,456
MH Thermal Generation	334	365	370	208	248	112	74	76	86
Import Energy (Incl Wind Purchase)	2,240	2,356	1,890	1,736	1,850	1,735	1,779	1,832	1,894
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	10,035	9,993	10,876	13,992	15,171	14,784	14,201	13,909	13,641

(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	120	120	127	140	145	146	145	145	145
MH Thermal Generation	52	59	62	35	44	20	13	14	17
Import Energy (Incl Wind Purchase)	170	180	151	145	159	150	149	156	163
Manitoba Domestic Energy Sales									
Total Export Sales	1,133	1,158	1,291	1,689	1,877	1,882	1,876	1,901	1,924

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	156.29	161.58	167.57	170.44	177.67	177.35	181.50	188.11	195.67
Import Energy (Incl Wind Purchase)	75.80	76.25	80.07	83.26	85.72	86.69	83.66	84.95	86.03
Manitoba Domestic Energy Sales									
Total Export Sales	112.95	115.89	118.74	120.72	123.72	127.33	132.14	136.65	141.08

PUB/MH I-208

Reference: Tab 13, 13.4 (3) 20-Year Financial Outlook Page 15 – Periodic Low Flows

a) Please define the hydraulic generation (GWh) employed as a 4-year in 20 event prior to 2018, 2018 to 2023, and after 2024.

ANSWER:

Simulation modeling of the hydraulic system was not undertaken for the periodic low flow analysis. As a result, there is no hydraulic generation data which corresponds to this periodic low flow event.

Instead of attempting to define a specific set of water conditions that would represent a periodic drought year, the financial consequence of such an event was determined. The financial impact of the periodic drought year is characterized by the difference between median and average net revenues summed over five (5) years. The financial consequences of periodic low water conditions were analyzed by assuming median revenue conditions for four consecutive years followed by the revenue impact of a periodic drought occurring in the fifth year.

This periodic drought is not considered to be equivalent to a 4-year in 20 event in the water flow record. The periodic drought was designed to incorporate the asymmetric impact of droughts on net revenues. As a result, the weighted impact of all drought events is implicitly included within the definition of this periodic drought. Please refer to the response to PUB/MH I-208(b) for an indication of the relative frequency of this periodic drought.

PUB/MH I-208

Reference: Tab 13, 13.4 (3) 20-Year Financial Outlook Page 15 – Periodic Low Flows

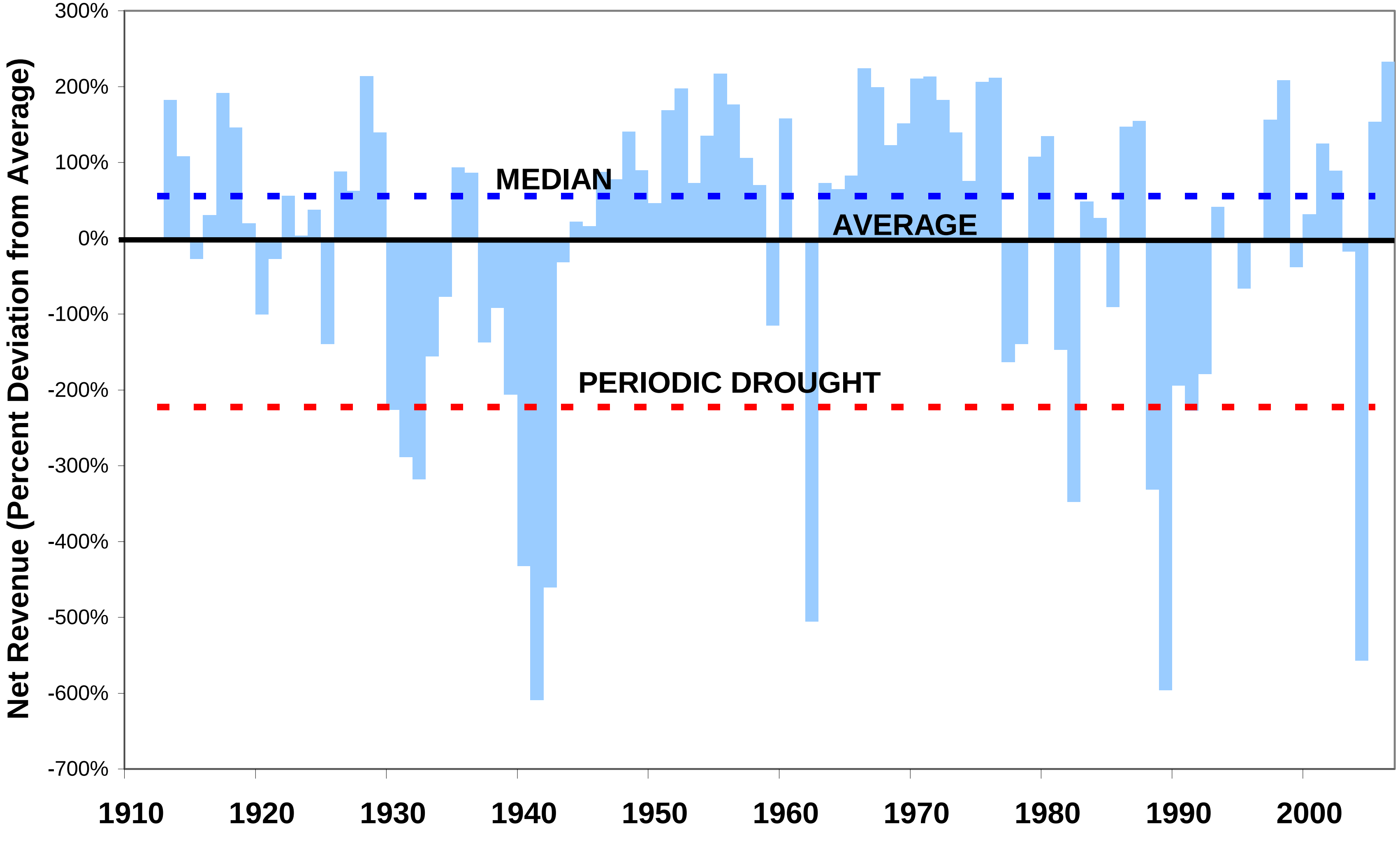
b) Please identify the post-LWR/CRD years that would have similar or lower hydraulic generation outputs.

ANSWER:

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. The graph on the following page shows the variation in the flow-related net revenue for the flow years of 1912/13 to 2005/06. The periodic drought is assumed to occur every five years. The four intervening years are assumed to produce net revenues which correspond to median flow conditions. The magnitude of the impact of the periodic low flow year was determined such that the weighted average of the resultant net revenues over the five years is equivalent to average net revenues.

The graph on the following page illustrates the magnitude of the net revenues corresponding to the periodic drought (expressed in terms of percent deviation from average) compared to the annual flow-related net revenues for the period of 1912/13 to 2005/06. The number of flow years that have similar or more severe consequences than the periodic flow year can be determined by observation.

FLOW-RELATED NET REVENUE



<u>PUB/MH I-208</u>

Reference: Tab 13, 13.4 (3) 20-Year Financial Outlook Page 15 – Periodic Low Flows

c) In the period of low flow years, what on-peak and off-peak prices and volumes did MH assume in defining revenues and costs?

<u>ANSWER</u>:

Please refer to the responses to PUB/MH I-208(a) and (b) for a description of the periodic low flow analysis. These responses indicate that the analysis of periodic low flows was undertaken in terms of only financial impact and not a specific simulation of the operation of the system under a set of hypothetical flow conditions. Consequently, the breakdown of the revenue and volume components is not available for this periodic low flow sensitivity.

<u>PUB/MH I-209</u>

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook
Page 12 - Alternative Scenarios

Please provide a table indicating the assumptions utilized for low and high export prices, including (GWh, ¢/kW.h, carbon adder, domestic consumption level, interest rates, exchange rates etc for the forecast period through 2029.

<u>ANSWER</u>:

The specific details of Manitoba Hydro's electricity export price forecast, including details on specific pricing factors such as the assumptions regarding CO2 premiums, contain commercially sensitive information, and therefore are confidential since public release could harm the Corporation in negotiation of contracts for export sales. For further information on the electricity export price forecast, please see the response to PUB/MH I-156(a).

The attached tables contain the background information for low and high export price sensitivities, in terms of revenues/costs, energy supply/demand and associated average prices. Similar information for the expected prices is included for reference.

The interest rates and exchange rates for each sensitivity case are kept constant and are consistent with the Integrated Financial Forecast (IFF09).

EXPORT REVENUE ASSUMPTIONS FOR HIGH PRICE SENSITIVITY

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	30,076	30,800	30,998	30,917	30,944	31,087	30,816	30,760	33,524
MH Thermal Generation	152	159	502	520	554	575	618	661	712	851	767
Import Energy (Incl Wind Purchase)	733	1,508	2,590	2,539	2,521	2,551	2,596	2,643	2,714	3,671	3,391
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	7,898	8,210	8,099	7,514	7,253	7,151	7,067	7,899	9,788

(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	59	61	69	73	87	97	109	139	142
Import Energy (Incl Wind Purchase)	39	58	196	196	201	208	223	235	250	345	318
Manitoba Domestic Energy Sales											
Total Export Sales	332	292	675	719	765	728	873	884	899	1,109	1,371

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	3.4	3.4	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
MH Thermal Generation	52.8	52.1	118.0	116.9	124.4	127.7	140.1	147.1	153.7	163.7	184.6
Import Energy (Incl Wind Purchase)	53.2	38.6	75.6	77.0	79.8	81.7	85.7	89.1	92.1	94.0	93.9
Manitoba Domestic Energy Sales											
Total Export Sales	36.2	41.0	85.5	87.6	94.5	96.9	120.3	123.6	127.3	140.4	140.1

EXPORT REVENUE ASSUMPTIONS FOR HIGH PRICE SENSITIVITY (Cont'd)

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	34,867	34,979	36,802	40,623	41,800	42,056	41,949	42,022	42,073	42,051
MH Thermal Generation	849	925	1,091	814	768	489	427	437	440	434
Import Energy (Incl Wind Purchase)	3,290	3,349	3,101	3,056	3,274	2,992	2,997	3,037	3,071	3,124
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	10,701	10,624	11,784	14,687	15,609	14,931	14,398	14,130	13,862	13,508

(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	116	117	123	136	140	141	140	140	141	140
MH Thermal Generation	161	180	215	166	164	106	94	100	104	106
Import Energy (Incl Wind Purchase)	320	335	325	329	368	322	303	331	352	369
Manitoba Domestic Energy Sales										
Total Export Sales	1,478	1,500	1,658	2,162	2,402	2,463	2,458	2,490	2,518	2,527

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	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
MH Thermal Generation	189.2	194.8	197.1	204.1	213.3	215.7	221.0	228.2	235.9	245.0
Import Energy (Incl Wind Purchase)	97.2	99.9	104.8	107.6	112.3	107.6	101.2	109.1	114.7	118.0
Manitoba Domestic Energy Sales										
Total Export Sales	138.1	141.2	140.7	147.2	153.9	164.9	170.7	176.2	181.7	187.1

EXPORT REVENUE ASSUMPTIONS FOR EXPECTED PRICE

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 (Incl Wind Purchase)	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	24,718	25,075	25,413	26,030	26,439	26,790	26,743	26,929	27,229
Total Export Sales	9,149	7,122	7,843	8,152	8,022	7,432	7,182	7,084	7,007	7,747	9,600

(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 (Incl Wind Purchase)	39	58	171	172	177	184	195	206	217	289	264
Manitoba Domestic Energy Sales											
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 (Incl Wind Purchase)	53.15	38.58	65.29	66.78	69.08	70.54	73.36	75.74	77.65	76.20	76.20
Manitoba Domestic Energy Sales											
Total Export Sales	36.24	41.02	65.90	66.89	71.71	73.93	90.87	92.31	94.95	105.31	105.56

EXPORT REVENUE ASSUMPTIONS FOR EXPECTED PRICE (Cont'd)

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	34,866	34,976	36,781	40,572	41,767	42,041	41,937	42,015	42,055	42,040
MH Thermal Generation	599	645	730	597	597	386	344	348	347	339
Import Energy (Incl Wind Purchase)	3,359	3,437	3,233	3,178	3,380	3,023	3,025	3,068	3,106	3,161
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 Energy Sales	10,516	10,426	11,530	14,541	15,510	14,843	14,331	14,064	13,787	13,439

