REFERENCE: Question MIPUG/MH I-002a

QUESTION:

Please confirm Manitoba Hydro has not internally completed or retained any third party to complete an assessment of the potential impact of the borrowing required under the Preferred Development Plan to the Province of Manitoba's credit rating.

RESPONSE:

The credit rating agencies examine Manitoba Hydro's financial performance and forecasts, and each views Manitoba Hydro's long term debt advances from the Province of Manitoba to be self-supporting**.** As described in the following quote from the Moody's Investors Service report on the Province of Manitoba dated July 23, 2013 (see PUB/MH I-085(b), Attachment 4, page 3):

> "Roughly one third of the province's total direct and indirect debt is attributed to Manitoba Hydro (issued and on-lent by the province) and is considered to be self-supporting. This Crown Corporation's ability to meet its own financial obligations without recourse to provincial subsidies is a positive credit attribute for the province. In our view, the likelihood that the contingent liability represented by Manitoba Hydro's debt would materialize remains relatively remote."

Consequently, when assessing the Province of Manitoba's debt, the credit rating agencies exclude Manitoba Hydro's debt levels when they calculate the Province of Manitoba's ratio of net tax-supported provincial debt as a percent of provincial GDP. Therefore, to the extent that Manitoba Hydro maintains its self-supporting status, Manitoba Hydro's capital investment plans should have no significant impact on the Province of Manitoba's credit rating.

As Manitoba Hydro's debt is expected to remain self-supporting in the future, it is not necessary for Manitoba Hydro to retain a third party to assess the hypothetical impact that future development plan borrowings may have on the Province of Manitoba's credit rating.

Manitoba Hydro will continue to take appropriate actions to ensure it remains a self-supporting corporation. As described by Moody's credit rating agency in its report:

> "Given the uptick in capex and corresponding debt, financial metrics are predicted to fall below targets in the next three fiscal years. The equity ratio, in particular, will be challenged and not likely to return to target until FY2032. The weakening financial profile restricts financial flexibility and adds risk in case of unexpected events such as low water levels, cost overruns and construction delays, given the nature of a hydroelectric plant's long construction cycle before cash generating begins. However, we view Manitoba Hydro as being capable of prudently managing debt and mitigating such risks by seeking rate increases and curtailing capital spending to continue as a self-supporting corporation." [Moody's Investors Service report on the Manitoba Hydro-Electric Board dated September 23, 2013; page 2 (see PUB/MH I-085(b), Attachment 3)]

REFERENCE: Question MIPUG/MH I-002a

QUESTION:

If any such assessment was prepared internally or by a third party retained by Manitoba Hydro, please provide a copy of the assessment.

RESPONSE:

Please see Manitoba Hydro's response to MIPUG/MH II-001a.

REFERENCE: MIPUG/MH-1-009a

QUESTION:

Please provide any references to recent literature about the use or inappropriateness of the "regret approach" in power system planning and evaluation. Please also provide references to the specific analyses and reports prepared and provided publicly by any other the other major hydro utilities in Canada regarding the use or non-use of the regret approach.

RESPONSE:

In general, theories of decision making under uncertainty are either descriptive or prescriptive. Descriptive theories provide formal rules for how individuals (and organizations) actually make decisions; prescriptive theories provide formal rules for how individuals (and organizations) should make decisions.[1] These prescriptive theories are based on fundamental axioms regarding what constitutes rational behavior. For example, transitivity is typically regarded as one essential axiom of rational behavior. Namely, if you prefer A to B and B to C, you really should prefer A to C. For the purposes of NFAT, our focus is on prescriptive decision-making: what should Manitoba Hydro do.

The dominant prescriptive theory is called expected utility. This theory has broad and deep analytical foundations dating back several decades.[2,3,4] Decision analysis, a widely-accepted and well-regarded approach for improved decision-making, is based on expected utility.[5,6] In this context, most forms of scenario analysis, sensitivity analysis, Monte Carlo analysis and the like

[1] There is also a third category: normative. Normative generally refers to how decisions should be made ideally, while prescriptive refers to how they should be made practically.

[2] John von Neumann and Oskar Morgenstern, Theory of Games and Economic Behavior, Princeton University Press, 1944.

[3] P.J.H. Schoemaker, *The Expected Utility Model: Its Variants, Purposes, Evidence and Limitations*, Journal of Economic Literature, 1982.

[4] Peter C. Fishburn, *Analysis of Decisions with Incomplete Knowledge of Probabilities*, Operations Research, March/April 1965.

[5] Ronald A. Howard, *Decision Analysis: Practice and Promise*, Management Science, June 1988.

[6] John Pratt, Howard Raiffa and Robert Schlaifer, Introduction to Statistical Decision Theory, MIT Press, 1995.

can be viewed as variations on decision analysis. Expected utility theory is intended specifically to provide guidance on what constitutes a good decision. Consequently, it is appropriate to use in the NFAT process.

By and large, regret theory is viewed as a descriptive rather than prescriptive theory.[7,8] In fact, it was developed in part in reaction to empirical evidence that individuals (and organizations) do not appear to follow the dictates of expected utility theory; that is, the decisions they actually make are often not the decisions they should make based on axioms of rationality. Regret theory is not generally intended to provide guidance on what constitutes a good decision, and there are very few advocates of regret theory as prescriptive.[9] Even advocates of incorporating regret into a prescriptive theory view it as a limited guideline for individuals not a general guideline for organizational decision making. A quote from David E. Bell sums up this view, "A consumer may wish to spend some…dollars in avoiding disappointment [but this]….paper does not suggest that people ought to make financial tradeoffs to avoid disappointment."[10] Consequently, it is not really appropriate to use in the NFAT process except as a supplement to analysis based more on expected utility.

A simple example will illustrate the difficulties with using the regret approach in the NFAT context.[11] One common axiom of rational decision-making is called "independence of irrelevant alternatives." That is, if Plan A is better than Plan B, Plan B should not suddenly be better than Plan A if a third alternative Plan C is introduced.

[7] Chris Starmer, *Developments in Non-Expected Utility Theory: The Hunt for a Descriptive Theory of Choice under Risk*, Journal of Economic Literature, June 2000.
[8] David E. Bell, *Regret in Decision Making Under Uncertainty*, Operations Research, Sep/Oct 1982.
[9] *Regret Theory: An Alternative Theory of Rational Choice Under Uncertainty*, Graham Loomes and Robert Sugden, The Economic Journal, December 1982.
[10] David E. Bell, *Disappointment in Decision Making Under Uncertainty*, Operations Research, Jan/Feb 1985.
[11] *In Praise of the Old Time Religion*, Ronald A. Howard, Utility Theories: Measurements and Applications, 1992.

Table 1 illustrates the choice between two alternatives A and B. The maximum regret for Alternative A is 1 (-50 is 1 worse than -49) and the maximum regret for Alternative B is 50 (50 is 50 worse than 100). Using the standard regret criterion of minimizing the maximum regret, A is better than B.

Table 1: Two Option Example

	Scenario 1	Scenario 2
Alternative A	-50	100
Alternative B	-49	50

Table 2: Three Option Example

	Scenario 1	Scenario 2
Alternative A	-50	100
Alternative B	-49	50
Alternative C	50	-200

Table 2 shows the same problem with a third Alternative C added. Using a regret approach, the maximum regret for Alternative A is now 100 (-50 is 100 worse than 50), the maximum regret for Alternative B is now 99 (-49 is 99 worse than 50), and the maximum regret for Alternative C is 300 (-200 is 300 worse than 100). Based on maximum regret, B is now better than A. With the regret approach, the addition of Alternative C has changed the ranking of A and B. This is generally regarded both by specialists and lay people as illogical, and inappropriate for making good decisions. The bottom line is that, while the regret approach may provide insight into how individuals (and organizations) actually make decisions, it does not provide particularly good guidance on how they should make decisions…particularly organizations.

Empirically, there are many available examples of firms, including electric utilities, using expected utility, or approaches consistent with expected utility, for investment planning and for finding the best investment decision. Nova Scotia's 2009 IRP update includes sensitivity analysis where the range of outcomes associated with each plan is compared.[12] There is no "scenario-by-scenario" regret analysis. In BC Hydro's recent IRP, there is some indication that concepts consistent with regret analysis were considered in the process. However, the main analytical framework and recommendations are based on decision analysis and expected utility.[13]

As far as we can determine, there are no available examples of firms, including electric utilities, using regret theory in any significant way for investment planning and for finding the best investment decision. Bean and Hoppock argue in favor of a regret approach for electric utility planning and use TVA as an example.[14] However, while TVA has mentioned a "least regrets" or "no regrets" approach, its IRP is based on a form of scenario analysis that is more consistent with expected utility.[15] Using more standard terminology, they are actually looking for the "most robust" alternative and their reference to regret really refers to the quality of the decision-making process not the decision itself.

[12] Nova Scotia Utility and Review Board, NSPI 2009 Integrated Resource Plan Update Report, 2009
[13] http://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html
[14] Patrick Bean and David Hoppock, *Least-Risk Planning for Electric Utilities*, Working Paper for Nicholas Institute for Environmental Policy Solutions, August 2013.
[15] http://www.tva.com/irp/pdf/irp_complete.pdf

REFERENCE: MIPUG/MH I-009a

QUESTION:

Please confirm that both Manitoba Hydro's "regret approach" and Hydro "utilitarian approach" derive the same relative expected values.

