SUBJECT: Economic Risk

REFERENCE: Chapter 1, Section 1.4.2.4 Annual Planning Cycle at 20:14-21:6

PREAMBLE: Referring to Chapter 1, Section 1.4.2.4, "the capital expenditure forecast (CEF) incorporates the assumptions related to new long-term generation and transmission resources required, as well as expenditures required to sustain the existing infrastructure and to meet safety, regulatory and reliability requirements."

QUESTION:

Please describe why the Bipole III transmission project was included in all of the alternatives studied, and provide all cost documentation concerning the costs to deliver under each of the alternatives.

RESPONSE:

Bipole III is included in all of the alternatives studied because it is an approved project which is proceeding regardless of the decision as to which of the NFAT development plans are pursued.

The Bipole III costs are equal for the NFAT plans and are provided on page 29 of IFF12 which is provided in the NFAT Business Case, Appendix – Corporate Documents, Appendix A, IFF 2012.

SUBJECT: Economic Risk

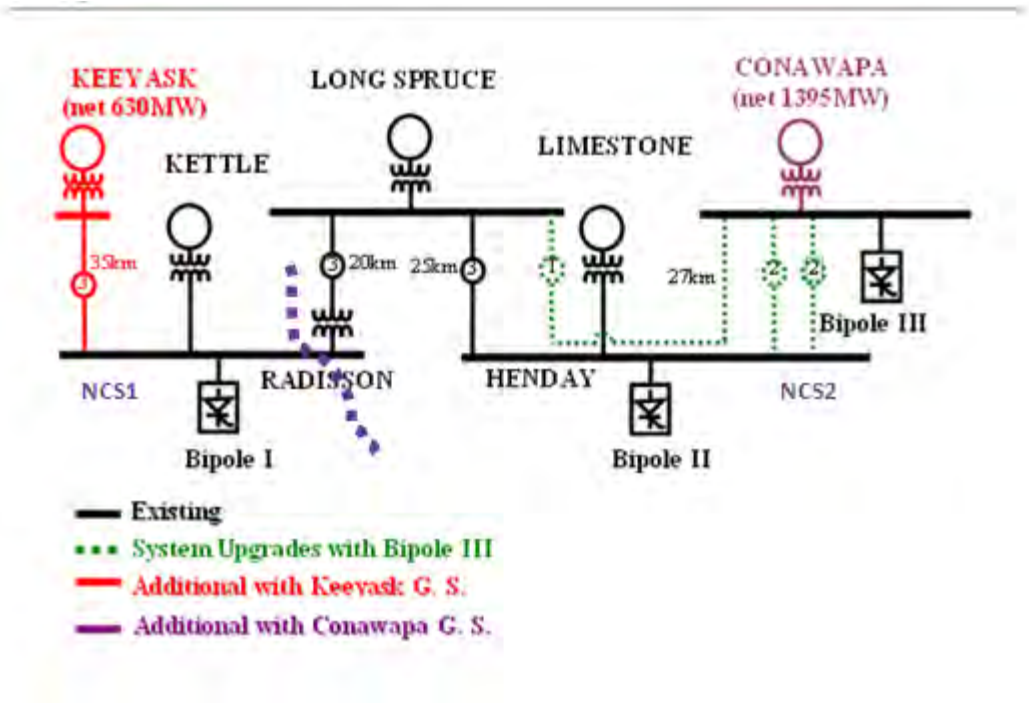
REFERENCE: Chapter 2, Sections 2.1.2.3 at 14:1-6 and 2.2.2.2 at 43:6-13 and 2.3.1 at 53:17-54:16.

QUESTION:

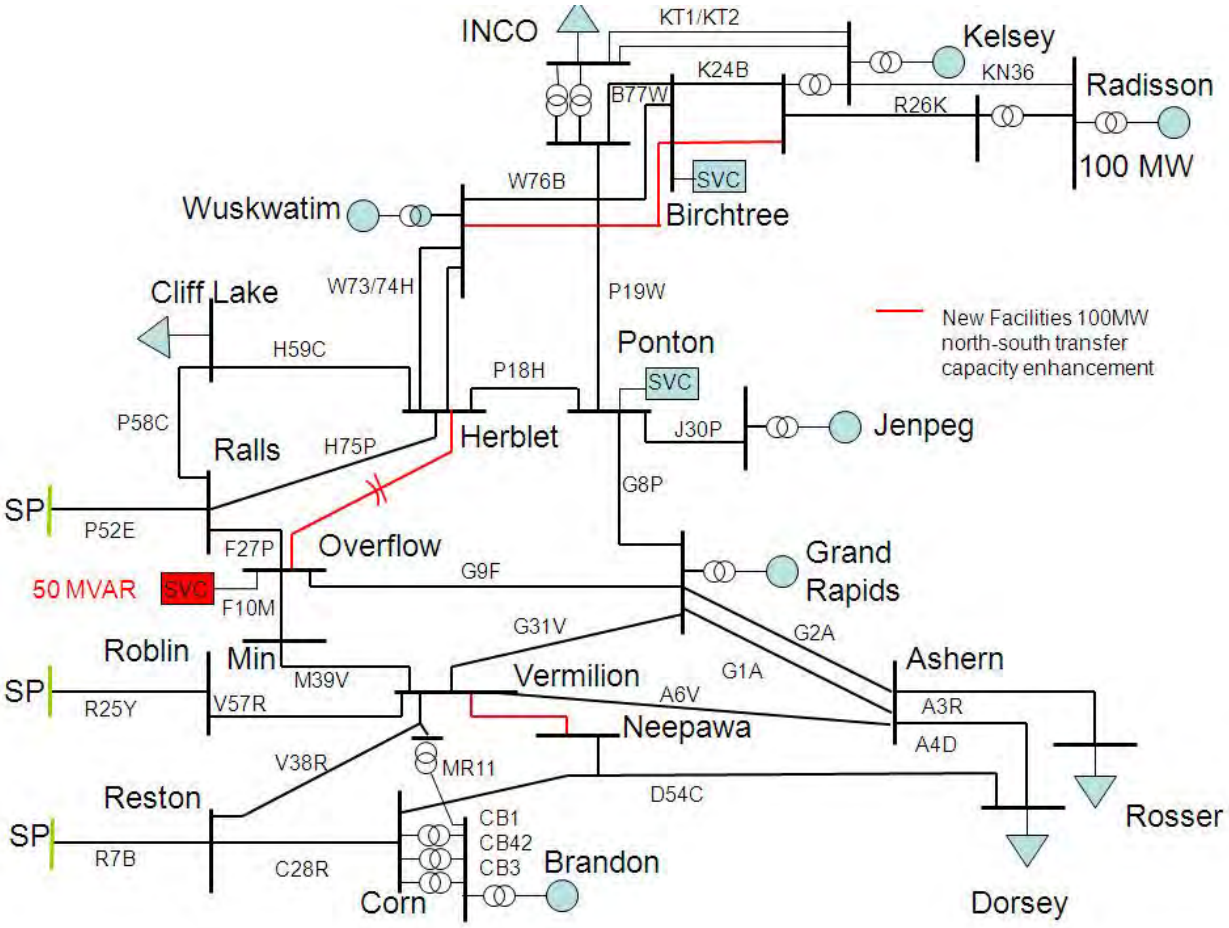
Referring to the descriptions of the transmission projects relating to each of Keeyask and Conawapa as contained in Chapter 2, please provide one-line or geographic diagrams illustrating the transmission lines in the northern Nelson area today, after construction of Bipole III, and after construction of the North-South Transmission Project.

RESPONSE:

The conceptual single line diagrams of the northern collector system upgrades and northern ac system upgrades for the Manitoba Hydro preferred development plan are shown below.



1


INCO
KT1/KT2
Kelsey
K24B
KN36
B77W
R26K
Radisson
100 MW
SVC
W76B
Wuskwatim
Birchtree
Cliff Lake
W73/74H
P19W
New Facilities 100MW
north-south transfer
capacity enhancement
H59C
Ponton
P18H
SVC
P58C
Ralls
H75P
Herblet
J30P
Jenpeg
G8P
SP
P52E
F27P
Overflow
Grand
Rapids
50 MVAR
SVC
F10M
G9F
G31V
G2A
Roblin
Min
M39V
Vermilion
G1A
Ashern
SP
R25Y
V57R
A6V
A3R
Neepawa
A4D
V38R
MR11
D54C
Reston
CB1
CB42
CB3
Rosser
SP
R7B
C28R
Brandon
Corn
Dorsey

2

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.2.2.2 at 43:6-13

QUESTION:

What is the expected or actual in-service dates of the Riel and Keewatinoow Converter Stations, and what will the initial and ultimate capability be of each converter station?

RESPONSE:

The in-service date for the Bipole III Converter Stations is currently October 2017.

The capability of each Converter Station is 2000 MW for the DC Equipment.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.2.2.2 at 43:6-13

QUESTION:

What events, projects, and/or policies will result in changes to the initial and/or ultimate capability of the Riel and Keewatinoow Converter Stations? Please quantify each such change in capability, including the anticipated costs.

RESPONSE:

There is no event anticipated that could cause a change in the capability of the Bipole III Converter Stations.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.2.2.2 at 43:6-13

QUESTION:

How much will each of the Keewatinoow and Riel Converter Stations cost, and are any of these costs allocated to the costs for the Keeyask and/or Conawapa Generating Stations?

RESPONSE:

The in-service cost for the Bipole III Converter Stations is $1.83 billion. No costs from the Bipole III project have been allocated to the Keeyask and/or Conawapa Generating Station projects.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.2.3.1 at 46:18.

QUESTION:

What are the costs of upgrading PR280, and have these costs been included in the total cost for the Keeyask project? If not, why not?

RESPONSE:

The portion of the costs associated with upgrading PR280 that is applicable to the Keeyask Project has been included in the total cost for the project. The estimated costs of this work is commercially sensitive information and cannot be publicly disclosed prior to completion of the tendering process.

SUBJECT: Economic Risk

REFERENCE: Chapter 15, Figure 15.4

QUESTION:

What are the costs of upgrading PR290, and have these costs been included in the total cost for the Conawapa project? If not, why not?

RESPONSE:

The costs of upgrading relevant sections of PR280 and PR290 as applicable to Conawapa have been included. These are (in 2012$):

- PR280 $0.023B
- PR290 $0.017B

Please refer to MMF/MH II-004c for more detail.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3 at 53:6-12.

QUESTION:

Please explain whether the North-South Transmission System Upgrade Project is necessary if only the Keeyask Generating Station is built.

RESPONSE:

The North-South Transmission System Upgrade Project is required only for development plans that include both Keeyask and Conawapa. If Keeyask is built first, then the North-South Transmission System Upgrade Project will be required when Conawapa comes in service.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3 at 53:6-12

PREAMBLE: The economic risk associated with energy that can or cannot be delivered to MISO depends upon the ability of the proposed transmission upgrades

QUESTION:

Please provide all transmission studies related to the ability of Manitoba Hydro's transmission system to deliver energy from Keeyask and Conawapa, including but not limited to contingency analyses, the critical contingencies examined, the associated N-1, N-1-1 and N-2 transfer capabilities, and the extent to which exports to the U.S. were assumed in these studies.

RESPONSE:

The response to this information request would require the disclosure of commercially sensitive information.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3 at 53:6-12

PREAMBLE: The economic risk associated with energy that can or cannot be delivered to MISO depends upon the ability of the proposed transmission upgrades

QUESTION:

How much of Keeyask and Conawapa capacity can be transmitted over the existing HVDC system?

RESPONSE:

No firm capacity is available to transfer power from Keeyask or Conawapa over the existing HVDC sysem.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3 at 53:6-12.

PREAMBLE: The economic risk associated with energy that can or cannot be delivered to MISO depends upon the ability of the proposed transmission upgrades

QUESTION:

How much of Keeyask and Conawapa capacity can be transmitted over the HVDC system after construction of Bipole III?

RESPONSE:

Please refer to the response to PUB-MH II-492b. Under normal operating conditions, without the North-South Transmission System Upgrade Project, about 1200 MW power of Keeyask and Conawapa may be transmitted over the HVdc system after the construction of Bipole III to respect the 4750 MW stability limit. Up to 1700MW power could be transferred on the HVdc system with completion of the HVDC collector system upgrades (part of the North-South Transmission System Upgrade Project).

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3 at 53:6-12.

PREAMBLE: The economic risk associated with energy that can or cannot be delivered to MISO depends upon the ability of the proposed transmission upgrades

QUESTION:

How much of Keeyask and Conawapa capacity can be transmitted over the HVDC system after construction of Bipole III and the North-South Transmission Upgrades?

RESPONSE:

With the completion of Keeyask Transmisison project (section 2.1.2.3 of the NFAT submission), Conawapa Transmission project (section 2.2.2.2 of the NFAT submission), and the North-south Transmission System upgrade project (section 2.3), all of the Keeyask and Conawapa power can be transmitted over the HVdc system under normal operating conditions.

Please refer to the response to PUB/MH I-192 and CAC/MH I-014a.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3.1 at 53:18-54:3.

PREAMBLE: The economic risk associated with energy that can or cannot be delivered to MISO depends upon the ability of the proposed transmission upgrades

QUESTION:

Are the HVdc collector system upgrades referred to in Section 2.3.1 required under all alternatives studied in the NFAT?

RESPONSE:

The HVdc collector system upgrades will be required for the alternatives requiring the development of both Keeyask and Conawapa Generating Stations.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3.1 at 53:18-54:3

PREAMBLE: The economic risk associated with energy that can or cannot be delivered to MISO depends upon the ability of the proposed transmission upgrades

QUESTION:

Please provide all studies that illustrate the need for these HVDC collector system upgrades, including all assumptions, contingency analyses, N-1, N-1-1 and N-2 transfer capabilities.

RESPONSE:

The response to this Information Request would require disclosure of Commercially Sensitive Information.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3.1 at 54:5-16

PREAMBLE: The economic risk associated with energy that can or cannot be delivered to MISO depends upon the ability of the proposed transmission upgrades

QUESTION:

Please provide all studies analyzing the need for the required AC upgrades listed as part of the North-South Transmission Upgrades, including all assumptions, contingency analyses, N-1, N-1-1, N-2 transfer capabilities, and forecasted exports.

RESPONSE:

The response to this Information Request would require the disclosure of Commercially Sensitive Information.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3.1 at 54:5-16.

PREAMBLE: The economic risk associated with energy that can or cannot be delivered to MISO depends upon the ability of the proposed transmission upgrades

QUESTION:

Are the AC upgrades associated with the North-South Transmission Upgrades necessary under all alternatives, or only those alternatives including Conawapa?

RESPONSE:

The AC upgrades associated with the North South Transmission Upgrades are only necessary in development plans that include both Keeyask and Conawapa.

SUBJECT: Economic Risk

REFERENCE: Chapter 2, Section 2.3.2 at 56:6-7.

PREAMBLE: The Manitoba-Minnesota Transmission Project will enable power to be exported to the United States based on current sales agreements, improve reliability and import capacity based on emergency and drought situations, and increase access to markets in the U.S.

QUESTION:

Please provide all transmission studies and analyses of the proposed Manitoba-Minnesota Transmission Project, either at 250 MW or 750 MW, including all assumptions, contingency analyses, N-1, N-1-1 and N-2 transfer capabilities, that illustrate the specific reliability benefits of the project.

RESPONSE:

Manitoba Hydro has completed a preliminary transmission study that analyzes the impact of both a 250 MW and 750 MW Transmission Project This report contains commercially sensitive information and cannot be provided on the public record.

The report demonstrates that the proposed projects meet the NERC TPL standards in terms of contingency analysis. The calculated incremental increase in Transfer Capability of 250 MW or 750 MW is based on system intact conditions and the ability to meet performance criteria following N-1, N-1-1 and N-2 contingencies. The Transfer Capablity for various prior outage conditions are calculated in seasonal operating studies. The first such study for the proposed Transmission Project would not be performed until 6-12 months prior to the inservice date. The availability of the Manitoba to U.S. interface has been historically very high (>95-98%) over the critical summer export period (May to August).