(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	116	117	123	136	140	140	140	140	141	140
MH Thermal Generation	90	100	115	97	102	66	61	64	66	67
Import Energy (Incl Wind Purchase)	265	278	276	277	304	266	266	277	287	300
Manitoba Domestic Energy Sales										
Total Export Sales	1,120	1,140	1,294	1,671	1,852	1,818	1,811	1,835	1,855	1,863

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	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
MH Thermal Generation	150.7	155.4	158.0	163.0	170.5	172.4	177.2	183.4	190.3	198.4
Import Energy (Incl Wind Purchase)	78.9	81.0	85.3	87.3	90.1	88.0	88.1	90.4	92.5	94.8
Manitoba Domestic Energy Sales										
Total Export Sales	106.5	109.4	112.3	114.9	119.4	122.5	126.4	130.4	134.5	138.6

EXPORT REVENUE ASSUMPTIONS FOR LOW PRICE SENSITIVITY

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	30,063	30,782	30,982	30,904	30,924	31,070	30,805	30,755	33,502
MH Thermal Generation	152	159	434	434	438	434	521	540	583	583	494
Import Energy (Incl Wind Purchase)	733	1,508	2,609	2,566	2,560	2,607	2,637	2,703	2,785	3,780	3,451
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	7,835	8,133	8,005	7,413	7,176	7,073	6,995	7,730	9,551

(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	34	33	35	36	44	48	54	57	53
Import Energy (Incl Wind Purchase)	39	58	156	156	160	165	172	180	188	241	222
Manitoba Domestic Energy Sales											
Total Export Sales	332	292	440	457	477	455	532	523	529	649	806

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	3.4	3.4	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
MH Thermal Generation	52.8	52.1	77.6	76.5	80.7	83.0	85.0	88.7	92.3	97.2	107.9
Import Energy (Incl Wind Purchase)	53.2	38.6	59.8	61.0	62.7	63.4	65.2	66.7	67.7	63.6	64.3
Manitoba Domestic Energy Sales											
Total Export Sales	36.2	41.0	56.1	56.1	59.6	61.3	74.1	74.0	75.6	84.0	84.4

EXPORT REVENUE ASSUMPTIONS FOR LOW PRICE SENSITIVITY (Cont'd)

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	34,859	34,978	36,768	40,532	41,690	42,004	41,932	41,997	42,041	42,029
MH Thermal Generation	545	576	637	529	432	313	291	292	290	285
Import Energy (Incl Wind Purchase)	3,373	3,454	3,272	3,225	3,517	3,051	3,042	3,089	3,126	3,170
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	10,469	10,375	11,463	14,481	15,406	14,763	14,289	14,012	13,735	13,384

(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	116	117	123	135	139	140	140	140	140	140
MH Thermal Generation	60	66	75	64	54	40	39	40	42	43
Import Energy (Incl Wind Purchase)	224	233	232	234	259	224	201	222	236	242
Manitoba Domestic Energy Sales										
Total Export Sales	908	924	1064	1333	1455	1349	1331	1339	1346	1345

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	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
MH Thermal Generation	110.7	114.4	117.7	121.0	125.0	128.8	133.3	138.4	144.1	151.4
Import Energy (Incl Wind Purchase)	66.4	67.6	71.0	72.4	73.7	73.5	66.1	71.9	75.4	76.4
Manitoba Domestic Energy Sales										
Total Export Sales	86.7	89.1	92.8	92.0	94.4	91.4	93.2	95.6	98.0	100.5

<u>PUB/MH I-210</u>

Reference: Tab 13, 13.4 (3) 20-Year Financial Outlook Alternative Scenarios

a) **Please file any forecasts relied upon in setting the long term interest rates and foreign currency rates utilized in the 20-year forecast.**

<u>ANSWER</u>:

Refer to Manitoba Hydro's response to PUB/MH I-46(c) for the forecasts relied upon in setting the long-term interest rates and foreign currency rate utilized in the 20-year forecast.

For the 2009/10 to 2012/13 period, the forecasters used to derive the interest rate forecasts were the same as those identified in Tables 1 and 3 of PUB/MH I-46(b). For the 2013/14 to 2019/20 period, Tables 2 and 4 of PUB/MH I-46(b) identify the forecasts for 90 Day T-bill and Canada Bond Yield 10 Year+ rates.

For the 2009/10 to 2012/13 period, the forecasters used to derive the foreign currency rate forecast were the same as those identified in Tables 1 and 3 of PUB/MH I-46(b). For the 2013/14 to 2019/20 period, the forecasters identified in Table 2 of PUB/MH I-46(b) were used in determining the foreign currency rate forecast.

For the remaining years of the long-term forecast post 2019/20, the forecasts of IHS Global Insight, Conference Board, Informetrica and Spatial Economics were used for interest rates and foreign currency rate forecasts.

<u>PUB/MH I-210</u>

Reference: **Tab 13, 13.4 (3) 20-Year Financial Outlook Alternative Scenarios**

b) Please provide an alternative scenario, which assumes interest rates to be 9.10% by 2013/14.

<u>ANSWER</u>:

An interest rate increase of 3.00% was applied to new long-term debt rates and sinking fund investments assumed in IFF09-1 (before provincial guarantee fees) beginning in 2013/14. Please refer to the attached schedules.

CONSOLIDATED PROJECTED OPERATING STATEMENT
ALTERNATIVE SCENARIO - INTEREST RATES AT 9.10% BY 2013/14
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
REVENUES											
General Consumers	1,652	1,670	1,739	1,808	1,869	1,953	2,028	2,101	2,178	2,256	2,336
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
	2,066	2,054	2,293	2,390	2,484	2,543	2,729	2,830	2,920	3,151	3,429
Cost of Gas Sold	351	332	340	346	342	349	350	351	352	353	352
	1,715	1,722	1,953	2,044	2,142	2,193	2,379	2,479	2,568	2,798	3,077
Other	28	29	31	32	32	33	34	34	35	36	36
	1,742	1,751	1,984	2,076	2,174	2,227	2,412	2,513	2,603	2,834	3,113
EXPENSES											
Operating and Administrative	446	456	482	492	501	512	522	532	555	568	589
Finance Expense	454	451	509	569	527	559	552	587	670	837	1,170
Depreciation and Amortization	394	415	437	468	480	502	513	518	539	573	609
Water Rentals and Assessments	120	110	111	113	114	114	115	115	115	115	124
Fuel and Power Purchased	103	131	248	249	259	268	296	341	362	440	418
Capital and Other Taxes	97	99	100	104	109	116	125	134	141	148	152
	1,613	1,663	1,888	1,994	1,992	2,071	2,123	2,228	2,382	2,681	3,062
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(13)	(15)	(15)
Net Income	129	88	98	83	180	151	281	274	208	137	36
Additional General Consumers Revenue											
General electricity rate increases		2.90%	2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
General gas rate increases		0.00%	1.50%	0.00%	1.00%	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%
Financial Ratios											
Equity	26%	25%	24%	24%	23%	22%	21%	20%	20%	19%	19%
Interest Coverage	1.24	1.15	1.15	1.12	1.25	1.18	1.29	1.24	1.16	1.10	1.02
Capital Coverage	1.39	1.09	1.14	1.28	1.35	1.61	1.94	1.84	1.83	1.84	1.86

PUB-MH-I-210 (b)

CONSOLIDATED PROJECTED OPERATING STATEMENT
ALTERNATIVE SCENARIO - INTEREST RATES AT 9.10% BY 2013/14
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
REVENUES									
General Consumers	2,392	2,454	2,514	2,581	2,651	2,721	2,801	2,877	2,957
Extraprovincial	1,201	1,223	1,379	1,758	1,940	1,908	1,903	1,928	1,950
	3,593	3,677	3,892	4,338	4,591	4,630	4,704	4,805	4,907
Cost of Gas Sold	351	350	350	349	348	347	346	346	345
	3,242	3,327	3,543	3,990	4,243	4,283	4,358	4,459	4,562
Other	37	38	39	39	40	41	42	42	43
	3,279	3,364	3,581	4,029	4,283	4,324	4,399	4,502	4,605
EXPENSES									
Operating and Administrative	602	615	634	647	660	673	686	699	713
Finance Expense	1,323	1,201	1,300	1,600	1,779	1,762	1,762	1,724	1,687
Depreciation and Amortization	638	644	672	734	778	795	813	816	827
Water Rentals and Assessments	129	130	136	150	154	155	155	156	157
Fuel and Power Purchased	435	459	473	459	492	420	395	424	445
Capital and Other Taxes	142	147	153	154	155	156	157	158	158
	3,270	3,196	3,369	3,744	4,018	3,961	3,968	3,978	3,989
Non-controlling Interest	(25)	(27)	(28)	(29)	(31)	(35)	(39)	(42)	(45)
Net Income	(16)	141	184	256	234	327	392	482	571
Additional General Consumers Revenue									
General electricity rate increases	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
General gas rate increases	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%	1.00%	0.00%	1.00%
Financial Ratios									
Equity	18%	18%	18%	19%	20%	21%	23%	25%	28%
Interest Coverage	0.99	1.08	1.10	1.14	1.13	1.18	1.22	1.27	1.33
Capital Coverage	1.49	1.58	1.57	1.68	1.55	1.76	1.84	2.01	2.05

CONSOLIDATED PROJECTED BALANCE SHEET
ALTERNATIVE SCENARIO - INTEREST RATES AT 9.10% BY 2013/14
(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	13,097	13,626	15,691	16,213	16,654	17,388	17,844	18,579	21,071	22,453	26,145
Accumulated Depreciation	(4,800)	(5,171)	(5,561)	(5,984)	(6,412)	(6,862)	(7,317)	(7,783)	(8,270)	(8,793)	(9,352)
Net Plant in Service	8,297	8,455	10,130	10,229	10,242	10,525	10,527	10,796	12,802	13,660	16,792
Construction in Progress	1,949	2,460	1,343	1,820	2,858	3,899	5,617	7,093	6,384	6,711	4,219
Current and Other Assets	2,421	2,374	2,503	2,551	2,292	2,442	2,690	2,909	3,282	3,019	3,314
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,397	14,083	14,707	15,499	16,973	18,941	20,906	22,575	23,498	24,433
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,786	10,166	11,322	13,140	14,429	15,563	16,846	14,564
Current and Other Liabilities	2,246	2,000	2,187	2,983	2,303	2,495	2,399	2,824	3,163	2,669	5,852
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,316	2,397	2,480	2,660	2,811	3,092	3,366	3,574	3,712	3,748
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,397	14,083	14,707	15,499	16,973	18,941	20,906	22,575	23,498	24,433

PUB-MH-I-210 (b)

CONSOLIDATED PROJECTED BALANCE SHEET
ALTERNATIVE SCENARIO - INTEREST RATES AT 9.10% BY 2013/14
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
ASSETS									
Plant in Service	27,296	27,767	31,689	34,791	36,100	36,928	37,547	38,302	38,934
Accumulated Depreciation	(9,942)	(10,541)	(11,172)	(11,867)	(12,611)	(13,375)	(14,159)	(14,948)	(15,749)
Net Plant in Service	17,353	17,226	20,517	22,924	23,489	23,553	23,388	23,354	23,185
Construction in Progress	4,526	5,457	3,114	880	273	122	210	208	341
Current and Other Assets	3,401	3,043	3,162	3,497	4,025	3,885	4,408	4,987	5,599
Goodwill	107	107	107	107	107	107	107	107	107
	25,388	25,833	26,901	27,408	27,895	27,667	28,114	28,656	29,232
LIABILITIES AND EQUITY									
Long-Term Debt	18,223	19,055	20,057	20,259	19,861	19,864	19,866	19,808	19,560
Current and Other Liabilities	3,165	2,638	2,521	2,568	3,218	2,660	2,710	2,825	3,074
Contributions in Aid of Construction	266	266	267	267	268	270	272	275	279
Retained Earnings	3,732	3,873	4,057	4,313	4,547	4,874	5,266	5,748	6,319
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0
	25,388	25,833	26,901	27,408	27,895	27,667	28,114	28,656	29,232