RESPONSE:

Confirmed.

Figure 2.7.1 in Appendix 9.3 is a “quilt” that provides the NPV of each of the 15 development plans under the 27 scenarios. The table below the quilt summarizes several probabilistic measures including expected value using the “regret” approach and expected value using the “utilitarian” approach. The row identified as “Expected Value” is the expected value using the “utilitarian” approach and the row identified as “EV Difference From All Gas” is the expected value using the “regret” approach. A comparison of these two measures shows that the “regret” approach and “utilitarian” approach of deriving expected value derives the same relative expected values (but not the same expected value).

REFERENCE: MIPUG/MH I-009a

QUESTION:

Please confirm that the figures provided by Manitoba Hydro in response to PUB/MH-1-149a (e.g. Tables 11.4, 11.5, 11.6, 11.7, and figures 11.15 and 11.16) are derived using the regret approach.

RESPONSE:

Confirmed.

As indicated in Manitoba Hydro's responses to MIPUG/MH I-009a and MIPUG/MH II-004a, although the regret approach is intuitively attractive, it generally is not considered appropriate or ideal for making important business or policy decisions and care must be taken not to provide misleading results.

The comparisons provided in Figures 11.15 and 11.16 in Manitoba Hydro's response to PUB/MH I-149a are intended to provide perspective by capturing the relative rate impacts (or regret) vs. the All Gas plan under two extreme scenarios (High-Low-High and Low-High-Low: economic indicator, export revenue and capital cost factors). This regret analysis is a supplement to the main expected utility analysis, and helps show how the possible outcomes of different alternatives may feel to ratepayers when two particular scenarios are considered as certain futures.

REFERENCE: Question MIPUG/MH I-17a

QUESTION:

Please indicate whether the KCN investment returns are portrayed in Appendix 11.4 as "non-controlling interest" or in some other way. If not as non-controlling interest, please provide a detailed description of where the KCN investment impacts are portrayed in Appendix 11.4.

RESPONSE:

Distributions to the KCN are reflected in “Non-Controlling Interest” in the pro forma financial statements found in Appendix 11.4.

Please also see Manitoba Hydro’s response to CAC/MH I-022(b).

REFERENCE: Question MIPUG/MH I-17b

QUESTION:

Please provide the same information for the Conawapa income opportunities - specifically how have these been estimated and where are they represented in Appendix 11.4 tables.

RESPONSE:

An assumption regarding Conawapa income opportunities has been included in financial evaluation and aggregated in the pro forma financial statements found in Appendix 11.4. However, the terms of Conawapa income opportunities are currently under negotiation and cannot be disclosed by Manitoba Hydro at this time.

REFERENCE: MIPUG/MH I-011a

QUESTION:

Please confirm that, based on the approach to modeling the debt guarantee fee in the economic analysis, an reduction in the debt guarantee fee without any corresponding change to interest rates would lower the discount rate.

RESPONSE:

Confirmed.

REFERENCE: MIPUG/MH I-025c

QUESTION:

Please provide the relevant tables as a percentage of total load growth for each of the utilities. Please indicate how the B.C. Hydro DSM is described as meeting over 2/3 of the projected load growth over the forecast period (per the BC Clean Energy Act). Is this a function of different ways of classifying DSM activities (e.g., past codes and standards, rate structures, etc.) between BC Hydro and Manitoba Hydro?

RESPONSE:

B.C. Hydro includes DSM programs, conservation rates and codes & standards in its assessment of its ability to meet DSM requirements under legislation as outlined under its 2013 Integrated Resource Plan. DSM programs include initiatives promoting energy efficient technologies, measures or behaviors and load displacement opportunities. Conservation rates include projected energy savings from rates. Codes & Standards includes codes and standards that have been enacted, announced or planned by federal and provincial governments.

In looking at DSM savings projections as outlined under BC Hydro's 2013 Integrated Resource Plan as presented in response to MIPUG/MH I-025c and in comparison to BC Hydro's Electric Load Forecast Fiscal 2013 to Fiscal 2033 (http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2012-electric-load-forecast-report.pdf), energy savings of 6,306 GW.h/year and demand savings of 1,365 MW in 2021/22 appear to represent 46% and 62% respectively of projected load growth to 2021/22.

Manitoba Hydro's projected energy reduction of 1,098 GW.h/year in 2021/22 presented in response to MIPUG/MH I-025(c) represents 29% of Manitoba's projected load growth to

2021/22. The projected demand reduction of 275 MW, including Curtailable Rates, represents 52% of projected load growth to 2021/22; removing Curtailable Rates, the projected demand reduction represents 33% of Manitoba’s projected load growth to 2021/22.

The tables as requested are updated below.

DSM Implementation Plan: Cumulative Energy Savings 2013/14 to 2021/22 (At Customer Meter)						
Utility	Sector	Codes and Standards (GW.h/year)	Rate Structures (GW.h/year)	Programs (GW.h)	Total	Total as % of Load Growth
MB Hydro	Residential	455	0	66	521	37%
	%	*87%*	*0%*	*13%*	*100%*	
	Commercial	87	0	311	398	24%*
	%	*22%*	*0%*	*78%*	*100%*	
	Industrial	0	0	179	179	
	%	*0%*	*0%*	*100%*	*100%*	
Reference: 2013 - 2016 Power Smart Plan 15 Year Supplementary Report	All Sectors	542	0	556	1,098	29%
	%	*49%*	*0%*	*51%*	*100%*	
BC Hydro	Residential	1,639	472	339	2,449	64%
	%	*67%*	*19%*	*14%*	*100%*	
Reference: http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/irp-chap-8-20130802.pdf	Commercial	617	356	778	1,751	42%
	%	*35%*	*20%*	*44%*	*100%*	
	Industrial	84	304	1,717	2,105	38%
	%	*4%*	*14%*	*82%*	*100%*	
	All Sectors	2,340	1,132	2,834	6,306	46%
	%	*37%*	*18%*	*45%*	*100%*	

*Manitoba Hydro does not forecast based upon commercial and industrial customer sectors. Manitoba Hydro forecasts General Service customers as General Service Mass Market and General Service Top Consumers. General Service Mass Market includes customer from the commercial and industrial sectors.

Please note for the following chart that the percentage of total load growth for capacity savings is not available at the sector level as BC Hydro does not present demand forecasts at the sector level within their load forecast and Manitoba Hydro does not forecast peak demand at the sector level.

DSM Implementation Plan: Cumulative Capacity Savings 2013/14 to 2021/22

(At Customer Meter)

Utility	Sector	Codes and Standards (MW/year)	Rate Structures (MW/year)	Programs (MW)	Total	Total as % of Load Growth
MB Hydro	Residential	91	0	19	110	n/a
	%	*83%*	*0%*	*17%*	*100%*	
	Commercial	24	0	83	107	n/a
	%	*22%*	*0%*	*78%*	*100%*	
	Industrial	0	0	173	173	n/a
	%	*0%*	*0%*	*100%*	*100%*	
	All Sectors including Curtailable Rates	115	0	275	390	52%
	%	*29%*	*0%*	*71%*	*100%*	
Reference: 2013 - 2016 Power Smart Plan 15 Year Supplementary Report	All Sectors excluding Curtailable Rates	115	0	127	243	33%
	%	*47%*	*0%*	*52%*	*100%*	
BC Hydro Reference: http://www.bchydro.com/content/dam/BCHydro/customer-	Residential	401	0	79	479	n/a
	%	*84%*	*0%*	*16%*	*100%*	
	Commercial	123	120	193	437	n/a
	%	*28%*	*27%*	*44%*	*100%*	

portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/irp-chap-8-20130802.pdf	Industrial	7	72	370	449	n/a
	%	*2%*	*16%*	*82%*	*100%*	
	All Sectors	531	192	642	1,365	62%
	%	*39%*	*14%*	*47%*	*100%*	

PREAMBLE: MIPUG/MH-1-28g indicates the economic analysis is based on 80% of the capital cost bring financed by debt. MIPUG/MH-1-11a indicates the economic analysis only includes the provincial guarantee fee as a component of the discount rate, and that the annual costs are not separately modeled.

QUESTION:

Please explain how the 80% ratio for capitalization has any relevance to the economic models in Appendix 9.3? Or is the 80% only used for preparing Figure 9.3 and not Appendix 9.3?

RESPONSE:

The 80% ratio for capitalization does not affect the economic comparisons used in the NFAT. The 80% is only used to estimate the portion of the project costs that are payments to the province related to the provincial guarantee fee. The value is used in preparing Figure 9.3, and it is used in Appendix 9.3 evaluations that reflect the economic benefits to the province such as Figures 2.7.3 and 2.7.6.

REFERENCE: MIPUG/MH I-032a

QUESTION:

Please confirm Plan #7 is based on building gas SCCT generation first, followed by Conawapa at a later date. Please indicate if the 2030/31 resource in this scenario (per plan 7 with 4x DSM) would be gas or Conawapa.