The reliability benefit of the 250 MW and 750 MW Transmission Project in terms of improved loss of load capability has been demonstrated in the NFAT Reliability Report attached to the NFAT submission as Appendix 13.1.

SUBJECT: Economic Risk

REFERENCE: Appendix 13.1 at 2

QUESTION:

Referring to the NFAT Reliability Evaluation , please provide the actual transmission studies performed in evaluating each alternative and all related documents. If the studies are not available, please provide the underlying assumptions, including what transmission facilities were included or excluded in each Alternative evaluated, and the results of contingency analyses.

RESPONSE:

As described on Page 2 of the NFAT Reliability Evaluation (located in Appendix 13.1 of the NFAT submission), the following alternative development plans were evaluated:

1. Preferred Plan: Keeyask, Conawapa, 750 MW Manitoba-U.S. tie line and a 245 MW SCGT

2. All Gas: Four 245 MW SCGT and three 357 MW CCGT

3. Keeyask Gas: Keeyask, two 245 MW SCGT and three 357 MW CCGT

4. Keeyask Gas Tie: Keeyask, two 245 MW SCGT and three 357 MW CCGT and a 250 MW capacity MH-U.S. tie line

The NFAT Reliability Evaluation examined the reliability of the above development plans in terms of metrics such as loss of load expectation over a 25-year planning window. Specific transmission studies for each of the development plans were not performed. The reliability analysis considered the outage rates of the generation in each development plan and the three Bipole HVDC system. The reliability of the Manitoba AC transmission network is much higher compared to the generation forced outage rate and hence can be ignored for this type of analysis.

The underlying assumptions in the NFAT Reliablity Evaluation are included in Section 3 (page 5 and 6) of Appendix 13.1 of the NFAT submission.

SUBJECT: Economic Risk

REFERENCE: Appendix 13.1 at 7

QUESTION:

Referring to the NFAT Reliability Evaluation at 7, please explain why the Keeyask GAS alternative was not changed to have a Keeyask ISD of 2019 in order to avoid breaching the 0.1 days/LOLE.

RESPONSE:

The addition of Keeyask in 2022/2023 is not solely based on reliability performance but on a series of other factors. In order to be able to consistently compare the costs, benefits and other attributes of each development plan assessed in the NFAT submission, in-service dates of the generation options were kept constant within each development plan. Therefore, the Keeyask GAS development plan (also referred to as K22/Gas or Plan 2) was not changed to have a Keeyask in-service date of 2019. Manitoba Hydro agrees that if the Keeyask ISD is advanced to 2019 for the Keeyask GAS development plan, there will be no breach in the 0.1 days/year in 2022 but the LOLE of later years can still be greater than 0.1 days/year. A Keeyask ISD of 2019 would not change the conclusions drawn from the reliability studies.

SUBJECT: Economic Risk

REFERENCE: Executive Summary at 18:1-3

QUESTION:

Please provide all studies supporting the assumptions included in the statement that "[t]he 750 MW interconnection would have 750 MW of export and import capability whereas the 250 MW interconnection is assumed to have 250 MW of export capability but only 50 MW of import capability."

RESPONSE:

The response to this Information Request would require the disclosure of Commercially Sensitive Information which cannot be filed on the public record.

The study that supports the statement is the confidential preliminary group Facility Study report. Both 50 MW and 250 MW import capability of the 230 kV interconnection were analyzed in the report. The higher import capability required the Glenboro phase shifter to mitigate impacts. The additional cost of the phase shifter and additional import capability was not included in the 250 MW plan included in NFAT. The 500 kV interconnection (Dorsey to Blackberry 500 kV line) was demonstrated to have 750 MW of export and import capability.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 23:3-13.

PREAMBLE: In order to analyze the financial and economic risk associated with building two hydro generating units and transmission facilities instead of examining other resources, such as importing power from other areas.

QUESTION:

Further to Chapter 5 at 23:3-13, please provide Manitoba Hydro's most recent transmission study, including contingency analyses for NERC N-1, N-1-1 and N-2 contingencies

RESPONSE:

The referenced section in Chapter 5 is referring to the reliability of Manitoba Hydro's 10-year capital plan. Each year, Manitoba Hydro conducts an assessment to ensure the plan meets the performance criteria specified in the NERC transmission planning standards (TPL-001 through TPL-004). The assessment reports contain Commercially Sensitive Information including potential Critical Energy Infrastructure Information and cannot be filed on the public record.

SUBJECT: Economic Risk

REFERENCE: Appendix 13.1 and Chapter 5, pp. 7-11.

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please state how Manitoba Hydro defines N-1, N-1-1 and N-2 transmission contingencies with respect to the HVDC system under both Manitoba Hydro's reliability criteria and the criteria of the North American Electric Reliability Corporation ("NERC"). For example, is a contingency loss of one pole of any of the three Bipoles considered to be a single contingency event (N-1) or must Manitoba Hydro experience a contingency outage of both poles of any one Bipole in order to be considered to be experiencing an N-1 contingency?

RESPONSE:

Manitoba Hydro adopts the NERC relaiblity criteria and definitions which apply to both the ac and dc system. Loss of a DC pole is considered as a single contingency (N-1). Manitoba Hydro system is designed to meet the NERC reliability performance criteria.

SUBJECT: Economic Risk

REFERENCE: Appendix 13.1 and Chapter 5, pp. 7-11.

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Similarly does Manitoba Hydro consider the successive loss of both poles of two entire Bipole circuits to be an N-1-1 event or two N-2 events or something else (please specify and explain)?

RESPONSE:

Loss of a bipole is considered as a multiple contingency, or N-2 (category C) event. Loss of both bipoles is an extreme event (category D). Manitoba Hydro system is designed to meet the NERC reliability performance criteria. NERC does not specifiy performance criteria for extreme events but requires that such events be evaluated for risks and consequences.

SUBJECT: Economic Risk

REFERENCE: Appendix 13.1 and Chapter 5, pp. 7-11.

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please state the MW value of the firm transfer capability of the HVdc system - both with and without the addition of Bipole III - before and after the occurrence of N-1, N-1-1 and N-2 transmission outages of each Bipole line and 500 kV AC line.

RESPONSE:

Bipole III is considered as the base case for all the alternatives evaluated in the NFAT. The critical stability limit for the three-bipole system is approximate 4750 MW with the addition of Bipole III, although the three-bipole system has a total capacity of 5854 MW.

The 4750 MW transfer capacity can be maintained with a loss of any pole power of a bipole (N-1). With the loss of a bipole, i.e. loss of pole subsequent to a pole loss (N-1-1), or loss of bipole (N-2), the transfer capacity reduces the transfer capability to 3854 MW for the outage of Bipole II or Bipole III, and 4000 MW for a Bipole I outage.

The 500 kV ac line is not part of the HVdc system and has no impact on the HVdc transfer capacity. If the 500 kV line to be constructed as part of the NFAT Preferred Plan goes out-of-service, the Manitoba Hydro-U.S. transfer capability will revert back to the current levels of 2175 MW exprt and 700 MW import during the duration of the outage.

SUBJECT: Economic Risk

REFERENCE: Appendix 13.1 and Chapter 5, pp. 7-11

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please provide all documents related to, arising from or used in connection with Manitoba Hydro's definition and evaluation of N-1, N-1-1 and N-2 transmission contingencies on the existing and planned HVDC transmission system and on its entire transmission system including, but not limited to studies of the steady state and dynamic response of its system to loss of each and every combination of Bipole, I, II and III.

RESPONSE:

The response to this Information Request would require production of Commercially Sensitive Information which cannot be provided on the public record.

SUBJECT: Economic Risk

REFERENCE: Appendix 13.1 and Chapter 5, pp. 7-11

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please state whether Manitoba Hydro has changed its reliability criteria with respect to the HVDC system and its Northern Hydro generation since portions of the HVDC system first began entering service in 1971. If so, please list the nature and date of each such change in those reliability criteria, the reasons for adopting each such change and provide all documents relating to, arising from or used in connection with making each such change.

RESPONSE:

Manitoba Hydro has historically adopted the "a dc pole reserve over load criteria" stated in the 1986 Transmission Planning Criteria (H&TPD 86-1), as quoted "The present Criteria is to maintain a dc pole reserve toward meeting the Manitoba Firm load demand in conjunction with existing southern system generation under median flows". This criteria was applied to the development of Limestone generation.

The reserve criteria is under continuous review by Manitoba Hydro. The past operating experience (significant outages of HVdc valve groups) and increasing economic benefit received from power exports have led to the criterion of maintaining "on-line valve group spare over generation" to cover value group outages. This "spare valve" criterion is considered to provide optimum reliability and economic benefits. The reserve criteria is currently under further investigation for the split Northern Collector System associated with Conawapa.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 5:4-6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Referring to Chapter 5 at 5:4-6, please confirm that the existing HVdc system was designed to bring 3562 MW of hydro generation in the Gillam area south to the Dorsey Converter Station. If not, please state why not and state the rated capability of the existing HVdc system (Bipoles I and II).

RESPONSE:

Please refer to the response to MMF/MH II-016e. The existing HVdc system was designed with the reserve criteria of "a dc pole spare over load". Bipole I and II have a total rating of 3854MW, which can carry power of the existing generation under normal conditions.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 5:4-6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please specify the limiting system component or components of the existing HVDC system and the limiting contingency or contingencies and identify all upgrades in voltage and/or current ratings ever evaluated by Manitoba Hydro to increase the capability of the existing HVDC system.

RESPONSE:

The response to this Information Request would require the disclosure of commercially sensitive information.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please confirm that the present HVdc system has a rating of 3854 MW and that the rating will rise to 6154 MW upon the addition of the 2300 MW capacity of Bipole III with all facilities in service. If not, please explain why not and state what the rating is and what it will be with the addition of Bipole III.

RESPONSE:

The existing Bipole I and II has a rating of 3854 MW (1854 MW of Bipole I and 2000 MW of Bipole II), and the rating of three-bipole system will increase to 5854 MW after the Bipole III project. Bipole III project provides 2000 MW increase in system capacity . The dc equipment of Bipole III can be overloaded up to additional 300 MW, but both ac and ac system upgrades would be required to utilize such capacity. This additional 300 MW capacity is planned to be provided with Conawapa.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please assume that Bipole III has been placed in service and state the rated transfer capability in MW of each of Bipole I, Bipole II and Bipole III, and the combined ratings of Bipoles I and II and of Bipoles I, II and III, and the dates on which such ratings will apply.

RESPONSE:

Please refer to the response to MMF/MH II-018a.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please state for each such rated capability in (b) above whether it has been determined under N-0, N-1, or N-1-1 conditions (please define the condition).

RESPONSE:

The ratings stated in the response to MMF/MH II-018a assumes the system intact conditions (N-0) with all elements in-service.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 5 and 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please confirm that the existing HVdc system (Bipoles I & II) is rated at 3854 MW and can accommodate the 3562 MW capability of Kettle, Long Spruce and Limestone but cannot accommodate the addition of 695 MW of generating capability at Keeyask which addition would bring the hydro capacity in the vicinity of Gillam to 4257 MW.

RESPONSE:

The existing Bipole I & II HVdc system is rated at 3854 MW and can accommodate the capability of Kettle, Long Spruce and Limestone under normal operating conditions, but does not meet the spare valve over generation criterion. The existing HVdc system can not provide transmission capacity for Keeyask power. Please also refer to the response to MMF/MH II-016e.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 5 and 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please state whether the existing HVdc system rated 3854 MW is designed to accommodate, and can accommodate, addition of the 200 MW Wuskwatim G.S.

RESPONSE:

The Wuskwatim 200 MW plant is integrated into the existing northern 230 kV AC system. The following additional transmission outlet facilities were added to accommodate Wuskwatim:

- New Thompson-Birchtree 230 kV station
- New Wuskwatim 230 kV station
- 42 km Thompson-Bichtree to Wuskwatim 230 kV transmission line
- Two 137 km Wuskwatim to Herblet Lake 230 kV transmission lines
- 160 km Herblet Lake to The Pas Ralls Island

It is not possible to physically connect Wuskwatim to the existing or future HVdc system.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 5 and 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please state the percentage losses on each of Bipole I, II and III when operating at full rated capacity, and specify those rated capacities.

RESPONSE:

Please refer to the response to PUB/MH I-187. The existing Bipole I and Bipole II HVdc system have a loss of about 8.8% when fully loaded with the existing generation (about 3600 MW). The north-south transmission loss of the three-bipole HVdc system averages about 6.5% when delivering the existing northern generation (about 3600 MW peak). Delivering the additional Keeyask generation (a total of 4230 MW generation at peak) will increase the average transmission losses to about 7.1%. The average north-south transmission loss will further increase to 8.6% with Conawapa online (a total of about 5580 MW peak generation).

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 5 and 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please state the amount of peak demand in the Northern part of Manitoba served by the asynchronous AC system.

RESPONSE:

Only the station loads at the Radisson and Henday converter stations are supplied by the northern collector system. Each station has a load in the range of 2-3MW.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 5 and 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please state the amount of peak demand in the Northern part of Manitoba served by the HVdc system.

RESPONSE:

There is no northern load served by the HVdc system.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 5 and 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please provide detailed descriptions of all instances of the outages, including simultaneous outages, of both Bipole I and Bipole II (both contingency and scheduled outages, specifying which), and provide dates, times, precipitating events, MW load lost, MW load unserved, cascading effects, transfer trips of loads and generation, etc.

RESPONSE:

As a joint effort of evaluating operation performance of the HVdc systems in-service, Manitoba Hydro provides an annual report on Bipole I and II outage statistics to the CIGRE HVdc working group. The report follows the CIGRE outage reporting criteria and includes detailed outage type, causes, energy utilization, energy availability and etc. These reports contain Commercially Sensitive Information and cannot be filed on the public record. The valve group outages are the most frequently occurring events.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 at 5 and 9 and Appendix 13.1 at 6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please provide all documents related to, arising from or used by Manitoba Hydro in connection with investigating such simultaneous or overlapping outages of both Bipole I and Bipole II, including the impact on angular and voltage stability and consequences to service to loads and generation in Manitoba and MISO (including amounts and locations of loads and generation dropped by any means, including special protection schemes).

RESPONSE:

The response to this Information Request would require the disclosure of commercially sensitive information.

SUBJECT: Economic Risk

REFERENCE: Executive Summary at pages 1-6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Referring to NFAT Executive Summary at pages 1-6, please state why the HVdc existing system needs 2300 MW of redundant (spare) capacity in Bipole III for contingency outages of Bipoles I and II whereas the redundant capacity will shrink to less than 1900 MW when Keeyask is added and drop further to less than 500 MW when Conawapa is added.

RESPONSE:

Bipole III is a major system reliability initiative to reduce dependence on the Dorsey Converter Station and the existing HVdc Interlake transmission corridor and provide the required supply during a catastrophic outages of these facilities. Bipole III has been reviewed and licensed by the Clean Environment Commission, and is included in the base case for the NFAT. In the event of loss of Biple I and II, Bipole III will provide 2000 MW north-south transmission capacity to serve the southern load. This is still the case with the development of Keeyask and Conawapa.

With the failure of Bipoles I and II, exports will be stopped, imports will be maximized, all hydro-electric generation not on the HVdc system and up to 2300 MW on Bipole III, and all thermal resources will be put into service in an attempt to meet domestic load for the duration of the outage.

SUBJECT: Economic Risk

REFERENCE: Executive Summary at pages 1-6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please confirm that, initially, Bipole III will provide 2300 MW of spare transfer capacity for delivering the 3562 MW of Kettle, Long Spruce and Limestone capability in the event of a contingency outage of both Bipoles I and II.

RESPONSE:

Please refer to the response to MMF/MH II-020a. Bipole III will provide up to 2300 MW north-south transmission capacity in the event of losing Bipole I and II.

