MIPUG/MH I-1

Letter of Application and Summary of Application

a) Please confirm that the letter contained at Tab 1 fully itemizes at paragraph one, bullets a) through e) the requested approvals Manitoba Hydro is seeking as part of its 2010/11 and 2011/12 General Rate Application.

ANSWER:

The letter in Tab 1 filed by Manitoba Hydro on December 1, 2009, Tab 1 includes all requested approvals Manitoba Hydro is seeking as part of its 2010/11 and 2011/12 GRA, with the following noted exceptions:

1) As noted on Page 5 of Tab 10 of the rate Application, Manitoba Hydro will be filing in due course an Application for a revised Energy Intensive Industrial rate.

2) Further to Board Order 1/10 dated January 5, 2010, Manitoba Hydro will be filing an Application for new rates in the Diesel zone.

3) Further to Board Order 18/10 dated February 9, 2010, Manitoba Hydro will file revised interim rate tariffs for Board approval.

<u>MIPUG/MH I-1</u>

Letter of Application and Summary of Application

b) **In the event that part a) above cannot be confirmed, please provide a full and complete list of all requested approvals Manitoba Hydro is seeking as part of its 2010/11 and 2011/12 General Rate Application.**

<u>ANSWER</u>:

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

<u>MIPUG/MH I-1</u>

Letter of Application and Summary of Application

c) Please provide the criteria used by Manitoba Hydro to arrive at the conclusion, as stated on page 3 of Tab 2, that "in consideration of the economic downturn and the effects on ratepayers, 2.9% increases in each of the next two years are considered to be reasonable".

<u>ANSWER</u>:

In the same recessionary period, Manitoba Hydro also faces many economic pressures, as evidenced by the reduction to projected revenues as a result of lower export prices. These pressures tend to exacerbate the risks faced by Manitoba Hydro. Manitoba Hydro believes that the proposed moderate rate increases achieve a reasonable balance for customers between the economic pressures due to the recession and the need for Manitoba Hydro to maintain a strong financial structure. A financially strong Manitoba Hydro is in the best long-term interests of all ratepayers.

Manitoba Hydro's overall rate level continues to be the lowest in Canada. Cumulative rate increases are 12.5% over the ten year period 1999/00 to 2009/10. The Manitoba cumulative CPI is 24.2% over the same period. Manitoba Hydro's cumulative 12.5% increase compares with 22.6% for BC Hydro, 18.2% for Hydro-Quebec and 33.5% for SaskPower.

The proposed rate increases requested are moderate compared to recently approved and requested rate increases in other Canadian jurisdictions. BC Hydro implemented 8.74% effective April 1, 2009 and Nova Scotia Power implemented 9.28% effective January 1, 2009. In addition, SaskPower recently requested a 7% rate increase, effective for August 1, 2010, which closely follows the June 1, 2009 8.5% rate increase.

MIPUG/MH I-1

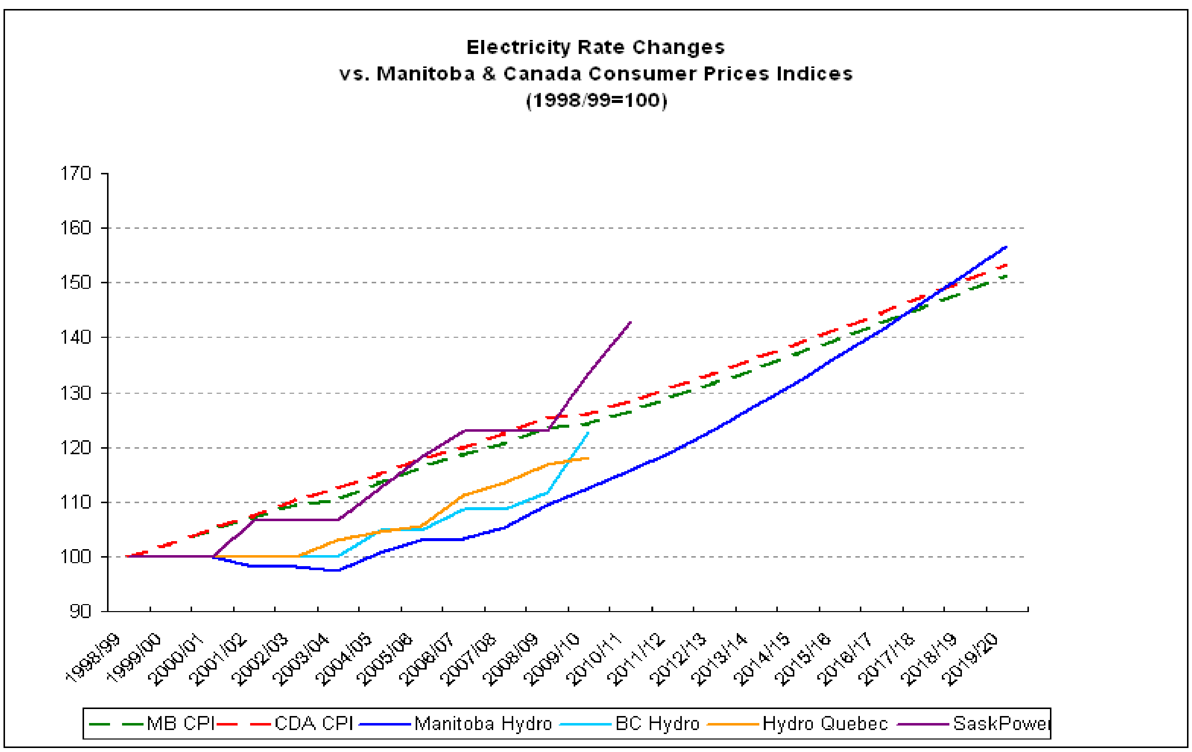
Letter of Application and Summary of Application

d) Please confirm if it is Hydro's view that 3.5% average annual general consumer rate increases (as shown in IFF-09-1) are "closely aligned with inflation" as stated on page 3 of tab 2.

ANSWER:

The excerpt from Tab 2 page 3 states "This is accomplished with domestic rate increases which, over the longer term, are closely aligned with projected rates of inflation." (emphasis added). This statement is supported with projected annual rate increases of 2.0% for the entire second decade of the 20 year Financial Forecast.

In addition, it should be recognized that Manitoba Hydro customers have benefitted significantly from low rates over the past several years. Cumulative rate changes since 1998/1999 are well below the CPI index and the rates of BC Hydro, Hydro Quebec and SaskPower.



Note:
Manitoba Hydro data based on annualized historical and forecasted rate increases
BC Hydro, Hydro Quebec and SaskPower data based on effective rate increases
SaskPower's 2010/11 data based on a February 2010 rate application for a 7% rate increase, effective August 1, 2010

<u>MIPUG/MH I-1</u>

Letter of Application and Summary of Application

e) Please quantify what, in Manitoba Hydro's view, constitutes an "adequate level of retained earnings", as stated on page 4 of Tab 2.

<u>ANSWER</u>:

Manitoba Hydro considers an adequate level of retained earnings to be a level sufficient to withstand the financial impacts of the risks faced by the corporation. The absolute magnitude of these risks has the potential to grow over time depending on the duration or severity and may change relative to the size of the corporation. As a result, Manitoba Hydro sets its financial targets based on debt/equity and does not quantify an absolute level of retained earnings appropriate for the corporation.

Please also see Manitoba Hydro's response to CAC/MSOS/MH 1-8(a).

MIPUG/MH I-2

Thermal Generation Resources

a) **With reference to page 35 of CEF09-1, the justification for the Brandon Unit 5 License Review indicates that Unit 5 contributes economic generation. However, the project description indicates that Bill 15 restricts the use of coal generation only to support emergency operations after December 31, 2009. Please discuss what Manitoba Hydro considers to be "economic generation" in this circumstance.**

ANSWER:

The project Justification for Brandon Unit 5 Licence Review contained in CEF09-1 has not been fully updated to reflect the current status of the project. The recent provision of Coal-fired Emergency Operations Regulation (MR 186/2009) associated with Bill 15, the Climate Change and Emissions Reductions Act, has limited the use of Brandon Unit 5 to "support emergency operations". The new regulation results in restricted operation but allows operations to support emergencies which have been defined to include energy generation during times of drought. Please refer to PUB/MH I-85(b) for more information on Regulation 186/2009, the Coal-fired Emergency Operations Regulation.

MIPUG/MH I-2

Thermal Generation Resources

b) Please describe in detail the magnitude of higher costs to Manitoba customers in the IFF-09 forecast period due to restricting Brandon Unit 5 to support emergency operations only. Please provide details in regards to specific impacts on each major component of MH's costs including fuel, purchased power and export revenues.

ANSWER:

Please refer to the response to PUB/MH I-85 (b). As stated in that response, a comprehensive financial evaluation of restricted operations at Brandon Unit 5 has not been evaluated as an isolated issue in the IFF forecast period. Therefore, the specific impact on fuel, power purchases and export revenue is not available.

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

Financial Targets

a) Please update the response to Coalition/MH I-86 (c) from the 2008 General Rate Application regarding financial target changes. Please confirm that financial targets apply to consolidated operations only.

<u>ANSWER</u>:

To reflect the achievement of 75:25 debt/equity ratio in 2009, the target was revised to maintain 75:25, except during years of major investment in the generation and transmission system. In addition, the capital coverage target was revised to maintain a capital coverage ratio of greater that 1.2 (excepting new major generation and transmission) from 1.0.

Manitoba Hydro confirms that the targets apply to consolidated operations only.

MIPUG/MH I-3

Financial Targets

b) Please update the response to Coalition/MH I-82 (j) from the 2008 General Rate Application regarding the calculation of the debt:equity ratios, including actuals for fiscal years ending 2008 and 2009 as well as forecasts from the IFF 09-1 forecasts for the 2010-2020 period.

ANSWER:

The following table provides the calculations requested.

Debt Ratio
($ millions)

	A	**B**	**C**	**D**	**E**	**F**	**G**	**(D-E+F-G) / (A+B+C+D-E+F-G)**
Fiscal Year Ended	Retained Earnings	Unamortized Customer Contributions	Accumulated Other Comprehensive Income	Long-Term Debt	Sinking Fund Investment	Short-Term Debt	Short-Term Investments	Debt Ratio*
2008	1,822	300	305	7,571	718	-	133	0.73
2009	2,120	296	(169)	8,180	666	100	170	0.77
2010	2,227	293	192	8,120	392	48	9	0.74
2011	2,315	291	178	8,640	264	40	14	0.75
2012	2,396	285	143	9,255	336	23	19	0.76
2013	2,479	280	178	9,635	344	109	25	0.76
2014	2,616	276	94	10,466	40	-	72	0.78
2015	2,738	273	71	11,784	146	-	87	0.79
2016	2,997	272	38	13,341	342	41	42	0.80
2017	3,268	270	17	14,959	518	21	48	0.80
2018	3,515	268	6	16,232	762	-	81	0.80
2019	3,772	267	3	16,767	508	72	61	0.80
2020	4,059	267	3	17,449	595	-	146	0.79

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

Ref A: As reported in the Financial Statistics of 2009 Annual Report (page 118) and the IFF09-1 Consolidated Projected Balance Sheet (page 25).

Ref B: As reported in the Financial Statistics of 2009 Annual Report (page 118) and the IFF09-1 Consolidated Projected Balance Sheet (page 25).

Ref C: As reported in the Financial Statistics of 2009 Annual Report (page 118).

Ref D: As calculated in the table below.

Ref E: As reported in the Financial Statistics of 2009 Annual Report (page 118).

Ref F: Represents "Notes payable" as reported on the Balance Sheet in the 2009 Annual Report (page 89).

Ref G: Represents "Cash and cash equivalents" as reported on the Balance Sheet in the 2009 Annual Report (page 88).

The following table provides the calculation of long-term debt used in the aforementioned debt ratio calculation.

($ millions)

	H	**I**	**D = (H+I)**
Fiscal Year Ended	Long-Term Debt	Current Portion Long-Term Debt	Long-Term Debt
2008	7,218	353	7,571
2009	7,661	519	8,180
2010	7,816	304	8,120
2011	8,613	27	8,640
2012	9,071	184	9,255
2013	8,786	849	9,635
2014	10,366	100	10,466
2015	11,522	262	11,784
2016	13,140	201	13,341
2017	14,429	530	14,959
2018	15,363	869	16,232
2019	16,446	321	16,767
2020	14,164	3,285	17,449

Ref H: As reported in the Financial Statistics of 2009 Annual Report (page 118) and the IFF09-1 Consolidated Projected Balance Sheet (page 25).

Ref I: As reported on the Balance Sheet in the 2009 Annual Report (page 89).

Financial Targets

c) Please provide the details of the calculation of the interest coverage ratios for that actual fiscal years ended 2008 and 2009 as well as forecasts from the IFF09-1 for the 2010-2020 period.

ANSWER:

The following table provides the calculations requested.

Interest Coverage Ratio
($ millions)

	A	**B**	**C**	**(A+B+C) / (B+C)**
Fiscal Year Ended	Net Income	Finance Expense	Capitalized Interest	Interest Coverage Ratio
2008	346	440	62	1.69
2009	298	439	78	1.58
2010	129	454	88	1.24
2011	88	451	127	1.15
2012	98	509	134	1.15
2013	83	569	106	1.12
2014	137	570	141	1.19
2015	122	588	205	1.15
2016	260	574	303	1.30
2017	271	590	404	1.27
2018	246	632	446	1.23
2019	257	719	426	1.22
2020	287	923	361	1.22

Ref A: As reported in the Financial Statistics of 2009 Annual Report (page 2) and the Consolidated Projected Operating Statement (IFF09-1) (page 3).
Ref B: As reported in the Financial Statistics of 2009 Annual Report (page 2) and the Consolidated Projected Operating Statement (IFF09-1) (page 3).

MIPUG/MH I-4

Financial Results and Forecasts: General Consumer Revenues

a) Please provide a copy of Schedule 4.2.0 with revenues broken out by General Service class and subclass (i.e. separately indicate revenues for GSS, GSM, GSL including all GSL sub-classes). Please show revenues at existing rates by class and subclass separately from additional general consumer revenues by class and subclass.

ANSWER:

The following tables provide the detailed General Service sector data by major sub-class (excludes Seasonal, FRWH and SEP), for each year reported on Schedule 4.2.0. All figures are in millions of dollars.

General Service Class / Sub-Class	2007/08 Actual $	2008/09 Actual $	2009/10 * $
Small ND	$106.2	$110.8	$115.2
Small ND DSM	-	-	($0.5)
Small Demand	$101.2	$105.7	$112.0
Small Dem DSM	-	-	($0.4)
Medium Demand	$146.0	$150.5	$154.8
Medium Dem. DSM		-	($0.5)
Large 750-30 kV	$62.8	$64.7	$68.6
Large 750-30 DSM	-	-	($0.2)
Large 30-100 kV	$32.3	$34.4	$37.1
Large 30-100 DSM	-	-	($0.0)
Large >100 kV	$163.0	$169.5	$165.0
Large >100 DSM	-	-	($0.0)
Total GCR	$1,074.6	$1,126.8	$1,160.0

* Includes 7 months of actual data.

General Service Class / Sub-Class	2010 /11 @ Apr 1/09 Rates	2010/11 @ Apr 1/10 Rates	2010/11 Incremental $
Small ND Small ND DSM	$114.9 ($2.1)	$118.2 ($2.2)	$3.3 ($0.0)
Small Demand Small Dem DSM	$112.1 ($1.7)	$115.9 ($1.8)	$3.8 ($0.0)
Medium Demand Medium Dem. DSM	$152.9 ($2.2)	$157.1 ($2.3)	$4.2 ($0.1)
Large 750-30 kV Large 750-30 DSM	$69.4 ($1.1)	$71.5 ($1.1)	$2.1 ($0.0)
Large 30-100 kV Large 30-100 DSM	$32.3 ($0.2)	$33.2 ($0.2)	$0.9 ($0.0)
Large >100 kV Large >100 DSM	$183.8 ($0.4)	$189.1 ($0.5)	$5.4 ($0.0)
EIIR	$4.9	$4.9	$0.0
Total GCR	$1,159.3	$1,192.7	$33.4

General Service Class / Sub-Class	2011/12 @ Apr 1/10 Rates	2011/12 @ Apr 1/11 Rates	2011/12 Incremental $
Small ND Small ND DSM	$120.0 ($3.0)	$123.5 ($3.1)	$3.5 ($0.1)
Small Demand Small Dem DSM	$117.4 ($2.5)	$120.9 ($2.6)	$3.5 ($0.0)
Medium Demand Medium Dem. DSM	$159.6 ($3.4)	$164.5 ($3.5)	$4.9 ($0.0)
Large 750-30 kV Large 750-30 DSM	$72.2 ($1.9)	$74.3 ($1.9)	$2.1 ($0.0)
Large 30-100 kV Large 30-100 DSM	$33.8 ($0.3)	$34.8 ($0.3)	$1.0 ($0.0)
Large >100 kV Large >100 DSM	$199.0 ($0.9)	$205.2 ($0.9)	$6.2 ($0.0)
EIIR	$7.5	$7.5	$0
Total GCR	$1,210.9	$1,246.0	$35.1

MIPUG/MH I-5

Financial Results and Forecasts: Extra Provincial Revenues

a) Please provide a copy of Schedule 4.3.0 with revenues broken out by Dependable and Short-term Opportunity sales.

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-13(c).

<u>MIPUG/MH I-5</u>

Financial Results and Forecasts: Extra Provincial Revenues

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

<u>ANSWER</u>:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-13(c).

MIPUG/MH I-6

Financial Results and Forecasts: Operating, Maintenance and Administrative

a) With reference to page 11 of Tab 4, please quantify the 2008/09 impact of the following and also provide the extent to which these impacts are expected to continue through the IFF09-1 forecast period:

i. Operating costs attributable to higher than normal maintenance expenditures.
ii. Increased number of trainees.
iii. Changes to accounting standards to eliminate the capitalization of interest and facilities overhead on stores withdrawals.

ANSWER:

i) As indicated in the Application, the increase in OM&A costs in 2008/09 is primarily due to the restoration of staffing levels given the high vacancy rates experienced in the 2007/08 period. During 2007/08 the staffing situation was managed by deferring non-essential maintenance and/or by performing some operational activities less frequently (e.g. tree trimming, hardware tightening etc.). Throughout the forecast period, operational areas continue to have an increased maintenance focus given our aging infrastructure.

ii) In 2008/09 there was an increase of approximately 98 trainees hired to address existing staff shortages and future anticipated attrition levels at a total cost net of capitalization of $7.2 million. Though the number of trainees continues to grow, the growth rate is at lower levels than experienced in 2008/09 based on supply/demand requirements.

iii) Canadian Accounting Standard change eliminating the capitalization of interest and facilities overhead on stores withdrawals impacted OM&A by $5.0 million. This change is applied throughout the forecast period.

MIPUG/MH I-6

Financial Results and Forecasts: Operating, Maintenance and Administrative

b) With reference to schedule 4.5.1, please provide an explanation for the increase in full time equivalent employees in 2009/10 by business unit.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-34(b)

MIPUG/MH I-6

Financial Results and Forecasts: Operating, Maintenance and Administrative

c) For each actual year from 2004/05 to present and for each forecast year in IFF-MH-09 please provide a calculation of the following, including all information used in the calculations:

> **i. Average OM&A per electricity customer.**
> **ii. Average OM&A per domestic kW.h sold.**
> **iii. Average domestic customers per full-time equivalent employee.**

ANSWER:

Please see the following table.

	Actual				
	2004/05	2005/06	2006/07	2007/08	2008/09
OM&A (in thousands)	298,613	310,659	323,466	322,697	359,660
# of Customers	505,666	509,791	516,861	521,599	527,472
# of Domestic kW.h sold	19,735,000,000	19,935,000,000	20,510,000,000	21,061,000,000	21,210,000,000
EFTs	5,866	5,980	5,991	6,071	6,276
OM&A per Customer	591	609	626	619	682
OM&A per Domestic kW.h sold	0.02	0.02	0.02	0.02	0.02
Customer per EFT	86	85	86	86	84

	Forecast - IFF09								
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
OM&A (in thousands)	371,504	379,695	403,370	411,425	419,641	428,159	436,710	445,432	466,943
# of Customers	531,804	536,267	540,756	545,215	549,623	553,968	558,286	562,580	566,841
# of Domestic kW.h sold	21,023,000,000	21,462,000,000	21,965,000,000	22,360,000,000	22,713,000,000	23,253,000,000	23,564,000,000	23,877,000,000	24,151,000,000
EFTs	6,613	6,669	6,669						
OM&A per Customer	699	708	746	755	764	773	782	792	824
OM&A per Domestic kW.h sold	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Customer per EFT*	80	80	81						

* EFTs are not forecasted past 2011/12; therefore, no information can be provided from 2013-2020.

MIPUG/MH I-6

Financial Results and Forecasts: Operating, Maintenance and Administrative

d) Please provide a table showing the data underlying the chart on page 4 of appendix 4.4.

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-17(b).

Financial Results and Forecasts: Operating, Maintenance and Administrative

e) For each actual year from 2004/05 to present and for each forecast year in IFF-MH-09 please provide a calculation of the following, including all information used in the calculations:

i. Average OM&A per electricity customer.
ii. Average OM&A per domestic kW.h sold.
iii. Average domestic customers per full-time equivalent employee.

ANSWER:

Please see Manitoba Hydro's response to MIPUG/MH I-6(c).

MIPUG/MH I-7

Financial Results and Forecasts: Depreciation and Amortization

a) Please discuss the rationale for shortening the amortization period for DSM from 15 years to 10 years.

ANSWER:

Manitoba Hydro's decision for shortening the amortization period for DSM from 15 to 10 years is supported by the following:

- Canadian and International Accounting Standards are evolving towards lower levels of capitalization and a more conservative representation of intangible assets on the balance sheet.
- A review of industry practices in Canada with respect to DSM amortization periods indicated amortization periods of 10 years or less.
- In Order 116/08, the MPUB indicated its concern regarding the amortization period used by MH for DSM costs and held the view that these costs either be expensed or amortized consistent with the shorter periods of amortization followed by other jurisdictions.

MIPUG/MH I-7

Financial Results and Forecasts: Depreciation and Amortization

b) With reference to page 17 of Tab 4, please quantify the 2008/09 impact of the following and also provide the extent to which these impacts are expected to continue through the IFF09-1 forecast period:

- **i. Depreciation expense due to increases in fixed assets.**
- **ii. Depreciation expense due to decreasing the amortization period for DSM costs from 15 to 10 years.**

ANSWER:

Please see the follow tables for the requested information.

i)

Depreciation on Fixed Assets ($000's)

	2009 Actual	2010 Forecast	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
Depreciation on Fixed Assets	320,266	328,848	342,189	366,523	391,543	400,845	419,066	430,406	435,717	457,887	489,283	495,452
$ Change		8,582	13,341	24,334	25,021	9,302	18,221	11,340	5,311	22,170	31,396	6,169
% Change		2.7%	4.1%	7.1%	6.8%	2.4%	4.5%	2.7%	1.2%	5.1%	6.9%	1.3%

ii)

DSM Amortization ($000's)

	2009 Actual	2010 Forecast	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
Amortization Expense (10 Year Period)	20,102	21,943	24,829	28,703	32,076	34,590	36,582	37,666	37,073	35,557	33,440	32,472
Amortization Expense (15 Year Period)	13,562	14,918	17,119	19,469	21,917	24,406	26,320	27,480	28,939	30,183	31,048	31,622
Difference (10 yr less 15 yr)	6,541	7,025	7,710	9,234	10,159	10,183	10,261	10,186	8,134	5,374	2,392	850

MIPUG/MH I-8

Financial Results and Forecasts: Water Rentals and Assessments

a) Please provide the current water rental rate. Please also discuss if Manitoba Hydro has any information to suggest water rentals may change within the IFF-09-1 forecast period.