RESPONSE:

It is confirmed that in Plan 7 it is assumed that a SCGT is developed in 2022 to bridge to the earliest in-service date of Conawapa Generating Station of 2026 as it is not preceeded by Keeyask Generating Station.

Manitoba Hydro has not analysed in detail Plan 7 with 4x DSM. Based on the 2013 Update assumptions and 4x DSM a new supply option is required in 2030. Either natural gas-fired resources or hydro resources could be developed as the next resource to fulfill the requirement in 2030. In the context of Plan 7, the next resource to fulfill the requirement in 2030 would be Conawapa Generating Station as it can be developed for 2030 without being preceeded by a SCGT.

REFERENCE: MIPUG/MH-I-34a

QUESTION:

Why are Trans-GOT depreciation costs included in the All Gas scenario?

RESPONSE:

The All Gas Development Plan includes depreciation on all of the generation outlet transmission (GOT) facilities required to connect the gas turbines with the integrated system.

REFERENCE: Question MIPUG/MH I-34b

QUESTION:

Please confirm that the example of Conawapa is representative of the depreciation calculations for the other scenarios. In particular, please confirm that the Conawapa rate of 1.42% is used for all hydraulic investment, and the 1.38% rate is used for all transmission.

RESPONSE:

The Conawapa example provided in response to MIPUG/MH I-034(b) is representative of the depreciation calculations assuming a depreciation rate of 1.42% for all development plans with new hydraulic investments. The 1.38% depreciation rate is assumed for all transmission lines relating to new hydraulic generating stations.

REFERENCE: Question MIPUG/MH I-34d

QUESTION:

Please provide the REF-REF-REF financial projections (in the form of Appendix 11.4) for plans #1, 4, 6 and 14.

RESPONSE:

The reference scenario pro forma financial statements for the Preferred Development Plan (Plan #14) under the 1.63% depreciation rate sensitivity for Keeyask and Conawapa are attached.

Other development plans were not prepared under the depreciation rate sensitivity. However, the response to MIPUG/MH I-34(d) demonstrates that an increase in depreciation rates from 1.42% to 1.63% for new hydraulic generating stations results in a minimal additional rate increase of 0.03% per year over the period 2014/15 to 2031/32 compared to the base case reference scenario. From the response to MIPUG/MH I-34(d), one can infer that plans #4 and #6, which include only Keeyask and have approximately one-third the total in-service cost compared to both Keeyask and Conawapa in the Preferred Development Plan (Plan #14), a depreciation rate sensitivity would result in an increase in annual rates of approximately one-third of 0.03% per year (or 0.01%) over the period 2014/15 to 2031/32 compared to the base case reference scenario.

Additionally, the All Gas Development Plan (Plan #1) does not include new hydraulic generating stations addressed in the response to MIPUG/MH I-34(d), and so would not be affected by any depreciation rate sensitivity associated with these plants.

Development Plan 14. Preferred Case - Depreciation Sensitivity
Development Plan Scenario Econ:REF Rev:REF Cap:REF

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
REVENUES																									
General Consumers Revenue at approved rates	1,331	1,361	1,374	1,390	1,404	1,424	1,447	1,462	1,485	1,506	1,529	1,552	1,575	1,598	1,621	1,644	1,669	1,693	1,717	1,741	1,765	1,790	1,814	1,838	1,862
Additional General Consumers Revenue	-	48	105	165	229	299	373	450	534	623	718	820	928	1,043	1,164	1,293	1,431	1,577	1,731	1,894	1,073	1,090	1,139	1,168	1,222
Extraprovincial	357	344	333	370	388	412	402	439	713	817	829	808	795	834	1,099	1,165	1,174	1,168	1,176	1,181	1,176	1,163	1,152	1,114	1,032
Other	14	15	15	15	15	16	16	16	17	17	17	18	18	18	19	19	19	20	20	21	21	21	22	22	23
Total Revenue	1,702	1,768	1,827	1,940	2,036	2,150	2,238	2,367	2,749	2,964	3,093	3,197	3,317	3,493	3,902	4,121	4,292	4,457	4,644	4,836	4,035	4,064	4,126	4,143	4,139
EXPENSES																									
Operating and Administrative	455	471	546	559	570	593	605	621	678	690	703	716	730	760	773	788	804	817	832	849	866	887	906	924	945
Finance Expense	452	442	491	519	577	658	774	782	988	1,082	1,074	1,081	1,075	1,179	1,400	1,581	1,547	1,506	1,513	1,448	1,401	1,394	1,401	1,393	1,378
Depreciation and Amortization	399	430	372	391	400	422	458	462	527	565	570	570	573	616	693	752	755	763	790	798	795	799	824	828	833
Water Rentals and Assessments	117	116	112	112	112	112	112	114	124	127	128	128	127	135	148	150	151	151	152	153	153	154	154	154	154
Fuel and Power Purchased	143	166	167	178	191	200	205	207	222	239	247	256	270	233	238	256	266	275	282	292	302	312	324	325	309
Capital and Other Taxes	87	95	101	109	119	127	134	141	149	157	166	174	181	187	190	191	194	196	201	201	203	203	204	206	207
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7
Total Expenses	1,663	1,729	1,798	1,877	1,978	2,120	2,297	2,335	2,696	2,869	2,897	2,933	2,965	3,118	3,449	3,727	3,726	3,716	3,776	3,747	3,728	3,756	3,819	3,836	3,833
Non-Controlling Interest	(14)	(24)	(23)	(17)	(14)	(13)	(9)	(9)	(7)	1	3	7	9	5	7	9	11	14	16	18	20	22	24	25	26
Net Income	54	63	51	80	73	42	(50)	41	59	94	194	258	344	369	445	385	556	728	852	1,071	288	286	282	282	279
Additional General Consumers Revenue Percent Increase	0.00%	3.50%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	-23.00%	0.09%	1.16%	0.48%	1.26%
Cumulative General Consumers Revenue Percent Increase	0.00%	3.50%	7.61%	11.89%	16.34%	20.97%	25.78%	30.78%	35.98%	41.38%	47.00%	52.85%	58.93%	65.24%	71.81%	78.65%	85.75%	93.13%	100.81%	108.80%	60.78%	60.92%	62.79%	63.57%	65.63%
Debt Ratio	76	78	84	85	86	87	88	89	89	90	90	89	88	87	86	85	83	81	78	75	74	73	72	71	70
Interest Coverage Ratio	1.09	1.10	1.08	1.10	1.08	1.04	0.95	1.04	1.05	1.07	1.14	1.17	1.22	1.23	1.27	1.24	1.35	1.46	1.55	1.73	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.09	0.90	0.77	0.90	1.21	1.36	1.08	1.56	1.53	1.58	1.60	1.68	1.86	2.10	2.70	2.36	2.48	2.66	2.76	3.67	1.89	1.63	1.59	1.51	1.45

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS												
Plant in Service	15,374	16,435	17,107	18,261	18,821	22,519	22,947	25,701	29,723	30,257	30,788	31,353
Accumulated Depreciation	5,173	5,536	5,856	6,223	6,612	7,028	7,482	7,939	8,459	9,017	9,583	10,149
Net Plant in Service	10,201	10,900	11,251	12,038	12,209	15,492	15,465	17,762	21,264	21,239	21,205	21,204
Construction in Progress	2,105	2,866	4,164	5,048	6,617	5,069	6,411	5,209	2,873	4,555	6,192	7,589
Current and Other Assets	1,869	1,735	1,391	1,579	1,791	2,029	1,845	1,968	2,032	1,696	1,781	2,082
Goodwill and Intangible Assets	180	165	151	136	126	116	140	147	231	224	218	214
Regulated Assets	231	225	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Assets	14,587	15,890	16,957	18,802	20,742	22,707	23,860	25,086	26,400	27,714	29,397	31,088
LIABILITIES AND EQUITY												
Long Term Debt	9,289	11,260	12,802	14,474	16,170	17,742	19,438	20,404	21,727	23,077	24,880	26,482
Current and Other Liabilities	2,231	1,503	1,659	1,794	2,004	2,376	1,897	2,128	2,076	1,966	1,662	1,485
Contributions in Aid of Construction	325	334	339	344	348	358	364	371	378	385	392	400
Retained Earnings	2,442	2,505	2,300	2,379	2,452	2,495	2,445	2,486	2,545	2,639	2,833	3,091
Accumulated Other Comprehensive Income	299	287	(142)	(189)	(232)	(264)	(283)	(303)	(326)	(354)	(370)	(370)
Total Liabilities and Equity	14,587	15,890	16,957	18,802	20,742	22,707	23,860	25,086	26,400	27,714	29,397	31,088