SUBJECT: Economic Risk

REFERENCE: Executive Summary at pages 1-6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please confirm that Bipole III will provide approximately 1900 MW of spare transfer capacity (Bipoles I and II of 3854 MW + 2300 MW for Bipole III) for delivering the existing hydro output as well as the output of Keeyask (3562 MW + 695 MW) and, if not, why not.

RESPONSE:

Bipole III will provide 2000 MW north-south capacity. Under normal operation, there will be approximately 1670 MW spare capacity on the three-bipole system with the addition of Keeyask. Keeyask will add 630 MW of new capacity to the system.

SUBJECT: Economic Risk

REFERENCE: Executive Summary at pages 1-6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please confirm that Bipole III will provide only approximately 400 MW of spare transfer capacity (Bipoles I and II of 3854 MW + 2300 MW for Bipole III=6154 MW) for delivering the existing hydro output as well as the output of Keeyask and Conawapa (3562 MW + 695 MW + 1485 MW = 5742 MW) and, if not, why not.

RESPONSE:

Please refer to the response to PUB/MH-I-192, CAC/MH-014a, and PUB/MH II-492b.

The existing HVdc system has to be divided into two separate systems to meet the reliability criteria with the in-service of Conawapa power. The limiting factor is the approximate 4750MW HVdc loading on a single HVdc system with three bipoles after Bipole III project. The development of Keeyask Transmission Project, Conawapa transmission project and North-south transmission system upgrades project will enable the delivery of most of Keeyask and Conawapa power. Only about 200 MW Conawapa generation is non-firm.

Dividing the HVDC system into two systems, and maintaining a valve group spare in each system, requires that 300 MW and 575 MW be held as spare in the separate HVdc systems, reducing the available HVdc transmission to 5280 MW. Keeyask will add 630 MW of new capacity to the system, and Conawapa will add 1400 MW of new capacity (during summer),

thus maximum generation is 5584 MW, leaving up to 300 MW of generation that will either use the ac transmission system, or not have firm transmission.

SUBJECT: Economic Risk

REFERENCE: Executive Summary at pages 1-6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Is it a fair characterization of Manitoba Hydro's long-term plan that Bipole III will be shifted from its initial role of providing backup for simultaneous contingency outages of both Bipoles I and II (a maximum credible event) to Bipole III's ultimate role of delivering the output of Keeyask and Conawapa under N-0 and N-1 conditions? If not, please state why not.

RESPONSE:

No, the question does not provide an accurate characterization. Bipole III will provide the backup power following simultaneous contingency outages of both Bipoles I and II for the existing system as well as the future system with Keeyask and Conawapa. The 2000 MW backup provided by Bipole III is critical to meet system reliability requirements up to year 2025. The Manitoba Hydro preferred development plan will provide additional backup power through the 500kV Manitoba Hydro-U.S. tie line which allows Manitoba Hydro to meet the system reliability beyond 2040 as detailed in the reliability evaluation (Appendix 13 of the NAFT submission).

SUBJECT: Economic Risk

REFERENCE: Executive Summary at pages 1-6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please provide Manitoba Hydro's current operating criteria (including the need for reserves) for loss of just one of the Bipole poles or lines, and its proposed operating criteria after the construction of Bipole III.

RESPONSE:

There is no specific operating criteria for loss of an HVdc pole. The NERC Transmission Planning standards (NERC TPL-002) defines loss of of an HVdc pole as a Category B contingency event. Following this loss, the system should be stable, thermal and voltage limits should be within applicable ratings, there should be no loss of demand or cascading outages. Curtailments of contracted Firm transfers (e.g. Manitoba to US transfers) are permitted assuming generation redispatch is available. Both pole and/or Bipole losses are normal contingencies analysed during operating and planning assessments.

If the loss results in a significant generation capacity loss in real time, then Manitoba Hydro would follow its real-time capacity and energy procedures (EOP-3324-1 Emergency Operations – Real Time Capacity and Energy Emergency Procedures).

Manitoba Hydro shares generation planning reserves with MISO to cover for contingency losses of generation. The Contingency Reserve Sharing Group (CRSG) requirement for the MISO

footprint is 2000 MW. MISO examines historic outages as well as credible (n-1) outages in determining the appropriate level of reserves. Historically, loss of the Manitoba to US 500 kV at maximum loading resulted in a loss of 1500 MW, which was considered the largest contingency in the western part of MISO. Manitoba Hydro's share of the reserve obligation is 150 MW of which 60 MW is required to be spinning. Manitoba Hydro can request up to 500 MW in contingency reserves from the reserve sharing group on top of curtailment of any exports.

Loss of a pole today would result in a maximum generation loss of 1000 MW assuming it was fully loaded due to a valve group prior outage, for example. After Bipole III goes into service, the potential maximum pole loss will not change (however, a larger prior outage would be covered initially). After Keeyask and Conawapa are placed in service, the rating of Bipole III will increase from 2000 MW to 2300 MW, hence the maximum pole loss will increase to 1150 MW. The CRSG requirement of 2000 MW will not change as a result of Bipole III being added.

SUBJECT: Economic Risk

REFERENCE: Executive Summary at pages 1-6

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please state whether Manitoba Hydro stiffened its reliability criteria in advance of building Bipole III (e.g., thereby requiring that Bipole III provide approximately 2300 MW of backup for the 3562 MW of generation that would otherwise be undeliverable upon occurrence of simultaneous or overlapping contingency outages of both Bipoles I and II) and will relax that criterion over time until Bipole III will provide only 400 MW of backup upon the in-service date of Conawapa in the event of outages of both Bipoles I and II? If not, please state why not and explain why these facts do not demonstrate that Manitoba Hydro plans to relax its reliability criteria.

RESPONSE:

Please see the response to MMF/MH II-020e. Manitoba Hydro did not relax its reliability criteria in the development of Bipole III, Keeyask and Conawapa. In fact, the Manitoba Hydro preferred development plan will improve the system reliability to above the industry standard as shown in Appendix 13 of the NFAT submission.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 pages 16-28 and Chapter 15 at 9:13-21

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please provide all documents related to, arising from or used in connection with curtailments of exports to the United States.

RESPONSE:

Curtailments of exports are possible for two reasons as follows;

a) Maintaining transmission reliability, and

b) Under circumstances defined in export contracts.

Transmission Reliability

Manitoba Hydro in coordination with the MISO Reliability Coordinator performs curtailment of exports to the United States to ensure reliability of the interconnected power system by mitigating the following system conditions:

1. System Operating Limit (SOL)/Interconnection Reliability Operating Limit (IROL) violations,
2. Over-schedules, and
3. Capacity/Energy emergencies in Manitoba

The curtailment is accomplished in accordance with NERC Standards, MISO RC Policies, and Manitoba Hydro Operating procedures as outlined in the following attachments:

1. MMF-MH II-021b Attachment 1 - MH Transmission Loading Relief (TLR) procedure (EOP-1653-01)
2. MMF-MH II-021b Attachment 2 - MH Manual Schedule Reduction (NOP-3653-01)
3. MMF-MH II-021b Attachment 3 - MH Emergency Operations - Real Time (EOP-3324-01)
4. MMF-MH II-021b Attachment 4 - MH Emergency Operations - Planning (EOP-3324-02)
5. MMF-MH II-021b Attachment 5 - MISO Congestion Management Procedure (RTO-RA-OP-001-r20)
6. MMF-MH II-021b Attachment 6 - NERC RC — Transmission Loading Relief (IRO-006-5)

Contract Curtailments

Each of Manitoba Hydro's export contracts define events on the Manitoba Hydro system which, if they were to occur, would give Manitoba Hydro the right to curtail deliveries of energy. However curtailments are only permitted if curtailment is necessary to allow Manitoba Hydro to continue to serve higher priority loads such as load in Manitoba.

Some events that would qualify include forced outages and derates of generating equipment or Manitoba Hydro's HVdc system, and maintenance outages necessary to avoid damage to equipment. The specific curtailments rights and details contained in each export contract are commercially sensitive and cannot be provided on the public record.

1. Purpose:

To provide a summary of how the Transmission Loading Relief (TLR) procedure is implemented by the Midwest ISO (MISO) Reliability Coordinator on Manitoba Hydro (MH) Transmission Facilities.

2. Scope:

Transmission Loading Relief procedures are used to prevent or manage potential or actual Security Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations to maintain reliability of the Bulk Electric System. This procedure identifies TLR levels and the actions to be taken by MH and the MISO Reliability Coordinator (RC) to implement the TLR procedures.

3. Procedure:

MISO St Paul continuously monitors the loading on the MHEX, MH-SPC and MH-ONT interfaces. The Interchange Distribution Calculator will automatically post the TLR Level on the NERC TLR Status web page.

3.1. ***Notification TLR Level 1*** - If 93% of the System Operating Limit (SOL) is reached, a TLR level 1 is initiated by the MISO RC. An exception exists for MHEX_S where TLR1 is called when the flow reaches or exceeds 99% of the SOL minus CRSG. A Level 1 is an alert to inform the marketplace and other Reliability Coordinators that curtailments are likely to occur. The Reliability Coordinator should announce a TLR level 0 once the Notification level is no longer necessary.

3.2. If 95% of the SOL is reached, MISO RC will initiate TLR Level 3a for next hour or TLR Level 3b for the current hour. An exception exists for MHEX_S where a TLR3 is called when the flow reaches or exceeds the SOL minus CRSG.

3.2.1. ***Reallocation TLR Level 3a -*** Transactions using Non-firm Point-to-Point Transmission Service are curtailed to allow Transactions using higher priority Point-to-Point Transmission Service.

3.2.2. ***Curtail TLR Level 3b*** - Curtail Transactions using Non-firm Point-to-Point Transmission Service to mitigate Operating Security Limit Violation

3.3. ***Reconfigure TLR Level 4 -*** If curtailment of non-firm point-to-point Transmission Service is insufficient to mitigate Operating Security Limit Violation, the transmission system may be reconfigured.

3.4. If attempts to accommodate all Firm Transactions by re-configuration is not possible or if further relief is required, TLR level 5 will be used to curtail firm transactions.

3.4.1. ***Reallocation TLR Level 5a -*** Transactions using Firm Point-to-Point Transmission Service are curtailed pro-rata to allow new Firm Transactions to begin (pro-rata). Also requires Pro-rata curtailment with Native Load.

3.4.2. ***Curtail TLR Level 5b*** - Curtail Transactions using Firm Point-to-Point Transmission Service to mitigate Operating Security Limit Violation. Also requires Pro-rata curtailment with Native Load.

3.5. ***Emergency Action TLR Level 6*** - Curtailment of Firm & Non-Firm transactions was unsuccessful in mitigating the Operating Security Limit Violation. Additional measures may be included redispatch, voltage reductions, interruptible and firm load shedding.

3.6. ***TLR Concluded TLR Level 0*** - Restore Firm & Non Firm Transactions.

4. TLR Notes:

4.1. Only transactions with a 5% or greater Transfer Distribution Factor (TDF) are subject to curtailments.

4.2. ***Fixed Dynamic Interchange Scheduled associated with External Asynchronous Resources (EAR)*** - EAR functions as an internal generator within MISO and is re-dispatched by MISO to mitigate Operating Security Limit Violations. The MISO Congestion procedures for EAR are as follows:

4.2.1. <u>MHEX Interface:</u>

a) MISO RC issues TLR and curtailment report will include the MHEB_EAR_MISO tag for reduction.

b) MISO RC will curtail the MHEB_EAR MISO tag. Curtailments by an external constraint will trigger an EEE (Excessive Energy Exemption) and thus will not be subject RSG charges. ***(** MISO internal procedures require MISO RC to contact MISO Scheduling to initiate the curtailment, **)***

c) MISO RC may reduce EAR for reliability purposes.

4.2.2. <u>Internal MISO Market flowgates:</u>

a) MISO RC issues TLR and the curtailment report shall exclude the MHEB_EAR_MISO tag for reduction EAR shall be dispatched by MISO Unit Dispatch System (UDS).

b) MISO RC will "disregard" the EAR tag prior to the "acknowledgement" process. By performing this step, the EAR tag will be displayed as "disregarded" at the top of the final congestion management report.
c) MISO RC "binds" the flowgate to maintain flow at 95% of limit or as prescribed by an operating guide. The EAR will then be automatically controlled by UDS.
d) If there is a mismatch between the EAR e-tag and the curtailment report on Midwest ISO Communication System (MCS), the Manitoba Hydro Operator will contact the MISO RC to verify the curtailment. The MISO RC may instruct MH-Operator not to curtail the tag and will inform the MISO Scheduling Department personnel to not deny the tag.

4.2.3. Non MISO Market flowgates:

a) Non-MISO RC issues TLR and curtailment report will include the MHEB_EAR_MISO tag for reduction.
b) MISO RC will curtail the MHEB_EAR MISO tag, .Curtailments by an external constraint will trigger an EEE (Excessive Energy Exemption) and thus will not be subject RSG charges.
c) MISO RC may reduce EAR for reliability purposes.
d) If there is a mismatch between the EAR e-tag and the curtailment report on MCS, the Manitoba Hydro Operator will contact the MISO RC to verify the curtailment. The MISO RC may instruct MH-Operator not to curtail the tag and will inform the MISO Scheduling Department personnel to not deny the tag.

4.3. ***MHEX_N Loss of Critical Element*** - Upon contingency loss of any critical element on the MH-USA interface, MISO RC will initiate the FAST procedure as detailed in EOP 3653-01. This procedure is a generation re-dispatch that will quickly reduce the north flow below the post contingency limits. Once the FAST procedure has been initiated, MISO RC will initiate TLR to reduce the schedules in order to end the FAST procedure.

4.4. **MHEX Metering** - There are two sets of metering values available for flows at Dorsey, Letellier, Richer and Glenboro, compensated and uncompensated values. The uncompensated values indicate the actual flows, including losses and any "off schedule" values on SPC or IESO (including the phase shifter bandwidth). The compensated values reflect the calculated values at the border. MH AGC controls to the compensated values and MISO monitors the uncompensated values to call TLR. There can be a difference of up to 50MW between the MISO values and the MH values. MH Control Centre also displays the uncompensated values and TLR is called on the uncompensated flow at the station.

4.5. ***MISO Monitoring*** - MISO St Paul uses the OGM (Operating Guide Monitoring Tool) to monitor the flows at the four Manitoba Hydro terminal stations. The OGM is programmed to provide alarming capability and instructions on using TLR procedures to ensure flows are maintained within limits. It is not required to call TLR if the flows are simply fluctuating in and out of alarm due to normal power system fluctuations, however if the flows are over the limit for more than 5 minutes, MISO St Paul will contact the MH operator to identify the source of the error. There are three potential sources for exceeding the flow limit, Manitoba Over-scheduling, Ontario Off Schedule, and/or SPC Off Schedule

a) Manitoba Over-scheduling, (having schedules higher than the posted schedule limit), then either manual schedule reduction or TLR can be used to reduce as detailed below.
b) Ontario being Off Schedule, an Off Load on the Whiteshell Phase shifters must be performed as soon as possible.
c) SPC being Off Schedule, MISO will call SPC Power System Supervisor (306-566-3546) and request corrective action be taken. If SPC is over-generating, they may elect to reduce hydraulic generation if the thermal generation cannot be reduced quickly enough.
d) If steps b & c above cannot be completed within 15 minutes of the request, MISO St Paul will proceed with TLR level 3.