CONSOLIDATED PROJECTED CASH FLOW STATEMENT
ALTERNATIVE SCENARIO - INTEREST RATES AT 9.10% BY 2013/14
(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	2,171	2,159	2,401	2,495	2,590	2,649	2,836	2,938	3,029	3,261	3,540
Cash Paid to Suppliers and Employees	(1,175)	(1,227)	(1,364)	(1,382)	(1,414)	(1,441)	(1,493)	(1,561)	(1,614)	(1,714)	(1,728)
Interest Paid	(473)	(445)	(504)	(568)	(532)	(540)	(549)	(587)	(695)	(869)	(1,188)
Interest Received	29	22	14	16	15	4	15	26	36	39	33
	552	510	547	561	660	672	810	816	756	717	656
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	900	800	600	600	1,400	1,400	2,000	1,800	2,000	1,600	1,200
Sinking Fund Withdrawals	262	227	27	103	483	-	3	-	-	456	171
Retirement of Long-Term Debt	(448)	(304)	(27)	(183)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(36)	(12)	19	(10)	(14)	(12)	(13)	(14)	(15)	(26)	(15)
	678	712	619	509	1,019	1,288	1,728	1,585	1,455	1,161	1,035
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1,151)	(1,117)	(1,046)	(1,035)	(1,513)	(1,800)	(2,206)	(2,236)	(1,806)	(1,755)	(1,354)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(175)	(106)	(200)	(158)	(240)	(198)	(256)
Other	(36)	(20)	(16)	(17)	(17)	(31)	(29)	(41)	(28)	(27)	(27)
	(1,281)	(1,236)	(1,160)	(1,168)	(1,705)	(1,937)	(2,434)	(2,434)	(2,074)	(1,980)	(1,637)
Net Increase (Decrease) in Cash	(52)	(15)	6	(98)	(26)	23	103	(33)	137	(102)	54
Cash at Beginning of Year	(32)	(84)	(99)	(92)	(190)	(216)	(193)	(90)	(123)	15	(87)
Cash at End of Year	(84)	(99)	(92)	(190)	(216)	(193)	(90)	(123)	15	(87)	(33)

CONSOLIDATED PROJECTED CASH FLOW STATEMENT
ALTERNATIVE SCENARIO - INTEREST RATES AT 9.10% BY 2013/14
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
OPERATING ACTIVITIES									
Cash Receipts from Customers	3,704	3,789	4,005	4,451	4,705	4,744	4,819	4,920	5,023
Cash Paid to Suppliers and Employees	(1,753)	(1,795)	(1,840)	(1,853)	(1,903)	(1,846)	(1,835)	(1,879)	(1,915)
Interest Paid	(1,345)	(1,228)	(1,310)	(1,621)	(1,820)	(1,828)	(1,819)	(1,801)	(1,784)
Interest Received	30	27	4	4	18	24	16	30	44
	636	793	859	981	999	1,094	1,180	1,270	1,367
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	1,200	1,000	1,000	200	200	-	-	-	-
Sinking Fund Withdrawals	285	741	171	-	-	369	-	-	60
Retirement of Long-Term Debt	(285)	(744)	(171)	-	-	(600)	-	-	(60)
Other	13	(25)	(23)	(24)	(24)	(25)	(27)	(29)	(30)
	1,213	971	977	176	176	(256)	(27)	(29)	(30)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(1,487)	(1,400)	(1,577)	(863)	(692)	(665)	(694)	(739)	(750)
Sinking Fund Payment	(291)	(347)	(204)	(191)	(196)	(200)	(184)	(187)	(191)
Other	(33)	(38)	(29)	(32)	(29)	(30)	(33)	(31)	(31)
	(1,811)	(1,785)	(1,810)	(1,085)	(917)	(895)	(911)	(957)	(972)
Net Increase (Decrease) in Cash	37	(21)	27	72	258	(57)	242	284	365
Cash at Beginning of Year	(33)	4	(17)	10	82	340	283	525	808
Cash at End of Year	4	(17)	10	82	340	283	525	808	1,173

PUB/MH I-211

Reference: **Tab 13, 13.4 (3) 20 -Year Financial Outlook, Page 16, Alternative Development Sequence Figure 9**

a) Please file the related capital expenditure forecast and financial forecast including operating statement, balance sheet and cash flow statement for the years 2009/10 though 2042 to illustrate the scenario which excludes the WPS and MP power sales which corresponds with the graph in figure 9.

ANSWER:

Please refer to the attached schedule and please refer to Appendix 15 to see the financial projections for the Alternative Development Sequence.

Incremental Change in CEF09-1 for the Alternative Development Scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Keeyask	(6)	(34)	(121)	(143)	(182)	(486)	(799)	(808)	(585)	(537)	(264)
Conawapa	9	12	51	83	34	67	(27)	208	308	11	(0)
US Tie Line	-	(1)	(2)	(8)	(18)	(32)	(79)	(65)	(0)	-	-
CCGT	-	-	-	-	-	-	-	-	-	-	-
North South Transmission	-	-	-	-	-	-	-	-	-	-	-
Adjusted New Major Gen & Trans	**3**	**(22)**	**(73)**	**(68)**	**(166)**	**(451)**	**(905)**	**(665)**	**(277)**	**(527)**	**(264)**

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Keeyask	(75)	-	-	-	-	-	-	-	-	-	-
Conawapa	(92)	(216)	(396)	(234)	(7)	-	-	-	-	-	-
US Tie Line	-	-	-	-	-	-	-	-	-	-	-
CCGT	-	-	-	-	-	-	-	-	-	-	91
North South Transmission	-	-	(345)	-	-	-	-	-	-	-	-
Adjusted New Major Gen & Trans	**(167)**	**(216)**	**(741)**	**(234)**	**(7)**	**-**	**-**	**-**	**-**	**-**	**91**

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Keeyask	-	-	-	-	-	-	-	-	-	-	-
Conawapa	-	-	-	-	-	-	-	-	-	-	-
US Tie Line	-	-	-	-	-	-	-	-	-	-	-
CCGT	389	452	35	-	-	-	-	-	-	-	-
North South Transmission	-	-	-	-	-	-	-	-	-	-	-
Adjusted New Major Gen & Trans	**389**	**452**	**35**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

CC GT = Combined Cycle Gas Turbine.

PUB/MH I-211

Reference: Tab 13, 13.4 (3) 20 -Year Financial Outlook,
Page 16, Alternative Development Sequence
Figure 9

b) Please confirm that MH would still be looking to maximize export sales in the absence of WPS and MP firm sales.

ANSWER:

Confirmed. Manitoba Hydro would continue to maximize export sales in the absence of WPS and MP firm sales.

PUB/MH I-212

Reference: **Tab 13, 13.4 (8) Affordable Energy Program,**
Appendix 9-1 Power Smart Plan Section 6.1.4
LIEEP, Affordable Energy Program Marketing Plan,
Bill Assistance Program Enhancement

Please provide the 2009/10 and 2010/11 operating and capital budgets under each component of the Affordable Energy Program including NHN, Bill Management Services and LIEEP, including indicating the number of MH staff dedicated to the AEP Team and to each of the three initiatives.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-111(b) for the LIEEP budget and response to PUB/MH I-112(e) for the number of EFT's working on LIEEP.

See attached for the 2009/10 NHN budget. A NHN budget for 2010/11 has not been provided by the Salvation Army and therefore, is not available at this time. Manitoba Hydro has no full time staff working exclusively on the NHN initiative. As a small component of some jobs, customer service staff will refer customers to the NHN program. The internal oversight required of the program is minimal as the Salvation Army administers the program.

Please see Manitoba Hydro's response to RCM/TREE/MH I-61 and PUB/MH I-32(b) for information related to Bill Management Services.

Revised: Feb. 26/09

THE SALVATION ARMY
CANADA & BERMUDA
MINISTRY UNIT BUDGET WORKSHEET

PUB/MH I-212
Attachment 1
Page 1 of 2

A/C No.	Account Name	900/910 Approved Budget 2008/09	900/910 Proposed Budget 09-10

FUND: 300 Weetamah

DEPT: 900 Neighbours Helping Neighbours * Admin. + Grants combined

INCOME

EXTERNAL INCOME

A/C No.	Account Name	Approved Budget 2008/09	Proposed Budget 09-10
611100	General Donations	1,500	5,203
611250	Specified Donations - Fineline		
611260	Specified Donations - hyrdro customers	10,000	20,000
611900	Other External Income - hyrdo grants	155,000	171,200
642220	Interest Income - Bank Account	250	
642400	Grants from THQ - General	1,000	
	TOTAL INCOME	167,750	196,403

EXPENSES

PERSONNEL EXPENSES

SALARIES & ALLOWANCES

A/C No.	Account Name	Approved Budget 2008/09	Proposed Budget 09-10
711200	Salaries	50,483	28,361
711840	Salary Recovery - 900		8,534
	TOTAL SALARIES & ALLOWANCES	50,483	36,895

PAYROLL TAXES & BENEFITS

A/C No.	Account Name	Approved Budget 2008/09	Proposed Budget 09-10
712100	Canada/Quebec Pension Premiums	1,645	1,230
712200	Employment Insurance Premiums	847	643
712400	Workers' Compensation/CSST Premiums	80	372
712510	Employee RRSP Contributions	2,075	1,601
712600	Employees' Health Benefit Plan	125	1,868
	TOTAL PAYROLL TAXES & BENEFITS	4,772	5,713
	TOTAL PERSONNEL EXPENSES	55,255	42,608

GENERAL OPERATIONS

A/C No.	Account Name	Approved Budget 2008/09	Proposed Budget 09-10
721100	Advertising & Promotion	150	300
721600	Fax & Telephone	2,100	2,500
721700	Office Supplies, Printing & Stationery	969	1,000
722103	THQ Finance Accounting Fees (RAC)	2,517	2,946
722120	Shared Office Expense Recovery - 900		2,075
722151	Admin. Fees - Brandon	500	1,500
722152	Admin. Fees - Dauphin	500	500
722154	Admin. Fees - Flin Flon	500	500
722155	Admin. Fees - Portage	500	500

THE SALVATION ARMY
CANADA & BERMUDA
MINISTRY UNIT BUDGET WORKSHEET

A/C No.	Account Name	900/910 Approved Budget 2008/09	900/910 Proposed Budget 09-10
FUND:	300 Weetamah		
DEPT:	900 Neighbours Helping Neighbours		
722156	Admin. Fees - Other	1,500	500
722400	Conventions, Conferences & Retreats	400	400
722500	Education & Training	200	200
722800	Travel, Meals, Parking	350	400
741100	Office Equipment		500
741600	Office Furniture		800
742605	Rent - Internal	9,480	4,400
751000	Management Support Assessment	8,125	12,221
769050	Customer Assistance - Wpg	73,000	109,000
769051	Customer Assistance - Brandon	2,033	8,000
769052	Customer Assistance - Dauphin	2,033	2,500
769054	Customer Assistance - Flin Flon	2,033	1,000
769055	Customer Assistance - Portage	2,033	2,000
769056	Customer Assistance - other	4,066	
	TOTAL GRANTS & ALLOCATIONS	85,198	122,500
	TOTAL EXPENSES	168,244	196,350
	NET SURPLUS/(DEFICIT) BEFORE TRANSFERS	-494	53

PUB/MH I-213

Reference: Tab 13, 13.4 (8) Affordable Energy Page 4 of 46

a) Please describe how MH determined that the energy burden for its low-income customers is "not at a crisis level."

ANSWER:

Manitoba Hydro does not have its own definition of levels of energy burden. The comment that the energy burden for its low income customers is not at a critical level was based on a high level assessment and used the benchmark of 15%, which was drawn from the referenced "severe energy burden" which was provided by the witness for RCM/TREE during the 2008/09 Manitoba Hydro General Rate Application.

In preparing the Manitoba Hydro's Affordable Energy Program, a high level assessment was undertaken on the energy burden within Manitoba. This assessment simply looked at two levels of income and assessed the energy burden based on the average energy cost of customers falling within the LICO x 125% category. As provided in Manitoba Hydro's Affordable Energy Program report, the energy burden ranged from 6.3% to 9.6%. Manitoba Hydro recognizes that the assessment was based on two levels of incomes and average energy costs. Individual customers will have a broad range of income levels and these customers will have a broad range of energy costs.

The concept of customers' "energy burden" is not used in the design or assessment of Manitoba Hydro's Affordable Energy Programs. The focus of Manitoba Hydro's Affordable Energy Program is to assist its customers with managing their energy bills through the three components of the Program: Demand Side Management, Bill Management, and Emergency Financial Assistance. The issue of affordability is outside the scope of Manitoba Hydro's mandate and is a matter of policy for legislators and government agencies responsible for these matters.

<u>PUB/MH I-213</u>

Reference: Tab 13, 13.4 (8) Affordable Energy Page 4 of 46

b) Please re-file the chart on page 18 utilizing 2009 energy rates compared with the 2003 LICO chart as it forms the current eligibility criteria for the program.