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
ASSETS													
Plant in Service	32,042	37,329	42,227	43,649	44,393	44,951	46,932	47,662	48,343	49,688	50,210	50,754	52,076
Accumulated Depreciation	10,719	11,333	12,024	12,774	13,528	14,289	15,078	15,874	16,668	17,466	18,288	19,114	19,946
Net Plant in Service	21,322	25,995	30,203	30,874	30,865	30,662	31,855	31,788	31,675	32,222	31,922	31,640	32,130
Construction in Progress	8,716	5,044	1,293	744	1,075	1,515	472	545	642	106	395	702	269
Current and Other Assets	2,329	2,170	2,457	2,831	3,021	3,281	3,295	4,366	4,457	2,738	2,857	2,843	2,684
Goodwill and Intangible Assets	210	207	203	199	196	192	188	185	181	177	174	170	166
Regulated Assets	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Assets	32,577	33,416	34,156	34,649	35,157	35,649	35,811	36,883	36,956	35,244	35,347	35,355	35,249
LIABILITIES AND EQUITY													
Long Term Debt	27,035	28,038	28,239	28,380	28,131	27,434	27,423	27,196	24,999	23,401	22,719	22,321	21,373
Current and Other Liabilities	2,070	1,529	1,615	1,574	1,767	2,220	1,532	1,752	3,725	3,316	3,809	3,923	4,475
Contributions in Aid of Construction	407	415	422	430	438	446	455	463	472	482	492	502	512
Retained Earnings	3,434	3,804	4,249	4,634	5,190	5,918	6,770	7,841	8,129	8,415	8,697	8,979	9,258
Accumulated Other Comprehensive Income	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)
Total Liabilities and Equity	32,577	33,416	34,156	34,649	35,157	35,649	35,811	36,883	36,956	35,244	35,347	35,355	35,249

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
OPERATING ACTIVITIES																									
Cash Receipts from Customers	1,692	1,768	1,827	1,940	2,036	2,150	2,238	2,367	2,749	2,964	3,093	3,197	3,317	3,493	3,902	4,121	4,292	4,457	4,644	4,836	4,035	4,064	4,126	4,143	4,139
Cash Paid to Suppliers and Employees	(782)	(822)	(900)	(931)	(963)	(1,001)	(1,024)	(1,048)	(1,136)	(1,175)	(1,202)	(1,230)	(1,262)	(1,266)	(1,296)	(1,330)	(1,356)	(1,377)	(1,401)	(1,426)	(1,451)	(1,476)	(1,503)	(1,519)	(1,520)
Interest Paid	(466)	(474)	(510)	(558)	(604)	(700)	(814)	(816)	(1,030)	(1,127)	(1,090)	(1,087)	(1,095)	(1,211)	(1,438)	(1,635)	(1,623)	(1,587)	(1,609)	(1,519)	(1,490)	(1,473)	(1,457)	(1,460)	(1,451)
Interest Received	28	17	24	26	31	39	41	38	35	33	17	19	28	33	41	55	71	78	89	69	86	64	60	60	68
Cash from Operating Activities	473	488	441	477	501	489	442	542	618	695	819	899	988	1,049	1,208	1,211	1,384	1,571	1,723	1,961	1,181	1,179	1,225	1,224	1,235
FINANCING ACTIVITIES																									
Proceeds from Long Term Debt	836	2,170	1,760	1,990	2,180	2,380	1,990	1,590	1,990	1,790	1,760	1,590	990	990	190	190	(10)	(40)	(10)	(10)	(40)	140	1,520	1,980	1,920
Sinking Fund Withdrawals	129	393	102	26	-	15	416	184	265	676	156	-	-	450	-	-	60	250	700	13	230	800	200	315	355
Retirement of Long Term Debt	(119)	(808)	(176)	(312)	(347)	(530)	(829)	(306)	(635)	(679)	(432)	-	-	(450)	-	-	(60)	(220)	(700)	(13)	(200)	(2,150)	(1,730)	(2,273)	(2,330)
Other Financing Activities	(42)	(7)	(16)	(18)	(16)	(12)	(24)	(13)	(34)	(9)	(1)	(1)	(1)	(1)	(1)	(9)	(8)	(8)	(7)	(26)	(27)	(27)	(28)	(28)	(26)
Cash from Financing Activities	804	1,748	1,670	1,685	1,817	1,852	1,554	1,455	1,586	1,777	1,483	1,589	989	989	189	181	(18)	(18)	(17)	(36)	(37)	(1,237)	(38)	(6)	(81)
INVESTING ACTIVITIES																									
Property Plant and Equipment net of contributions	(1,378)	(1,913)	(2,010)	(2,041)	(2,124)	(2,023)	(1,791)	(1,635)	(1,865)	(2,199)	(2,151)	(1,943)	(1,798)	(1,596)	(1,129)	(853)	(1,056)	(977)	(919)	(781)	(758)	(788)	(788)	(830)	(866)
Sinking Fund Payment	(107)	(208)	(124)	(188)	(165)	(227)	(216)	(220)	(248)	(338)	(245)	(263)	(288)	(310)	(309)	(324)	(339)	(349)	(351)	(328)	(341)	(343)	(307)	(308)	(305)
Other Investing Activities	(17)	(16)	(21)	(20)	(32)	(42)	(28)	(28)	(33)	(38)	(29)	(32)	(25)	(25)	(28)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)	(27)	(27)
Cash from Investing Activities	(1,502)	(2,138)	(2,155)	(2,249)	(2,321)	(2,292)	(2,035)	(1,884)	(2,146)	(2,575)	(2,425)	(2,238)	(2,110)	(1,932)	(1,466)	(1,203)	(1,420)	(1,352)	(1,295)	(1,136)	(1,125)	(1,157)	(1,121)	(1,165)	(1,198)
Net Increase (Decrease) in Cash	(225)	99	(44)	(86)	(3)	49	(40)	113	58	(103)	(124)	250	(133)	106	(69)	189	(54)	201	410	789	19	(1,216)	66	52	(44)
Cash at Beginning of Year	43	(183)	(84)	(128)	(214)	(217)	(168)	(208)	(95)	(37)	(140)	(264)	(14)	(147)	(41)	(110)	79	25	225	636	1,424	1,443	228	293	346
Cash at End of Year	(183)	(84)	(128)	(214)	(217)	(168)	(208)	(95)	(37)	(140)	(264)	(14)	(147)	(41)	(110)	79	25	225	636	1,424	1,443	228	293	346	301

Development Plan 14. Preferred Case - Depreciation Sensitivity
Development Plan Scenario Econ:REF Rev:REF Cap:REF

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062
REVENUES																									
General Consumers Revenue at approved rates	1,886	1,910	1,935	1,959	1,983	2,007	2,031	2,056	2,080	2,104	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128
Additional General Consumers Revenue	1,268	1,281	1,314	1,346	1,430	1,524	1,551	1,606	1,703	1,835	1,857	1,841	1,851	1,940	1,964	1,988	2,070	2,093	2,092	2,117	2,098	2,120	2,160	2,180	2,206
Extraprovincial	1,002	981	962	974	961	954	954	964	939	935	928	968	985	1,003	1,021	1,040	1,058	1,077	1,097	1,117	1,137	1,157	1,178	1,199	1,221
Other	23	24	24	24	25	25	26	26	27	27	28	29	29	30	30	31	31	32	33	33	34	35	35	36	37
Total Revenue	4,179	4,197	4,235	4,304	4,399	4,511	4,562	4,652	4,748	4,902	4,941	4,966	4,994	5,101	5,143	5,187	5,288	5,330	5,349	5,395	5,397	5,440	5,502	5,543	5,592
EXPENSES																									
Operating and Administrative	966	987	1,010	1,032	1,062	1,087	1,113	1,146	1,174	1,210	1,240	1,269	1,300	1,331	1,364	1,385	1,418	1,439	1,460	1,482	1,504	1,526	1,549	1,564	1,588
Finance Expense	1,357	1,336	1,318	1,324	1,331	1,321	1,307	1,307	1,289	1,328	1,294	1,278	1,252	1,228	1,201	1,191	1,168	1,141	1,095	1,066	1,016	986	964	932	899
Depreciation and Amortization	865	869	875	888	906	975	983	1,002	1,046	1,076	1,092	1,115	1,130	1,215	1,241	1,259	1,336	1,374	1,408	1,451	1,472	1,510	1,556	1,600	1,643
Water Rentals and Assessments	155	155	155	156	156	156	156	157	157	157	157	163	166	169	172	175	178	181	184	188	191	194	198	202	205
Fuel and Power Purchased	317	330	355	376	412	436	462	496	533	577	609	593	604	615	626	637	649	661	673	685	697	710	722	735	749
Capital and Other Taxes	208	210	213	216	218	221	223	226	230	232	233	235	233	235	235	238	239	240	242	241	242	243	244	245	246
Corporate Allocation	7	7	7	7	7	7	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total Expenses	3,876	3,894	3,932	3,999	4,093	4,203	4,252	4,340	4,435	4,585	4,631	4,658	4,690	4,798	4,845	4,890	4,994	5,041	5,068	5,118	5,128	5,175	5,239	5,284	5,336
Non-Controlling Interest	28	30	32	34	36	38	41	43	45	47	49	49	50	51	53	53	54	55	57	59	61	63	65	66	69
Net Income	276	273	271	270	271	270	270	270	269	269	262	259	253	251	246	244	240	234	224	218	208	203	198	193	187
Additional General Consumers Revenue Percent Increase	0.96%	-0.09%	0.50%	0.49%	2.02%	2.20%	0.25%	1.00%	2.10%	2.95%	0.02%	-0.41%	0.26%	2.22%	0.59%	0.60%	1.99%	0.54%	-0.02%	0.61%	-0.46%	0.53%	0.94%	0.45%	0.61%
Cumulative General Consumers Revenue Percent Increase	67.23%	67.08%	67.91%	68.73%	72.13%	75.92%	76.36%	78.12%	81.87%	87.23%	87.26%	86.50%	86.99%	91.15%	92.27%	93.42%	97.27%	98.33%	98.29%	99.49%	98.58%	99.63%	101.51%	102.42%	103.65%
Debt Ratio	69	68	68	67	66	66	65	64	64	63	62	61	60	59	58	57	56	55	54	53	52	51	49	48	47
Interest Coverage Ratio	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.43	1.36	1.31	1.23	1.25	1.33	1.40	1.36	1.23	1.50	1.50	1.53	1.54	1.48	1.48	1.48	1.52	1.51	1.50	1.51	1.50	1.49	1.50	1.50	1.50