5. Reference Documents:

5.1. NERC Standard IRO-006-4 - Transmission Loading Relief
5.2. MH OATT Attachment Q - Curtailment Procedures (NERC Appendix 9C1 - Transmission Loading Relief Procedure - Eastern Interconnection
5.3. NOP 3760-1 - MHEX_S Realtime Dynamic Dispatchable (EAR) Procedure.
5.4. NOP-3653-01 - Manual Schedule Reduction Procedure for MHEX-N & MHEX-S Interface
5.5. EOP 3653-1 MHEX_N FAST Generation Runback Procedure

Revision History:

Rev No.	Date of Issue	Owner or Author	Ext. Review	Appr. By	Revision	Review Date
0	2009 03 16	CNM	LSH	BAP	Was CSOI 6-4-1-0.	2010 03 01
1	2011 04 18	CNM	MR	LSH	Corrected section 4.3 EOP 3653-01was CSOI 6-4.2.0.	2012 05 04
2	2011 06 08	LSH	JW	LSH	Revised 4.2.2 d) If the EAR tag is included on the curtailment report and MISO RC has not called to verify, the Manitoba Hydro Operator will contact the MISO RC anytime the EAR tag was curtailed. The MISO RC may instruct MH-Operator not to curtail the tag and will inform the MISO Scheduling Department personnel to not deny the tag. Add same statement from	2016 06 08

					above to section 4.2.3	
3	2011-06-29	LSH	JW MH, AR MISO	LSH	Changed 4.2.2 d)If there is a mismatch between the EAR e-tag and the curtailment report on Midwest ISO Communication System (MCS), the Manitoba Hydro Operator will contact the MISO RC to verify the curtailment. The MISO RC may instruct MH-Operator not to curtail the tag and will inform the MISO Scheduling Department personnel to not deny the tag. Add same statement from above to section 4.2.3	2016-06-29
4	2011-08-22	LSH	JW	LSH	Revised section 3.1 and 3.2 to reflect changes in limits for ONT, SPC and USA.	2016-06-29

1. Purpose:

To identify a process between the Manitoba Hydro System Operator and the MISO, IESO and SPC Reliability Coordinators to perform a BA to BA curtailment on the MHEX, ONT, and SPC interfaces when projected “over-scheduling” occurs.

2. Scope:

The Manitoba Hydro System Operator is responsible for monitoring schedules on the MHEX, ONT, and SPC interfaces. When projected “over-scheduling” occurs the Manitoba Hydro System Operator will contact the MISO Reliability Coordinator and/or appropriate Reliability Coordinator to notify them of the over schedule and that a BA to BA curtailment will be initiated.

3. Background:

3.1. Interface over-scheduling may be caused by:

- Errors in the ATC calculations
- Non-Firm transmission service schedules - Firm Transmission customers have until 1500 hours EST day prior to schedule on their firm transmission reservations, after 1500 hours EST the unscheduled firm transmission service is released for sale as hourly non-firm transmission service. The firm customer does not lose the right to schedule upon the original reservation. Thus if both the firm and non-firm customer schedule transactions the interface will be over-scheduled.

3.2. If real-time flows actually reach the defined operating limit, the MISO Reliability Coordinator will utilize NERC TLR to control the flow.

3.3. Late Tags - Late tags flowing north that come in after 20 minutes before the hour as “Late Tags” per the Manitoba tariff timing requirements will be automatically denied by webtrans.

4. Procedure

4.1. **Interface Monitoring -** If the Manitoba Hydro System Operator determines that the next hour MHEX, ONT, or SPC transfer limit will be exceeded, the System Operator shall immediately contact the MISO St. Paul Reliability Coordinator and/or the applicable Reliability Coordinator to communicate which interface has been overscheduled and that a BA to BA curtailment will be initiated by Manitoba Hydro. Notice should be provided to the applicable

Reliability Coordinator by xx:40 but after xx:30. The Reliability Coordinator will require information on the amount of overscheduled megawatts and the duration.

4.2. **BA to BA Curtailment -** Manitoba Hydro System Operator using the curtailment wizard in webTrans will initiate a "Pro-Rata by Priority" curtailment of etags for the upcoming hour as outline in EMS instruction.

4.3. **MISO Tariff Administration Notification** - The System Operator shall contact the MISO Carmel Tariff Administrator to communicate that a manual schedule reduction has been initiated on the MHEX, ONT, or SPC interface and that no additional transmission service should be sold for the next hour (s).

4.4. **MISO, IESO and SPC Reliability Coordinator Updates** - The Manitoba Hydro System Operator will communicate each hour with MISO St. Paul Reliability Coordinator to provide status updates.

5. Reference Documents:

EMS 3-08-9 - webTrans Curtailment Wizard

Revision History:

Rev No.	Date of Issue	Owner or Author	Ext. Review	Appr. By	Revision	Review Date
0	2009-03-15	CNM	LSH	BAP	Modified format and changed naming convention. Was CSOI-6-4.2.1	2010-03-15
1	2011-06-20	LSH	JW - MH/AR - MISO	LSH	MISO is no longer able to perform manual schedule reduction and results in almost a complete rewrite.	2016-06-20

1. Purpose:

This procedure shall be invoked immediately when experiencing capacity or energy emergencies.

2. Scope:

This procedure defines energy and capacity emergencies and identifies the steps to manage and correct such events. Coupled with EOP-3324-2 Emergency Operations - Planning Horizon, comprises Manitoba Hydro's Capacity and Energy Emergency plan. Communications and instructions to MISO (Reliability Coordinator and Balancing Authority), Independent Electricity System Operator (Balancing Authority), Saskatchewan Power Corporation (Balancing Authority), Curtailable Customers, Major Customers, Power Sales and Operations, and Manitoba Hydro's Public Affairs Department are outlined herein.

3. Procedure:

3.1. This procedure serves and provides specific alert, warning, and event levels to mitigate a capacity emergency.

3.2. MH shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory or statutory requirements.

3.3. Manitoba Hydro operates and schedules resources inside Manitoba to ensure energy and capacity supplies are adequate to meet Manitoba Hydro domestic load, firm commitments and required operating reserves, considering the single most severe contingency loss. Capacity and energy emergencies should only occur upon multiple contingency losses or during certain planned maintenance outages. Management of capacity and energy emergencies depends if they are slow developing or immediate:

3.3.1 Slowly developing emergencies are those emergencies that can be predicted in advance of the operating day (such as forecast error, predicted equipment failure, drought).

3.3.2 Immediate energy/capacity emergencies are expected to result from a sudden multiple contingency losses as a result of unforeseen circumstances.

3.4. This instruction is prepared for Real Time (current day) operation. EOP-3324-2 Emergency Operations - Planning Horizon details emergency operations for the planning horizon (next day operations).

3.5. An emergency exists whenever MH is no longer able to provide for its customer's anticipated energy needs and provide Operating Reserves. There

are three levels of energy emergencies in accordance with NERC Appendix 5C. They are called “Energy Emergency Alerts” (EEA) levels 1 to 3:

3.5.1 EEA1 – All resources are in use – concerned about sustaining Operating Reserves

3.5.2 EEA2 – Load Management Procedures in effect

3.5.3 EEA3 – Firm Load Shed is imminent or in progress

3.6. Steps to Manage and Correct Energy Emergencies:

3.6.1 These steps are sequenced in ascending order of emergency severity, however the magnitude or rate of progress of the emergency may not allow enough time to initiate or complete the steps in sequential order. As conditions require, MH may move directly to any step in this procedure, and give direction to complete actions provided in the earlier steps as time permits. Continue on to the next step in the sequence until the generation and load are matched (including reserves) and transmission line loadings are within System Operating Limits.

3.6.2 If operating conditions exist or are anticipated, where all available internal resources are committed or are operating at maximum values to meet firm load demand, firm transactions, and operating reserves:

1. System Operator will cancel scheduled generator, HVDC and critical transmission line maintenance outages that have not commenced and recall units and critical lines (that restrict imports) from maintenance outages.
2. Increase all generation on line to full load as required subject to all physical or license constraints, normal operating limits, and System Operating Limits.
3. Contact the Real Time Traders in Power Sales & Operations (PSO) to request the curtailment of non-capacity backed energy sales and/or purchase sufficient resources up to the maximum import transfer limits.
4. Start Natural Gas based Thermal Generation:
   - Brandon CT’s for Emergency Requirements. If time permits, utilize normal start (approx. 34 minutes to full load) and quick start (19 minutes to full load) if required. Request Real Time Traders to arrange gas if possible, if gas is not available, proceed to start on oil.
   - If emergency is expected to be greater then 8 hours request Selkirk Units 1 & 2 be brought on line as soon as possible. Expected startup time is 8-10 hours.
5. Contact Real Time Traders to request the curtailment of applicable capacity backed contract transactions. The majority of capacity backed contracts

contains clauses that allow for the transactions to be curtailed upon contingent loss of generation or HVDC equipment once all available MH generation, including CTs, is online (or fails to start).

6. System Operator will advise all stations and key personnel by declaring a Red Day (Policy B7) to use extra diligence to minimize the risk of tripping system equipment.

7. **Request MISO RC to declare a "NERC Energy Emergency Alert 1".**

   MISO will broadcast via the MAPP Communication Network (MCN) and NERC Reliability Coordinator Information System (RCIS) that Manitoba Hydro is in EEA level 1 and has all available resources in use.

8. Start Coal based Thermal Generation (if available in generate mode):

   - If emergency is expected to be greater then 12 hours, system operator shall request Brandon Unit 5 to be brought on line as soon as possible.

9. Request stand-by staff to locate to Dovercourt for support. Stand-by staff will initiate the Level 2 Emergency Response Team (excluding Power Trading Staff). Among other actions, Emergency Operations Centre (EOC) staff will:

   - Request re-evaluation of the interface system security limits by System Performance.
   - Notify the Division Manager of the situation and provide details.
   - Notify Public Affairs that a public appeal may be required.

10. Curtail Option "A" load as follows:

    a. Canexus - Call 1 - 204 - 728 - 2267

    When answered make the following statement,

    "This is the Manitoba Hydro Control Centre calling to have Canexus curtail their Option A load."

    Canexus protects a load of 7 MW and will curtail the balance. This will provide up to 118 MW of relief for up to 4 ¼ hours. It can be used for a maximum of 10 hours per day in the summer and 6 hours per day in the winter.

    b. ERCO Worldwide: Call 1 - 204 - 748 - 8253

    When answered make the following statement,

    "This is the Manitoba Hydro Control Centre calling to have ERCO Worldwide curtail their Option A load."

    ERCO protects a load of 1.5 MW and will curtail the balance. This will provide up to 28.5 MW of relief for up to 4 ¼ hours. It can be used for a

maximum of 10 hours per day in the summer and 6 hours per day in the winter.

11. Curtail Option C loads (1 hour notice required) as follows:

    a. TCPL: Call first: 1 - 403 - 920 - 5501 (or secondly 1 - 403 - 265 - 7960)

    When answered make the following statement:

    "This is the Manitoba Hydro Control Centre calling to have TransCanada Power curtail their Option C load."

    TCPL protects a load of 33 MW and will curtail the balance. This will provide up to 31 MW of relief, beginning in 1 hour, for up to 4 ¼ hours and can be used for a maximum of 8 hours per day.

12. Request generating stations reduce their non-essential station service demand.

13. The Emergency Response Team will update Public Affairs and will respond to all calls not directly involved in the dispatch of resources needed to mitigate the emergency.

14. The Emergency Response Team may inform EMO (945 - 5555) and call out additional help as needed, to initiate press releases, and generally assist as required.

15. **Request MISO RC to declare a "NERC Energy Emergency Alert 2".**

    MISO RC will broadcast via the MCN and NERC RCIS that Manitoba Hydro is in EEA level 2 and "Load Management Procedures Have Been Implemented."

16. If MH is operating HVdc in parallel and has sufficient HVdc generation capacity to load paralleled poles above 1500 MW, seek approval from MISO RC to increase Most Severe Single contingency to above 1500 MW.

17. Notify IESO & SPC that MH is experiencing a Level 2 Emergency and that load management procedures are being implemented.

18. Confirm MISO RC has elevated Import Transactions from transmission Priority 6 to Priority 7.

19. Consume MHEB MISO-MBHydro CRSG reserves and remove MH available reserves from the MISO-MBHydro CRSG ARS system. Advise MISO BA (acting as MISO-MBHydro CRSG Administrator) that MHEB is currently experiencing an EEA2 and consistent with CRSG protocols has elected to remove MHEB's reserves from the ARS system.

    If Brandon CTs had been carrying spinning reserves and these reserves were then consumed, call Brandon G.S. Station Operator (726-9107 or 204-578-3121/3131) to inform them that the CT loading has increased.

20. Submit MISO-MBHydro CRSG ARS request for emergency energy and identify the loss type as “other extreme conditions.”
21. Contact Real Time Traders to request they recall remaining firm interchange transactions (i.e., recall export power purchase agreements identified as Capacity Resources per MISO Tariff).
22. Implement Emergency Energy purchases from neighbouring Balancing Authorities.
23. Suspend Standards of Conduct – Send message on MCN “Manitoba Hydro is experiencing an EEA2, Curtailable load shed is in effect. MH is suspending the Standards of Conduct in order to be able to share related transmission information with the MH marketing staff to cope with the emergency.” Log the time and send an email message to Manager SCD, Manager TSD, and MH Compliance Officer as detailed in NOP-1628-1

    As part of this process, supervisory staff from the Power Trading Office will be requested to come to Dovercourt to provide additional support in their role as EOC member.
24. The Emergency Response Team will request approval from the PSO Stand-by staff to draw forebay levels below their normal operating minimum as long as the license and structural limits are maintained as detailed in NOP-3323-4 Hydraulic Plants Operating Parameters. If approval is not readily available, do not violate normal limits and instead proceed to the next step.
25. The Emergency Response Team will contact Public Affairs to initiate a public appeal for voluntary load curtailment

    Message for Public Appeal:

    This is an emergency announcement. Due to ____ all electrical customers of Manitoba Hydro (in the ____ Area) are urged to reduce their use of electricity until further notice. Specifically, you should:

    - Use only essential lighting in your home or business.
    - Refrain from using any appliances except as absolutely necessary.
    - Delay, if possible, cooking, washing or drying operations using electrical equipment.

    If in Winter:

    - Disconnect electric space heaters, car warmers and car block heaters.
    - Turn off all decorative or ornamental lighting.

    Manitoba Hydro is curtailing all non-essential loads. Maximum assistance is being received from neighbouring utilities but this is not sufficient to meet Manitoba's needs. A voluntary reduction in electrical usage could

eliminate the need for planned power interruptions by area on a rotating basis.

Customers will be advised when the situation returns to normal.

26. Request CDCC to reduce street lighting and festival lighting load to minimum.

27. The Emergency Response Team will initiate a request for a voluntary load reduction from major customers.

Major Customers	Phone	Max Load
INCO (Thompson)	1-204-788-5567	115
Pax	2-53-160	
HBM&S (Flin Flon)	1-204-687-2389	104
Enbridge (Edmonton Emergency Dispatcher)	1-877-420-8800	82
Canexus (Partial Load Curtailment)	1-204-728-2267	120
TCPL (Partial Load Curtailment)	1-403-920-5501	64
Manitoba Rolling Mills (Selkirk)	1-204-485-0448	44.9
	1-204-795-7447	
Tolko	1-204-623-8635	20.0
	1-204-623-2966	
Simplot (Brandon)	1-204-729-2795	26.8
	1-204-729-2796	
Griffin Steel (Transcona)		17.5
Office Hours	222-4252 Ext 232	
After Hours (ask for	222-4253	
Shift Electrician)	222-4254	
TVX Gold Inc.	1-204-358-2066	9.1
Louisiana Pacific (Minitonas)	1-204-525-2479	8.8

Most current telephone numbers for major customers will be in the SCC phonebook explorer. A detailed list of all large industrial customers is available from the Load Research Section in the Rates Department at local 4859 during normal working hours.

28. Update the MISO RC no less than each hour on the status of the energy emergency for EEA2 and EEA3 level emergencies.

29. Request mutual assistance from SPC operating reserve per Manitoba-Saskatchewan Standard Operating Practice MS-9. Dependant on the operating conditions at the time, Grand Rapids and/or power south of Ponton may need to be re-dispatched. TLAP study mode with the SPC detail can be used to maximize the import capability.

30. Request MISO RC declare a “NERC Energy Emergency Alert 3”.

MISO RC will broadcast via the MCN & the NERC RCIS that Manitoba Hydro is in an EEA3 and “Firm Load interruption imminent.”

This message goes to all Reliability Coordinators, Control Areas and Merchants.