<u>ANSWER</u>:

The chart on page 18 of the Bill Assistance Report was recalculated as shown below by applying 2009 energy rates to the consumption for electricity and natural gas based upon the 2003 Residential Energy Use Survey. The 2003 Residential Energy Use Survey identified average annual energy consumption of 24,079 kWh for the all-electric occupancy and a combined energy consumption of 7,839 kWh of electricity and 2,769 m^3 of natural gas for the gas heated occupancy. The results are shown below.

Heat Source	Energy Cost	Income	Energy Burden
Electric	$1,684	$17,000	9.9%
Electric	$1,684	$24,000	7.0%
Gas	$1,940	$17,000	11.4%
Gas	$1,940	$24,000	8.1%

PUB/MH I-213

Reference: Tab 13, 13.4 (8) Affordable Energy Page 4 of 46

c) Please re-file the chart utilizing 2009 energy rates and an updated LICO table.

ANSWER:

The chart on page 18 of the Bill Assistance Report was recalculated as shown below by applying 2009 energy rates to the consumption for electricity and natural gas based upon the 2009 Residential Energy Use Survey. The 2009 Residential Energy Use Survey identified average annual energy consumption of 21,116 kWh for the all-electric occupancy and a combined energy consumption of 7,250 kWh of electricity and 2,499 m^3 of natural gas for the gas heated occupancy. The results are shown below.

Heat Source	Energy Cost	Income	Energy Burden
Electric	$1,487	$17,000	8.7%
Electric	$1,487	$24,000	6.2%
Gas	$1,790	$17,000	10.5%
Gas	$1,790	$24,000	7.5%

Note that the $17,000 is the estimated income threshold below which customers may begin to start accessing different forms of social assistance.

The $24,000 income level represents the average income of Manitoba Hydro LICO-125 customers. In the 2003 Residential Energy Use Survey this average was $23,813 and was rounded to $24,000 for the table. In the 2009 Residential Energy Use Survey this average was $23,597 which also rounds to $24,000 for the table. The average of LICO-125 customers will always be in this range because the maximum income limits prevent it from increasing. The 2009 Residential Energy Use Survey utilized income increments of $5,000 compared to the $10,000 increments of the 2003 Residential Energy Use Survey which resulted in the slight change in average income.

PUB/MH I-213

Reference: Tab 13, 13.4 (8) Affordable Energy Page 4 of 46

d) Please discuss to what extent is the energy burden impacted by the number of individuals in a household where household income levels remains the same.

ANSWER:

The following table was compiled using the estimated energy cost for all residential customers with incomes from $20,000 to $24,999.

Heat Source	People in household	2009 Energy Cost	Average Income	2009 Energy Burden
Electric	One Person	$ 1,374	$ 22,500	6.1%
Electric	Two People	$ 1,672	$ 22,500	7.4%
Electric	Three People	$ 1,915	$ 22,500	8.5%
Electric	Four People	n/a*	$ 22,500	n/a
Electric	Five or more People	n/a*	$ 22,500	n/a
Gas	One Person	$ 1,655	$ 22,500	7.4%
Gas	Two People	$ 1,843	$ 22,500	8.2%
Gas	Three People	$ 1,912	$ 22,500	8.5%
Gas	Four People	$ 2,029	$ 22,500	9.0%
Gas	Five or more People	$ 2,355	$ 22,500	10.5%

* There were insufficient electricity heated survey respondents with 4 or more people to estimate the energy use with any significance of accuracy within this group.

Generally, for a fixed income, the energy burden will rise as the family size increases.

PUB/MH I-213

Reference: Tab 13, 13.4 (8) Affordable Energy Page 4 of 46

e) Based on the 2009 energy costs and utilizing average monthly consumption for both Electric and Gas, with respect to a single parent with two children on social assistance, please indicate what percentage of his/her maximum shelter allowance, energy represents.

ANSWER:

The 2009 Residential survey had insufficient returns for LICO-125 families of 1 adult and 2 children to estimate average use with any statistical validity. Manitoba Hydro is also not an expert in shelter allowances and what factors determine how much an individual or family receives under social programs.

PUB/MH I-213

Reference: Tab 13, 13.4 (8) Affordable Energy Page 4 of 46

f) Please provide a similar example of the current pretax income energy burden [electric & natural gas] for a single individual working 40 hours a week at the current Manitoba minimum wage.

ANSWER:

A single individual earning $9.00 an hour (Manitoba minimum wage as of October 1, 2009) would earn $18,720 in 52 weeks at 40 hours a week. Using the 2009 survey data, customers that earn under $20,000 have average energy costs of $1,091 for all electric customers and $1,597 for natural gas heated customers.

The specific energy burden of a customer earning $18,720 per year and having these energy costs would be as provided in the following table. The specific energy burden of any specific customer would depend on their specific energy costs.

Heat Source	2009 Energy Cost	Average Income	2009 Energy Burden
Electric	$1,091	$18,720	5.8%
Gas	$1,597	$18,720	8.5%

The energy burden for low income single individuals is lower for electric heat source because many of these people are apartment dwellers.

PUB/MH I-213

Reference: Tab 13, 13.4 (8) Affordable Energy Page 4 of 46

g) Please indicate the number of Low Income customers who have a severe energy burden, high-energy burden and normal energy burden. Please define each of the parameters.

ANSWER:

Manitoba Hydro does not define levels of energy burden [see response to PUB/MH I-213(a)].

The following table provides an estimate of the number of LICO standard and LICO-125 customers by energy burden ranges compared with all Manitoba Hydro residential customers:

Energy Burden	LICO Customers	LICO Percent	LICO-125 Customers	LICO-125 Percent	Overall Customers	Overall Customers
3.00% or Less	13,979	18.7%	20,380	19.3%	208,458	47.5%
3.01% to 6.00%	12,505	16.7%	23,861	22.6%	145,742	33.2%
6.01% to 9.00%	18,766	25.0%	29,563	27.9%	47,178	10.7%
9.01% to 12.00%	15,440	20.6%	16,930	16.0%	21,139	4.8%
12.01% to 15.00%	9,313	12.4%	9,635	9.1%	10,634	2.4%
Over 15.00%	4,935	6.6%	5,415	5.1%	5,945	1.4%
Total	74,938	100.0%	105,784	100.0%	439,096	100.0%

PUB/MH I-214

Reference: **Tab 13, 13.4 (8)Affordable Energy Program**
Page 18 of 46, Customer Consumption Profile

a) **Please provide an electricity consumption profile for low-income customers and separately define the all-electric heat and natural gas heating customers.**

ANSWER:

The following table provides the monthly electricity profile for LICO-125 customers.

Electricity kW.h	Heating Fuel Electric	Heating Fuel Gas
January	3471	820
February	2980	717
March	2513	639
April	2239	648
May	1324	482
June	1186	531
July	765	563
August	734	551
September	768	558
October	1166	570
November	1639	547
December	2331	622
Total	21116	7250

PUB/MH I-214

Reference: Tab 13, 13.4 (8)Affordable Energy Program
Page 18 of 46, Customer Consumption Profile

b) Can MH determine from its province-wide load research and/or comparing the different summer & winter use profiles, the amount of supplementary electric heating being employed by various customer groups? Please explain and quantify.

ANSWER:

The 2009 data is not available in a suitable form at this time to allow for an analysis of electricity use for electric heat. To provide some insight, the following table provides the information based on the 2003 data. The information indicates that the use of supplementary electric heat increases as household income increases.

Income	% Supp Elec Heat
< $30,000	18.3%
$30,000 - $59,999	22.6%
$60,000 - $89,999	24.0%
$90,000 +	29.7%

The use of supplementary heat as well as increased use of the furnace fan, car plugs and lighting during the winter can be seen in the electricity profile for gas heated customers in the table provided in response to PUB/MH I-214(a). The summer months of May to September average 556 kW.h per month compared to the winter months of November to March that average 669 kW.h per month.

PUB/MH I-215

Reference: **Tab 13, 13.4 (8)Affordable Energy Program-Eligibility Criteria page 26 of 46**

a) **Please describe in full what changes in eligibility criteria are being considered for access to the LIEEP.**

ANSWER:

No changes are being considered with regards to eligibility criteria for Manitoba Hydro’s Lower Income Energy Efficiency Program. The reference is to the eligibility requirements which will be used for the Bill Management and Crisis Management components of Manitoba Hydro’s Affordable Energy Program.

<u>PUB/MH I-215</u>

Reference: Tab 13, 13.4 (8)Affordable Energy Program-Eligibility Criteria page 26 of 46

b) Please provide a comparison of the number of customers who would qualify for access to the AEP under the new criteria versus the current 125% of all LICO.

<u>ANSWER</u>:

The new criteria has not been determined at this time.

PUB/MH I-216

Reference: **Tab 13, 13.4 (8) Affordable Energy Program reconnection fees, interest charges**

a) **Please indicate the amounts collected in 2009/09 in reconnection fees, security deposits and interest charges for customers who participated in the Neighbors Helping Neighbors program.**

ANSWER:

Manitoba Hydro does not identify Neighbours Helping Neighbours (NHN) participation within its customer information/billing system. To obtain data on the above mentioned fees/ charges would require a manual search and review of all 469 customer accounts for the 2008/09 NHN participants.

Customers participating in the NHN program typically do not incur reconnection fees as they are encouraged to contact the NHN program staff upon receipt of a disconnection notice, prior to actual disconnection. Once a client has contacted NHN, Manitoba Hydro is notified and all collection activity is suspended pending the outcome of their meeting with NHN program staff. If the client is eligible, grant monies are applied against the outstanding balance and the client is advised to contact Manitoba Hydro directly to make arrangements on any remaining balance. If the client is not eligible, they are still provided with referrals/counseling and encouraged to contact Manitoba Hydro directly to make arrangements to resolve their account prior to disconnection.

Security deposits are assessed when setting up a new customer account and only where satisfactory credit information is not provided by the customer. Customers participating in the NHN program are existing customers and therefore security deposits were not collected.

PUB/MH I-216

Reference: **Tab 13, 13.4 (8) Affordable Energy Program reconnection fees, interest charges**

b) **Please provide an estimate of the amount of foregone reconnection fees, security deposits and interest charges forecast for 2010/11 and 2011/12.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-216(a). Reconnection fees and security deposits are not typically assessed for NHN clients and the amount of interest charges incurred by previous NHN clients is not readily available; therefore, a forecast for 2010/11 and 2011/12 is not available.

PUB/MH I-217

Reference: Tab 13, 13.4 (8) Affordable Energy Program, Page 28 of 46

Please indicate what information is to be gathered when LIEEP staff contact NHN participants and how that information will be utilized to determine eligibility for the LIEEP.

ANSWER:

Manitoba Hydro is currently working with The Salvation Army to refine how to facilitate access for qualifying customers to LIEEP. The Salvation Army will help the potential customers fill out the application form and then send it directly to Manitoba Hydro. The information requested is the same for any customer applying for LIEEP and includes things such as household size and income. Income verification is determined by the customer providing a copy of the most recent tax return as the corresponding notice of assessment. These can be easily obtained from Canada Revenue Agency and no cost to the customer. The process will be monitored to determine its success.

PUB/MH I-218

Reference: Tab 13, 13.4 (8) Affordable Energy Program, Page 29 of 46

Please provide the estimated time lines for the completion of a landlord program.

ANSWER:

Manitoba Hydro is currently developing a program to allow private landlords to participate in LIEEP. Subject to approvals and competing priorities, the estimated implementation timeline is during the summer 2010.

<u>PUB/MH I-219</u>

Reference: Tab 13, 13.4 (8) Affordable Energy Program page 29 of 46 NHN Annual Cost

Please provide a table indicating the NHN Annual Costs for the past five years including the number of customers assisted, level of assistance, level of program funding provided by MH, private donations, administrative and marketing expense, total program cost per customer assisted and program costs as a percentage of MH's distribution revenue.

<u>ANSWER</u>:

The following table presents a summary of the Neighbours Helping Neighbours program annual costs and activity as provided by the Salvation Army.