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
ASSETS																									
Plant in Service	52,660	53,263	54,262	55,013	57,700	58,375	59,079	61,113	62,510	63,579	64,597	65,297	67,994	69,230	70,603	71,980	73,389	74,915	76,463	77,836	79,198	80,623	82,045	83,525	85,359
Accumulated Depreciation	20,811	21,679	22,554	23,442	24,348	25,322	26,306	27,307	28,353	29,430	30,522	31,638	32,769	33,986	35,228	36,476	37,801	39,165	40,563	42,005	43,468	44,969	46,517	48,109	49,745
Net Plant in Service	31,849	31,584	31,708	31,571	33,352	33,053	32,774	33,806	34,156	34,149	34,075	33,660	35,225	35,245	35,375	35,504	35,588	35,750	35,900	35,831	35,730	35,654	35,528	35,415	35,613
Construction in Progress	621	997	1,205	1,808	272	851	1,440	712	955	1,077	1,212	1,651	137	158	128	122	215	139	29	56	72	97	140	200	(89)
Current and Other Assets	2,561	2,743	2,608	2,589	2,590	2,706	2,825	2,617	2,534	3,095	3,314	3,564	3,453	3,681	3,840	3,959	3,869	2,450	1,467	979	892	771	560	429	317
Goodwill and Intangible Assets	163	159	155	152	148	144	141	137	133	130	126	123	119	115	112	108	104	101	97	94	90	86	83	79	76
Regulated Assets	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Assets	35,194	35,483	35,676	36,120	36,362	36,754	37,180	37,273	37,780	38,450	38,727	38,997	38,935	39,199	39,455	39,693	39,776	38,440	37,494	36,959	36,784	36,609	36,310	36,124	35,917
LIABILITIES AND EQUITY																									
Long Term Debt	21,575	22,077	21,629	21,779	21,878	22,427	23,225	23,024	24,022	24,420	24,619	24,292	24,290	24,290	24,239	24,039	22,438	20,438	19,237	17,829	17,629	17,703	16,702	16,502	16,052
Current and Other Liabilities	3,932	3,436	3,796	3,808	3,670	3,231	2,577	2,590	1,818	1,810	1,616	1,943	1,618	1,621	1,671	1,843	3,264	3,671	3,679	4,311	4,106	3,631	4,112	3,910	3,943
Contributions in Aid of Construction	522	533	543	554	565	577	588	600	611	622	634	645	656	666	677	700	722	745	768	791	813	836	859	881	904
Retained Earnings	9,534	9,807	10,078	10,348	10,619	10,889	11,159	11,428	11,697	11,967	12,228	12,487	12,740	12,991	13,237	13,481	13,721	13,955	14,179	14,397	14,606	14,808	15,007	15,199	15,387
Accumulated Other Comprehensive Income	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)
Total Liabilities and Equity	35,194	35,483	35,676	36,120	36,362	36,754	37,180	37,273	37,780	38,450	38,727	38,997	38,935	39,199	39,455	39,693	39,776	38,440	37,494	36,959	36,784	36,609	36,310	36,124	35,917

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
OPERATING ACTIVITIES												
Cash Receipts from Customers	4,179	4,197	4,235	4,304	4,399	4,511	4,562	4,652	4,748	4,902	4,941	4,966
Cash Paid to Suppliers and Employees	(1,546)	(1,577)	(1,620)	(1,662)	(1,723)	(1,768)	(1,815)	(1,878)	(1,937)	(2,011)	(2,066)	(2,076)
Interest Paid	(1,429)	(1,413)	(1,399)	(1,404)	(1,419)	(1,415)	(1,403)	(1,418)	(1,404)	(1,451)	(1,436)	(1,432)
Interest Received	69	73	83	84	90	96	103	114	119	125	138	149
Cash from Operating Activities	1,274	1,280	1,299	1,322	1,347	1,424	1,447	1,471	1,525	1,566	1,578	1,606
FINANCING ACTIVITIES												
Proceeds from Long Term Debt	2,540	2,380	1,750	2,380	2,180	2,130	1,770	780	1,180	570	180	(20)
Sinking Fund Withdrawals	261	100	285	190	192	191	50	300	200	-	100	-
Retirement of Long Term Debt	(2,900)	(2,390)	(1,860)	(2,240)	(2,240)	(2,040)	(1,640)	(990)	(990)	(190)	(190)	10
Other Financing Activities	(27)	(27)	(29)	(29)	(30)	(31)	(51)	(39)	(40)	(45)	(41)	(42)
Cash from Financing Activities	(126)	63	146	300	102	250	129	51	350	335	49	(52)
INVESTING ACTIVITIES												
Property Plant and Equipment net of contributions	(913)	(956)	(1,183)	(1,330)	(1,126)	(1,229)	(1,268)	(1,280)	(1,612)	(1,164)	(1,127)	(1,113)
Sinking Fund Payment	(299)	(298)	(305)	(305)	(312)	(316)	(321)	(333)	(333)	(341)	(205)	(209)
Other Investing Activities	(28)	(28)	(28)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)	(30)
Cash from Investing Activities	(1,239)	(1,281)	(1,516)	(1,663)	(1,466)	(1,573)	(1,617)	(1,642)	(1,975)	(1,535)	(1,362)	(1,352)
Net Increase (Decrease) in Cash	(91)	62	(70)	(41)	(17)	101	(41)	(120)	(100)	366	265	202
Cash at Beginning of Year	301	211	272	202	162	145	246	205	84	(16)	350	615
Cash at End of Year	211	272	202	162	145	246	205	84	(16)	350	615	818

For the year ended March 31	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062
OPERATING ACTIVITIES													
Cash Receipts from Customers	4,994	5,101	5,143	5,187	5,288	5,330	5,349	5,395	5,397	5,440	5,502	5,543	5,592
Cash Paid to Suppliers and Employees	(2,109)	(2,146)	(2,182)	(2,220)	(2,256)	(2,293)	(2,331)	(2,368)	(2,407)	(2,446)	(2,486)	(2,518)	(2,561)
Interest Paid	(1,418)	(1,383)	(1,370)	(1,368)	(1,358)	(1,336)	(1,257)	(1,210)	(1,148)	(1,126)	(1,103)	(1,072)	(1,036)
Interest Received	159	154	165	175	186	178	145	144	133	141	147	142	138
Cash from Operating Activities	1,626	1,726	1,756	1,773	1,860	1,879	1,906	1,961	1,976	2,009	2,060	2,094	2,133
FINANCING ACTIVITIES													
Proceeds from Long Term Debt	(60)	(20)	(20)	(50)	(70)	(90)	780	1,110	2,140	1,970	1,350	1,980	1,790
Sinking Fund Withdrawals	325	-	-	50	100	800	533	200	288	-	262	131	249
Retirement of Long Term Debt	(285)	10	10	(10)	(140)	(1,520)	(1,980)	(1,920)	(2,547)	(2,380)	(1,875)	(2,380)	(2,180)
Other Financing Activities	(42)	(43)	(44)	(45)	(46)	(47)	(48)	(49)	(50)	(52)	(53)	(54)	(69)
Cash from Financing Activities	(62)	(53)	(54)	(55)	(156)	(857)	(715)	(659)	(169)	(462)	(316)	(323)	(210)
INVESTING ACTIVITIES													
Property Plant and Equipment net of contributions	(1,157)	(1,231)	(1,317)	(1,341)	(1,472)	(1,418)	(1,408)	(1,367)	(1,346)	(1,417)	(1,430)	(1,505)	(1,510)
Sinking Fund Payment	(217)	(216)	(225)	(236)	(240)	(246)	(208)	(181)	(176)	(166)	(170)	(161)	(158)
Other Investing Activities	(30)	(31)	(30)	(15)	(15)	(14)	(14)	(13)	(36)	(37)	(37)	(38)	(38)
Cash from Investing Activities	(1,405)	(1,477)	(1,572)	(1,591)	(1,727)	(1,679)	(1,629)	(1,561)	(1,558)	(1,620)	(1,637)	(1,704)	(1,706)
Net Increase (Decrease) in Cash	159	195	130	127	(23)	(656)	(439)	(260)	248	(72)	107	67	218
Cash at Beginning of Year	818	976	1,171	1,301	1,428	1,405	749	310	51	299	227	334	400
Cash at End of Year	976	1,171	1,301	1,428	1,405	749	310	51	299	227	334	400	618

REFERENCE: MIPUG/MH I-036c

QUESTION:

If the heating choice initiative is a DSM program, why is it included in the load forecast where other DSM programs are not?