31. **MANUALLY SHED LOAD** using the EMS Load Shed program and/or the the Winnipeg Central Load Shed Procedures (EOP-2832-1) to balance load and generation and maintain interconnection load levels within System Operating Limits.

    Initiate additional load shedding as required to maintain ACE at practical zero (i.e. should average approximately zero).

    Rotate customer load - Winter or Summer block of load, curtail the next block, and return service to the first block.

3.7. Termination of Emergency (above procedure should be reversed to return to normal), including:

3.7.1 Reinstate the Standards of Conduct as soon as possible per NOP-1628-1 Standards of Conduct Administration.

3.7.2 Return MH's MISO-MBHydro CRSG to normal level.

3.7.3 Request MISO RC terminate energy alert (Alert 0).

3.7.4 The Emergency Response Team will contact Public Affairs to terminate the public appeal for voluntary load curtailment.

Message to Follow Public Appeal:

"This is an announcement from Manitoba Hydro. The power emergency situation is now over and normal service is resumed. The cooperation of Hydro customers in averting a major power outage is greatly appreciated."

3.8. Prepare an Energy Emergency Alert 3 Report as per NERC EOP-002 and Disturbance Reporting Requirements as per EOP-3324-6, as applicable.

3.9. Checklist

The following is a checklist that can be used during an emergency. It provides only high level details, however the step numbers are directly from this procedure. The check list can also be used in reverse to return to normal.

Step	Description	During Emerg.	Return to Normal
1	Recall all available generation, HVdc and critical transmission		
2	Increase all on line generation to full load		
3	Request Real Time Traders curtail non-capacity backed energy sales and/or purchase resources to maximum import		
4	Start natural gas based thermal generation		
5	Request Real Time Traders curtail applicable capacity backed contract transactions		
6	Declare Red Day		
7	**Request MISO RC declare EEA1**		
8	Start coal based thermal generation		
9	Stand-by staff to Dovercourt – Level 2 Emergency Response Team		
10	Curtail Option A Load		
11	Curtail Option C Load		
12	Request Generating Stations to reduce their non-essential station service		
13	Emergency Response Team update Public Affairs		
14	Emergency Response Team inform EMO (if required)		
15	**Request MISO RC declare EEA2**		
16	Request MISO RC approve loading HVdc paralleled poles above 1500 MW		
17	Notify IESO & SPC of EEA2 status		
18	Confirm MISO RC has elevated import transactions from Priority 6 to 7		
19	Consume MHEB MISO-MBHydro CRSG reserves and remove from ARS system		
20	Submit MISO-MBHydro ARSG ARS request for “other extreme conditions”		
21	Contact Real Time Traders to curtail all remaining firm transactions		
22	Implement emergency energy purchases from neighbouring BAs		
23	Suspend Standards of Conduct		

24	Emergency Response Team request approval from PSO to draw forebays		
25	Emerg. Resp. Team requests voluntary load curtailment through Public Affairs		
26	CDCC to curtail street and festival lighting		
27	Emergency Response Team requests major customers curtail load		
28	Update MISO RC on status on an hourly basis		
29	Request mutual assistance from SPC		
30	**Request MISO RC declare EEA3**		
31	**Manually Shed Load**		

4. Reference Documents:

NERC STANDARDS:

EOP-001

EOP-002

EOP-003

AGREEMENTS:

MH-MISO BA Coordination Agreement (after January 6, 2009)

US Interconnected Parties Interconnection Agreements (prior to January 6, 2009)

SPC Agreement (Schedule “T”)

Manitoba-Saskatchewan Standard Operating Practice MS-9

Interconnection Agreement Between Independent Electricity Market Operator and Manitoba Hydro-Electric Board

OPERATING PROCEDURES:

EOP-3324-6 Disturbance Reporting Requirements

EOP-3324-2 Emergency Operations - Planning Horizon

EOP-3325-01 Restricted Operation of Brandon Unit # 5 (Coal)

NOP-1628-1 Standards of Conduct Administration

NOP-3314-1 Operational Modes for Canexus

NOP-3323-4 Hydraulic Plants Operating Parameters

NOP-3760-2 MISO-MBHydro CRSG Activation

5. Revision History:

Rev No.	Date of Issue	Owner or Author	Ext. Review	Appr. By	Revision
0	2009-04-19	KDG	MISO	BAP	Modified format and changed naming convention. Was CSOI- 3-5-1-0
1	2010-01-15	VK	MISO	BAP	Modifications to step 4, step 9 and checklist as per EOP-3325-01, Restricted Operation of Brandon Unit # 5 (Coal)
2	2010-05-07	VK	MISO	BAP	Modifications to step 11 and step 28 to remove Option A curtailable load of 52 MW allocated to Tembec
3	2010-12-20	BM	MISO	BAP	Modifications to steps 1 – 7 to reflect proper ordering of curtailing non-capacity and capacity backed contracts with CT generation
4	2012-03-27	GG	MISO	LSH	Modified section 1 to clearly indicate that this procedure will be invoked immediately when required.
5	2012-08-31	BM	MISO	LSH	Removed ability to curtail non-firm load at Canexus

1. Purpose:

Procedure to invoke when a capacity or energy emergency is anticipated within the planning horizon, either day ahead or earlier in advance of the operating day.

2. Scope:

Coupled with EOP-3324-1 Emergency Operations - Real Time capacity and Energy Emergency Procedures, this procedure comprises Manitoba Hydro's Capacity and Energy Emergency plan. Communications and instructions to MISO (Reliability Coordinator and Balancing Authority), Independent Electricity System Operator (Balancing Authority), Saskatchewan Power Corporation (Balancing Authority), Customer Service Operations, Power Sales & Operations, and Manitoba Hydro's Public Affairs Department are outlined herein. This procedure applies to capacity and energy emergency procedures for emergencies that are anticipated with Day Ahead or longer lead times.

3. Procedure:

3.1. Manitoba Hydro operates and schedules resources inside Manitoba to ensure energy and capacity supplies are adequate to meet Manitoba Hydro domestic load, firm commitments and required operating reserves, considering the single most severe contingency loss. Capacity and energy emergencies should only occur upon multiple contingency losses or during certain planned maintenance outages. Management of capacity and energy emergencies depends if they are slow developing or immediate.

3.1.1 Slowly developing emergencies are those emergencies that can be predicted in advance of the operating day (such as forecast error, predicted equipment failure, drought).

3.1.2 Immediate capacity and energy emergencies are expected to result from a sudden multiple contingency losses as a result of unforeseen circumstances.

3.2. This instruction applies to the planning horizon when capacity and energy emergencies are anticipated Day Ahead or further in advance of the operating day. EOP-3324-1 Emergency Operations - Real Time Capacity and Energy Emergency Procedures details emergency operations for the Real Time horizon.

3.3. Possible causes for Planning Horizon Capacity and Energy Emergencies

3.3.1 Loss of HVDC transmission capacity for an extended period

An HVDC transmission loss may develop into an energy or capacity emergency. If the emergency is expected to be extend beyond 4 hours when the ambient temperature is below 0 degrees Celsius or 8 hours when the ambient temperature is above 0 degrees Celsius, HVDC paralleling procedures would be initiated as per NOP-4430-17 among other capacity and energy emergency operating procedures.

3.3.2 Inadequate fuel supply

Power Sales & Operations Division is responsible to ensure that adequate fuel supplies are available to meet energy demands for Manitoba Hydro load and firm commitments. Fuel supplies include water storage in reservoirs, coal, oil, gas, and interconnection contract adverse water clauses. The Generation Reliability Engineer (GRE) is responsible for planning the generation resources on a daily basis within the established guidelines in the Weekly Operating Plan while respecting license conditions. System Control Department staff are responsible to operate within these plans. PSO will interface with the GRE if an energy or capacity emergency is anticipated due to inadequate fuel supply.

3.4. Steps to Manage Anticipated Capacity/Energy Emergencies:

If operating conditions are foreseen where all available resources are insufficient to meet firm load demand, firm transactions, and operating reserves due to forced loss of generation resources, the following steps are to be taken:

1. The Generation Reliability Engineer (GRE) will determine the extent of the emergency through consultation with Power Sales & Operations Division staff.
2. The GRE will inform the Stand-by staff to evaluate the options available to minimize the impacts of the emergency.
3. The Stand-by staff may activate the Dovercourt Emergency Response Team (ERT) at any time during this process (Standards of Conduct must be suspended to include Power Trading Staff on ERT, see NOP-1628-1 Standards of Conduct Administration).
4. The GRE will defer generator maintenance scheduled to commence during the expected emergency time frame and have any generators recalled from maintenance outages, when feasible. If applicable, the GRE will coordinate with the Network Reliability Officer to recall non-forced out transmission

equipment or defer transmission outages, for outages that restrict import capability or access to MHEB generation capacity.

5. Power Sales & Operations Division will attempt to procure adequate supplies by purchasing or modifying scheduled transactions to mitigate the emergency.
6. The GRE will make arrangements to schedule thermal generation on line. (Brandon Units 6 and 7 may provide an additional 8 MW per unit during winter operation if the de-icing feature is turned off).
7. The Stand-by staff or ERT will contact System Performance to verify import capabilities on all interfaces and identify emergency transfer limits.
8. The GRE will notify Rates Department to curtail Dual Fuel Heating and Industrial Surplus Energy interruptible customer load.
9. The Stand-by staff or ERT will notify MISO Reliability Coordinator, IESO and SaskPower of the anticipated emergency and provide details and expected duration of emergency operation.
10. The GRE will request generating stations minimize their non-essential station service demand.
11. The Stand-by staff or ERT will investigate mitigation alternatives. e.g. HVDC parallel operation, system reconfiguration (temporary bypass etc.).
12. The Stand-by staff or ERT will contact major customers to initiate voluntary load reduction (see EOP-3324-1).
13. The Stand-by staff or ERT will contact Public Affairs to plan for and initiate an appeal for voluntary load curtailment (see EOP-3324-1).
14. The Network Reliability Officer will arrange for a 5% voltage reduction on the distribution system:

    Contact each Customer Service Manager and request all distribution stations automatic voltage regulating devices placed on manual and initiate a voltage reduction at each station to 116 volts on the distribution station bus.

    - Customer Service Operations Winnipeg West
    - Customer Service Operations Winnipeg Central (*)
    - Customer Service Operations Westman
    - Customer Service Operations Eastman
    - Customer Service Operations Parkland
    - Customer Service Operations Interlake
    - Customer Service Operations North

(*) In Winnipeg Central the following procedure will be initiated to obtain the 5% voltage reduction:

If time does not permit the full execution of any of the steps, proceed to the next step.

a) Block transformer load tap changers and feeder regulators in their present position

b) Lower system voltage to 95% of normal voltage (to achieve 116 V on the stations' distribution bus)

15. The Stand-by staff or ERT will issue operating instructions to SCC as per decisions reached in concert with above departments and distribute to senior management.

16. If the emergency progresses into a Real Time capacity and energy emergency, proceed with steps in EOP-3324-1 Emergency Operations - Real Time Capacity and Energy Emergency Procedures.

4. Reference Documents:

EOP-3324-1 Emergency Operations - Real Time Capacity and Energy Emergency Procedures

NOP-1628-1 Standards of Conduct Administration

5. Revision History:

Rev No.	Date of Issue	Owner or Author	Ext. Review	Appr. By	Revision
0	2009-04-19	KDG	MISO	BAP	Modified format and changed naming convention. Was CSOI-3-5.1.1
1	2009-06-05	KDG		BAP	Expanded step to recall or defer generation outages to include coordinating with Network Reliability Officer to do the same for relevant transmission outages.
2	2011-01-26	GG		LSH	Added a note that Brandon CTs can supply an additional 8 MW per unit if the de-icing feature is turned off. Replaced GRO with GRE. Other minor changes.
3	2012-05-01	BM		LAS	General review. Revised roles due to TSO department re-organization.

A. Introduction

1. **Title: Reliability Coordination — Transmission Loading Relief (TLR)**
2. **Number: IRO-006-5**
3. **Purpose:** To ensure coordinated action between Interconnections when implementing Interconnection-wide transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.
4. **Applicability:**

   4.1. Reliability Coordinator.

   4.2. Balancing Authority.
5. **Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required; the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall provide evidence (such as dated logs, voice recordings, Tag histories, and studies, in electronic or hard copy format) that, when a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure was made from another Reliability Coordinator, Balancing Authority, or Transmission Operator in that other Interconnection, it complied with the request or provided a reliability reason why it could not comply with the request (R1).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

   1.2. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Reliability Coordinator and Balancing Authority shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator and Balancing Authority shall maintain evidence to show compliance with R1 for the most recent twelve calendar months plus the current month.
- If a Reliability Coordinator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				The responsible entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity neither complied with the request, nor provided a reliability reason why it could not comply with the request.

E. Variances

None.

F. Associated Documents

None.

G. Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 8, 2005	Revised Attachment 1	Revision
3	February 26, 2007	Revised Purpose and Attachment 1 related to NERC NAESB split of the TLR procedure	Revision
4	October 23, 2007	Completed NERC/NAESB split	Revision
5	TBD	Removed Attachment 1 and made into a new standard, eliminated unnecessary requirements.	Revision
5	November 4, 2010	Approved by the Board of Trustees	
5	April 21, 2011	FERC Order issued approving IRO-006-5 (approval effective June 27, 2011)	

SUBJECT: Economic Risk

REFERENCE: Chapter 5 pages 16-28 and Chapter 15 at 9:13-21

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please provide in computer-readable form for the period beginning January 1, 2007: Hourly pre-schedules and post-schedules on the HVdc system.

RESPONSE:

Manitoba Hydro dispatches generating resources to meet domestic load demand and interchange commitments. Depending on the hydraulic conditions, hydro generation is typically dispatched firstly at Winnipeg River, Kelsey, Jenpeg, and Wuskwatim, followed by HVdc and Grand Rapids generation, and lastly the thermal generation at Selkirk and Brandon. Once the ac hydro generation is fully dispatched, any further changes in load and interchange schedules will be followed by HVdc generation. As a result, there is no normally termed “schedules” on the HVdc system. Rather the HVdc generation is dispatched as required. Hourly HVdc loading is Commercially Sensitive Information and cannot be filed on the public record.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 pages 16-28 and Chapter 15 at 9:13-21

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please provide in computer-readable form for the period beginning January 1, 2007: Manitoba Hydro's hourly integrated demand.

RESPONSE:

Please see the attachment to this response.

SUBJECT: Economic Risk

REFERENCE: Chapter 5 pages 16-28 and Chapter 15 at 9:13-21

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please provide in computer-readable form for the period beginning January 1, 2007: Manitoba Hydro's hourly locational marginal price at the Manitoba-MISO interconnection(s).

RESPONSE:

The response to this Information Request would require the disclosure of Commercially Sensitive Information and cannot be filed on the public record.

SUBJECT: Economic Risk

REFERENCE: Chapter 15 at 11:16-19

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Manitoba Hydro states that it will have an increase in import transfer capability up to 1500 MW with the construction of the Great Northern Transmission Project. Will this increased transfer capability exist without the construction of the Manitoba-Minnesota Transmission Project?

RESPONSE:

No. The increased import capability requires the construction of new transmission due to both thermal and voltage issues. The 750 MW 500 kV Manitoba-Minnesota Transmission Project increases both the export and import capability by 750 MW over today's capability of 700 MW import and 2175 MW export. Therefore, the new capability will be 1450 MW import and 2925 MW export.

SUBJECT: Economic Risk

REFERENCE: Chapter 6 at 5:22-27

PREAMBLE: The NPV of the alternatives depends in part upon the amount of revenue received from exports to the U.S. The costs of transmission and the ability of the transmission to deliver this power is at issue.

QUESTION:

Manitoba Hydro notes that generation and transmission are being built in MISO to take advantage of windows of opportunity to fulfill RPS requirements. Has Manitoba Hydro analyzed the expected costs of MISO's currently proposed transmission investment over the next 10 years and, if so, please provide such studies?