YEAR	2004/05	2005/06	2006/07	2007/08	2008/09
MH Donations - Grants	$20,000	$34,574	$71,087	$77,522	$100,488
MH Donations -Admin	$40,576	$45,689	$63,500	$78,750	$81,250
Private donations	$9,214	$7,381	$9,315	$13,886	$29,647
Total Donations	$69,790	$87,644	$143,902	$170,158	$211,385
Value of Grants Provided	$19,175	$55,612	$74,698	$95,564	$120,835
Program Administration	$35,656	$41,988	$67,075	$74,617	$72,514
Program Expenses	$54,831	$97,600	$141,773	$170,181	$193,349
Additional MH Marketing Expenditures*	N/A	$10,639	$4,610	$11,501	$5,788
# of Clients Assisted	146	309	274	330	469
Cost/Client Assisted	$376	$350	$534	$551	$425
% of MH General Consumers Revenue	0.003	0.006	0.009	0.010	0.011

* "Additional MH Marketing Expenditures" represent direct expenditures made by Manitoba Hydro to market the NHN program. These costs are incremental to the above mentioned MH grant and administration donations which are provided to the Salvation Army and therefore will not be present within the Salvation Army financial statements for the program.

PUB/MH I-220

Reference: **Tab 13, 13.4 (8) Affordable Energy Program page 30 of 46 - Basic Monthly Charge**

a) Please provide an estimate of the administrative cost for MH to implement its own screening process based on LICO x 125% eligibility criteria.

ANSWER:

Manitoba Hydro is not considering a reduction of the Basic Monthly Charge based on income. Manitoba Hydro would reduce the Basic Monthly Charge for all customers.

PUB/MH I-220

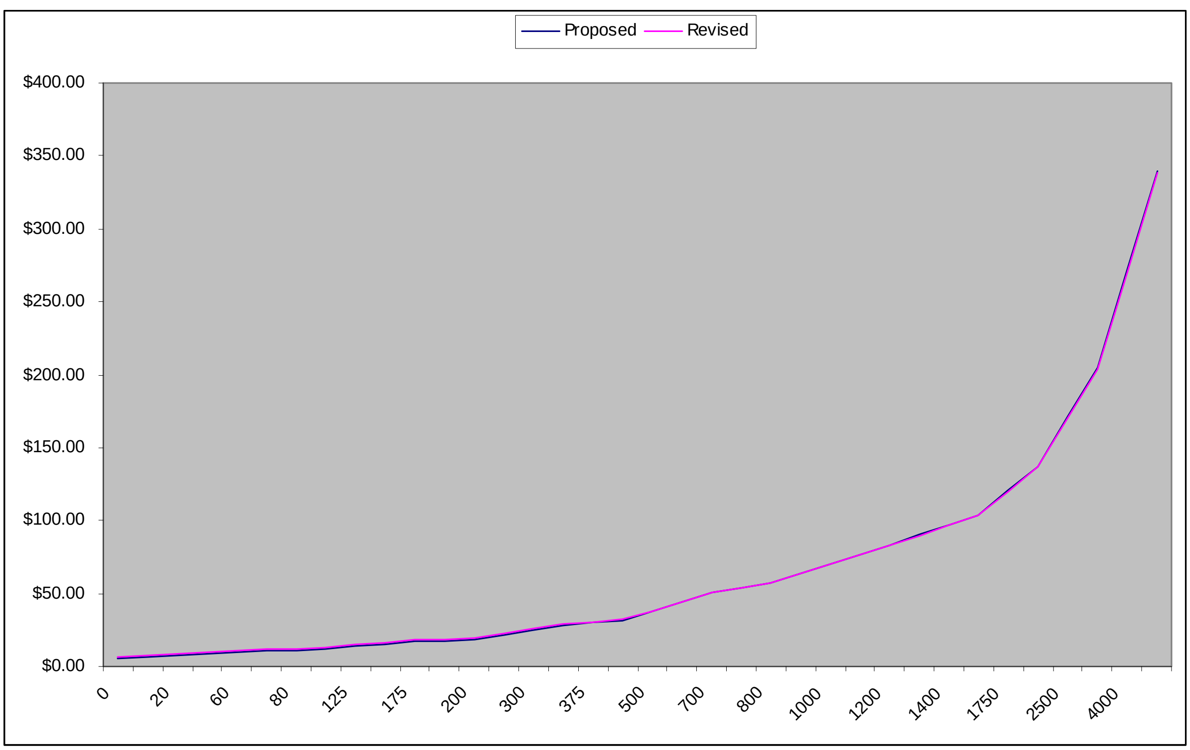
Reference: **Tab 13, 13.4 (8) Affordable Energy Program page 30 of 46 - Basic Monthly Charge**

b) **Please provide a tabular and graphical illustration of the billing impacts of MH's proposed Basic Monthly Charge reduction on the various consumption patterns of customers.**

ANSWER:

The following graph and table show the difference between the Residential rate originally proposed in the Application (Appendix 10.3) and the Residential rate revised in accordance with Board Order 18/10, for various levels of consumption. As shown in the rates below, the proposed rates reflected a lower monthly Basic Charge.

	Proposed	Revised
Basic Charge:	$5.85	$6.85
First 900 kW.h @	6.37¢	6.25¢
Balance of kW.h @	6.75¢	6.71¢



KW.h	Proposed $/Month	Revised $/Month	DIFF. $/Month
0	$5.85	$6.85	$1.00
10	$6.49	$7.48	$0.99
20	$7.12	$8.10	$0.98
40	$8.40	$9.35	$0.95
60	$9.67	$10.60	$0.93
75	$10.63	$11.54	$0.91
80	$10.95	$11.85	$0.90
100	$12.22	$13.10	$0.88
125	$13.81	$14.66	$0.85
150	$15.41	$16.23	$0.82
175	$17.00	$17.79	$0.79
185	$17.63	$18.41	$0.78
200	$18.59	$19.35	$0.76
250	$21.78	$22.48	$0.70
300	$24.96	$25.60	$0.64
350	$28.15	$28.73	$0.58
375	$29.74	$30.29	$0.55
400	$31.33	$31.85	$0.52
500	$37.70	$38.10	$0.40
600	$44.07	$44.35	$0.28
700	$50.44	$50.60	$0.16
750	$53.63	$53.73	$0.10
800	$56.81	$56.85	$0.04
900	$63.18	$63.10	($0.08)
1000	$69.93	$69.81	($0.12)
1100	$76.68	$76.52	($0.16)
1200	$83.43	$83.23	($0.20)
1300	$90.18	$89.94	($0.24)
1400	$96.93	$96.65	($0.28)
1500	$103.68	$103.36	($0.32)
1750	$120.56	$120.14	($0.42)
2000	$137.43	$136.91	($0.52)
2500	$171.18	$170.46	($0.72)
3000	$204.93	$204.01	($0.92)
4000	$272.43	$271.11	($1.32)
5000	$339.93	$338.21	($1.72)

PUB/MH I-221

Reference: Tab 13, 13.4 (8) Affordable Energy Program page 32 of 46

a) Please elaborate on how MH is proposing to expand the Manitoba Bill Assistance Stakeholder Working Group.

ANSWER:

It is envisioned that through discussions with various stakeholders, potential individuals will be identified which may join the Bill Assistance Stakeholder working group. These potential members may include government officials or other stakeholders with expertise in social programming.

<u>PUB/MH I-221</u>

Reference: Tab 13, 13.4 (8) Affordable Energy Program page 32 of 46

b) Please indicate the timeframe being considered for the work steps set out, including expansion of the working group, formulation of working group recommendations and an Affordable Energy Summit.

<u>ANSWER</u>:

As indicated in PUB/MH I-221(a), Manitoba Hydro is proposing to expand the Manitoba Bill Assistance Stakeholder working group and schedule the first meeting in the Spring of 2010. This is part of the overall Marketing Plan with the Affordable Energy Summit anticipated to take place in Spring/Summer 2010.

PUB/MH I-222

Reference: Tab 13, 13.4 (8) Affordable Energy Program Marketing Plan

a) Please file in these proceedings The Affordable Energy Marketing Plan.

ANSWER:

Please see attached plan

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor 360 Portage Ave
Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147
mmurphy@hydro.mb.ca

February 3, 2010

PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. G. Gaudreau, Executive Director

Dear Mr. Gaudreau:

Re: Centra Gas Manitoba Inc. ("Centra")
Response to Directive 6 from Order 128/09: Revised Marketing and Promotional Plan for the Affordable Energy Program

In Order 128/09 issued on September 16, 2009 with respect to Centra's 2009/10 & 2010/11 General Rate Application, the Manitoba Public Utilities Board ("PUB") directed Centra "to develop and file with the Board a revised marketing and promotional plan for the LIEEP and FRP, designed to educate and encourage lower income customers to participate". Accordingly, Centra is enclosing herewith a copy of the Affordable Energy Program Marketing Plan.

If you have any questions with respect to this submission or require a paper copy, please contact the writer at 360-3468, or Greg Barnlund at 360-5243.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Murphy

Marla D. Murphy
Barrister and Solicitor
Att.
cc: Mr. B. Peters, Fillmore Riley
Mr. R. Cathcart, Cathcart Advisors Inc.
Mr. B. Ryall, Energy Consultants Inc.

AFFORDABLE ENERGY PROGRAM MARKETING PLAN

1 BACKGROUND

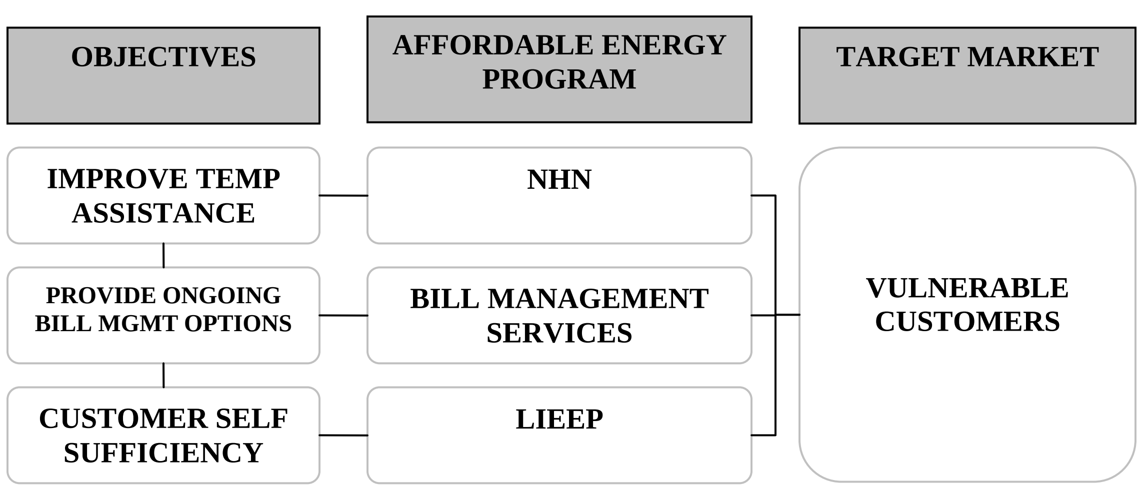
1.1 Bill Assistance Program Enhancement

Manitoba Hydro is consolidating and enhancing its three main bill assistance program components under one umbrella program called the Affordable Energy Program (AEP). Current programming is comprehensive, and will only become more effective as a result of these enhancements. Recently, the LIEEP has been identified as a leader in the country for lower income energy efficiency programs.

Through this consolidation, all program components that target lower income households will work together to create customized solutions to aid program participants in managing their bills and reducing their energy burdens.

The overall objective for the enhanced AEP is to improve the affordability of energy for lower income customers while maintaining efficient operations of Manitoba Hydro. To that end, an enhanced marketing plan has been developed to promote the AEP and ensure qualified customers are aware and can easily participate in the program, as described in Section 2.

Below is a table outlining the three key components of the AEP and the program objectives they are designed to satisfy. Neighbours Helping Neighbours (NHN) will focus on providing temporary financial assistance, as well as reducing outstanding arrears. Bill Management Services will focus on providing customers with tools to help them better manage their energy bills such as equal payment plans and pick your payment date options. The Lower Income Energy Efficiency Program (LIEEP) will anchor the overall AEP offering sustainable solutions to help customers move towards self sufficiency through energy efficiency upgrades which will reduce their energy bills.



Manitoba Hydro has a strong history of collaborating with various government, social and commmunity organizations including the Salvation Army which is responsible for operating the NHN program. Manitoba Hydro currently refers a large number of customers to various program partners to seek aid that falls outside Manitoba Hydro's scope of assistance. The AEP team has identified the opportunity to gain valuable referrals from its program partners by actively and reciprocally encouraging them to include the AEP as part of their toolkit used in assisting their clients facing financial hardship. Manitoba Hydro believes that increasing two-way communication between the AEP team and the program partners will help to further solidify the AEP as a key element of a broad social services portfolio. Research of other jurisdictional programming illustrates that this holistic approach to customer aid is more effective at creating sustainable change in customers' financial situations that would not be possible without the cooperation of multiple parties.