RESPONSE:

The Heating Fuel Choice initiative, as outlined in Manitoba Hydro's response to PUB/MH I-253b, seeks to educate customers on their fuel choice options so customers make informed decisions when choosing between natural gas and electricity for heating. The influence of education campaigns are traditionally reflected within the Load Forecast.

REFERENCE: MIPUG/MH I-036c

QUESTION:

Please provide a calculation of the LUC of the heating choice initiative.

RESPONSE:

The objective of the Heating Fuel Choice initiative, as outlined under Manitoba Hydro's response to PUB/MH I-253b, is to educate customers on their fuel choice options so customers make informed decisions when choosing between natural gas and electricity for heating. Manitoba Hydro does not calculate LUC for education based campaigns.

REFERENCE: MIPUG/MH I-038f

PREAMBLE: The response to MIPUG/MH-1-38f indicates that the previous "Medium-High" and "Medium-Low" load forecast sensitivities were based on the "most pessimistic and optimistic" forecasts of industry economic analysts.

QUESTION:

By "most pessimistic" and "most optimistic" does Manitoba Hydro mean reviewing the main or most likely forecasts provided by each economic forecaster and selecting the one that was lowest/highest among the group, or does this mean taking the low/high scenario from each of the forecasters reviewed and using a mean of these values? If neither of the above, please describe how "most pessimistic" and "most optimistic" were determined.

RESPONSE:

In response to MIPUG/MH I-038f, Manitoba Hydro stated "The Medium Low / Medium High scenarios were based on the most pessimistic and optimistic forecasts of industry analysts." This approach was also referenced in response to MIPUG/MH I-038a. This representation of the past methodology for different economic outlooks was incorrect. Following is a detailed description of the determination of the economic outlooks used in the development of the Medium Low and Medium High load forecast scenarios.

Manitoba Hydro's forecasting methodology to develop the base case forecast of economic indicators used in the preparation of the Load Forecast is a consensus approach using a number of independent forecasters. Prior to the introduction of the current probabilistic-based approach as outlined on page 44 of the 2013 Load Forecast included as Appendix D of the submission, the former scenario-based approach to develop the low and high scenarios for economic indicators, some of which are inputs to the Load Forecast, was determined by adjusting their respective base case forecasts for the standard deviation at approximately the 2.5^{th} and 97.5^{th} percentiles.

The previous approach to calculate the low/high based scenarios for economic variables was as follows:

- Determine the last year of the low and high scenario forecast period by adjusting the last year of the base scenario by 1.95 standard deviations of historical data.
- The standard deviation was derived by statistically analyzing historical data based on the previous twenty year period.
- For each year between the start of the forecast period to the last year of the forecast period (as calculated in first point above), a method of linear interpolation was utilized to calculate the annual forecasted data.
- The medium low scenario was determined by taking the average of the low and base case scenario for each year of the forecast period.
- The medium high scenario was determined by taking the average of the high and base case scenario for each year of the forecast period.

REFERENCE: CAC/MH I-051

QUESTION:

Please provide a detailed rationale for limiting dependable energy planning to imports that can be delivered during the "off-peak" period (with an atypical definition of off-peak hours). Why must this be limited to off-peak hours? The attached report does not appear to provide any justification for this off-peak limit.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-055 and MIPUG/MH II-019c.

REFERENCE: CAC/MH I-051

QUESTION:

Why is only U.S. transmission used in determining the off-peak import capability? (per footnote 4)

RESPONSE:

The report entitles "Review of the Generation Planning Criteria", provided as an attachment to CAC/MH I-051, states at page 20 regarding imports from Ontario:

- Imports of energy from Ontario should not, at this time, be considered as dependable energy as the current Ontario market rules do not provide for firm transmission service out of Ontario, the Ontario market rules do not provide for physical delivery (the Ontario rules allow financial settlement in lieu of physical delivery), and in any event energy out of North Western Ontario is not assured in a drought as the sub-region is predominately hydro and its supply is correlated with Manitoba Hydro own hydro resources.

The same report states at page 20 regarding imports from Saskatchewan:

- For regions where there is no organized market (i.e. Saskatchewan) imports of energy on firm transmission under the terms of a bilateral contract remain a potential source of dependable energy.

Manitoba Hydro would consider off-peak imports from Saskatchewan as dependable energy provided a firm energy commitment in the form of a bilateral contract is in place. At the present time, there are no bilateral import contracts in place with Saskatchewan.

REFERENCE: CAC/MH I-051

PREAMBLE: "Imports of energy from a large power market whose resources are predominantly thermal pose very little risk of curtailment due to lack of energy supply, provided … the deliveries are scheduled in a period which does not coincide with the peak load in the power market." page 19 of the Attachment to CAC/MH-1-51

QUESTION:

Given the energy criteria is based on delivery of energy within an annual window (as opposed to capacity which mucst be delivered at the moment required) why wouldn't any times of peak hours in the entire year be considered dependable or low risk of supply interruption? For example, is it not likely that there will be weeks of relatively low power demand at some point in each given year? Shoulder months? cool summer weeks?

RESPONSE:

As noted in the response to CAC/MH I-055, "Manitoba Hydro currently has capacity export obligations over the on-peak hours during the time when no new resources are required and it would not be appropriate to assume, on the planning horizon, that Manitoba Hydro is importing during on-peak hours when in fact it has export obligations."

There would be periods of relatively low on peak demand at some points during the year- particualry during the spring and fall which is when scheduled generation unit maintenance is most often completed. The actual surplus during the spring and fall maintenance seasons can be signifcanlty less than what might be expected based on the overall supply/demand balance due the simultaneous outages of many units for scheduled maintenance.

As also stated in the response to CAC/MH I-055, "Manitoba Hydro notes that the capacity criterion contains a factor, the reserve against breakdown of plant and equipment and increase in demand above forecast, to cover uncertainty in the capacity supply/demand balance. The energy criterion contains no similar factor to cover the uncertainty in the energy supply/demand balance. There is, however, a number of sources of uncertainty in the dependable energy supply situation: transmission outages which may restrict imports to less than the 100% of the assumed 700 MW U.S. firm transfer capability for the planning horizon; the ability of the thermal generation units to perform over the longer term at the projected capacity factors; actual average annual wind generation; increased Manitoba load; and timing of water flows during a critical flow period. Further, there is always the possibility of a drought occurring worse than the drought of record. Although Manitoba Hydro does not explicitly plan for such energy contingencies, including a drought worse than the drought of record, the ability to import on-peak if necessary serves as the reserve margin to protect against loss of load during such energy contingencies."

PREAMBLE: Page 23 of the Attachment to CAC/MH-1-51

QUESTION:

Please file the latest extract dealing with Manitoba Hydro from the NERC LTRA reports.

RESPONSE:

The 2012 NERC LTRA is a public document filed at:

http://www.nerc.com/files/2012_ltra_final.pdf

Manitoba Hydro is discussed throughout the report so extracting all information is not practical. The main section discussing Manitoba is on pages 112-121.

SUBJECT: Load Forecast Sensitivities

REFERENCE: Chapter 12 page 8; MIPUG/MH I-38

PREAMBLE: This DSM sensitivity and stress test analysis can also be viewed as being representative of a lower load growth sensitivity

QUESTION:

Does Manitoba Hydro see the 4x DSM scenario as an appropriate "lowest" range of possibilities for load forecasts when comparing scenarios for the 2013 update (since load sensitivities not provided).

RESPONSE:

Adjusting the 2013 Load Forecast by the energy savings presented under the 4x DSM stress test scenario results in approximately 2100 GW.h lower net Manitoba load requirements by 2032/33 than the 1x DSM scenario (32,667 GW.h load forecast minus 2,803 GW.h under 4x DSM = 29,864 GW.h by 2032/33 compared to 32,667 GW.h load forecast minus 701 GW.h under 1x DSM = 31,966 GW.h).

This results in a forecast similar to the 10% Probabilistic-based forecast of 30,196 GW.h for 2032/33 presented at page 44 of the 2013 Load Forecast included as Appendix D of this filing. Using a forecast similar to the 10% Probabilistic-based forecast is appropriate for the purpose of a low scenario analysis.

SUBJECT: U.S. Interconnection

REFERENCE: MIPUG/MH I-020 and PUB/MH I-051a and PUB/MH I-051b

QUESTION:

If Manitoba Hydro becomes minority owner of the U.S. Interconnection (at 49%) what additional costs, extraterritorial exposure and regulatory risks are involved with ownership (e.g., related to FERC or other extraterritorial legal or regulatory jurisdiction)?

RESPONSE:

As a minority owner of the U.S. Interconnection, Manitoba Hydro would be taking on a portion of the capital costs for constructing the line and ongoing operational and maintenance costs.

The cost burden associated with minority ownership is less than if another party held those obligations and participated in the project as an investor due to Manitoba Hydro's lower cost of capital and return on equity requirements.

Manitoba Hydro is currently investigating an appropriate investment and ownership structure to minimize as much as possible any U.S. regulatory or tax exposure that financial participation in the US transmission line would create for the Corporation. A final decision on that structure has yet to be made.