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH I-24(c) and (d).

MIPUG/MH I-8

Financial Results and Forecasts: Water Rentals and Assessments

b) Please expand Schedule 4.8.0 to show separately:

i. The calculation of the water rentals in each year (i.e. show both the volume and the applicable water rental rate.
ii. NEB assessments.
iii. Extra provincial water rentals.
iv. Memberships in MISO.
v. Other industry association memberships.
vi. Land rentals.
vii. Any other applicable assessments or land rentals.

ANSWER:

Please see the following schedule.

MANITOBA HYDRO **Schedule 4.8.0**
WATER RENTALS AND ASSESSMENTS

	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
Generation (KWh)	34,898,352,791	34,194,576,744	33,124,647,729	30,525,187,500	30,067,000,000
Generation (HP-YR)[1]	5,740,739	5,624,969	5,448,967	5,021,358	4,945,987
$/HP-YR	$ 20.32	$ 20.32	$ 20.32	$ 20.32	$ 20.32
(in thousands of $)					
Rental Amount	116,652	114,299	110,723	102,034	100,453
Minimum Required Adjustment[2]	0	250	515	307	-
Other Adjustment[3]	354				
Water Rentals	$ 117,006	$ 114,549	$ 111,238	$ 102,341	$ 100,453
Land Rentals	728	728	728	728	728
NEB Assessments	1,375	1,517	997	997	1,031
MISO Memerships	3,324	4,618	4,074	4,635	4,780
Other Industry Memberships	733	856	2,034	1,075	1,213
Other	601	732	484	501	2,519
Land Rentals & Assessments	6,761	8,451	8,317	7,936	10,271
Total Water Rentals and Assessments	$ 123,767	$ 123,000	$ 119,555	$ 110,277	$ 110,724

[1] Generation (HP-YR) is station Generation (kWh) converted to HP-YR and adjusted (increased) for effeciency losses.
[2] Minimum Required Adjustment is the Minimum Water Rental per station not met.

[3] Other Adjustment is due to a rounding difference.

Financial Results and Forecasts: Capital and Other Taxes

a) Please provide a copy of Schedule 4.10.0 showing the amounts paid to the Town of Gillam and the Frontier School Division in 2007/08 and 2008/09 as part of capital and other taxes rather than OM&A.

ANSWER:

Please see the revised schedule 4.10.0:

MANITOBA HYDRO
CAPITAL AND OTHER TAXES

Schedule 4.10.0
(000's)

	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
Capital Tax	$ 38,353	$ 44,303	$ 44,627	$ 47,272	$ 47,899
Grants in Lieu of Taxes	9,332	9,324	12,828	12,897	13,155
Payroll Tax	8,121	8,979	9,075	9,257	9,442
Business & Property Tax	1,346	1,202	1,851	1,845	1,881
Other Municipal Payments	5,224	5,693	4,500	4,500	4,500
Total Capital and Other Taxes	$ 62,376	$ 69,501	$ 72,881	$ 75,771	$ 76,877

MIPUG/MH I-10

IFF-09-1

a) Please provide copies of the consolidated and electric operations projected operating statements, balance sheets and projected cash flow statements assuming:

- **i. Annual general consumer revenue increases of 2.0% beginning 2010/11 and continuing through 2019/20.**
- **ii. No increase in general consumer revenues in 2010/11, other increases in 2011/12 and beyond as assumed in IFF-09-1.**
- **iii. A 2.9% average annual general consumer rate increase implemented August 1, 2010 instead of April 1, 2010.**
- **iv. A 2.9% average annual general consumer rate increase implemented August 1, 2010 instead of April 1, 2010, coupled with rate adjustments necessary in 2011/12 through 2015/16 to arrive at the same 2015/16 debt to equity ratio as in IFF-09-1.**

ANSWER:

Please refer to the attached schedules.

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF09-1)
2.0% Rate Increases Starting in 2010/11
(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	1,660	1,717	1,767	1,807	1,867	1,918	1,964	2,014	2,063	2,110
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
	2,066	2,043	2,271	2,349	2,422	2,457	2,619	2,694	2,756	2,957	3,203
Cost of Gas Sold	351	332	340	346	342	349	350	351	352	353	352
	1,715	1,711	1,932	2,003	2,080	2,108	2,269	2,343	2,404	2,604	2,851
Other	28	29	31	32	32	33	34	34	35	36	36
	1,742	1,741	1,963	2,035	2,112	2,141	2,303	2,377	2,439	2,640	2,888
EXPENSES											
Operating and Administrative	446	456	482	492	501	512	522	532	555	568	589
Finance Expense	454	451	511	573	577	600	594	620	675	778	1,001
Depreciation and Amortization	394	415	438	469	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	133	140	146	150
	1,613	1,663	1,890	1,999	2,042	2,113	2,164	2,261	2,387	2,621	2,890
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	129	78	75	38	68	24	130	106	39	5	(17)
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%	2.00%
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%	77%	79%	81%	82%	83%	84%	85%	86%
Interest Coverage	1.24	1.13	1.12	1.06	1.09	1.03	1.14	1.10	1.03	1.00	0.99
Capital Coverage	1.39	1.07	1.09	1.18	1.10	1.30	1.56	1.45	1.42	1.50	1.72

CONSOLIDATED PROJECTED BALANCE SHEET (IFF09-1)
2.0% Rate Increases Starting in 2010/11
(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	17,387	17,844	18,579	21,071	22,401	25,835
Accumulated Depreciation	(4,800)	(5,171)	(5,562)	(5,985)	(6,414)	(6,864)	(7,320)	(7,787)	(8,275)	(8,799)	(9,357)
Net Plant in Service	8,297	8,455	10,129	10,228	10,240	10,523	10,524	10,792	12,796	13,602	16,478
Construction in Progress	1,949	2,460	1,343	1,820	2,840	3,856	5,534	6,950	6,161	6,448	4,170
Current and Other Assets	2,421	2,374	2,503	2,565	2,287	2,442	2,673	2,936	3,257	2,975	3,430
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,397	14,082	14,720	15,475	16,928	18,838	20,785	22,322	23,133	24,185
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,986	10,366	11,722	13,540	15,029	16,163	17,446	15,564
Current and Other Liabilities	2,246	2,010	2,221	2,876	2,271	2,370	2,367	2,742	3,118	2,646	5,598
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,305	2,362	2,400	2,468	2,492	2,621	2,727	2,766	2,771	2,754
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,397	14,082	14,720	15,475	16,928	18,838	20,785	22,322	23,133	24,185

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF09-1)
2.0% Rate Increases Starting in 2010/11
(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	2,149	2,379	2,454	2,528	2,564	2,726	2,802	2,865	3,067	3,314
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)	(503)	(572)	(588)	(583)	(596)	(623)	(703)	(809)	(1,014)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	551	499	527	516	540	544	653	645	585	584	607
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	900	800	600	800	1,400	1,600	2,000	2,000	2,000	1,600	1,400
Sinking Fund Withdrawals	262	227	27	103	483	-	5	-	-	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	710	1,021	1,489	1,730	1,785	1,455	1,161	1,235
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)	(117)	(176)	(109)	(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)	(1,914)	(2,393)	(2,372)	(1,993)	(1,885)	(1,582)
Net Increase (Decrease) in Cash	(52)	(25)	(14)	57	(126)	119	(9)	58	47	(139)	261
Cash at Beginning of Year	(32)	(84)	(109)	(124)	(67)	(193)	(74)	(83)	(25)	23	(116)
Cash at End of Year	(84)	(109)	(124)	(67)	(193)	(74)	(83)	(25)	23	(116)	144

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
2.0% Rate Increases Starting in 2010/11
(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 *	-	23	47	72	99	127	156	186	217	249	282
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	1,573	1,786	1,854	1,925	1,954	2,109	2,183	2,239	2,434	2,682
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	417	413	469	529	534	556	549	575	630	732	956
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	1,724	1,828	1,867	1,934	1,983	2,075	2,199	2,428	2,695
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	68	63	27	56	15	118	97	28	(8)	(27)
*Additional General Consumers Revenue											
Percent Increase		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase		2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	17.17%	19.51%	21.90%

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
2.0% Rate Increases Starting in 2010/11
(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	2,872	2,940	2,666	2,820	3,047	3,309	3,630	3,348	3,804
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,561	15,312	16,757	18,656	20,595	22,123	22,922	23,963
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,054	8,969	10,349	11,705	13,523	15,012	16,146	17,429	15,547
Current and Other Liabilities	2,156	1,937	2,153	2,810	2,212	2,311	2,308	2,683	3,059	2,587	5,539
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,251	2,297	2,325	2,380	2,395	2,514	2,611	2,639	2,631	2,604
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,561	15,312	16,757	18,656	20,595	22,123	22,922	23,963

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
2.0% Rate Increases Starting in 2010/11
(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	1,573	1,786	1,854	1,925	1,954	2,110	2,183	2,239	2,434	2,682
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)	(478)	(546)	(561)	(556)	(568)	(594)	(675)	(780)	(985)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	483	495	479	507	505	611	605	541	537	562
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	600	740	1,400	1,600	2,000	2,000	2,000	1,600	1,400
Sinking Fund Withdrawals	262	227	27	103	483	-	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	619	712	1,020	1,488	1,730	1,785	1,455	1,161	1,235
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(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)	(117)	(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)	(1,123)	(1,648)	(1,877)	(2,355)	(2,334)	(1,954)	(1,846)	(1,543)
Net Increase (Decrease) in Cash	(114)	(2)	(4)	68	(121)	116	(14)	56	42	(147)	255
Cash at Beginning of Year	66	(48)	(50)	(54)	14	(107)	9	(5)	50	92	(55)
Cash at End of Year	(48)	(50)	(54)	14	(107)	9	(5)	50	92	(55)	200

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF09-1)
0% Rate Increase in 2011
(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	1,637	1,704	1,771	1,831	1,912	1,986	2,056	2,132	2,208	2,285
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
	2,066	2,020	2,258	2,354	2,446	2,502	2,686	2,786	2,874	3,102	3,378
Cost of Gas Sold	351	332	340	346	342	349	350	351	352	353	352
	1,715	1,688	1,918	2,008	2,103	2,153	2,336	2,435	2,522	2,750	3,026
Other	28	29	31	32	32	33	34	34	35	36	36
	1,742	1,718	1,950	2,040	2,136	2,186	2,370	2,469	2,557	2,785	3,063
EXPENSES											
Operating and Administrative	446	456	482	492	501	512	522	532	555	568	589
Finance Expense	454	452	512	575	579	600	590	610	657	749	959
Depreciation and Amortization	394	415	438	469	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	103	109	116	125	133	140	146	150
	1,613	1,664	1,891	2,001	2,043	2,112	2,161	2,251	2,369	2,592	2,848
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	129	54	60	40	90	70	201	207	175	179	201
Additional General Consumers Revenue											
General electricity rate increases		0.00%	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%	77%	77%	79%	80%	81%	82%	82%	82%	82%
Interest Coverage	1.24	1.09	1.09	1.06	1.13	1.09	1.23	1.20	1.16	1.15	1.15
Capital Coverage	1.39	1.02	1.06	1.19	1.15	1.41	1.73	1.68	1.75	1.94	2.32

CONSOLIDATED PROJECTED BALANCE SHEET (IFF09-1)
0% Rate Increase in 2011
(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	17,387	17,844	18,579	21,071	22,401	25,835
Accumulated Depreciation	(4,800)	(5,171)	(5,562)	(5,985)	(6,414)	(6,864)	(7,320)	(7,787)	(8,275)	(8,799)	(9,357)
Net Plant in Service	8,297	8,455	10,129	10,228	10,240	10,523	10,524	10,792	12,796	13,602	16,478
Construction in Progress	1,949	2,460	1,343	1,820	2,840	3,856	5,534	6,950	6,161	6,448	4,170
Current and Other Assets	2,421	2,374	2,504	2,551	2,287	2,473	2,673	2,937	3,197	3,033	3,352
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,397	14,083	14,706	15,475	16,960	18,838	20,786	22,262	23,191	24,108
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,986	10,366	11,722	13,340	14,829	15,763	17,046	14,764
Current and Other Liabilities	2,246	2,034	2,259	2,898	2,285	2,370	2,464	2,739	3,118	2,589	5,588
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,281	2,324	2,364	2,454	2,523	2,724	2,931	3,106	3,285	3,486
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,397	14,083	14,706	15,475	16,960	18,838	20,786	22,262	23,191	24,108

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF09-1)
0% Rate Increase in 2011
(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	2,126	2,366	2,459	2,552	2,609	2,794	2,894	2,983	3,212	3,489
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)	(505)	(574)	(589)	(585)	(594)	(614)	(682)	(782)	(978)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	551	476	512	519	563	588	722	745	723	757	818
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	900	800	600	800	1,400	1,600	1,800	2,000	1,800	1,600	1,000
Sinking Fund Withdrawals	262	227	27	103	484	-	5	-	-	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	710	1,021	1,489	1,530	1,785	1,255	1,161	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)	(99)	(117)	(176)	(109)	(201)	(159)	(242)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(17)	(31)	(29)	(41)	(28)	(27)	(27)
	(1,281)	(1,236)	(1,160)	(1,169)	(1,687)	(1,914)	(2,393)	(2,372)	(1,993)	(1,885)	(1,582)
Net Increase (Decrease) in Cash	(52)	(48)	(29)	60	(103)	163	(140)	159	(14)	34	71
Cash at Beginning of Year	(32)	(84)	(132)	(162)	(102)	(205)	(42)	(182)	(24)	(38)	(4)
Cash at End of Year	(84)	(132)	(162)	(102)	(205)	(42)	(182)	(24)	(38)	(4)	67

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
0% Rate Increase in 2011
(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 *	-	-	34	77	122	172	224	278	335	394	458
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	1,550	1,773	1,859	1,949	1,999	2,177	2,275	2,357	2,580	2,857
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	417	413	471	532	535	556	546	566	612	703	913
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	1,506	1,726	1,830	1,869	1,934	1,979	2,066	2,181	2,399	2,652
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	44	49	30	78	61	190	199	164	166	190
*Additional General Consumers Revenue											
Percent Increase		0.00%	2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase		0.00%	2.90%	6.50%	10.23%	14.09%	18.08%	22.21%	26.49%	30.92%	35.50%

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
0% Rate Increase in 2011
(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	2,872	2,926	2,666	2,851	3,047	3,310	3,570	3,405	3,726
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,932	14,547	15,312	16,789	18,656	20,597	22,063	22,979	23,886
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,054	8,969	10,349	11,705	13,323	14,812	15,746	17,029	14,747
Current and Other Liabilities	2,156	1,960	2,191	2,832	2,226	2,311	2,405	2,680	3,059	2,530	5,529
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,227	2,259	2,288	2,366	2,427	2,617	2,816	2,980	3,146	3,336
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,932	14,547	15,312	16,789	18,656	20,597	22,063	22,979	23,886

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
0% Rate Increase in 2011
(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	1,550	1,773	1,859	1,949	1,999	2,177	2,275	2,357	2,580	2,857
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)	(547)	(562)	(557)	(566)	(586)	(654)	(753)	(950)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	460	481	483	529	548	680	705	680	709	773
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	600	740	1,400	1,600	1,800	2,000	1,800	1,600	1,000
Sinking Fund Withdrawals	262	227	27	103	484	-	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	619	712	1,021	1,488	1,530	1,785	1,255	1,161	835
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(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)	(99)	(117)	(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)	(1,123)	(1,648)	(1,877)	(2,355)	(2,334)	(1,954)	(1,846)	(1,543)
Net Increase (Decrease) in Cash	(114)	(25)	(19)	71	(99)	160	(145)	156	(19)	25	65
Cash at Beginning of Year	66	(48)	(73)	(92)	(21)	(119)	40	(105)	51	32	57
Cash at End of Year	(48)	(73)	(92)	(21)	(119)	40	(105)	51	32	57	123

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF09-1)
2.90% Rate Increase Effective August 1, 2010
(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	1,660	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	2,044	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	1,712	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	1,741	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	511	569	571	589	575	591	633	720	925
Depreciation and Amortization	394	415	438	469	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	103	109	116	125	133	140	146	150
	1,613	1,663	1,889	1,995	2,035	2,102	2,145	2,232	2,345	2,563	2,813
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	129	78	96	82	137	120	259	270	246	256	286
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%	78%	79%	80%	80%	80%	80%	80%
Interest Coverage	1.24	1.13	1.15	1.12	1.19	1.15	1.29	1.27	1.23	1.22	1.22
Capital Coverage	1.39	1.07	1.14	1.28	1.25	1.52	1.86	1.83	1.91	2.14	2.55

** 2.90% Rate Increase Effective August 1, 2010*

CONSOLIDATED PROJECTED BALANCE SHEET (IFF09-1)
2.90% Rate Increase Effective August 1, 2010
(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	17,387	17,844	18,579	21,071	22,401	25,835
Accumulated Depreciation	(4,800)	(5,171)	(5,562)	(5,985)	(6,414)	(6,864)	(7,320)	(7,787)	(8,275)	(8,799)	(9,357)
Net Plant in Service	8,297	8,455	10,129	10,228	10,240	10,523	10,524	10,792	12,796	13,602	16,478
Construction in Progress	1,949	2,460	1,343	1,820	2,840	3,856	5,534	6,950	6,161	6,448	4,170
Current and Other Assets	2,421	2,374	2,503	2,551	2,318	2,473	2,673	2,885	3,181	3,093	3,292
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,397	14,082	14,705	15,506	16,959	18,838	20,734	22,246	23,251	24,048
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,786	10,366	11,522	13,140	14,429	15,363	16,646	14,164
Current and Other Liabilities	2,246	2,010	2,199	2,995	2,167	2,369	2,406	2,766	3,110	2,580	5,574
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,305	2,385	2,467	2,603	2,724	2,982	3,253	3,498	3,754	4,040
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,397	14,082	14,705	15,506	16,959	18,838	20,734	22,246	23,251	24,048

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF09-1)
2.90% Rate Increase Effective August 1, 2010
(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	2,149	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)	(503)	(569)	(578)	(576)	(582)	(594)	(663)	(754)	(949)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	551	500	548	560	612	637	777	810	789	833	898
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	900	800	600	600	1,600	1,400	1,800	1,800	1,800	1,600	800
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	510	1,220	1,289	1,529	1,585	1,255	1,161	635
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)	(117)	(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)	(25)	8	(98)	146	13	(87)	23	52	110	(49)
Cash at Beginning of Year	(32)	(84)	(109)	(101)	(200)	(54)	(41)	(128)	(105)	(53)	56
Cash at End of Year	(84)	(109)	(101)	(200)	(54)	(41)	(128)	(105)	(53)	56	7

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
2.90% Rate Increase Effective August 1, 2010
(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 *	-	23	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	1,574	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	413	469	526	527	545	530	546	588	674	879
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	1,724	1,824	1,861	1,923	1,964	2,047	2,157	2,371	2,618
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	68	85	72	124	112	247	262	235	243	275
*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%

** 2.90% Rate Increase Effective August 1, 2010*

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
2.90% Rate Increase Effective August 1, 2010
(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	2,872	2,926	2,698	2,851	3,047	3,259	3,554	3,465	3,666
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,547	15,343	16,788	18,656	20,545	22,047	23,039	23,826
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,054	8,769	10,349	11,505	13,123	14,412	15,346	16,629	14,147
Current and Other Liabilities	2,156	1,936	2,131	2,928	2,108	2,310	2,347	2,707	3,051	2,521	5,515
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,251	2,320	2,391	2,516	2,627	2,875	3,137	3,371	3,615	3,890
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,547	15,343	16,788	18,656	20,545	22,047	23,039	23,826

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
2.90% Rate Increase Effective August 1, 2010
(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	1,574	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)	(478)	(542)	(551)	(548)	(554)	(566)	(635)	(726)	(921)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	483	517	524	579	597	735	769	745	785	852
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	600	540	1,600	1,400	1,800	1,800	1,800	1,600	800
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	1,161	635
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(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)	(117)	(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)	(2)	18	(87)	150	10	(92)	21	46	101	(55)
Cash at Beginning of Year	66	(48)	(50)	(32)	(119)	31	41	(51)	(30)	16	118
Cash at End of Year	(48)	(50)	(32)	(119)	31	41	(51)	(30)	16	118	62

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CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF09-1)
2.9% Annual Rate Increase Implemented August 1, 2010 followed by Additional Rate Increases to 2015/16 to Arrive at the same Debt / Equity Ratio in 2015/16
(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	1,660	1,739	1,809	1,872	1,956	2,032	2,105	2,183	2,261	2,341
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
	2,066	2,044	2,294	2,392	2,486	2,546	2,733	2,835	2,925	3,156	3,434
Cost of Gas Sold	351	332	340	346	342	349	350	351	352	353	352
	1,715	1,712	1,954	2,046	2,144	2,197	2,383	2,484	2,573	2,803	3,082
Other	28	29	31	32	32	33	34	34	35	36	36
	1,742	1,741	1,985	2,078	2,176	2,230	2,417	2,518	2,608	2,839	3,119
EXPENSES											
Operating and Administrative	446	456	482	492	501	512	522	532	555	568	589
Finance Expense	454	451	511	569	570	589	574	590	631	718	922
Depreciation and Amortization	394	415	438	469	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	103	109	116	125	133	140	146	150
	1,613	1,663	1,889	1,995	2,035	2,101	2,144	2,231	2,344	2,562	2,811
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	129	78	97	84	139	124	264	276	252	263	293
Additional General Consumers Revenue											
General electricity rate increases		2.90%*	2.96%	3.56%	3.56%	3.56%	3.56%	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%	78%	79%	80%	80%	80%	80%	79%
Interest Coverage	1.24	1.13	1.15	1.12	1.20	1.16	1.30	1.28	1.23	1.23	1.23
Capital Coverage	1.39	1.07	1.14	1.29	1.26	1.53	1.87	1.84	1.94	2.16	2.60