1.2 Existing Marketing

A key area of the program that is being enhanced is the marketing plan. Manitoba Hydro currently uses community newsletters and magazines, bill inserts, corporate website, targeted mail drops, and public service announcements. In addition, the program is currently promoted through Manitoba Hydro customer service staff and other community groups and stakeholders. This marketing approach has generated over 1 700 customer applications since the start of the program. In order to increase the participation, consultations have taken place with other lower income programs and stakeholders. The findings of this research are presented in Section 1.3 of this report.

1.3 Existing Research

a) Demographics

i. Manitoba Hydro Residential Survey

Manitoba Hydro uses 125% of the federal government Low Income Cut Off (LICO) to define the lower income customer base. The following information summarizes the current demographic data on lower income households in Manitoba. Approximately 93 000 customers are directly paying their own utility bills and are within the LICO x 125% threshold, with approximately 70% owning their dwelling.

LICO x 125% DWELLING TYPES			
	OWN	**RENT**	**TOTAL**
Single	54 426	5 696	60 122
Multiplex	4 705	3 001	7 706
Townhouse	1 510	3 067	4 577
Mobile	2 993	507	3 500
Subtotal (Net Apartments)	**63 634**	**12 271**	**75 905**
Apartment	2 145	15 147	17 292
Total	**65 779**	**27 418**	**93 197**
Total %	71%	29%	100%

It is important to note that the demographic information listed above is based on information collected in 2003. This information will be updated early in 2010 pending the results of the 2009 Manitoba Hydro Residential Customer Survey. The updated information is not expected to affect the overall direction of the strategy outlined in this plan, but will be reviewed and applied as necessary.

ii. Statistics Canada

The City of Winnipeg, in partnership with local community organizations, other levels of government and the Community Social Data Strategy group, matched 2006 Statistics Canada Census Data to Winnipeg neighbourhood geographic areas. Aggregate household income data by neighbourhood was analyzed and was used to identify areas in which to target communications within the City of Winnipeg.

b) Key Learnings from other Utilities & Stakeholders

Manitoba Hydro has been invited to present its Lower Income Energy Efficiency Program at various Canadian and United States lower income energy efficiency conferences, including Chartwell's Best Practices Summit on Serving Low Income Customers in April 2009 and Chartwell's Webinar on Low-Income Energy Efficiency Programs in December 2009. As a result, Manitoba Hydro has been able to gain learnings from other presenting utilities that have been delivering lower income programs for many years. A prime example is San Diego Gas & Electric (SDG&E) that started its lower income energy efficiency program in the 1980's. Its program has grown substantially since its inception with it serving over 20 000 lower income customers a bundled offering of services in 2009. Another example is Entergy, a utility that was able to help over 17 000 customers through its Power To Care fund in 2008. Discussions have also taken place with Chartwell, an independent information services company that facilitates knowledge exchange among utility professionals. Consultations with their researchers have emphasised the importance of building upon Manitoba Hydro's existing bill assistance structure and slowly ramping up initiatives and promotion as experience is gained. It should be noted that the organizations listed above are just a small sample of the numerous entities Manitoba Hydro has been working with to further refine its program and marketing efforts.

Below is a set of barriers to participation and marketing tactics that were identified during the research process.

Barriers to Participation

The barriers to participation listed below are addressed by the marketing strategy outlined later on in this plan:

i. Confusion & Lack of program understanding - Bill Assistance programs can often be complex with multiple offerings which can lead to customers having difficulty understanding which program to utilize and/or how it can help them reduce their energy bills.
ii. Lack of Trust - Due to the intrusive nature of some bill assistance programs, specifically those that involve home visits, customers are occasionally hesitant to participate as they do not trust strangers to come into their homes. A common example would be an energy audit. In addition, customers may be sceptical of "free" energy upgrades, and may be less sceptical if they heard this message delivered by a community group, which is a trusted source.
iii. Not a priority, set aside and later forgotten - Lower income customers face numerous challenges on a daily basis, and energy efficiency and reducing energy bills is not always top priority. As a result, the marketing message must be relevant and motivational to lead customers to act upon it quickly, or risk that it will be forgotten.
iv. Ineffective Messaging - Marketing messages and the mediums that are used to communicate messages must be carefully selected to ensure they appeal to the target audience.

Marketing Tactics

Below is a list of marketing tactics that are commonly used by utilities to promote their bill assistance offerings, some of which are already in use by Manitoba Hydro. Those not currently in use have been reviewed, and where applicable, have been incorporated into the marketing strategy laid out later on in the report.

i. Direct mail, Bill Messaging, Email Campaign, Automated Outbound Calling
   - Allows for targeted messaging to specific customer groups
   - Offers one of the highest response rates of all mediums
   - Used by Dominion Virginia Power, San Diego Gas & Electric, Entergy, Pacific Gas & Electric, TXU Energy

ii. Program Partners/Social Networks

- Use newsletters, seminars, meetings, and leadership summits to build relationships with partners
- Provide unique training opportunities to educate them on the lower income programs
- Partners include social agencies, community leaders, etc.
- Used by Entergy, San Diego Gas & Electric, NV Energy, Pacific Gas & Electric, Public Service Enterprise Group

iii. Neighbourhood Approach/Targeted Canvassing

- Targeted message and delivery channel for specific customer segments
- Used by San Diego Gas & Electric

iv. Internal marketing campaign

- Elicit employee "buy in" to programming in an effort to improve program delivery
- Used by Entergy, Public Service Enterprise Group, Clark Public Utilities

v. Internet/Electronic Marketing (Text, Facebook, Twitter, etc.)

- Using emerging communication forms to deliver program marketing messages
- Used by San Diego Gas & Electric

vi. Annual low income report

- Tool used for disseminating program results on an annual basis that works well for internal and external marketing, not necessarily for program participants, but for program partners and internal/external stakeholders
- Used by Entergy

vii. Community Events/Public Relations Activities

- Hold events for communities where residents are invited to learn about the lower income programming.
- Used by Pacific Gas & Electric

2 MARKETING OBJECTIVE & STRATEGY

It is critical to build awareness of the comprehensive Affordable Energy Program through a solid marketing strategy. Manitoba Hydro must expand its understanding of the motivators and barriers within the lower income market segment, and promote the program in a way that will minimize barriers and maximize participation. Below is a summary of the marketing strategy including the steps that will be taken to implement it.

2.1 Objective

The marketing objective of the Affordable Energy Program is to increase awareness and participation in Manitoba Hydro's enhanced and comprehensive Affordable Energy Program resulting in reduced energy burdens for lower income Manitobans.

2.2 Target Market

The overall target market for Manitoba Hydro's Affordable Energy Program is lower income households, particularly those that are struggling with managing their energy bills. The target market becomes more narrow at the point where emergency assistance is required through the NHN program, where more specific criteria is used to indentify vulnerable customers in genuine need.

This target market faces key barriers related to participation in lower income programs, specifically a general lack of awareness of energy conservation and bill management options. As mentioned earlier in the Key Learnings section, additional research has revealed more barriers including lack of program understanding, security fears related to energy audits, program participation not being made a priority by the individual and then later forgotten, and ineffective messaging.

2.3 Marketing Strategy

The marketing strategy for the Affordable Energy Program is to create a simple yet compelling umbrella education and communication program that positions the "Affordable Energy Program" as an easy way for Manitobans to save energy and manage their utility bills. The common bond between all program communications will be the elements of reliability and trust, which will be communicated by personalizing the "Affordable Energy Program" as caring, considerate, approachable, friendly and knowledgeable. Under this umbrella, targeted messaging will be developed to address the needs of individual market segments.

2.4 Marketing Research

Both quantitative and qualitative research will assist in developing communications that provide compelling messaging to appropriate market segments as follows.

a) Updated Demographic Study

Manitoba Hydro is currently completing the 2009 Residential Customer Survey. This survey has been designed to provide detailed information on the number of lower income consumers, family size, income levels, types of heating equipment, types of housing, target market geographical information, and any relationship that may exist between income and consumption. Completion of the survey as well as the tabulation and review of the results is expected early in 2010.

b) Qualitative Pre-testing of Messaging and Materials

Focus group testing will be performed to provide feedback on messaging and potential market acceptance of the advertising materials. Lower income participants will be shown different versions of advertising materials, and will be probed to determine the most relevant, understandable and motivating messages. As this is still a relatively new target market for Manitoba Hydro, it is important to ensure that the messages and “look and feel” of the campaign materials are compelling and address any communication barriers presented by this "hard to reach" group. In the absence of focus groups, there is the potential for a substantive media investment to be placed behind a message that is either not understood, believable, trusted, or motivating, resulting in a poor response to the campaign.

Benefits/strengths of group discussions include data and insights that would be less accessible without the interaction found in a group setting, as listening to others’ verbalized experiences stimulates memories, ideas, and experiences in participants. Probing on an issue of interest when group members engage can result in an increased elaboration on a topic and broader insight into understanding an issue.

c) Quantitative Monitoring of Program Awareness through Omnibus Study

Equally important to pre-testing the marketing materials through focus groups is continuously monitoring the response of the campaign. It is critical to continuously measure the breakthrough of the media campaign to ensure the target group is aware of the advertising and main message is being conveyed. In addition, the impact of the advertising can be tracked to determine whether the creative is motivating to the target group, thus providing an indication as to whether the target group may respond to the advertising by participating in the AEP and potentially identifying the barriers to participation. This would be achieved by asking four to five questions on an omnibus survey every four to six months during the first year of the campaign, with a baseline survey performed prior to the campaign being launched.

An omnibus survey is a quantitative survey that interviews a large and representative sample of people with a view to find the results to represent the whole population. It allows clients to share the costs of research by pooling questions. All the questions for a given wave are then put to a representative sample as part of a single questionnaire. Each individual client's questions are of course confidential, and results are processed in such a way as to ensure that each party only sees their own data. An omnibus survey is conducted on a set timetable, and takes place regularly throughout the year - typically on a monthly basis.

d) Ongoing Research

Throughout the life of the program, ongoing evaluation will be performed through a number of metrics as outlined in Section 4 of this plan. Information will be gleaned from these metrics to continuously evolve the marketing plan. Manitoba Hydro will also work closely with program partners such as the Social Planning Council to get their feedback on the marketing strategy and incorporate it into future initiatives.

2.5 Marketing Tactics

A two pronged marketing approach that focuses on education and communication will be used to achieve the objective of increased awareness and participation in the AEP. Tactics in both areas will support the comprehensive and holistic nature of the AEP and leverage working with program partners to extend the reach of the campaign across all communities in Manitoba.

a) Education

Education will be a valuable component of the Affordable Energy Program, not just education of the customer, but also education of the service providers and program partners. Other successful programs such as Entergy's Lower Income Program have shown that energy efficiency programs increase energy savings and enhance the persistence of savings by providing customer education and training to staff. Education also helps the customer feel more committed to the program and gives the customer a degree of control over their energy usage and related savings.

The following marketing activities will be introduced into the Affordable Energy Program:

i. Develop a team of "Affordable Energy Champions"

   A team of "Affordable Energy Champions" comprised of key staff within Manitoba Hydro and program partners will be developed. The team will be trained on the key components of the program through a "train the trainer" model. Through this network, opportunities for community educational workshops will be identified where information can be disseminated.

ii. Develop supporting customer educational materials

Supporting materials will be developed to promote the program offerings and encourage energy efficient behaviour. An example would be a "leave behind" document left with a participating homeowner that explains the importance of energy efficient behaviours such as turning off the lights when leaving the room or lowering the thermostat when leaving the home for an extended period of time.

iii. Develop an educational component related to renting

An educational component specifically targeted to lower income tenants/owners who pay their own utility bills, similar to the "before you rent" campaign in Quebec will be developed to help customers avoid renting accommodations with energy bills that do not fit their budget.

iv. Investigate tenant/owner led neighbourhood education programs

Consultations with community groups will take place to determine other educational opportunities specific to lower income neighbourhoods where tenant/owner led neighbourhood "Affordable Energy Action Plans" may be developed, similar to tenant led community animation models that have been developed in Ontario.

b) Communication

i. Enhance Manitoba Hydro Communications: Increased awareness of the Affordable Energy Program will be achieved through the following communication vehicles:

- Mass Media:
  - A layered mass media approach will be used to communicate the Affordable Energy Program offering to the lower income market, with special focus on using media vehicles that can reach the target group. This includes bus benches (Feb-May, Aug-Nov) and public recycling bins (May-Aug) in an attempt to provide top of mind awareness of the AEP. Direct mail (Feb-May, Aug-Oct), radio (Feb-June, Aug-Oct), and select community newspapers (Feb-Apr, Aug-Oct) will be used to reinforce the message and provide a "call to action" where targeted customers will contact Manitoba Hydro to inquire into the program.
  - Supporting promotional materials will consist of bill inserts, Manitoba Hydro website, and messages heard while "on hold" when calling the Manitoba Hydro customer service line.
  - Targeted activities in partnership with communities may include promotional brochure drops and presentations will take place in communities/areas with high penetration of lower income households.