SUBJECT: U.S. Interconnection

REFERENCE: MIPUG/MH I-020 and PUB/MH I-048

QUESTION:

PUB/MH I-048 has costs allocated to Manitoba Hydro for 66% of U.S. Interconnection Combined Capital and Operating Costs for plans 6, 12 and 15 and 40% of costs for plans 5 and 14. Are these same cost ratios maintained throughout the analysis period? Is it Manitoba Hydro's expectation that in practice under plans 6, 12 and 14 this responsibility would be transferred at a future date to an as yet unidentified firm power purchaser?

RESPONSE:

Yes, the same cost ratios are maintained throughout the detailed analysis period with respect to 66% of US Interconnection combined capital and operating costs for Plans 6, 12 and 15; and 40% of costs for Plans 5 and 14.

As stated in Chapter 14 page 31:

> "It is Manitoba Hydro's intent to arrange for some or all of the Manitoba Hydro ownership to be transferred to another owner for the economic benefit of Manitoba Hydro as soon as an appropriate opportunity can be developed."

SUBJECT: Hurdle Rate Policy

REFERENCE: CAC/MH I-102

QUESTION:

Please confirm that according to the hurdle rate policy (per page 3 of 6 lines 19-26 of the attachment to CAC/MH-1-102) all plans being assessed in the NFAT qualify for consideration as "low" risk projects.

RESPONSE:

Please see the response to PUB/MH I-151(c) for a description of the application of Manitoba Hydro's hurdle rate policy during analysis of the development plan, including how uncertainty and risk has been accounted for within the cash flows prior to discounting.

SUBJECT: Payments to the Government

REFERENCE: Chapter 9 page 24; PUB/MH I-073a

PREAMBLE: It must be recognized that the debt guarantee fee provides Manitoba Hydro a benefit and has the potential to incur costs to the Province. See Chapter 11 - Financial Evaluation of Development Plans for discussion of provincial borrowing and credit rating implications.

QUESTION:

Please reference a specific reference to where in Chapter 11 the "provincial borrowing and credit rating implications" are discussed. If this is an incorrect reference, please provide a reference in the NFAT filing to where Manitoba Hydro believes this information has been addressed.

RESPONSE:

Manitoba Hydro receives provincial borrowings as long term debt advances from the Province of Manitoba. Manitoba Hydro's levels of net long term debt advances are discussed throughout Chapter 11 (for example in Section 11.3).

The credit rating agencies examine Manitoba Hydro's financial performance and forecasts, and each view Manitoba Hydro's long term debt advances from the Province of Manitoba to be self-supporting. Manitoba Hydro's debt is expected to remain self-supporting in the future and Manitoba Hydro's financial forecasts, ratios and evaluations have been extensively evidenced throughout the NFAT filing (including Chapter 11 and the 216 distinct sets of pro-forma financial statements in Appendix 11.4). As described in Manitoba Hydro's response to MIPUG/MH II-001a, to the extent that Manitoba Hydro maintains its self-supporting status, Manitoba Hydro's capital investment plans should have no significant impact on the Province of Manitoba's credit rating.

SUBJECT: Load Forecast

QUESTION:

Please provide the missing page 1 of the response (the table with years 2012/13 to 2029/30 for the System Firm Winter Peak Demand and Capacity Resources (MW) @ generation No New Resources with Modified Load scenario).

RESPONSE:

The following table is The System Firm Winter Peak Demand and Capacity Resources (MW) @ generation – No New Resources Table for the 2012/13 to 2030/31 fiscal years.

Date: October 4, 2013

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
NFAT 2012 Reference
MIPUG-0043b No New Resources with modified load

Fiscal Year		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Power Resources																			
New Power Resources																			
New Hydro																			
Conawapa																			
Keeyask																			
1 **Total New Hydro**																			
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
New Imports																			
Contracted																			
Proposed																			
3 **Total New Imports**																			
4 **Total New Power Resources**	1+2+3																		
Base Supply Power Resources																			
Existing Hydro		5 166	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177	5 177
Existing Thermal																			
Brandon Coal - Unit 5		105	105	105	105	105	105	105											
Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Contracted Imports		550	550	385	385	385	385	385	385	385	385	385	385	385					
Proposed Imports				220	220	220	220	220	220	220	220	220	220	220					
Pointe du Bois Rebuild																			
Bipole III Reduced Losses							90	90	90	90	90	90	90	90	90	90	90	90	90
5 **Total Base Supply Power Resources**		**6 233**	**6 244**	**6 299**	**6 299**	**6 299**	**6 389**	**6 389**	**6 284**	**6 284**	**6 284**	**6 284**	**6 284**	**6 284**	**5 679**	**5 679**	**5 679**	**5 679**	**5 679**
6 **Total Power Resources**	4+5	**6 233**	**6 244**	**6 299**	**6 299**	**6 299**	**6 389**	**6 389**	**6 284**	**6 284**	**6 284**	**6 284**	**6 284**	**6 284**	**5 679**	**5 679**	**5 679**	**5 679**	**5 679**
Peak Demand																			
2012 Modified Load Forecas		4 491	4 609	4 676	4 789	4 895	5 025	5 162	5 210	5 280	5 348	5 416	5 485	5 554	5 622	5 689	5 757	5 826	5 894
Less: 2012 Base DSM Forecast		- 12	- 36	- 58	- 77	- 95	- 111	- 127	- 142	- 154	- 165	- 176	- 181	- 185	- 189	- 194	- 195	- 193	- 191
7 **Manitoba Net Load**		4 479	4 573	4 618	4 712	4 800	4 914	5 035	5 068	5 126	5 183	5 240	5 304	5 369	5 433	5 495	5 562	5 633	5 703
Contracted Exports		605	605	605	358	358	358	358	358	358	358	358	358	358					
Proposed Exports																			
8 **Total Exports**		605	605	605	358	358	358	358	358	358	358	358	358	358					
9 **Total Peak Demand**	7+8	**5 084**	**5 178**	**5 223**	**5 070**	**5 158**	**5 272**	**5 393**	**5 426**	**5 484**	**5 541**	**5 598**	**5 662**	**5 727**	**5 433**	**5 495**	**5 562**	**5 633**	**5 703**
10 Reserves		463	483	508	565	576	590	604	608	615	622	629	636	644	652	659	667	676	684
11 **System Surplus/(Deficit)**	6-9-10	**686**	**583**	**568**	**664**	**565**	**527**	**392**	**250**	**185**	**121**	**57**	**(14)**	**(87)**	**(406)**	**(475)**	**(550)**	**(630)**	**(708)**
12 Less: Brandon Unit 5		- 105	- 105	- 105	- 105	- 105	- 105	- 105											
Exportable Surplus	11+12	**581**	**478**	**463**	**559**	**460**	**422**	**287**	**250**	**185**	**121**	**57**							

SUBJECT: Curtailable Rate Program

REFFERENCE: MIPUG/MH I-037

QUESTION:

For the purposes of this hearing, has there been any changes to Manitoba Hydro's evidence regarding the Curtailable Rate Program evidence filed in the 2012/13 and 2013/14 General Rate Application, or is the evidence filed at that time still relevant?

RESPONSE:

Manitoba Hydro's evidence regarding the Curtailable Rate Program ("CRP") filed in the 2012/13 & 2013/14 General Rate Application is still relevant.

Please note that the implementation of the following two changes to the CRP, which were approved on an interim basis in Order 43/13, have been deferred until such time as the Public Utilities Board grants final approval: a change in the defined hours for peak and off-peak periods, and the elimination of Curtailment Options "C" and "CE".

REFERENCE: Question PUB/MH I-149a Revised

QUESTION:

Please provide Figure 11.10 in table format.

RESPONSE:

The data underlying Figure 11.10 is provided below.

1. All Gas

	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
P10	4,048	10,971	18,216	25,796	32,824	39,363	45,430	51,681	57,364	62,291
P25	4,055	11,058	18,441	26,202	33,273	39,776	46,379	52,795	58,134	63,116
P50	4,058	11,106	18,530	26,446	33,672	40,222	46,794	53,059	58,834	63,873
P75	4,065	11,193	18,744	26,798	34,117	40,593	47,313	53,740	59,782	64,846
P90	4,068	11,240	18,878	27,106	34,508	41,048	47,583	54,455	60,228	65,535

2. K22 Gas

	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
P10	4,047	10,951	18,109	25,584	32,489	38,676	44,751	50,704	56,033	60,567
P25	4,055	11,067	18,438	26,221	33,396	39,676	45,896	51,795	57,006	61,633
P50	4,059	11,143	18,650	26,663	33,974	40,400	46,807	52,790	58,192	62,587
P75	4,066	11,232	18,944	27,173	34,760	41,464	47,931	53,848	59,043	63,359
P90	4,070	11,296	19,149	27,689	35,491	42,115	48,429	54,401	59,625	64,138

7. Gas C26

	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
P10	4,052	11,050	18,446	26,297	33,397	39,384	45,201	50,834	55,903	60,448
P25	4,060	11,171	18,774	26,866	34,204	40,533	46,379	52,127	57,196	61,656
P50	4,064	11,236	18,993	27,482	35,113	41,372	47,295	53,014	58,208	62,652
P75	4,072	11,353	19,286	28,034	35,995	42,515	48,660	54,274	59,662	63,909
P90	4,076	11,426	19,515	28,498	36,733	43,391	49,596	55,369	60,286	64,607