** 2.90% Rate Increase Effective August 1, 2010*

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CONSOLIDATED PROJECTED BALANCE SHEET (IFF09-1)
2.9% Annual Rate Increase Implemented August 1, 2010 followed by Additional Rate Increases to 2015/16
to Arrive at the same Debt / Equity Ratio in 2015/16
(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	17,387	17,844	18,579	21,071	22,401	25,835
Accumulated Depreciation	(4,800)	(5,171)	(5,562)	(5,985)	(6,414)	(6,864)	(7,320)	(7,787)	(8,275)	(8,799)	(9,357)
Net Plant in Service	8,297	8,455	10,129	10,228	10,240	10,523	10,524	10,792	12,796	13,602	16,478
Construction in Progress	1,949	2,460	1,343	1,820	2,840	3,856	5,534	6,950	6,161	6,448	4,170
Current and Other Assets	2,421	2,374	2,503	2,551	2,323	2,481	2,673	2,885	3,210	2,975	3,346
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,397	14,082	14,705	15,511	16,968	18,838	20,734	22,275	23,133	24,101
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,786	10,366	11,522	13,140	14,429	15,363	16,446	14,164
Current and Other Liabilities	2,246	2,010	2,198	2,993	2,167	2,369	2,392	2,747	3,113	2,630	5,588
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,305	2,385	2,469	2,608	2,732	2,996	3,272	3,524	3,787	4,080
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,397	14,082	14,705	15,511	16,968	18,838	20,734	22,275	23,133	24,101

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF09-1)
2.9% Annual Rate Increase Implemented August 1, 2010 followed by Additional Rate Increases to 2015/16
to Arrive at the same Debt / Equity Ratio in 2015/16
(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	2,149	2,402	2,497	2,593	2,653	2,841	2,943	3,034	3,266	3,545
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)	(503)	(569)	(578)	(576)	(582)	(594)	(657)	(753)	(937)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	551	500	549	562	615	640	781	814	800	839	916
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	510	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)	(117)	(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)	(25)	8	(97)	148	17	(83)	28	63	(84)	169
Cash at Beginning of Year	(32)	(84)	(109)	(101)	(197)	(49)	(33)	(115)	(88)	(25)	(108)
Cash at End of Year	(84)	(109)	(101)	(197)	(49)	(33)	(115)	(88)	(25)	(108)	60

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
2.9% Annual Rate Increase Implemented August 1, 2010 followed by Additional Rate Increases to 2015/16
to Arrive at the same Debt / Equity Ratio in 2015/16
(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 *	-	23	70	115	163	216	270	327	386	448	513
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	1,574	1,809	1,897	1,990	2,043	2,224	2,324	2,408	2,633	2,913
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	417	413	469	526	527	545	529	545	586	673	877
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	1,724	1,824	1,861	1,923	1,963	2,046	2,155	2,369	2,616
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	68	86	73	127	115	252	268	241	250	283
*Additional General Consumers Revenue											
Percent Increase		2.90%*	2.96%	3.56%	3.56%	3.56%	3.56%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase		2.90%	5.95%	9.72%	13.63%	17.67%	21.86%	26.13%	30.54%	35.11%	39.84%

** 2.90% Rate Increase Effective August 1, 2010*

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
2.9% Annual Rate Increase Implemented August 1, 2010 followed by Additional Rate Increases to 2015/16
to Arrive at the same Debt / Equity Ratio in 2015/16
(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	2,872	2,926	2,702	2,859	3,047	3,259	3,583	3,348	3,720
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,547	15,348	16,797	18,656	20,545	22,076	22,922	23,879
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	1,936	2,130	2,926	2,108	2,310	2,334	2,688	3,054	2,571	5,528
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,251	2,320	2,394	2,521	2,636	2,888	3,156	3,397	3,647	3,930
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,547	15,348	16,797	18,656	20,545	22,076	22,922	23,879

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
2.9% Annual Rate Increase Implemented August 1, 2010 followed by Additional Rate Increases to 2015/16 to Arrive at the same Debt / Equity Ratio in 2015/16
(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	1,574	1,809	1,897	1,990	2,043	2,224	2,324	2,408	2,633	2,913
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)	(478)	(542)	(551)	(548)	(554)	(566)	(628)	(724)	(908)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	483	518	525	581	601	739	774	757	792	870
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 contributions	(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)	(117)	(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)	(2)	19	(85)	153	14	(88)	25	58	(92)	163
Cash at Beginning of Year	66	(48)	(50)	(31)	(117)	36	50	(38)	(12)	45	(47)
Cash at End of Year	(48)	(50)	(31)	(117)	36	50	(38)	(12)	45	(47)	116

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IFF-09-1

b) Please provide a detailed discussion of how the general $15 million provision commencing in 2011/12 pertaining to anticipated impacts of the transition to IFRS was estimated.

ANSWER:

A provision for IFRS of $15 million was first included in IFF08-1 for general and administrative costs and rate regulated assets that may no longer be eligible for deferral upon the conversion to IFRS. Given the prevailing uncertainties with regards to rate regulated accounting within IFRS, the $15 million general provision for IFRS was maintained at the same level and timing as that first provided in IFF08 with the only change being its reclassification to OM&A from depreciation & amortization expense.

<u>MIPUG/MH I-10</u>

IFF-09-1

c) Given that IFF-09-1 assumes rate increases in excess of inflation targets throughout the forecast period, please describe in detail the efforts Manitoba Hydro is undertaking to improve productivity. In particular, please provide specific examples of productivity improvement targets by business unit or cost centre, and how these will be implemented and monitored, as described on page 11 of appendix 4.4.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-20(d).

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Load Forecast

a) Please provide a schedule, similar to MIPUG/MH I- 3 (c) i and ii from the 2008 EIIR proceeding, that compares, for 2000 through 2010 for each of GSL <30kV, GSL>30kV and <100kV, and GSL >100kV:

i. Manitoba Hydro's forecast sales (kW.h) to GSL customers for each of the next 20 years (i.e. the 2000 load forecast should show sales forecasts for 2001 through 2020, the 2001 load forecast should show sales forecasts for 2002 through 2021 etc).

ii. Manitoba Hydro's actual sales to GSL customers for 2000 through 2009.

ANSWER:

The tables on the following pages provide forecast sales (GW.h) from the 2000 to 2009 System Load Forecasts (the 2010 forecast is not yet available) for fiscal years 2000/01 to 2029/30 inclusive for each General Service Large sub-class. The last table provides actual data for the period 2000 to 2009. Limited Use of Billing Demand (LUBD) sales are not included in these figures.

LARGE 750-30 kV (Forecast GW.h)

FIS YR	YEAR OF SYSTEM LOAD FORECAST									
ENDING	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
2001	1,175									
2002	1,224	1,159								
2003	1,273	1,178	1,158							
2004	1,323	1,201	1,204	1,194						
2005	1,366	1,230	1,226	1,233	1,471					
2006	1,406	1,260	1,248	1,271	1,494	1,509				
2007	1,442	1,287	1,266	1,288	1,512	1,521	1,565			
2008	1,475	1,317	1,282	1,305	1,527	1,586	1,636	1,546		
2009	1,505	1,349	1,297	1,322	1,543	1,629	1,657	1,573	1,530	
2010	1,523	1,382	1,310	1,338	1,559	1,643	1,681	1,585	1,558	1,558
2011	1,541	1,417	1,331	1,354	1,576	1,661	1,692	1,602	1,575	1,574
2012	1,560	1,451	1,354	1,370	1,599	1,683	1,706	1,623	1,593	1,591
2013	1,578	1,481	1,379	1,385	1,622	1,706	1,724	1,646	1,611	1,611
2014	1,596	1,509	1,402	1,401	1,646	1,729	1,744	1,661	1,637	1,633
2015	1,613	1,534	1,424	1,419	1,669	1,752	1,763	1,675	1,660	1,645
2016	1,630	1,557	1,445	1,439	1,692	1,772	1,782	1,690	1,681	1,665
2017	1,646	1,577	1,467	1,458	1,715	1,792	1,801	1,706	1,704	1,685
2018	1,661	1,595	1,489	1,477	1,737	1,813	1,820	1,722	1,724	1,706
2019	1,675	1,611	1,511	1,496	1,758	1,834	1,840	1,743	1,743	1,729
2020	1,688	1,626	1,533	1,516	1,780	1,857	1,860	1,765	1,763	1,750
2021	1,701	1,638	1,556	1,536	1,801	1,879	1,880	1,788	1,781	1,770
2022		1,649	1,579	1,555	1,822	1,902	1,900	1,811	1,800	1,790
2023			1,603	1,575	1,842	1,925	1,920	1,833	1,819	1,811
2024				1,596	1,861	1,948	1,940	1,856	1,837	1,831
2025					1,880	1,971	1,960	1,878	1,856	1,851
2026						1,994	1,980	1,902	1,874	1,873
2027							2,000	1,925	1,892	1,894
2028								1,950	1,911	1,916
2029									1,929	1,938
2030										1,961

LARGE 30 - 100 kV (Forecast GW.h)

FIS YR	YEAR OF SYSTEM LOAD FORECAST									
ENDING	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
2001	535									
2002	623	505								
2003	682	646	679							
2004	739	758	694	784						
2005	743	772	701	888	736					
2006	746	785	708	891	771	807				
2007	750	798	715	877	806	1,022	861			
2008	753	810	723	863	837	1,277	990	964		
2009	757	821	730	849	867	1,457	1,117	1,218	990	
2010	760	833	737	835	897	1,605	1,257	1,368	1,154	944
2011	763	845	745	821	900	1,628	1,396	1,474	1,273	853
2012	764	848	752	807	898	1,627	1,451	1,479	1,345	868
2013	766	851	755	809	896	1,624	1,453	1,483	1,353	855
2014	768	854	759	812	895	1,622	1,455	1,488	1,356	906
2015	770	857	761	814	895	1,620	1,457	1,492	1,358	1,091
2016	772	860	763	816	896	1,622	1,458	1,496	1,361	1,095
2017	774	863	766	819	897	1,624	1,460	1,499	1,362	1,099
2018	776	866	768	821	899	1,627	1,462	1,503	1,365	1,102
2019	777	869	770	824	901	1,629	1,463	1,505	1,369	1,103
2020	779	871	773	826	903	1,631	1,464	1,507	1,372	1,107
2021	781	874	775	829	905	1,632	1,465	1,509	1,375	1,111
2022		876	778	831	907	1,634	1,467	1,511	1,379	1,116
2023			780	834	911	1,636	1,468	1,513	1,382	1,120
2024				836	914	1,638	1,469	1,515	1,386	1,124
2025					917	1,640	1,470	1,517	1,389	1,128
2026						1,641	1,471	1,519	1,392	1,132
2027							1,472	1,522	1,396	1,136
2028								1,524	1,399	1,140
2029									1,403	1,144
2030										1,149

LARGE >100 (Forecast GW.h)

FIS YR	YEAR OF SYSTEM LOAD FORECAST									
ENDING	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
2001	3,991									
2002	4,319	4,173								
2003	4,385	4,445	4,474							
2004	4,426	4,607	4,480	4,687						
2005	4,526	4,739	4,577	4,880	4,833					
2006	4,626	4,871	4,673	4,950	5,132	5,089				
2007	4,726	5,003	4,789	5,061	5,436	5,122	5,135			
2008	4,826	5,085	4,905	5,163	5,580	5,205	5,213	5,158		
2009	4,926	5,168	5,021	5,244	5,714	5,309	5,285	5,378	5,390	
2010	5,026	5,250	5,137	5,325	5,828	5,442	5,545	5,823	5,633	5,018
2011	5,121	5,332	5,254	5,406	5,928	5,536	5,805	6,011	5,952	5,354
2012	5,176	5,402	5,370	5,498	5,828	5,469	5,995	6,195	6,246	5,635
2013	5,231	5,472	5,470	5,588	5,728	5,349	6,055	6,371	6,531	5,829
2014	5,286	5,542	5,570	5,668	5,648	5,229	6,115	6,547	6,591	5,920
2015	5,341	5,612	5,640	5,748	5,658	5,109	6,175	6,709	6,651	6,078
2016	5,396	5,682	5,710	5,828	5,668	5,184	6,235	6,871	6,711	6,178
2017	5,451	5,752	5,780	5,908	5,678	5,259	6,295	6,997	6,731	6,278
2018	5,506	5,822	5,850	5,988	5,738	5,334	6,355	7,123	6,831	6,338
2019	5,561	5,892	5,920	6,068	5,798	5,409	6,385	7,189	6,931	6,365
2020	5,616	5,962	5,990	6,148	5,858	5,459	6,415	7,255	7,031	6,465
2021	5,671	6,032	6,060	6,228	5,918	5,509	6,445	7,321	7,131	6,565
2022		6,102	6,130	6,308	5,978	5,559	6,475	7,387	7,231	6,665
2023			6,200	6,388	6,088	5,609	6,505	7,453	7,331	6,765
2024				6,468	6,198	5,659	6,535	7,519	7,431	6,865
2025					6,308	5,709	6,565	7,585	7,531	6,965
2026						5,759	6,595	7,651	7,631	7,065
2027							6,625	7,717	7,731	7,165
2028								7,783	7,831	7,265
2029									7,931	7,365
2030										7,465

ACTUALS (GW.h)

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

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Load Forecast

b) Please provide a copy of Table 3 from the 2009/10 to 2029/30 Electric Load Forecast that separates out the General Service load forecast into each GS class and subclass.

ANSWER:

The following three tables provide the breakdown of the General Service forecast sector into its subclasses.

Fiscal Year Ending	Total General Service	Small Non-Demand	Small Demand (excl LUBD)	Small Demand LUBD	Medium (excl. LUBD/SEP)	Medium LUBD
2010	14,056.3	1,571.9	1,889.4	3.7	3,024.1	4.4
2011	14,412.4	1,595.1	1,916.7	3.7	3,074.7	4.4
2012	14,830.6	1,621.4	1,947.6	3.8	3,123.9	4.4
2013	15,136.4	1,647.8	1,978.1	3.8	3,172.5	4.5
2014	15,399.7	1,673.2	2,007.3	3.8	3,231.5	4.5
2015	15,848.5	1,697.4	2,034.7	3.8	3,274.2	4.6
2016	16,067.0	1,721.8	2,062.2	3.8	3,317.1	4.6
2017	16,286.8	1,746.7	2,089.9	3.9	3,360.3	4.6
2018	16,467.5	1,771.8	2,117.8	3.9	3,403.9	4.6
2019	16,616.9	1,797.7	2,146.0	3.9	3,447.8	4.6
2020	16,840.4	1,824.0	2,174.3	3.9	3,492.0	4.7
2021	17,064.4	1,850.6	2,202.8	3.9	3,536.4	4.7
2022	17,288.0	1,877.6	2,231.0	4.0	3,580.4	4.7
2023	17,512.7	1,905.3	2,259.3	4.0	3,624.5	4.7
2024	17,737.0	1,933.5	2,287.3	4.0	3,668.3	4.8
2025	17,962.3	1,961.9	2,315.6	4.0	3,712.4	4.8
2026	18,192.7	1,991.6	2,345.0	4.0	3,758.2	4.8
2027	18,424.2	2,021.7	2,374.6	4.1	3,804.4	4.8
2028	18,658.1	2,052.5	2,404.6	4.1	3,851.3	4.8
2029	18,893.2	2,083.8	2,434.9	4.1	3,898.5	4.9
2030	19,129.7	2,115.8	2,465.4	4.1	3,946.1	4.9

Fiscal Year Ending	Large <30 (excluding LUBD, SEP)	Large <30 LUBD	Large 30-100 kV	Large >100 kV (ex LUBD)	Large >100 kV LUBD	General Service Seasonal
2010	1,558.3	2.0	943.6	5,018.0	0.4	4.6
2011	1,574.3	2.1	853.5	5,354.4	0.4	4.7
2012	1,590.8	2.1	868.0	5,635.2	0.4	4.7
2013	1,610.7	2.1	854.5	5,829.3	0.4	4.7
2014	1,633.2	2.1	906.3	5,919.9	0.4	4.7
2015	1,645.2	2.2	1,090.6	6,078.4	0.4	4.8
2016	1,665.0	2.2	1,094.6	6,178.4	0.4	4.8
2017	1,684.9	2.2	1,098.7	6,278.4	0.4	4.8
2018	1,706.3	2.3	1,101.5	6,338.4	0.4	4.8
2019	1,729.1	2.3	1,103.2	6,365.4	0.4	4.9
2020	1,749.5	2.3	1,107.3	6,465.4	0.4	4.9
2021	1,770.1	2.3	1,111.4	6,565.4	0.4	4.9
2022	1,790.4	2.4	1,115.5	6,665.4	0.4	5.0
2023	1,810.8	2.4	1,119.7	6,765.4	0.4	5.0
2024	1,831.1	2.4	1,123.8	6,865.4	0.4	5.0
2025	1,851.5	2.4	1,127.9	6,965.4	0.4	5.0
2026	1,872.8	2.5	1,132.0	7,065.4	0.4	5.1
2027	1,894.3	2.5	1,136.2	7,165.4	0.4	5.1
2028	1,916.2	2.5	1,140.3	7,265.4	0.4	5.1
2029	1,938.3	2.6	1,144.5	7,365.4	0.4	5.2
2030	1,960.5	2.6	1,148.7	7,465.4	0.4	5.2

Fiscal Year Ending	General Service FRWH	SEP Medium	SEP Large	Diesel Federal Govt.	Diesel Provincial Govt.	Diesel Non-Govt
2010	7.9	19.5	2.7	1.8	0.4	3.4
2011	7.5	12.5	2.7	1.8	0.4	3.5
2012	7.2	12.5	2.7	1.9	0.4	3.6
2013	6.8	12.5	2.7	1.9	0.4	3.7
2014	6.5	0	0	1.9	0.4	3.8
2015	6.2	0	0	1.9	0.4	3.9
2016	5.9	0	0	1.9	0.4	4.0
2017	5.6	0	0	1.9	0.4	4.1
2018	5.3	0	0	2.0	0.4	4.2
2019	5.0	0	0	2.0	0.4	4.3
2020	4.8	0	0	2.0	0.4	4.3
2021	4.5	0	0	2.0	0.4	4.4
2022	4.3	0	0	2.0	0.4	4.5
2023	4.1	0	0	2.0	0.4	4.6
2024	3.9	0	0	2.0	0.4	4.7
2025	3.7	0	0	2.1	0.4	4.8
2026	3.5	0	0	2.1	0.4	4.9
2027	3.3	0	0	2.1	0.4	5.0
2028	3.2	0	0	2.1	0.4	5.1
2029	3.0	0	0	2.1	0.4	5.2
2030	2.9	0	0	2.1	0.4	5.3

MIPUG/MH I-11

Load Forecast

c) Page 11 of Appendix 7.1 states that one of the economic assumptions is that real electricity prices will increase 0.9% per year throughout the forecast period. Please contrast this with the 3.5% average annual General Consumer Revenue increases beginning 2012/13 in IFF09-1. Please discuss what changes to the load forecast would be expected with these higher average annual rate increases.

ANSWER:

The real electricity price increase of 0.9% corresponds to the nominal price increase of 2.9%. IFF09-1 in section 1.2 increased the electricity price forecast beginning in 2012/13 from 2.9% to 3.5%.

Raising the price forecast by 0.6% would widen the gap between electricity and gas prices. This change would cause residential standard to gain about 10 more customers per year from residential all-electric. That would decrease the forecast by 0.2 GW.h per year.

For general service mass market, this would decrease their average use by about 5 kW.h per customer, or 0.3 GW.h per year.

The total effect would be a decrease of about 0.5 GW.h each year beginning in 2012/13, amounting to about 10 GW.h by 2029/30.

Load Forecast

d) With reference to page 24 of Appendix 7.1, please indicate the magnitude (GW.h) in each year of speculative loads assumed to be related to new, large industrial customers.

<u>ANSWER</u>:

Potential Large Industrial
2009 Base Forecast
12 Month Totals

Fiscal Year	GW.h
2009/10	0
2010/11	0
2011/12	0
2012/13	100
2013/14	200
2014/15	300
2015/16	400
2016/17	500
2017/18	600
2018/19	700
2019/20	800
2020/21	900
2021/22	1,000
2022/23	1,100
2023/24	1,200
2024/25	1,300
2025/26	1,400
2026/27	1,500
2027/28	1,600
2028/29	1,700
2029/30	1,800

MIPUG/MH I-11

Load Forecast

e) With reference to the scenario included on page 46 of Appendix 7.1:

i. Is it Manitoba Hydro's view that current industrial rates approximate marginal cost?

ANSWER:

No, current industrial rates are below marginal cost.

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

Load Forecast

e) With reference to the scenario included on page 46 of Appendix 7.1:

ii. Is it MH's view that applying for, but not implementing, an EIIR rate has resulted in industrial customers electing not to locate to or expand in Manitoba?

<u>ANSWER</u>:

Over the past two years, there have been potential new investment projects in energy intensive industries that have considered but rejected the possibility of locating in Manitoba for reasons which primarily include the uncertainty of electricity rates. It is therefore Manitoba Hydro's view that uncertainty over industrial rates is having a significant influence on assessments of potential investment related to both new loads and expansions of existing loads in Manitoba.

MIPUG/MH I-12

Energy Supply

a) Please provide a copy of the 2009 Power Resource Plan that supports the information provided in Tab 8: Energy Supply.

ANSWER:

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.

MIPUG/MH I-12

Energy Supply

b) Please provide a revised version of tables 1 and 2 from tab 8 assuming the lower levels of wind energy referenced on page 7 of tab 8.

ANSWER:

Since there is assumed to be no firm capacity associated with wind development, it is not necessary to revise Table 1. The revised dependable energy for the lower level of wind development is incorporated into Table 2 which is on the next page.

Table 2

System Firm Energy Demand and Dependable Resources (GW.h) - Revised Wind Energy
2009 Base Load Forecast

Fiscal Year	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Power Resources																
Manitoba Hydro Plants																
Existing	21090	21080	21060	21040	21030	20920	20900	20880	20870	20850	20840	20830	20820	20820	20810	20560
Wuskwatim		550	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250
Conawapa - (net addition)													2151	4550	4550	4550
Keeyask - (net addition)									1371	2900	2900	2900	2900	2900	2900	2900
Bipole III HVDC LINE								243	243	258	258	258	258	162	162	162
Manitoba Thermal Plants																
Brandon Unit 5 (Drought Operation)	811	811	811	811	811	811	811	811	811							
Selkirk	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCCT	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354
Wind: 238 MW	631	749	749	749	749	749	749	749	749	749	749	749	749	749	749	749
Demand Side Management	440	606	719	819	842	798	825	890	949	993	1037	1082	1115	1151	1158	1133
Major Rerunnering (incremental to existing)																
Kelsey Rerunnering																
Pointe du Bois							60	150	150	150	150	150	150	150	150	150
Imports	2796	2796	2796	2705	2705	2410	2414	2414	2797	3258	3846	3948	4652	4715	4715	4014
TOTAL POWER RESOURCES	29075	29899	30692	30681	30694	30245	30316	31198	32497	33715	34337	34474	37352	39754	39751	38775
Demand																
2009 Base Load Forecast	24759	25323	25763	26177	26783	27137	27495	27808	28088	28452	28818	29185	29555	29927	30300	30681
Non-Committed Construction Power		10	30	55	90	100	120	125	100	80	80	100	90	30	5	
Exports																
Total Contracted Sales	3404	3385	3259	3156	3156	1560	1352	1352	1926	2614	3494	3648	4992	5086	5086	3589
TOTAL DEMAND	28163	28718	29052	29388	30029	28797	28967	29285	30114	31146	32392	32933	34637	35043	35391	34270
SURPLUS (w/ B#5)	912	1181	1640	1293	665	1448	1349	1913	2383	2569	1945	1541	2715	4711	4360	4505
EXPORTABLE SURPLUS	101	370	829	482	-146	637	538	1102	1572	2569	1945	1541	2715	4711	4360	4505

MIPUG/MH I-12

Energy Supply

c) Please provide a revised version of tables 1 and 2 from tab 8 assuming an east side routing of BIPOLE III.