- Outbound calls to targeted customers.
- Note: A media calendar is included in Appendix A. A media development calendar is included in Appendix B.

  - Manitoba Hydro Staff:

    - As indicated earlier, a team of "Affordable Energy Champions" will be developed within Manitoba Hydro which will consist of representatives from all departments which interact with lower income customers including: Bill Management Services, Call Centre, District Offices, and the Affordable Energy Unit. Additional training will be provided for these key staff members, who in turn, will train staff within each department to ensure the program offerings are communicated to all customers at all relevant opportunities.

ii. Strengthen marketing support from program partners:

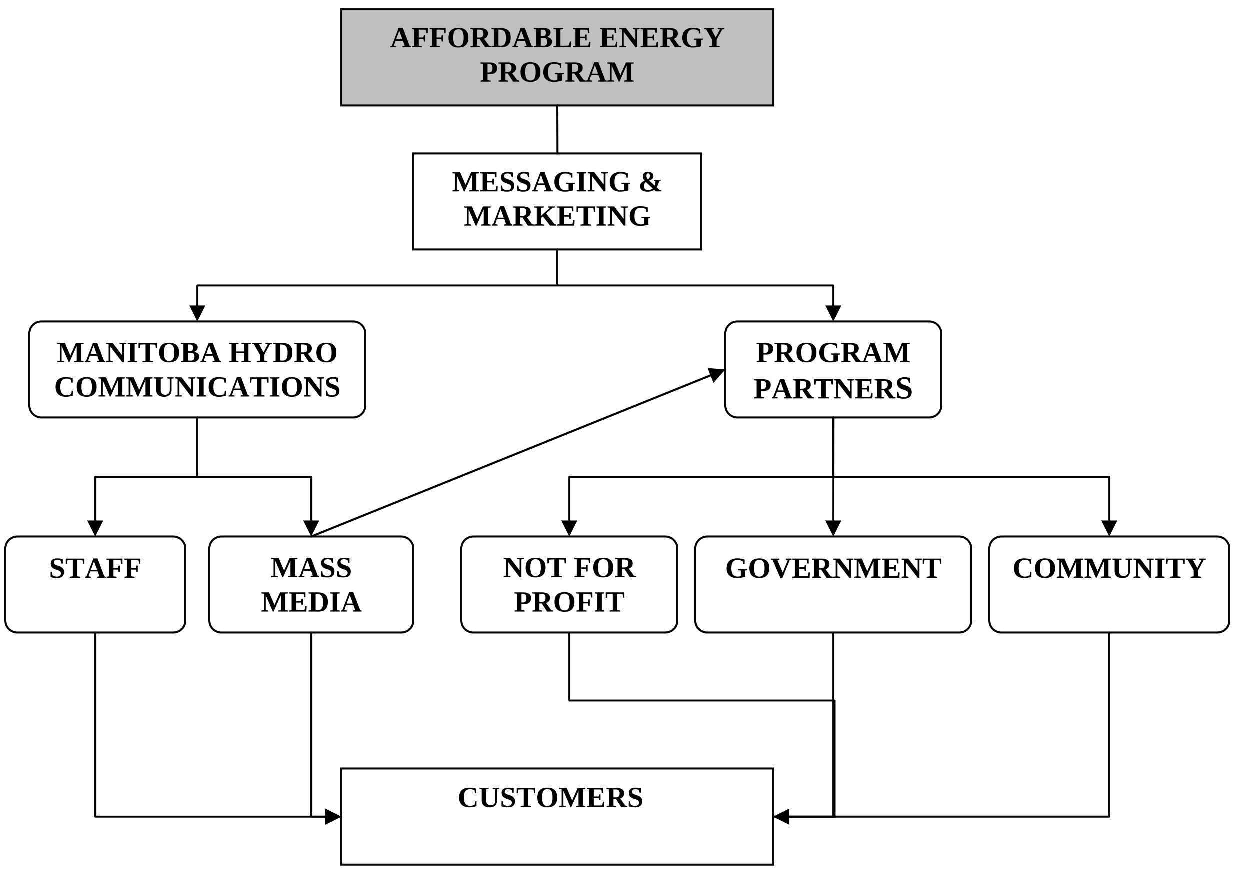
  - The use of trusted sources in the community is common amongst other jurisdictional lower income programming and has been affirmed as an important strategy by stakeholders to deliver messages to lower income customers. Therefore, in addition to targeting the lower income customer, it will also be important to increase the awareness of the Affordable Energy Program to potential program partners who can promote the program through direct customer contact, community events, etc. Manitoba Hydro will also attend lower income conferences, seminars and events throughout the province to promote the program to other stakeholders. The objective will be to broaden the team of "Affordable Energy Champions" to include external stakeholders that can act as ambassadors to promote the program, and provide constant reinforcement of bill management and energy efficiency behaviours. Program partners will disseminate AEP promotional materials to their clients and provide specific offerings tailored to meet their clients' needs.

  - Program partners will include, and not be limited to the following:
    - Not for profit groups (NGO's) such as Habitat for Humanity, Winnipeg Harvest, Winnipeg Foundation, United Way, and Salvation Army will be instrumental in promoting the program to lower income Manitobans with whom they already interface.
    - Government services such as the Province of Manitoba Public Trustee, Winnipeg Housing & Homelessness Initiative, and Manitoba Housing Authority.
    - Community groups such as the Westminster Housing Society, Spence Neighbourhood Association, Thompson Neighbourhood Renewal Corporation, Dakota Ojibway Tribal Council Housing Authority, and the North End Housing Project.

- Private Sector corporations and retailers, such as Giant Tiger, that service lower income customers will also be approached to distribute supporting materials, such as brochures and posters, to their customers.

Note: The AEP's program partners are constantly evolving and the AEP team is eager to grow the number of partners associated with the program.

The chart below illustrates the communication path of the Educational and Awareness messages delivered through various tactics flowing down to the customer.



3 BUDGET

Estimated Lower Income Budget Proposal*

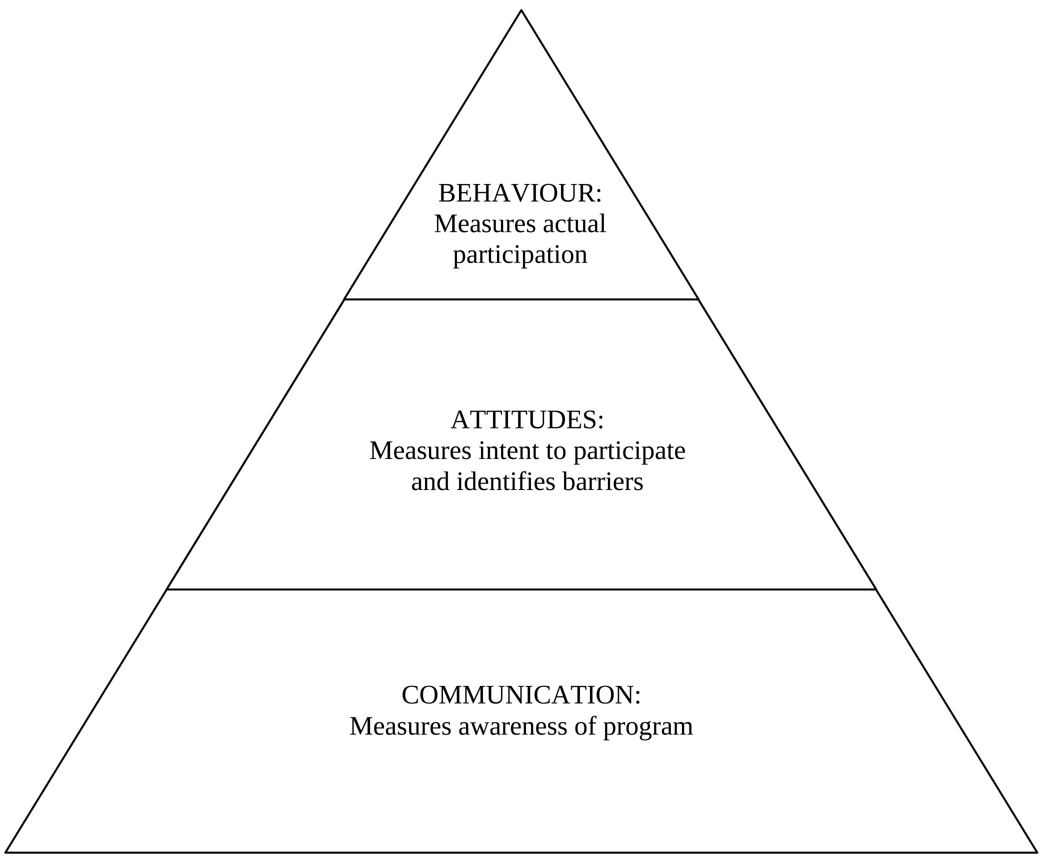
	2009-2010	2010-2011	Total
Research			
Pre-Program Focus Groups	$10,000	$0	$10,000
Customer Satisfaction Tracking Study**	$0	$0	$0
OmniBus	$5,000	$10,000	$15,000
Total	*$15,000*	*$10,000*	*$25,000*
Creative Development & Production	*$11,950*	$10,900	*$22,850*
Media			
Bus Benches / Transit Shelters	$900	$9,900	$10,800
Recycling Bins (Silver Boxes)	$0	$6,180	$6,180
NCI Radio	$1,000	$4,500	$5,500
CKJS Ethnic Radio	$1,000	$4,500	$5,500
City targeted newspaper/magazine	$2,500	$10,000	$12,500
MCNA Rural (select markets)	$5,000	$25,000	$30,000
Power Smart**	$0	$0	$0
Total	*$10,400*	*$60,080*	*$70,480*
Direct Marketing			
Canvassing	$0	$5,000	$5,000
Phone Calls (outbound)	$0	$10,000	$10,000
Community Intiatives	$1,000	$4,000	$5,000
Direct Mail	$10,000	$50,000	$60,000
Total	*$11,000*	*$69,000*	*$80,000*
OVERALL TOTAL	**$48,350**	**$149,980**	**$198,330**

* Subject to change based on media availability and cost of proposed activities
** No cost to Affordable Energy Program

4 MARKETING EVALUATION

The following pyramid provides a high level overview of the components of the evaluation of the AEP marketing program. The evaluation begins with measuring against the goal of increasing the awareness of the AEP to the entire target market, then builds up to the to the ultimate goal of increasing their participation in the program, as described below.

- The first level measures the awareness of the program. Customers will be asked if they are aware of the program, and if so, asked where they heard about the AEP.
- The second level measures the intent of the target group to participate in the program, and asks those that are aware of the program if they intend to participate. If customers do not intend to participate, they are asked about their barriers to participation which will provide insight into their attitudes about the program.
- The third level measures the actual behavioural changes that result from the marketing, which is measured through the actual participation of the target group.



5 CONCLUSION

Manitoba Hydro is enhancing and consolidating the design, delivery and marketing of its current bill assistance and Lower Income Energy Efficiency Program under one comprehensive program called the Affordable Energy Program. Current programming is comprehensive, and will only become more effective through these enhancements. Recently, the LIEEP has been identified as a leader in the country for lower income energy efficiency programs. In addition, approximately 1 700 applications have been received for the LIEEP program which were generated through past promotional activity such as bill inserts, advertisements in targeted magazines, targeted mail drops and very importantly, through partnerships with community groups and other stakeholders.

Based on extensive consultations held with these stakeholders and utilities in other jurisdictions, key learnings have been incorporated into an enhanced umbrella marketing plan that that will position the Affordable Energy Program as an easy way for lower income Manitobans to save energy and manage their utility bills. Enhanced marketing tactics focusing on education and communication will be supported through a media campaign that targets lower income households, community groups and other program partners. Ongoing research will be performed to ensure the messaging is relevant and motivating to the target group. Through this consolidation of programming, enhanced marketing strategy, and continuous evaluation, Manitoba Hydro will continue to evolve the Affordable Energy Program to improve accessibility and program awareness, ultimately leading to reducing the energy burden of Manitoba Hydro's lower income customers.

