

1 **SUBJECT: Capital Costs**

2

3 **REFERENCE: CAC/MH I-002a**

4

5 **QUESTION:**

6 If the P50 estimate is considered the "most likely Base Estimate amount", what does the Point
7 Estimate represent?

8

9 **RESPONSE:**

10 The Point Estimate is the risk-free, escalation-free (or bare) costs based on an initial set of
11 assumptions and current market conditions (i.e. overnight costs) (refer to Appendix 2.4 page 1
12 of 27). The Point Estimate is comprised of both the direct and indirect cost estimate, developed
13 on first principles, manufacturer quotes, general industry costs and historical costs. It does not
14 include contingency or labour management reserve.

15

16 The base estimate includes the point estimate plus contingency. A P50 base estimate would
17 include the point estimate plus P50 contingency which has an equal likelihood of cost overrun
18 or underrun.

1 **REFERENCE: Question CAC/MH I-001**

2

3 **QUESTION:**

4 Please provide a copy of the actual corporate policy/standard as originally requested.

5

6 **RESPONSE:**

7 This approach was adopted following an Executive Committee Recommendation which is not a
8 published document, but reflects the corporate direction regarding capital cost estimates for
9 new major generation and transmission where the estimated capital cost is great than \$250
10 million.

1 **SUBJECT:** Keeyask

2

3 **REFERENCE:** CAC/MH I-003a

4

5 **QUESTION:**

6 With the inclusion of the Management Reserves for Labour and Escalation, what P value is the
7 Keeyask Base Dollar cost of \$4.1 B equivalent to?

8

9 **RESPONSE:**

10 Please see Manitoba Hydro's response to PUB/MH II – 447.

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH I-003b**

4

5 **QUESTION:**

6 The response states that the \$3.3 B value used in Appendix 9.3 excludes the cost of the KIP.
7 However, if one sums the values included in the third column of the Table provided (excluding
8 the KIP) one gets \$2.93 B (2.86+0.55+0.11-0.59), not \$3.3 B. Please reconcile.

9

10 **RESPONSE:**

11 To clarify, The capital cost estimate of \$3.3 B (2014 constant dollars) provided in Table 001 of
12 Appendix 9.3 is a base dollar cost estimate for the Keeyask Generating Station only. The
13 Reference NFAT economic analysis does not include labour reserve, and capital costs incurred
14 or estimated to June 2014 (including KIP costs) as they are considered sunk costs and common
15 to all development plans.

16

17 In Manitoba Hydro's response to CAC/MH I-3 (b), to illustrate that the Keeyask capital cost
18 estimate used in the NFAT economic analysis was consistent with that used in IFF12, Manitoba
19 Hydro identified the amount of KIP costs and removed all Sunk Costs (which included KIP) and
20 de-escalated to 2012\$.

	Table 3, Appendix 2.4 (2012 dollars)	Table 001, Appendix 9.3 Economic Summary Table (Ref-Ref-Ref) (2014 dollars)	Table 001, Appendix 9.3 (2012 dollars)
Purpose of Estimate	Capital cost estimate used in the Integrated Financial Forecast IFF12	Reference capital cost estimate used in the NFAT economic analysis	De-escalated to 2012 dollars to be able to compare to Table 3 estimates
Point Estimate Keyask Infrastructure Project (KIP)	\$0.29 B	\$0.30 B	\$0.29 B
Point Estimate for Keyask Generating Station	\$2.76 B	\$2.86 B	\$2.76 B
Contingency*	\$0.53 B	\$0.55 B	\$0.53 B
Management Reserve			
• Labour Reserve	\$0.38 B	-	-
• Escalation Reserve**	\$0.12 B	\$0.11 B	\$0.10 B
Sunk Costs from March 31, 2012 to June 30, 2014		-\$0.59 B	-\$0.57 B
TOTAL BASE DOLLAR COST	\$4.1 B	\$3.3 B	\$3.1 B
Reconcile Labour Reserve	-\$0.38 B		\$0.38 B
Reconcile Escalation Reserve portion allocated to Labour Reserve	-\$0.02 B		\$0.02 B
Reconcile sunk costs	-\$0.57 B		\$0.57 B
Comparative Totals	\$3.1 B		\$4.1 B

* Reference capital cost estimate for Keyask is based on a P50 Contingency

** Reference capital cost estimate for Keyask is based on 0.6%/yr real escalation

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH 1-003b**

4

5 **QUESTION:**

6 Please explain why, for purposes of the economic analysis, the Labour Reserve was excluded
7 from the costs for Keeyask.

8

9 **RESPONSE:**

10 Please refer to Manitoba Hydro's response to PUB/MH II-447.

1 **REFERENCE: Question CAC/MH I-004**

2

3 **QUESTION:**

4 Please provide an actual copy of Corporate policy G911 as originally requested.

5

6 **RESPONSE:**

7 A copy of the Corporate Policy G911 is attached.

Subject: Projected Escalation, Interest, Exchange and Hurdle Rates
Number: G911
Revised: 2011 08 05

Contact: For interpretation or further information on this policy, contact:
Economic Forecasting Consultant

Projected Escalation, Interest and Exchange Rates

Projected escalation, interest and exchange rates will be used for:

- project evaluations
- estimates in planning studies
- all input to the Capital Expenditure Forecast (COPP 98.13)

Process of Development for Escalation, Interest, Exchange and Hurdle Rates

- Economic Analysis recommends the projected escalation, interest, market exchange and hurdle rates.
- Executive Committee authorizes the recommended escalation, interest, market exchange and hurdle rates.
- Financial Planning enters applicable projected rates into the SAP system for corporate use.

See the following for further detail:

Projected Escalation Rates—Estimates of escalation will be applied at applicable rates as outlined in the [Projected Escalation, Interest and Exchange Rates](#) (G911-1)

[Projected Interest Rates](#) (G911-2)

[Projected Exchange Rates](#) (G911-3)

[Hurdle Rates](#) (G911-4)

[Composite Index Matrix for Escalating Historical Cost Estimates](#) (G911-5)

For more information on this policy, contact:
Economic Forecasting Consultant

PROJECTED ESCALATION, INTEREST, & EXCHANGE RATES - G911-1

ITEM (Fiscal Year)	Historical					Projected**						
	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19 & on
*1. Hydro-Electric Generation Plant												
Weight												
Earthworks 0.16	5.1	7.2	-4.2	5.1	6.3							
Concrete 0.15	6.1	7.8	-5.2	7.0	5.3							
Equipment 0.25	7.3	6.8	-8.3	6.8	4.9							
Infrastructure Construction/Operation 0.21	4.9	6.7	-2.1	4.0	4.8							
Permitting, Engineering & Administration 0.23	2.7	3.0	0.1	6.0	4.7							
1.00												
Hydro Projects:												
Composite	5.2	6.1	-4.0	5.8	5.1	1.8	2.1	2.1	1.9	1.9	1.9	1.9
Escalation Rate												
*2. General Constr.(Composite)	4.4	4.6	-0.4	2.1	3.2	1.8	2.1	2.1	1.9	1.9	1.9	1.9
Labour	2.4	1.4	4.6	3.2	2.3							
Materials	6.0	7.3	-4.2	1.1	3.9							
3. M.H. long-term Cdn interest rate	5.71	5.65	5.75	5.27	4.64	4.15	4.30	4.85	5.55	5.95	6.15	6.30
4. Interest Capitalization Rate						12/13	13/14	14/15	15/16	16/17	17/18	18/19
						6.6	6.2	6.3	6.3	6.3	6.3	6.2
	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
	6.4	6.7	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
5. Weighted Average Cost of Capital (%)						----- 7.05 ----->						
*6. Consumer Price Index												
MbCPI	1.9	2.2	0.6	1.0	2.8	1.7	1.8	1.8	1.8	1.8	1.9	1.9
CdnCPI	2.1	2.2	0.4	2.0	2.8	1.8	2.1	2.1	1.9	1.9	1.9	1.9
7. Real Weighted Avg. Cost of Capital (7.05 - 1.9)/1.019 (%)						----- 5.05 ----->						
8. Real Hurdle Rates for Project Evaluation (minimum % rates of return)						----- 5.05 to 15+ ----->						
*9. GDP Price Deflator												
U.S.	2.6	2.0	0.9	1.5	2.1	1.6	1.8	2.0	1.8	1.8	1.8	1.8
Cdn.	3.3	2.9	-0.8	2.8	3.2	1.9	2.0	2.2	1.8	1.8	1.8	1.8
10. U.S. - Cdn. Exchange Rate (C\$/US\$)	1.03	1.13	1.09	1.02	0.99	1.00	0.99	1.02	1.03	1.04	1.04	1.04

* Represents current fiscal year over previous fiscal year, % change

Item 1 Historical: Model based on Keeyask costs.

Includes both Statistics Canada and Bureau of Labor Statistics indexes.

Item 2 Historical: Canadata Construction Cost Index - REED CONSTRUCTION DATA

Item 3 Average of 10 year and 30 year Canadian long bond rates plus credit spread plus Provincial guarantee fee; Historical - Bloomberg actuals provided by Manitoba Hydro Treasury.

Item 4 Provided by Financial Planning Department: interest capitalization rates based on projected embedded cost of debt.

The interest capitalization rate should only be used for budgeting purposes.

Item 5 Nominal Cost of Capital = 0.75 * MH LT Cdn. Interest Rate + 0.25 * Imputed Cost of Equity = 0.75(6.30) + 0.25(6.30 + 3) = 7.05

where a 3% premium is added to the MH LT Cdn Interest rate to impute a value for equity.

Note: The italicized items are preliminary

EFFECTIVE May 11 2012

RE-ISSUED September 11 2012

RE-ISSUED October 11 2012

Item 6 Historical: Statistics Canada - The Consumer Price Index - 62-001- X, Table 1 & Table 3

Item 7 (Nominal Cost of Capital - MbCPI)/(1 + (MbCPI/100)) - This is rounded to 5.05%

Item 8 See Application and Derivation of Hurdle Rates (G911-4) for further information

Item 9 Historical Statistics Canada - National Income and Expenditure Accounts - Table 30

U.S. Bureau of Economic Analysis - National Accounts Data - Table 5

Item 10 Historical: Bank of Canada Weekly Financial Statistics

Exchange rates reflect average for the fiscal year.

Exchange rate at March 31 2013 is projected to be 1.00.

** Projected as per Economic Outlook 2012 - Spring 2012 (EO12-1) & Fall 2012 Update;

forecasts of items 3,6, 9 and 10 are based on a consensus view from surveys of private sector forecasters.

Executive Committee Minute # 1415.03

Subject: Projected Interest Rates
Number: G911-2
Revised: 2009 06 02

[First screen of this guideline](#)

Contact: For interpretation or further information on this policy, contact:
Economic Forecasting Consultant

When evaluating and screening projects, apply the Weighted Average Cost of Capital (WACC), appropriately adjusted for the relative risk of the project (see [Hurdle Rates](#) G911-4)

Estimates of interest capitalized for Capital Project Budget Estimates included within Capital Project Justification (CPJ) submissions are calculated using rates based on the weighted average cost of debt (WACD) and the G911-1 projected long term Canadian debt rate. The rates are calculated and input to the SAP system by the Financial Planning Department.

Rates are applied to capital estimates as follows:

- Interest for the current month for a sub-project (Level 2 of the Work Breakdown Structure) is calculated on the opening month's balance of total accumulated net costs (including salvage material, salvage labour expense, customer contributions, holdbacks and outstanding accounts payable).
- Interest capitalization is to cease the month after plant additions are placed in-service

Note: The in-service date for interest capitalization and depreciation purposes is the date Corporate Controller Division is notified that a project has been placed into service.

- No interest will be applied on expenditures that are in-service when purchased (for example equipment, tool and vehicle purchases).
- No interest will be applied on expenditures for projects with an expected duration of one month or less.

Subject: Projected Exchange Rate
Number: G911-3
Revised: 2009 06 02

[First screen of this guideline](#)

Contact: For interpretation or further information on this policy, contact:
Economic Forecasting Consultant

The market U.S. exchange rate is forecast in the schedule of [Projected Escalation, Interest and Exchange Rates](#) (G911-1) and is also provided by Economic Analysis Department. This rate should be used for the evaluation of new transactions.

Example 1: New long term export sales to the United States—forecast revenues should be converted at the market rate in the Projected Escalation, Interest and Exchange Rates schedule, to make an economic evaluation of revenues as compared to costs in Canadian dollars.

Example 2: Short term transaction—current exchange rates should be applied when comparing a Canadian sale or purchase option to the U.S. option.

Example 3: Bid evaluations—current market values should be applied so that foreign bids can be assessed on a common dollar basis with Canadian bids.

Treasury Division should be consulted about the exchange rates to be used or for questions on daily or monthly market exchange rates (as for examples 2 and 3) or on the Exposure Management Program.

Reporting Revenues for the Integrated Financial Forecast (IFF)—U.S. revenue stream will initially be projected at the Cdn./U.S. market exchange rate. Firm revenues required to hedge U.S. dollar outflows may subsequently be revalued at the historical cost of existing \$U.S. designated debt issues.

Subject: Hurdle Rates
Number: G911-4
Revised: 2012 10 18

[First screen of this guideline](#)

Contact: For interpretation or further information on this policy, contact:
Economic Forecasting Consultant

Manitoba Hydro will maintain hurdle rates for purposes of evaluating the economics of investment decisions and project proposals. The hurdle rates used in the economic analyses will reflect the degrees of risk deemed to be inherent in the associated cash flows and will be categorized as:

- low risk
- low to medium risk, or
- medium to high risk

E.C 1009.05

Application and Derivation of Hurdle Rates

Capital expenditures undertaken by Manitoba Hydro are for reliability, safety, contractual, regulatory and environmental obligations and the general obligations to serve, or are undertaken for economic reasons. To evaluate the economics of a project, Manitoba Hydro utilizes business case principles involving the techniques of discounted cash flow (DCF), net present value (NPV) or internal rate of return (IRR).

See the following:

1. [Background](#)
2. [Derivation of Hurdle Rates](#)
3. [Application of Hurdle Rates](#)

[Benchmark Hurdle Rates Classifications](#)

- Low Risk
- Low to Medium Risk
- Medium to High Risk

1. Background

Three forms of economic analysis are generally used in investment decisions. The choice of which one to use is made by the analyst based on the type of project. The three forms are as follows:

1. Cost/benefit analysis is used to determine if a project is economically viable. If the benefits of the project are greater than the costs over the analysis period, considering the time value of money, the project is economically viable and has a positive cost/benefit.
2. Least cost analysis is used to determine the least cost approach given a number of available alternatives. The costs of each alternative are compared on a consistent basis over the analysis period, taking into account the time value of money, in an effort to determine the least cost alternative.
3. Internal Rate of Return (IRR) Analysis

In these analyses, Manitoba Hydro uses risk adjusted hurdle rates to discount future revenues and costs and determine whether the resulting NPV is positive. A hurdle rate is defined as the minimum expected rate of return that would be acceptable to justify making the investment. Generally, the starting point for development of a hurdle rate is the weighted average cost of capital (WACC), that is, the company's overall cost of financing. Depending on the type of project to be evaluated, a further risk premium can be added beyond that which is incorporated in the WACC to recognize additional uncertainty in future cash flows.

2. Derivation of Hurdle Rates

Manitoba Hydro's overall WACC is calculated using the cost of debt and the imputed rate for equity which are then weighted by Manitoba Hydro's target capital structure of 75% debt and 25% equity. The cost of debt is the forecast interest rate on the Government of Canada long term (10 year+) bond yield, plus provincial-federal borrowing spread and the provincial guarantee fee. The imputed cost of equity is calculated based on the fact that regulated investor owned utilities receive a regulated return on equity which is approximately 3% higher than the current market cost of new long term debt.

Therefore, Manitoba Hydro's WACC is calculated as follows:

$$\text{WACC} = (\text{Cost of Debt} \times 75\%) + (\text{Imputed Cost of Equity} \times 25\%)$$

WACC is usually used to assess investments in Manitoba Hydro's core business mix, that is, generation, transmission and distribution for domestic markets along with the types of export business in which the corporation has historically engaged. If a project falls outside of these core activities or has an unusual degree of risk, then the hurdle rate would be greater than WACC.

Risk Accounted for Outside of the Hurdle Rate

The selection of an appropriate discount rate depends on the risk associated with the cash flow projections. If future anticipated cash flows for a project have

already been adjusted to reflect a degree of uncertainty, or if risk has been accounted for by some other means, then a lower risk premium would need to be incorporated in the applicable hurdle rate.

3. Application of Hurdle Rates

Hurdle rates are applied to arrive at a quantitative determination of a project's relative acceptability. However, the economic evaluation of a project or investment is only one component in determining whether to proceed. Other factors such as ensuring the safety and reliability of the system, customer service or operational efficiency are also considered. The weighting of these components may vary for each project or investment. Therefore, a project with a positive or negative NPV may or may not be approved depending on the significance of these other components.

As a general guideline, the company provides benchmark hurdle rates classified as low, medium and high risk investments or projects. These benchmark rates (in real terms) are demarcated by 5.05%, 10% and 15%+ for low, medium and high risk projects, respectively. In practice, each cash flow component will have varying levels of risk specific to the nature of that project. Therefore the risk classification of certain projects may not precisely equal one of the benchmark categories but instead fall within the range of the guideline rates provided.

Following is a description of these guideline categories together with examples. The examples are not intended to be all inclusive but rather are illustrative indications. As noted above, the hurdle rate is partly dependent on the degree to which risk has been recognized in the cash flow projections for the specific investment and is therefore not necessarily based on the type of project. For assistance in determining the appropriate risk adjusted rate for any project, departments should contact the Economic Analysis Department or Financial Planning Department. Where a hurdle rate other than at the top end of the range in each of the following risk categories is selected, Executive approval is required.

Benchmark Hurdle Rate Classifications

Low Risk (5.05%)

A project with a low level of risk is defined as one which belongs in Manitoba Hydro's core business mix, that is, generation, transmission and distribution for domestic markets along with the types of export business in which the corporation has historically engaged. Such projects would be evaluated using WACC, that is, a real discount/hurdle rate of 5.05%.

General examples include, but are not limited to:

- projects required to meet safety, environmental or regulatory standards
- mandatory expenditures to maintain operational integrity of the system
- cost minimization/operational efficiency projects
- power resource projects (for example, demand side management, supply side enhancements and new generation) undertaken mainly to meet Manitoba Hydro's obligation to service domestic load or exports under existing contracts, and with minimal challenges and uncertainties

Low to Medium Risk (greater than 5.05% up to 10%)

A project that would be classified as ranging from low to medium risk is defined as one which belongs in Manitoba Hydro's core business mix (as defined for low risk), but which presents additional challenges and uncertainties. To recognize this exposure, a real discount/hurdle rate in the range of greater than 5.05% up to 10% is required.

General examples include, but are not limited to:

- certain customer service and joint ventures for utility services
- power loss reduction projects
- Manitoba Hydro International projects with guaranteed contracts
- power resource projects (for example, demand side management, supply side enhancements and new generation) with typical challenges and uncertainties

Medium to High Risk (greater than 10% to 15%+)

A project with a medium to high level risk is defined as one which does not belong in Manitoba Hydro's core business mix or which presents significant additional challenges and uncertainties. To recognize this exposure, a real discount/hurdle rate in the range of greater than 10% to 15%+ is required.

General examples include, but are not limited to:

- certain projects with highly uncertain cash flows which may be offered to Manitoba Hydro International
- major initiatives to gain new sources of revenue
- investments in new technology not directly related to core business

- power resource projects (for example, demand side management, supply side enhancements and new generation) with atypically high challenges and uncertainties

Composite Index Matrix for Escalating Historical Cost Estimates (G911-5)

Based on escalation rates from Item #1 of G911-1

Needs For and Alternatives To

CAC/MH II-005 - Attachment - Corporate Policy G911

	75/76	76/77	77/78	78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	87/88	88/89	89/90	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	
% chge	13.4	10.0	6.8	7.8	8.8	9.3	12.8	7.6	5.7	3.0	2.4	1.7	4.3	6.2	5.4	4.0	-0.5	0.1	3.8	5.3	3.9	3.2	4.2	3.1	4.5	4.1	-0.5	3.3	3.3	7.8	6.6	5.9	5.2	6.1	-4.0	5.8	5.1	
75/76	1.00	1.10	1.17	1.27	1.38	1.51	1.70	1.83	1.93	1.99	2.04	2.07	2.16	2.30	2.42	2.51	2.50	2.51	2.60	2.74	2.85	2.94	3.06	3.16	3.30	3.43	3.41	3.53	3.64	3.93	4.19	4.43	4.66	4.95	4.75	5.03	5.29	
76/77		1.00	1.07	1.15	1.25	1.37	1.54	1.66	1.76	1.81	1.85	1.88	1.96	2.09	2.20	2.29	2.28	2.28	2.36	2.49	2.59	2.67	2.78	2.87	3.00	3.12	3.10	3.21	3.31	3.57	3.81	4.03	4.24	4.50	4.32	4.57	4.81	
77/78			1.00	1.08	1.17	1.28	1.45	1.56	1.64	1.69	1.73	1.76	1.84	1.95	2.06	2.14	2.13	2.13	2.21	2.33	2.42	2.50	2.61	2.69	2.81	2.92	2.91	3.00	3.10	3.35	3.57	3.77	3.97	4.21	4.05	4.28	4.50	
78/79				1.00	1.09	1.19	1.34	1.44	1.53	1.57	1.61	1.64	1.71	1.81	1.91	1.99	1.98	1.98	2.05	2.16	2.25	2.32	2.42	2.49	2.60	2.71	2.70	2.78	2.88	3.10	3.31	3.50	3.68	3.91	3.75	3.97	4.18	
79/80					1.00	1.09	1.23	1.33	1.40	1.44	1.48	1.50	1.57	1.67	1.76	1.83	1.82	1.82	1.89	1.99	2.07	2.13	2.22	2.29	2.39	2.49	2.48	2.56	2.64	2.85	3.04	3.22	3.39	3.59	3.45	3.65	3.84	
80/81						1.00	1.13	1.21	1.28	1.32	1.35	1.38	1.44	1.52	1.61	1.67	1.66	1.66	1.73	1.82	1.89	1.95	2.03	2.10	2.19	2.28	2.27	2.34	2.42	2.61	2.78	2.94	3.10	3.29	3.16	3.34	3.51	
81/82							1.00	1.08	1.14	1.17	1.20	1.22	1.27	1.35	1.42	1.48	1.47	1.48	1.53	1.61	1.68	1.73	1.80	1.86	1.94	2.02	2.01	2.08	2.14	2.31	2.47	2.61	2.75	2.91	2.80	2.96	3.11	
82/83								1.00	1.06	1.09	1.11	1.13	1.18	1.26	1.32	1.38	1.37	1.37	1.42	1.50	1.56	1.61	1.67	1.73	1.80	1.88	1.87	1.93	1.99	2.15	2.29	2.43	2.55	2.71	2.60	2.75	2.89	
83/84									1.00	1.03	1.05	1.07	1.12	1.19	1.25	1.30	1.30	1.30	1.35	1.42	1.47	1.52	1.58	1.63	1.71	1.78	1.77	1.82	1.89	2.03	2.17	2.30	2.41	2.56	2.46	2.60	2.74	
84/85										1.00	1.02	1.04	1.09	1.15	1.22	1.26	1.26	1.26	1.31	1.38	1.43	1.48	1.54	1.59	1.66	1.72	1.72	1.77	1.83	1.97	2.10	2.23	2.34	2.49	2.39	2.53	2.66	
85/86											1.00	1.02	1.06	1.13	1.19	1.23	1.23	1.23	1.28	1.34	1.40	1.44	1.50	1.55	1.62	1.68	1.68	1.73	1.79	1.93	2.06	2.18	2.29	2.43	2.33	2.47	2.59	
86/87												1.00	1.04	1.11	1.17	1.21	1.21	1.21	1.26	1.32	1.37	1.42	1.48	1.52	1.59	1.66	1.65	1.70	1.76	1.90	2.02	2.14	2.25	2.39	2.29	2.43	2.55	
87/88													1.00	1.06	1.12	1.16	1.16	1.16	1.20	1.27	1.32	1.36	1.42	1.46	1.53	1.59	1.58	1.63	1.69	1.82	1.94	2.05	2.16	2.29	2.20	2.33	2.45	
88/89														1.00	1.05	1.10	1.09	1.09	1.13	1.19	1.24	1.28	1.33	1.37	1.44	1.49	1.49	1.54	1.59	1.71	1.82	1.93	2.03	2.16	2.07	2.19	2.30	
89/90															1.00	1.04	1.03	1.04	1.08	1.13	1.18	1.21	1.27	1.30	1.36	1.42	1.41	1.46	1.51	1.62	1.73	1.83	1.93	2.05	1.97	2.08	2.19	
90/91																1.00	1.00	1.00	1.03	1.09	1.13	1.17	1.22	1.25	1.31	1.36	1.36	1.40	1.45	1.56	1.67	1.76	1.85	1.97	1.89	2.00	2.10	
91/92																	1.00	1.00	1.04	1.09	1.14	1.17	1.22	1.26	1.32	1.37	1.36	1.41	1.46	1.57	1.67	1.77	1.86	1.98	1.90	2.01	2.11	
92/93																		1.00	1.04	1.09	1.14	1.17	1.22	1.26	1.32	1.37	1.36	1.41	1.45	1.57	1.67	1.77	1.86	1.98	1.90	2.01	2.11	
93/94																			1.00	1.05	1.09	1.13	1.18	1.21	1.27	1.32	1.31	1.36	1.40	1.51	1.61	1.70	1.79	1.90	1.83	1.93	2.03	
94/95																				1.00	1.04	1.07	1.12	1.15	1.20	1.25	1.25	1.29	1.33	1.43	1.53	1.62	1.70	1.81	1.74	1.84	1.93	
95/96																					1.00	1.03	1.07	1.11	1.16	1.20	1.20	1.24	1.28	1.38	1.47	1.56	1.64	1.74	1.67	1.77	1.86	
96/97																						1.00	1.04	1.07	1.12	1.17	1.16	1.20	1.24	1.34	1.43	1.51	1.59	1.69	1.62	1.71	1.80	
97/98																							1.00	1.03	1.08	1.12	1.12	1.15	1.19	1.28	1.37	1.45	1.52	1.62	1.55	1.64	1.73	
98/99																								1.00	1.04	1.09	1.08	1.12	1.15	1.25	1.33	1.41	1.48	1.57	1.51	1.59	1.68	
99/00																									1.00	1.04	1.04	1.07	1.11	1.19	1.27	1.35	1.42	1.50	1.44	1.53	1.60	
00/01																										1.00	1.00	1.03	1.06	1.15	1.22	1.29	1.36	1.44	1.39	1.47	1.54	
01/02																												1.00	1.03	1.07	1.15	1.23	1.30	1.37	1.45	1.39	1.47	1.55
02/03																													1.00	1.03	1.11	1.19	1.26	1.32	1.40	1.35	1.43	1.50
03/04																														1.00	1.08	1.15	1.22	1.28	1.36	1.30	1.38	1.45
04/05																															1.00	1.07	1.13	1.19	1.26	1.21	1.28	1.35
05/06																																1.00	1.06	1.11	1.18	1.14	1.20	1.26
06/07																																	1.00	1.05	1.12	1.07	1.13	1.19
07/08																																		1.00	1.06	1.02	1.08	1.13
08/09																																			1.00	0.96	1.02	1.07
09/10																																				1.00	1.06	1.11
10/11																																					1.00	1.05
11/12																																						1.00

An example:

\$250 million estimate made in 1999/00 and escalated to 2011/12.

Base price in 1999/00 = \$250 million

New Estimate in 2011/12 = \$250 million * (2011/12 index) / (1999/00 index)

= \$250 million * (1.60 / 1.00)

= \$400 million

Note 1: Historical Hydro Project Index Matrix to be updated annually each Spring

Note 2: Historical values may change, due to Statistics Canada revisions associated with technology changes and new items included in index

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH 1-008**

4

5 **PREAMBLE:** The response states that 25% of the capital cost of the Keeyask generating
6 station is forecast to be financed through equity by partners.

7

8 **QUESTION:**

9 What is Manitoba Hydro's assumed share of the total equity invested in the project? Please
10 provide both a dollar value and a percentage value (i.e. of the 25% total how many percentage
11 points are Manitoba Hydro's), reconciling both with the \$6.2 B total capital cost.