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. Manitoba Hydro has no current information on a hypothetical east side route.

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

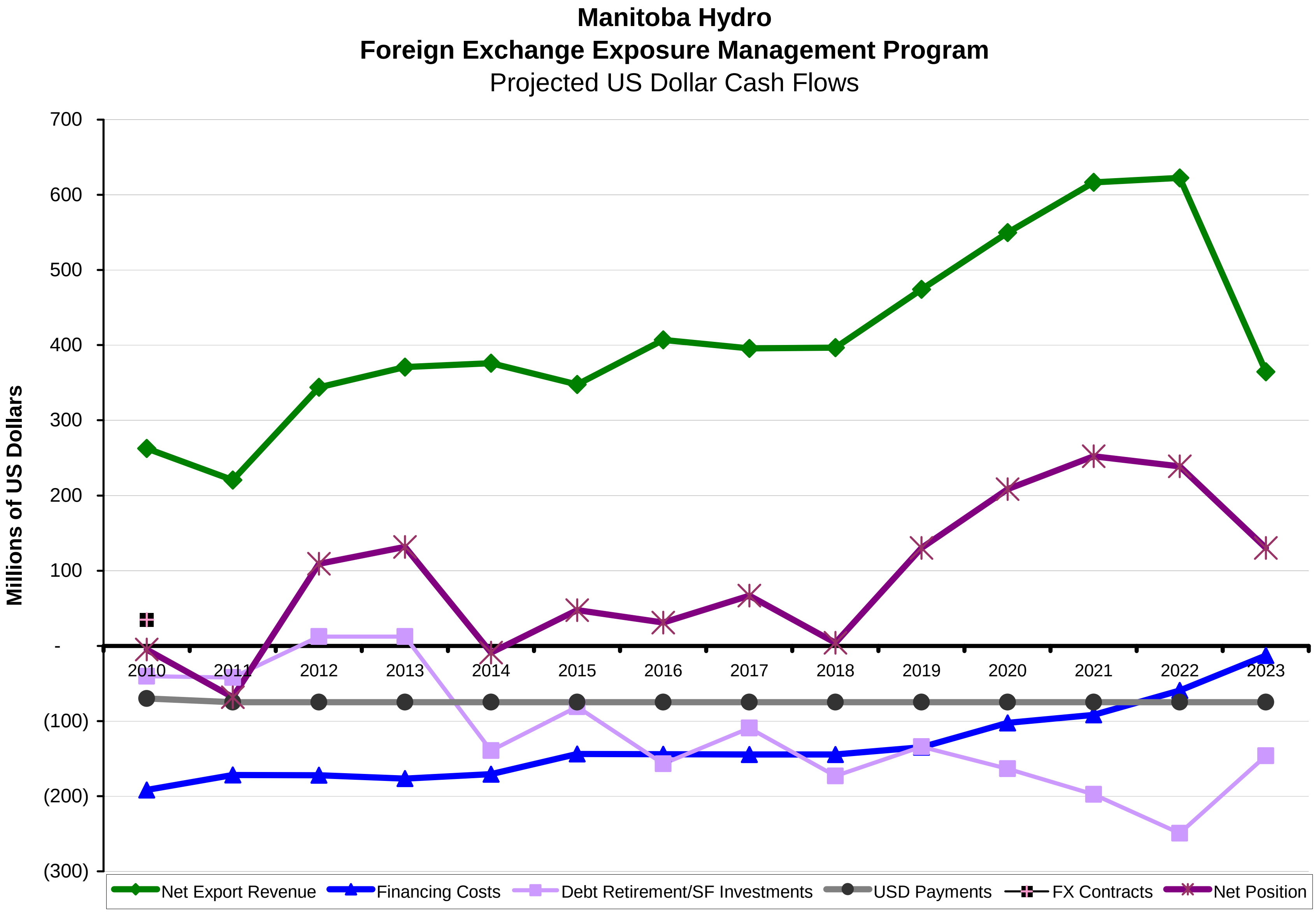
Exposure Management

a) Please provide an updated version of the information from MIPUG/MH I-9 b) from the 2008 General Rate Application regarding US$ cash flows.

<u>ANSWER</u>:

Please see the attached graph.

The information presented in this graph extends to September 2023 in order to align with the maturity of the last US long term debt issue within the existing US long term debt portfolio.



Manitoba Hydro
Foreign Exchange Exposure Management Program
Projected US Dollar Cash Flows
Millions of US Dollars
700
600
500
400
300
200
100
-
(100)
(200)
(300)
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Net Export Revenue
Financing Costs
Debt Retirement/SF Investments
USD Payments
FX Contracts
Net Position

MIPUG/MH I-13

Exposure Management

b) Please update the response to MIPUG/MH I-9 c) from the 2008 General Rate Application for years 2007 through 2009.

ANSWER:

The designated exchange rate of Manitoba Hydro's U.S. debt for the 2006/07 was $1.2320.

Effective April 1, 2007 Manitoba Hydro adopted the financial instruments CICA accounting recommendations. As a result, the Corporation established cash flow hedging relationships between U.S. long term debt balances and future U.S. export revenues, as well as fair value hedging relationships between U.S. long term debt balances and U.S. sinking fund investments. Accordingly, foreign exchange translation gains and losses on U.S. long term debt balances in effective cash flow hedge relationships are recognized in Other Comprehensive Income (OCI) until future hedged U.S. export revenues are realized, at which time the respective Accumulated OCI balances are also recognized in net income.

The historical weighted average foreign exchange rate of the U.S. long term debt balances in cash flow hedging relationships at fiscal year end was $1.1632 at March 31, 2008 and $1.1603 at March 31, 2009.

MIPUG/MH I-13

Exposure Management

c) Please provide Manitoba Hydro's most recent US/Cdn Exchange rate forecast.

ANSWER:

Refer to Manitoba Hydro's response to CAC/MSOS/MH I-30(b) for the most recent US/Cdn Exchange rate forecast.

MIPUG/MH I-14

Major Projects

a) Please provide an update to MIPUG/MH I-10 a) from the 2008 General Rate Application showing plant in service and accumulated depreciation in IFF MH09-1 for all major projects.

ANSWER:

Please see the attached table below.

MH09-1 Major Projects Net Plant In Service ($ Millions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wuskwatim											
Plant In Service	0	0	1 591	1 591	1 591	1 591	1 591	1 591	1 591	1 591	1 591
Accumulated Depreciation	0	0	11	39	68	96	125	153	181	210	238
Net Plant In Service	0	0	1 580	1 551	1 523	1 495	1 466	1 438	1 409	1 381	1 352
Herblet Lake-The Pas 230 kV Transmission											
Plant In Service	0	0	91	93	93	93	93	93	93	93	93
Accumulated Depreciation	0	0	1	3	4	6	8	10	12	13	15
Net Plant In Service	0	0	90	91	89	87	85	83	82	80	78
Keeyask											
Plant In Service	0	0	0	0	0	0	0	0	0	777	3 956
Accumulated Depreciation	0	0	0	0	0	0	0	0	0	3	39
Net Plant In Service	0	0	0	0	0	0	0	0	0	773	3 917
Kelsey Re-runnering											
Plant In Service	64	82	98	101	101	101	101	101	101	101	101
Accumulated Depreciation	0	2	3	5	6	8	10	11	13	14	16
Net Plant In Service	64	80	95	96	94	93	91	89	88	86	85
Kettle Improvements & Upgrades											
Plant In Service	1	26	26	47	68	76	76	76	76	76	76
Accumulated Depreciation	0	0	1	1	2	3	5	6	7	8	9
Net Plant In Service	1	26	25	46	66	72	71	70	69	68	66
Pointe du Bois Modernization											
Plant In Service	2	27	34	40	50	86	86	400	400	400	400
Accumulated Depreciation	1	2	3	5	7	10	13	19	25	31	37
Net Plant In Service	1	26	31	35	43	76	73	381	375	369	363
Bipole 3 Transmission and Converters											
Plant In Service	1	1	2	3	7	16	21	22	2 233	2 233	2 233
Accumulated Depreciation	0	0	0	0	0	0	0	1	20	66	112
Net Plant In Service	1	1	2	3	7	16	21	21	2 213	2 167	2 122
Riel 230/500kV Station											
Plant In Service	2	2	2	2	2	268	268	268	268	268	268
Accumulated Depreciation	0	0	0	0	0	7	15	22	30	38	46
Net Plant In Service	2	2	2	2	1	261	253	245	237	229	222
Firm Import/Export Upgrades											
Plant In Service	0	0	5	5	5	5	5	5	5	210	210
Accumulated Depreciation	0	0	0	0	0	0	0	0	1	4	9
Net Plant In Service	0	0	5	5	5	5	4	4	4	205	201

MIPUG/MH I-14

Major Projects

b) Please provide a detailed description of the $891.2 million increase in capital costs for the Keeyask Generating Station shown on page 9 of CEF09-1. Please describe and quantify the nature of the major cost increase drivers.

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH I-58(a) and (b).

MIPUG/MH I-14

Major Projects

c) Please provide a detailed description of the $1,346.4 million increase in capital costs for the Conawapa Generating Station shown on page 10 of CEF09-1.

ANSWER:

Please see Manitoba Hydro's responses to PUB/MH I-52(a) and (b).

MIPUG/MH I-15

System Capacity and Energy Resources and DSM

a) Please update the response to MIPUG/MH I – 11 c) from the 2008 General Rate Application showing the impact of DSM programs on customers by class in the current PCOSS.

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-69(b).

<u>MIPUG/MH I-16</u>

Sinking Funds

a) Please provide an update with respect to any progress Manitoba Hydro has made on discussions with the Province of Manitoba with respect to removing sinking fund requirements.

<u>ANSWER</u>:

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

<u>MIPUG/MH I-16</u>

Sinking Funds

b) Please provide the assumed earnings rate on the Sinking Funds for the period of the current IFF, including the basis for the earnings estimates.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH I-25(a). On a forecast basis, the earnings on the existing sinking fund portfolio are forecasted utilizing the actual known investment returns. The earnings on the incremental new sinking fund contributions is based upon Manitoba Hydro's forecast long term Canadian and US borrowing rates, exclusive of the Provincial Debt Guarantee Fee.

MIPUG/MH I-16

Sinking Funds

c) Please provide the annual contributions to and withdrawals from the Sinking Funds for the period of the current IFF.

ANSWER:

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

<u>MIPUG/MH I-16</u>

Sinking Funds

d) **Please provide a copy of the electric operations operating statement, balance sheet and cash flow statements assuming the statutory requirement for sinking funds were removed.**

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH I-25(b) regarding some of the potential financial statement implications of removing the sinking fund requirements.

MIPUG/MH I-17

Corporate Risk Management

a) Please provide an estimate of the magnitude of the impact of a 5-year drought assuming it coincides with high energy prices.

ANSWER:

The following table indicates that the impact of the 5-year drought given high energy prices is $2.8 billion and this compares to an impact of $2.0 billion for the case of expected energy prices. The drought is assumed to begin in fiscal year 2011/12 and corresponds to flow years 1987/88 to 1991/92.

	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	-268	-426	-254	-285	-287	-1521
Expense						
Water Rental	-24	-36	-17	-19	-16	-111
Fuel & Power Purchase	344	614	128	193	124	1403
Net Revenue (Excluding Finance Expense)	-588	-1004	-366	-460	-395	-2812
Impact of 5-Year Drought on Energy (GWh/yr)						
Extra-Provincial Sales	-3265	-4249	-3099	-3185	-3048	-16846
Hydro Generation	-7153	-10717	-5077	-5548	-4793	-33289
Fuel & Power Purchase	3325	5611	1586	1923	1363	13807

MIPUG/MH I-17

Corporate Risk Management

b) Please provide a copy of the electricity operations operating statements showing the average general consumer rate increases that would be necessary to maintain the debt:equity ratios in IFF-MH-09-1 assuming loss of Manitoba Hydro's export markets.

ANSWER:

Loss of the entire export market for the full duration of the IFF period is highly unlikely. To analyze the full impacts, extensive analysis would have to be undertaken. The following projections simplistically assume no exports but do not factor in likely impacts to import capabilities, current and future domestic load, and system generation and transmission requirements which are expected to be significant. The attached projections show that cumulative general consumers rate increases would be 84.95% higher compared to MH09-1.

MIPUG-MH I-17(b)

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
LOSS OF EXPORT MARKET WITH RATE INCREASES STARTING IN 2011 TO MATCH THE D/E RATIO IN MH09-1
(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 *	-	857	624	699	777	803	967	1,053	1,125	1,338	1,603
Extraprovincial	-	-	-	-	-	-	-	-	-	-	-
Other	7	7	8	8	8	8	8	9	9	9	9
	1,167	2,023	1,809	1,898	1,989	2,039	2,220	2,321	2,405	2,630	2,909
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	424	430	469	528	528	546	532	547	589	676	880
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
	1,467	1,523	1,724	1,826	1,862	1,923	1,965	2,048	2,158	2,372	2,619
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	(300)	500	86	72	125	111	247	263	235	244	276
*Additional General Consumers Revenue											
Percent Increase	0.00%	74.21%	-11.97%	3.71%	3.69%	0.50%	7.52%	3.34%	2.65%	8.45%	9.45%
Cumulative Percent Increase	0.00%	74.21%	53.35%	59.05%	64.92%	65.75%	78.21%	84.16%	89.03%	105.01%	124.38%
Financial Ratios											
Debt	78%	75%	76%	76%	78%	79%	80%	80%	80%	80%	80%
Interest Coverage	0.42	1.89	1.14	1.11	1.18	1.15	1.29	1.28	1.23	1.22	1.22
Capital Coverage (excl Major Gen.)	0.22	2.07	1.15	1.31	1.26	1.54	1.91	1.87	1.96	2.21	2.71

MIPUG/MH I-17

Corporate Risk Management

c) Please provide a copy of schedules B1-B3 from PCOSS10 assuming the complete loss of Manitoba Hydro's export markets.

ANSWER:

The scenario cited in the question has an extremely low probability, particularly within the short term time horizon as represented by PCOSS10. Nevertheless, Manitoba Hydro has endeavored to prepare a version of the PCOSS that incorporates the loss of export markets as requested. Preparing this study required making a significant number of very broad and simplifying assumptions:

- Loss of access to extraprovincial markets, and ability to make export sales therein, is complete and lasts throughout the year represented by PCOSS10;
- Loss of access to export markets is accompanied by complete loss of access to import power from extraprovincial sources, however access to Manitoba IPP remains;
- All fixed costs of Manitoba Hydro's existing infrastructure remain in place;
- All purely variable export related costs that can be avoided in the short term are eliminated;
- Export related costs that are only variable in the longer term, such as reductions in staffing, remain;
- Any unavoidable variable or fixed costs that were formerly assigned or allocated to the Export class are allocated between the Domestic classes.

The specific changes in costs and their allocation as implemented in the hypothetical PCOSS are as follows:

- All Export revenue is removed;
- The uniform rate adjustment is eliminated as there is no longer export revenue to fund the initiative;
- Affordable Energy Fund expenditures are assigned entirely to the Residential class, which is the treatment that is most consistent with cost causality;
- Fuel and variable maintenance costs for Brandon Unit 5, other than that related to operation for environmental or staff proficiency training, are eliminated;

- Water rental fees related to Export energy are eliminated;
- NEB charges, which are assessed based on level of Export sales, are eliminated;
- No change is made for the cost of the ‘Trading Desk’ or other business areas for staffing reductions that could be achieved in the absence of Export sales, but are only achievable over the longer term;
- Cost of all power purchases and the associated transmission is eliminated, other than Dependable Purchases contracted with Manitoba IPP;
- MISO/MAPP fees are eliminated.

The removal of $546 million in Export Revenue, which is only partially offset by the elimination of $195 million in Operating costs, would result in a significant change in Contributions to Reserve included as part of Interest costs in the PCOSS. The resulting revenue shortfall would necessitate dramatic rate increases from domestic classes over the longer term, but no such increases have been included in the short term time horizon as assumed in our scenario.

The adjustment to Contributions to Reserve has been implemented using two different approaches, the results of which are depicted below:

- In the first scenario the Contributions to Reserve have been revised to reflect a substantial net loss for the test year of the study.
- In the second version the required Contributions to Reserve, as determined in the IFF and used in the filed version of PCOSS10, have not been changed. As the costs included in the scenario exceed the forecast class revenue, the overall Revenue Cost Coverage (RCC) calculated will be below unity. To make the resulting RCCs comparable to other versions of the PCOSS, the class RCC’s are also shown restated using the overall RCC as a base.

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S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	490,271	469,313	95.7%	-	469,313	95.7%
General Service - Small Non Demand	102,008	110,177	108.0%	-	110,177	108.0%
General Service - Small Demand	109,113	114,889	105.3%	-	114,889	105.3%
General Service - Medium	154,465	158,956	102.9%	-	158,956	102.9%
General Service - Large 0 - 30kV	73,679	67,889	92.1%	-	67,889	92.1%
General Service - Large 30-100kV*	42,577	44,588	104.7%	-	44,588	104.7%
General Service - Large >100kV*	181,776	192,906	106.1%	-	192,906	106.1%
*Includes Curtailment Customers						
SEP	1,494	1,315	88.0%	-	1,315	88.0%
Area & Roadway Lighting	17,101	19,613	114.7%	-	19,613	114.7%
Total General Consumers	1,172,485	1,179,646	100.6%	-	1,179,646	100.6%
Diesel	11,826	4,665	39.4%	-	4,665	39.4%
Export	-	-	0.0%	-	-	0.0%
Total System	1,184,311	1,184,311	100.0%	-	1,184,311	100.0%

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SUMMARY

	C U S T O M E R			D E M A N D				E N E R G Y		
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh
Residential	104,857	466,759	18.72	177,856	0%	n/a	n/a	207,558	6,811,218	5.66 **
GS Small - Non Demand	20,711	52,716	32.74	34,683	0%	n/a	n/a	46,614	1,478,206	5.50 **
GS Small - Demand	6,577	11,260	48.68	41,291	38%	2,203	7.17	61,245	1,983,393	4.37
General Service - Medium	5,663	1,859	253.85	57,637	100%	7,008	8.22	91,165	3,032,155	3.01
General Service - Large <30kV	2,906	259	n/a	25,494	100%	3,452	8.23 *	45,278	1,533,322	2.95
General Service - Large 30-100kV	1,830	30	n/a	10,116	100%	2,455	4.87 *	30,631	1,151,746	2.66
General Service - Large >100kV	2,126	14	n/a	32,397	100%	9,476	3.64 *	147,254	5,626,174	2.62
SEP	337	25	1,124.68	239	0%	n/a	n/a	918	22,550	5.13 **
Area & Roadway Lighting	12,645	153,710	6.86	2,117	0%	n/a	n/a	2,339	99,432	4.48 **
Total General Consumers	157,652	686,631		381,829		24,594		633,004	21,738,196	
Diesel	251	732	28.61	377	0%	n/a	n/a	11,198	12,820	90.29 **
Export	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a ***
Total System	157,903	687,363		382,206		24,594		644,202	21,751,016	

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

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Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	490,271	207,558	42.3%	51,610	10.5%	33,223	6.8%	58,363	11.9%	139,517	28.5%
General Service - Small Non Demand	102,008	46,614	45.7%	11,939	11.7%	6,001	5.9%	14,589	14.3%	22,865	22.4%
General Service - Small Demand	109,113	61,245	56.1%	14,668	13.4%	7,006	6.4%	3,227	3.0%	22,967	21.0%
General Service - Medium	154,465	91,165	59.0%	22,149	14.3%	9,339	6.0%	4,822	3.1%	26,990	17.5%
General Service - Large <30kV	73,679	45,278	61.5%	10,888	14.8%	4,367	5.9%	2,700	3.7%	10,446	14.2%
General Service - Large 30-100kV	42,577	30,631	71.9%	7,035	16.5%	3,081	7.2%	1,788	4.2%	41	0.1%
General Service - Large >100kV	181,776	147,254	81.0%	32,397	17.8%	0	0.0%	2,106	1.2%	20	0.0%
SEP	1,494	918	61.4%	239	16.0%	0	0.0%	324	21.7%	13	0.9%
Area & Roadway Lighting	17,101	2,339	13.7%	418	2.4%	447	2.6%	567	3.3%	13,330	77.9%
Total General Consumers	1,172,485	633,004	54.0%	151,341	12.9%	63,465	5.4%	88,487	7.5%	236,188	20.1%
Diesel	11,826	11,198	94.7%	0	0.0%	0	0.0%	0	0.0%	628	5.3%
Export	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total System	1,184,311	644,202	54.4%	151,341	12.8%	63,465	5.4%	88,487	7.5%	236,816	20.0%

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S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates	Class RCC ÷ Total System RCC
Residential	631,712	469,313	74.3%	-	469,313	74.3%	96.2%
General Service - Small Non Demand	130,629	110,177	84.3%	-	110,177	84.3%	109.2%
General Service - Small Demand	142,379	114,889	80.7%	-	114,889	80.7%	104.5%
General Service - Medium	201,760	158,956	78.8%	-	158,956	78.8%	102.1%
General Service - Large 0 - 30kV	96,177	67,889	70.6%	-	67,889	70.6%	91.5%
General Service - Large 30-100kV*	55,771	44,588	79.9%	-	44,588	79.9%	103.5%
General Service - Large >100kV*	240,623	192,906	80.2%	-	192,906	80.2%	103.9%
*Includes Curtailment Customers							
SEP	1,513	1,315	86.9%	-	1,315	86.9%	112.6%
Area & Roadway Lighting	21,220	19,613	92.4%	-	19,613	92.4%	119.7%
Total General Consumers	1,521,783	1,179,646	77.5%	-	1,179,646	77.5%	100.4%
Diesel	12,516	4,665	37.3%	-	4,665	37.3%	48.3%
Export	-	-	0.0%	-	-	0.0%	0.0%
Total System	1,534,299	1,184,311	77.2%	-	1,184,311	77.2%	100.0%

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Customer, Demand, Energy Cost Analysis
MIPUG/MH I-17(c) -- No Change in Contribution to Reserves
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	126,556	466,759	22.59	233,609	0%	n/a	n/a		271,546	6,811,218	7.42	**
GS Small - Non Demand	23,807	52,716	37.64	45,626	0%	n/a	n/a		61,195	1,478,206	7.23	**
GS Small - Demand	7,708	11,260	57.04	54,336	38%	2,203	9.43		80,335	1,983,393	5.74	
General Service - Medium	6,125	1,859	274.56	75,910	100%	7,008	10.83		119,725	3,032,155	3.95	
General Service - Large <30kV	3,075	259	n/a	33,642	100%	3,452	10.64	*	59,459	1,533,322	3.88	
General Service - Large 30-100kV	1,929	30	n/a	13,440	100%	2,455	6.26	*	40,402	1,151,746	3.51	
General Service - Large >100kV	2,234	14	n/a	43,424	100%	9,476	4.82	*	194,965	5,626,174	3.47	
SEP	356	25	1,187.66	242	0%	n/a	n/a		915	22,550	5.13	**
Area & Roadway Lighting	15,372	153,710	8.33	2,774	0%	n/a	n/a		3,075	99,432	5.88	**
Total General Consumers	187,162	686,631		503,002		24,594			831,619	21,738,196		
Diesel	278	732	31.66	417	0%	n/a	n/a		11,821	12,820	95.46	**
Export	n/a	n/a	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a	***
Total System	187,440	687,363		503,419		24,594			843,440	21,751,016		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

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S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	631,712	271,546	43.0%	69,177	11.0%	43,242	6.8%	61,266	9.7%	186,481	29.5%
General Service - Small Non Demand	130,629	61,195	46.8%	16,003	12.3%	7,811	6.0%	15,294	11.7%	30,326	23.2%
General Service - Small Demand	142,379	80,335	56.4%	19,660	13.8%	9,119	6.4%	3,383	2.4%	29,881	21.0%
General Service - Medium	201,760	119,725	59.3%	29,687	14.7%	12,155	6.0%	5,056	2.5%	35,137	17.4%
General Service - Large <30kV	96,177	59,459	61.8%	14,593	15.2%	5,684	5.9%	2,831	2.9%	13,609	14.2%
General Service - Large 30-100kV	55,771	40,402	72.4%	9,429	16.9%	4,011	7.2%	1,875	3.4%	54	0.1%
General Service - Large >100kV	240,623	194,965	81.0%	43,424	18.0%	0	0.0%	2,208	0.9%	26	0.0%
SEP	1,513	915	60.5%	242	16.0%	0	0.0%	340	22.5%	16	1.1%
Area & Roadway Lighting	21,220	3,075	14.5%	560	2.6%	582	2.7%	595	2.8%	16,408	77.3%
Total General Consumers	1,521,783	831,619	54.6%	202,775	13.3%	82,604	5.4%	92,847	6.1%	311,938	20.5%
Diesel	12,516	11,821	94.4%	0	0.0%	0	0.0%	0	0.0%	695	5.6%
Export	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total System	1,534,299	843,440	55.0%	202,775	13.2%	82,604	5.4%	92,847	6.1%	312,633	20.4%

MIPUG/MH I-18

Time of Use

a) **Page 5 of Tab 10 indicates that possible rate proposals for Time-of-Use Rates applicable to the GSL >30kV subclasses are being considered and will be reviewed by the Manitoba Hydro-Electric Board at its January 2010 meeting. Please provide an update on the status of Manitoba Hydro's consideration of Time-of-Use rates.**

ANSWER:

The Manitoba Hydro-Electric Board (MHEB) did not review a TOU proposal at its January 21, 2010 Meeting. The MHEB did approve the current EIIR proposal that was filed with the PUB as part of this current proceeding. That proposal has a TOU aspect in that the higher, marginal cost based rate would apply to only the on-peak portion of energy consumption over and above a baseline amount.