RESPONSE:

The referenced section in Chapter 6 said several things:

- "Over the next several years, Manitoba Hydro anticipates that there will be generation and transmission investment driven by RPS requirements." Over the past four MISO MTEP studies, investment has been: $1.2 B (MTEP10), $6.4B (MTEP11), $1.5B (MTEP12), and $1.5B (MTEP13). Significant transmission investment was approved for a multi-valued portfolio of seventeen projects in MTEP11 to provide regional public policy benefits (i.e. RPS requirements). The majority of the investment in MTEP13 is for reliability needs. Proposed air regulations show the potential for a 3-7 GW capacity shortfall as early as 2016. MTEP futures assume between 5-9 GW of new wind and up to 2 GW of solar will be added by 2028 based on the current state mandate or goal. Therefore, significant investment in MISO is expected over the next 10-15 years to help integrate wind and solar to meet state RPS requirements.
- Ref:https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP13/MTEP13%20Report.pdf

- "Manitoba Hydro currently has an opportunity to build new transmission as part of a regional plan that includes infrastructure to meet RPS requirements or assist with regional wind integration." The opportunity is twofold. On the one hand, Minnesota Power needs 250 MW to meet its long term capacity and energy needs and the new transmission helps to facilitate that transaction. On the other hand, the new line increases regional reliability, increases Manitoba to U.S. transfer bi-directional capability and allows for optimization of renewable energy resources. This was well documented in the Manitoba-MISO wind synergy report and summarized in MTEP2013.

Manitoba Hydro does not have a report that analyzes the cost of MISO's investment plan over the next ten years. MISO is responsible for ensuring the investment is prudent. The best documentation available are the MISO MTEP reports, which are publicly available on MISO's website.

SUBJECT: Economic Risk

REFERENCE: Chapter 6 at 5:22-27

PREAMBLE: The NPV of the alternatives depends in part upon the amount of revenue received from exports to the U.S. The costs of transmission and the ability of the transmission to deliver this power is at issue.

QUESTION:

Manitoba Hydro notes that generation and transmission are being built in MISO to take advantage of windows of opportunity to fulfill RPS requirements. Will Manitoba Hydro pay a share of the MISO's currently proposed transmission investment over the next 10 years?

RESPONSE:

No, Manitoba Hydro will not pay a share of the MISO's currently proposed transmission investment over the next 10 years. The other MISO transmission projects are proceeding without Manitoba Hydro's involvement and Manitoba Hydro will not be responsible for a share of these other transmission project costs.

SUBJECT: Economic Risk

REFERENCE: Chapter 6 at 5:22-27

PREAMBLE: The NPV of the alternatives depends in part upon the amount of revenue received from exports to the U.S. The costs of transmission and the ability of the transmission to deliver this power is at issue.

QUESTION:

Manitoba Hydro notes that generation and transmission are being built in MISO to take advantage of windows of opportunity to fulfill RPS requirements. Will Manitoba Hydro benefit from transmission currently being planned in MISO, and if so, please describe the expected benefit to Manitoba Hydro both in dollars and other forms of benefits and, if so, how much does Hydro anticipate its share will be.

RESPONSE:

The MISO transmission build out is occurring regardless of Manitoba Hydro's plans and Manitoba Hydro will not directly benefit from these transmission projects as they will not increase the transfer capability between Manitoba and MISO. Therefore, there will be no direct incremental benefit or costs to Manitoba Hydro.

SUBJECT: Economic Risk

REFERENCE: Chapter 6 at 27:19-23

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Chapter 6 page 27 at 19:22 states: "For those development plans in which Keeyask and Conawapa are both constructed, it is expected that transmission improvements will be required in the Manitoba Hydro system once the second plant comes into service to be able to transmit all the firm power to southern Manitoba. As the additional north-south transmission would not be required for over ten years, the final determination of the design will be made nearer to the time it is needed." Please provide all studies showing that the transmission of Keeyask power will not depend upon the North-South Transmission Project.

RESPONSE:

The response to this Information Request would require the disclosure of commercially sensitive information.

SUBJECT: Economic Risk

REFERENCE: Chapter 7, Figure 7.3 at page 11

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Referring to Figure 7.3 in Chapter 7 at page 11, please provide detailed documentation describing the calculation of the levelized cost of the various types of resource technologies.

RESPONSE:

Please see Manitoba Hydro's response to LCA/MH I-308.

SUBJECT: Economic Risk

REFERENCE: Chapter 7, Figure 7.3 at page 11

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Referring to Figure 7.3 in Chapter 7 at page 11, does the levelized cost of any of the technologies include the costs of Bipole III, the Manitoba-Minnesota Transmission Project or the North-South Transmission Upgrade Project?

RESPONSE:

The levelized costs of resource technologies shown in Figure 7.3 only include transmission sufficient to connect to the grid. As a result the levelized costs shown in Figure 7.3 do not contain the costs associated with the Bipole III, Manitoba-Minnesota or North-South transmission projects.

SUBJECT: Economic Risk

REFERENCE: Chapter 7, Figure 7.3 at page 11

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

If the answer to part (b) is no, please explain why the hydro technology does not include these costs; if the answer to part (b) is yes, please provide the levelized cost of each transmission project (Bipole III, MMTP or the North-South Transmission Upgrade Project) attributable to each type of resource studied.

RESPONSE:

It is typical of levelized cost calculations for generation technologies to contain costs for generation and transmnission to the point of connection to the grid to allow for comparision and facilitate high level screening.

The cost of transmission projects such as the Manitoba-Minnesota Transmission Project and the North-South Transmission Upgrade Project are included as part of a comprehensive plan to meet growing domestic loads and firm export commitments. The various development plans that were created and presented as part of the Business Case include the costs of transmission required to provide the benefits associated with each development plan.

SUBJECT: Economic Risk

REFERENCE: Chapter 9 at 6:3 - 7:7 and Appendix 9.2

PREAMBLE: The NPV of the alternatives depends in part upon the amount of revenue received from exports to the U.S. The costs of transmission and the ability of the transmission to deliver this power is at issue.

QUESTION:

Manitoba's SPLASH generation system production cost model contains inputs for the electricity export prices and proposed export power sales, as well as flow-related electricity export revenues. Please provide in computer readable form the inputs for the electricity export prices and proposed power sales, including amounts, prices, types by year and by development plan, including the amount of associated revenue by each type of export sale by year by plan.

RESPONSE:

The inputs requested have not been provided as they are considered Commercially Sensitive information.

Please see Appendix 3.1 of the NFAT Business Case entitled "Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO – The Brattle Group" for a general explanation of the expected trend of future electricity prices in MISO.

Please also see Appendix 9.3 of the NFAT Business Case, Tables 1.4 to Tables 1.11, which contain long-term import and export contracts.

SUBJECT: Economic Risk

REFERENCE: Appendix 9.3 at 1.5.1.2, 1.5.1.3, and 1.5.1.4

PREAMBLE: The NPV of the alternatives depends in part upon the amount of revenue received from exports to the U.S. The costs of transmission and the ability of the transmission to deliver this power is at issue.

QUESTION:

Please provide on an annual basis the final long-term price forecasts for on-peak all-in, on-peak long-term firm dependable and off-peak energy, for each of the 2012/13, August 2012/2013 and 2013/2014 Energy Price Forecasts described in Appendix 9.3 at Sections 1.5.1.2, 1.5.1.3 and 1.5.1.4.

RESPONSE:

Response to this Information Request would require the provision of Commercially Sensitive Information.

Please see Appendix 3.1 of the NFAT Business Case entitled "Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO – The Brattle Group" for a general explanation of the expected trend of future electricity prices in MISO.

SUBJECT: Economic Risk

REFERENCE: Chapter 9, Figure 9.3 at page 25.

PREAMBLE: The NFAT describes in Chapter 5, pages 7-11, the attributes and necessity for its HVDC and AC transmission system in order to serve Manitoba customers and deliver hydro energy to Manitoba and elsewhere. Such revenue from delivery of hydro energy is important to the economics of the various alternatives.

QUESTION:

Please explain why the NPVs for water rental, capital tax transfer and provincial guarantee fees are not subtracted from the NPV of the Benefits to Manitoba Hydro and instead appear as cumulative benefits.

RESPONSE:

The NPVs for water rental, capital tax transfer and provincial guarantee fees are already included as a cost in the calculation of the NPV of Benefits to Manitoba Hydro. The reason they are added back in Figure 9.3 and appear as cumulative benefits is to provide an indication of the economic benefit to the Province as a whole.

So, from the perspective of Manitoba Hydro, the water rental, capital tax transfer and provincial guarantee fees are a cost. From the perspective of the provincial government and taxpayers, they are a benefit.

SUBJECT: Economic Risk

REFERENCE: Chapter 13 at 23, Table 13.2

QUESTION:

Table 13.2 in Chapter 13 shows the incremental capital expense between four alternatives. Please explain how the Preferred Development Plan is only $3.5 billion more than the K19/G24/250MW plan when Conawapa is anticipated to cost more than $10 billion alone.

RESPONSE:

The incremental capital expenditure values summarized in Table 13.2 of Chapter 13 are 2014 incremental present values calculated using a 6% real discount rate and expressed in millions of 2014 dollars. The difference of approximately $3.5 billion present value dollars between the Preferred Developmen Plan and the K19/Gas24/250MW plan is consistent with the difference in the capital expenditure assumptions used in the economic evaluations provided in Chapters 9 and 10 of the submission. The approximate $10 billion estimate for Conawapa is expressed in nominal dollars, or in-service dollars, and includes interest and escalation during construction.

SUBJECT: Economic Risk

REFERENCE: Chapter 13 at 27:4-12

QUESTION:

Referring to Chapter 13 at 27:4-12, please provide all spreadsheets calculating the expected unserved energy costs of the Preferred Development Plan and the three other alternatives reviewed, including the amount of unserved energy assumed under each alternative annually.

RESPONSE:

The calculations are provided in the Appendix E of the NFAT Reliability Evaluation report which is referred to as Appendix 13.1. The original calculations are provided in the attached spreadsheet "Present Worth Calculation-MMF-033".

SUBJECT: Environmental Impacts

REFERENCE: MMF/MH I-028

PREAMBLE: With respect to the North-South Transmission System Upgrade Project, approximately 452 km of additional transmission lines are proposed (Kelsey GS to Birchtree Station - 80 km, Birchtree Station to Wuskwatim GS - 42 km, Herblet Lake Station to Overflowing River Station - 210 km, Vermillion Station to Neepawa Station - 130k) (Business Case, Section 2.3.1, p. 54). These new lines may or may not follow existing lines. The new lines will increase habitat loss and fragmentation on the landscape. The Bipole III Project includes 1,384 km of new transmission lines.

The table "Macro-environmental comparison of Resource Options" from CAC/MH I-231a does not include the 452 km of transmission lines discussed above or the footprint of the Bipole III project. Rather it simply states that the North-South Upgrade Project is under study. Residual effects of these transmission lines will fall within the study areas of those components that are part of the PDP. Therefore, they need to be considered in a cumulative environmental effects assessment of the PDP and alternative plans.

QUESTION:

Provide a map showing the hypothetical locations of these new transmission lines within Manitoba.

RESPONSE:

Please see the attachment file (MMF/MH II-034a Attachment), which shows the terminating stations of the proposed new lines. The final line routings would be subject to the enviromenal and licensing process.

Needs For and Alternatives To
MMF/MH II-034a Attachment

Future Transmission Station Connections

Legend

- North South Transmission Project
- Conawapa Generation Outlet Transmission Project
- Final Preferred Route (July 18 2013)
- Bipole I & II (Existing)
- Existing Transmission Line - 500 kV
- Existing Transmission Line 138-230 kV
- Road
- Railway Line
- First Nation
- Wildlife Management Area
- National/Provincial Park
- Provincial Forest

0 5 10 20 30 40 Kilometers

0 5 10 20 30 40 Miles

Projection: UTM
Datum: NAD 1983
Zone: 14N
False Easting: 500000
False Northing: 0
Central Meridian: -99
Scale Factor: 0.9996
Latitude Of Origin: 0
Linear Unit: Metre
Scale: 1:500 000

Manitoba Hydro

December 2013

SUBJECT: Environmental Impacts

REFERENCE: MMF/MH I-028

PREAMBLE: With respect to the North-South Transmission System Upgrade Project, approximately 452 km of additional transmission lines are proposed (Kelsey GS to Birchtree Station - 80km, Birchtree Station to Wuskwatim GS - 42km, Herblet Lake Station to Overflowing River Station - 210km, Vermillion Station to Neepawa Station - 130k) (Business Case, Section 2.3.1, p. 54). These new lines may or may not follow existing lines. The new lines will increase habitat loss and fragmentation on the landscape. The Bipole III Project includes 1,384 km of new transmission lines.

The table "Macro-environmental comparison of Resource Options" from CAC/MH I-231a does not include the 452 km of transmission lines discussed above or the footprint of the Bipole III project. Rather it simply states that the North-South Upgrade Project is under study. Residual effects of these transmission lines will fall within the study areas of those components that are part of the PDP. Therefore, they need to be considered in a cumulative environmental effects assessment of the PDP and alternative plans.

QUESTION:

Include the residual biophysical effects of the Bipole III Project in the evaluation of cumulative environmental effects for the PDP and other alternatives.

RESPONSE:

Cumulative effects assessments will be undertaken in conjunction with environmental assessments of all projects identified in the preferred and alternative development plans, before any project is licensed and developed. (For example, Bipole III was considered in the cumulative effects of the Keeyask Project, for which the Clean Environment Commission recently completed public hearings.) As appropriate, Bipole III will be considered in the cumulative effects assessments of those projects in the preferred and alternative development plans.

SUBJECT: Environmental Impacts

REFERENCE: MMF/MH I-028

PREAMBLE: With respect to the North-South Transmission System Upgrade Project, approximately 452 km of additional transmission lines are proposed (Kelsey GS to Birchtree Station - 80km, Birchtree Station to Wuskwatim GS - 42km, Herblet Lake Station to Overflowing River Station - 210km, Vermillion Station to Neepawa Station - 130k) (Business Case, Section 2.3.1, p. 54). These new lines may or may not follow existing lines. The new lines will increase habitat loss and fragmentation on the landscape. The Bipole III Project includes 1,384 km of new transmission lines.

The table "Macro-environmental comparison of Resource Options" from CAC/MH I-231a does not include the 452 km of transmission lines discussed above or the footprint of the Bipole III project. Rather it simply states that the North-South Upgrade Project is under study. Residual effects of these transmission lines will fall within the study areas of those components that are part of the PDP. Therefore, they need to be considered in a cumulative environmental effects assessment of the PDP and alternative plans.

QUESTION:

"Proximity to Load Centre" falls under "Social & Policy" rather than "Environmental". Please explain how the environmental impact of transmission lines is a social or policy issue.

RESPONSE:

For the purpose of screening resource technologies, the characteristic Proximity to Load Centre has been grouped into the category of "Social & Policy" and is a proxy for a combination of different social and policy issues including those associated with transmission right-of-ways. In the context of social impacts of projects, two of these issues include the potential impacts, Land Use and Wildlife Species of Interest. Some associated social or policy issues with these environmental characteristics include, and are not limited to, the following:

- Increased accessibility to formerly isolated wildlife species of interest potentially affecting hunters, trappers and other resource harvesters.

- Increased land use impacts potentially affecting hunters, trappers, farmers and others wishing to undertake a development within a transmission right-of-way corridor.
- Increased land use impacts potentially associated with right-of-way vegetation management potentially affecting hunters, trappers, farmers and others wishing to utilize areas near a transmission right-of-way corridor.
- Aesthetic issues associated with transmission rights-of-way may be an environmental issue but are also a social or a policy matter.
- A transmission line ROW can also affect commercial resource based industries including foresty, and mining. In addition commercial tourism operations such as lodges and outfitters can also be affected. These would all be considered in socio-economic impact assessmemt.
- Implications to conservation and protected lands are considered in routing and assessment as well as heritage and archeological resources
- Potential effects on the transportation system and community services are also considerd in socio-economic assseement.
- Longer transmission has a greater risk of weather related impacts such as icing and its associated loss of line impacts, which have the potential for short-term social impacts.