12

13 **RESPONSE:**

14 The NFAT financial evaluation assumes that the KCN invest in the preferred ownership
15 arrangement. Under this arrangement, the KCN will invest \$25 million plus preferred
16 distributions from first unit in-service to Joint Keeyask Development Agreement (JKDA) final
17 close and the percentage ownership will be a function of the total dollar value invested and the
18 capital cost of the Keeyask project. Based on the NFAT reference scenario capital cost of \$5.7
19 billion, Manitoba Hydro's equity investment will be \$1.3 billion or approximately 98%. Based
20 on the CEF12 capital cost of \$6.2 billion, Manitoba Hydro's equity investment in the project will
21 be \$1.4 billion or approximately 98%.

22

23 Under a common equity arrangement, the KCN may invest up to 25% of the total 25% equity in
24 the Keeyask Project and Manitoba Hydro's investment will be at least 75%.

25

26 The following schedule shows the capital structure of KHLP and calculations of owners' equity
27 based on the different project capital costs.

	KHLP Capital Structure (\$ Millions)		
	NFAT		
	Reference		
	Scenario	CEF12	
Total Project In-Service Cost	5,711	6,220	
Less:	-	-	
Transmission	(203)	(202)	
Interest on MH Equity	(174)	(196)	
KHLP Generating Station In-Service Cost	5,334	5,822	
Total Project Debt	75%	4,001	4,366
Total Project Equity	25%	1,334	1,455
<u>Preferred Arrangement:</u>			
KCN Equity Investment	32	30	
KCN Ownership Percentage	2.37%	2.07%	
MH Equity Investment	1,302	1,425	
MH Ownership Percentage	97.63%	97.93%	
<u>Common Arrangement:</u>			
KCN Equity Investment	333	364	
KCN Ownership Percentage	25%	25%	
MH Equity Investment	1,000	1,092	
MH Ownership Percentage	75%	75%	

1

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH 1-008**

4

5 **PREAMBLE:** The response states that 25% of the capital cost of the Keeyask generating
6 station is forecast to be financed through equity by partners.

7

8 **QUESTION:**

9 Is the capitalized interest of \$0.85 B (Chapter 2, Table 2.2) calculated based on the total capital
10 spending for the project or just that portion that is assumed to be debt-financed?

11

12 **RESPONSE:**

13 The capitalized interest in the amount of \$0.85 billion represents the interest on the debt
14 financed portion of the Keeyask Generating Station reflected as interest capitalized on the KHL
15 financial statements and then consolidated with Manitoba Hydro electric operations.

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH 1-008**

4

5 **PREAMBLE:** The response states that 25% of the capital cost of the Keeyask generating
6 station is forecast to be financed through equity by partners.

7

8 **QUESTION:**

9 If based on the total, why is there any need to add in an additional amount for "Interest on MH
10 Equity"?

11

12 **RESPONSE:**

13 Manitoba Hydro will finance the 75% debt portion of the Keeyask Generating Station capital
14 cost to KHLF. The interest capitalized on this portion is reflected as KHLF interest capitalized.

15 In addition, Manitoba Hydro will finance its share of the equity investment in KHLF and the
16 associated interest capitalized is reflected in the Manitoba Hydro's electric operations. When
17 KHLF is consolidated with Manitoba Hydro electric operations, the interest capitalized on the
18 KHLF debt portion (\$0.788 billion under the reference scenario) and the interest capitalized on
19 Manitoba Hydro's equity portion (\$0.174 billion) are added together (\$0.962 billion) to reflect
20 the approximate 98% share of the capital cost Manitoba Hydro is financing (excluding the
21 equity amount contributed by the KCN).

22

23 Please also see Manitoba Hydro's responses to CAC/MH II-006(a) and (b).

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH 1-008**

4

5 **PREAMBLE:** The response states that 25% of the capital cost of the Keeyask generating
6 station is forecast to be financed through equity by partners.

7

8 **QUESTION:**

9 If not based on the total capital investment cost, is the "Interest on MH Equity" calculated
10 based on the total 25% equity assumed or just on Manitoba Hydro's share of the total equity
11 (i.e., excluding the equity contributed by First Nation partners)? As part of the response, please
12 explain and provide the rationale for the treatment.

13

14 **RESPONSE:**

15 Please see the responses to CAC/MH II-006 (a) to (c).

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH I-008**

4

5 **QUESTION:**

6 Is the \$6.2 B figure the value that is used in the Financial Evaluations as the in-service cost of
7 Keeyask (Chapter 11)?

8

9 **RESPONSE:**

10 The financial evaluation incorporates nine different Keeyask capital costs based on all possible
11 combinations of low, reference and high base capital costs with low, reference and high
12 escalation and interest rates. Under these scenarios, Keeyask capital costs range from \$5.0
13 billion to \$6.7 billion and the CEF12 Keeyask capital cost of \$6.2 billion is a value within that
14 range but is not a specific capital cost used in the financial evaluation. The following table
15 shows the Keeyask capital costs under each of the nine capital cost scenarios used in the
16 financial evaluation.

17

**Preferred Development Plan
Keeyask 2019-20 In-Service Cost
Billions of Dollars**

Base Capital Cost Scenario	Economic Indicator Scenario	In-Service Cost
Low	Low	5.014
Low	Ref	5.309
Ref	Low	5.396
Low	High	5.640
Ref	Ref	5.711
High	Low	5.979
Ref	High	6.075
High	Ref	6.334
High	High	6.740

1 **REFERENCE: CAC/MH I-008**

2

3 **SUBJECT: Keeyask**

4

5 **QUESTION:**

6 If not, what is the value used and why is it different?

7

8 **RESPONSE:**

9 Please see Manitoba Hydro's response to CAC/MH II-007(a).

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH I-008**

4

5 **QUESTION:**

6 Is "Interest on MH Equity" included in the in-service Keeyask capital cost for purposes of the
7 financial evaluations and why is its inclusion/exclusion appropriate?

8

9 **RESPONSE:**

10 Interest on Manitoba Hydro's equity portion is included in the NFAT financial evaluation. The
11 combined interest capitalization on the KHP debt portion and Manitoba Hydro's equity portion
12 (excluding the KCN equity contribution) represents the interest charges on the total amount
13 Manitoba Hydro is financing on the Keeyask project. Please also see the responses to CAC/MH
14 II-006(a)-(d).

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH I-010**

4

5 **QUESTION:**

6 Please confirm that the "dollars spent to March 31, 2012" are captured in the IFF12 forecast
7 balance sheets and, similarly, in the forecast balance sheets provided in Appendix 11.4.

8

9 **RESPONSE:**

10 Confirmed, costs spent to March 31, 2012 are included in the opening balance of Construction
11 in Progress in each development plan and scenario in Appendix 11.4.

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH I-010**

4

5 **QUESTION:**

6 If not, how are these costs accounted for in the financial evaluations?

7

8 **RESPONSE:**

9 Please see Manitoba Hydro's response to CAC/MH II-008.

1 **SUBJECT: Keeyask**

2

3 **REFERENCE: CAC/MH I-010 and CAC/MH I-134**

4

5 **QUESTION:**

6 Was the Labour Reserve for Keeyask also excluded from the economic evaluations? Also, was
7 the escalation reserve included or excluded for purposes of the economic evaluations?

8

9 **RESPONSE:**

10 Please refer to Manitoba Hydro's response to PUB/MH II-447 for an explanation of where
11 labour reserve and the respective escalation reserve on the labour reserve was and was not
12 included in the NFAT economic and financial evaluations. The escalation reserve, as described
13 in Appendix 2.4 of the NFAT submission, was applied to the capital cost estimates for Keeyask.

1 **SUBJECT: Conawapa**

2

3 **REFERENCE: CAC/MH I-013**

4

5 **QUESTION:**

6 Why was the Labour Reserve excluded from the capital costs of Conawapa used for purposes of
7 the economic evaluations?

8

9 **RESPONSE:**

10 Please refer to Manitoba Hydro's response to PUB/MH II-447.

1 **SUBJECT: Transmission Reliability**

2

3 **REFERENCE: CAC/MH I-014 a**

4

5 **QUESTION:**

6 Why is the criteria the largest single piece of equipment as opposed to say the loss of the entire
7 Bipole III line due to a single event such as adverse weather?

8

9 **RESPONSE:**

10 The loss of a largest single piece, i.e. the HVdc valve group, is the most frequent outage that
11 occurs in Manitoba Hydro's HVDC operation experience and similar experience is expected for
12 Bipole III operation. Therefore, the valve outage is considered when evaluating the firm transfer
13 capability of HVdc system. The performance of the three-bipole system meets the NERC
14 reliability performance standard, including the contingency of Bipole III loss.

1 **SUBJECT: Transmission Reliability**

2

3 **REFERENCE: CAC/MH I-014a , CAC/MH I-18b**

4

5 **QUESTION:**

6 Alternatively, if a single piece of equipment out of service is the relevant consideration then
7 why aren't the 900 MW and 1,000 MW HVDC poles (noted in page 10 of the attachment to
8 CAC/MH 1-051) the relevant consideration?

9

10 **RESPONSE:**

11 As indicated in the response to CAC/MH II-13a, the Manitoba Hydro system can meet the NERC
12 reliability standard for the loss of a 2000MW bipole, so the loss of a 900-1000MW pole is not a
13 reliability concern for the Manitoba Hydro system. A pole loss has been studied historically in
14 addition to valve losses and bipole losses. The loss of 900-1000MW pole is a low probability
15 event (< 1%) as stated in Appendix 13 of the NFAT submission, therefore it is not considered to
16 be an economically attractive option to cover for this loss with additional spare HVdc capability
17 when evaluating the firm transfer capability of the HVdc system.

1 **SUBJECT: Capital Costs**

2

3 **REFERENCE: CAC/MH 1-017b and CAC/MH 1-018b**

4

5 **QUESTION:**

6 Please confirm that the \$331 M cost for the Manitoba portion was used in the NFAT economic
7 evaluations and whether it was also used for the NFAAT financial evaluations?

8

9 **RESPONSE:**

10 As stated in Manitoba Hydro's response to CAC/MH I-018b, the \$331 million cost for the
11 Manitoba portion of the 750 MW US interconnection was the in-service cost which includes
12 interest and escalation.

13

14 The base estimate of \$267 million (2012\$) was used in the NFAT Economic evaluations. Adding
15 interest and escalation to this base estimate yields the \$331 million in-service cost.

16

17 The \$331 million in-service cost was used in the NFAT financial evaluations.

1 **SUBJECT: Capital Costs**

2

3 **REFERENCE: CAC/MH I-018b**

4

5 **QUESTION:**

6 Was the updated capital cost of \$350 M incorporated into the 2013 Update (Chapter 12)? If
7 not, why not?

8

9 **RESPONSE:**

10 The increase in estimate from \$331 million to \$350 million reflects an updated in-service cost
11 estimate for the Manitoba portion of the 750 MW US interconnection. This information was not
12 available for inclusion in the economic analysis for the 2013 Update (Chapter 12). Please refer
13 to Manitoba Hydro's response to CAC/MH I-018b.

1 **SUBJECT: Partnership Agreements**

2

3 **REFERENCE: CAC/MH I-022a and CAC/MH I-024**

4

5 **QUESTION:**

6 For purposes of the financial projections, what percentage of KCN ownership interest was
7 assumed (per CAC/MH 1-024)?

8

9 **RESPONSE:**

10 As indicated in the response to MIPUG/MH I-017(a), the percentage of KCN equity ownership
11 ranges from 1.9% to 2.5% depending upon the capital cost scenario. Under all scenarios, the
12 KCN are projected to invest \$25 million plus preferred distributions from first unit in-service to
13 final close and the percentage ownership will be a function of the total dollar value invested
14 and the capital cost of the Keeyask project. The response to CAC/MH II-006(a) provides the
15 calculation of the KCN ownership interest in terms of total dollar value as well as percentage
16 interest under the reference scenario.

1 **SUBJECT: Partnership Agreements**

2

3 **REFERENCE: CAC/MH I-024**

4

5 **QUESTION:**

6 Please provide the projected financial statement for the Keeyask Partnership of the first year
7 that Keeyask is in-service all year and provide a schedule that sets out how the annual
8 distribution for the preferred-unit partners would be calculated based on these results.

9

10 **RESPONSE:**

11 Please see the response to CAC/MH II-076 for the KHLP projected operating statement.

12

13 The following schedule provides the calculation of the projected KCN Preferred Distribution for
14 the 2022/23 fiscal year.

KCN Preferred Distribution Calculation
Millions of Dollars

	<u>2022/23</u>		
Keeyask Partnership Revenue			293.004
Marketing Risk Fee			<u>(8.790)</u>
Revenue Net of Marketing Risk Fee			284.214
Less:			
Amortization of Pre-Construction Capital Expenditures			(4.126)
Operating and Administration			(15.269)
Interest on Pre-Construction Costs			<u>(17.740)</u>
Adjusted Gross Revenue			247.079
	% Share per		
	1% of KCN	KCN	
	Ownership	Ownership	
	Interest	Interest	
Share of Adjusted Gross Revenue:			
Adjusted Gross Revenue \$0 to \$250 million	0.8%	2.37%	4.685
Adjusted Gross Revenue \$250 million to \$1 billion	1.2%	2.37%	-
Adjusted Gross Revenue > \$1 billion	1.6%	2.37%	<u>-</u>
1 KCN Preferred Distribution			4.685

1 **REFERENCE: Question CAC/MH I-022b**

2

3 **QUESTION:**

4 Does the non-controlling interest shown in the financial statements in Appendix 11.4 only
5 reflect the preferred dividends projected to be paid to the KCN or does it include other items as
6 well?

7

8 **RESPONSE:**

9 The non-controlling interest shown in the financial statements in Appendix 11.4 also includes
10 NCN's share of the projected net income or loss from the Wuskwatim Power Limited
11 Partnership.

1 **SUBJECT: Partnership Agreements**

2

3 **REFERENCE: CAC/MH I-022 b)**

4

5 **QUESTION:**

6 If other items are included what are they and how will their values vary under the various
7 scenarios?

8

9 **RESPONSE:**

10 The attached schedule shows the breakdown of non-controlling interest between NCN's 33%
11 share of WPLP income and losses and preferred distributions to the KCN.

**Development Plan
Scenario**

**K19 Sales C25 750 MW
Economics:REF Rev:REF Cap:REF**

Fiscal Year Ending 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	
NCN's Share (33%) of WPLP Net Income	(14)	(24)	(23)	(17)	(14)	(13)	(9)	(9)	(7)	(4)	(2)	2	4	0	2	4	5	8	10	11	13	15	17	18	19	
KCN's Preferred Distributions before repayments	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	6	6	6	6	7	7	7	7	7	7	7
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	

**Development Plan
Scenario**

**K19 Sales C25 750 MW
Economics:REF Rev:HIGH Cap:REF**

Fiscal Year Ending 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
NCN's Share (33%) of WPLP Net Income	(14)	(24)	(19)	(12)	(10)	(7)	(4)	(3)	1	3	6	9	11	11	13	15	17	20	22	24	26	28	29	32	37
KCN's Preferred Distributions before repayments	-	-	-	-	-	-	-	-	-	7	7	8	8	9	9	9	9	10	10	11	11	11	12	13	13
Non-Controlling Interest	(14)	(24)	(19)	(12)	(10)	(7)	(4)	(3)	1	10	13	17	19	20	22	25	27	30	32	35	37	39	41	44	50

**Development Plan
Scenario**

**K19 Sales C25 750 MW
Economics:REF Rev:LOW Cap:REF**

Fiscal Year Ending 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
NCN's Share (33%) of WPLP Net Income	(14)	(24)	(27)	(21)	(19)	(18)	(13)	(14)	(16)	(13)	(11)	(6)	(4)	(11)	(10)	(8)	(7)	(4)	(3)	(1)	1	3	5	4	0
KCN's Preferred Distributions before repayments	-	-	-	-	-	-	-	-	-	3	3	3	3	3	3	3	3	3	4	4	4	4	4	3	3
Non-Controlling Interest	(14)	(24)	(27)	(21)	(19)	(18)	(13)	(14)	(16)	(10)	(8)	(3)	(1)	(8)	(7)	(5)	(3)	(1)	1	3	5	7	9	8	4

**Development Plan
Scenario**

**K19 Sales C25 750 MW
Economics:REF Rev:REF Cap:REF**

Fiscal Year Ending 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
NCN's Share (33%) of WPLP Net Income	20	22	24	26	27	29	31	33	35	37	38	38	39	40	41	41	42	43	45	46	48	49	51	53	55
KCN's Preferred Distributions before repayments	8	8	8	8	9	9	9	10	10	10	10	11	11	11	11	12	12	12	13	13	13	13	14	14	14
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	64	66	69

**Development Plan
Scenario**

**K19 Sales C25 750 MW
Economics:REF Rev:HIGH Cap:REF**

Fiscal Year Ending 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
NCN's Share (33%) of WPLP Net Income	40	43	45	49	52	54	57	60	62	65	67	67	69	70	72	74	75	76	78	80	82	84	87	89	92
KCN's Preferred Distributions before repayments	13	13	15	15	15	16	17	17	18	18	18	19	19	19	20	20	21	21	22	22	22	23	23	24	24
Non-Controlling Interest	53	56	60	64	67	70	74	77	80	83	85	86	88	90	92	94	96	97	99	102	105	107	110	113	116

**Development Plan
Scenario**

**K19 Sales C25 750 MW
Economics:REF Rev:LOW Cap:REF**

Fiscal Year Ending 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
NCN's Share (33%) of WPLP Net Income	(0)	1	2	2	3	4	5	7	8	9	9	8	8	9	9	10	10	11	12	12	13	14	15	16	18
KCN's Preferred Distributions before repayments	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	6
Non-Controlling Interest	3	4	5	6	7	8	9	10	11	13	13	12	13	13	14	14	15	15	16	17	19	20	21	22	23

1 **SUBJECT: Partnership Agreements**

2

3 **REFERENCE: CAC/MH I-022b**

4

5 **QUESTION:**

6 If other items are also included, please provide the annual distribution of preferred dividends to
7 KCN for the preferred development plan under the following cases:

8 i) Economic:REF/Rev:REF/Capital:REF;

9 ii) Economic:REF/Rev:HIGH/Capital:REF and

10 iii) Economics:REF/Rev:LOW/Capital:REF

11

12 **RESPONSE:**

13 Please see the response to CAC/MH II-019b.

1 **SUBJECT: Export Contract**

2

3 **REFERENCE: CAC/MH I-027a**

4

5 **QUESTION:**

6 Unless otherwise agreed to in the sale arrangement, would these sales to MP and WPS
7 normally trigger charges (under the Manitoba Hydro Tariff) that would be payable to Manitoba
8 Hydro? If so, what are the current Manitoba Hydro Tariff charges for such service?

9

10 **RESPONSE:**

11 Under normal conditions, Manitoba Hydro would earn Transmission Revenues under the
12 Manitoba Hydro Open Access Transmission Tariff (OATT) for transmission services provided to
13 Manitoba Hydro transmission customers. For Firm Point-to-Point electricity sales, Manitoba
14 Hydro transmission service charges would be \$4,673.29 \$MW-MO (per megawatt for one
15 month). This would include Schedule 1 - Scheduling, System Control and Dispatch Service;
16 Schedule 2 - Reactive Supply and Voltage Control from Generation Sources Service; and
17 Schedule 7 - Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service.

18

19 The Coordination Agreement with MISO and Manitoba Hydro waives transmission service
20 charges to encourage open access (to avoid transmission “pancaking” of tariff rates in multiple
21 jurisdictions). The waiving of transmission charges is reciprocal and occurs in the following
22 cases:

- 23 • MISO shall waive all transmission service charges for Point-to-Point Transmission Service
24 involving service from a generating source located either inside or outside the ISO Tariff
25 Zone to load in the Manitoba Hydro Zone.
- 26 • Manitoba Hydro shall waive all transmission service charges for Point-to-Point
27 Transmission Service involving service from a generating source inside or outside the
28 Manitoba Hydro Zone to a load that is located inside the ISO Tariff Zone.

1 Therefore, for electricity sales to Minnesota Power (MP) and Wisconsin Public Service
2 Corporation (WPS) from Manitoba Hydro, the transmission service charges within Manitoba
3 would be waived under the Coordination Agreement.

4

5 For electricity sales from MP and WPS to Manitoba Hydro, there would be no transmission
6 service charges within Manitoba since there is no transfer pricing agreement. Manitoba Hydro
7 Energy Marketing (the customer in this case) and Transmission are both owned by Manitoba
8 Hydro.

1 **SUBJECT: Export Contract**

2

3 **REFERENCE: CAC/MH I-027b**

4

5 **QUESTION:**

6 What are the current MISO Tariff charges for such service and what share would accrue to
7 Manitoba Hydro?

8

9 **RESPONSE:**

10 MISO posts the tariff rates on their public website, which are adjusted from time to time (and
11 vary according to specific transaction). When Manitoba Hydro enters into a long term sale with
12 an export customer, that company pays the MISO tariff fee. With respect to the new U.S.
13 Interconnection, Manitoba Hydro has yet to determine whether it will be a registered
14 Transmission Owner in MISO. As a result, it is not possible to say definitively whether it would
15 share in any MISO revenues from the new transmission line as provided for under the MISO
16 Tariff.

1 **SUBJECT: Export Markets**

2

3 **REFERENCE: CAC/MH I-033**

4

5 **QUESTION:**

6 Are the on-peak and off-peak price forecasts in Slide 33 meant to reflect on-peak and off-peak
7 opportunity prices? If not, what do they represent and how does this differ from forecast on-
8 peak and off-peak opportunity prices used in the economic and financial evaluations?

9

10 **RESPONSE:**

11 Manitoba Hydro notes that the Reference CAC/MH I-033 in turn references slide 33 of
12 Appendix 3.1 which is Brattle's report "Long Term Price Forecast to Manitoba Hydro's Export
13 Market in MISO" dated March 2013. Slide 33 contains forecasts of On-Peak and Off-Peak
14 Energy prices on a chart labeled "Annual Average Energy and Capacity Prices".

15

16 The On-Peak and Off-Peak Energy forecasts on Slide 33 can be considered The Brattle Group's
17 expectations for day-ahead market prices, under the specified scenario assumptions, for the
18 MRO-west region (which includes Minn Hub) of MISO. Manitoba Hydro's surplus opportunity
19 energy would generally be sold into the MISO Day Ahead market or sold under short term
20 bilateral contracts at pricing based on the current short term expectations in the MISO Day
21 Ahead Market.

22

23 The value of Capacity shown on the Annual Average Energy and Capacity Prices represents the
24 annual value of Capacity divided by the 8760 hours (All Hours) in a year. For the purpose of
25 preparing the electricity export price forecast, Manitoba Hydro allocates the annual value of
26 Capacity over the 4170 hours in the On Peak period.

- 1 Manitoba Hydro applies the consensus On-Peak Energy Forecast when forecasting revenues
- 2 from the export of on-peak opportunity energy. Off-peak opportunity energy is valued at the
- 3 Off-Peak Energy price. In its forecast of opportunity revenues, Manitoba Hydro also accounts
- 4 for additional value related to short-term forward sales and revenues from non flow related
- 5 market transactions.

1 **SUBJECT: Export Markets**

2

3 **REFERENCE: CAC/MH I-037 a) and PUB/MH I-235 b)**

4

5 **QUESTION:**

6 What rate(s) of inflation would have to be used in order to translate the constant 2013 U.S. in
7 Figure 3.13 into nominal dollars over the period 2013-2034?

8

9 **RESPONSE:**

10 The set of electricity price forecasts shown in Figure 3.13 in Chapter 3 of the NFAT submission
11 are from the March 2013 report on “Long-Term Price Forecast for Manitoba Hydro’s Export
12 Market in MISO – The Brattle Group” as provided in Appendix 3.1 of the NFAT submission.

13

14 The US GDP Deflator inflation rates, as provided in page 1 of Appendix 11.2 of the NFAT
15 submission, should be used to convert the 2013 US constant dollars to nominal dollars.

1 **SUBJECT: Load Forecast**

2

3 **REFERENCE: CAC/MH I-043 and CAC/MH I-047 b**

4

5 **QUESTION:**

6 Please confirm that by not accounting for non-persistence of savings achieved to date the
7 2027/2028 load forecast is understated by almost 500 GWh (per Figure 4.10).

8

9 **RESPONSE:**

10 Not confirmed. The starting year of the Load Forecast is based upon weather adjusted actual
11 energy consumption. As the starting point is actual energy consumption, it is assumed to reflect
12 all energy savings achieved to date due to past codes & standards and Power Smart program
13 activity and, as no additional future adjustments are made to this base year consumption, the
14 energy savings achieved to date is assumed to persist.

1 **SUBJECT: Load Forecast**

2

3 **REFERENCE: CAC/MH I-043 and CAC/MH I-047 b**

4

5 **QUESTION:**

6 If not confirmed, please explain why and what, if any, understatement does exist.

7

8 **RESPONSE:**

9 Please refer to Manitoba Hydro's response to CAC/MH II-026a.

1 **SUBJECT: Load Forecast**

2

3 **REFERENCE: CAC/MH I-048**

4

5 **QUESTION:**

6 Does the load forecast assume the introduction of any new codes/standards after 2027/28? If
7 yes, what are they and when are they assumed to come into effect?

8

9 **RESPONSE:**

10 The load forecast does not assume the introduction of any new codes/standards after 2027/28.

1 **REFERENCE: CAC/MH I-075b**

2

3 **PREAMBLE:** The congestion component of the LMP at Manitoba Hydro Electric Board
4 has been negative for most of the time since 2011.

5

6 **QUESTION:**

7 Will the Great Northern Transmission Line to be constructed by MP reduce the Congestion
8 Component?

9

10 **RESPONSE:**

11 As noted in Chapter 6, Section 6.5.3 New Transmission Interconnection, “the new transmission
12 interconnection is an international transmission line, with two distinct components – the
13 Manitoba-Minnesota Transmission Project (MMTP) in Manitoba and the Great Northern
14 Transmission Line (GNL) in Minnesota. The interconnection would have an incremental
15 transfer capability of 750 MW for both exports from and imports into Manitoba.” Both
16 components are required for the line to function.

17

18 Manitoba Hydro anticipates that in the future, under the preferred development plan,
19 increased exports will be achieved on the larger interconnection with the 750 MW
20 interconnection upgrade (i.e. Great Northern Transmission and the Manitoba Minnesota
21 Transmission Project), and as a result the future relative congestion levels are not expected to
22 change significantly from recent historic levels.

23

24 Also, as noted in the response to CAC/MH I-031, “In the future, Manitoba Hydro anticipates this
25 regional transmission planning process will help minimize future congestion in the MISO
26 market. However should Keeyask and Conawapa proceed without a new major interconnection,
27 additional off-peak congestion at Minnesota Hub and at the MHEB LMP node can be expected as

1 a significant proportion of the surplus energy that these projects would produce would have to sold
2 in the off peak hours.”

3

4 Some degree of a negative congestion component at the MHEB node is to be expected as
5 Manitoba Hydro was a significant net exporter most times during the January 2011- August
6 2013 period as shown in the response to CAC/MH 1-075b. Net importing regions tend to have
7 positive congestion components in their locational marginal prices while net exporting regions
8 tend to have a negative congestion component.

1 **SUBJECT: Export Markets**

2

3 **REFERENCE: CAC/MH I- 075b**

4

5 **PREAMBLE:** The congestion component of the LMP at Manitoba Hydro Electric Board
6 has been negative for most of the time since 2011.

7

8 **QUESTION:**

9 Will the proposed 500 MW Minnesota-Manitoba Transmission project (particularly the U.S.
10 portion) further reduce the Congestion Component?

11

12 **RESPONSE:**

13 As explained in the response to CAC/MH I-031, Manitoba Hydro is not proposing to build a 750
14 kV, or a 500 MW interconnection. As indicated in Section 2.4 page 56 of the NFAT filing, “The
15 proposed Manitoba-Minnesota Transmission Project is a 750 MW, 500 kV AC transmission
16 line.”

17

18 Please see Manitoba Hydro’s response to CAC/MH II-030a.

1 **SUBJECT: Imports**

2

3 **REFERENCE: CAC/MH I-086**

4

5 **QUESTION:**

6 With respect to column 5 in the Table provided, what was the off-peak transmission limit used
7 to determine the values of Plans 4 and 14? In each case, please indicate how this limit was
8 determined.

9

10 **RESPONSE:**

11 As shown in Table 5.8 of the NFAT Business Case the firm transfer capability of the existing U.S.
12 interconnection is 700 MW.

13

14 For Plan 4 (K19/Gas/250MW) the 250 MW U.S. interconnection is assumed for planning
15 purposes to have a firm transfer capability for imports of 50 MW, bringing the total firm import
16 capability to 750 MW.