4. K19 Gas 250mw

	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
P10	4,047	10,916	18,048	25,415	32,140	38,270	44,182	49,960	55,242	59,944
P25	4,054	11,045	18,362	25,956	32,921	39,163	45,170	51,010	56,233	60,735
P50	4,059	11,120	18,668	26,557	33,618	39,791	46,104	52,374	57,431	61,799
P75	4,066	11,232	18,903	27,208	34,643	41,088	47,447	53,242	58,561	63,134
P90	4,071	11,310	19,173	27,734	35,415	41,766	48,020	53,935	59,009	63,463

13. K19 C25 250mw

	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
P10	4,052	11,013	18,362	26,132	33,113	38,776	44,247	49,489	54,049	57,930
P25	4,061	11,181	18,810	26,953	34,227	40,313	46,021	51,401	56,194	60,045
P50	4,068	11,299	19,252	27,875	35,636	41,666	47,542	53,028	57,604	61,564
P75	4,076	11,443	19,585	28,652	36,948	43,656	49,623	55,052	59,696	63,828
P90	4,082	11,551	19,965	29,483	38,167	45,093	51,098	56,566	61,314	65,349

14. K19 Exp C25 750mw

	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
P10	4,052	11,006	18,342	26,100	32,998	38,731	44,042	49,164	53,547	57,288
P25	4,060	11,169	18,766	26,906	34,126	40,089	45,646	50,899	55,532	59,361
P50	4,067	11,295	19,219	27,776	35,378	41,215	47,046	52,513	56,951	60,802
P75	4,076	11,429	19,537	28,490	36,576	43,272	49,134	54,496	59,072	63,059
P90	4,081	11,544	19,908	29,350	37,838	44,476	50,477	55,956	60,673	64,677

12. K19 Imp C31 750mw

	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
P10	4,052	11,017	18,376	26,139	33,018	39,016	44,619	49,940	54,563	58,224
P25	4,059	11,143	18,678	26,681	33,984	40,305	46,145	51,602	56,394	60,337
P50	4,065	11,243	19,017	27,269	34,909	41,497	47,514	53,117	57,819	61,830
P75	4,072	11,348	19,279	28,021	36,210	43,340	49,577	55,185	59,917	63,919
P90	4,077	11,437	19,596	28,656	37,236	44,600	50,865	56,571	61,439	65,552

1

6. K19 Imp Gas 750mw

	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
P10	4,048	10,934	18,106	25,573	32,307	38,531	44,477	50,282	55,552	60,244
P25	4,055	11,065	18,409	26,098	33,141	39,448	45,488	51,331	56,605	61,095
P50	4,060	11,167	18,744	26,707	33,910	40,137	46,443	52,717	57,782	62,110
P75	4,068	11,260	19,008	27,426	34,966	41,482	47,845	53,572	58,872	63,394
P90	4,072	11,341	19,291	27,992	35,782	42,189	48,406	54,298	59,352	63,754

REFERENCE: Question PUB/MH I-149a Revised

QUESTION:

Please provide a copy of Appendix 11.2 showing, for each rate, the underlying interest rate assumed as compared to the debt guarantee fee (where relevant).

RESPONSE:

The attached table restates the interest rates from the comparable table in Appendix 11.2 under the reference scenario excluding the Provincial guarantee fee.

Projected Escalation, Interest and Exchange Rates
Reference Scenario

Fiscal Year Ending	2013	2014	2015	2016	2017	2018	2019	2020 & on
MB CPI	1.70	1.80	1.80	1.80	1.80	1.80	1.90	1.90
CDN CPI	1.80	2.10	2.10	1.90	1.90	1.90	1.90	1.90
Cdn GDP Deflator - % chg	1.90	2.00	2.20	1.80	1.80	1.80	1.80	1.80
US GDP Deflator - % chg	1.60	1.80	2.00	1.80	1.80	1.80	1.80	1.80
Hydro Project Escalation (real) - %				0.60				
Gas Fired Generation Projects Escalation (real) - %				0.50				
MH Short Term Cdn T-Bill Rate - % *	1.00	1.30	2.10	2.95	3.65	3.75	3.80	3.80
MH Short Term Cdn BA Rate - % *	1.35	1.65	2.40	3.25	3.95	4.05	4.10	4.10
MH Cdn Long Term Rate - % *	3.15	3.30	3.85	4.55	4.95	5.15	5.30	5.30
MH Short Term US Rate - % *	0.70	0.70	0.95	1.90	3.55	4.50	4.65	4.65
MH US Long Term Rate - % *	2.85	3.05	3.70	4.45	5.15	5.75	5.75	5.75
WACC (nominal) - %				7.05				
WACC (real) - %				5.05				
US - Cdn Exchange Rate (Cdn $/US $)	1.00	0.99	1.02	1.03	1.04	1.04	1.04	1.04
Interest Capitalization Rate - %	6.58	6.19	6.12	6.21	6.26	6.23	6.19	6.30
Provincial Guarantee Fee	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

* Excludes the Provincial guarantee fee.

REFERENCE: Question PUB/MH I-149a Revised

QUESTION:

Please explain why Manitoba Hydro projects a Short Term Canada T-Bill Rate including a Manitoba provincial debt guarantee fee? Is this intended as a borrowing rate for Manitoba Hydro? Does Manitoba Hydro issue Treasury Bills?

RESPONSE:

Manitoba Hydro issues short term debt promissory notes in its own name.

Although Manitoba Hydro does not issue Treasury Bills, on a forecast basis, the 90 day Canadian T-Bill rate is utilized as an interest rate proxy for the Corporation's short term debt. As the provincial debt guarantee fee is charged on the Corporation's year-end short term debt balances, Manitoba Hydro adds the provincial debt guarantee fee rate to the forecasted interest rate for its short term debt.

REFERENCE: Question PUB/MH I-149a Revised

QUESTION:

Please provide a detailed description of the use (if any) of the Manitoba Hydro Short term Canadian T-Bill Rate, as reported in Appendix 11.2, in any of the financial or economic calculations conducted for Appendix 9.3, Appendix 11.4, or any other part of the NFAT filing.

RESPONSE:

Interest charges are not included in the incremental cash flow analysis in the economic evaluation and as such, the MH Short Term Canadian Debt Rate or T-bill Rate is not included in the economic analysis.

For financial forecasting purposes, Manitoba Hydro's rates for projecting interest expense on short term borrowings and interest income on short term investments is equal to the Canadian T-Bill rate plus Provincial guarantee fee and is expressed as "MH Short Term Canadian T-Bill Rate" in Appendix 11.2.

For the purposes of discounting general consumers revenue and deriving the risk-free social discount rate, Manitoba Hydro uses the "MH Short Term Canadian T-Bill Rate" in Appendix 11.2 and removes the Provincial guarantee fee.

REFERENCE: Question PUB/MH I-149a Revised

QUESTION:

Please provide Figure 11.14, Figure 11.15 and Figure 11.16 using a real discount rate of 5.05%, based on the assumption of 5.05% as being representative of a real return on investment of comparable risk and duration that would be available to ratepayers.

RESPONSE:

Please see the response to PUB/MH II-432b.

REFERENCE: Question PUB/MH I-149a Revised

QUESTION:

Please provide a detailed description as to why Manitoba Hydro considers it appropriate to use a risk free discount rate of 1.86% (real) for the consumers investment in higher electricity prices now (first 20 years) in exchange for the potential for lower electricity prices in the very long term (typically years 21-50). How is that ratepayer projection "risk free"? What alternative ratepayer investments has Manitoba Hydro considered in determining 1.86% to be the reasonable real discount rate (e.g., paying down mortgages or consumer debt for residential customers, investments in plant expansions or developing new markets for industrial customers).

RESPONSE:

There are two reasons for discounting future benefits and costs in economic and financial analysis. One is to recognize the cost of capital, either the weighted average cost of debt and equity for a specific undertaking, or the opportunity cost of capital if investment funds had it been used elsewhere. The other reason for discounting is to recognize the time-value of money.

Manitoba Hydro applied a cost of capital based discount rate both in its economic analysis of the alternative resource development plans from a Manitoba Hydro perspective (Chapter 9 of the NFAT application) and in the multiple account benefit-cost analysis (Chapter 13). The discount rate from the Manitoba Hydro perspective reflects the cost of capital for the corporation (including an imputed cost for equity and the debt guarantee fee). The discount rate for the benefit-cost analysis reflects the estimated social opportunity cost of capital, a weighted average of the different sources of capital in the economy and their respective opportunity cost.

The cost of capital for Manitoba Hydro, which is equivalent to 5.05% real, was fully taken into account in the financial analysis through the projected interest expense payments in the pro forma financial statements, and it was integral to the calculation of revenue requirements and consequent rate increases over the planning period.

The 1.86% discount rate that was used for the NPV analysis of consumers revenue was not intended to reflect or replace the cost of capital, as the cost of capital is already part of the rate projections. Rather, the 1.86% is used in order to calculate a summary levelized cost indicator of the rate projections over time. The 1.86% represents the real after-tax risk-free interest rate on savings, which reflects the time-value of money, as opposed to the compensation customers require to accept different levels of risk.