Manitoba Hydro intends to develop and review additional TOU proposals once the current GRA review is completed.

MIPUG/MH I-18

Time of Use

b) Please indicate if Manitoba Hydro has undertaken any consultation with GSL >30kV customers with respect to potential Time-of-Use rates since the 2008 GRA. If so, please provide copies of any relevant presentations or correspondence.

ANSWER:

Manitoba Hydro has not undertaken consultation with GSL > 30 kV customer with respect to potential Time-of-Use rates since the 2008 GRA.

<u>MIPUG/MH I-18</u>

Time of Use

c) **Please provide an estimate of the minimum amount of time that would be necessary to develop and apply a TOU rate for GSL customers, including the provision for customer consultation.**

<u>ANSWER</u>:

If a decision were made by Manitoba Hydro to proceed with a TOU rate, it would require some 6-8 months to finalize, consult with customers and prepare an Application.

MIPUG/MH I-19

Rate Objectives

a) **With respect to Rate Objective #1 (page 2 of Tab 10) please indicate how much longer Hydro anticipates attainment of this objective will take.**

ANSWER:

Rate objective #1 states:

Manitoba Hydro's long-term target is to have all class Revenue Cost Coverage (RCC) ratios in the range of 95% to 105%, and further that all classes should be gradually moved toward RCC's of unity.

Manitoba Hydro intends to commission an independent review of the Cost of Service Study methodologies before relying on the results of the study for rate design. Once this independent review is completed, Manitoba Hydro will consider differential rate changes in the future to address this targeted zone of reasonableness (ZOR).

MIPUG/MH I-19

Rate Objectives

b) **Based on the current PCOSS, please indicate the average annual rate increases by class and sub-class that would be necessary to move all rate classes within the 95% to 105% zone of reasonableness within 5 years.**

ANSWER:

Based on the current PCOSS (assuming no additional revenue requirement), the average annual required rate increases needed to bring all classes within the 95% to 105% Zone of Reasonableness in five years are as follows:

Class	PCOSS10 RCC	Average Annual Increase	RCC after 5 Years of Increases
Residential	96.4%	0.00%	96.4%
General Service - Small Non Demand	105.7%	-0.14%	105.0%
General Service - Small Demand	102.8%	0.00%	102.8%
General Service - Medium	101.3%	0.00%	101.3%
General Service - Large 0 – 30 kV	92.3%	0.64%	95.0%
General Service - Large 30-100 kV	106.8%	-0.37%	105.0%
General Service - Large >100 kV	109.2%	-0.85%	105.0%
Area & Roadway Lighting	100.0%	0.00%	100.0%

<u>MIPUG/MH I-19</u>

Rate Objectives

c) **Based on the current PCOSS, please indicate the average annual rate increases by class and sub-class that would be necessary to move all rate classes to unity within 5 years.**

<u>ANSWER</u>:

Based on the current PCOSS (assuming no additional revenue requirement), the average annual required rate increases needed to bring all classes to unity in five years are as follows:

Class	PCOSS10 RCC	Average Annual Increase	RCC after 5 Years of Increases
Residential	96.4%	0.81%	100.0%
General Service - Small Non Demand	105.7%	-1.21%	100.0%
General Service - Small Demand	102.8%	-0.60%	100.0%
General Service - Medium	101.3%	-0.30%	100.0%
General Service - Large 0 – 30 kV	92.3%	1.79%	100.0%
General Service - Large 30-100 kV	106.8%	-1.44%	100.0%
General Service - Large >100 kV	109.2%	-1.91%	100.0%
Area & Roadway Lighting	100.0%	0.00%	100.0%

MIPUG/MH I-20

Proof of Revenue

a) **Please provide a schedule that shows all billing determinants and rates used to calculate the class revenues in the Proof of Revenues in Appendix 10.1 and Appendix 10.2, including assumptions related to the Energy Intensive revenues.**

ANSWER:

The tables on the following pages provide billing determinants for the Residential and General Service rate classes based on:

1) Fiscal 2010/11 forecast data at current April 1, 2009 rates and interim-approved April 1, 2010 rates, which were revised in accordance with Board Order 18/10, for which final interim-approval is pending.

2) Fiscal 2011/12 forecast data at proposed April 1, 2010 rates and proposed April 1, 2011 rates.

Assumptions related to the Energy Intensive revenues are discussed in response to MIPUG/MH I-20(b).

Please note that Manitoba Hydro’s response to MIPUG/MH I-20(c) which was filed on March 4, 2010 did not reflect the revised residential rates in accordance with Board Order 18/10. Incorporating the revised rates results in the 2010/11 DSM Savings for the Residential class to be $10,575,268 rather than the $10,664,700 as shown in the filed response.

RESIDENTIAL: Fiscal 2010/11 - Current April 1, 2009 Rates versus Proposed April 1, 2010 Rates

Forecast Data 2010/11	Cust Months	>200 A Custs	1st Block of 900 kW.h	2nd Block of 1100 kW.h	Balance of kW.h	Total kW.h
Basic	5,346,203	32,499	3,553,763,914	-	3,280,511,833	6,834,275,747
Diesel	6,952	-	5,354,638	2,350,911	215,891	7,921,440
Seasonal	(annual) 20,855	-	75,887,086	-	5,234,664	81,121,750
FRWH	55,233	-		-	22,975,349	22,975,349

Current April 2009 Rates	Basic Charge	>200 A Charge	1st Block of 900 kWh	2nd Block of 1100 kW.h	Balance of kW.h
Basic	$6.85	$6.85	$0.0625	-	$0.0630
Seasonal	(annual) $82.20		$0.0625	-	$0.0630
Diesel	$6.85		$0.0625	$0.0630	$0.4127
FRWH	(average) $22.29				

Forecast $ @ Apr/09 Rates	$ in BC & >200 Amp	$ in 1st Block	$ in 2nd Block	$ in Balance	Total Revenue	Adj. Factor	Adjusted Revenue
Basic	$36,844,109	$222,110,245	-	$206,672,245	$465,626,599	1.000	$465,809,667
Diesel	$47,621	$334,665	$158,107	$89,098	$619,492	1.006	$623,212
Seasonal	$1,714,281	$4,742,943	-	$329,784	$6,787,008	0.991	$6,725,157
FRWH	$1,231,144	-	-	-	$1,231,144	1.000	$1,231,235

Proposed April 2010 Rates	Basic Charge	>200 A Charge	1st Block of 900 kWh	2nd Block of 1100 kW.h	Balance of kW.h
Basic	$6.85	$6.85	$0.0625	-	$0.0671
Seasonal	(annual) $84.60		$0.0625	-	$0.0671
Diesel	$6.85		$0.0625	$0.0671	$0.4127
FRWH	(average) $22.94				

Forecast $ @ Apr/10 Rates	$ in BC & >200 Amp	$ in 1st Block	$ in 2nd Block	$ in Balance	Total Revenue	Adj. Factor	Adjusted Revenue
Basic	$36,844,109	$222,110,245	-	$220,122,344	$479,076,697	1.000	$479,265,053
Diesel	$47,621	$334,665	$157,746	$89,098	$629,131	1.006	$632,908
Seasonal	$1,764,333	$4,742,943	-	$351,246	$6,858,522	0.991	$6,796,019
FRWH	$1,266,919	-	-	-	$1,266,919	1.000	$1,266,919

GENERAL SERVICE: Fiscal 2010/11 - Current April 1, 2009 Rates versus Proposed April 1, 2010 Rates

Forecast Data 2010/11	**Cust Months**	**3 Phase Cust Months**	**1st 11000 kWh**	**Next 8500 kW.h & ND Runoff**	**Balance of kWh**	**Total kW.h**	**Billable Demand**
Small ND	613,993	136,906	1,464,475,544	130,592,135	0	1,596,067,679	0
Small Demand	136,642	88,260	769,089,647	433,209,272	714,397,146	1,916,696,065	2,201,433
Small LUBD	769	725			3,739,056	3,739,056	15,828
Seasonal	(annual) 830		4,650,000	0	0	4,650,000	0
FRWH	5,222				7,539,999	7,539,999	0
Medium	22,138		240,585,152	181,482,396	2,652,626,735	3,074,694,283	6,240,034*
Med. LUBD	263				4,426,482	4,426,482	72,441*
Large <30	2,883				1,574,302,879	1,574,302,879	3,702,760*
L<30 LUBD	222				2,057,000	2,057,000	34,192
Lrg30-100	357				853,454,110	853,454,110	1,698,636*
Lrg >100	156				5,354,440,000	5,354,440,000	9,037,304
L>100 LUBD	12				416,000	416,000	14,872
DFC Fed Govt	535				1,845,800	1,845,800	0
DFC Prov Gov	264				383,200	383,200	0
DFC Non-Gov	1367		(1st 2000 kW.h)	1,316,1760	2,197,864	3,514,040	0
SEP Med	216				12,500,000	12,500,000	0
SEP Lrg <30	60				2,700,000	2,700,000	0

* Billable Demand reduced for these customers when applying the Proposed April 1, 2010 Rates due to elimination of the winter ratchet.
Expected Billable kV.A to be:
Medium = 5,977,745 kV.A; Medium LUBD = 58,514; Large <30 kV = 3,661,324; Large 30-100 kV = 1,696,014 kV.A

Current April 2009 Rates	Basic Charge	3 Ph Charge	1st 11000 kWh Chg	Next 8500 kW.h Chg & ND Bal.	Balance of kWh Charge	Demand Charge
Small ND	$17.00	$6.74	$0.0666	$0.0448		
Small Demand	$17.00	$6.74	$0.0666	$0.0448	$0.0286	$8.34
Small LUBD	$17.00	$6.74			$0.0767	$2.09
Seasonal	(annual) $204.00		$0.0666	$0.0448		
FRWH	(average) $98.58					
Medium	$27.60		$0.0642	$0.0448	$0.0286	$8.34
Med. LUBD	$27.60				$0.0767	$2.09
Large <30	$0.00				$0.0273	$7.08
L<30 LUBD	$0.00				$0.0681	$1.77
Large 30-100	$0.00				$0.0258	$6.06
Large >100	$0.00				$0.0252	$5.40
L>100 LUBD	$0.00				$0.0559	$1.41
DFC Fed Govt	$17.00				$1.38363	
DFC Prov Gov	$17.00				$1.38363	
DFC Non-Gov	$17.00		First 2000 kW.h @ $0.0666		$0.4127	
SEP Med	$50.00		$0.04761 average energy charge & $0.0062 dist. charge (per kW.h)			
SEP Lrg <30	$100.00		$0.05561 average energy charge & $0.0033 dist. charge (per kW.h)			

Forecast $ @ Apr/09 Rates	**Basic Chg Revenue.**	**3 Ph Chg Revenue**	**1st Block Revenue**	**2nd Block Rev.& ND Runoff**	**Run-Off Revenue**	**Demand Charge Revenue**	**Adj Factor**	**Adjusted Revenue**
Small ND	$10,437,881	$922,746	$97,534,071	$5,850,528	$0	$0	1.001	$114,876,398
Small D.	$2,322,914	$594,872	$51,221,370	$19,407,775	$20,431,758	$18,359,951	0.995	$111,794,269
Small LUBD	$13,073	$4,887			$286,786	$33,081	1.000	$337,826
Seasonal	$169,320		$309,690				1.010	$483,687
FRWH	$514,785						1.000	$514,761
Medium	$611,009		$15,445,567	$8,130,411	$75,865,125	$52,041,884	1.002	$152,367,780
Med. LUBD	$7,259				$339,511	$151,402	1.000	$498,173
Lrg <30	$0				$42,978,469	$26,215,541	1.000	$69,194,015
L<30 LUBD	$0				$140,082	$60,520	1.000	$200,600
Lrg30-100	$0				$22,019,116	$10,293,734	1.000	$32,312,850
Lrg >100	$0				$134,931,888	$48,806,842	1.000	$183,738,729
L100 LUBD	$0				$23,254	$20,970	1.000	$44,224
DFC Fed G	$9,095				$2,553,904		1.000	$2,563,037
DFC Prov G	$4,488				$530,207		1.000	$534,651
DFC Non-G	$23,239		$87,657		$907,058		1.022	$1,039,542
SEP Med	$10,800				$672,600		1.000	$683,400
SEP Lrg <30	$6,000				$159,052		1.000	$165,052

Proposed April 2010 Rates	Basic Charge	3 Ph Charge	1st 11000 kWh Chg	Next 8500 kW.h Chg & ND Bal.	Balance of kWh Charge	Demand Charge
Small ND	$17.65	$7.00	$0.0684	$0.0469		
Small Demand	$17.65	$7.00	$0.0684	$0.0469	$0.0305	$8.34
Small LUBD	$17.65	$7.00			$0.0786	$2.09
Seasonal	(annual) $211.80		$0.0684	$0.0469		
FRWH	(average)$101.44					
Medium	$27.60		$0.0684	$0.0469	$0.0305	$8.34
Med. LUBD	$27.60				$0.0786	$2.09
Large <30	$0.00				$0.0288	$7.08
L<30 LUBD	$0.00				$0.0696	$1.77
Large 30-100	$0.00				$0.0269	$6.06
Large >100	$0.00				$0.0262	$5.40
L>100 LUBD	$0.00				$0.0569	$1.41
DFC Fed Govt	$17.00				$1.38363	
DFC Prov Gov	$17.00				$1.38363	
DFC Non-Gov	$17.00		First 2000 kW.h @ $0.0684		$0.4127	
SEP Med	$50.00		$0.04761 average energy charge & $0.0062 dist. charge (per kW.h)			
SEP Lrg <30	$100.00		$0.05561 average energy charge & $0.0033 dist. charge (per kW.h)			

Forecast $ @ Apr/10 Rates	Basic Chg Revenue.	3 Ph Chg Revenue	1st Block Revenue	2nd Block Rev.& ND Runoff	Run-Off Revenue	Demand Charge Revenue	Adj Factor	Adjusted Revenue
Small ND	$10,836,976	$958,342	$100,170,127	$6,124,771	$0	$0	1.001	$118,225,213
Small D.	$2,411,731	$617,820	$52,605,732	$20,317,515	$21,789,113	$18,359,951	0.995	$115,539,253
Sm LUBD	$13,573	$5,075			$293,890	$33,081	1.000	$345,619
Seasonal	$175,794		$318,060				1.010	$498,675
FRWH	$529,720						1.000	$529,707
Medium	$611,009		$16,456,024	$8,511,524	$80,905,115	$49,854,393	1.002	$156,619,491
Med. LUBD	$7,259				$347,921	$122,294	1.000	$477,475
Lrg <30	$0				$45,339,923	$25,922,174	1.000	$71,262,102
L<30 LUBD	$0				$143,167	$60,520	1.000	$203,687
Lrg30-100	$0				$22,957,916	$10,277,845	1.000	$33,235,760
Lrg >100	$0				$140,286,328	$48,806,842	1.000	$189,093,169
L100 LUBD	$0				$23,670	$20,970	1.000	$44,640
DFC Fed G	$9,443				$2,553,904		1.000	$2,563,385
DFC Prov G	$4,660				$530,207		1.000	$534,823
DFC Non-G	$24,128		$90,026		$907,058		1.022	$1,043,723
SEP Med	$10,800				$672,600		1.000	$683,400
SEP Lrg <30	$6,000				$159,052		1.000	$165,052

RESIDENTIAL: Fiscal 2011/12 - Proposed April 1, 2010 Rates versus Proposed April 1, 2011 Rates

Forecast Data 2011/12	Customer Months	>200 A Customers	1st Block of 900 kW.h	2nd Block of 1100 kW.h	Balance of kW.h	Total kW.h
Basic	5,394,396	32,792	3,590,961,200	-	3,326,834,723	6,917,795,923
Diesel	7,044	-	5,433,195	2,411,104	228,576	8,072,875
Seasonal	(annual) 20,930	-	77,364,760	-	5,599,340	82,964,100
FRWH	52,464	-		-	21,825,048	21,825,048

Proposed April 2010 Rates	Basic Charge	>200 A Charge	1st Block of 900 k.Wh	2nd Block of 1100 kW.h	Balance of kWH
Basic	$5.85	$5.85	$0.0637	-	$0.0675
Seasonal	(annual) $82.20		$0.0637	-	$0.0675
Diesel	$5.85		$0.0637	$0.0675	$0.4127
FRWH	(average) $22.94				

Forecast $ @ Apr/10 Rates	$ in BC & >200 Amp	$ in 1st Block	$ in 2nd Block	$ in Balance	Total Revenue	Adj. Factor	Adjusted Revenue
Basic	$31,749,050	$228,744,228	-	$224,561,344	$485,054,622	1.000	$485,245,328
Diesel	$41,207	$346,095	$162,750	$94,333	$644,385	1.006	$648,254
Seasonal	$1,720,446	$4,928,135	-	$377,955	$7,026,537	0.991	$6,962,503
FRWH	$1,203,404	-	-	-	$1,203,404	1.000	$1,203,404

Proposed April 2011 Rates	Basic Charge	>200 A Charge	1st Block of 900 k.Wh	2nd Block of 1100 kW.h	Balance of kWH
Basic	$4.85	$4.85	$0.0647	-	$0.0723
Seasonal	(annual) $82.20		$0.0647	-	$0.0723
Diesel	$4.85		$0.0647	$0.0723	$0.4127
FRWH	(average) $23.60				

Forecast $ @ Apr/11Rates	$ in BC & >200 Amp	$ in 1st Block	$ in 2nd Block	$ in Balance	Total Revenue	Adj. Factor	Adjusted Revenue
Basic	$26,321,862	$232,335,190	-	$240,530,150	$499,187,202	1.000	$499,383,465
Diesel	$34,163	$351,528	$174,323	$94,333	$654,347	1.006	$658,276
Seasonal	$1,720,446	$5,005,500	-	$404,832	$7,130,778	0.991	$7,065,794
FRWH	$1,238,157	-	-	-	$1,238,157	1.000	$1,238,157

GENERAL SERVICE: Fiscal 2011/12 - Proposed April 1, 2010 Rates versus Proposed April 1, 2011 Rates

Forecast Data 2011/12	**Cust Months**	**3 Phase Cust Months**	**1st 11000 kWh**	**Next 8500 kW.h & ND Runoff**	**Balance of kWh**	**Total kW.h**	**Billable Demand**
Small ND	617,376	137,660	1,485,660,618	135,745,318	0	1,621,405,936	0
Small Demand	137,394	88,745	774,406,811	438,480,562	734,724,003	1,947,611,375	2,236,941
Small LUBD	774	730			3,763,367	3,763,367	15,931
Seasonal	(annual) 835		4,670,000	0	0	4,670,000	0
FRWH	4,968				7,169,999	7,169,999	0
Medium	22,260		241,934,404	182,579,887	2,699,416,760	3,123,931,051	6,089,296
Med. LUBD	264				4,443,313	4,443,313	58,740
Large <30	2,896				1,590,819,485	1,590,819,485	3,700,832
L<30 LUBD	225				2,085,000	2,085,000	34,657
Lrg30-100	359				867,984,670	867,984,670	1,721,759
Lrg >100	156				5,635,200,000	5,635,200,000	9,502,861
L>100 LUBD	12				416,000	416,000	14,872
DFC Fed Govt	539				1,861,100	1,861,100	0
DFC Prov Gov	266				386,300	386,300	0
DFC Non-Gov	1,378		(1st 2000 kW.h)	1,334,077	2,271,563	3,605,640	0
SEP Med	216				12,500,000	12,500,000	0
SEP Lrg <30	60				2,700,000	2,700,000	0

Proposed April 2010 Rates	Basic Charge	3 Ph Charge	1st 11000 kWh Chg	Next 8500 kW.h Chg & ND Bal.	Balance of kWh Charge	Demand Charge
Small ND	$17.65	$7.00	$0.0684	$0.0469		
Small Demand	$17.65	$7.00	$0.0684	$0.0469	$0.0305	$8.34
Small LUBD	$17.65	$7.00			$0.0786	$2.09
Seasonal	(annual) $211.80		$0.0684	$0.0469		
FRWH	(average)$101.44					
Medium	$27.60		$0.0684	$0.0469	$0.0305	$8.34
Med. LUBD	$27.60				$0.0786	$2.09
Large <30	$0.00				$0.0288	$7.08
L<30 LUBD	$0.00				$0.0696	$1.77
Large 30-100	$0.00				$0.0269	$6.06
Large >100	$0.00				$0.0262	$5.40
L>100 LUBD	$0.00				$0.0569	$1.41
DFC Fed Govt	$17.00				$1.38363	
DFC Prov Gov	$17.00				$1.38363	
DFC Non-Gov	$17.00		First 2000 kW.h @ $0.0684		$0.4127	
SEP Med	$50.00		$0.04761 average energy charge & $0.0062 dist. charge (per kW.h)			
SEP Lrg <30	$100.00		$0.05561 average energy charge & $0.0033 dist. charge (per kW.h)			