17

18 For Plan 14 (K19/C25/750MW (WPS Sale & Inv)) the new US interconnection is assumed to have
19 an import capability of 750MW. In the NFAT submission, for energy planning purposes
20 Manitoba Hydro assumed the ability to import energy on the new interconnection on a
21 guaranteed basis at 375 MWh/hr during the off-peak hours. When added to the existing
22 interconnection, the total firm transmission service for planning purposes is 1075 MW.

1 **SUBJECT: Imports**

2

3 **REFERENCE: CAC/MH I-094**

4

5 **QUESTION:**

6 Please explain why, under New Imports, the Capacity is shown as "Proposed" but the
7 Dependable Energy is shown as "Contracted" and explain what the difference is between the
8 two designations.

9

10 **RESPONSE:**

11 The Supply and Demand Tables for the K19/C31/750MW development plan are shown on Pages
12 31 to 36 of Appendix 4.2.

13

14 The K19/C31/750MW development plan accommodates a six year deferral of the Conawapa
15 G.S. through the additional import capability provided by the new interconnection.

16

17 The Proposed Imports for the 2025/26 through to the 2030/31 fiscal years in the New Power
18 Resources section of the Winter Peak Capacity Supply and Demand Table reflect future capacity
19 purchases that will be required to defer Conawapa. These capacity imports are classified as
20 "Proposed" as there is no contract currently in place for these future purchases and it is
21 assumed that the purchases will be made at some time in the future closer to the need date.
22 Similarly the dependable energy import purchases which enable the deferral of Conawapa to
23 2031 are shown as Market Purchases in the Base Supply Power Resources section of the
24 Dependable Energy Supply and Demand Table.

- 1 The Contracted Imports shown in the in the New Power Resources Section of the Dependable
- 2 Energy Supply and Demand Tables are related to signed contracts which are contingent upon
- 3 new resources and are therefore shown in the New Power Resources section of the table.

1 **SUBJECT: Imports**

2

3 **REFERENCE: CAC/MH I-094**

4

5 **QUESTION:**

6 Please explain why, under New Imports, the Capacity values only extend to 2030/31 where as
7 the Dependable Energy values extend to 2035/36. Are both not associated with the same
8 purchase arrangements?

9

10 **RESPONSE:**

11 Please refer to Manitoba Hydro's response to CAC/MH II-032a.

12

13 The purchases shown in the New Imports Sections of the Winter Peak Capacity and the
14 Dependable Energy Supply and Demand Tables are not associated with the same purchase
15 arrangements.

1 **SUBJECT: Imports**

2

3 **REFERENCE: CAC/MH I-095**

4

5 **QUESTION:**

6 If the one-year on-peak import is reflected as an increase in Market Purchases for 2024/25, why
7 doesn't the level of Market Purchases decrease in 2025/26 (as opposed to increasing)?

8

9 **RESPONSE:**

10 Total Dependable Imports for each year of the development plan is based on the Generation
11 Planning Criteria which limits the total quantity of dependable imports to that which can be
12 imported during the off-peak period. For the K19/C25/250MW development plan a one-year
13 on-peak import contract in 2024/25 was also included to cover a one year dependable energy
14 deficit prior to the earliest in-service date of Conawapa and this is reflected in the Market
15 Purchases of the Dependable Energy Supply and Demand Table located on Page 42 of
16 Appendix 4.2.

17

18 Based on the Generation Planning Criteria total off-peak imports on 750 MW of firm import
19 transmission (700 MW existing interconnection plus 50 MW from new interconnection)
20 amounts to 3291 GWh. For the 2024/25 fiscal year total imports, including Contracted,
21 Proposed and Market Purchases, amounts to 3489 GW.h which includes a 198 GW.h on-peak
22 purchase.

23

24 For the 2025/26 fiscal year total imports amounts to 3291 GWh. If the quantity of Contracted
25 Imports had remained the same in 2025/26 Market Purchases would have decreased. The
26 increase in Market Purchases in the 2025/26 fiscal year is a result of the decrease in Contracted
27 Imports in that year.

1 **SUBJECT: NPV**

2

3 **REFERENCE: CAC/MH 1-101**

4

5 **PREAMBLE:** The response states that the economic analysis includes the cost and
6 benefits Manitoba Hydro experiences in proceeding with the projects.

7

8 **QUESTION:**

9 Please confirm that the economic analysis also includes the costs (i.e. equity contributions) and
10 benefits (i.e. income sharing) that participating First Nations will experience.

11

12 **RESPONSE:**

13 Not confirmed.

14

15 As stated in Manitoba Hydro's response to CAC/MH I-101, "The economic analysis does not
16 include any equity contributions from the participating First Nations and the income sharing.
17 These are not project capital costs and are accounted for in the financial analyses."

1 **SUBJECT: NPV**

2

3 **REFERENCE: CAC/MH I-102**

4

5 **QUESTION:**

6 Please provide an actual copy of Manitoba Hydro's updated Hurdle Rate Policy.

7

8 **RESPONSE:**

9 Please see Manitoba Hydro's response to CAC/MH II-005.

1 **SUBJECT: Capital Costs**

2

3 **REFERENCE: CAC/MH I-103**

4

5 **QUESTION:**

6 Under CGAAP are all such costs considered "expenses" or would some be capitalized?

7

8 **RESPONSE:**

9 The economic analysis only recognizes such costs as incremental cash flows and does not
10 distinguish between operating and capital accounting treatment. The financial evaluation in
11 Chapter 11 classifies equipment replacement and refurbishments costs which extend the useful
12 life of the generating station as capital and are amortized over the life of the asset. These costs
13 can be seen beyond the in-service date of Keeyask in the Net Capital Expenditure table for the
14 Preferred Development Plan in Appendix 11.1 (p.6). Operating costs are recognized in the
15 financial evaluation in the period in which they are incurred.

1 **SUBJECT: Rate Impacts**

2

3 **REFERENCE: CAC/MH I-103**

4

5 **QUESTION:**

6 Are these replacement costs all treated as O&M for purposes of the financial analyses
7 performed in Chapter 11?

8

9 **RESPONSE:**

10 Please see Manitoba Hydro's response to CAC/MH II-036(a).

1 **SUBJECT: NPV**

2

3 **REFERENCE: CAC/MH I-111**

4

5 **QUESTION:**

6 What is the impact on Table 13.3 of assuming that 75% of incremental investment is debt
7 financed?

8

9 **RESPONSE:**

10 As described in Manitoba Hydro's response to CAC/MH I-111, for the economic analysis of all
11 15 development plans analyzed in Chapter 9, a simplifying assumption was made that 80% of
12 the capital costs will be debt financed. However, the provincial debt guarantee fee information
13 in Table 13.3 was not derived through this economic assumption, but rather was prepared
14 using the debt guarantee fees calculated for the eight development plans in the financial
15 evaluation (Chapter 11). The financial evaluation assumed even-annual rate increases in order
16 to achieve the targeted 75:25 debt:equity ratio by the end of 2031/32, and consequently the
17 provincial debt guarantee fees tabulated in Table 13.3 were based on the projected capital
18 structure and debt balances from year-to-year for each development plan (reference scenario).
19 Financial projections in which the capital structure is held at 75:25 in each year are not
20 available. Conceptually, financial projections assuming a constant 75:25 capital structure would
21 show significantly higher rate increases in the near term of the projections, thereby generating
22 additional cash flow such that the levels of debt financing and debt guarantee fees would be
23 reduced during this timeframe.

1 **SUBJECT: NPV**

2

3 **REFERENCE: CAC/MH I-111**

4

5 **QUESTION:**

6 What is the impact on Table 13.3 of assuming that 75% of incremental investment is debt
7 financed?

8

9 **RESPONSE:**

10 Table 13.3 was prepared recognizing that the debt:equity ratio of the corporation increases in
11 the near term and returns to 75:25 in time. The values in Table 13.3 were based on detailed
12 financial modeling of the entire corporation for each of the four development plans presented.
13 The financing model for a specific development plan does not change the total debt of the
14 corporation, and thus will not alter the debt guarantee fee that is calculated in Table 13.3.

15

16 Estimates of the debt guarantee that were calculated using the 1% interest charge on 80% of
17 the capital were used in determining the transfers to the province in the probabilistic
18 evaluation for the 27 development plans Chapter 10, figure 10.8 page 19 and Chapter 9
19 Figure 9.3 page 25.

1 **SUBJECT: NPV**

2

3 **REFERENCE: CAC/MH I-111**

4

5 **QUESTION:**

6 Can a reasonable estimate of this impact on debt guarantee fee revenues be determined by
7 multiplying the values in Table 13.3 by 93.75% (i.e. 75/80)?

8

9 **RESPONSE:**

10 Please see Manitoba Hydro's response to CAC/MH II-037b.

1 **SUBJECT: NPV**

2

3 **REFERENCE: CAC/MH I-122**

4

5 **QUESTION:**

6 Based on the historical trends in water rental rates is it reasonable to assume that they will
7 remain fixed over the next 35 years?

8

9 **RESPONSE:**

10 Manitoba Hydro assumes that water rentals will be fixed over the life of the analysis because
11 there have been no indications from the province that they will increase the rental rate. It is
12 possible the rates could be increased or decreased. Should the water rentals increase, this
13 would result in a decrease in the NPV of the Manitoba Hydro benefits (or the “Market Valuation
14 Account” of Chapter 13) but would be offset by an equivalent increase in the Transfers to
15 Government (or the “Manitoba Government Account” of Chapter 13).

1 **SUBJECT: NPV**

2

3 **REFERENCE: CAC/MH I-124**

4

5 **QUESTION:**

6 Please clarify the definition of the \$22.3/MWh by indicating whether it is in real or nominal \$
7 and whether the discount rate used to derive the levelized price is the same as that used in the
8 reference case economic evaluation.

9

10 **RESPONSE:**

11 As stated in Manitoba Hydro's response to CAC/MH I-124, the 22.3 is the mean of the 9-point
12 representation of Figure 2.3 of Appendix 9.3. The calculation of the mean considered the
13 probability weightings associated with Manitoba Hydro's forecasts of natural gas and carbon
14 prices for carbon and gas across the nine scenarios identified in Figure 2.3. The 22.3 is
15 expressed in units of \$/MWh in real dollars and was determined by using the 5.05% discount
16 rate used in the reference case economic evaluation.

1 **REFERENCE: Question CAC/MH I-143**

2

3 **QUESTION:**

4 Please provide materials from the credit rating agencies that review Manitoba's provincial debt
5 and bond ratings that substantiates the claim "that the Corporation's net debt levels are
6 excluded from this ratio".

7

8 **RESPONSE:**

9 The ratio referenced in this information request is net tax-supported provincial debt as a
10 percent of provincial GDP. As stated in Manitoba Hydro's response to CAC/MH I-143:

11 "The ratio of net tax-supported provincial debt as a percent of provincial GDP is a
12 measure used by organizations such as credit rating agencies in their review of
13 provincial debt levels. However, as Manitoba Hydro's long-term debt advances are
14 considered to be self-supporting, the Corporation's net debt levels are excluded from
15 this ratio. Therefore, the ratio of Manitoba Hydro's net debt as a percentage of
16 provincial GDP for each year in the study period is not an appropriate measure when
17 reviewing Manitoba Hydro's debt levels, and organizations such as credit rating agencies
18 do not use this measure in their analysis of Manitoba Hydro."

19

20 Credit rating reports for Manitoba Hydro and the Province of Manitoba were filed by Manitoba
21 Hydro in response to PUB/MH I-085(a) and (b).

22

23 The credit rating agency reports for the Manitoba Hydro-Electric Board do not include ratios
24 comparing Manitoba Hydro's debt to provincial GDP. This measure is not used by credit rating
25 agencies in their analysis of Manitoba Hydro.

1 As demonstrated in the 2013 credit rating reports for the Province of Manitoba, as filed in
2 PUB/MH I-085b, each of the credit rating agencies exclude Manitoba Hydro's debt from their
3 ratios of provincial debt as a percentage of provincial GDP.

4

5 **Moody's:**

6 On page 6 of the July 23, 2013 report from Moody's on the Province of Manitoba, Moody's has
7 a schedule which takes the total Provincial "Direct and Indirect Debt" (for example \$30.531
8 billion for 2013F) and then subtracts Manitoba Hydro debt, Manitoba HydroBonds and
9 Promissory Notes, and sinking funds in order to calculate a "*Net Direct and Indirect Debt*"
10 (\$18.321 billion for 2013F). As also shown in this schedule, Moody's calculated Net Direct and
11 Indirect Debt (which excludes Manitoba Hydro's net debt) was then used to determine the
12 percentage of debt to GDP. In the following excerpt from page 2 of the same report, Moody's
13 also utilizes debt levels that exclude net Manitoba Hydro debt when describing the provincial
14 debt ratios: "As a percentage of GDP, net direct and indirect debt remained relatively stable,
15 hovering around 30% between 2007-08 to 2012-13."

16

17 **S&P:**

18 On page 10 of the September 13, 2013 report from S&P on the Province of Manitoba, S&P
19 differentiates between tax-supported debt and self-supporting debt. "At the end of fiscal 2013,
20 tax-supported debt (adjusted for sinking funds) stood at an estimated C\$18.5 billion, ... Net self-
21 supported debt, which includes debt issued for Manitoba Hydro, was C\$9.6 billion." S&P's debt
22 to GDP ratios in the report exclude Manitoba Hydro's self-supporting debt and specifically refer
23 to the Province's tax-supporting debt. For example, on page 10 of the same report S&P states
24 that: "In fiscal 2013, tax-supported debt increased to 33% of GDP."

1 **DBRS:**

2 On page 1 of the October 11, 2013 report from DBRS on the Province of Manitoba, DBRS
3 includes a table of financial information that defines the provincial debt levels as being “tax-
4 supported debt + unfunded pension liabilities.” By definition, these tax-supported debt levels
5 and the associated debt/GDP ratios exclude Manitoba Hydro’s self-supported debt.

1 **REFERENCE: Question CAC/MH I-143**

2

3 **QUESTION:**

4 If no such materials can be provided, please respond to the initial information request as posed.

5

6 **RESPONSE:**

7 Please see Manitoba Hydro's response to CAC/MH II-041a.

1 **REFERENCE: Question CAC/MH I-150**

2

3 **QUESTION:**

4 Please provide the 2013 Update's forecast of the various interest rates set out in Appendix 11.2
5 - as requested in the initial interrogatory.

6

7 **RESPONSE:**

8 Please see the attached table.

**Projected Escalation, Interest and Exchange Rates
2013 Update**

Fiscal Year Ending	2014	2015	2016	2017	2018	2019	2020 & on
MB CPI	1.80	2.00	2.00	2.00	2.00	2.00	2.00
CDN CPI	1.50	2.00	2.00	2.00	2.00	2.00	2.00
Cdn GDP Deflator - % chg	1.80	1.80	1.80	1.80	1.90	1.90	1.90
US GDP Deflator - % chg	1.90	2.10	1.90	2.00	2.00	2.00	1.90
Hydro Project Escalation (real) - %				0.60			
Gas Fired Generation Projects Escalation (real) - %				0.50			
MH Short Term Cdn T-Bill Rate - %	2.05	2.45	3.35	4.25	4.70	4.90	4.90
MH Short Term Cdn BA Rate - %	2.35	2.75	3.65	4.55	5.00	5.20	5.20
MH Cdn Long Term Rate - %	4.50	4.85	5.20	5.95	6.40	6.75	6.75
MH Short Term US Rate - %	1.65	2.00	2.55	4.20	5.05	5.45	5.55
MH US Long Term Rate - %	4.35	4.80	5.30	6.00	6.50	6.90	7.10
WACC (nominal) - %				7.50			
WACC (real) - %				5.40			
US - Cdn Exchange Rate (Cdn \$/US \$)	1.02	1.01	1.01	1.03	1.03	1.03	1.03
Interest Capitalization Rate - %	6.20	5.88	5.92	6.03	6.09	6.07	6.12

1 **REFERENCE: Question CAC/MH I-152b**

2

3 **QUESTION:**

4 Please reconcile Manitoba Hydro's choice of 6% real as the social opportunity cost of capital
5 with the Treasury Board of Canada's recommendation that 8% is the appropriate value.

6

7 **RESPONSE:**

8 The rationale for using a 6% discount rate in the MABCA is provided on pages 5-6 of Chapter 13.

9 It is consistent with recent research and it is more reflective of a provincial perspective than an
10 8% rate. Specifically, in the weighted average opportunity cost of capital there is likely to be
11 greater weight on inflows of capital than displacement of other investment than what Treasury
12 Board Secretariat might assume for Canada as a whole.

1 **QUESTION:**

2 Please provide copies (or internet links to copies) to both the Burgess and Zerbe study and the
3 M. Moore et. al. study referenced in footnote #7.

4

5 **RESPONSE:**

6 The requested articles are protected by copyright and as such Manitoba Hydro is not able to
7 provide copies. The articles can be purchased online at the following links:

- 8
- <http://www.degruyter.com/view/j/jbca.2011.2.2/jbca.2011.2.2.1065/jbca.2011.2.2.1065.xml>
 - <http://www.degruyter.com/view/j/jbca.2013.4.issue-1/jbca-2012-0008/jbca-2012-0008.xml>.
- 9

1 **REFERENCE: Question CAC/MH I-152c**

2

3 **QUESTION:**

4 In work Marvin Shaffer did for Manitoba Hydro regarding the Wuskwatim Project (Chapter 13,
5 footnote #5) did he provide any view as to what the appropriate social opportunity cost of
6 capital was? If so, please indicate what they were.

7

8 **RESPONSE:**

9 The Wuskwatim benefit-cost analysis used a 6% to 8% discount rate. It was noted that the low
10 end of the range is more appropriate for projects which result in greater outside borrowing
11 (capital inflows) than displacement of other investment. Please also see Manitoba Hydro's
12 response to CAC/MH II-044.

1 **REFERENCE: Question CAC/MH I-152c**

2

3 **QUESTION:**

4 Has Marvin Shaffer provided any recent (i.e., last five years) evidence/opinion as to the
5 appropriate real social opportunity cost of capital to be used in benefit-cost analysis? If so,
6 please provide.

7

8 **RESPONSE:**

9 Dr. Shaffer summarizes the issues and historical research concerning the weighted average
10 opportunity cost of capital-based discount rate on pages 124-127 of his text ***Multiple Account***
11 ***Benefit-Cost Analysis***, University of Toronto Press, 2010.

1 **SUBJECT: Project Benefits**

2

3 **REFERENCE: CAC/MH I-153a**

4

5 **QUESTION:**

6 Please explain more fully why the social opportunity cost of capital is the appropriate discount
7 rate if the Market Valuation account is looking at the project from "the point of view of
8 Manitoba Hydro and its project partners".

9

10 **RESPONSE:**

11 The purpose of benefit-cost analysis is to assess the benefits and costs of a project (or in this
12 case development plan) from the point of view of society as a whole. It typically starts with the
13 analysis of benefits and costs from the point of view of the investor or implementing agency
14 (the incremental revenues and expenditures the project entails) and then makes a series of
15 adjustments to capture benefits and costs to other parties (taxpayers, consumers, workers, the
16 environment, affected communities) not fully reflected in the project incremental revenues and
17 expenditures. In other words, adjustments are made to move from the investor perspective to
18 the broader social point of view.

19

20 All of the benefits and costs (the project incremental revenues and expenditures and social
21 adjustments) are estimated each year over the life of the investment or planning period. Then
22 they are discounted to calculate the equivalent net present value of the annual cash flows. A
23 discount rate reflecting the weighted average opportunity cost of capital is generally used.

24

25 A primary difference between the multiple account and the more traditional benefit-cost
26 analysis is that the social adjustments are disaggregated by account to highlight trade-offs as
27 opposed to just a bottom line, and not all of the benefits and costs are monetized, to recognize

1 that for some consequences dollar estimates of value would not be reliable or considered
2 appropriate.

3 The market valuation account in a multiple account benefit-cost analysis is in effect the starting
4 point for any traditional benefit-cost analysis as discussed above. It captures the benefits and
5 costs (incremental revenues and expenditures) from the point of view of the investor or
6 implementing agency. It is called the market valuation account because it reflects the value of
7 the project outputs and inputs at market prices.

8

9 In the case of the analysis presented in Chapter 13, the market valuation account captures the
10 incremental revenues and expenditures for Manitoba Hydro and its project partners – what
11 they receive from incremental export and other surplus sales, and what they pay to develop the
12 new facilities and operate the system.

13

14 While capturing the consequences for Manitoba Hydro and its project partners, the annual
15 benefits and costs in this market valuation account are still part of the benefit-cost analysis.
16 They are considered along with the social adjustments – the estimated net benefits or costs to
17 government, consumers, workers, the environment and affected communities not fully
18 reflected in the incremental revenues and expenditures – in order to assess the net benefits
19 from the perspective of society as a whole. Consequently, when the incremental revenues and
20 expenditures for Manitoba Hydro and its partners are discounted to determine their equivalent
21 present values, they are discounted at the same social opportunity cost of capital rate as the
22 benefits and costs in all of the other accounts.

1 **SUBJECT: Project Benefits**

2

3 **REFERENCE: CAC/MH I-153a**

4

5 **QUESTION:**

6 If the Market Valuation account looks at the project from the point of view of Manitoba Hydro
7 and its partners, what point of view does the economic evaluation undertaken in Chapter 9 look
8 at the project from - given it includes the same costs and benefits?

9

10 **RESPONSE:**

11 The present values in Chapter 9 are calculated at Manitoba Hydro's discount rate. It provides an
12 economic analysis of the consequences for Manitoba Hydro and its partners. Chapter 13 is a
13 benefit-cost analysis of the consequences for Manitoba as a whole.

1 **REFERENCE: Question CAC/MH I-158**

2

3 **QUESTION:**

4 What is the basis for Manitoba Hydro's view that the various Plans will not have disproportional
5 impacts on: i) urban vs. rural Manitobans or ii) low vs. high income Manitobans. In responding,
6 please address the fact the various Plans will result in different patterns of future rate
7 increases.

8

9 **RESPONSE:**

10 How different income classes and urban versus rural residents will be affected will depend on
11 overall cumulative rate increases, rate structure and use. What the multiple account analysis
12 indicates is that consumers as a whole will face higher rate increases in the short to medium
13 term and lower rate increases over the long term with the preferred plan as compared to the
14 alternatives. The impact on different residents in the different groups in those time periods will
15 vary depending on their use characteristics and on future rate structure decisions.

1 **REFERENCE: CAC/MH I-156a**

2

3 **PREAMBLE:** The NFAAT Application states: "This account (i.e. the Manitoba Economy
4 account) assess the consequences of the different plans for the Manitoba Economy".

5

6 **QUESTION:**

7 Does Manitoba Hydro agree or disagree with the premise that the different plans will have
8 different effects on the disposable income that Manitoba ratepayers will have to spend/save?

9 If it disagrees, please explain why?

10

11 **RESPONSE:**

12 To the extent Manitobans' power bills are affected, there may be impacts on their ability to
13 save or spend on other things.

1 **REFERENCE: CAC/MH I-156a**

2

3 **PREAMBLE:** The NFAAT Application states: "This account (i.e. the Manitoba Economy
4 account) assess the consequences of the different plans for the Manitoba Economy"

5

6 **QUESTION:**

7 If Manitoba Hydro agrees, please indicate where/how the economic and social implications of
8 these impacts are accounted for in its multiple account analyses.

9

10 **RESPONSE:**

11 As explained in the response to CAC/MH I-156a, benefit-cost analysis is not the same as
12 economic impact analysis. The purpose of the economic activity account is to estimate
13 potential employment net benefits (in economic terms, economic rents) where wages paid
14 differ from the workers' opportunity cost. It is not clear what economic impacts may occur due
15 to more or less spending on power bills. Most important, Manitoba Hydro is unaware of any
16 evidence to support that such impacts would have a significant effect on the employment net
17 benefits (wages in excess of opportunity costs).

1 **REFERENCE: CAC/MH I-159**

2

3 **PREAMBLE:** Manitoba Hydro has declined to provide the requested information on the
4 basis that the suggested approach is inappropriate.

5

6 **QUESTION:**

7 Does Manitoba Hydro agree that assessing the appropriateness of the analytical approaches
8 taken by Manitoba Hydro in preparing its NFAAT application falls within the scope of the
9 current NFAAT Review and, in particular, is part of determining whether the "preferred and
10 alternative resource and conservation evaluations are complete, accurate, thorough,
11 reasonable and sound"? If not, why not?

12

13 **RESPONSE:**

14 The response to this Information Request contemplates production of a legal argument which
15 matter is not appropriately part of the evidence of Manitoba Hydro.

1 **REFERENCE: CAC/MH I-159**

2

3 **PREAMBLE:** Manitoba Hydro has declined to provide the requested information on the
4 basis that the suggested approach is inappropriate.

5

6 **QUESTION:**

7 If yes, why is it appropriate for Manitoba Hydro to decline to provide information requested
8 simply on the basis that it does not agree with the approach suggested?

9

10 **RESPONSE:**

11 Please see the response to CAC/MH II-050a.

1 **REFERENCE: CAC/MH I-159**

2

3 **PREAMBLE:** Manitoba Hydro has declined to provide the requested information on the
4 basis that the suggested approach is inappropriate.

5

6 **QUESTION:**

7 Please provide a response to CAC/MH 1-159 as originally posed.

8

9 **RESPONSE:**

10 The use of the requested information in the multiple account benefit-cost analysis would be
11 misleading and methodologically incorrect.

12

13 Both the market valuation account and the cumulative rate increases included in the customer
14 account reflect the impact of the development plans on customers. The addition of the present
15 value of both accounts would double count the development plans net benefits (or costs) in the
16 summary table provided in Table 13.9. That would be methodologically incorrect.

1 **REFERENCE: CAC/MH I-159**

2

3 **PREAMBLE:** The response states: "It would be incorrect to calculate the present value
4 of the customer rate impact and add it to the other monetized accounts because it
5 would overlap with what is already reflected in the market valuation account"

6

7 **QUESTION:**

8 Please explain more fully why the calculation would overlap with what is already reflected in
9 the market valuation account.

10

11 **RESPONSE:**

12 The net present value costs calculated in the market valuation account indicate the net costs
13 that customers will have to pay for. To then calculate a net present value of the rate impact
14 effects discussed in the customer account would double count the net cost impact, since that is
15 what the rate impacts reflect.

1 **REFERENCE: CAC/MH I-159**

2

3 **PREAMBLE:** The response states: "It would be incorrect to calculate the present value
4 of the customer rate impact and add it to the other monetized accounts because it
5 would overlap with what is already reflected in the market valuation account"

6

7 **QUESTION:**

8 Please explain how this overlap differs from the overlap that exists between what is included in
9 the Market Valuation Account and the Government Account.

10

11 **RESPONSE:**

12 The government account captures the adjustment needed in a multiple account benefit-cost
13 analysis to recognize that some of what is included in the market valuation account as a cost to
14 Manitoba Hydro (and therefore to its customers) is simply a transfer to the government.
15 Therefore, this amount constitutes an offsetting benefit from an overall Manitoba point of
16 view. In other words, the government account adjusts for those amounts included as Manitoba
17 Hydro expenditures that are not resource costs from an overall Manitoba perspective.

1 **REFERENCE: CAC/MH I-159**

2

3 **PREAMBLE:** The response states: "It would be incorrect to calculate the present value
4 of the customer rate impact and add it to the other monetized accounts because it
5 would overlap with what is already reflected in the market valuation account"

6

7 **QUESTION:**

8 Please explain why it is inappropriate to include the overlap related to customer rates but
9 appropriate to include the overlap associated with the items included in the Government
10 Account.

11

12 **RESPONSE:**

13 Please see Manitoba Hydro's response CAC/MH II-051b.

1 **REFERENCE: Question CAC/MH I-159**

2

3 **QUESTION:**

4 Please confirm that the purpose of the Rate Impact segment of the Manitoba Hydro Customer
5 Account is to consider the relative impact on rates and what customers will pay for electricity in
6 the short to medium vs. longer term under the various plans. If not confirmed, what is the
7 purpose?

8

9 **RESPONSE:**

10 The description is correct.

1 **REFERENCE: Question CAC/MH I-159**

2

3 **QUESTION:**

4 Please explain more fully why using Manitoba Hydro's value for the social opportunity cost of
5 capital "overstates estimates of the social time preference". In particular, why is the fact that
6 the cost of capital is already reflected in the rate relevant, when the purpose is to look at the
7 impact of the resulting rates on customers over different time frames.

8

9 **RESPONSE:**

10 The social opportunity cost of capital is a weighted average of the different sources of capital in
11 an economy (savings, displaced investment and increased borrowing from outside the
12 jurisdiction) and their respective costs. The social rate of time preference is the rate at which
13 people would willingly trade-off present for future consumption opportunities (or present
14 versus future benefits or costs). The time preference rate is commonly estimated by the after-
15 tax interest rate on savings because that is the rate at which people are compensated for
16 trading off present for future consumption opportunities.