SUBJECT: Environmental Impacts

REFERENCE: MMF/MH I-029c

PREAMBLE: Cumulative effects are of an additive, interactive, synergistic, and often indirect nature (Hegmann et al. 1999). Transmission interconnections to other jurisdictions are not considered in each resource technology; however, they are likely to be induced effects of the PDP.

QUESTION:

Please clarify whether or not interconnections to other jurisdictions have been considered within the assessment of macro-environmental effects of the PDP.

RESPONSE:

Manitoba Hydro notes that the referenced Information Reqeuest, MMF/MH I-029c references Manitoba Hydro's screening of individual resource options. As indicated in the response to MMF/MH I-029c, transmission interconnections are not part of the screening of resource options because the transmission interconnections are not required to develop the individual resources.

However, the transmission interconnections are considered at a development plan level. The macro-environmental effects of the transmission interconnection in the Preferred Development Plan have been considered and are described in the response to CAC/MH I-231a.

SUBJECT: Socio-economic impacts: employment

PREAMBLE: In the "Socio-economic Comparison of Resource Options" table (CAC/MH 1-231a), employment estimates are provided for the Keeyask, Conawapa, Gas, and Wind Resource Options. Construction employment estimates are greatest for Keeyask (4300 direct, 3400 indirect) and Conawapa (5000 direct, 4100 indirect), with Northern and Aboriginal employment at 500-1700 for Keeyask, and greater for Conawapa, though not yet known.

To understand not only employment effects, but other potential socio-economic effects, it is necessary to have an understanding of the estimated direct employment, per year, for each project, as well as for both projects.

QUESTION:

Please confirm the up-to-date construction schedule estimates (preferably by month, if available) for the Keeyask and Conawapa projects.

RESPONSE:

Please refer to the NFAT Submission Chapter 15 Figure 15.3 and Figure 15.4 for the up-to-date construction schedule estimates for the Keeyask and Conawapa projects respectively.

SUBJECT: Socio-economic impacts: employment

REFERENCE: MMF/MH 1-001a; MMF/MH 1-001b

PREAMBLE: In the "Socio-economic Comparison of Resource Options" table (CAC/MH 1-231a), employment estimates are provided for the Keeyask, Conawapa, Gas, and Wind Resource Options. Construction employment estimates are greatest for Keeyask (4300 direct, 3400 indirect) and Conawapa (5000 direct, 4100 indirect), with Northern and Aboriginal employment at 500-1700 for Keeyask, and greater for Conawapa, though not yet known.

To understand not only employment effects, but other potential socio-economic effects, it is necessary to have an understanding of the estimated direct employment, per year, for each project, as well as for both projects.

QUESTION:

Please provide the locations where it is anticipated the direct workforce will reside, and specify the number of workers that will reside in camps versus communities.

RESPONSE:

Keeyask construction workers will be housed at a camp capable of accommodating up to 2000 people on the north shore of Gull Rapids. The camp will be 140 kilometers via the north access road from Gillam and 190 kilometers from Thompson. The 50 – 100 workers for the south access road will likely reside in camp accommodations south of the river, but the exact location has not yet been determined.

According to current plans, Conawapa construction workers will be housed in a camp capable of accommodating 2,500 people. It is currently planned to be located two kilometers southwest of the generating station site. By road, the Conawapa construction camp is approximately 29 km northeast of Fox Lake Cree Nation (Bird Lake) and 88 km northeast of Gillam.

Few, if any, construction workers are expected to commute to either construction site on a daily basis.

Operational staff will commute on a daily basis to Keeyask. Operational staff at Conawapa will commute on a rotational basis and will be accommodated in a staff house near the generating station.

SUBJECT: Socio-economic impacts: business opportunities

REFERENCE: MMF/MH 1-001a; MMF/MH 1-001b

PREAMBLE: The "Socio-economic Comparison of Resource Options" table (CAC/MH 1-231a) provides a figure of $200 million for Northern and Aboriginal Local Business Opportunities. The text that follows (p.23 of 29) states that "Total value of the contracts to the four Cree Nations will total over $200 million, which is substantial for these communities with limited experience."

QUESTION:

Please confirm whether the $200 million in contracts in the Socio-economic Comparison of Resource Options table in CAC-MH I-231a is entirely planned for the KCNs.

RESPONSE:

Yes, the $200 million in contracts identified in the aforementioned table are entirely planned for the KCNs and were negotiated as part of the Joint Keeyask Development Agreement (JKDA). Please see the response to PUB/MH II-499b for more information.

SUBJECT: Socio-economic impacts: business opportunities

REFERENCE: MMF/MH 1-001a; MMF/MH 1-001b;

PREAMBLE: The text on p.23 (CAC/MH 1-231a) refers to concerns raised by the MMF regarding the difference in business opportunities between the KCNs and other Northern and Aboriginal groups and communities, to which Manitoba Hydro states that "The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding business opportunities are the subject of review in the environmental review process." The PUB process defers to the CEC process for socioeconomic assessment information, however, the Metis have not been identified as a distinct and separate group in the CEC process, and Metis-specific effects have not been identified and assessed as such.

QUESTION:

Please indicate the dollar amount of contracts in relation to the PDP that are anticipated to be filled by Northern and Aboriginal businesses other than the KCNs.

RESPONSE:

On the Keeyask project, all contracts not designated as Direct Negotiation Contracts with the KCNs will be procured through an open-tender–process and as such, it is not possible to estimate the dollar amount of contracts that may be filled by northern and Aboriginal businesses other than the KCNs. All northern and Aboriginal businesses, other than the KCNs, will have the opportunity to submit tenders on this work as well as sub contracting opportunities on a number of different contracts. The KCNs will have an opportunity to bid on subcontracting opportunities via the bid depository process as outlined in the Joint Keeyask Development Agreement.

Manitoba Hydro's Northern Purchase Policy encourages participation in business and employment opportunities for Aboriginal northern communities within the Northern Affairs boundary. Regarding the procurement process, Manitoba Hydro maintains a Vendor Database which is populated based on vendor input via Vendor Registration (see website http://www.hydro.mb.ca/selling_to_mh/vendor_information.shtml). Vendors are asked to self declare status of being a Northern Aboriginal Contractor. Definitions are:

i. Northern Aboriginal: A First Nations, Non-status Indian, Métis or Inuit person who has resided in Manitoba, north of the Northern Affairs Boundary, for a cumulative period of 5 years or more.

ii. Northern Aboriginal contractor: a Northern business (including Aboriginal Joint Venture, partnership or corporation) that is:

- at least 51 per cent owned and controlled by a Northern Aboriginal; and
- if the business has 6 or more full-time staff, at least one-third of them are Aboriginal people.

Project Development Agreements for Conawapa are currently under negotiation and dollar amounts are not yet determined.

SUBJECT: Socio-economic impacts: infrastructure and services

REFERENCE: MMF/MH 1-001a; MMF/MH 1-001b; CAC/MH 1-231a

PREAMBLE: Under the "Infrastructure and Services" component/topic of the "Socio-economic Comparison of Resource Options" table (CAC/MH 1-231a), the only factor considered is housing. The text on p.5 of 29 (CAC/MH 1-231a) states that "...the socio-economic matrix focuses on housing, for which proponents of large projects accept some measure of responsibility. However, the matrix does not include other services such as transportation, health care and policing for which other agencies take a leading responsibility." For large projects, it is not unusual for project-specific socio-economic effects to require management from a responsible party other than the proponent. It is also understood that responsible parties are better able to respond to changes (for example, in demand for services) with complete and detailed information regarding potential project effects.

QUESTION:

Please provide a rationale, other than that already provided (i.e. that other agencies have a lead responsibility) for not including other items under Infrastructure and Services (e.g. transportation, health care, and policing) on which the various resource options may have an effect.

RESPONSE:

On September 30, 2013 Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. PUB Order 119/13 added demand side (DSM) to the resource options to be considered in the matrices, and Manitoba Hydro has chosen to also include transmission projects. The matrices were filed in response to CAC/MH I-231a.

As noted in that response, the Keeyask Generation Project environmental impact assessment identified 38 valued environmental components and dozens more supporting topics. The VECs were originally selected through a process involving the members and advisers from Keeyask Cree Nations, staff of Manitoba Hydro and professionals in their respective fields. The list was subsequently shared with government specialists and other interested communities and organizations, which resulted in adjustments to the list.

The NFAT Terms of Reference explicitly state that the environmental reviews are beyond the NFAT's scope. Rather, the PUB directed that "a high level summary" be produced for the socio-economic analysis. The matrices and accompanying text in CAC/MH I-231a is intended to meet the PUB's objectives. The selection of topics is explained in CAC/MH I-231a.

SUBJECT: Socio-economic impacts: infrastructure and services

REFERENCE: MMF/MH 1-001a; MMF/MH 1-001b;

PREAMBLE: Under the "Infrastructure and Services" component/topic of the "Socio-economic Comparison of Resource Options" table (CAC/MH 1-231a), the only factor considered is housing. The text on p.5 of 29 (CAC/MH 1-231a) states that "...the socio-economic matrix focuses on housing, for which proponents of large projects accept some measure of responsibility. However, the matrix does not include other services such as transportation, health care and policing for which other agencies take a leading responsibility." For large projects, it is not unusual for project-specific socio-economic effects to require management from a responsible party other than the proponent. It is also understood that responsible parties are better able to respond to changes (for example, in demand for services) with complete and detailed information regarding potential project effects.

There is concern that project construction will result in increased demand on infrastructure and services in the project area(s), and that this effect will be greatest for current Northern and Aboriginal residents who will experience a change in their ability to access or use infrastructure and services at current levels. It is presently not known whether construction schedules for Keeyask and Conawapa will overlap, but in the case that they do, it is anticipated that these effects will be of a greater magnitude.

It is also understood that each project will undergo a separate environmental review process; however, there is an additional concern that these separate review processes will fail to consider the combined effects of the separate PDP components.

QUESTION:

Please describe how the combined socio-economic effects of the separate components of the PDP will be considered and assessed, and through which process.

RESPONSE:

Manitoba Hydro notes there are a number of the concerns and statements in the preamble regarding infrastructure and services that are currently being considered and addressed.

According to the Cumulative Effects Assessment Summary for the Keeyask Generation Project Environmental Impact Statement:

> It is anticipated that the influx of non-local construction workers from future projects will add to the pressure on community-based infrastructure and services, particularly emergency (i.e., RCMP) and social services in Gillam. Future project and activities may increase the magnitude of effects from small to moderate for the short term due to an increase in workers and associated service needs. Collaborative mitigation measures are in place to address these concerns.

The Keeyask Project, in particular the generating project, has undergone many years of environmental study involving Manitoba Hydro and the Keeyask Cree Nations. In effect, it has been subject to two environmental evaluations, the first by the KCNs based on their own Cree world view and the next by the partnership for the regulatory reviews currently being conducted by the federal and provincial governments.

The regulatory reviews of the Keeyask Project under *The Environment Act* (Manitoba) and the *Canadian Environmental Assessment Act* include a cumulative effects assessment that considers effects of past, current and future projects. The Keeyask cumulative effects assessment is available in chapter 7 of the Response to the EIS Guidelines, filed as part of the Keeyask Environmental Impact Statement. The Cumulative Effects Assessment Summary was subsequently filed in the CEC proceedings in July 2013 in response to CEC Rd1 CEC-0020. Through this mechanism, the combined socio-economic effects of projects with overlapping spatial and temporal effects are considered.

Conawapa and the transmission projects will also be subject to extensive environmental assessments that will include cumulative effects assessments.

SUBJECT: Socio-economic impacts: infrastructure and services

PREAMBLE: Under the "Infrastructure and Services" component/topic of the "Socio-economic Comparison of Resource Options" table (CAC/MH 1-231a), the only factor considered is housing. The text on p.5 of 29 (CAC/MH 1-231a) states that "...the socio-economic matrix focuses on housing, for which proponents of large projects accept some measure of responsibility. However, the matrix does not include other services such as transportation, health care and policing for which other agencies take a leading responsibility." For large projects, it is not unusual for project-specific socio-economic effects to require management from a responsible party other than the proponent. It is also understood that responsible parties are better able to respond to changes (for example, in demand for services) with complete and detailed information regarding potential project effects.

There is concern that project construction will result in increased demand on infrastructure and services in the project area(s), and that this effect will be greatest for current Northern and Aboriginal residents that will experience a change in their ability to access or use infrastructure and services at current levels. It is presently not known whether construction schedules for Keeyask and Conawapa will overlap, but in the case that they do, it is anticipated that these effects will be of a greater magnitude.

It is also understood that each project will undergo a separate environmental review process; however, there is an additional concern that these separate review processes will fail to consider the combined effects of the separate PDP components.

QUESTION:

Please estimate the combined effects of the Keeyask and Conawapa projects on Infrastructure and Services, including housing, transportation, health care services, and policing.

RESPONSE:

As noted in the response to MH/MMF I-38d, infrastructure and services have been considered in the Cumulative Effects Assessment Summary for the Keeyask Generation Project

Environmental Impact Statement. As such, Manitoba Hydro notes that these topics are subject to full review under the environmental reviews.

The following are extracted from the Cumulative Effects Assessment Summary:

- Housing: The summary notes that construction workers will be housed in construction camps, Manitoba Hydro has plans to upgrade and increase housing in Gillam, and income earned by the KCNs through their project investment could be used to invest in community housing. The summary then concludes: "All future projects require additional workforces with some workers likely drawn from within and outside the Local Study Area. This non-local workforce may place an increased demand for housing in Gillam and Thompson, although the Gillam Redevelopment Program will offset some of that demand. Existing house shortages in KCNs, short term crowding and ongoing demand for temporary accommodation may occur with the [Keeyask] Project in combination with future projects."
- Travel, access and safety: The summary notes Manitoba Infrastructure and Services is improving PR 280 prior to the Keeyask Generation Project, and the project will re-route PR 280 over the generating station, thereby reducing the travel distance between Gillam and Thompson. It concludes: "Other future projects are not expected to overlap [with the Keeyask Project] spatially with water or ice-based travel. In terms of road travel safety, the expected increases in traffic due to cumulative effects of the [Keeyask] Project (during the construction phases) with other future projects may result in overall moderate to large residual effects for a short period of project overlap; however, the conclusion from the residual effects significance assessment in chapter 6 remains unchanged [i.e. it is not significant]."

- Transportation: The summary concludes, “With future projects and activities, traffic is expected to increase sizably; however, due to road and service upgrades, the significance of effects is not expected to increase.”

- Health care services and policing: Health care services and policing are included under “Infrastructure and Services” in the summary. Proposed mitigation includes on-going communication with services providers to allow for effective and timely planning of service delivery; emergency medical and ambulance services and a health clinic at the construction camp; and efforts with the Northern Regional Health Authority to secure on-site public health care professionals for the project. The summary concludes: “It is anticipated that the influx of non-local construction workers from future projects will add to the pressure on community-based infrastructure and services, particularly emergency (i.e., RCMP) and social services in Gillam. Future project and activities may increase the magnitude of effects from small to moderate for the short term due to an increase in workers and associated service needs. Collaborative mitigation measures are in place to address these concerns.”

SUBJECT: Socio-economic impacts: personal, family and community life

REFERENCE: MMF/MH 1-001a; MMF/MH 1-001b;

PREAMBLE: "Worker interaction with local residents" is listed under the "Personal, Family, and Community Life" component/topic of the "Socio-economic Comparison of Resource Options" table (CAC/MH 1-231a). The text on p.26 of 29 (CAC/MH 1-231a) describes measures to address adverse effects of worker interaction (i.e. camps, and committees established to address issues) yet concludes that "...some adverse effects are expected." There is concern that these effects will be greatest for current Northern and Aboriginal residents. It is presently not known whether construction schedules for Keeyask and Conawapa will overlap, but in the case that they do, it is anticipated that these effects will be of a greater magnitude. It is also understood that each project will undergo a separate environmental review process; however, there is an additional concern that these separate review processes will fail to consider the combined effects of the separate PDP components.