Forecast $ @ Apr/10 Rates	**Basic Chg Revenue.**	**3 Ph Chg Revenue**	**1st Block Revenue**	**2nd Block Rev.& ND Runoff**	**Run-Off Revenue**	**Demand Charge Revenue**	**Adj Factor**	**Adjusted Revenue**
Small ND	$10,896,686	$963,620	$101,619,186	$6,366,455	$0	$0	1.001	$119,982,951
Small D.	$2,425,004	$621,215	$52,969,426	$20,564,738	$22,409,082	$18,656,085	0.995	$117,075,464
Sm LUBD	$13,661	$5,110			$295,801	$33,296	1.000	$347,867
Seasonal	$176,853		$319,428				1.010	$501,126
FRWH	$503,942						1.000	$503,942
Medium	$614,376		$16,548,313	$8,562,997	$82,332,211	$50,784,729	1.002	$159,128,554
Med. LUBD	$7,286				$349,244	$122,766	1.000	$479,297
Lrg <30	$0				$45,815,601	$26,201,895	1.000	$72,017,496
L<30 LUBD	$0				$145,116	$61,343	1.000	$206,459
Lrg30-100	$0				$23,348,788	$10,433,860	1.000	$33,782,648
Lrg >100	$0				$147,642,240	$51,315,448	1.000	$198,957,688
L100 LUBD	$0				$23,670	$20,970	1.000	$44,640
DFC Fed G	$9,521				$2,575,074		1.000	$2,584,633
DFC Prov G	$4,703				$534,496		1.000	$539,151
DFC Non-G	$24,324		$91,251		$937,474		1.022	$1,076,265
SEP Med	$10,800				$672,600		1.000	$683,400
SEP Lrg <30	$6,000				$159,052		1.000	$165,052

Proposed April 2011 Rates	**Basic Charge**	**3 Ph Charge**	**1st 11000 kWh Chg**	**Next 8500 kW.h Chg & ND Bal.**	**Balance of kWh Charge**	**Demand Charge**
Small ND	$18.25	$7.30	$0.0703	$0.0488		
Small Demand	$18.25	$7.30	$0.0703	$0.0488	$0.0320	$8.34
Small LUBD	$18.25	$7.30			$0.0801	$2.09
Seasonal	(annual) $219.00		$0.0703	$0.0488		
FRWH	(average)$104.38					
Medium	$27.60		$0.0703	$0.0488	$0.0320	$8.34
Med. LUBD	$27.60				$0.0801	$2.09
Large <30	$0.00				$0.0301	$7.08
L<30 LUBD	$0.00				$0.0709	$1.77
Large 30-100	$0.00				$0.0281	$6.06
Large >100	$0.00				$0.0273	$5.40
L>100 LUBD	$0.00				$0.0580	$1.41
DFC Fed Govt	$18.25				$1.38363	
DFC Prov Gov	$18.25				$1.38363	
DFC Non-Gov	$18.25		First 2000 kW.h @ $0.0703		$0.4127	
SEP Med	$50.00		$0.04761 average energy charge & $0.0062 dist. charge (per kW.h)			
SEP Lrg <30	$100.00		$0.05561 average energy charge & $0.0033 dist. charge (per kW.h)			

Forecast $ @ Apr/11 Rates	**Basic Chg Revenue.**	**3 Ph Chg Revenue**	**1st Block Revenue**	**2nd Block Rev.& ND Runoff**	**Run-Off Revenue**	**Demand Charge Revenue**	**Adj Factor**	**Adjusted Revenue**
Small ND	$11,267,112	$1,004,918	$104,441,942	$6,624,372	$0	$0	1.001	$123,479,338
Small D.	$2,507,441	$647,839	$54,440,798	$21,397,851	$23,511,168	$18,656,085	0.995	$120,574,060
Sm LUBD	$14,126	$5,329			$301,446	$33,296	1.000	$354,196
Seasonal	$182,865		$328,301				1.010	$516,156
FRWH	$518,547						1.000	$518,547
Medium	$614,376		$17,007,988	$8,919,898	$86,381,336	$50,784,729	1.002	$163,992,997
Med. LUBD	$7,286				$355,909	$122,766	1.000	$485,962
Lrg <30	$0				$47,883,666	$26,201,895	1.000	$74,294,731
L<30 LUBD	$0				$147,827	$61,343	1.000	$209,169
Lrg30-100	$0				$24,390,370	$10,433,860	1.000	$34,824,230
Lrg >100	$0				$153,840,960	$51,315,448	1.000	$205,156,408
L100 LUBD	$0				$24,128	$20,970	1.000	$45,098
DFC Fed G	$9,845				$2,575,074		1.000	$2,584,957
DFC Prov G	$4,863				$539,359		1.000	$539,311
DFC Non-G	$25,150		$93,786		$937,474		1.022	$1,079,701
SEP Med	$10,800				$672,625		1.000	$683,400
SEP Lrg <30	$6,000				$159,052		1.000	$165,052

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Proof of Revenue

b) If not provided in part (a), please indicate the number of customers by GSL subclass anticipated to be charged the energy intensive rate in Appendix 10.1 and 10.2.

ANSWER:

As noted on Pages 5 and 6, Tab 10 of the General Rate Application Filing, the Proof of Revenues included in Appendices 10.1 and 10.2 include EIIR revenue based on past methodology with revised customer data. These values have since been updated with a new methodology which was filed with the Public Utilities Board on February 12, 2010.

Customer consultations regarding the EIIR are still on-going and the preliminary estimates shown below are subject to change.

Large >100 kV

2010/11: 1 customer with incremental revenue of $2,747,000

2011/12: 2 customers with incremental revenue of $4,993,000

Large 30-100 kV

2010/11: no customers

2011/12: 1 customer with incremental revenue of $1,347

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Proof of Revenue

c) If not provided in part (a) please provide the calculation (including both rate and load assumptions by class and subclass) used to calculate the DSM reduction.

ANSWER:

The tables below provide the DSM savings (kW.h, kW and revenue) by class / subclass for fiscal years 2010/11 and 2011/12. The associated rates are provided below each year.

2010/11 DSM Savings

Class / Subclass	kW.h Savings	kW Savings	Revenue @ 2009 Rates	Revenue @ 2010 Rates
Residential	159,699,008	432,046	$10,045,068	$10,664,700
Small ND	34,417,062	96,184	$2,097,720	$2,162,080
Small Dem.	31,736,603	92,676	$1,747,778	$1,808,078
Medium	42,545,524	109,860	$2,212,783	$2,293,619
Large <30	21,481,445	66,780	$1,100,447	$1,132,669
Large30-100	3,116,143	12,589	$162,425	$165,852
Large>100	9,109,085	37,891	$449,593	$458,702
Total DSM	302,104,870	848,026	$17,815,813	$18,685,700

Current April 1, 2009 Rates vs Proposed April 1, 2010 Rates

Class / Subclass	Current April 1, 2009 Rates			Proposed April 1, 2010 Rates		
	kW.h $	kV.A $	kW $	kW.h $	kV.A $	kW $
Residential *	$0.06290	$0.00	$0.000	$0.06678	$0.00	$0.000
Small ND *	$0.06095	$0.00	$0.000	$0.06282	$0.00	$0.000
Small Dem.	$0.02860	$8.34	$9.065	$0.03050	$8.34	$9.065
Medium	$0.02860	$8.34	$9.065	$0.03050	$8.34	$9.065
Large <30	$0.02730	$7.08	$7.696	$0.02880	$7.08	$7.696
Large30-100	$0.02580	$6.06	$6.516	$0.02690	$6.06	$6.516
Large>100	$0.02520	$5.40	$5.806	$0.02620	$5.40	$5.806

* The energy rates shown for Residential and Small ND are weighted rates based on the percentage of kW.h's associated with each rate block as determined by the 2008/09 Bill Frequency Distributions.

2011/12 DSM Savings

Class / Subclass	kW.h Savings	kW Savings	Revenue @ 2010 Rates	Revenue @ 2011 Rates
Residential	231,984,808	624,118	$15,491,945	$16,436,124
Small ND	48,501,833	136,681	$3,046,885	$3,139,039
Small Dem.	44,797,006	129,696	$2,542,001	$2,609,196
Medium	62,648,031	163,482	$3,392,873	$3,486,845
Large <30	33,376,319	120,211	$1,886,482	$1,929,872
Large30-100	4,807,027	22,763	$277,634	$283,402
Large>100	16,137,646	85,428	$918,872	$936,624
Total DSM	442,252,670	1,282,378	$27,556,693	$28,821,102

Proposed April 1, 2010 Rates versus Proposed April 1, 2011 Rates

Class / Subclass	Current April 1, 2009 Rates			Proposed April 1, 2010 Rates		
	kW.h $	kV.A $	kW $	kW.h $	kV.A $	kW $
Residential *	$0.06678	$0.00	$0.000	$0.07085	$0.00	$0.000
Small ND *	$0.06282	$0.00	$0.000	$0.06472	$0.00	$0.000
Small Dem.	$0.03050	$8.34	$9.065	$0.03200	$8.34	$9.065
Medium	$0.03050	$8.34	$9.065	$0.03200	$8.34	$9.065
Large <30	$0.02880	$7.08	$7.696	$0.03010	$7.08	$7.696
Large30-100	$0.02690	$6.06	$6.516	$0.02810	$6.06	$6.516
Large>100	$0.02620	$5.40	$5.806	$0.02730	$5.40	$5.806

Demand Billing Concessions

a) Without providing information specific to any one customer's load, please provide a detailed sample calculation of the demand billing concession for each eligible class and subclass. For clarity, the calculation should illustrate:

- **i. The demand and energy billing determinants, including both metered demand and ratcheted demand**
- **ii. The applicable demand and energy rates.**
- **iii. The customer's bill before any concession is applied.**
- **iv. The calculation of the demand concession.**
- **v. The customer's bill following application of the concession.**

ANSWER:

i. Demand and Energy Billing Determinants (as shown in attached worksheets)

Energy Consumed (kWh) per Billing Period
Recorded Demand (kVA) per Billing Period
Billing Demand (kVA) per Billing Period (includes ratchet amount as requested)

ii. Approved 2009 rates for General Service Large (GSL) and General Service Medium rates classes and subclasses as shown on Manitoba Hydro's website were used to calculate the applicable revenues and deferrals.

http://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/historical.shtml

iii. Customer's Bill, minus applicable municipal, provincial and federal taxes and other adjustments, prior to application of deferral is shown in the attached worksheet in the column, "Revenue 2009 Rates"

iv. Calculation of the Monthly Demand Deferral is based on the following formula:

Deferral Threshold = Avg Unit Energy Cost (Sep 06 - Aug 08) x 1.10

The deferral threshold is determined based on the average unit energy cost during the 24 month period ending with the August 2008 billing period, increased by 10 percent to account for variances in production levels.

Average Unit Energy Cost = Revenue (2009 Rates) / Energy Consumed

The average unit energy cost is determined for each billing period by dividing the total revenue obtained from fixed, energy and demand charges by the total energy consumed during the billing period.

$$Demand\,Deferral(kVA) = \frac{Energy\,Consumed\,x\,(Avg\,Unit\,Energy\,Cost - Deferral\,Threshold)}{Unit\,Demand\,Ch\mathrm{arg}e\,(at\;2009\,Rates)}$$

v. Calculation of the customer's bill is determined by subtracting the amount of the Billing Deferral from the combined value of the fixed, energy and demand charges applied to the customer energy and demand for each billing period. Applicable municipal, provincial, federal taxes and other adjustments are then applied.

$$Billing\ Deferral(\$) = Energy\ Consumed\ \ x\ (Avg\ Unit\ Energy\ Cost - Deferral\ Threshold\,)$$

Deferral analysis worksheets providing detailed billing deferral calculations for each eligible class and subclass are attached for information.

Energy Consumption, Average Unit Cost and Billing Deferral Information

GSM - All

Billing Period	Srvc Count	Bill Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)	Demand Deferral (kVA)	Billing Deferral ($)	Period Description
						Rate Class:	GSM - All					
2009, NOV	**1**	**30**	**14,086,065**	**36,625**	**36,625**	**0.534**	**$ 708,451.77**	**$ 0.05029**	**$ 0.04943**	**1,453**	**$ 12,114.02**	**Deferral Period**
2009, OCT	**1**	**31**	**14,086,330**	**36,774**	**36,774**	**0.515**	**$ 709,704.10**	**$ 0.05038**	**$ 0.04943**	**1,605**	**$ 13,382.01**	
2009, SEP	**1**	**30**	**9,399,474**	**36,518**	**36,518**	**0.357**	**$ 573,527.05**	**$ 0.06102**	**$ 0.04943**	**13,062**	**$ 108,939.90**	
2009, AUG	**1**	**31**	**1,788,769**	**4,930**	**25,679**	**0.094**	**$ 265,459.88**	**$ 0.14840**	**$ 0.04943**	**21,227**	**$ 177,034.45**	
2009, JUL	**1**	**31**	**1,799,083**	**4,858**	**25,679**	**0.094**	**$ 265,754.85**	**$ 0.14772**	**$ 0.04943**	**21,203**	**$ 176,831.82**	
2009, JUN	**1**	**30**	**10,360,326**	**37,016**	**37,016**	**0.389**	**$ 605,160.74**	**$ 0.05841**	**$ 0.04943**	**11,155**	**$ 93,035.72**	
2009, MAY	1	31	5,771,280	34,981	34,981	0.222	$ 456,937.96	$ 0.07917	$ 0.04943			
2009, APR	1	30	8,242,538	34,935	34,935	0.328	$ 527,234.38	$ 0.06397	$ 0.04943			
2009, MAR	1	31	11,222,012	34,829	34,829	0.433	$ 611,559.13	$ 0.05450	$ 0.04943			
2009, FEB	1	28	9,755,023	36,684	36,684	0.396	$ 585,078.12	$ 0.05998	$ 0.04943			
2009, JAN	1	31	17,999,364	36,612	36,612	0.661	$ 820,265.79	$ 0.04557	$ 0.04943			
2008, DEC	1	31	6,016,778	36,645	36,645	0.221	$ 477,839.04	$ 0.07942	$ 0.04943			
2008, NOV	1	30	18,739,182	36,630	36,630	0.711	$ 841,574.72	$ 0.04491	$ 0.04943			
2008, OCT	1	31	20,232,875	36,579	36,579	0.743	$ 883,868.99	$ 0.04368	$ 0.04943			
2008, SEP	1	30	18,524,084	38,081	38,081	0.676	$ 847,526.33	$ 0.04575	$ 0.04943			
2008, AUG	1	31	20,130,562	36,802	36,802	0.735	$ 882,800.56	$ 0.04385	$ 0.04943			**24 Month Deferral Threshold Period (used to determine baseline threshold for deferral calculation)**
2008, JUL	1	31	11,848,923	36,678	36,678	0.434	$ 644,913.62	$ 0.05443	$ 0.04943			
2008, JUN	1	30	19,341,998	35,697	35,697	0.753	$ 851,034.03	$ 0.04400	$ 0.04943			
2008, MAY	1	31	19,783,270	35,852	35,852	0.742	$ 864,949.20	$ 0.04372	$ 0.04943			
2008, APR	1	30	18,957,775	35,963	35,963	0.732	$ 842,265.78	$ 0.04443	$ 0.04943			
2008, MAR	1	31	19,670,762	35,712	35,712	0.740	$ 860,561.78	$ 0.04375	$ 0.04943			
2008, FEB	1	29	18,441,305	35,516	35,516	0.746	$ 823,766.74	$ 0.04467	$ 0.04943			
2008, JAN	1	31	19,498,137	45,409	35,727	0.577	$ 936,495.59	$ 0.04803	$ 0.04943			
2007, DEC	1	31	18,495,730	35,864	35,864	0.693	$ 828,219.36	$ 0.04478	$ 0.04943			
2007, NOV	1	30	19,254,432	35,860	35,860	0.746	$ 849,886.97	$ 0.04414	$ 0.04943			
2007, OCT	1	31	19,951,447	36,059	36,059	0.744	$ 871,485.43	$ 0.04368	$ 0.04943			
2007, SEP	1	30	18,514,210	35,606	35,606	0.722	$ 826,596.16	$ 0.04465	$ 0.04943			
2007, AUG	1	31	19,349,432	35,988	35,988	0.723	$ 853,673.58	$ 0.04412	$ 0.04943			
2007, JUL	1	31	11,135,585	35,437	35,437	0.422	$ 614,160.12	$ 0.05515	$ 0.04943			
2007, JUN	1	30	18,899,470	35,721	35,721	0.735	$ 838,577.87	$ 0.04437	$ 0.04943			
2007, MAY	1	31	18,691,571	35,792	35,792	0.702	$ 833,219.95	$ 0.04458	$ 0.04943			
2007, APR	1	30	19,473,620	35,438	35,438	0.763	$ 852,640.44	$ 0.04378	$ 0.04943			
2007, MAR	1	31	19,950,626	35,703	35,703	0.751	$ 868,490.81	$ 0.04353	$ 0.04943			
2007, FEB	1	28	18,013,059	35,475	35,475	0.756	$ 811,174.89	$ 0.04503	$ 0.04943			
2007, JAN	1	31	19,439,446	36,091	36,091	0.724	$ 857,104.90	$ 0.04409	$ 0.04943			
2006, DEC	1	31	16,029,685	35,606	35,606	0.605	$ 755,545.01	$ 0.04713	$ 0.04943			
2006, NOV	1	30	19,386,569	35,601	35,601	0.756	$ 851,508.11	$ 0.04392	$ 0.04943			
2006, OCT	1	31	19,812,138	35,333	35,333	0.754	$ 861,440.11	$ 0.04348	$ 0.04943			
2006, SEP	1	30	19,502,628	35,256	35,256	0.768	$ 851,950.10	$ 0.04368	$ 0.04943			

24 Month Base Line Analysis for Determination of Per Unit Cost Deferral Threshold

	Srvc Count	Billing Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)
24 Mth Sum	**24.0**	**731.0**	**443,572,379**	**868,457**	**858,776**		**$ 19,932,461.11**		
24 Mth Avg	**1.0**	**30.5**		**36,186**	**35,782**	**0.699**		**$ 0.04494**	**$ 0.04943**

Energy Consumption, Average Unit Cost and Billing Deferral Information

GSL - 750 to 30 kV

Billing Period	Srvc Count	Bill Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)	Demand Deferral (kVA)	Billing Deferral ($)	Period Description
						Rate Class:	GSL - 750 to 30 kV					
2009, NOV	**1**	**30**	**14,086,065**	**36,625**	**36,625**	**0.534**	**$ 643,852.80**	**$ 0.04571**	**$ 0.04511**	**1,194**	**$ 8,451.64**	**Deferral Period**
2009, OCT	**1**	**31**	**14,086,330**	**36,774**	**36,774**	**0.515**	**$ 644,916.73**	**$ 0.04578**	**$ 0.04511**	**1,333**	**$ 9,437.84**	
2009, SEP	**1**	**30**	**9,399,474**	**36,518**	**36,518**	**0.357**	**$ 515,154.84**	**$ 0.05481**	**$ 0.04511**	**12,878**	**$ 91,174.89**	
2009, AUG	**1**	**31**	**1,788,769**	**4,930**	**25,679**	**0.094**	**$ 230,639.29**	**$ 0.12894**	**$ 0.04511**	**21,180**	**$ 149,952.49**	
2009, JUL	**1**	**31**	**1,799,083**	**4,858**	**25,679**	**0.094**	**$ 230,920.86**	**$ 0.12835**	**$ 0.04511**	**21,152**	**$ 149,755.63**	
2009, JUN	**1**	**30**	**10,360,326**	**37,016**	**37,016**	**0.389**	**$ 544,911.94**	**$ 0.05260**	**$ 0.04511**	**10,960**	**$ 77,598.84**	
2009, MAY	1	31	5,771,280	34,981	34,981	0.222	$ 405,219.65	$ 0.07021	$ 0.04511			
2009, APR	1	30	8,242,538	34,935	34,935	0.328	$ 472,361.08	$ 0.05731	$ 0.04511			
2009, MAR	1	31	11,222,012	34,829	34,829	0.433	$ 552,946.71	$ 0.04927	$ 0.04511			
2009, FEB	1	28	9,755,023	36,684	36,684	0.396	$ 526,034.85	$ 0.05392	$ 0.04511			
2009, JAN	1	31	17,999,364	36,612	36,612	0.661	$ 750,595.60	$ 0.04170	$ 0.04511			
2008, DEC	1	31	6,016,778	36,645	36,645	0.221	$ 423,704.63	$ 0.07042	$ 0.04511			
2008, NOV	1	30	18,739,182	36,630	36,630	0.711	$ 770,920.08	$ 0.04114	$ 0.04511			
2008, OCT	1	31	20,232,875	36,579	36,579	0.743	$ 811,336.81	$ 0.04010	$ 0.04511			
2008, SEP	1	30	18,524,084	38,081	38,081	0.676	$ 775,322.74	$ 0.04185	$ 0.04511			
2008, AUG	1	31	20,130,562	36,802	36,802	0.735	$ 810,120.72	$ 0.04024	$ 0.04511			**24 Month Deferral Threshold Period (used to determine baseline threshold for deferral calculation)**
2008, JUL	1	31	11,848,923	36,678	36,678	0.434	$ 583,155.84	$ 0.04922	$ 0.04511			
2008, JUN	1	30	19,341,998	35,697	35,697	0.753	$ 780,771.32	$ 0.04037	$ 0.04511			
2008, MAY	1	31	19,783,270	35,852	35,852	0.742	$ 793,917.21	$ 0.04013	$ 0.04511			
2008, APR	1	30	18,957,775	35,963	35,963	0.732	$ 772,167.07	$ 0.04073	$ 0.04511			
2008, MAR	1	31	19,670,762	35,712	35,712	0.740	$ 789,852.77	$ 0.04015	$ 0.04511			
2008, FEB	1	29	18,441,305	35,516	35,516	0.746	$ 754,902.67	$ 0.04094	$ 0.04511			
2008, JAN	1	31	19,498,137	45,409	35,727	0.734	$ 785,246.29	$ 0.04027	$ 0.04511			
2007, DEC	1	31	18,495,730	35,864	35,864	0.693	$ 758,847.00	$ 0.04103	$ 0.04511			
2007, NOV	1	30	19,254,432	35,860	35,860	0.746	$ 779,533.02	$ 0.04049	$ 0.04511			
2007, OCT	1	31	19,951,447	36,059	36,059	0.744	$ 799,974.00	$ 0.04010	$ 0.04511			
2007, SEP	1	30	18,514,210	35,606	35,606	0.722	$ 757,524.86	$ 0.04092	$ 0.04511			
2007, AUG	1	31	19,349,432	35,988	35,988	0.723	$ 783,034.53	$ 0.04047	$ 0.04511			
2007, JUL	1	31	11,135,585	35,437	35,437	0.422	$ 554,893.66	$ 0.04983	$ 0.04511			
2007, JUN	1	30	18,899,470	35,721	35,721	0.735	$ 768,860.20	$ 0.04068	$ 0.04511			
2007, MAY	1	31	18,691,571	35,792	35,792	0.702	$ 763,683.71	$ 0.04086	$ 0.04511			
2007, APR	1	30	19,473,620	35,438	35,438	0.763	$ 782,532.64	$ 0.04018	$ 0.04511			
2007, MAR	1	31	19,950,626	35,703	35,703	0.751	$ 797,429.32	$ 0.03997	$ 0.04511			
2007, FEB	1	28	18,013,059	35,475	35,475	0.756	$ 742,919.52	$ 0.04124	$ 0.04511			
2007, JAN	1	31	19,439,446	36,091	36,091	0.724	$ 786,219.37	$ 0.04044	$ 0.04511			
2006, DEC	1	31	16,029,685	35,606	35,606	0.605	$ 689,702.65	$ 0.04303	$ 0.04511			
2006, NOV	1	30	19,386,569	35,601	35,601	0.756	$ 781,308.41	$ 0.04030	$ 0.04511			
2006, OCT	1	31	19,812,138	35,333	35,333	0.754	$ 791,025.48	$ 0.03993	$ 0.04511			
2006, SEP	1	30	19,502,628	35,256	35,256	0.768	$ 782,034.22	$ 0.04010	$ 0.04511			