1 **REFERENCE: Question CAC/MH I-159**

2

3 **QUESTION:**

4 In Manitoba Hydro's view, what would be the appropriate discount rate to use and why?

5

6 **RESPONSE:**

7 Manitoba Hydro believes that for the multiple account benefit-cost analysis, consistent with
8 standard benefit-cost practice, a social opportunity cost of capital should be used to calculate
9 present value benefits and costs. That is what was done for all of the present value calculations
10 in Chapter 13.

1 **REFERENCE: CAC/MH I-159**

2

3 **PREAMBLE:** Table 13.9 in the Application shows comparative total monetized net
4 benefits (costs) on a PV basis for a number of the Multiple Accounts for various Plans.

5

6 **QUESTION:**

7 For each of the Multiple Accounts where a monetized PV has been calculated please indicate
8 what discount rate was used and why that rate was considered appropriate.

9

10 **RESPONSE:**

11 As stated in the response to CAC/MH II-052c, Manitoba Hydro considers it appropriate to use a
12 discount rate reflecting the social opportunity cost of capital for benefit-cost analysis, and that
13 is what was used for all of the present value calculations in Chapter 13 and summarized in Table
14 13.9. The social opportunity cost of capital used in this analysis is 6%.

1 **REFERENCE: Question CAC/MH I-040a and CAC/MH I-172b**

2

3 **QUESTION:**

4 Please prepare a response to CAC/MH 1-172 b) using an own price elasticity estimate of -0.06
5 for all customer classes and assuming that Manitoba Hydro's current load forecast is consistent
6 with real electricity price growth of 0% per year.

7

8 **RESPONSE:**

9 Using a real price increase of 2% per year, and assuming a price elasticity of -0.06, the following
10 table shows the effect the price increase would have on the electricity consumption forecast.

Fiscal Year	2013 Gross Firm Energy (GW.h)	Forecast With Assumed Price Effect (GW.h)	Price Effect (GW.h)
2013/14	25239	25209	-30
2014/15	25676	25615	-61
2015/16	26013	25920	-93
2016/17	26322	26197	-125
2017/18	26606	26448	-158
2018/19	27003	26811	-192
2019/20	27398	27171	-227
2020/21	27789	27527	-263
2021/22	28197	27897	-300
2022/23	28605	28268	-338
2023/24	29013	28636	-377
2024/25	29418	29002	-416
2025/26	29822	29365	-457
2026/27	30225	29727	-499
2027/28	30625	30085	-541
2028/29	31041	30456	-585
2029/30	31453	30824	-629
2030/31	31863	31189	-674
2031/32	32265	31545	-720
2032/33	32667	31900	-767

11

1 **REFERENCE: CAC/MH I-175a**

2

3 **QUESTION:**

4 Please explain why it is the high upfront cost of the two hydro plants that leads to the Preferred
5 Plan being affected by the discount rate. Doesn't the the choice of discount rate have more
6 impact on the valuation of costs/benefits in subsequent future years as opposed to the
7 "upfront" years?

8

9 **RESPONSE:**

10 As stated in Manitoba Hydro's response to CAC/MH I-175a, the discount rate is one of the
11 highest impact factors across all development plans in the economic evaluations. Discounting
12 reduces the influence of events that occur at a later time. The development plans with a large
13 upfront cost are affected because the benefits associated with those costs occur much later
14 than the costs do, and as such, these benefits need to be larger to offset the costs.
15 Development plans that have both costs and benefits distributed over the planning horizon are
16 less sensitive to the discount rate.

1 **REFERENCE: CAC/MH I-176a and CAC/MH I-184a**

2

3 **QUESTION:**

4 Please provide a graphic that for each of the Plans evaluated sets out its expected NPV on one
5 axis and its 10th percentile NPV value on the other axis.

6

7 **RESPONSE:**

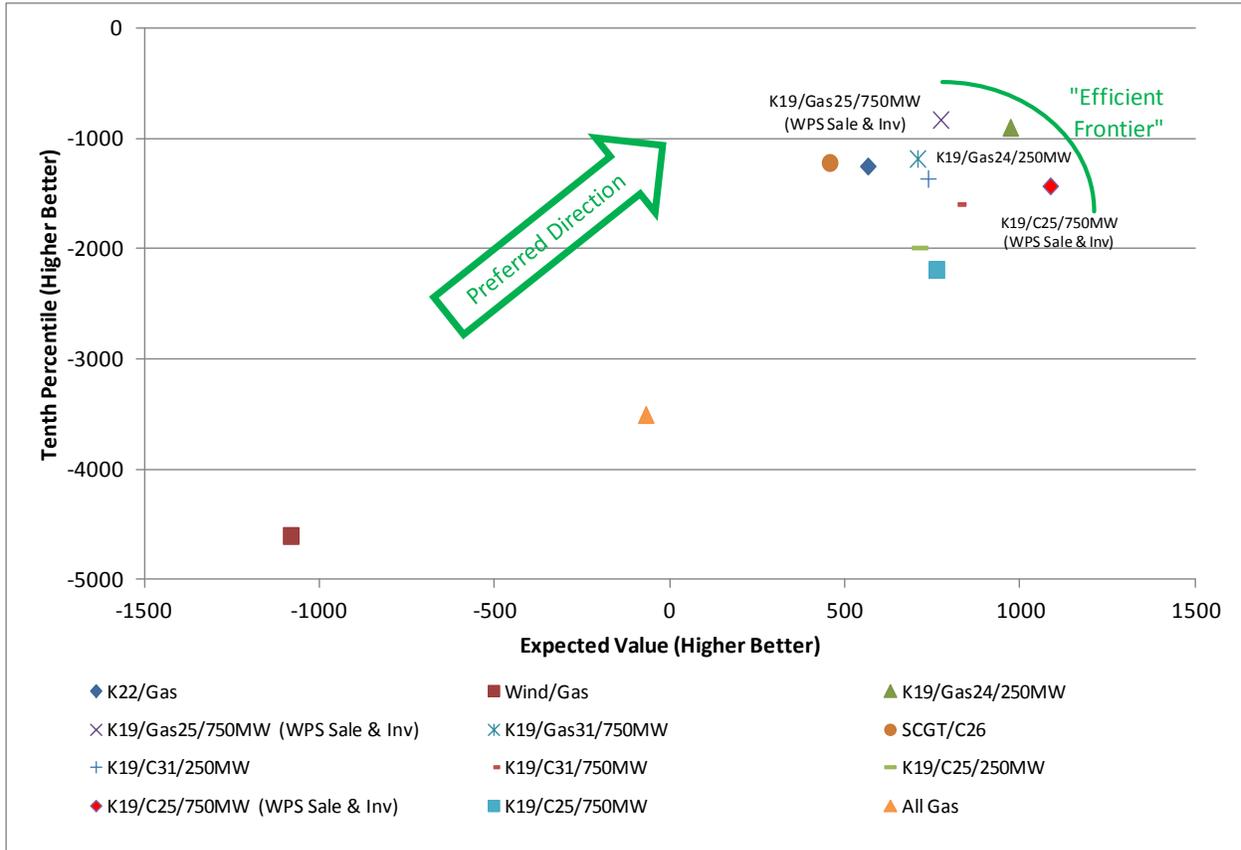
8 Financial investment alternatives are sometimes displayed on an X-Y plot with the expected
9 value of the return on one axis (a fundamental measure of return) and the standard deviation
10 of the return on the other axis (a fundamental measure of risk). Such plots are an outgrowth of
11 modern portfolio theory that dictates that investments should be chosen based on mean and
12 variance. In many cases, the “efficient frontier” is also displayed – the set of non-dominated
13 alternatives. Dominated alternatives are those where there is another choice that is better
14 based both on mean and variance. Non-dominated alternatives are those where there is no
15 better alternative based on both mean and variance, and where a tradeoff between risk and
16 return is required.¹

17

18 As discussed in CAC/MH I-184a, the standard deviation or variance is not a particularly good
19 measure to evaluate risk-return tradeoffs for investments (such as those faced by Manitoba
20 Hydro) with asymmetric uncertainty - more upside than downside or vice versa. A 10th
21 percentile value provides a better indication of risk than standard deviation. As requested, the
22 chart below displays the expected value on one axis and the 10th percentile value on the other
23 axis for each development plan evaluated in Chapter 10 of the NFAT submission.

¹ For a more detailed explanation of modern portfolio theory, see for example David G. Luenberger, [Investment Science](#), Oxford University Press, 2014, Chapter 6.

- 1 As the figure indicates, plans with higher expected values and higher 10th percentile values are
- 2 preferred. Also, as the figure indicates, there are three non-dominated plans on the efficient
- 3 frontier to the upper right: K19/Gas25/750MW (WPS Sale & Inv), K19/Gas24/250MW,
- 4 K19/C25/750MW (WPS Sale & Inv).



5

1 **REFERENCE: CAC/MH I-176a**

2

3 **PREAMBLE:** The response suggests that the comparative "risks" of two Plans can be
4 determined by looking at their relative NPVs for a specific P values.

5

6 **QUESTION:**

7 Assume there are two Plans and the first has a benefit of \$170 guaranteed while the second has
8 an expected benefit of \$200 but the P25 and P75 values are \$110 and \$290 respectively. In
9 Manitoba Hydro's view which Plan is more risky and why? Does Manitoba Hydro agree that the
10 choice between the two Plans is not obvious and depends on the decision makers' views
11 regarding "risk"?

12

13 **RESPONSE:**

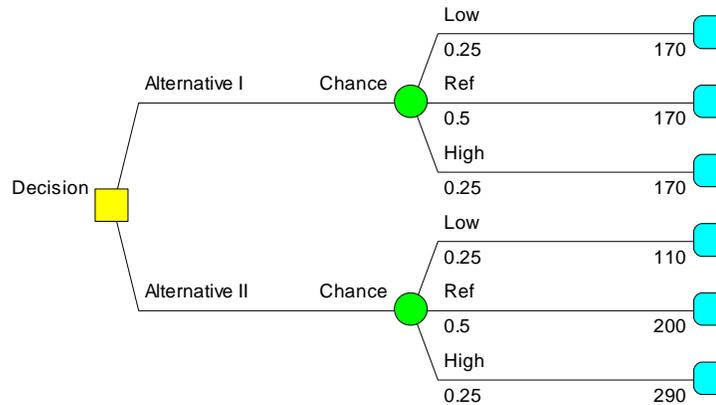
14 Yes, Manitoba Hydro agrees that the choice between the two plans is not obvious and depends
15 on the decision makers' views regarding "risk". Moreover, the decision on choosing between
16 the plans would also consider other factors which have not been able to be integrated into the
17 economic calculations but which would affect those calculations (e.g. opportunities or scenarios
18 which are not quantified currently) and factors which are not able to be readily integrated into
19 the economic calculations (e.g. energy security, reliability, socioeconomics, environmental,
20 provincial revenues, GHG reductions, northern and aboriginal benefits, etc.).

21

22 The choice between the two alternatives clearly depends on risk aversion. A simple example
23 based on this question may be instructive. Figure 1 shows a choice between Alternative I with a
24 certainty of \$170 and Alternative II with a 25% chance of \$110, a 50% chance of \$200 and a 25%
25 chance of \$290. The expected value of Alternative II is \$200.

1

Figure 1. Decision Problem



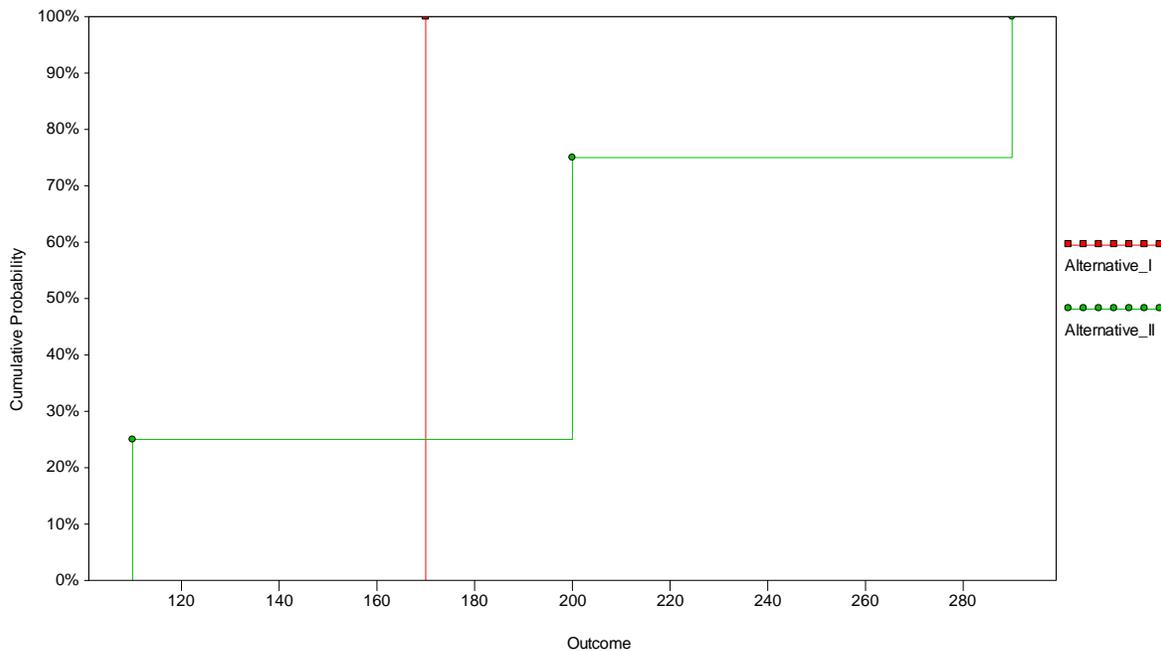
2

3 Figure 2 shows S curves for the two alternatives. As the figure indicates, the two alternatives
4 present a choice between “lower value and lower risk” (Alternative I) and “higher value and
5 higher risk” (Alternative II). The choice between these alternatives depends on risk attitude.

6

7

Figure 2. S Curves



8

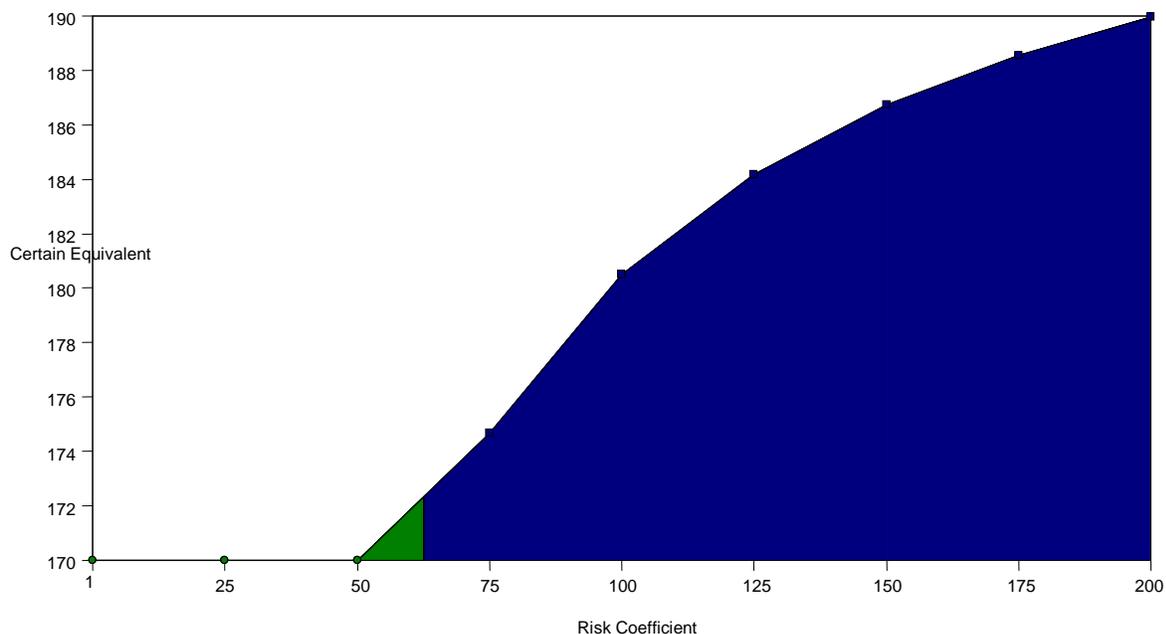
1 Risk attitude is generally measured through what is called a utility function. One common form
 2 of utility function is exponential. An exponential utility function is characterized by a single
 3 parameter – the risk coefficient. This is also referred to as the risk aversion or risk tolerance
 4 coefficient. Using a utility function, one can convert uncertain outcomes into an equivalent
 5 fixed amount, called the “certain equivalent.”

6

7 Figure 3 shows how the choice between the two alternatives varies depending on the risk
 8 coefficient. For low values of the risk coefficient (relatively risk averse), the best choice is to
 9 take the certainty of Alternative I. This is reflected in the green region of the figure. The certain
 10 equivalent is \$170. For high values of the risk coefficient (relatively risk tolerant), the best
 11 choice is to choose the more uncertain Alternative II. This is reflected in the blue region of the
 12 figure. The certain equivalent if one chooses Alternative II gradually rises towards \$200 with
 13 increasing risk tolerance. In this example, the switch between alternatives occurs at a risk
 14 coefficient between 50 and 75. That is, below a risk coefficient of around 62, the best choice is
 15 Alternative I; above a risk coefficient of around 62, the best choice is Alternative II.

16

Figure 3. Sensitivity to Risk Coefficient



17

- 1 There is not one correct level of risk aversion. In general, the level and importance of risk
- 2 aversion reflects the characteristics of the parties affected by the decision (e.g., high wealth vs.
- 3 low wealth) and the range of possible outcomes (e.g., large gains/losses vs. small gains/losses).

1 **REFERENCE: CAC/MH I-178**

2

3 **PREAMBLE:** The response states that: "When evaluating alternatives based on
4 maximizing a single objective (such as NPV), an alternative with an S curve strictly to the
5 right is clearly superior or dominant"

6

7 **QUESTION:**

8 Is it possible that even though one alternative's S curve is strictly to the right of a second
9 alternative, it may not necessarily have the better outcome for all the possible circumstances
10 analyzed?

11

12 **RESPONSE:**

13 S-curves are useful for comparing the possible outcomes of alternatives in a compact, visual
14 way. For example, one can determine from an S-curve the probability that an alternative will
15 have an outcome above any particular level, and which alternative has the highest probability
16 of achieving an outcome above any particular level. This information is useful for balancing risk
17 and return, and for identifying the best alternative. The fact that one curve is strictly to the
18 right of another indicates that the probability of achieving an outcome above any particular
19 level is higher with one alternative than the other, no matter what the level. This is called
20 stochastic dominance (or sometimes first-order stochastic dominance) and generally, if the
21 decision-maker prefers more to less, no matter what the decision-maker's attitude towards risk
22 is, the stochastically dominant alternative is preferable.

23

24 On the other hand, S-curves are not designed for, nor are they useful for, examining the
25 outcome of an alternative in a particular state (or scenario) or for comparing the outcomes of
26 alternatives in a particular scenario. The S-curve for each alternative reflects the outcome of
27 that alternative in all scenarios, each with the appropriate probability. However, individual
28 scenarios are not necessarily located at the same probability point on the S-curve for each
29 alternative. Consequently, comparing S-curves at a particular probability does not represent a

1 scenario-by-scenario comparison. For example, the fact that one curve is strictly to the right of
 2 another says very little about the comparison of outcomes in particular scenarios (as is made
 3 clear by the example below). In most approaches to economic decision-making, this “scenario-
 4 by-scenario” comparison is not highly relevant.

5

6 A simple example may be instructive.

7

8 Table 1 shows an example of a decision problem with two alternatives (I and II) in five possible
 9 scenarios (ranging from very low to very high.) It shows the name of each scenario in the first
 10 column, the probability of that scenario in the second column, and the outcome in that
 11 scenario of choosing Alternative I or Alternative II in the third and fourth columns, respectively.
 12 The expected value of Alternative I and Alternative II is also provided in the last row of the third
 13 and fourth columns, respectively. Lastly, the fifth column shows the difference between the
 14 outcomes of the two alternatives in each scenario.

15

Table 1 – CASE 1 Data

		CASE 1		
Scenario	Probability	Alternative I	Alternative II	II-I
Very Low	10%	\$ (100)	\$ (75)	\$ 25
Low	20%	\$ (50)	\$ (25)	\$ 25
Reference	40%	\$ -	\$ 25	\$ 25
High	20%	\$ 50	\$ 75	\$ 25
Very High	10%	\$ 100	\$ 125	\$ 25
<i>Expected Value</i>		\$ -	\$ 25	

16

17

18 As the table indicates, Alternative II not only has a higher expected value by \$25 but it is
 19 superior by \$25 in all five scenarios. That is, no matter which scenario occurs, Alternative II
 20 comes out \$25 better than Alternative I. Assuming the decision-maker prefers more money to

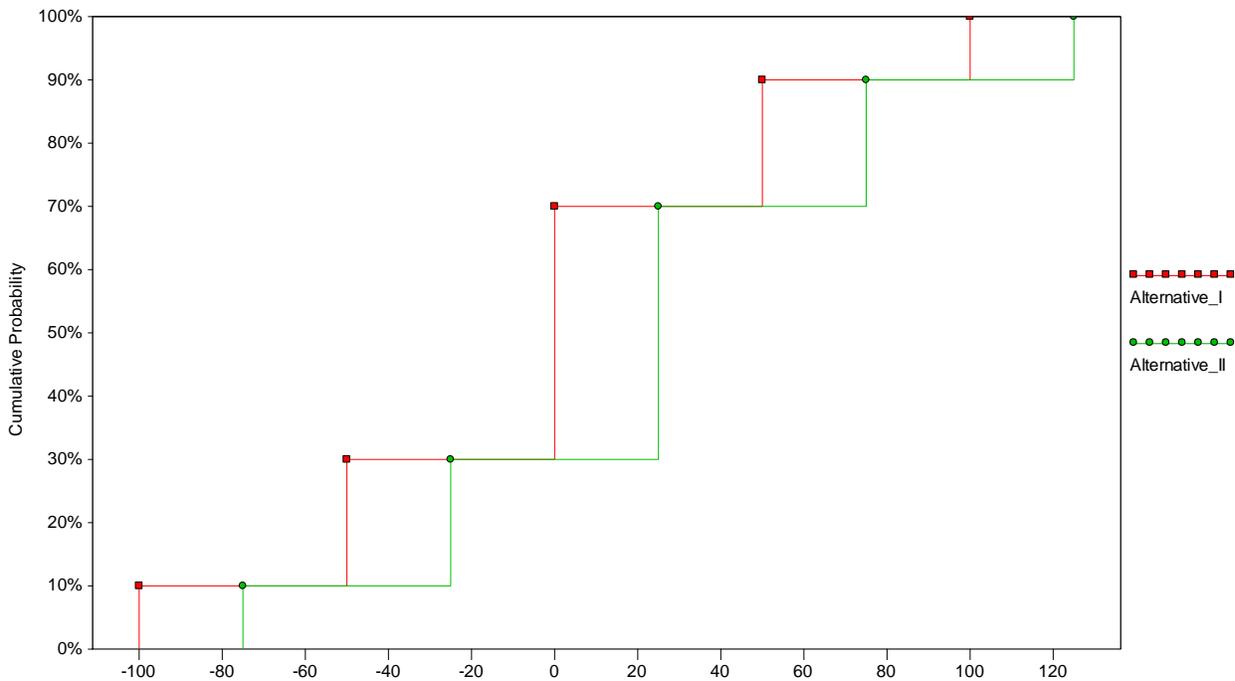
1 less, it is difficult (if not impossible) to find a rationale for choosing Alternative I based on these
2 outcomes. The decision appears obvious, and Alternative II is clearly best.

3

4 Figure 1 shows the S-curves for the two alternatives. This figure shows that Alternative II
5 stochastically dominates Alternative I; that is, no matter what level is chosen, Alternative II
6 always has an equal or higher probability of exceeding it. Alternative II dominates Alternative I.
7 However, it does not show any scenario-by-scenario comparisons.

8

Figure 1 – CASE 1 S-Curves



9

10

11 Table 2 shows a similar example with the same scenarios and probabilities. The outcomes for
12 Alternative I given in the third column are the same as in Case 1. The outcomes for Alternative
13 II given in the fourth column are reordered, but the expected value comparison remains the
14 same. Alternative II has a higher expected value by \$25. Because of the reordering, the
15 difference between the outcomes of the two alternatives in each scenario, given in the fifth
16 column, is very different than before. Depending on the scenario, Alternative II ranges from

1 \$225 better than Alternative I (in the very low scenario) to \$175 worse than Alternative I (in the
2 very high scenario).

3

4

Table 2 – CASE 2 Data

Scenario	Probability	CASE 2		
		Alternative I	Alternative II	II-I
Very Low	10%	\$ (100)	\$ 125	\$ 225
Low	20%	\$ (50)	\$ 75	\$ 125
Reference	40%	\$ -	\$ 25	\$ 25
High	20%	\$ 50	\$ (25)	\$ (75)
Very High	10%	\$ 100	\$ (75)	\$ (175)
<i>Expected Value</i>		\$ -	\$ 25	

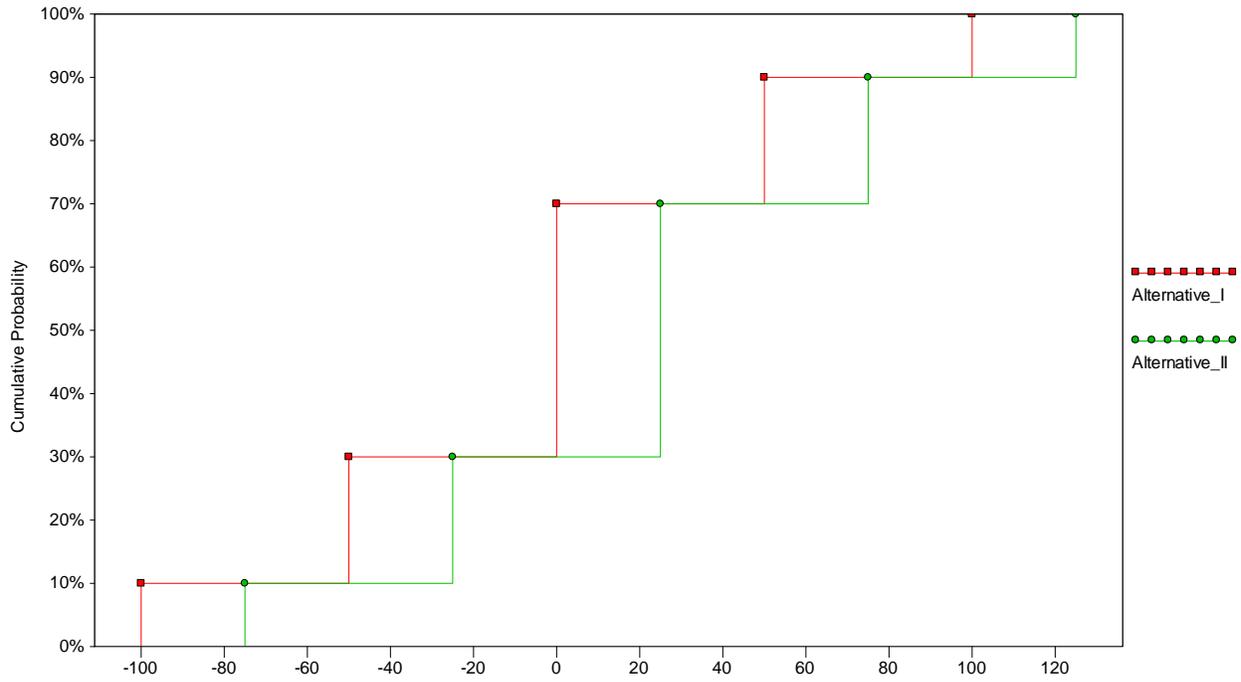
5

6

7 Figure 2 shows the S-curves for the two alternatives. Notice that the S-curves are exactly the
8 same as in Case 1. As before, the S-curves reveal that, no matter what level is chosen,
9 Alternative II always has an equal or higher probability of exceeding it. Again as before, the S-
10 curves reveal nothing about the scenario-by-scenario comparison. Although it may not be quite
11 so obvious, based on most views of “rational” economic decision-making, it is difficult to find a
12 rationale for choosing Alternative I. More specifically, if the decision-maker prefers more
13 money to less, no matter what the decision-maker’s attitude towards risk is, Alternative II is
14 best.