APPENDIX A

MEDIA CALENDAR

Media	QTY	COST	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC		% of media
Bus Benches / Transit Shelters	15	$ 1,800.00	-	-	1 - 2 wks	4 wks	2 - 3 wks	-	-	4 wks	4 wks	4 wks	4 wks	-	$ 10,800.00	7%
Recycling Bins (Silver Boxes)	15	$ 1,545.00	-	-	-	-	4 wks	4 wks	4 wks	4 wks	-	-	-	-	$ 6,180.00	4%
Direct Mail	25,000	$ 10,000.00	-	-	x	x	x	-	-	x	x	x	-	-	$ 60,000.00	40%
NCI Radio	30	$ 500.00	-	-	1 - 2 wks	2 wks	1 - 2 wks	-	-	2 wks	2 wks	2 wks	-	-	$ 5,500.00	4%
CKJS Ethnic Radio	30	$ 500.00	-	-	1 - 2 wks	2 wks	1 - 2 wks	-	-	2 wks	2 wks	2 wks	-	-	$ 5,500.00	4%
City targeted newspaper/magazine	TBD	$ 2,500.00	-	-	x	x	-	-	-	x	x	x	-	-	$ 12,500.00	8%
MCNA Rural (select markets)	TBD	$ 5,000.00	-	-	x	x	x	-	-	x	x	x	-	-	$ 30,000.00	20%
Radio - Power Smart Campaign	2	$0	-	-	-	-	x	x	-	-	-	-	-	-	$ -	0%
															$ 130,480.00	
Production																
Bus Benches	15	-	-	-	$ 1,200.00	-	-	-	$ 1,200.00	-	-	-	-	-	$ 2,400.00	2%
Recycling Bins (Silver Boxes)	15	-	-	-	-	$ 1,200.00	-	-	-	-	-	-	-	-	$ 1,200.00	1%
Direct Mail	25,000	-	-	-	$ 2,500.00	$ 1,000.00	$ 500.00	-	$ 2,500.00	$ 500.00	$ 500.00	$ 500.00	-	-	$ 8,000.00	5%
Radio	30 sec	-	-	-	$ 3,000.00	-	-	-	$ 3,000.00	-	-	-	-	-	$ 6,000.00	4%
Newspaper	TBD	-	-	-	$ 250.00	-	-	-	-	-	-	-	-	-	$ 250.00	0%
															$ 17,850.00	
														TOTAL	$ 148,330.00	

* Media Calendar contains high level estimates that are subject to change

APPENDIX B

DEVELOPMENT CALENDAR

	QTY	COST	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
Research															
Pre-Program Focus Groups	1	$ 10,000.00	-	x	-	-	-	-	-	-	-	-	-	-	**$ 10,000.00**
Customer Satisfaction Tracking Study		$ -	-	-	-	-	-	-	-	x	-	-	-	-	**$ -**
OmniBus	3	$ 5,000.00	-	-	x	-	-	x	-	-	x	-	-	-	**$ 15,000.00**
Direct Marketing															
Canvassing	2/year	$ 2,500.00	-	-	-	-	x	-	-	-	-	x	-	-	**$ 5,000.00**
Phone Calls (call centre)	2/year	$ 5,000.00	-	-	-	-	x	-	-	-	-	x	-	-	**$ 10,000.00**
Community Initiatives		$ 5,000.00	-	-	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	**$ 5,000.00**
Manitoba Hydro Communications															
Hydro Gram		$ -	-	-	x	-	-	-	-	-	-	-	-	-	**$ -**
Energy Matters		$ -	-	-	-	x	-	-	-	x	-	-	-	-	**$ -**
Website		$ -	-	x	x	x	x	x	x	x	x	x	x	x	**$ -**
Bill Insert		$ -	-	-	-	x	-	-	-	-	x	-	-	-	**$ -**
Please Hold Canada		$ -	-	-	-	-	x	x	x	x	x	x	-	-	**$ -**
Develop Creative Concept	1	$ 5,000.00	-	x	-	-	-	-	-	-	-	-	-	-	**$ 5,000.00**
														TOTAL	**$ 50,000.00**

* Development Calendar contains high level estimates that are subject to change

<u>PUB/MH I-222</u>

Reference: Tab 13, 13.4 (8) Affordable Energy Program Marketing Plan

b) Please indicate the author(s) of the marketing plan.

<u>ANSWER</u>:

The affordable Energy Program Marketing Plan was developed by Manitoba Hydro's employees working within The Affordable Energy Unit and Business Communications Department.

PUB/MH I-223

Reference: Tab 13, 13.4 (8) Affordable Energy Program Marketing Plan 1.3 Existing Research

a) Please file a copy of the 2009 Manitoba Hydro Residential Customer Survey, including an interpretive summary of the findings in the survey.

ANSWER:

Please see Appendix 45 for a copy of the 2009 Manitoba Hydro Residential Customer Survey. The results of the survey are in the process of being analyzed and a report is currently not available. It is expected that the survey report will be completed in the Fall of 2010. An analysis of the data related to the low income demographics is being undertaken separately and a report is expected to be completed during April 2010.

PUB/MH I-223

Reference: Tab 13, 13.4 (8) Affordable Energy Program Marketing Plan 1.3 Existing Research

b) Please provide a comparison of the detailed demographic information resulting from the 2009 MH Residential Customer Survey with the current 2003 based demographic information.

ANSWER:

The following tables provide a comparison of the dwelling types based on the 2003 and 2009 surveys. Caution must be exercised when comparing the data obtained from each survey as the 2009 survey was designed to better capture low income information. Specifically, the income question in the 2009 survey was divided into $5,000 increments compared to the $10,000 increments of the 2003 survey. The more defined income levels in the 2009 survey allows for a better fit for the income answers as defined by the LICO and LICO-125 definitions.

LICO x 125% DWELLING TYPES - 2003 Survey			
	OWN	**RENT**	**TOTAL**
Single	54426	5696	60122
Multiplex	4705	3001	7706
Townhouse	1510	3067	4577
Mobile	2993	507	3500
Subtotal (Net Apartments)	**63634**	**12271**	**75905**
Apartment	2145	15147	17292
Total	**65779**	**27418**	**93197**
Total %	71%	29%	100%

LICO x 125% DWELLING TYPES - 2009 Survey			
	OWN	**RENT**	**TOTAL**
Single	64024	4720	68744
Multiplex	5164	1822	6986
Townhouse	1735	1654	3389
Mobile	2777	102	2879
Subtotal (Net Apartments)	**73700**	**8298**	**81998**
Apartment	5156	18630	23786
Total	**78856**	**26928**	**105784**
Total %	75%	25%	100%

PUB/MH I-223

Reference: Tab 13, 13.4 (8) Affordable Energy Program Marketing Plan 1.3 Existing Research

c) Please provide a summary of the 2006 statistical information, including aggregate household income used to identify neighborhoods for targeted communication.

ANSWER:

A copy of the statistical information including the aggregate household income used to identify neighborhoods for targeted communications is shown below. The strategy for targeting neighborhoods was a follows:

- Did not include inner city neighborhoods, as it was deemed that BUILD and NERC were already promoting the program in these areas;
- Ranked remaining households on incidence of low income being above 15%;
- Removed all neighborhoods with rental greater than 40% (promoting lower income homeowners program);
- Ranked by % of Winnipeg's average income of $63,023
- Neighborhoods that met above criteria and were below 90% of Winnipeg's average income were broken down into groups. The first group of approximately 5,600 privately owned lower income homes were targeted, with other groupings remaining for potential future mail drops. Below is the breakdown of the homes that were in these groups, with the first group being targeted in August/September 2009.

Neighbourhood	Household Average Income	PERCENT OF WPG AVG INCME	Percent of Occupied Private Dwellings that are Rented	Incidence of Income (before tax dollars) Private Households	Total Occupied Private Dwellings	NON RENTED HOUSEHOLDS
Group 1: total of 5,671 homes						
Talbot-Grey	$41,354	66%	34.4%	30.6%	1,080	708
Brooklands	$44,053	70%	27.6%	32.1%	940	681
Varennes	$46,767	74%	23.8%	19.7%	515	393
Victoria West	$47,097	75%	16.1%	22.7%	1,140	956
Munroe West	$47,136	75%	25.5%	18.0%	1,390	1,036
King Edward	$47,245	75%	23.8%	18.9%	2,490	1,897
Subtotal Group 1					**7,555**	**5,671**
Group 2: total of 6,134 homes						
Jefferson	$47,419	75%	34.2%	20.5%	3,860	2,540
Lord Roberts	$48,682	77%	33.2%	26.3%	2,280	1,523
Melrose	$48,777	77%	19.5%	20.0%	565	455
East Elmwood	$48,950	78%	23.4%	23.5%	1,290	988
Dufresne	$49,181	78%	29.3%	17.2%	185	131
Kensington	$49,696	79%	23.8%	23.1%	110	84
Brockville	$50,082	79%	20.0%	15.6%	515	412
Subtotal Group 2					**8,805**	**6,134**
Group 3: total of 6,304 homes						
Shaughnessy Park	$50,734	81%	21.9%	20.1%	895	699
Minto	$51,290	81%	25.3%	21.3%	2,280	1,703
Ebby-Wentworth	$51,610	82%	30.9%	18.1%	325	225
Sargent Park	$51,681	82%	19.0%	18.9%	2,370	1,920
Maybank	$52,648	84%	24.3%	16.1%	1,030	780
St. George	$53,198	84%	14.2%	19.2%	1,140	978
Subtotal Group 3					**8,040**	**6,304**
Group 4: total of 2,840 homes						
Sturgeon Creek	$54,980	87%	38.8%	21.2%	1,440	882
Leila-McPhillips Triangle	$56,092	89%	27.0%	26.7%	1,255	917
Norberry	$56,156	89%	21.3%	18.5%	545	429
Parc La Salle	$56,312	89%	17.8%	18.5%	745	613
Subtotal Group 4					**3,985**	**2,840**

PUB/MH I-224

Reference: **Tab 13, 13.4 (8) Affordable Energy Program Marketing Plan - MH Presentations**

a) **Please file a copy of the presentations made by MH and related speakers notes, at Chartwell's Best Practices Summit on Serving Low Income Customers in April 2009 and the Chartwell's Webinar on Low- Income Energy Efficiency Program in December 2009.**

ANSWER:

The presentations can be found in Appendix 35. There were no speaker's notes recorded with the presentation.

PUB/MH I-224

Reference: Tab 13, 13.4 (8) Affordable Energy Program Marketing Plan - MH Presentations

b) Please provide a summary of MH's understanding of the San Diego Gas & Electric 2009 bundled low-income program offerings.

ANSWER:

Based on a broad overview, the following provides Manitoba Hydro's high level understanding of San Diego Gas & Electric's low income programming.

San Diego Gas & Electric (SDG&E) offers a combination of Assistance Programs to help customers manage their energy use and save money on their monthly bills. The programs are funded through the Public Goods Charge on all customers' utility bills. SDG&E leverages opportunities to promote all customer assistance programs. The Energy Efficiency Program includes energy education, weatherization, basic energy efficiency measures such as compact fluorescent light bulbs, appliance repair & replacement, and minor home repair. This program began in the 1980's.

SDG&E offers bundled offerings for potential customers, targeted messages and delivery options based on customer preferences. Specific marketing strategies include direct mail, outbound calling, targeted canvassing, whole neighbourhood approach, leveraging of state and local social programming and cross promotion and integration of internal programs.

PUB/MH I-225

Reference: Tab 13, 13.4 (8)Affordable Energy Program Affordable Energy Champions

Please indicate the status on the development of "Affordable Energy Champions" team within MH and program partners.

ANSWER:

Manitoba Hydro has informally been developing Affordable Energy Champions within Manitoba Hydro and with program partners. The process will be further formalized later in 2010.

PUB/MH I-226

Reference: Tab 13, 13.4 (8) Affordable Energy Program Marketing Research, Appendix B

a) Please provide the current timelines to commence and complete the marketing research components.

ANSWER:

Manitoba Hydro estimates that pre-program focus groups and analysis of results will be completed shortly. Quantitative research will be on-going.

PUB/MH I-226

Reference: **Tab 13, 13.4 (8) Affordable Energy Program Marketing Research, Appendix B**

b) Please file a summary of all pre-program focus group results, including copies of proposed marketing material.

ANSWER:

The information will be filed upon completion.