24 Month Base Line Analysis for Determination of Per Unit Cost Deferral Threshold

	Srvc Count	Billing Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)
24 Mth Sum	**24.0**	**731.0**	**443,572,379**	**868,457**	**858,776**		**$ 18,189,656.48**		
24 Mth Avg	**1.0**	**30.5**		**36,186**	**35,782**	**0.707**		**$ 0.04101**	**$ 0.04511**

Energy Consumption, Average Unit Cost and Billing Deferral Information

GSL - 30 to 100 kV

Billing Period	Srvc Count	Bill Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)	Demand Deferral (kVA)	Billing Deferral ($)	Period Description
						Rate Class:	GSL - 30 to 100 kV					
2009, NOV	**1**	**30**	**14,086,065**	**36,625**	**36,625**	**0.534**	**$ 585,366.46**	**$ 0.04156**	**$ 0.04128**	**651**	**$ 3,944.10**	**Deferral Period**
2009, OCT	**1**	**31**	**14,086,330**	**36,774**	**36,774**	**0.515**	**$ 586,277.76**	**$ 0.04162**	**$ 0.04128**	**790**	**$ 4,789.35**	
2009, SEP	**1**	**30**	**9,399,474**	**36,518**	**36,518**	**0.357**	**$ 463,807.01**	**$ 0.04934**	**$ 0.04128**	**12,502**	**$ 75,759.76**	
2009, AUG	**1**	**31**	**1,788,769**	**4,930**	**25,679**	**0.094**	**$ 201,763.76**	**$ 0.11279**	**$ 0.04128**	**21,108**	**$ 127,914.86**	
2009, JUL	**1**	**31**	**1,799,083**	**4,858**	**25,679**	**0.094**	**$ 202,029.86**	**$ 0.11230**	**$ 0.04128**	**21,084**	**$ 127,770.84**	
2009, JUN	**1**	**30**	**10,360,326**	**37,016**	**37,016**	**0.389**	**$ 491,614.88**	**$ 0.04745**	**$ 0.04128**	**10,548**	**$ 63,923.21**	
2009, MAY	1	31	5,771,280	34,981	34,981	0.222	$ 360,882.37	$ 0.06253	$ 0.04128			
2009, APR	1	30	8,242,538	34,935	34,935	0.328	$ 424,363.57	$ 0.05148	$ 0.04128			
2009, MAR	1	31	11,222,012	34,829	34,829	0.433	$ 500,588.62	$ 0.04461	$ 0.04128			
2009, FEB	1	28	9,755,023	36,684	36,684	0.396	$ 473,984.64	$ 0.04859	$ 0.04128			
2009, JAN	1	31	17,999,364	36,612	36,612	0.661	$ 686,252.31	$ 0.03813	$ 0.04128			
2008, DEC	1	31	6,016,778	36,645	36,645	0.221	$ 377,301.56	$ 0.06271	$ 0.04128			
2008, NOV	1	30	18,739,182	36,630	36,630	0.711	$ 705,448.71	$ 0.03765	$ 0.04128			
2008, OCT	1	31	20,232,875	36,579	36,579	0.743	$ 743,676.92	$ 0.03676	$ 0.04128			
2008, SEP	1	30	18,524,084	38,081	38,081	0.676	$ 708,693.74	$ 0.03826	$ 0.04128			
2008, AUG	1	31	20,130,562	36,802	36,802	0.735	$ 742,387.09	$ 0.03688	$ 0.04128			**24 Month Deferral Threshold Period (used to determine baseline threshold for deferral calculation)**
2008, JUL	1	31	11,848,923	36,678	36,678	0.434	$ 527,970.90	$ 0.04456	$ 0.04128			
2008, JUN	1	30	19,341,998	35,697	35,697	0.753	$ 715,347.38	$ 0.03698	$ 0.04128			
2008, MAY	1	31	19,783,270	35,852	35,852	0.742	$ 727,673.01	$ 0.03678	$ 0.04128			
2008, APR	1	30	18,957,775	35,963	35,963	0.732	$ 707,047.90	$ 0.03730	$ 0.04128			
2008, MAR	1	31	19,670,762	35,712	35,712	0.740	$ 723,920.39	$ 0.03680	$ 0.04128			
2008, FEB	1	29	18,441,305	35,516	35,516	0.746	$ 691,014.14	$ 0.03747	$ 0.04128			
2008, JAN	1	31	19,498,137	45,409	35,727	0.734	$ 719,557.55	$ 0.03690	$ 0.04128			
2007, DEC	1	31	18,495,730	35,864	35,864	0.693	$ 694,522.63	$ 0.03755	$ 0.04128			
2007, NOV	1	30	19,254,432	35,860	35,860	0.746	$ 714,074.43	$ 0.03709	$ 0.04128			
2007, OCT	1	31	19,951,447	36,059	36,059	0.744	$ 733,266.39	$ 0.03675	$ 0.04128			
2007, SEP	1	30	18,514,210	35,606	35,606	0.722	$ 693,435.94	$ 0.03745	$ 0.04128			
2007, AUG	1	31	19,349,432	35,988	35,988	0.723	$ 717,302.63	$ 0.03707	$ 0.04128			
2007, JUL	1	31	11,135,585	35,437	35,437	0.422	$ 502,044.79	$ 0.04508	$ 0.04128			
2007, JUN	1	30	18,899,470	35,721	35,721	0.735	$ 704,075.58	$ 0.03725	$ 0.04128			
2007, MAY	1	31	18,691,571	35,792	35,792	0.702	$ 699,139.03	$ 0.03740	$ 0.04128			
2007, APR	1	30	19,473,620	35,438	35,438	0.763	$ 717,175.19	$ 0.03683	$ 0.04128			
2007, MAR	1	31	19,950,626	35,703	35,703	0.751	$ 731,086.32	$ 0.03664	$ 0.04128			
2007, FEB	1	28	18,013,059	35,475	35,475	0.756	$ 679,715.43	$ 0.03773	$ 0.04128			
2007, JAN	1	31	19,439,446	36,091	36,091	0.724	$ 720,247.64	$ 0.03705	$ 0.04128			
2006, DEC	1	31	16,029,685	35,606	35,606	0.605	$ 629,339.74	$ 0.03926	$ 0.04128			
2006, NOV	1	30	19,386,569	35,601	35,601	0.756	$ 715,915.54	$ 0.03693	$ 0.04128			
2006, OCT	1	31	19,812,138	35,333	35,333	0.754	$ 725,268.12	$ 0.03661	$ 0.04128			
2006, SEP	1	30	19,502,628	35,256	35,256	0.768	$ 716,819.16	$ 0.03676	$ 0.04128			

24 Month Base Line Analysis for Determination of Per Unit Cost Deferral Threshold

	Srvc Count	Billing Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)
24 Mth Sum	**24.0**	**731.0**	**443,572,379**	**868,457**	**858,776**		**$ 16,648,346.92**		
24 Mth Avg	**1.0**	**30.5**		**36,186**	**35,782**	**0.707**		**$ 0.03753**	**$ 0.04128**

Energy Consumption, Average Unit Cost and Billing Deferral Information

GSL - >100 kV

Billing Period	Srvc Count	Bill Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)	Demand Deferral (kVA)	Billing Deferral ($)	Period Description
						Rate Class:	GSL - >100 kV					
2009, NOV	**1**	**30**	**14,086,065**	**36,625**	**36,625**	**0.534**	**$ 552,742.49**	**$ 0.03924**	**$ 0.03922**	**52**	**$ 281.72**	**Deferral Period**
2009, OCT	**1**	**31**	**14,086,330**	**36,774**	**36,774**	**0.515**	**$ 553,555.12**	**$ 0.03930**	**$ 0.03922**	**209**	**$ 1,126.91**	
2009, SEP	**1**	**30**	**9,399,474**	**36,518**	**36,518**	**0.357**	**$ 434,065.28**	**$ 0.04618**	**$ 0.03922**	**12,115**	**$ 65,420.34**	
2009, AUG	**1**	**31**	**1,788,769**	**4,930**	**25,679**	**0.094**	**$ 183,742.50**	**$ 0.10272**	**$ 0.03922**	**21,035**	**$ 113,586.82**	
2009, JUL	**1**	**31**	**1,799,083**	**4,858**	**25,679**	**0.094**	**$ 184,002.40**	**$ 0.10228**	**$ 0.03922**	**21,009**	**$ 113,450.15**	
2009, JUN	**1**	**30**	**10,360,326**	**37,016**	**37,016**	**0.389**	**$ 460,967.96**	**$ 0.04449**	**$ 0.03922**	**10,111**	**$ 54,598.92**	
2009, MAY	1	31	5,771,280	34,981	34,981	0.222	$ 334,332.31	$ 0.05793	$ 0.03922			
2009, APR	1	30	8,242,538	34,935	34,935	0.328	$ 396,360.95	$ 0.04809	$ 0.03922			
2009, MAR	1	31	11,222,012	34,829	34,829	0.433	$ 470,868.60	$ 0.04196	$ 0.03922			
2009, FEB	1	28	9,755,023	36,684	36,684	0.396	$ 443,920.18	$ 0.04551	$ 0.03922			
2009, JAN	1	31	17,999,364	36,612	36,612	0.661	$ 651,288.77	$ 0.03618	$ 0.03922			
2008, DEC	1	31	6,016,778	36,645	36,645	0.221	$ 349,505.80	$ 0.05809	$ 0.03922			
2008, NOV	1	30	18,739,182	36,630	36,630	0.711	$ 670,029.40	$ 0.03576	$ 0.03922			
2008, OCT	1	31	20,232,875	36,579	36,579	0.743	$ 707,395.06	$ 0.03496	$ 0.03922			
2008, SEP	1	30	18,524,084	38,081	38,081	0.676	$ 672,445.67	$ 0.03630	$ 0.03922			
2008, AUG	1	31	20,130,562	36,802	36,802	0.735	$ 706,019.60	$ 0.03507	$ 0.03922			**24 Month Deferral Threshold Period (used to determine baseline threshold for deferral calculation)**
2008, JUL	1	31	11,848,923	36,678	36,678	0.434	$ 496,654.06	$ 0.04192	$ 0.03922			
2008, JUN	1	30	19,341,998	35,697	35,697	0.753	$ 680,182.16	$ 0.03517	$ 0.03922			
2008, MAY	1	31	19,783,270	35,852	35,852	0.742	$ 692,140.56	$ 0.03499	$ 0.03922			
2008, APR	1	30	18,957,775	35,963	35,963	0.732	$ 671,937.49	$ 0.03544	$ 0.03922			
2008, MAR	1	31	19,670,762	35,712	35,712	0.740	$ 688,548.01	$ 0.03500	$ 0.03922			
2008, FEB	1	29	18,441,305	35,516	35,516	0.746	$ 656,508.63	$ 0.03560	$ 0.03922			
2008, JAN	1	31	19,498,137	45,409	35,727	0.734	$ 684,278.85	$ 0.03509	$ 0.03922			
2007, DEC	1	31	18,495,730	35,864	35,864	0.693	$ 659,755.29	$ 0.03567	$ 0.03922			
2007, NOV	1	30	19,254,432	35,860	35,860	0.746	$ 678,854.34	$ 0.03526	$ 0.03922			
2007, OCT	1	31	19,951,447	36,059	36,059	0.744	$ 697,496.42	$ 0.03496	$ 0.03922			
2007, SEP	1	30	18,514,210	35,606	35,606	0.722	$ 658,827.78	$ 0.03558	$ 0.03922			
2007, AUG	1	31	19,349,432	35,988	35,988	0.723	$ 681,940.89	$ 0.03524	$ 0.03922			
2007, JUL	1	31	11,135,585	35,437	35,437	0.422	$ 471,975.19	$ 0.04238	$ 0.03922			
2007, JUN	1	30	18,899,470	35,721	35,721	0.735	$ 669,160.03	$ 0.03541	$ 0.03922			
2007, MAY	1	31	18,691,571	35,792	35,792	0.702	$ 664,301.69	$ 0.03554	$ 0.03922			
2007, APR	1	30	19,473,620	35,438	35,438	0.763	$ 682,101.77	$ 0.03503	$ 0.03922			
2007, MAR	1	31	19,950,626	35,703	35,703	0.751	$ 695,551.97	$ 0.03486	$ 0.03922			
2007, FEB	1	28	18,013,059	35,475	35,475	0.756	$ 645,494.09	$ 0.03583	$ 0.03922			
2007, JAN	1	31	19,439,446	36,091	36,091	0.724	$ 684,764.08	$ 0.03523	$ 0.03922			
2006, DEC	1	31	16,029,685	35,606	35,606	0.605	$ 596,221.81	$ 0.03719	$ 0.03922			
2006, NOV	1	30	19,386,569	35,601	35,601	0.756	$ 680,786.93	$ 0.03512	$ 0.03922			
2006, OCT	1	31	19,812,138	35,333	35,333	0.754	$ 690,061.39	$ 0.03483	$ 0.03922			
2006, SEP	1	30	19,502,628	35,256	35,256	0.768	$ 681,848.63	$ 0.03496	$ 0.03922			

24 Month Base Line Analysis for Determination of Per Unit Cost Deferral Threshold

	Srvc Count	Billing Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)
24 Mth Sum	**24.0**	**731.0**	**443,572,379**	**868,457**	**858,776**		**$ 15,815,411.66**		
24 Mth Avg	**1.0**	**30.5**		**36,186**	**35,782**	**0.707**		**$ 0.03565**	**$ 0.03922**

Rate Class Type	Monthly Charge $/Mth	Energy Block 1 $/kWh	Energy Block 2 $/kWh	Energy Block 3 $/kWh	Demand Charge $/kVA
GSM - All	$27.60	$0.0642	$0.0448	$0.0286	$8.34
GSL - 750 to 30 kV	$0.00	$0.0273			$7.08
GSL - 30 to 100 kV	$0.00	$0.0258			$6.06
GSL - >100 kV	$0.00	$0.0252			$5.40

MIPUG/MH I-21

Demand Billing Concessions

b) Please provide a copy of the table requested in part (a) above assuming the winter ratchet had been eliminated effective June 1, 2009.

ANSWER:

A copy of the table requested in part (a) is included assuming that the winter ratchet shown for the July 09 and August 09 billing periods (see part a) had been eliminated. The example provided references the impact for a representative GSL 30-100 kV account with consumption behavior as shown.

Energy Consumption, Average Unit Cost and Billing Deferral Information

GSL - 30 to 100 kV

Billing Period	Srvc Count	Bill Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)	Demand Deferral (kVA)	Billing Deferral ($)	Period Description
						Rate Class:	GSL - 30 to 100 kV					
2009, NOV	**1**	**30**	**14,086,065**	**36,625**	**36,625**	**0.534**	**$ 585,366.46**	**$ 0.04156**	**$ 0.04128**	**651**	**$ 3,944.10**	**Deferral Period**
2009, OCT	**1**	**31**	**14,086,330**	**36,774**	**36,774**	**0.515**	**$ 586,277.76**	**$ 0.04162**	**$ 0.04128**	**790**	**$ 4,789.35**	
2009, SEP	**1**	**30**	**9,399,474**	**36,518**	**36,518**	**0.357**	**$ 463,807.01**	**$ 0.04934**	**$ 0.04128**	**12,502**	**$ 75,759.76**	
2009, AUG	**1**	**31**	**1,788,769**	**4,930**	**4,930**	**0.488**	**$ 76,023.01**	**$ 0.04250**	**$ 0.04128**	**360**	**$ 2,182.30**	
2009, JUL	**1**	**31**	**1,799,083**	**4,858**	**4,858**	**0.498**	**$ 75,856.42**	**$ 0.04216**	**$ 0.04128**	**261**	**$ 1,583.19**	
2009, JUN	**1**	**30**	**10,360,326**	**37,016**	**37,016**	**0.389**	**$ 491,614.88**	**$ 0.04745**	**$ 0.04128**	**10,548**	**$ 63,923.21**	
2009, MAY	1	31	5,771,280	34,981	34,981	0.222	$ 360,882.37	$ 0.06253	$ 0.04128			
2009, APR	1	30	8,242,538	34,935	34,935	0.328	$ 424,363.57	$ 0.05148	$ 0.04128			
2009, MAR	1	31	11,222,012	34,829	34,829	0.433	$ 500,588.62	$ 0.04461	$ 0.04128			
2009, FEB	1	28	9,755,023	36,684	36,684	0.396	$ 473,984.64	$ 0.04859	$ 0.04128			
2009, JAN	1	31	17,999,364	36,612	36,612	0.661	$ 686,252.31	$ 0.03813	$ 0.04128			
2008, DEC	1	31	6,016,778	36,645	36,645	0.221	$ 377,301.56	$ 0.06271	$ 0.04128			
2008, NOV	1	30	18,739,182	36,630	36,630	0.711	$ 705,448.71	$ 0.03765	$ 0.04128			
2008, OCT	1	31	20,232,875	36,579	36,579	0.743	$ 743,676.92	$ 0.03676	$ 0.04128			
2008, SEP	1	30	18,524,084	38,081	38,081	0.676	$ 708,693.74	$ 0.03826	$ 0.04128			
2008, AUG	1	31	20,130,562	36,802	36,802	0.735	$ 742,387.09	$ 0.03688	$ 0.04128			**24 Month Deferral Threshold Period (used to determine baseline threshold for deferral calculation)**
2008, JUL	1	31	11,848,923	36,678	36,678	0.434	$ 527,970.90	$ 0.04456	$ 0.04128			
2008, JUN	1	30	19,341,998	35,697	35,697	0.753	$ 715,347.38	$ 0.03698	$ 0.04128			
2008, MAY	1	31	19,783,270	35,852	35,852	0.742	$ 727,673.01	$ 0.03678	$ 0.04128			
2008, APR	1	30	18,957,775	35,963	35,963	0.732	$ 707,047.90	$ 0.03730	$ 0.04128			
2008, MAR	1	31	19,670,762	35,712	35,712	0.740	$ 723,920.39	$ 0.03680	$ 0.04128			
2008, FEB	1	29	18,441,305	35,516	35,516	0.746	$ 691,014.14	$ 0.03747	$ 0.04128			
2008, JAN	1	31	19,498,137	45,409	35,727	0.734	$ 719,557.55	$ 0.03690	$ 0.04128			
2007, DEC	1	31	18,495,730	35,864	35,864	0.693	$ 694,522.63	$ 0.03755	$ 0.04128			
2007, NOV	1	30	19,254,432	35,860	35,860	0.746	$ 714,074.43	$ 0.03709	$ 0.04128			
2007, OCT	1	31	19,951,447	36,059	36,059	0.744	$ 733,266.39	$ 0.03675	$ 0.04128			
2007, SEP	1	30	18,514,210	35,606	35,606	0.722	$ 693,435.94	$ 0.03745	$ 0.04128			
2007, AUG	1	31	19,349,432	35,988	35,988	0.723	$ 717,302.63	$ 0.03707	$ 0.04128			
2007, JUL	1	31	11,135,585	35,437	35,437	0.422	$ 502,044.79	$ 0.04508	$ 0.04128			
2007, JUN	1	30	18,899,470	35,721	35,721	0.735	$ 704,075.58	$ 0.03725	$ 0.04128			
2007, MAY	1	31	18,691,571	35,792	35,792	0.702	$ 699,139.03	$ 0.03740	$ 0.04128			
2007, APR	1	30	19,473,620	35,438	35,438	0.763	$ 717,175.19	$ 0.03683	$ 0.04128			
2007, MAR	1	31	19,950,626	35,703	35,703	0.751	$ 731,086.32	$ 0.03664	$ 0.04128			
2007, FEB	1	28	18,013,059	35,475	35,475	0.756	$ 679,715.43	$ 0.03773	$ 0.04128			
2007, JAN	1	31	19,439,446	36,091	36,091	0.724	$ 720,247.64	$ 0.03705	$ 0.04128			
2006, DEC	1	31	16,029,685	35,606	35,606	0.605	$ 629,339.74	$ 0.03926	$ 0.04128			
2006, NOV	1	30	19,386,569	35,601	35,601	0.756	$ 715,915.54	$ 0.03693	$ 0.04128			
2006, OCT	1	31	19,812,138	35,333	35,333	0.754	$ 725,268.12	$ 0.03661	$ 0.04128			
2006, SEP	1	30	19,502,628	35,256	35,256	0.768	$ 716,819.16	$ 0.03676	$ 0.04128			

24 Month Base Line Analysis for Determination of Per Unit Cost Deferral Threshold

	Srvc Count	Billing Days	Energy Consumed (kWh)	Recorded Demand (kVA)	Billing Demand (kVA)	Load Factor	Revenue 2009 Rates	Average Unit Energy ($/kWh)	Deferral Threshold ($/kWh)
24 Mth Sum	**24.0**	**731.0**	**443,572,379**	**868,457**	**858,776**		**$ 16,648,346.92**		
24 Mth Avg	**1.0**	**30.5**		**36,186**	**35,782**	**0.707**		**$ 0.03753**	**$ 0.04128**

MIPUG/MH I-21

Demand Billing Concessions

c) Page 1 of Tab 13 indicates that appendix 13.1 includes a forecast of the relief that would be provided if the program were extended to March 31, 2010, however appendix 13.1 appears to include information only to November 30, 2009. Please expand the table in appendix 13.1 to include forecast concessions through March 31, 2010.

ANSWER:

The accompanying table, including forecast of demand deferrals if the program were extended to March 31, 2010, is attached for information.

Response to Question MIPUG/MH I-21(c)

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

MIPUG/MH I-21

Demand Billing Concessions

d) Please provide a table, for June 2009 through November 2009, showing the savings by month that customers would have realized had the winter ratchet been eliminated effective June 1, 2009 for:

i. The customers who subscribed to the Demand Billing Deferrals program.
ii. All GSM and GSL customers (by subclass).

ANSWER:

i. For the customers eligible and subscribing to the Billing Demand Deferral program, the following are the estimated savings by month that would have been realized if the winter ratchet had been eliminated effective June 1, 2009.