1

Figure 2 – CASE 2 S-Curves



2

1 **REFERENCE: CAC/MH I-179a**

2

3 **PREAMBLE:** The response states that "the K19/C25/750 MW plan has more surplus
4 power than gas plans and thus would be in a better situation to accommodate higher
5 load growth than the two gas plans"

6

7 **QUESTION:**

8 Please confirm that this is only true if the surplus power is dependable energy that has not
9 been committed to firm (contracted) exports.

10

11 **RESPONSE:**

12 Surplus dependable energy would not be greater in the K19/C25/750 MW plan than the gas
13 plans if all the dependable energy were committed to firm contracted exports.

14

15 However, when comparing the supply/demand tables in Appendix 4.2 of the Submission, it can
16 be seen that the surplus firm capacity and energy would be significantly greater in the
17 K19/C25/750 MW plan than the gas plans before new export sales are contracted in addition to
18 the MP 250MW and WPS 300MW contracts. It is assumed that eventually those firm surpluses
19 would be mainly eliminated through additional contracts but adding such contracts would take
20 a number of years to achieve and in the meantime those surpluses would be available to be
21 held back for higher than forecast Manitoba domestic load.

22

23 Furthermore, compared to the gas plans, the K19/C25/750 MW plan, even with additional firm
24 export contracts, utilizing all dependable energy, provides a higher level of system reliability to
25 address generation or major transmission outages or unexpectedly high load peaks, and a
26 higher level of energy security to mitigate unexpectedly severe droughts or unexpectedly high
27 energy consumption. This is due to a variety of reasons including the ability to give priority to
28 Manitoba domestic load over exports contracts in unforeseen emergency conditions and the

- 1 overall benefits arising from additional import capability on the new interconnection beyond
- 2 that which would be included in the dependable energy determinations. Please refer to Figure
- 3 13.2 of the submission, Appendix 13.1 of the submission, Manitoba Hydro's response to
- 4 MNP/MH I-072 and Manitoba Hydro's response to LCA/MH I-037.

1 **QUESTION:**

2 For those scenarios assuming higher capital costs than in the Reference case, were the higher
3 capital costs assumed for all new capital spending by Manitoba Hydro (including the spending
4 common to all plans) or were the higher capital costs assumed only for the Generation and
5 Transmission capital spending that varied across the plans?

6

7 **RESPONSE:**

8 Under the high capital cost scenario, only the projects specific to the development plans (not
9 the projects common to all plans) increased in cost. However, all project costs, including both
10 the development plan specific projects and the projects common to all plans, increased due to
11 higher escalation and interest rates under the high economic indicator scenario.

1 **REFERENCE: CAC/MH I-001b**

2

3 **QUESTION:**

4 Why does a plan for new interconnections and export contracts necessarily require Keeyask at
5 an earlier date than required for Manitoba Hydro Load?

6

7 **RESPONSE:**

8 The plan for the new interconnections and export contracts require Keeyask at an earlier date
9 because the export counterparties are pursuing contracts with Manitoba Hydro for supply
10 from a new hydropower resource during that timeframe. Once Keeyask is licensed there is a
11 high degree of certainty Manitoba Hydro will have sufficient dependable and dispatchable
12 resources in time to meet the requirements of the export contract and provide sufficient
13 surplus energy to justify developing the new interconnections.

14

15 Both Minnesota Power and Wisconsin Public Service want new hydro for their contracts and
16 this interconnection rather than existing hydro or wind.

1 **REFERENCE: CAC/MH I-078**

2

3 **QUESTION:**

4 Please explain why the 2012/13 through 2047/48 profile for Dependable Surplus Energy is
5 different as between the K19/Gas24/250 MW and K19/Gas25/750 MW Plans. Why aren't they
6 the same in all years except 2024/25?

7

8 **RESPONSE:**

9 There are differences in the amount of exportable surplus dependable energy between the
10 K19/Gas25/750MW (WPS Sale & Inv) development plan and the K19/Gas24/250MW
11 development plan for the following reasons:

12

13 1. The K19/Gas25/750MW (WPS Sale & Inv) development plan includes the dependable
14 energy obligations under the proposed WPS sale agreement which decreases the amount
15 of surplus dependable energy.

16

17 2. The K19/Gas25/750MW (WPS Sale & Inv) development plan includes a 750 MW
18 interconnection which has a higher firm import capability than the 250 MW
19 interconnection. The increased import capability provides additional dependable energy
20 during the off-peak hours.

1 **SUBJECT: Capital Costs**

2

3 **REFERENCE: MIPUG/MH I-003c**

4

5 **QUESTION:**

6 For each of the four projects please show the spending by year that accumulates to the Total
7 Sunk Costs.

8

9 **RESPONSE:**

10 Please see the attached table.

Total Sunk Costs and Amortization Expense by Project

Economics: Reference
Market Prices: Reference
Capital Costs: Reference

(\$millions)

Project	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Conawapa GS			0.2	8.5	28.1	32.6	34.0	33.4	35.2	29.7	28.2	56.1	72.1	17.9	376.1
Keeyask GS	51.8	25.2	31.2	33.2	32.2	36.0	43.0	54.1	58.5	55.7	79.8	197.7	328.7	159.7	1,186.7
Keeyask GOT	1.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	(1.5)	0.7	0.4	2.1	1.4	8.5	13.4
US Tie Line									0.8	0.2	0.1	0.1	0.1	0.0	1.2
															1,577.4

Keeyask GOT - 2010 \$1.8M of Keeaysk Transmission plus interest was transferred to BiPole III

1 **REFERENCE: MIPUG/MH I-009a**

2

3 **PREAMBLE:** The response states that "there is little support, analytical or empirical, for
4 using the regret approach to make complex, future altering decisions.

5

6 **QUESTION:**

7 Please provide the third party references Manitoba Hydro has relied on in making this
8 statement.

9

10 **RESPONSE:**

11 Please refer to Manitoba Hydro's response to MIPUG/MH II-4a.

1 **REFERENCE: MIPUG/MH I-013a and MIPUG/MH I-028g**

2

3 **SUBJECT: NPV**

4

5 **QUESTION:**

6 For purposes of the Government Account calculations presented in Chapter 13, were the capital
7 tax and debt guarantee fee values used consistent with those calculated in the economic or the
8 financial analyses?

9

10 **RESPONSE:**

11 The annual cash flow estimates of the capital tax and debt guarantee fee are consistent with
12 the values used in the financial analysis.

1 **REFERENCE: MIPUG/MH I-013a and MIPUG/MH I-028g**

2

3 **SUBJECT: Socio-economic**

4

5 **QUESTION:**

6 Based on the response to part (a), please comment on whether there are any
7 inconsistencies/double counting in the presentation in Table 13.9 of the Overall Monetized Net
8 Benefit (Cost) for the various Plans presented.

9

10 **RESPONSE:**

11 There were no inconsistencies or double counting. Please see the response to CAC/MH II-051b.

1 **SUBJECT: Partnership Agreements**

2

3 **REFERENCE: MIPUG/MH I-016b and MIPUG/MH I-017d**

4

5 **QUESTION:**

6 Does the non-controlling interest shown under each development plan and scenario in
7 Appendix 11.4 include just that related to Wuskwatim and Keeyask (where applicable)? If not,
8 what else is included?

9

10 **RESPONSE:**

11 Please see Manitoba Hydro's responses to CAC/MH II-019(a) and (b).

1 **SUBJECT: Partnership Agreements**

2

3 **REFERENCE: MIPUG/MH I-017a**

4

5 **QUESTION:**

6 Is the 1.9% to 2.4% ownership interest range for KCN with respect to the percentage of the
7 total project or with respect to its percentage of the total equity in the project?

8

9 **RESPONSE:**

10 The KCN will own between 1.9% and 2.5% of the total equity in the project.

1 **REFERENCE: MIPUG/MH I-038**

2

3 **SUBJECT: Load Forecast**

4

5 **QUESTION:**

6 Please confirm that the Medium Low and Medium High Scenario approach looked at possible
7 changes in the load forecast due to changes in economic inputs and customer growth but not
8 weather.

9

10 **RESPONSE:**

11 The Medium Low and Medium High Scenarios assumed normal weather, the same as the Base
12 forecast.

1 **REFERENCE: MIPUG/MH I-038**

2

3 **SUBJECT: Load Forecast**

4

5 **QUESTION:**

6 What types of uncertainties are captured in the probability based analysis adopted in the
7 1990's and, in particular, are they comparable to those reflected in the earlier approach?

8

9 **RESPONSE:**

10 The probabilistic-based approach, as outlined on page 44 of the 2013 Load Forecast included as
11 Appendix D of the submission, uses historical annual variations in weather adjusted load. It
12 therefore incorporates all effects other than weather, namely economic, population,
13 expansions and reductions to Top Consumers, and all other changes in energy use.

14

15 The Medium Low and Medium High scenarios represent different outlooks of future economic
16 growth in Manitoba. When compared to the Base Forecast, the Medium Low scenario included
17 lower population growth, lower housing formation rates, lower economic growth, lower oil and
18 natural gas price increases, lower electric space heat saturation rates, lower business formation
19 rates, lower business electricity usage, more shutdowns/closures of existing large customers
20 and lower probabilities of large electrical-intensive industries locating in the province.

21

22 When compared to the Base Forecast, the Medium High scenario included higher population
23 growth, higher housing formation rates, higher economic growth, higher oil and natural gas
24 price increases, higher electric space heat saturation rates, higher business formation rates,
25 higher business electricity usage, less shutdowns/closures of existing large customers and
26 higher probabilities of large electrical-intensive industries locating in the province.

1 **REFERENCE: PUB/MH I-026b**

2

3 **QUESTION:**

4 Do the wind storage provisions apply regardless of whether the new intertie is for 250 MW or
5 750 MW?

6

7 **RESPONSE:**

8 The wind storage provisions in the Energy Exchange Agreement with Minnesota Power are
9 independent of the capacity of the new U.S. interconnection.

1 **REFERENCE: Question PUB/MH I-026b**

2

3 **QUESTION:**

4 What investment (i.e. what dollars and for what facilities) is MP making in a "new international
5 transmission line"?

6

7 **RESPONSE:**

8 MP is investing in 51% of the cost of the interconnection project within Minnesota. MP
9 estimates that total construction costs for the Minnesota portion of the Project on a proxy
10 route, including substation construction, will cost between \$406 Million and \$609 Million (2013
11 dollars) with a mid-point of \$507 Million.

1 **REFERENCE: Question PUB/MH I-042f**

2

3 **QUESTION:**

4 Do Manitoba Hydro's firm export contracts require that the transmission system delivering the
5 load be able to do so in the event of single contingency equipment failure?

6

7 **RESPONSE:**

8 Yes. Manitoba Hydro's firm export contracts require Manitoba Hydro to provide firm
9 transmission service on the AC network to facilitate energy and capacity transfers according to
10 the system criteria associated with firm transmission service.

11

12 However, Manitoba Hydro is not required to provide a similar level of firmness of transmission
13 service on its HVDC system. The firm export contracts expose the buyer to the risks of the
14 generating system which is defined to include all of Manitoba Hydro's HVDC facilities. As a
15 result single contingency equipment failures on the HVDC system are a reason to curtail
16 contract deliveries to avoid curtailment of higher priority loads.

1 **REFERENCE: Question CAC/MH I-078b**

2

3 **QUESTION:**

4 Please provide the forecast operating statement for KHLP consistent with the net income
5 projection shown in Table 2.

6

7 **RESPONSE:**

8 The following projected operating statement for the Keeyask Hydro Limited Partnership
9 represents the contractual arrangements.

Keeyask Hydro Power Limited Partnership
Projected Operating Statement
Preferred Development Plan - REF REF REF
(In Millions of Dollars)

For the year ended March 31

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
REVENUES														
Revenue	0	0	0	0	0	0	0	30	212	270	284	291	299	296
	0	0	0	0	0	0	0	30	212	270	284	291	299	296
EXPENSES														
Operating and Administrative	0	0	0	0	0	0	0	5	15	15	15	15	16	16
Finance Expense	0	0	(0)	0	0	0	0	19	173	235	240	240	239	239
Depreciation and Amortization	0	0	0	0	0	0	0	6	58	80	80	80	80	80
Water Rentals and Assessments	0	0	0	0	0	0	0	2	13	15	15	15	15	15
	0	0	(0)	0	0	0	0	31	259	345	350	350	350	349
1 Net Income	-	-	0	-	(0)	(0)	-	(2)	(47)	(75)	(66)	(59)	(51)	(53)

Keeyask Hydro Power Limited Partnership
Projected Operating Statement
Preferred Development Plan - REF REF REF
(In Millions of Dollars)

For the year ended March 31

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
REVENUES													
Revenue	303	308	317	326	334	343	353	362	372	376	375	379	387
	303	308	317	326	334	343	353	362	372	376	375	379	387
EXPENSES													
Operating and Administrative	15	16	16	16	15	15	16	16	16	16	16	16	16
Finance Expense	235	233	231	229	216	207	205	201	198	195	191	188	184
Depreciation and Amortization	80	80	80	80	80	80	80	80	80	80	80	80	80
Water Rentals and Assessments	15	15	15	15	15	15	15	15	15	15	15	15	15
	345	344	342	339	326	317	316	312	309	305	302	299	296
2 Net Income	(42)	(36)	(25)	(14)	8	26	37	50	63	71	73	80	92

1 **REFERENCE: PUB/MH I-088b**

2

3 **PREAMBLE:** Pages 3-72 of the response provide the debt/equity ratio for each Plan and
4 associated scenarios.

5

6 **QUESTION:**

7 Can the debt/equity ratios reported for each Plan be calculated from the data provided in the
8 schedule? If yes, please indicate how this would be done. If not, please provide a revised set of
9 schedules with the relevant data required to calculate the debt/equity ratio and indicate how
10 the information would be used in the calculation.

11

12 **RESPONSE:**

13 The debt/equity ratio can be calculated from the data provided in the response to PUB/MH II-
14 088(b) using the following formula:

15

Debt /

16

(Retained Earnings + Contributions in Aid of Construction +

17

Accumulated Other Comprehensive Income + Non-Controlling Interest + Debt)

18

1 **REFERENCE: PUB/MH I-088b**

2

3 **PREAMBLE:** Pages 3-72 of the response provide the debt/equity ratio for each Plan and
4 associated scenarios.

5

6 **QUESTION:**

7 Please indicate how the Debt value reported in the response can be derived from the Pro-
8 Forma financial statements in Appendix 11.4.

9

10 **RESPONSE:**

11 For the purposes of the debt/equity ratio calculation, debt is the sum of the long-term
12 (including the current portion) and short-term debt balances less sinking fund assets, short-
13 term investments and debt attributed to the gas operations. Long-term debt on the pro forma
14 balance sheet in Appendix 11.4 excludes the current portion which is classified in Current &
15 Other Liabilities. Short-term debt and debt attributed to Centra Gas are also classified in
16 Current & Other Liabilities. Sinking fund assets and short-term investments are classified in
17 Current & Other Assets on the pro forma balance sheet.

18

19 The following schedule provides the corresponding values to calculate the debt for the
20 Preferred Development Plan debt equity ratio under the reference scenario.

Development Plan K19 Sales C25 750 MW
 Development Plan Scenario Economics:REF Rev:REF Cap:REF

**ELECTRIC OPERATIONS
 CALCULATION OF NET DEBT**
 In Millions of Dollars

1

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
Long Term Debt (including current portion)	10 097	11 471	13 114	14 821	16 700	18 571	19 744	21 039	22 406	23 530	25 080	26 482	27 685	28 038	28 239	28 440	28 581	28 334	27 636	27 626	27 399	25 401	25 202	24 921	24 523
Sinking Fund Assets	(320)	(129)	(152)	(311)	(489)	(700)	(498)	(533)	(518)	(188)	(277)	(542)	(830)	(691)	(1 003)	(1 328)	(1 606)	(1 708)	(1 361)	(1 678)	(1 792)	(1 337)	(1 446)	(1 424)	(1 376)
Short Term Debt	183	84	128	215	220	172	215	105	51	160	90	53	-	107	190	18	-	-	-	-	-	-	-	-	-
Short Term Investments	-	-	-	-	-	-	-	-	-	-	-	-	(4)	-	-	-	(113)	(287)	(668)	(1 425)	(1 412)	(166)	(193)	(232)	(156)
Debt for Gas Operations	(295)	(325)	(330)	(340)	(360)	(380)	(390)	(400)	(410)	(420)	(440)	(450)	(460)	(470)	(480)	(490)	(500)	(510)	(520)	(530)	(540)	(550)	(560)	(570)	(580)
Net Debt for Debt/Equity Ratio	9 665	11 100	12 760	14 386	16 072	17 664	19 071	20 211	21 530	23 081	24 453	25 543	26 392	26 984	26 947	26 640	26 362	25 829	25 088	23 993	23 655	23 348	23 003	22 695	22 412

2

Development Plan K19 Sales C25 750 MW
 Development Plan Scenario Economics:REF Rev:REF Cap:REF

**ELECTRIC OPERATIONS
 CALCULATION OF NET DEBT**
 In Millions of Dollars

3

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
Long Term Debt (including current portion)	24 375	24 177	24 279	24 429	24 378	24 277	24 625	24 624	24 622	25 020	25 019	24 817	24 490	24 490	24 489	24 439	24 238	22 638	21 837	21 236	20 829	20 428	19 702	19 502	19 102
Sinking Fund Assets	(1 410)	(1 609)	(1 627)	(1 743)	(1 863)	(1 988)	(2 261)	(2 498)	(2 445)	(2 792)	(2 901)	(2 915)	(2 803)	(3 012)	(3 230)	(3 406)	(3 539)	(2 975)	(2 819)	(2 803)	(2 834)	(2 815)	(2 587)	(2 743)	(2 778)
Short Term Debt	-	-	-	-	-	60	-	88	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Short Term Investments	(242)	(69)	(178)	(106)	(62)	-	(66)	-	-	(105)	(340)	(508)	(650)	(830)	(947)	(1 064)	(1 028)	(366)	(144)	(69)	(153)	(243)	(257)	(381)	(447)
Debt for Gas Operations	(590)	(600)	(610)	(620)	(630)	(640)	(660)	(670)	(680)	(700)	(710)	(720)	(740)	(750)	(760)	(770)	(780)	(790)	(790)	(800)	(800)	(810)	(810)	(810)	(800)
Net Debt for Debt/Equity Ratio	22 134	21 898	21 863	21 961	21 823	21 709	21 638	21 544	21 728	21 424	21 068	20 674	20 298	19 898	19 553	19 198	18 892	18 507	18 084	17 565	17 041	16 560	16 048	15 569	15 077

1 **REFERENCE: PUB/MH I-095b**

2

3 **QUESTION:**

4 Please provide the value for marginal cost used in the 2011-2012 Power Smart Review.

5

6 **RESPONSE:**

7 Programs are evaluated using the same levelized marginal value that was in used in developing
8 the program plan. Thus, the 2011-2012 Power Smart Annual Review used a levelized marginal
9 value of 8.52 cents/kW.h (2011\$), which is the marginal value used in the 2011 Power Smart
10 Plan.

1 **REFERENCE: PUB/MH I-099a**

2

3 **QUESTION:**

4 Please confirm that "nominal" means the reported value is constant over the 30 years.

5

6 **RESPONSE:**

7 The table presented in MIPUG/MH I-7a of the 2012/13 & 2013/14 Manitoba Hydro General
8 Rate Application (GRA), refiled as PUB/MH I-099a of this proceeding, should not have been
9 labeled "nominal dollars" as was outlined in Manitoba Hydro's response to CAC/MH II-56 of the
10 the 2012/13 & 2013/14 GRA. The levelized marginal values are shown in the year's dollars of
11 the associated Power Smart Plan. For example, the levelized marginal value used in the 2011
12 Power Smart Plan is in 2011 dollars, the levelized marginal value used in the 2010 Power Smart
13 Plan is in 2010 dollars, etc.

1 **REFERENCE: PUB/MH 1-105a**

2

3 **PREAMBLE:** The last paragraph of the response compares Manitoba's Net Peak Load
4 with the combined capacity of B I & II.

5

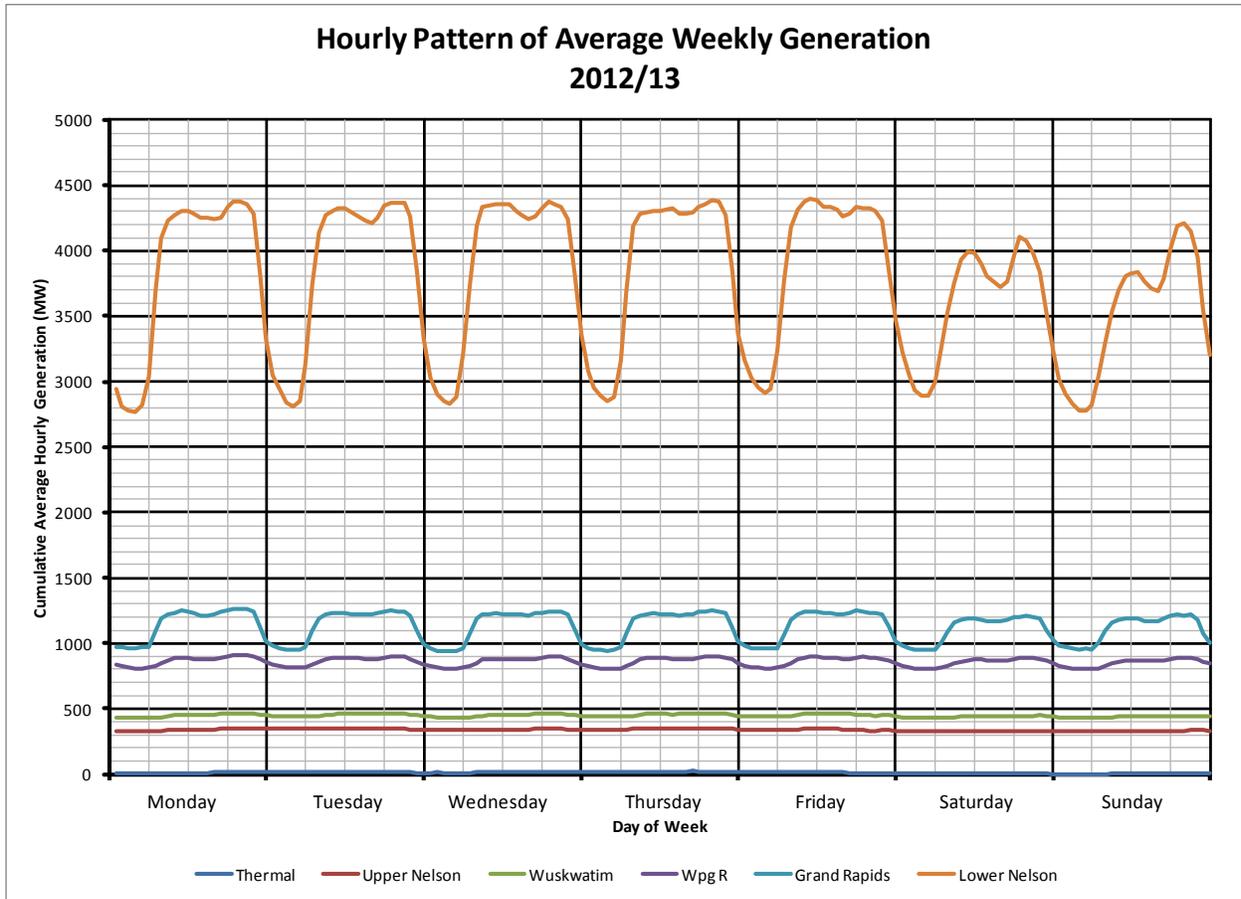
6 **QUESTION:**

7 The comparison does not account for the Manitoba Hydro generation located in the southern
8 part of the province and which does not require the use of the Bipole lines. Please revise so as
9 to take this additional generation into account.

10

11 **RESPONSE:**

12 The hydro-electric generation that does not utilize the HVDC system consists of generation at
13 Winnipeg River generating stations, Grand Rapids generating station, Jenpeg generating
14 station, Kelsey generating station and Wuskwatim generating station. The combined capacity
15 of these stations is about 1650 MW, while the capacity of the stations that do utilize the HVDC
16 system is 3550 MW (Kettle, Long Spruce and Limestone). Even if the full 1650 MW were
17 available to meet peak loads of 4500 MW, the remaining 2850 MW must be provided by the
18 HVDC system (or utilize thermal and imports), providing only 700 MW spare capacity (15.5%
19 just more than the requisite 12%). As peak load grows to 5000 MW, then 3350 MW of HVDC
20 generation would be required, leaving only 150 MW or 3% of capacity spare; 450 MW of
21 thermal generation would need to be available to provide the 12% capacity reserve required in
22 planning. See the graph of average hourly generation patterns.



1

1 **REFERENCE: Question CAC/MH I-112b and CAC/MH I-134**

2

3 **QUESTION:**

4 This response states that the management reserves for labour and escalation were not included
5 in the NFAT financial evaluation of Keeyask. However, the response to CAC/MH 1-134 suggests
6 that the escalation reserve was included in the NFAT analysis. Please reconcile.

7

8 **RESPONSE:**

9

10 The table in the response to CAC/MH I-134 shows the accurate breakdown of the costs included
11 in the Conawapa capital estimate for the NFAT financial evaluation. The response to PUB/MH I-
12 112b should have stated that the escalation reserve is included; however, the amount of
13 escalation reserve in the NFAT financial evaluation reference scenario is lower compared to
14 CEF12 because the reference case excludes the labour reserve.

15

16 Please also refer to Manitoba Hydro's response to PUB/MH II-447.

1 **REFERENCE: Question PUB/MH I-113B and CAC/MH I-135**

2

3 **QUESTION:**

4 This response states that the management reserves for labour and escalation were not included
5 in the NFAT financial evaluation of Conawapa. However, the response to CAC/MH 1-135
6 suggests that the escalation reserve was included in the NFAT analysis. Please reconcile.

7

8 **RESPONSE:**

9 The table in the response to CAC/MH I-135 shows the accurate breakdown of the costs included
10 in the Conawapa capital estimate for the NFAT financial evaluation. The response to PUB/MH I-
11 113(b) should have stated that the escalation reserve is included; however, the escalation
12 reserve in the NFAT financial evaluation reference scenario is lower compared to CEF12 due to
13 the higher escalation rate being applied to a base which excludes the labour reserve.

1 **REFERENCE: PUB/MH I-123b**

2

3 **QUESTION:**

4 Given the size of the MISO market, why wouldn't the maximum imports "available" under each
5 Plan be based simply on the import capabilities provided in response to PUB/MH 1-123 a?

6

7 **RESPONSE:**

8 The information provided in PUB/MH I-123a identifies the maximum import capability of the
9 existing and new 250 MW and 750 MW US interconnections.

10

11 The information provided in PUB/MH I-123b identifies the highest annual imports anticipated
12 by the SPLASH model for each of the 15 development plans. The amount of imports is based on
13 the import capability of the interconnections and additionally will vary by plan depending on
14 the timing and type of installed generation and firm obligations of each of the plans.

1 **REFERENCE: Question PUB/MH I-124**

2

3 **QUESTION:**

4 The response suggests that when Manitoba Hydro purchases power from the MISO market for
5 import the only transmission tariffs paid are Manitoba Hydro's tariffs. Please confirm that this is
6 the case. If so, who does the revenue from the tariff accrue to (i.e. just Manitoba Hydro or is it
7 shared with other MISO transmission owners?)

8

9 **RESPONSE:**

10

11 Confirmed. Tariff Coordination Agreements state that the transmission fees on the US side are
12 waived provided that the energy is used to serve Manitoba network load. In Manitoba,
13 Manitoba Hydro does not charge itself or share any revenues with MISO for network
14 integration transmission service when energy is purchased to serve Manitoba network load.

1 **REFERENCE: PUB/MH I-131**

2

3 **PREAMBLE:** The response states that generally Manitoba Hydro's system offers energy
4 that qualifies in both states.

5

6 **QUESTION:**

7 Please explain how Manitoba Hydro's system offers energy that generally meets Minnesota's
8 requirement that hydro be from small (<100 MW) stations.

9

10 **RESPONSE:**

11 The State of Minnesota Renewable Portfolio Standard recognizes electricity generated by solar,
12 wind, hydroelectric facilities less than 100 megawatts (MW), hydrogen and biomass as eligible
13 for renewable status. Manitoba Hydro's renewable energy generated from the hydroelectric
14 facilities of Laurie River I and II, McArthur Falls, Pine Falls, Pointe du Bois and Slave Falls and the
15 St. Leon and St. Joseph windfarms all qualify as renewable energy in Minnesota.

1 **Reference: Question PUB/MH I-133a**

2

3 **QUESTION:**

4 Please explain further the comment that "neither (500 kV) project was deemed eligible for cost
5 sharing" and any implications this has for the financing of the project.

6

7 **RESPONSE:**

8 The 500 kV alternatives were studied by MISO but neither achieved the requisite threshold to
9 trigger project funding by MISO. Because the project does not meet the MISO funding criteria,
10 Manitoba Hydro and Minnesota Power will have to finance the project in order for the project
11 to move forward.

1 **REFERENCE: PUB/MH I-143a**

2

3 **PREAMBLE:** The response states that the balance of the interconnection facilities will
4 be owned by Minnesota Power.

5

6 **QUESTION:**

7 Please indicate exactly what facilities will be owned by Minnesota Power and whether they
8 change as between the 230 kV and 500 kV interconnection options.

9

10 **RESPONSE:**

11 In Manitoba, Manitoba Hydro will own all the facilities.

12

13 In Minnesota, should a 230 kV interconnection be built, Minnesota Power would own all the
14 facilities.

15

16 In Minnesota, should a 500 kV interconnection be built, the details of the actual facilities to be
17 owned by Minnesota Power and those whose ownership will be shared have yet to be
18 determined. However the intent is that on an overall basis Manitoba Hydro will own 49% and
19 Minnesota Power will own 51% of the facilities.

1 **REFERENCE: PUB/MH I-143a**

2

3 **PREAMBLE:** The response states that the balance of the interconnection facilities will
4 be owned by Minnesota Power.

5

6 **QUESTION:**

7 Under the 500 kV option, how do those to be owned by MP facilities differ from those that it
8 was originally anticipated that WPS would invest in?

9

10 **RESPONSE:**

11 Prior to WPS' funding withdrawal in the U.S. line, WPS' share was proposed to be 27% (200MW
12 out of 750MW), and Minnesota Power's share was proposed to be 33% (250MW out of
13 750MW) with Manitoba Hydro owning hold the remaining 40%.

14

15 The ownership details of specific facilities associated with each ownership ratio have yet to be
16 determined. For example within Minnesota Power's share, MP may wish to own 100% of the
17 station costs which would require it to have a lesser ownership percentage in line costs.

1 **REFERENCE: Question PUB/MH I-143a and CAC/MH I-089c**

2

3 **QUESTION:**

4 The response to PUB/MH 1-143a suggests that 49% ownership gives Manitoba Hydro access to
5 49% of the intertie capacity for export purposes. However, the response to CAC/MH 1-089c
6 suggests there is no link between ownership and the "right to use". Please reconcile.

7

8 **RESPONSE:**

9 There does not need to be a match between the holders of transmission rights ("right to use")
10 and the owners/investors.

11

12 The "right to use" is associated with who requests and is granted transmission service rights as
13 outlined in the transmission tariff. If requests for transmission service exceed the available
14 transmission capacity, the transmission provider (either Manitoba Hydro or MISO) will arrange
15 for the construction of new facilities that satisfy requested transmission service. The parties
16 requesting the transmission service will then be responsible for paying for the costs of the new
17 transmission facilities.

18

19 In order to build the new facilities, the transmission provider will execute a Facilities
20 Construction Agreement which will specify which Parties are responsible for funding,
21 constructing and owning the new transmission line and those who will receive the new firm
22 transmission service rights.

1 **REFERENCE: Question PUB/MH I-143a and PUB/MH I-143b**

2

3 **QUESTION:**

4 If Manitoba were to invest in (but not own) more than 49% of the line would the transmission
5 rights that MISO grant it increase accordingly?

6

7 **RESPONSE:**

8 No. These are separate issues. Please see Manitoba Hydro's response to CAC/MH II-091.

1 **REFERENCE: PUB/MH I-144**

2

3 **QUESTION:**

4 Please reconcile the \$277 M cost for the Manitoba portion with the \$353 M cost reported in
5 CAC/MH 1-016b.

6

7 **RESPONSE:**

8 As stated in Manitoba Hydro's response to PUB/MH I-144, the cost of the Manitoba-Minnesota
9 Transmission Project portion of the 750 MW U.S. interconnection used in analysis was \$277
10 million (2014\$ CDN). This project is described in Chapter 2 (Section 2.4) of the NFAT Business
11 Case.

12

13 The \$353 million (2014\$ CDN) provided in Manitoba Hydro response to CAC/MH I-016b is the
14 cost of the North-South Transmission Upgrade Project. This project is described in Chapter 2
15 (Section 2.3) of the NFAT Business Case.

1 **REFERENCE: PUB/MH 1-145**

2

3 **QUESTION:**

4 Does the range quoted in this response refer to the high/low cost for Manitoba Hydro's portion
5 of the entire 500 kV interconnection - both the Manitoba and Minnesota sections? If not what
6 does it cover?

7

8 **RESPONSE:**

9 As stated in PUB/MH I-145, Manitoba Hydro only applied its assumptions on high and low
10 project estimates to the portion of the capital for which Manitoba Hydro is responsible in a
11 development plan.

12

13 The range quoted in PUB/MH I-145 refers to the high and low capital costs of the Manitoba-
14 Minnesota Transmission Project and Manitoba Hydro's portion of the Great Northern
15 Transmission Line Project.

1 **REFERENCE: PUB/MH I-149a**

2

3 **PREAMBLE:** The response states that the appropriate discount rate is the real return on
4 risk free savings of the customer.

5

6 **QUESTION:**

7 Explain more fully why it is appropriate to use a "risk free" rate.

8

9 **RESPONSE:**

10 The risk-free rate is appropriate for discounting dollar amounts in the NPV analysis of
11 consumers revenue because financial risk associated with high and low interest rates has
12 already been incorporated into the probabilistic scenario runs. The economic analysis does not
13 explicitly incorporate interest costs, and so the real weighted average cost of capital (RWACC)
14 used for discounting in economic analysis incorporates financial risk. To re-introduce financial
15 risk into the discount rate in NPV analysis of consumers revenue would be equivalent to
16 double-counting the risk.

17

18 It is important to recognize that the discount rate in the NPV analysis of consumers revenue is
19 used solely to weight rate impacts at different points in time.

20 Please also refer to MIPUB/MH II-034.

1 **REFERENCE: PUB/MH I-149a**

2

3 **PREAMBLE:** The response states that the appropriate discount rate is the real return on
4 risk free savings of the customer.

5

6 **QUESTION:**

7 Please explain more fully why it is appropriate to use a rate that reflects return on savings and,
8 in particular, the Short Term Canadian T-Bill rate.

9

10 **RESPONSE:**

11 A short-term Treasury Bill rate offered by the Government of Canada is generally accepted by
12 economists and financial analysts to be the closest instrument to risk-free that is available in
13 Canada. Any non-Canadian instrument would expose the individual to currency exchange risk.
14 Longer term instruments in a normal economy typically have higher interest rates because they
15 already incorporate higher risks associated with exposure to unforeseen economic pressures
16 over a longer period.

1 **REFERENCE: PUB/MH I-149a**

2

3 **PREAMBLE:** The response states that the appropriate discount rate is the real return on
4 risk free savings of the customer.

5

6 **QUESTION:**

7 Given that many customers (residential and non-residential) are carrying debt, why wouldn't a
8 rate that reflects their savings in debt carrying costs be appropriate?

9

10 **RESPONSE:**

11 The debt interest rate assumed by an electric customer includes components for expected
12 inflation, and a certain level of financial risk associated with the type and purpose of the loan.

13 As explained in the response to CAC/MH II-095(a), financial risk should not be factored into the
14 discount rate for NPV analysis of consumers revenue, as it has already been incorporated into
15 the interest rates used in the probabilistic financial forecasts. As the analysis is performed in
16 real dollars, inflation is also removed from the discount rate. Accordingly, the short-term
17 Treasury Bill rate, adjusted for inflation, is the most appropriate rate to use.

1 **REFERENCE: PUB/MH I 149a**

2

3 **PREAMBLE:** NFAT Chapter 13, Footnote #7 describes the basis for the social discount
4 rates as a weighting of three different sources of capital - savings, borrowing and
5 borrowing from outside.

6

7 **QUESTION:**

8 In the Burgess and Zerbe study, what were the values they attributed to the capital from each
9 of these sources in order to derive their 6.6%-7.3% real social opportunity cost of capital and
10 what were the weights applied to each?

11

12 **RESPONSE:**

13 Burgess and Zerbe use the following estimates for the weights (sourcing of capital) and
14 respective opportunity costs in their base case estimate. The weighted average for these values
15 is 6.92%. The range in weighted average rates they calculate is based on different elasticities of
16 savings, investment and outside borrowing (out of Manitoba) with respect to interest rates as
17 shown in Table 1 of their article.

18

	Displaced Investment	Increased Saving	Increased Outside Borrowing
Weight	0.54	0.10	0.36
Opportunity Cost	8.5%	3.5%	5.5%

1 **REFERENCE: PUB/MH I 149a**

2

3 **PREAMBLE:** NFAAT Chapter 13, Footnote #7 describes the basis for the social discount
4 rates as a weighting of three different sources of capital - savings, borrowing and
5 borrowing from outside.

6

7 **QUESTION:**

8 What would be the result if Burgess and Zerbe study was applied with a zero weight to "outside
9 borrowing" and proportionally increase the weights for the other two sources?

10

11 **RESPONSE:**

12 If the weight for outside borrowing was zero, the weighted average opportunity cost would
13 increase to approximately 7.7%.

1 **REFERENCE: Question PUB/MH I-149a**

2

3 **QUESTION:**

4 Please confirm that the NPV values in Table 11.2 - 11.7 are in 2012\$. If not what is their basis?

5

6 **RESPONSE:**

7 The values in Tables 11.2 – 11.7 of Manitoba Hydro’s response to PUB/MH I-149(a) are the
8 cumulative general consumers revenues, which were deflated from nominal dollars to 2012\$
9 and discounted at the 1.86% real discount rate.

1 **REFERENCE: Question PUB/MH I-149a**

2

3 **QUESTION:**

4 Please confirm that for Table 11.8 the inflation rate used to convert the 2013/2014 nominal
5 dollar values to 2011/13 (constant dollar values) was the 1.8% reported in Appendix 11.2, page
6 1 under 2014. If this is not the case please fully explain what Manitoba Hydro fiscal year is
7 equivalent to 2012\$.

8

9 **RESPONSE:**

10 The inflation rates listed in Appendix 11.2, labelled "MB CPI", were used to deflate all forecast
11 years' figures from their nominal values to 2012\$. Deflation is done by creating a cumulative
12 index from the series of annual CPI figures. The index for 2013/14 would be:

13
$$\text{Previous Year's Index} \times (1 + \text{Current Year's MB CPI})$$

14
$$\text{or}$$

15
$$1.000 \times (1 + 1.80\%) = 1.0180$$

16 To convert 2013/14 nominal dollar consumers' revenue to 2012/2013 (2012\$) you would divide
17 by 1.0180 so $\$1,384 = \$1,409 / 1.0180$

1 **PREAMBLE:** The response to PUB/MH 1-149 a) suggests that it addresses CAC/MH 1-
2 141 a&b, CAC/MH 1-142, CAC/MH 1-155b) and CAC/MH 1-163.

3

4 **REFERENCE: PUB/MH I-149 a-d**

5

6 **QUESTION:**

7 The response does not provide the requested information based on a 5.05% discount rate.
8 Manitoba Hydro has indicated that it believes use of this rate to be inappropriate. As this claim
9 is untested, please respond to the original IRs using 5.05%.

10

11 **RESPONSE:**

12 Please see Manitoba Hydro's response to PUB/MH II-432(b).

1 **REFERENCE: PUB/MH I-156a**

2

3 **PREAMBLE:** The original question requested supporting calculations related to the
4 imputed interest rate associated with equity used in the RWACC.

5

6 **QUESTION:**

7 The response does not explain the basis for the imputed interest associated with equity (i.e. the
8 3% premium over the cost of debt). Please provide the rationale for using a 3% premium in
9 order to determine the cost of equity - as originally requested.

10

11 **RESPONSE:**

12 Please see Manitoba Hydro's response to PUB/MH II-381b.

1 **REFERENCE: PUB/MH I-161**

2

3 **QUESTION:**

4 In what units is the 22.3 value for electricity prices expressed, over what period of time (i.e. # of
5 years) is the levelized electricity price calculated. Is the result (22.3) in real or nominal dollars
6 and, if real, what year's dollars?

7

8 **RESPONSE:**

9 Please see Manitoba Hydro's responses to CAC/MH I-124 and CAC/MH II-40.

1 **REFERENCE: PUB/MH I-168a**

2

3 **QUESTION:**

4 Using a similar table please note the worst (in red) and best (in green) Plan for each of the 27
5 scenarios.

6

7 **RESPONSE:**

8 The following table highlights in red the lowest net present value of a development plan and in
9 green the highest net present value of a development plan for each of the 27 scenarios.

Energy Prices	Discount Rates	Capital Costs	1 2 3 4 5 6 7 8 9 10 11 12 13 14 15														
			All Gas	K22/Gas	Wind/Gas	K19/Gas24/250MW	K19/Gas25/750MW (WPS Sale & Inv)	K19/Gas31/750MW	SCGT/C26	CCGT/26	Wind/C26	K22/C29	K19/C31/250MW	K19/C31/750MW	K19/C25/250MW	K19/C25/750MW (WPS Sale & Inv)	K19/C25/750MW
Low (30%)	Low (15%)	High (30%)	-4043	-3792	-7483	-3190	-2855	-3418	-3309	-3529	-4449	-4064	-3506	-3554	-3459	-2841	-3642
		Ref (50%)	-3049	-2532	-5189	-1877	-1616	-2130	-2401	-2482	-3079	-2786	-2166	-2138	-2124	-1410	-2177
		Low (20%)	-2247	-1590	-3508	-890	-703	-1175	-1655	-1627	-1989	-1773	-1099	-1022	-1069	-292	-1030
	Ref (50%)	High (30%)	-463	-1212	-2869	-911	-730	-1191	-1297	-1531	-2174	-2539	-2161	-2323	-2510	-2155	-2816
		Ref (50%)	208	-278	-1337	95	257	-185	-582	-704	-1129	-1496	-1050	-1153	-1368	-929	-1559
		Low (20%)	750	408	-219	837	974	548	6	-29	-298	-678	-176	-243	-473	20	-585
	High (35%)	High (30%)	1204	25	-657	117	203	-182	-284	-517	-1015	-1659	-1413	-1622	-2029	-1810	-2383
		Ref (50%)	1708	785	487	963	1060	679	323	187	-145	-755	-434	-592	-994	-698	-1243
		Low (20%)	2114	1336	1321	1580	1674	1297	822	762	547	-51	327	201	-189	157	-364
Ref (55%)	Low (15%)	High (30%)	-5014	-2511	-6882	-1796	-2103	-2041	-1760	-1703	-2266	-840	-334	0	206	853	498
		Ref (50%)	-4020	-1251	-4588	-482	-865	-753	-852	-656	-897	438	1006	1415	1541	2284	1963
		Low (20%)	-3217	-309	-2906	504	49	202	-107	199	193	1451	2073	2531	2597	3402	3110
	Ref (50%)	High (30%)	-671	-46	-2166	341	109	85	23	-43	-463	-237	104	190	152	470	170
		Ref (50%)	0	887	-635	1346	1097	1091	738	784	582	806	1215	1360	1295	1696	1427
		Low (20%)	542	1573	483	2089	1813	1824	1326	1459	1414	1624	2089	2270	2189	2645	2401
	High (35%)	High (30%)	1308	1091	57	1258	1041	998	879	764	426	168	391	366	109	268	2
		Ref (50%)	1812	1851	1201	2104	1898	1859	1487	1468	1295	1073	1370	1396	1144	1380	1143
		Low (20%)	2218	2402	2035	2721	2512	2478	1986	2044	1987	1777	2132	2189	1949	2235	2022
High (15%)	Low (15%)	High (30%)	-6435	-1499	-6433	-692	-1694	-1006	-355	-23	-173	2355	2796	3410	3819	4372	4455
		Ref (50%)	-5441	-239	-4140	621	-456	282	552	1024	1196	3633	4135	4826	5154	5803	5921
		Low (20%)	-4638	703	-2458	1607	458	1237	1298	1879	2286	4646	5203	5941	6210	6922	7068
	Ref (50%)	High (30%)	-1158	941	-1580	1398	713	1127	1241	1336	1172	2014	2308	2571	2746	2940	2993
		Ref (50%)	-487	1874	-48	2403	1701	2134	1956	2163	2217	3057	3420	3741	3888	4166	4250
		Low (20%)	55	2560	1070	3146	2417	2867	2543	2838	3049	3875	4293	4652	4783	5115	5225
	High (35%)	High (30%)	1210	2017	671	2246	1691	1993	1956	1951	1794	1935	2127	2228	2170	2203	2236
		Ref (50%)	1713	2777	1816	3092	2549	2854	2563	2656	2663	2839	3106	3259	3206	3315	3377
		Low (20%)	2120	3328	2650	3709	3163	3473	3063	3231	3355	3543	3867	4051	4010	4170	4256

1 **REFERENCE: PUB/MH I-187**

2

3 **QUESTION:**

4 Please confirm that the discussion of losses provided in the response is with respect to losses
5 on Manitoba Hydro's system and does not cover any additional losses related to exports that
6 may/will be incurred on U.S. transmission facilities. In calculating revenues are export volumes
7 further adjusted to account for such losses?

8

9 **RESPONSE:**

10 It is confirmed that the losses described in PUB/MH I-187 reflect the estimated losses over the
11 Manitoba Hydro system.

12

13 The point of delivery for export transactions is at the Manitoba – U.S. border, referred to as the
14 Manitoba Hydro Electric Board node. Losses within the MISO market are accounted for in the
15 congestion component of the locational marginal price, rather than using a volume adjustment
16 for losses. As noted in the response to CAC/MH I-075a, “Manitoba Hydro applies a basis
17 differential to the forecast MINN HUB prices to account for losses and congestion between
18 MINN HUB and MHEB”.

1 **REFERENCE: Question PUB/MH I-190**

2

3 **QUESTION:**

4 Please explain why this type of technical assessment is considered Commercially Sensitive
5 Information.

6

7 **RESPONSE:**

8 The technical assessment referenced in PUB/MH 1-190 contains Critical Energy Infrastructure
9 information. Any specific engineering, vulnerability, or detailed design information about
10 proposed or existing critical infrastructure (physical or virtual) in the referenced report that:

11 1. Relates details about the production, generation, transmission, or distribution of
12 energy;

13 2. Could be useful to a person planning an attack on critical infrastructure; or

14 3. Gives strategic information beyond the location of the critical infrastructure;

15 is required to be kept confidential.

1 **REFERENCE: PUB/MH I-225a**

2

3 **PREAMBLE:** Chapter 13, Tables 13.2 and 13.3 set out values for Coal Taxes and
4 Potential Carbon Charges paid to the Manitoba Government.

5

6 **QUESTION:**

7 If not included in the economic evaluation but included in the Market Evaluation (per Table
8 13.2), please reconcile this with the statement on page 5 (Chapter 13) that the market
9 evaluation relied on the same annual revenue and expenditure cash flows as the economic
10 evaluation.

11

12 **RESPONSE:**

13 The economic evaluation does include provincial coal taxes and carbon charges on gas
14 generation.

1 **REFERENCE: PUB/MH I-225a**

2

3 **PREAMBLE:** Chapter 13, Tables 13.2 and 13.3 set out values for Coal Taxes and
4 Potential Carbon Charges paid to the Manitoba Government.

5

6 **QUESTION:**

7 Are Coal Taxes and Potential Carbon Charges paid to the Manitoba Government included in the
8 Financial Evaluation (Chapter 11)?

9

10 **RESPONSE:**

11 Coal taxes and potential carbon charges are included in the financial evaluation in Chapter 11.

1 **REFERENCE: PUB/MH I-231**

2

3 **PREAMBLE:** In Chapter 13 (page 32), only capital tax and water rentals were included as
4 net benefits to the Manitoba Government.

5

6 **QUESTION:**

7 Why was the debt guarantee fee included in the transfers to the Province for purposes of the
8 Conclusions (Chapter 14, Figure 14.1 and page 53) but not in the Manitoba Government part of
9 the Multiple Account analysis?

10

11 **RESPONSE:**

12 The provincial debt guarantee fees are payments made by Manitoba Hydro to the Province of
13 Manitoba. The Province utilizes these transfers as it sees fit for the benefit of Manitobans and
14 therefore the provincial debt guarantee fees were treated as representing a benefit which
15 should be considered in Chapter 14, along with water rentals and capital taxes. In Chapter 14
16 the benefits to Manitoba Hydro and the transfers to government are shown separately; they
17 are not combined in an overall evaluation so as to recognize the difference in the
18 characteristics of these benefits.

19

20 The provincial debt guarantee fees were not included as part of the net benefits in Chapter 13
21 because it was assumed that the fees are paid in exchange for the guarantee that the Province
22 provides.

1 **REFERENCE: PUB/MH 1-231**

2

3 **PREAMBLE:** In Chapter 13 (page 32), only capital tax and water rentals were included as
4 net benefits to the Manitoba Government.

5

6 **QUESTION:**

7 Please reconcile the total benefits of Pathways 4 and 5 (\$3,098 M and \$3,697 M respectively)
8 shown on pages 53-54 with the values shown in Figure 14.1 of Chapter 14. In doing so, please
9 provide a schedule that sets out the derivation of these two values.

10

11 **RESPONSE:**

12 The question above refers to the comparison of the NPV of 3 development plans: All Gas,
13 K19/C31/750MW (Pathway 4) and K19/C25/750MW (Pathway 5). The table below includes the
14 information included in the Figure 14.1 only for these plans.

15

16 **Development Plan NPV's – Including Potential Cash Transfers to the Province @ 5.05% Real**

17

Discount Rate

18

(Millions 2014 Dollars)

Development Plan / Pathway	Benefits to Manitoba Hydro	Water Rental & Capital Tax	Provincial Guarantee Fee	Total Development Plan NPV
All Gas – Pathway 1	131	209		340
K19/C31/750MW – Pathway 4	1,360	960	1,270	3,438
K19/C25/750MW – Pathway 5	1,696	1,094	1,247	4,037

19

1 The NPV of the K19/C31/750MW development plan minus the NPV of the All Gas plan is
2 \$3,098 million (\$3438- \$340).

3

4 The NPV of the K19/C25/750MW development plan minus the NPV of the All Gas plan is
5 \$3,697 million (\$4,037 - \$340).

1 **REFERENCE:** Question PUB/MH I-244 and PUB/MH I-177a

2

3 **QUESTION:**

4 The response states that over the period additional cash transfers are fully recovered from
5 incremental export revenue. Please confirm that the "period" referred to is the 68 year study
6 period.

7

8 **RESPONSE:**

9 The total study life or period used for the economic analysis is 78 years (See Section 1.2 in
10 Appendix 9.3 – Economic Evaluation Documentation). The financial evaluation encompasses a
11 50-year study period (See Section 11.2 in Chapter 11 – Financial Evaluation of Development
12 Plans).

1 **REFERENCE: Question PUB/MH I-245**

2

3 **QUESTION:**

4 Please confirm that 6% was the discount rate used to establish the 2014 present value under
5 each Plan.

6

7 **RESPONSE:**

8 Confirmed.

1 **REFERENCE: Question PUB/MH I-245**

2

3 **QUESTION:**

4 Why is this considered to be the appropriate discount rate for applying to employment
5 benefits?

6

7 **RESPONSE:**

8 The same discount rate was used for all of the present value calculations in Chapter 13, in
9 accordance with standard benefit-cost practice.

1 **REFERENCE: Question PUB/MH I-245 and PUB/MH I-149a**

2

3 **QUESTION:**

4 Why shouldn't the same discount rate be used for employment benefits (accruing to
5 Manitobans in the form of wages) Manitoba Hydro also be applied to General Consumer
6 Revenues (being paid by Manitobans) as opposed to Manitoba's approach which is to use 6%
7 and 1.83% respectively?

8

9 **RESPONSE:**

10 The present value of the employment benefits was calculated using the same weighted average
11 opportunity cost of capital-based rate (6%) that was used to discount all monetized benefits
12 and costs in the Multiple Account Benefit-Cost Analysis.

13

14 The discount rate used in the financial analysis (and not in any part of the MABCA in Chapter
15 13) serves a different purpose. Its purpose is to weight the rate impacts at different points in
16 time in order to calculate a levelized value indicator of the impact over the planning period. The
17 discount rate in the financial analysis is based on what economists call time preference – the
18 rate that reflects the trade-off that people would willingly make between benefits or costs now
19 and in the future.

1 **REFERENCE: Question PUB/MH I-246**

2

3 **QUESTION:**

4 Please confirm that 6% was the discount rate used to establish the 2014 present value under
5 each plan.

6

7 **RESPONSE:**

8 Confirmed.

1 **REFERENCE: Question PUB/MH I-246**

2

3 **QUESTION:**

4 Why is this considered to be the appropriate discount rate for applying to GHG external costs?

5

6 **RESPONSE:**

7 Please see Manitoba Hydro's response to CAC/MH II-114b.

1 **REFERENCE: PUB/MH I-247c**

2

3 **QUESTION:**

4 Why were bill savings from DSM not included in the Multiple Account analysis in Chapter 13?

5

6 **RESPONSE:**

7 The four development plans considered in the Multiple Account Evaluation have included the
8 same level of DSM. Therefore, the impact of DSM in the analysis is indifferent when comparing
9 among these plans.

1 **REFERENCE: PUB/MH I-247c**

2

3 **QUESTION:**

4 Under what circumstances would it be appropriate to include such savings in the Multiple
5 Account Analysis.

6

7 **RESPONSE:**

8 It would be necessary to consider the consequences of DSM if the DSM expenditures and or
9 savings differed among the plans.

1 **REFERENCE: Question PUB/MH I-247c**

2

3 **QUESTION:**

4 Please provide a general description of how this would be done (i.e. how would the annual
5 savings for each Plan be determined and how would they be discounted?).

6

7 **RESPONSE:**

8 The consequences of differing levels of DSM on the overall net benefits of the different
9 development plans would be captured by taking into account:

10

11 1) the reduction in Manitoba Hydro expenditures for new supply and /or increase in export
12 sales revenues and/or other changes in generation production cost because of the
13 estimated reduction in domestic electricity requirements;

14 2) Manitoba Hydro's expenditures in support of the DSM initiatives; and

15 3) customer expenditures required to achieve the reduction in requirements.

16

17 The net of those effects (present valued at the 6% social opportunity cost-based discount rate)
18 would indicate how Manitoba Hydro and its customers as a whole would be affected (whether
19 and to what extent there would be customer savings).

20

21 The distributional effect on different groups of customers, in particular DSM program
22 participants versus non-participants would be based on comparing rates associated with
23 different levels of DSM, all being applied to the same development plan.

24

25 Development plans can be compared to each other at different levels of DSM but each set of
26 comparisons would assume the same level of DSM.

1 **REFERENCE: PUB/MH 1-259**

2

3 **QUESTION:**

4 Over what period of time (i.e. # of years) is the 6.69 cents/kWh levelized value of avoided cost
5 calculated? Also, please confirm that the value is expressed in real 2012\$.

6

7 **RESPONSE:**

8 The marginal value of 6.69 cents/kWh was levelized over 30 years, between 2012-13 and
9 2021-22.

10

11 The value of 6.69 cents/kWh is expressed in 2012 constant (real) dollars.

1 **REFERENCE: Question PUB/MH I-1-288a, PUB/MH I-289b and PUB/MH I-289c**

2

3 **QUESTION:**

4 Please confirm that all of the contracts set out in Appendix 9.3, Table 1.9 have terms specifically
5 tying Manitoba Hydro to the construction of new hydraulic generation with annual dependable
6 energy in excess of the contract amounts.

7

8 **RESPONSE:**

9 Confirmed. Although the contracts listed in Table 1.9 of Appendix 9.3 do not require Manitoba
10 Hydro to build anything, they have been predicated on that occurring and anticipate the
11 delivery of energy and equivalent amounts of environmental attributes from new large hydro
12 facilities.

13

14 The addition of Keeyask and Conawapa will add new dependable hydraulic energy in excess of
15 the amounts needed by the contracts.

1 **SUBJECT: Caribou**

2

3 **REFERENCE: CAC/MH I-170**

4

5 **PREAMBLE:** “Fuel pricing is one of the most important considerations driving electrical
6 resource decisions and regional market prices for electricity. Recent reductions in cost
7 due to developments in shale gas extraction have increased the attractiveness of natural
8 gas as a supply source, particularly in relation to coal.”