Billing Period	Winter Ratchet Savings
Jun 09	$17,139
Jul 09	$50,819
Aug 09	$24,624
Sep 09	$23,863
Oct 09	$75,331
Nov 09	$68,658

ii. For all GSM and GSL customer, the following are the estimated reductions in demand charges by month that would have been realized if the winter ratchet had been eliminated effective June 1, 2009.

Billing Period	GSL >100 kV	GSL 30 - 100 kV	GSL 750 V - 30 kV	GSM
Jun 09	$13,671	$4,912	$27,595	$370,941
Jul 09	$45,937	$7,151	$32,173	$481,281
Aug 09	$17,729	$7,765	$42,949	$479,208
Sep 09	$190,851	$6,894	$35,573	$435,952
Oct 09	$239,013	$9,326	$7,841	$313,300
Nov 09	$232,644	$8,714	$15,736	$209,432

The primary factors influencing the ratchet expense for customers in the GSL rate categories include the economic recession, curtailed operations and plant closures in the >100 kV subclass that dramatically increased the impact of the winter ratchet in this subclass.

The primary influences in the remaining two GSL rate subclasses included the economic recession, which resulted in curtailed operations and plant closures in some cases, along with harsh weather during the 2008/09 winter period, which increased winter demand levels for customers heavily reliant on electric heating.

The impact of the winter ratchet on GSM accounts is heavily influenced by electric heating, which historically results in higher winter peaks being established. The harsh weather during the 2008/09 winter period increased winter demand levels for these customers. As a result, the 70 percent winter ratchet had a greater influence during the summer and fall periods covered by the Jun 09 - Nov 09 billing periods.

Note: The information provided in the above response is preliminary in nature. It is anticipated that the actual impact of the 70 percent winter ratchet may be lower when the existing 25 percent (or proposed 50%) of contract criteria is fully implemented into the analysis.

MIPUG/MH I-22

PCOSS 10 - Overview

a) Please provide the terms of reference for the review of the cost-of-service methods referenced on page 2 of tab 11.

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS/MH I-68(a).

<u>MIPUG/MH I-22</u>

PCOSS 10 - Overview

b) Please provide an estimate of the anticipated consulting costs for the review of the cost-of-service study.

<u>ANSWER</u>:

It is premature to estimate the consulting costs related to the review of the cost of service study in advance of the finalization of the Terms of Reference.

PCOSS 10 - Overview

c) Please provide a detailed explanation for how MH estimated that 42% of the positions related to the trading desk were purely export related, as stated on page 9 of PCOSS10.

ANSWER:

The text on page 9, "It was estimated that 42% of the positions related to the trading desk were purely export related," should be clarified. The distinction between positions serving the export market versus domestic customers is not as definitive as the statement would make it appear. While there are positions that are entirely export related; others have responsibilities that serve both domestic and export markets. More accurately, 42% of the EFTs have been estimated to be export related.

The percentage of export related EFTs was determined by reviewing the current organizational chart for the Power Sales and Operation Division. Positions were evaluated in order to create a hypothetical organization structure of the Division if Manitoba Hydro did not make any export sales.

Any position whose duties were entirely related to facilitating export sales was removed from the structure. For positions that supported both domestic and export customers, an estimate was made of the EFT reductions that could be made by reducing the number of positions within the same job classification, or by the consolidating the remaining duties with other similar positions.

Comparing the resulting hypothetical organization structure to the existing structure indicated that 42% of the EFTs would not exist if Manitoba Hydro did not make export sales.

<u>MIPUG/MH I-22</u>

PCOSS 10 - Overview

d) Please provide, in electronic format, the 2002/03 through 2007/08 energy use profile data used to construct the generation energy weightings described on page 10 of PCOSS10.

<u>ANSWER</u>:

Please see Appendix 38 provided in response to RCM/TREE/MH I-3(e)(iii).

For the reasons outlined in RCM/TREE/MH I-3(a), Manitoba Hydro respectfully declines to provide the requested materials in excel format.

MIPUG/MH I-22

PCOSS 10 - Overview

e) Please provide a table, similar to that provided in MIPUG/MH I-28 (a) from the 2008 GRA, that shows the impact by customer class and subclass (both in terms of total dollars and RCC ratio) of each of the methodology changes between PCOSS08 and PCOSS10.

ANSWER:

The following variance analysis shows the impact on customer class costs and RCC for each methodology change between PCOSS08 (prepared consistent with PUB Order 116/08) and PCOSS10.

PCOSS10 Variance Analysis

Effect of Changes in Methodology Used in PCOSS08 and PCOSS10[1]

Customer Class	PCOSS10 116/08[2]	Incremental Change in RCC: Forecast of Export Revenue[3]	DSM[4]	Thermal Plant Costs[5]	Other Export Costs[6]	PCOSS10[7]
Residential	94.6%	0.4%	0.4%	0.8%	0.2%	96.4%
General Service - Small Non Demand	105.0%	0.1%	0.1%	0.4%	0.1%	105.7%
General Service - Small Demand	104.7%	-0.3%	-1.4%	-0.2%	0.0%	102.8%
General Service - Medium	101.5%	-0.1%	0.4%	-0.4%	-0.1%	101.3%
General Service - Large 0 - 30kV	92.8%	0.2%	-0.5%	-0.2%	0.0%	92.3%
General Service - Large 30-100kV*	112.7%	-0.7%	-3.3%	-1.5%	-0.4%	106.8%
General Service - Large >100kV*	114.1%	-0.9%	-1.1%	-2.4%	-0.5%	109.2%
*Includes Curtailment Customers						
SEP	87.1%	-0.2%	0.0%	0.0%	0.0%	86.9%
Area & Roadway Lighting	95.3%	-1.7%	6.0%	0.3%	0.1%	100.0%
Total General Consumers	100.6%	0.0%	0.0%	-0.1%	0.0%	100.5%
Diesel	37.7%	3.7%	2.1%	2.9%	0.7%	47.1%
Export	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Total System	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%

[1] Changes to PCOSS methodology are cumulative, and the impact attributed to a specific change may vary depending on the sequence in which the steps are performed.
[2] Version of PCOSS using methodology consistent with PCOSS08 submitted March 3, 2009 and prepared in compliance with PUB
[3] Version of PCOSS that includes Export Revenue as used in the Integrated Financial Forecast, and not based on actual recent prices
[4] Version of PCOSS that assigns DSM costs to the customer class that benefits from the DSM programming, as done prior to PCOSS08
[5] Version of PCOSS that assigns only the fuel and variable mainteance costs for Brandon Unit 5, excluding portion related to training and reliability runs, to the Export class.
[6] Version of PCOSS that assigns only the directly attributable portion of 'Trading Desk' and MISO/MAPP costs to the Export class
[7} PCOSS as filed for 2010/11 & 2011/12 GRA

PCOSS10 Variance Analysis
Effect of Changes in Methodology Used in PCOSS08 and PCOSS10[1]

Customer Class	PCOSS10 116/08[2]	Incremental Change in Costs less Net Export Revenue ($ 000s): Forecast of Export Revenue[3]	DSM[4]	Thermal Plant Costs[5]	Other Export Costs[6]	PCOSS10[7]
Residential	514,295	(672)	(2,056)	(3,839)	(958)	506,770
General Service - Small Non Demand	106,304	(260)	(271)	(580)	(141)	105,052
General Service - Small Demand	110,124	98	1,491	79	22	111,815
General Service - Medium	156,585	165	(673)	462	120	156,659
General Service - Large 0 - 30kV	73,148	74	544	345	88	74,199
General Service - Large 30-100kV*	39,573	55	1,166	542	134	41,471
General Service - Large >100kV*	169,018	512	1,370	3,401	839	175,139
*Includes Curtailment Customers						
SEP	1,510	3	-	-	-	1,513
Area & Roadway Lighting	20,806	407	(1,305)	(50)	(13)	19,844
Total General Consumers	1,191,362	382	267	360	91	1,192,462
Diesel	12,386	(382)	(267)	(360)	(91)	11,287
Export	479,855	66,266	-	-	-	546,121
Total System	1,683,604	66,266	-	-	-	1,749,870

[1] Changes to PCOSS methodology are cumulative, and the impact attributed to a specific change may vary depending on the sequence in which the steps are performed.
[2] Version of PCOSS using methodology consistent with PCOSS08 submitted March 3, 2009 and prepared in compliance with PUB
[3] Version of PCOSS that includes Export Revenue as used in the Integrated Financial Forecast, and not based on actual recent prices
[4] Version of PCOSS that assigns DSM costs to the customer class that benefits from the DSM programming, as done prior to PCOSS08
[5] Version of PCOSS that assigns only the fuel and variable mainteance costs for Brandon Unit 5, excluding portion related to training and reliability runs, to the Export class.
[6] Version of PCOSS that assigns only the directly attributable portion of 'Trading Desk' and MISO/MAPP costs to the Export class
[7} PCOSS as filed for 2010/11 & 2011/12 GRA

PCOSS 10 - Overview

f) Please provide a copy of Schedules B1-B3 reflecting the situation after the proposed rate increases are applied to all classes, similar to MIPUG/MH I – 25 (c) from the 2008 GRA.

ANSWER:

The updated Schedules B1-B3 reflects the April 1, 2010 interim rate increases as approved in Board Order 33/10. The interim rates included a 2.9% increase for all customer classes, with the exception of Area and Roadway Lighting.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2010
Revenue Cost Coverage Analysis

S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	573,324	500,596	87.3%	52,137	552,733	96.4%
General Service - Small Non Demand	118,388	114,908	97.1%	10,445	125,353	105.9%
General Service - Small Demand	126,131	119,120	94.4%	11,071	130,191	103.2%
General Service - Medium	176,874	163,383	92.4%	15,648	179,031	101.2%
General Service - Large 0 - 30kV	83,755	69,909	83.5%	7,398	77,307	92.3%
General Service - Large 30-100kV*	46,952	45,863	97.7%	4,256	50,119	106.7%
General Service - Large >100kV*	198,315	198,519	100.1%	17,844	216,363	109.1%
*Includes Curtailment Customers						
SEP	1,515	1,315	86.8%	-	1,315	86.8%
Area & Roadway Lighting	20,883	19,837	95.0%	629	20,466	98.0%
Total General Consumers	1,346,135	1,233,450	91.6%	119,428	1,352,878	100.5%
Diesel	12,583	4,683	37.2%	1,158	5,840	46.4%
Export	425,552	546,138	128.3%	(120,585)	425,552	100.0%
Total System	1,784,270	1,784,270	100.0%	-	1,784,270	100.0%

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	116,818	466,759	20.86	200,896	0%	n/a	n/a		203,473	6,811,218	5.94
GS Small - Non Demand	21,889	52,716	34.60	38,661	0%	n/a	n/a		47,393	1,478,206	5.82
GS Small - Demand	7,098	11,260	52.53	45,902	38%	2,203	7.97		62,060	1,983,393	4.56
General Service - Medium	5,602	1,859	251.12	63,614	100%	7,008	9.08		92,009	3,032,155	3.03
General Service - Large <30kV	2,807	259	n/a	27,863	100%	3,452	8.89	*	45,686	1,533,322	2.98
General Service - Large 30-100kV	1,760	30	n/a	10,298	100%	2,455	4.91	*	30,638	1,151,746	2.66
General Service - Large >100kV	2,038	14	n/a	30,280	100%	9,476	3.41	*	148,153	5,626,174	2.63
SEP	358	25	1,193.73	242	0%	n/a	n/a		915	22,550	5.13
Area & Roadway Lighting	15,488	153,710	8.40	2,446	0%	n/a	n/a		2,320	99,432	4.79
Total General Consumers	173,859	686,631		420,202		24,594			632,647	21,738,196	
Diesel	255	732	29.02	382	0%	n/a	n/a		10,788	12,820	87.13
Export	n/a	n/a	n/a	53,610	0%	n/a	n/a		371,942	7,901,000	5.39
Total System	174,114	687,363		474,194		24,594			1,015,378	29,652,016	

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2010
Functional Breakdown

S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	521,187	203,473	39.0%	48,238	9.3%	40,143	7.7%	55,884	10.7%	173,449	33.3%
General Service - Small Non Demand	107,943	47,393	43.9%	11,159	10.3%	7,251	6.7%	13,949	12.9%	28,191	26.1%
General Service - Small Demand	115,060	62,060	53.9%	13,710	11.9%	8,465	7.4%	3,086	2.7%	27,739	24.1%
General Service - Medium	161,226	92,009	57.1%	20,701	12.8%	11,284	7.0%	4,611	2.9%	32,619	20.2%
General Service - Large <30kV	76,356	45,686	59.8%	10,176	13.3%	5,277	6.9%	2,582	3.4%	12,635	16.5%
General Service - Large 30-100kV	42,696	30,638	71.8%	6,575	15.4%	3,723	8.7%	1,710	4.0%	50	0.1%
General Service - Large >100kV	180,471	148,153	82.1%	30,280	16.8%	0	0.0%	2,014	1.1%	24	0.0%
SEP	1,515	915	60.4%	242	16.0%	0	0.0%	342	22.5%	17	1.1%
Area & Roadway Lighting	20,254	2,477	12.2%	417	2.1%	577	2.8%	580	2.9%	16,202	80.0%
Total General Consumers	1,226,708	632,805	51.6%	141,498	11.5%	76,722	6.3%	84,756	6.9%	290,927	23.7%
Diesel	11,425	10,788	94.4%	0	0.0%	0	0.0%	0	0.0%	637	5.6%
Export	425,552	371,942	87.4%	53,610	12.6%	0	0.0%	0	0.0%	0	0.0%
Total System	1,663,685	1,015,535	61.0%	195,108	11.7%	76,722	4.6%	84,756	5.1%	291,564	17.5%

MIPUG/MH I-23

PCOSS Allocation Ratios

a) For the energy allocators (E12) and (E13) and demand allocators (D13) and (D14) please provide the allocation percentages by class and subclass, similar to that provided in MIPUG/MH I-27 a) in the 2008 GRA Proceeding.

ANSWER:

The following tables show the class share of the requested PCOSS10 energy and demand allocation tables expressed as a percentage.

Allocation Table	Prospective Cost Of Service Study D13 Avg CP Adjusted for Losses - Domestic Only			
		Curtailable Class	Class	Total
Residential	Standard & All Electric		33.9%	33.9%
	Seasonal		0.2%	0.2%
	Water Heating		0.1%	0.1%
Total Residential		0.0%	34.2%	34.2%
General Service Small:	Non-Demand		7.9%	7.9%
	Demand		9.7%	9.7%
	Seasonal		0.0%	0.0%
	Water Heating		0.0%	0.0%
Total General Service Small		0.0%	17.6%	17.6%
SEP	GSM			0.0%
	GSL			0.0%
Total SEP		0.0%	0.0%	0.0%
General Service Medium			14.7%	14.7%
General Service Large	0-30KV		7.2%	7.2%
	30-100KV	0.8%	3.8%	4.7%
	>100KV	10.6%	10.8%	21.4%
Total General Service Large		11.5%	21.9%	33.3%
Area & Roadway Lighting			0.3%	0.3%
Total General Consumers		11.5%	88.5%	100.0%
Diesel				0.0%
Export				0.0%
Total System		11.5%	88.5%	100.0%

Allocation Table	Prospective Cost Of Service Study D14 Average Coincident Peak - Adjusted For Losses			
		Curtailable Class	Class	Total
Residential	Standard & All Electric		25.3%	25.3%
	Seasonal		0.1%	0.1%
	Water Heating		0.0%	0.0%
Total Residential		0.0%	25.5%	25.5%
General Service Small:	Non-Demand		5.9%	5.9%
	Demand		7.2%	7.2%
	Seasonal		0.0%	0.0%
	Water Heating		0.0%	0.0%
Total General Service Small		0.0%	13.1%	13.1%
SEP	GSM			0.0%
	GSL			0.0%
Total SEP		0.0%	0.0%	0.0%
General Service Medium			10.9%	10.9%
General Service Large	0-30KV		5.4%	5.4%
	30-100KV	0.6%	2.9%	3.5%
	>100KV	7.9%	8.1%	16.0%
Total General Service Large		8.5%	16.3%	24.8%
Area & Roadway Lighting			0.2%	0.2%
Total General Consumers		8.5%	66.0%	74.6%
Diesel				0.0%
Export			25.4%	25.4%
Total System		8.5%	91.5%	100.0%

Allocation Table

Prospective Cost Of Service Study
E12 12 Period Marginal Cost Weighted Energy Table

		Curtailable Class	Class	Total
Residential	Standard & All Electric		25.7%	25.7%
	Seasonal		0.3%	0.3%
	Water Heating		0.1%	0.1%
Total Residential		0.0%	26.0%	26.0%
General Service Small:	Non-Demand		5.6%	5.6%
	Demand		7.4%	7.4%
	Seasonal		0.0%	0.0%
	Water Heating		0.0%	0.0%
Total General Service Small		0.0%	13.0%	13.0%
SEP	GSM			0.0%
	GSL			0.0%
Total SEP		0.0%	0.0%	0.0%
General Service Medium			11.3%	11.3%
General Service Large	0-30KV		5.6%	5.6%
	30-100KV	0.8%	3.2%	4.0%
	>100KV	9.3%	9.7%	19.0%
Total General Service Large		10.0%	18.5%	28.5%
Area & Roadway Lighting			0.3%	0.3%
Total General Consumers		10.0%	69.1%	79.1%
Diesel				0.0%
Export			20.9%	20.9%
Total System		10.0%	90.0%	100.0%

Allocation Table

Prospective Cost Of Service Study
E13 12 Period Marginal Cost Weighted Energy Table - Thermal

		Curtailable Class	Class	Total
Residential	Standard & All Electric		32.4%	32.4%
	Seasonal		0.3%	0.3%
	Water Heating		0.1%	0.1%
Total Residential		0.0%	32.8%	32.8%
General Service Small:	Non-Demand		7.1%	7.1%
	Demand		9.4%	9.4%
	Seasonal		0.0%	0.0%
	Water Heating		0.0%	0.0%
Total General Service Small		0.0%	16.5%	16.5%
SEP	GSM			0.0%
	GSL			0.0%
Total SEP		0.0%	0.0%	0.0%
General Service Medium			14.2%	14.2%
General Service Large	0-30KV		7.1%	7.1%
	30-100KV	0.9%	4.0%	5.0%
	>100KV	11.7%	12.3%	24.0%
Total General Service Large		12.6%	23.4%	36.1%
Area & Roadway Lighting			0.4%	0.4%
Total General Consumers		12.6%	87.4%	100.0%
Diesel				0.0%
Export				0.0%
Total System		12.6%	87.4%	100.0%

MIPUG/MH I-23

PCOSS Allocation Ratios

b) Please also provide versions of the tables provided in part (a) for the demand allocators (D13) and (D14) using the method from PCOSS08 (i.e. without the adjustments described on pages 10 and 11 of PCOSS10).

ANSWER:

The demand allocators (D13 and D14) in PCOSS10 are prepared using the average coincident peak load factors (CP LF) from the two most recent Load Research studies. Only the single year CP LF from the most recent Load Research study was used when calculating the allocators in PCOSS08.

The following tables are prepared using coincident peak load factors from only the single most recent Load Research study, consistent with the method used for PCOSS08.

Allocation Table	Prospective Cost Of Service Study D13 Avg CP Adjusted for Losses - Domestic Only			
		Curtailable Class	Class	Total
Residential	Standard & All Electric		35.4%	35.4%
	Seasonal		0.2%	0.2%
	Water Heating		0.1%	0.1%
Total Residential		0.0%	35.7%	35.7%
General Service Small:	Non-Demand		7.5%	7.5%
	Demand		9.5%	9.5%
	Seasonal		0.0%	0.0%
	Water Heating		0.0%	0.0%
Total General Service Small		0.0%	17.0%	17.0%
SEP	GSM			0.0%
	GSL			0.0%
Total SEP		0.0%	0.0%	0.0%
General Service Medium			14.3%	14.3%
General Service Large	0-30KV		7.0%	7.0%
	30-100KV	0.8%	3.7%	4.5%
	>100KV	10.5%	10.8%	21.3%
Total General Service Large		11.3%	21.5%	32.8%
Area & Roadway Lighting			0.3%	0.3%
Total General Consumers		11.3%	88.7%	100.0%
Diesel				0.0%
Export				0.0%
Total System		11.3%	88.7%	100.0%

Allocation Table	Prospective Cost Of Service Study D14 Average Coincident Peak - Adjusted For Losses			
		Curtailable Class	Class	Total
Residential	Standard & All Electric		26.2%	26.2%
	Seasonal		0.1%	0.1%
	Water Heating		0.0%	0.0%
Total Residential		0.0%	26.4%	26.4%
General Service Small:	Non-Demand		5.5%	5.5%
	Demand		7.0%	7.0%
	Seasonal		0.0%	0.0%
	Water Heating		0.0%	0.0%
Total General Service Small		0.0%	12.6%	12.6%
SEP	GSM			0.0%
	GSL			0.0%
Total SEP		0.0%	0.0%	0.0%
General Service Medium			10.6%	10.6%
General Service Large	0-30KV		5.1%	5.1%
	30-100KV	0.6%	2.7%	3.3%
	>100KV	7.8%	8.0%	15.8%
Total General Service Large		8.4%	15.9%	24.3%
Area & Roadway Lighting			0.2%	0.2%
Total General Consumers		8.4%	65.6%	74.0%
Diesel				0.0%
Export			26.0%	26.0%
Total System		8.4%	91.6%	100.0%

MIPUG/MH I-24

Provincial Government Charges

a) Please provide a schedule similar to the response to MIPUG/MH I-29 a) from the 2008 General Rate Application that indicates all actual or forecast provincial government charges paid or forecast to be paid from electricity operations for fiscal years ending 2007 through 2020. Please include and separately indicate any provincial government mitigation or settlement obligations assumed by Manitoba Hydro. Please indicate Manitoba Hydro's actual or forecast gross electricity operation revenues and actual or forecast gross electricity export revenues for the same periods.

ANSWER:

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

MIPUG/MH I-24

Provincial Government Charges

b) Please indicate any changes to the methods of calculation of any of the charges or any additional charges since the 2008 General Rate Application. Please discuss the basis for such changes (e.g. policy direction from the Province, new legislation etc).

ANSWER:

With respect to the charges and payments listed in the response to MIPUG/MH I-24(a) there have been no changes in the methods of calculation or additional charges since the 2008 General Rate Application.

MIPUG/MH I-25

Demand Side Management

a) Please provide a schedule showing the DSM savings to date by customer class and subclass for both demand and energy.

ANSWER:

Savings to Date to 2007/08 (at generation)

	GW.h	Average Winter MW
Residential	464	113
Commercial	422	76
Industrial	474	299
Total	1,360	488

MIPUG/MH I-25

Demand Side Management

b) **Manitoba Hydro's Load Forecast (at page 47 of Appendix 7.1) indicates the potential load impacts of prolonged periods of natural gas prices rising above electricity prices for space heating. Does Manitoba Hydro's DSM strategy include any programs to encourage the use of natural gas over electricity for space heating? Please discuss.**

ANSWER:

Manitoba Hydro's DSM strategy does not include any programs to encourage fuel switching. Manitoba Hydro's DSM strategy is to promote the efficient use of energy once a particular energy choice is made by customers.