9

10 **QUESTION:**

11 Please provide any information Manitoba Hydro has on the price elasticity of electricity
12 demand.

13

14 **RESPONSE:**

15 Please see Manitoba Hydro’s response to PUB/MH I-256.

1 **REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.:59**

2

3 **PREAMBLE:** To determine low income rate impact CAC MB requires the following
4 information.

5

6 **QUESTION:**

7 For 2009, based on the Residential Survey, please provide the average annual electricity bill for
8 residential customers by location (Winnipeg/Non-Winnipeg), home ownership status
9 (Own/Rent) and dwelling type (single detached/other).

10

11 **RESPONSE:**

12 Based on the 2009 Residential Energy Use Survey, the following table shows the 2009 average
13 annual electricity bill, taxes included, by location, ownership and dwelling type.

LOCATION	OWNERSHIP	DWELLING TYPE	2009 AVERAGE ANNUAL ELECTRICITY BILL
Winnipeg	Own	Single Detached	\$889
		Multi-Attached	\$737
		Apartment Suite	\$570
	Rent	Single Detached	\$689
		Multi-Attached	\$801
		Apartment Suite	\$402
Outside Winnipeg	Own	Single Detached	\$1,670
		Multi-Attached	\$1,147
		Apartment Suite	\$1,032
	Rent	Single Detached	\$1,641
		Multi-Attached	\$852
		Apartment Suite	\$577

14

1 **REFERENCE:** Appendix D 2013 Electric Load Forecast; Page No.:59, CAC/MH I-190

2

3 **PREAMBLE:** To determine low income rate impact CAC MB requires the following
4 information.

5

6 **QUESTION:**

7 For the period of January 2000 to June 2008, please provide the total number of residential
8 customers by month in each of the following four categories:

9

10 (1) <200 amp service <175 kWh;

11 (2) <200 Amp & >175 kWh;

12 (3) >200 Amp & <175 kWh;

13 (4) >200 Amp & >175 kWh.

14

15 **RESPONSE:**

16 The following presents the number of residential customers broken out by the above noted
17 categories:

1

Residential Basic Customer Counts by Monthly Consumption					
Month	RES BASIC <200 AMP		RES BASIC >200 AMP		Total Customers
	Less than 175 kW.h	Greater than 175 kW.h	Less than 175 kW.h	Greater than 175 kW.h	
2000 JAN	6,756	272,187	8	1,387	280,338
2000 FEB	8,106	269,381	11	1,377	278,875
2000 MAR	9,728	271,293	13	1,398	282,432
2000 APR	9,900	267,450	13	1,360	278,723
2000 MAY	12,630	267,442	10	1,381	281,463
2000 JUN	18,124	262,648	22	1,367	282,161
2000 JUL	16,078	265,341	28	1,368	282,815
2000 AUG	16,494	264,114	22	1,391	282,021
2000 SEP	14,799	268,634	12	1,426	284,871
2000 OCT	11,582	270,511	7	1,427	283,527
2000 NOV	10,013	274,582	13	1,442	286,050
2000 DEC	7,644	272,752	11	1,441	281,848
2001 JAN	7,242	275,658	13	1,451	284,364
2001 FEB	8,277	270,930	11	1,439	280,657
2001 MAR	10,045	272,672	12	1,440	284,169
2001 APR	10,860	269,140	6	1,407	281,413
2001 MAY	13,682	269,212	16	1,407	284,317
2001 JUN	17,214	265,656	18	1,402	284,290
2001 JUL	16,128	268,104	31	1,417	285,680
2001 AUG	16,604	265,579	26	1,432	283,641
2001 SEP	16,627	269,122	15	1,462	287,226
2001 OCT	12,106	273,599	14	1,488	287,207
2001 NOV	10,555	277,359	15	1,502	289,431
2001 DEC	9,042	280,013	13	1,532	290,600
2002 JAN	7,446	278,424	13	1,514	287,397
2002 FEB	8,432	275,286	8	1,496	285,222
2002 MAR	9,312	276,659	9	1,506	287,486
2002 APR	9,987	274,239	19	1,476	285,721
2002 MAY	12,019	273,272	11	1,457	286,759
2002 JUN	17,778	268,972	23	1,472	288,245
2002 JUL	15,503	271,775	20	1,485	288,783
2002 AUG	16,815	271,113	20	1,500	289,448
2002 SEP	16,240	274,408	20	1,541	292,209
2002 OCT	10,478	279,723	10	1,531	291,742
2002 NOV	9,249	282,567	7	1,571	293,394
2002 DEC	8,559	280,872	12	1,562	291,005

2003 JAN	7,222	283,455	9	1,574	292,260
2003 FEB	7,582	281,221	14	1,564	290,381
2003 MAR	8,625	282,178	12	1,583	292,398
2003 APR	10,418	278,371	14	1,570	290,373
2003 MAY	12,435	277,800	11	1,570	291,816
2003 JUN	18,448	272,600	34	1,548	292,630
2003 JUL	16,482	276,604	16	1,579	294,681
2003 AUG	16,391	273,119	28	1,577	291,115
2003 SEP	16,933	277,816	21	1,625	296,395
2003 OCT	12,193	282,214	18	1,642	296,067
2003 NOV	9,076	286,527	13	1,672	297,288
2003 DEC	8,557	285,401	11	1,668	295,637
2004 JAN	6,789	288,128	13	1,691	296,621
2004 FEB	7,657	284,963	14	1,659	294,293
2004 MAR	9,170	286,491	13	1,648	297,322
2004 APR	9,957	283,381	13	1,635	294,986
2004 MAY	12,576	283,541	21	1,662	297,800
2004 JUN	37,116	331,242	27	1,625	370,010
2004 JUL	31,430	341,220	28	1,648	374,326
2004 AUG	32,942	338,343	25	1,662	372,972
2004 SEP	30,694	344,926	14	1,728	377,362
2004 OCT	25,728	348,657	16	1,785	376,186
2004 NOV	22,845	353,433	16	1,931	378,225
2004 DEC	18,600	353,717	22	2,009	374,348
2005 JAN	16,632	355,653	20	2,049	374,354
2005 FEB	20,297	349,311	22	2,019	371,649
2005 MAR	22,691	349,359	20	2,021	374,091
2005 APR	23,496	347,699	14	1,998	373,207
2005 MAY	27,141	346,109	28	1,966	375,244
2005 JUN	33,951	360,137	27	1,975	396,090
2005 JUL	30,408	366,346	40	2,018	398,812
2005 AUG	34,303	366,125	43	2,037	402,508
2005 SEP	33,841	370,676	40	2,054	406,611
2005 OCT	29,286	375,886	18	2,089	407,279
2005 NOV	24,102	384,189	19	2,132	410,442
2005 DEC	22,540	388,240	16	2,114	412,910
2006 JAN	18,529	391,695	22	2,175	412,421
2006 FEB	23,011	386,168	18	2,165	411,362
2006 MAR	25,044	384,950	33	2,162	412,189
2006 APR	47,602	376,147	98	2,122	425,969
2006 MAY	54,881	369,147	148	2,083	426,259
2006 JUN	52,906	371,254	153	2,082	426,395
2006 JUL	50,360	374,154	130	2,120	426,764
2006 AUG	54,801	370,076	143	2,119	427,139
2006 SEP	51,972	373,255	99	2,181	427,507
2006 OCT	47,083	378,560	111	2,197	427,951

2006 NOV	41,782	384,519	115	2,225	428,641
2006 DEC	41,219	385,439	88	2,273	429,019
2007 JAN	36,436	390,535	71	2,301	429,343
2007 FEB	39,520	387,777	81	2,300	429,678
2007 MAR	44,617	382,941	91	2,298	429,947
2007 APR	48,754	379,025	126	2,273	430,178
2007 MAY	57,694	370,282	142	2,267	430,385
2007 JUN	54,705	373,566	143	2,271	430,685
2007 JUL	52,775	375,813	149	2,270	431,007
2007 AUG	53,637	375,290	149	2,282	431,358
2007 SEP	54,893	374,414	129	2,311	431,747
2007 OCT	53,793	376,022	141	2,327	432,283
2007 NOV	42,666	387,647	119	2,367	432,799
2007 DEC	40,858	389,906	92	2,416	433,272
2008 JAN	33,952	397,242	76	2,456	433,726
2008 FEB	37,214	394,244	78	2,460	433,996
2008 MAR	36,872	394,921	86	2,459	434,338
2008 APR	43,694	388,471	105	2,447	434,717
2008 MAY	48,449	384,054	131	2,426	435,060
2008 JUN	56,523	376,495	186	2,385	435,589

1

2 Please note the following data considerations:

3

4 January 2000 – June 2004: The data displays the number of bills split by Rate group and
 5 classified based on monthly usage from the billing system prior to conversion to the current
 6 billing system. Due to constraints of the previous system, customers on bi-monthly billing
 7 would be categorized based upon the energy for the entire billing period. This data does not
 8 include previous Winnipeg Hydro customers as this is prior to the acquisition.

9

10 June 2004 – March 2006: The data displays the number of bills split by Rate group and classified
 11 based on monthly usage from the billing system prior to conversion to the current billing
 12 system. Due to constraints of the previous system, customers on bi-monthly billing would be
 13 categorized based upon the energy for the entire billing period. This data includes previous
 14 Winnipeg Hydro customers.

April 2006 – June 2008: The data displays the number of customers in each month split by Rate Group and classified based on the monthly usage. For customers on bi-monthly billing, for the months the customer did not have a bill, the customer would be included in the count for the under 175 kW.h category.

1 **REFERENCE:** Appendix D 2013 Electric Load Forecast; Page No.:59 ; Question CAC/MH
2 I-190

3

4 **PREAMBLE:** To determine low income rate impact CAC MB requires the following
5 information.

6

7 **QUESTION:**

8 For the period of July 2008 to March 2011, please provide the total number of residential
9 customers in each of the following four categories:

10

11 (1) <200 Amp&<900 kWh;

12 (2) <200 Amp&>900 kWh;

13 (3) >200 Amp&<900 kWh;

14 (4) >200 Amp&>900 kWh,

15

16 by month.

17

18 **RESPONSE:**

19 The following presents the number of residential customers broken out by the above noted
20 categories:

Residential Basic Customer Counts by monthly consumption					
Month	RES <200AMP		RES >200AMP		Total Bills
	< 900 kW.h	> 900 kW.h	< 900 kW.h	> 900 kW.h	
2008 JUL	269,698	163,689	566	2,021	435,974
2008 AUG	255,897	177,920	517	2,084	436,418
2008 SEP	258,877	175,415	437	2,200	436,929
2008 OCT	267,987	166,993	375	2,289	437,644
2008 NOV	227,926	207,597	242	2,461	438,226
2008 DEC	198,671	237,314	172	2,562	438,719
2009 JAN	151,122	285,126	136	2,619	439,003
2009 FEB	185,833	250,757	157	2,604	439,351
2009 MAR	198,401	238,344	188	2,587	439,520
2009 APR	207,242	229,757	211	2,571	439,781
2009 MAY	250,245	186,979	299	2,495	440,018
2009 JUN	252,590	184,869	375	2,434	440,268
2009 JUL	268,063	169,744	577	2,240	440,624
2009 AUG	276,878	161,213	608	2,239	440,938
2009 SEP	273,590	164,951	551	2,313	441,405
2009 OCT	237,726	201,387	302	2,580	441,995
2009 NOV	234,800	204,737	272	2,650	442,459
2009 DEC	205,980	233,908	206	2,770	442,864
2010 JAN	159,097	281,040	161	2,833	443,131
2010 FEB	192,642	247,763	171	2,840	443,416
2010 MAR	208,981	231,630	239	2,772	443,622
2010 APR	229,303	211,523	287	2,738	443,851
2010 MAY	259,483	181,483	384	2,655	444,005
2010 JUN	279,506	161,768	598	2,455	444,327
2010 JUL	238,161	203,411	575	2,509	444,656
2010 AUG	230,889	211,065	616	2,489	445,059
2010 SEP	272,045	170,353	647	2,491	445,536
2010 OCT	277,128	165,724	472	2,701	446,025
2010 NOV	232,173	211,286	307	2,928	446,694
2010 DEC	196,372	247,555	226	3,032	447,185
2011 JAN	160,619	283,626	201	3,067	447,513
2011 FEB	191,977	252,432	206	3,064	447,679
2011 MAR	190,092	254,681	242	3,038	448,053

1 **REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2;**
2 **Page No.:7; CAC/MH 1-139**

3
4 **PREAMBLE:** To determine low income rate impact CAC MB requires the following
5 information.

6
7 **QUESTION:**
8 Please provide a schedule that sets out Manitoba Hydro's approved Residential rates for 1999
9 and 2000 and the effective dates for rates during those two calendar years.

10
11 **RESPONSE:**
12 Residential electricity rates in effect for 1999 and 2000 are shown below. These rates were in
13 effect as of April 1, 1997 and remained in effect until November 1, 2001, when Uniform Rate
14 Legislation was introduced. Prior to uniform rates (which allowed for all grid-connected
15 customers in Manitoba to pay the same class rates), rates varied by rate zone. A description of
16 these zones is provided below.

Residential	Zone 1	Zone 2	Zone 3
Monthly Basic Charge:			
<200 Amp	\$6.25	\$7.63	\$13.65
>200 Amp	\$12.50	\$13.88	\$19.90
Energy Charge:			
First 175 kWh	\$0.0578	\$0.0653	\$0.0733
Balance of kWh	\$0.0516	\$0.0516	\$0.0516

17
18 **Zone 1:** Winnipeg (legal boundary)
19 **Zone 2:** Medium Density – 100 metered services or more with a line density of at least 15
20 customers per kilometer of distribution line outside of Zone 1.
21 **Zone 3:** Low Density – less than 100 metered services, outside of all other rate zones.

1 **SUBJECT: Export Markets; Load Forecast**

2

3 **REFERENCE: CAC/MH I-201**

4

5 **PREAMBLE:** In the response to CAC/MH I-201, it is indicated that CO2 price sensitivities
6 were performed by MISO, Northern States Power, and Minnesota Power.

7

8 **QUESTION:**

9 How does the load growth for those sensitivities compare to the base or BAU cases for the
10 three entities?

11

12 **RESPONSE:**

13 MISO's 2012 Transmission Expansion Plan's "Combined Policy" scenario references a Demand
14 growth rate of 0.5%/year and Energy growth rate of 1.9%/year. However these results should
15 be prefaced that the "Combined Policy" scenario includes a number of variant assumptions
16 relative to the BAU case (i.e. more than just a carbon price). Below is a short synopsis of the
17 scenario provided in the MISO MTEP 2012 report (page 116):

18 *The Combined Policy future scenario was developed to capture the effects of multiple*
19 *future policy scenarios into one future. This scenario includes a federal RPS, smart grid*
20 *and electric vehicles. The federal RPS assumes all states are required to meet a 20*
21 *percent federal RPS mandate by 2025. This future includes 23 GW of coal retirements,*
22 *with the smallest and least efficient coal units retired. Smart grid is modeled by reducing*
23 *the demand growth rate, assuming that a higher penetration of smart grid will lower the*
24 *overall growth of demand. Electric vehicles are modeled by increasing the energy growth*
25 *rate. They are assumed to increase off-peak energy usage and increase the overall*
26 *energy growth rate.*

27 Manitoba Hydro cannot confirm what load growth assumptions were used by Minnesota Power
28 and Northern State Power in their CO2 sensitivity analysis.

1 **SUBJECT: Natural Gas**

2

3 **REFERENCE: CAC/MH I-205**

4

5 **PREAMBLE:** In the response to CAC/MH I-205, it is indicated that volatility results will
6 vary by natural gas hub.

7

8 **QUESTION:**

9 Are you aware of any North American hubs where natural gas prices still exhibit high volatility
10 over the past 5 years?

11

12 **RESPONSE:**

13 The response to CAC/MH I-205 noted that volatility in the post-2006 period will vary depending
14 on the specific North American natural gas hub chosen. This statement refers to the 2007 U.S.
15 Energy Information Administration natural gas price volatility study which noted different
16 historical levels of price volatility at the benchmark Henry, Chicago, and New York City Hubs.
17 Manitoba Hydro does not have a comprehensive database of historical price volatility data for
18 all North American natural gas hubs. However, natural gas prices at the Transco NY and
19 Algonquin Citygate trading points in the Northeast U.S. in particular have recently experienced
20 high price volatility as a result of local pipeline constraints and high pipeline transportation load
21 factors due to residential and commercial fuel switching away from refined petroleum products
22 to natural gas and increased use of gas-fired power generation (see U.S. EIA Short-Term Energy
23 Outlook Supplement, January 2013:

24 http://www.eia.gov/forecasts/steo/special/pdf/2013_sp_01.pdf).

25

26 A recent study prepared by ICF International for the ISO New England concludes that while
27 improved supply access over the long-term will lower volatility, New England will continue to
28 see higher price volatility than the Henry Hub for the foreseeable future (see Section 3.2 of Gas-

- 1 Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies,
- 2 November 2013:
- 3 <http://www.iso->
- 4 [ne.com/committees/comm_wkgrps/prtcpts_comm/pac/mtrls/2013/nov202013/icf_upstream](http://www.iso-ne.com/committees/comm_wkgrps/prtcpts_comm/pac/mtrls/2013/nov202013/icf_upstream)
- 5 [_gen_impacts_white_paper_11-18-2013.pdf](http://www.iso-ne.com/committees/comm_wkgrps/prtcpts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11-18-2013.pdf)

1 **SUBJECT: Export Markets; Price Forecasts**

2

3 **REFERENCE: CAC/MH I-209**

4

5 **PREAMBLE:** In the response to CAC/MH I-209, it is indicated that the impact of new
6 hydro generation on regional export prices would be minimal with no transmission
7 constraints. The Independent Market Monitor for MISO currently defines three Narrow
8 Constrained Areas (Minnesota, Wisconsin-Upper Michigan, and North Wisconsin-Upper
9 Michigan) [Pg.61 of the 2012 State of the Market Report].

10

11 **QUESTION:**

12 How would the new Manitoba Hydro generation impact export prices if the constraints
13 identified by the Independent Market Monitor are not alleviated?

14

15 **RESPONSE:**

16 Manitoba Hydro notes that the discussion on page 61 of the 2012 State of the Market Report
17 address market power rather than physical transmission congestion. As stated on page 61,
18 “NCAs are chronically constrained areas that raise more severe potential local market power
19 concerns (i.e., tighter market power mitigation measures are employed)”. In other words, the
20 comment specifically relates to the monitoring for the potential exertion of market power
21 during period of high demand/ prices, not identifying regions that are necessarily experiencing
22 negative economic impacts due to physical congestion of the transmission system.

23

24 MISO’s June 2013 Northern Area Study stated:

25 *“Economic benefits for MISO from new potential Manitoba Hydro to MISO tie-lines could*
26 *be realized with minimal incremental transmission investment. The Northern Area Study*
27 *identified Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV upgrade as a cost-*
28 *effective option to mitigate the remaining out-year congestion from wind on the*

1 *Dakotas – Minnesota border (B/C ratio 3.46 – 14.74 depending on scenario*
2 *assumption)."*

3

4 The Northern Area study concluded that only “*minimal incremental transmission investment*” to
5 the existing transmission system will be required to take advantage of Manitoba Hydro’s new
6 export power capacity, and the two identified upgrades showed significant overall economic
7 benefits. Manitoba Hydro has not conducted a specific price impact analysis with and without
8 the Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV upgrades. However, given the
9 overall benefits to the market and the minimal incremental transmission investment required
10 for the upgrades, it is a reasonable assumption that both of these upgrades will be undertaken
11 as part of MISO’s formal transmission planning process. Therefore, Manitoba Hydro anticipates
12 that new hydro generation, combined with proposed transmission interconnection upgrades as
13 per the Preferred Development Plan, and with anticipated transmission updates within MISO,
14 would not increase existing congestion, in the region and in turn, would not negatively impact
15 export market prices due to congestion.

1 **SUBJECT: Wind**

2

3 **REFERENCE: CAC/MH I-213**

4

5 **PREAMBLE:** In the response to CAC/MH I-213, four benefits to Manitoba Hydro's
6 domestic customers are identified. The first of these, labeled "a", refers to favorable
7 recognition in US markets of the complementary nature of hydropower and wind and
8 the benefits to US consumers.

9

10 **QUESTION:**

11 Please explain how this benefits Manitoba Hydro's domestic customers.

12

13 **RESPONSE:**

14 The response to CAC/MH 1-213 stated in part:

15

16 "Additional benefits to Manitoba Hydro's domestic customers which were beyond the scope of
17 the MHWSS but which also result from new hydropower in Manitoba and a new 500 kV
18 transmission line include:

19 a) Favorable recognition in U.S. markets of the complementary nature of new renewable
20 hydropower in Manitoba and planned wind power development in MISO. As a result new
21 hydro is not seen as a competitor to US wind but rather as necessary to enable additional
22 wind development. This recognition may result in US decision makers and regulators being
23 even more supportive of imports from Manitoba Hydro. The substantial Load Cost Savings
24 identified by the MHWSS and the displacement of carbon-based energy in MISO with
25 carbon-free energy from Manitoba are two significant benefits for U.S. consumers which
26 are important to U.S. decision makers and regulators."

27

28 Support of U.S. decision makers and regulators for imports from Manitoba Hydro is an
29 important part of the Preferred Development Plan and for Manitoba Hydro's exports in general.
30 The Minnesota Public Utilities Commission (MPUC) has already approved the 250 MW sale to

- 1 Minnesota Power, and is also reviewing the Minnesota section of the new interconnection (the
- 2 Great Northern Transmission line). Without these approvals, the benefits that the preferred
- 3 development plan brings to Manitoba Hydro's domestic customers would not be obtained.

1 **SUBJECT: Export Markets**

2

3 **REFERENCE: CAC/MH I214a**

4

5 **PREAMBLE:** In the response to CAC/MH I-214a, it is indicated that Minnesota imports
6 15 TWh of their states' electricity needs.

7

8 **QUESTION:**

9 Please confirm that even if all of those imports were generated from coal, the amount of
10 electricity derived from coal in Minnesota is 63%.

11

12 **RESPONSE:**

13 Mathematically, if the 15 TWh of imports to Minnesota referenced in CAC/MH I-214a were all
14 assumed to be coal generation, the portion of coal generation in the Minnesota electricity
15 energy mix would be around 63%.

16

17 As previously noted in the response to CAC/MH 1-214a, "MISO does not dispatch generation
18 within a state to meet only the loads within a state. Rather MISO dispatches the entire regional
19 generation fleet to meet the aggregate load of the region, subject to transmission limits, and
20 without regard to state boundaries."

1 **SUBJECT: Wind**

2

3 **REFERENCE: CAC/MH I-215a**

4

5 **PREAMBLE:** In the response to CAC/MH I-215a, a map indicating the amount of wind
6 capacity by state is used to indicate that most of the wind in MISO is located in Iowa and
7 Illinois. Figure 1-1 of MISO's 2013 Wind Capacity Report indicates that there is only 625
8 MW of wind in MISO's Zone 4 and 5 combined (covering Illinois and Missouri) and only
9 287 MW is in Zone 6 (Indiana and Kentucky), while 79% of wind capacity is in Zones 1
10 (the Dakotas, much of Minnesota, and western Wisconsin) and 3 (Iowa and southern
11 Minnesota).

12

13 **QUESTION:**

14 Please confirm that much of the wind generation indicated on the NREL map in the southern
15 MISO states is not actually located in MISO.

16

17 **RESPONSE:**

18 Manitoba Hydro cannot confirm that much of the wind generation indicated on the NREL map
19 in the southern MISO states is not actually located in MISO. Manitoba Hydro does not have
20 access to the NREL mapping information as it relates to MISO membership. However, it is
21 Manitoba Hydro's understanding that much of the wind generation in Iowa is owned or
22 contracted to MidAmerican Energy, who is Iowa's largest energy company and a MISO member.

1 **SUBJECT: Rate Impacts**

2

3 **REFERENCE: Chapter 11 Financial Evaluation of Development Plans; CAC/MH I-140;**
4 **CAC/MH I-165; CAC/MH I-181a; CAC/MH I-191b**

5

6 **PREAMBLE:** CAC wishes to understand the rate impacts, bill impacts and relative
7 affordability of electricity compared to other Provinces for average and low income
8 residential customers resulting from the preferred and alternative plans.

9

10 **QUESTION:**

11 The Minister of Finance 2013 Report under The Affordability Utility Rate Act was Tabled in the
12 Legislature on August 26 2013. Please use the data in response CAC/MH I-140 to generate a
13 Table(s) that show(s) the rate impacts for the Preferred Plan as follows:

14

15 (i) 2015-2025 by year, the average residential rates;

16 (ii) bill impacts by year for residential electric heating customer per response CAC/MH I-191b;

17 (iii) similar bill impacts for low income customer using (defined) Manitoba Hydro LI threshold
18 for DSM .

19

20 **RESPONSE:**

21 Please see the tables below for the data as requested in i), ii) and iii). Please note that the
22 annual kWh usage for the low income customer group (LICO-125) provided in response to part
23 iii), is based on electric heat services, to be consistent with the consumption levels reported in
24 response to CAC/MH I-191(b).

Preferred Plan	Residential Rates	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
K19 Exp C25 750mw	Monthly Basic Charge:	\$7.63	\$7.93	\$8.24	\$8.57	\$8.91	\$9.26	\$9.63	\$10.01	\$10.41	\$10.82	\$11.25
	Energy Charge (per kWh):	\$0.0772	\$0.0802	\$0.0834	\$0.0867	\$0.0901	\$0.0937	\$0.0974	\$0.1012	\$0.1052	\$0.1094	\$0.1137

Income Range:	Single Detached	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Annual kWh Usage (Electric Heat Billed)											
Under \$25,000	23,233	\$1,885	\$1,958	\$2,037	\$2,117	\$2,200	\$2,288	\$2,378	\$2,471	\$2,569	\$2,672	\$2,777
\$25,000 - \$49,999	28,146	\$2,264	\$2,352	\$2,446	\$2,543	\$2,643	\$2,748	\$2,857	\$2,968	\$3,086	\$3,209	\$3,335
\$50,000 - \$74,999	29,316	\$2,355	\$2,446	\$2,544	\$2,645	\$2,748	\$2,858	\$2,971	\$3,087	\$3,209	\$3,337	\$3,468
\$75,000 - \$99,999	31,902	\$2,554	\$2,654	\$2,760	\$2,869	\$2,981	\$3,100	\$3,223	\$3,349	\$3,481	\$3,620	\$3,762
\$100,000 plus	32,254	\$2,582	\$2,682	\$2,789	\$2,899	\$3,013	\$3,133	\$3,257	\$3,384	\$3,518	\$3,658	\$3,802
Overall	28,574	\$2,297	\$2,387	\$2,482	\$2,580	\$2,681	\$2,789	\$2,899	\$3,012	\$3,131	\$3,256	\$3,384
LICO-125	24,317	\$1,969	\$2,045	\$2,127	\$2,211	\$2,298	\$2,390	\$2,484	\$2,581	\$2,683	\$2,790	\$2,900

Income Range:	Multi-Attached	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Annual kWh Usage (Electric Heat Billed)											
Under \$25,000	16,152	\$1,338	\$1,391	\$1,446	\$1,503	\$1,562	\$1,625	\$1,689	\$1,755	\$1,824	\$1,897	\$1,971
\$25,000 - \$49,999	15,261	\$1,270	\$1,319	\$1,372	\$1,426	\$1,482	\$1,541	\$1,602	\$1,665	\$1,730	\$1,799	\$1,870
\$50,000 - \$74,999	17,271	\$1,425	\$1,480	\$1,539	\$1,600	\$1,663	\$1,729	\$1,798	\$1,868	\$1,942	\$2,019	\$2,099
\$75,000 - \$99,999	17,546	\$1,446	\$1,502	\$1,562	\$1,624	\$1,688	\$1,755	\$1,825	\$1,896	\$1,971	\$2,049	\$2,130
\$100,000 plus	15,882	\$1,318	\$1,369	\$1,423	\$1,480	\$1,538	\$1,599	\$1,662	\$1,727	\$1,796	\$1,867	\$1,941
Overall	16,346	\$1,353	\$1,406	\$1,462	\$1,520	\$1,580	\$1,643	\$1,708	\$1,774	\$1,845	\$1,918	\$1,994
LICO-125	15,923	\$1,321	\$1,372	\$1,427	\$1,483	\$1,542	\$1,603	\$1,666	\$1,732	\$1,800	\$1,872	\$1,945

Income Range:	Apartment Suite	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Annual kWh Usage (Electric Heat Billed)											
Under \$25,000	7,946	\$705	\$732	\$762	\$792	\$823	\$856	\$890	\$924	\$961	\$999	\$1,038
\$25,000 - \$49,999	8,847	\$775	\$805	\$837	\$870	\$904	\$940	\$977	\$1,015	\$1,056	\$1,098	\$1,141
\$50,000 - \$74,999	9,330	\$812	\$843	\$877	\$912	\$948	\$985	\$1,024	\$1,064	\$1,106	\$1,151	\$1,196
\$75,000 - \$99,999	10,711	\$918	\$954	\$992	\$1,031	\$1,072	\$1,115	\$1,159	\$1,204	\$1,252	\$1,302	\$1,353
\$100,000 plus	12,668	\$1,070	\$1,111	\$1,155	\$1,201	\$1,248	\$1,298	\$1,349	\$1,402	\$1,458	\$1,516	\$1,575
Overall	8,969	\$784	\$814	\$847	\$880	\$915	\$952	\$989	\$1,028	\$1,068	\$1,111	\$1,155
LICO-125	7,608	\$679	\$705	\$733	\$762	\$792	\$824	\$857	\$890	\$925	\$962	\$1,000

1

1 **SUBJECT: Rate Impacts**

2

3 **PREAMBLE:** CAC wishes to understand the rate impacts, bill impacts and relative
4 affordability of electricity compared to other Provinces for average and low income
5 residential customers resulting from the preferred and alternative plans.

6

7 **QUESTION:**

8 The Minister of Finance 2013 Report under The Affordability Utility Rate Act was Tabled in the
9 Legislature on August 26 2013. Please provide a comparison of future Manitoba Hydro, BC, Sask
10 and PQ electricity costs for 2015-2025 in both tabular and chart form based on Annual Basic
11 Utility Bundle Cost Comparison (found on the page 2 of this document) and assuming the
12 following (i) Manitoba Hydro electricity costs start in 2013 at \$844/yr and escalate as per
13 Preferred Plan from 2015-2025; (ii) BC, Saskatchewan and Quebec electricity prices escalate at
14 the rate of Canadian Deflator (CAC/MH I-150) (iii) all provincial natural gas and auto insurance
15 costs increase at the Canadian Deflator. Please show the Deflator on the chart and in the Table
16 show also the 2025 Totals and Gap from Manitoba.

Annual basic utility bundle cost comparison for the year ended March 31, 2013

This annual summary provides a comparison of the cost of a bundle of Manitoba's basic utility services with the cost of that same bundle in other Canadian provinces during the year ended March 31, 2013. The bundle includes electricity, natural gas (home heating) and auto insurance services. The comparative costs were developed based on a methodology developed by Deloitte LLP.

Province	Electricity (non-electric heat)	Natural gas (home heating)	Automobile insurance	Total	Gap from Manitoba
British Columbia	\$1,007	\$845	\$1,472	\$3,324	\$593
Alberta	1,768	618	2,491	4,877	2,146
Saskatchewan	1,496	744	1,168	3,408	677
Manitoba	844	735	1,152	2,731	-
Ontario	1,494	792	5,380	7,666	4,935
Quebec	756	1,327	1,356	3,439	708
New Brunswick	1,342	2,254	1,882	5,478	2,747
Nova Scotia	1,687	2,372	1,708	5,767	3,036
Prince Edward Island	1,652	2,547	1,828	6,027	3,296
Newfoundland	1,406	2,462	1,707	5,575	2,844
Average	\$1,345	\$1,470	\$2,014	\$4,829	\$2,098

Utility bundle component calculation summary

Electricity

The annual cost of electricity for each province is the weighted average¹ of the annual cost of electricity for each of two centres surveyed in the province. The annual cost of electricity for each of the two centres surveyed in each province, one urban and one rural, is based on monthly electricity utilization that reflects actual Manitoba experience for non-electric heat residential customers, multiplied by the actual monthly rates in effect for that centre. Manitoba electricity utilization experience reflected in the 2013 results is 11,075 kWh per year.

Natural gas (home heating)

The annual cost of home heating for each province is the weighted average¹ of the annual cost of natural gas heating for each of two centres surveyed in the province. The annual cost of natural gas for each of the two centres surveyed in each province, one urban and one rural, is based on monthly natural gas utilization that reflects actual Manitoba experience for residential customers, multiplied by the actual monthly rates in effect for that centre. Manitoba natural gas utilization experience reflected in the 2013 results is 2,427 cubic metres per year. In a limited number of centres surveyed, where natural gas is not available, a heat equivalent amount of heating oil is utilized as the basis for calculating the annual cost of heating.

Auto insurance

The annual cost of auto insurance for each province is the weighted average¹ of the annual cost of auto insurance in each of two centres surveyed in the province. The annual cost of auto insurance in each centre, one urban and one rural, is based on the average of the cost of annual insurance coverage for a sample of ten vehicle/driver/coverage profiles. The ten vehicle/driver/coverage profiles were developed to reflect the most popular vehicles insured in Manitoba and proportional representation of actual driver ages, driver safety ratings and insurance coverage purchased for passenger vehicles in Manitoba.

¹ Weighting is between costs in the two sample centres, one urban and one rural, based on data published by Statistics Canada in their 2011 survey of "Private Dwellings occupied by usual residents" for each province.

1 **RESPONSE:**

2 The GDP deflator rate assumed in the preamble to this Information Request is considerably less
3 than the average rate increases being proposed for these three utilities. The GDP deflator is a
4 general measure of the cost changes of all goods and services produced in a country. In
5 general, utilities across Canada have been experiencing cost increases greater than the rate of
6 the GDP price deflator. Thus, where better information is available on the proposed future rate
7 increases for these utilities, Manitoba Hydro has incorporated that information instead of the
8 GDP Deflator proxy.

9
10 The British Columbia government has announced electricity rate increases of 9.0% for 2014 and
11 6.0% for 2015, while the British Columbia Utilities Commission (BCUC) has capped rate
12 increases for BC Hydro in 2016, 2017 and 2018 at 4.0%, 3.5% and 3.0% respectively. The
13 Saskatchewan Rates Review Panel (SRRP) is currently reviewing proposed increases for
14 SaskPower of 5.5% for 2014, and 5.0% in each of the following two years (2015 and 2016).
15 Hydro Quebec is also proposing a rate increase of 3.4% for 2014, which, when incorporated
16 with a proposed increase to their rate of return, will result in an overall average increase of
17 approximately 5.8% this year. As the information provided in the bundled cost comparison was
18 only to March 31, 2013, the approved 2013/14 rate increases for all utilities has also been
19 incorporated as shown in the tables below.

20
21 Despite the incorporation of this better information, Manitoba Hydro remains concerned that
22 the the GDP deflator is not reflective of future rates of other utilities, hence this information
23 should be interpreted with caution. Table (i) provides Manitoba Hydro's electricity costs
24 specified in the preamble escalated in accordance with the Preferred Development Plan. Table
25 ii) provides BC, Saskatchewan and Quebec electricity prices escalated in accordance with the
26 rate increases approved or proposed above, and at the GDP deflator thereafter. Table iii)
27 provides the balance of the requested calculations; although Manitoba Hydro notes that it does
28 not have information to suggest the stated assumption is reasonable.

i) MH electricity costs of \$844/yr escalated as per Preferred Plan

Electricity Costs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
K19 Exp C25 750mw		3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Manitoba	\$844	\$874	\$908	\$944	\$981	\$1,020	\$1,060	\$1,102	\$1,145	\$1,191	\$1,238	\$1,287	\$1,337

ii) BC,Sask, Quebec electricity prices escalated for approved and proposed rate increases and at rate of Cdn Deflator (CAC/MH I-150)

Electricity Costs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cdn GDP Deflator - % chg		1.80%	1.80%	1.80%	1.80%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
Approved & Proposed Rate Increases:													
- British Columbia		1.44%	9.0%	6.0%	4.0%	3.5%	3.0%						
- Saskatchewan		4.9%	5.5%	5.0%	5.0%								
- Quebec		2.41%	5.8%										
British Columbia	\$1,007	\$1,022	\$1,113	\$1,180	\$1,227	\$1,270	\$1,309	\$1,333	\$1,359	\$1,385	\$1,411	\$1,438	\$1,465
Saskatchewan	\$1,496	\$1,569	\$1,656	\$1,738	\$1,770	\$1,803	\$1,838	\$1,872	\$1,908	\$1,944	\$1,981	\$2,019	\$2,057
Quebec	\$756	\$774	\$788	\$802	\$817	\$832	\$848	\$864	\$881	\$897	\$914	\$932	\$950

iii) all provincial natural gas & auto insurance costs increase at Cdn Deflator

Natural Gas Costs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cdn GDP Deflator - % chg		1.80%	1.80%	1.80%	1.80%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
Manitoba	\$735	\$748	\$762	\$775	\$789	\$804	\$820	\$835	\$851	\$867	\$884	\$901	\$918
British Columbia	\$845	\$860	\$876	\$891	\$908	\$925	\$942	\$960	\$978	\$997	\$1,016	\$1,035	\$1,055
Saskatchewan	\$744	\$757	\$771	\$785	\$799	\$814	\$830	\$845	\$862	\$878	\$895	\$912	\$929
Quebec	\$1,327	\$1,351	\$1,375	\$1,400	\$1,425	\$1,452	\$1,480	\$1,508	\$1,537	\$1,566	\$1,596	\$1,626	\$1,657
Auto Insurance	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cdn GDP Deflator - % chg		1.80%	1.80%	1.80%	1.80%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
Manitoba	\$1,152	\$1,173	\$1,194	\$1,215	\$1,237	\$1,261	\$1,285	\$1,309	\$1,334	\$1,359	\$1,385	\$1,411	\$1,438
British Columbia	\$1,472	\$1,498	\$1,525	\$1,553	\$1,581	\$1,611	\$1,642	\$1,673	\$1,704	\$1,737	\$1,770	\$1,804	\$1,838
Saskatchewan	\$1,168	\$1,189	\$1,210	\$1,232	\$1,254	\$1,278	\$1,303	\$1,327	\$1,352	\$1,378	\$1,404	\$1,431	\$1,458
Quebec	\$1,356	\$1,380	\$1,405	\$1,431	\$1,456	\$1,484	\$1,512	\$1,541	\$1,570	\$1,600	\$1,630	\$1,661	\$1,693

1 The table below provides the 2025 totals and the level of cost compared to Manitoba.

Province	Electricity (non-electric heat)	Natural Gas (home heating)	Automobile Insurance	Total	Increase over Manitoba
Manitoba	\$1,337	\$918	\$1,438	\$3,693	-
British Columbia	\$1,465	\$1,055	\$1,838	\$4,358	\$665
Saskatchewan	\$2,057	\$929	\$1,458	\$4,444	\$751
Quebec	\$950	\$1,657	\$1,693	\$4,300	\$607

2

1 **SUBJECT: Load Forecast**

2

3 **REFERENCE: Chapter 3; Table 3.1; Page No. 5; CAC/MH I-240a**

4

5 **PREAMBLE:** Historically, electricity consumption has been associated with economic
6 activity, as measured by real Gross Domestic Product (GDP). A growing economy is
7 associated with increased electricity consumption while economic downturns have a
8 tendency to reduce or stall the growth of consumption. While the correlation between
9 GDP and electricity consumption has been moderated by shifts away from
10 manufactured goods and more towards services, the decrease in North American
11 electricity consumption during the 2008–2009 economic recession demonstrates that
12 overall economic conditions still have a significant impact on electricity consumption.”

13

14 In Table 3.1, Manitoba Hydro provides the NERC forecast of annual Total Demand
15 Growth Across Regions. In Figure 3.4, Comparison of Forecast GDP, Manitoba Hydro
16 suggests that GDP growth in the US will outstrip GDP growth in Manitoba. At page 6 of
17 the September 5, 2013 powerpoint document Manitoba Hydro Electric Load Forecast,
18 the corporation summarizes its findings related growth in residential load. September 5,
19 2013 powerpoint document Manitoba Hydro Electric Load Forecast.

20

21 **QUESTION:**

22 The response provided to CAC/MH 1–240a compares the term “total internal demand”
23 employed by NERC to the term “Gross Total Peak” used by Manitoba Hydro. As per the original
24 question, please explain how the definition of the term “total internal demand”, as employed
25 by NERC, differs from the term “Load Growth” as employed by Manitoba Hydro.

26

27 **RESPONSE:**

28 As outlined in Manitoba Hydro’s response to CAC/MH I-240a, differences in inclusions and
29 exclusions under the NERC definition of “Total Internal Demand” result in an overall lower
30 growth rate than Manitoba Hydro’s forecast growth rate based on Gross Total Peak.

1 Manitoba Hydro's load growth at the system level for demand is defined with respect to Gross
2 Total Peak. Manitoba Hydro's Gross Total Peak is based upon annual peak and includes station
3 service, and excludes projected reductions due to DSM programs, future HVDC line loss
4 reductions and net export sale and purchase losses.

5

6 NERC's "Load Growth" is based on their definition of "Total Internal Demand". "Total Internal
7 Demand" is calculated based upon maximum monthly peak and includes reductions due to
8 DSM programs, future HVDC line loss reductions and net export sale and purchase losses, and
9 excludes station service.

1 **SUBJECT: Load Forecast**

2

3 **REFERENCE: Chapter 3; Table 3.1; Page No. 5; CAC/MH I-240b**

4

5 **PREAMBLE:** Historically, electricity consumption has been associated with economic
6 activity, as measured by real Gross Domestic Product (GDP). A growing economy is
7 associated with increased electricity consumption while economic downturns have a
8 tendency to reduce or stall the growth of consumption. While the correlation between
9 GDP and electricity consumption has been moderated by shifts away from
10 manufactured goods and more towards services, the decrease in North American
11 electricity consumption during the 2008–2009 economic recession demonstrates that
12 overall economic conditions still have a significant impact on electricity consumption.”

13

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15 Growth Across Regions. In Figure 3.4, Comparison of Forecast GDP, Manitoba Hydro
16 suggests that GDP growth in the US will outstrip GDP growth in Manitoba. At page 6 of
17 the September 5, 2013 powerpoint document Manitoba Hydro Electric Load Forecast,
18 the corporation summarizes its findings related growth in residential load. September 5,
19 2013 powerpoint document Manitoba Hydro Electric Load Forecast.

20

21 **QUESTION:**

22 Please confirm that Manitoba Hydro accepts the NERC analysis of Annuals Total Internal
23 Demand Growth for MRO Manitoba as displayed by NERC.

24

25 **RESPONSE:**

26 Manitoba Hydro accepts the NERC values of Annual Total Internal Demand Growth for MRO
27 based upon the definition as outlined in response to CAC/MH II-136. These values have
28 inclusions and exclusions that differ from Manitoba Hydro’s Gross Total Peak Forecast that
29 overall results in a lower 10 year average growth rate with the inclusion of DSM program
30 demand reductions being a large part of the difference.

1 **SUBJECT: Load Forecast**

2

3 **REFERENCE: Chapter 3; Table 3.1; Page No. 5; CAC/MH 1-240c**

4

5 **PREAMBLE:** Historically, electricity consumption has been associated with economic
6 activity, as measured by real Gross Domestic Product (GDP). A growing economy is
7 associated with increased electricity consumption while economic downturns have a
8 tendency to reduce or stall the growth of consumption. While the correlation between
9 GDP and electricity consumption has been moderated by shifts away from
10 manufactured goods and more towards services, the decrease in North American
11 electricity consumption during the 2008–2009 economic recession demonstrates that
12 overall economic conditions still have a significant impact on electricity consumption.”

13

14 In Table 3.1, Manitoba Hydro provides the NERC forecast of annual Total Demand
15 Growth Across Regions. In Figure 3.4, Comparison of Forecast GDP, Manitoba Hydro
16 suggests that GDP growth in the U.S. will outstrip GDP growth in Manitoba. At page 6 of
17 the September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast,
18 the corporation summarizes its findings related growth in residential load. September 5,
19 2013 PowerPoint document Manitoba Hydro Electric Load Forecast.

20

21 **QUESTION:**

22 Please provide any comparable 10 year analysis for the MISO region and MRO-Manitoba Hydro.

23

24 **RESPONSE:**

25 Another comparable load growth analysis for the MISO region is provided by MISO in its annual
26 MISO Transmission Expansion Plan (MTEP). As noted in Chapter 6, Section 6.2.1, Expectation of
27 Gradual Load Growth, “MISO has estimated a compound annual load-growth rate of 0.95% over
28 the next 10 years in its 2012 Transmission Expansion Plan.”

29

30 Since Manitoba Hydro filed its submission in August 2013, MISO released its 2013 MTEP, which
31 indicates an average annual growth rate of 0.75% for demand and a 0.81% growth rate for
32 energy for the MISO region to 2028 under its Business as Usual (BAU) scenario.

1 **REFERENCE: Chapter 1; Section 1.4.1.2; 1.4.1.3; Page No. 14, 15; CAC/MH I-249**

2

3 **PREAMBLE:** According to the filing, a significant strength of the proposed project is the
4 consultation with the KCN partners and the application of Aboriginal Traditional
5 Knowledge.

6

7 It is well established that the KCN partners, who reside closest to the proposed
8 development site, will directly experience many of the positive and negative impacts of
9 the development.

10

11 **QUESTION:**

12 Please confirm that neither ATK nor direct input from KCN partners were taken into
13 consideration in the development of the MABCA framework.

14

15 **RESPONSE:**

16 The MA-BCA evaluation framework was structured following principles of benefit-cost analysis.
17 MA-BCA has compared the trade-offs of different development plans, some of which include
18 Keeyask, from the perspective of Manitobans generally and not from the perspective of any
19 particular community of Manitobans.

20

21 As described in the NFAT submission, the KCN partners have been participating in a
22 collaborative process for the planning and licensing of the Keeyask Generating Station
23 specifically. The KCN partners contributed their ATK, including their worldview, to the planning
24 and environmental assessment of the project. Information from the assessment contributed to
25 an understanding of the environmental and socio-economic effects of the Keeyask Project used
26 in the MA-BCA.

1 **REFERENCE: Question CAC/MH I-250**

2

3 **QUESTION:**

4 Please confirm that, aside from the information found specifically within Chapter 13, Dr. Shaffer
5 was not otherwise advised of circumstances in which the views of the KCN differed from those
6 of Manitoba Hydro.

7

8 **RESPONSE:**

9 As set out in the response to CAC/MH I-250, Dr. Shaffer relied on the information provided and
10 referenced in Chapter 13.

1 **REFERENCE: Question CAC/MH I-162a**

2

3 **PREAMBLE:** Section 32 Part (1) of SARA states that:

4 "no person shall kill, harm, harass, capture or take an individual of a wildlife species that
5 is listed as an extirpated species, an endangered species or a threatened species".

6

7 Section 33 of SARA states that:

8 "no person shall damage or destroy the residence of one or more individuals of a
9 wildlife species that is listed as an endangered species or a threatened species, or that is
10 listed as an extirpated species if a recovery strategy has recommended the
11 reintroduction of the species into the wild in Canada".

12

13 Section 72 of SARA states that:

14 "The agreement may be entered into, or the permit issued, only if the competent
15 minister is of the opinion that (a) the activity is scientific research relating to the
16 conservation of the species and conducted by qualified persons; (b) the activity benefits
17 the species or is required to enhance its chance of survival in the wild; or affecting the
18 species is incidental to the carrying out of the activity."

19

20 Section 73(3) states that:

21 "The agreement may be entered into, or the permit issued, only if the competent
22 minister is of the opinion that (a) all reasonable alternatives to the activity that would
23 reduce the impact on the species have been considered and the best solution has been
24 adopted; (b) all feasible measures will be taken to minimize the impact of the activity on
25 the species or its critical habitat or the residences of its individuals; and the activity will
26 not jeopardize the survival or recovery of the species."

27

28 In its response to 162a, Manitoba Hydro states that "If Lake Sturgeon were to be listed
29 as endangered Manitoba Hydro would apply for permits to construct and operate the
30 Project."

1 **QUESTION:**

2 Taking into account the strong language used within SARA, does Manitoba Hydro have a plan if
3 Lake Sturgeon are listed as endangered and Manitoba Hydro is subsequently refused permits to
4 construct and operate the project? If yes, what is this plan?

5

6 **RESPONSE:**

7 Manitoba Hydro notes that in the case of Keeyask, it is considered highly unlikely that a listing
8 decision will be made prior to the planned start of construction in June 2014. Furthermore,
9 Manitoba Hydro has judged the likelihood of Lake Sturgeon being listed under the *SARA* at this
10 time to be low. (Please refer to the response to PUB/MH I-196a for further information.)

11 Manitoba Hydro believes that the Lake Sturgeon stewardship activities being currently
12 undertaken could result in a reassessment of its status by COSEWIC and the potential for listing
13 under *SARA* at any time is thus reduced. Regardless of whether the Lake Sturgeon are listed
14 under the *SARA*, the federal Department of Fisheries and Oceans (DFO) will continue to manage
15 the species under the *Fisheries Act*, and has indicated its intent to apply strict standards to that
16 management, because of the at risk status of the species.

17

18 However, if Lake Sturgeon are listed as endangered under the *SARA*, it is recognized there will
19 be an additional prohibition on causing harm to the species, above and beyond that already
20 prohibited by the *Fisheries Act* and if harm to the species cannot be avoided, then permits will
21 be needed to ensure continued compliance with the *SARA*, at least over the short term. Over
22 the long term, activities can also be authorized in recovery strategies or action plans which the
23 DFO must develop once the species is listed.

24

25 Manitoba Hydro is aware that permits under the *SARA* for incidental harm to listed endangered
26 or threatened species have not been commonly issued for industrial activities. To some extent
27 this has been because the implementation of the *SARA* has been in its early stages and the
28 regulatory and policy regime required for permit applications has been under development.

1 With the recent implementation of the *Permits Authorizing and Activities Affecting Listed*
2 *Wildlife Species Regulations* (SOR/2013-140), and the development of policy by Environment
3 Canada and the DFO, the interpretation of the s. 73 permit conditions is better understood, it is
4 evident that such permits can, and have been, obtained.

5

6 Manitoba Hydro is committed to conserving and enhancing Lake Sturgeon populations in
7 Manitoba, and is engaged in extensive stewardship efforts as due diligence to ensure that its
8 operations and developments do not jeopardize the sustainability of Lake Sturgeon
9 populations. These include an internal formal Lake Sturgeon Stewardship and Enhancement
10 Program (LSSEP), and a *Memorandum of Understanding Respecting Lake Sturgeon* with
11 Manitoba Conservation and Water Stewardship (MCWS), to coordinate its activities with the
12 Manitoba Lake Sturgeon Management Strategy. For more information on the LSSEP please
13 refer to Appendix 2.1 Lake Sturgeon - Mitigation and Enhancement, of the submission.

14

15 Manitoba Hydro has also proactively entered into negotiations on a Memorandum of
16 Understanding with the DFO and MCWS, that will set out the process for developing a
17 Conservation Agreement under the SARA. A Conservation Agreement on Lake Sturgeon will set
18 out binding stewardship and enhancement activities, timelines, and responsibilities of the
19 Parties.

20

21 Conserving and enhancing Lake Sturgeon populations has been a high priority in the planning of
22 the Keeyask Generation Project, which has been designed to avoid and minimize impacts on the
23 species. Measures include turbines with high fish survival rates, barriers to prevent larger fish
24 from passing through the powerhouse, and selective transportation of fish upstream. In
25 addition, new habitat will be constructed to ensure that habitat for all life stages will be
26 available above and below the generating station, and a new stocking program to enhance Lake
27 Sturgeon populations in the areas directly affected by Keeyask, as well as the broader region,

1 will be implemented. Strict measures will also be implemented during the construction phase
2 to ensure protection of the species. Manitoba Hydro will use an adaptive management
3 strategy, including comprehensive monitoring and adjustment of mitigation measures as
4 required to ensure continued protection of the species once the Project is in operation.

5

6 Manitoba Hydro is confident that the proposed measures for the Keeyask Generation Project,
7 which are summarized in Appendix 2.1 Lake Sturgeon – Mitigation and Enhancement, will
8 minimize the potential for any harm to the individual Lake Sturgeon. If harm to the species can
9 be avoided completely, then there will be no need for permits under the *SARA*. However, if
10 there remains a potential for harm in either the construction or operational phase of the
11 Keeyask Generation Project, permits under either s. 73 or s. 74 of the *SARA* will need to be
12 secured, at least in the short term until such time as recovery strategies or action plans are
13 developed by the DFO.

14

15 Manitoba Hydro is also confident the Keeyask Generation Project design, in conjunction with
16 the enhancement of Lake Sturgeon habitat, stocking, and further activities to be implemented
17 through the LSSEP and cooperative stewardship with our Project partners, will meet the
18 conditions of s. 73 of the *SARA*, and therefore permits will be able to be secured. Manitoba
19 Hydro will continue to work with the DFO throughout the planning process to determine what,
20 if any, additional steps need to be taken to meet the *SARA* permit requirements.

21

22 A principal purpose of the Conservation Agreement currently in negotiation is to establish
23 activities to be carried out to conserve the Lake Sturgeon, and to enhance its potential for
24 recovery. In this respect, while the Conservation Agreement is not itself a permit under the
25 *SARA*, the binding commitments under it can be relied upon, along with other project specific
26 requirements, to facilitate compliance with the conditions for *SARA* permits. The negotiations

1 towards a Conservation Agreement are therefore expected to reduce the risk that a permit
2 under the *SARA* would be denied.

3

4 In essence, while Manitoba Hydro recognizes that there is no guarantee that *SARA* permits, if
5 needed, will be secured, it is confident that the actions it is undertaking now, both in the design
6 of the Keeyask Generation Project, and its work to enhance and recover the species, make the
7 likelihood of a permit under the *SARA* being denied, low.

8

9 Manitoba Hydro's response to the unlikely situation that permits under the *SARA* could not be
10 secured prior to the start of construction, would be to delay the project and make further
11 efforts to work with the DFO to determine what additional measures could be undertaken to
12 secure a permit for construction. If a construction permit was refused outright then Manitoba
13 Hydro would exercise the optionality built into the development plan and proceed with another
14 form of generation.

15

16 Manitoba Hydro believes the extensive mitigation and enhancement measures being
17 developed in the pre-construction phase, and the ongoing commitment by Manitoba Hydro, in
18 conjunction with its project partners and the DFO and MCWS, to the stewardship of Lake
19 Sturgeon on the Nelson River, result in little risk that an operating permit would not be granted
20 if Lake Sturgeon were listed after project construction has been completed.

21

22 Furthermore, once the Lake Sturgeon are listed, it is likely the recovery strategies and action
23 plans to be developed may establish specific hydro related activities which are authorized on
24 the Nelson River which will make long term operational permits under the *SARA* unnecessary.

1 **REFERENCE: CAC/MH I-162a**

2

3 **PREAMBLE:** In its response to 162a, Manitoba Hydro states that "Given the
4 precautionary approach of the DFO on Lake Sturgeon protection, which would be
5 incorporated into the conditions of a Fisheries Act authorization for the Project that
6 Manitoba Hydro would be required to satisfy, it is expected that any cost and timing
7 delays that could result from a potential Lake Sturgeon listing and permitting
8 requirements would not be sufficient to negate the positive conclusions regarding
9 Pathways 3, 4 or 5."

10

11 **QUESTION:**

12 Please explain how Manitoba Hydro came to the conclusion that "any cost and timing delays
13 that could result from a potential Lake Sturgeon listing and permitting requirements would not
14 be sufficient to negate the positive conclusions regarding Pathways 3, 4 or 5." Please provide
15 any analysis that was used in coming to this conclusion.

16

17 **RESPONSE:**

18 Manitoba Hydro has examined a one year delay to Keeyask and Conawapa in Chapter 10 of the
19 NFAT submission. It is expected that this would provide sufficient time to satisfy any permitting
20 requirements that could arise in the event of a decision to list Lake Sturgeon under the *Species*
21 *At Risk Act (SARA)*. The DFO has indicated, that while Lake Sturgeon is not listed under the
22 *SARA*, its "at risk" status is a key factor in its consideration of conditions for authorizations to be
23 issued under the *Fisheries Act*. For this reason, Manitoba Hydro considers it is unlikely any
24 additional requirements to meet the conditions for permits under the *SARA* would cause more
25 than a one year delay .

26

27 This is also consistent with the terms of the export agreements with Minnesota Power and
28 Wisconsin Public Service, which allow for a delay of up to two years for regulatory reasons. The
29 analysis shows that a one year delay in the in-service date of both Keeyask and Conawapa
30 would result in a \$97 million NPV cost in the reference scenario, which is not sufficient to

- 1 negate the positive conclusions regarding Pathways 3, 4 or 5. Please refer to the response to
- 2 CAC/MH I-231b for further information.