QUESTION:

Please estimate the combined effects of the Keeyask and Conawapa projects on "personal, family, and community life", particularly in terms of "worker interaction with local residents", and indicate the communities in which these effects are estimated to be greatest, and during which years of project construction.

RESPONSE:

The Cumulative Effects Assessment Summary for the Keeyask Generation Project Environmental Impact Statement sets out eight mitigation actions regarding public safety and worker interaction, including a series of strategies to keep workers at the camp, a multi-party committee to provide a coordinated approach to address issues across all Manitoba Hydro projects, and regular dialogue with the RCMP regarding policing matters. The cumulative effects summary concludes:

> There is a potential for adverse effects during the construction of the [Keeyask] project due to potential workers interactions. Future projects will further increase the number

of non-local, temporary construction workers in Gillam, increasing the potential for adverse effects. As many as 2,300 local and non-local workers will be required at the peak of the proposed Conawapa construction.

The residual adverse effects of the Keeyask Project on public safety and worker interaction may interact cumulatively with adverse effects of other projects and activities planned during the Keeyask construction phase. A collaborative and cooperative mitigation program is proposed to mitigate these potential effects.

REFERENCE: MMF/MH I-039b

SUBJECT: Socio-economic impacts

PREAMBLE: The information presented in the "Socio-economic Comparison of Resource Options" table (CAC/MH 1-231a) is not complete, or detailed enough, to allow for an understanding of the socio-economic effects of the resource options. Further, it presents very general information for all of the components of the PDP, but the same type and level of information is not provided in the NFAT submission, or to subsequent Round 1 IRs, including MMF/MH 1-004a, MMF/MH 1-004c, MMF/MH 1-038a, MMF/MH 1-039a, MMF/MH 1-046a, for the alternatives and other options.

It is still not clear whether, or how, the PDP is superior to the alternatives in even the most general socio-economic terms, and with respect to the Metis in particular.

QUESTION:

Please explain whether, and how, any of the three development plans that were eliminated (see Chapter 9) were preferable, in socio-economic terms, to the development plans that were carried forward in the analysis.

RESPONSE:

The three plans eliminated for the economic uncertainty analysis from the 15 plans reviewed in the response to MMF/MH II-40a are Plans 12, 14 and 15.

At a macro level, Plan 12 is similar to other plans in Group A (1, 2, 4, 6, and 8). They differ only in that Plan 12 does not include a U.S. Interconnection. The interconnection represents a small portion of potential socio-economic effects of the plans. For example, the interconnections represent only about 1-2% of the total employment opportunities. Unlike most of the jobs and business opportunities created in the Group A plans, the limited opportunities associated with the interconnections would occur in southern Manitoba. The elimination of the interconnection would also avoid potential effects on agricultural practices and southern resource users.

At a macro level, Plan 14 is similar to the effects of Plans 11 and 13. Together, they constitute the "Group C" plans identified in the response to MMF-MH II-40a. The differences between those plans and other development plans are described in MMF-MH II-40a.

Plan 15 (Wind and C26) was also among the three plans deleted from further consideration in Chapter 10. Again, its merits relative to the other plans is discussed in the response to MMF-MH II-40a.

REFERENCE: MMF/MH I-046a

SUBJECT: Socio-economic impacts

PREAMBLE: The information presented in the "Socio-economic Comparison of Resource Options" table (CAC/MH 1-231a) is not complete, or detailed enough, to allow for an understanding of the socio-economic effects of the resource options. Further, it presents very general information for all of the components of the PDP, but the same type and level of information is not provided in the NFAT submission, or to subsequent Round 1 IRs, including MMF/MH 1-004a, MMF/MH 1-004c, MMF/MH 1-038a, MMF/MH 1-039a, MMF/MH 1-046a, for the alternatives and other options.

It is still not clear whether, or how, the PDP is superior to the alternatives in even the most general socio-economic terms, and with respect to the Metis in particular.

QUESTION:

Please explain whether, and how, the 8 development plans that were selected for financial evaluation (see Chapter 11) are preferable, in socio-economic terms, to the 15 development plans identified in Chapter 8.

RESPONSE:

The eight plans reviewed in the financial evaluation are Plans 1, 4, 5, 6, 7, 9, 11 and 13, as numbered in the response to MMF/MH II-40a. Previously eliminated from the economic uncertainty analysis were Plans 12, 14 and 15 (please see the response to MMF/MH II-40b). Eliminated from the financial evaluation were Plans 2, 3, 9 and 11.

In terms of macro socio-economic effects, Plans 1, 4 and 6 (which are part of the financial evaluation) are very similar to Plans 2, 8 and 12. All would include the effects of Keeyask and Conawapa, three gas turbines, and the North-South Transmission Upgrade, and all except for

Plan 12 would be affected by a new U.S. Interconnection. The effects on these plans are discussed in the response to MMF/MH II-40a.

Plans 5 and 7 are also similar to each other, as well as Plan 3 (which was eliminated from the financial analysis). Each is comprised of Keeyask, gas turbines, and a new U.S. Interconnection. They do vary in details: the timing and composition of the gas turbines is different between the two plans, and the size of the U.S. Interconnection varies from 750 MW to 250 MW. However, these details are not considered in the macro analysis. For more discussion about these plans, please see the response to MMF/MH II-40a.

Plans 11 and 13 are similar to each other, as well as Plan 14 (which was eliminated from the economic uncertainty analysis). Each is comprised of a hydro-electric project and gas turbines, but no U.S. Interconnection. They differ in that Plan 11 would develop Keeyask and Plans 13 and 14 would develop Conawapa. The timing and composition of the gas turbines also differ. Total employment opportunities vary only marginally, and all three plans would be expected to experience other socio-economic effects in a similar manner when considered at a macro level. The effects on these plans are discussed in the response to MMF/MH II-40a.

Plan 11 (all gas) differs substantially from the other plans that include hydroelectric generating stations. The effects on this plan are also discussed in the response to MMF/MH II-40a.

SUBJECT: Macro-environmental

REFERENCE: CAC/MH 1-231a; MMF/MH 1-048; MMF/MH 1-053a

PREAMBLE: The proponent treats the analysis of macroenvironmental and socio-economic factors using the same methodology; yet, the definitions are very different and require the use of different methodologies. In particular, the Proponent continues to give no consideration to the "significance" of the "changes to air, land, water, flora and fauna" in the macroenvironmental analysis. In its response to MMF-053a, MH provides its view that "the specific use of "significance", as required in the environmental reviews, is not being applied in the NFAT review. Rather, as used in the NFAT submission, "significant" is synonymous with words such as important, major, noteworthy and substantial." This is not meaningful for the purposes of comparing the alternatives with respect to the "changes to air, land, water, flora and fauna".

QUESTION:

Please provide the specific criteria for determining whether "changes to the air, land, water, flora and fauna" are "important, major, noteworthy and substantial" in comparing the development plans, specifying different criteria for the five different environmental aspects, as appropriate.

RESPONSE:

As noted in the response to MMF/MH I-053a, the determination of "significance" is a requirement of the *Canadian Environmental Assessment Act.* The NFAT Terms of Reference explicitly exclude a duplication of matters being considered in the environmental reviews. As such, the term "significant" in the macro environmental and socio-economic analysis, including in the Multiple Accounts Benefit Cost Analysis, should not be confused with the methodology and criteria established for environmental assessments under environmental legislation. Rather, it is used in a manner similar to everyday lexicon, based on the user's professional judgement.

SUBJECT: Economic Risk

REFERENCE: MMF/MH 1-007; MMF/MH 1-069

PREAMBLE: Figure 3.3 illustrates a downward trend in the rate of real GDP growth since 1971. (This corrects a misstatement in MMF-07 submitted during Round 1). In its response to MMF-007, Hydro provides the requested best-fit line in Figure 3.3 clearly showing a decline in real GDP for Manitoba, Canada and the U.S. over the past 40 years. In its response to MMF-069, Hydro provides Table 1 showing projections of Manitoba Real GDP indicating that RGDP is expected to stabilize by 2018 at 1.9%, which is equivalent to the RGDP of the best fit line in Figure 3.3 in 2011.

QUESTION:

Please provide the data used to create Figure 3.3 in tabular format.

RESPONSE:

Please see the following table which provides a comparison of historical real GDP (% change).

	MB	USA	CDN
1971	2.60%	3.36%	5.50%
1972	5.96%	5.31%	5.45%
1973	4.11%	5.79%	6.96%
1974	-0.16%	-0.55%	3.69%
1975	-0.88%	-0.21%	1.82%
1976	6.56%	5.36%	5.20%
1977	0.45%	4.60%	3.46%
1978	5.18%	5.58%	3.95%
1979	5.65%	3.13%	3.80%
1980	0.81%	-0.28%	2.16%
1981	8.74%	2.54%	3.50%
1982	-2.63%	-1.94%	-3.02%
1983	0.71%	4.52%	2.57%
1984	8.25%	7.19%	5.57%
1985	6.47%	4.14%	4.68%
1986	0.22%	3.46%	2.20%
1987	1.50%	3.20%	4.04%
1988	-0.53%	4.11%	4.74%
1989	2.66%	3.57%	2.38%
1990	2.47%	1.88%	0.13%
1991	-3.36%	-0.23%	-2.12%
1992	1.04%	3.39%	0.85%
1993	0.36%	2.85%	2.61%
1994	3.90%	4.07%	4.55%
1995	0.27%	2.51%	2.74%
1996	3.07%	3.74%	1.68%
1997	3.72%	4.46%	4.25%
1998	4.25%	4.36%	4.14%
1999	1.58%	4.83%	5.00%
2000	4.26%	4.14%	5.12%
2001	0.81%	1.08%	1.69%
2002	1.56%	1.81%	2.80%
2003	1.37%	2.54%	1.93%
2004	2.16%	3.47%	3.14%
2005	2.64%	3.07%	3.16%
2006	3.40%	2.66%	2.62%
2007	2.28%	1.91%	2.01%
2008	4.01%	-0.34%	1.18%
2009	-0.50%	-3.07%	-2.71%
2010	2.30%	2.39%	3.37%
2011	2.20%	1.81%	2.53%
2012	2.20%	2.21%	1.71%

1

SUBJECT: Economic Risk

REFERENCE: MMF/MH 1-007; MMF/MH 1-069

PREAMBLE: Figure 3.3 illustrates a downward trend in the rate of real GDP growth since 1971. (This corrects a misstatement in MMF-07 submitted during Round 1). In its response to MMF-007, Hydro provides the requested best-fit line in Figure 3.3 clearly showing a decline in real GDP for Manitoba, Canada and the U.S. over the past 40 years. In its response to MMF-069, Hydro provides Table 1 showing projections of Manitoba Real GDP indicating that RGDP is expected to stabilize by 2018 at 1.9%, which is equivalent to the RGDP of the best fit line in Figure 3.3 in 2011.

QUESTION:

Please explain on what basis the projections for long-term RGDP, provided in Table 1 of the response to MMF-069, are considered to be maintained at 1.9% to the end of the planning period, rather than declining further consistent with the historic trend in RGDP, which has been declining for Manitoba, Canada and the US since 1971. In the response, identify any key social, economic or other factors that account for the sudden end to the long-term decline in RGDP in Manitoba.

RESPONSE:

The basis of the projection for long-term RGDP is the values produced from a consensus average of both publicly-available and subscription-based forecasters. Please see Manitoba Hydro's response to MMF/MH II-42c for further details.

SUBJECT: Economic Risk

REFERENCE: MMF/MH 1-007; MMF/MH 1-069

PREAMBLE: In reviewing Table 1 provided in response to MMF-069, it is apparent that three long-term projections for RGDP were provided: by Spatial Economics, the Conference Board of Canada and Informetrica. It appears, however, that the three projections are not averaged and that lesser weight has been given to the Spatial Economics projections, the only one of the three that suggests that the long-term trend in declining RGDP will continue throughout the future planning period as it has historically.

QUESTION:

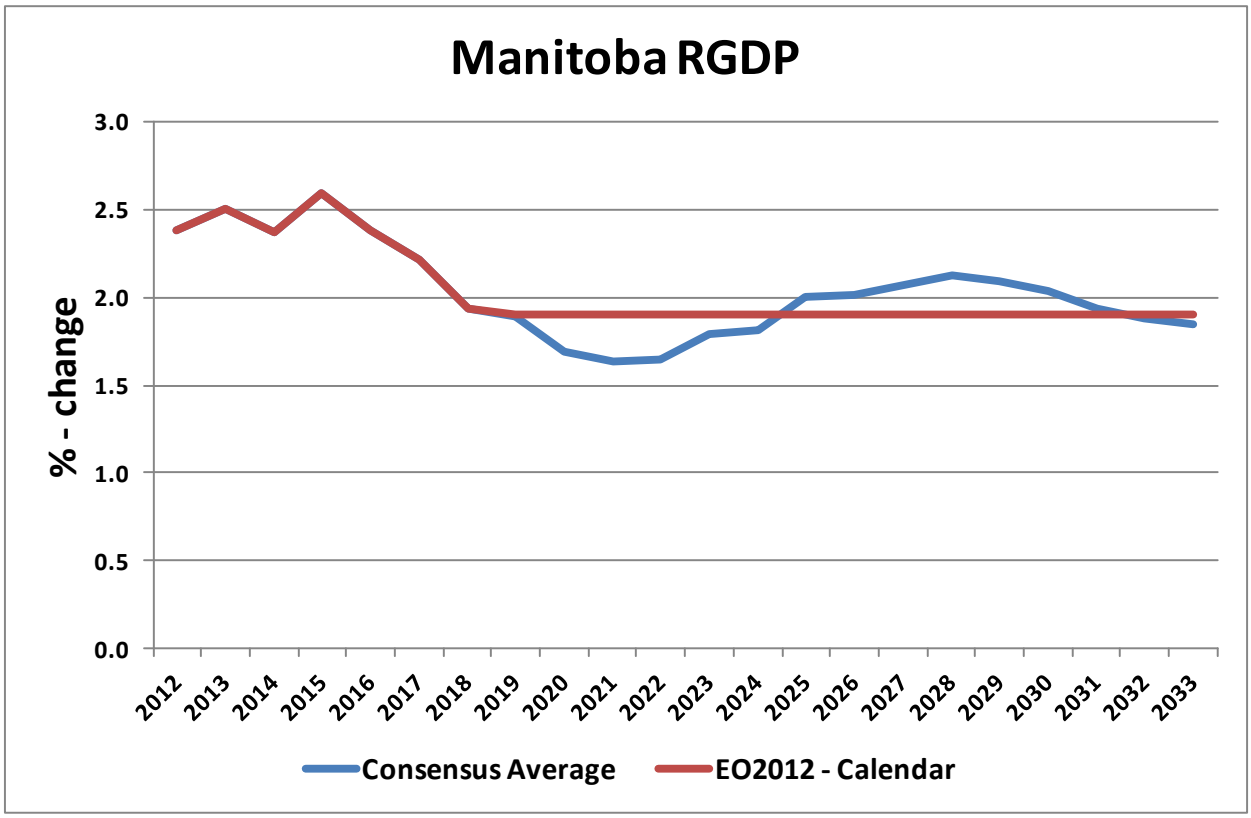
Please explain why the Spatial Economics projections have been given less weight in the determination of long-term Manitoba RGDP.

RESPONSE:

The forecast of Manitoba RGDP is derived from the average of the consensus survey using the sources as listed in Table 1 in the response to MMF/MH I-069.

The following chart presents Manitoba Hydro's Manitoba RGDP forecast, compared to the forecast of the consensus survey.

Figure 1 – Forecast of Manitoba RGDP (2012 Economic Outlook)



From 2012 – 2018, Manitoba Hydro's annual forecast is equal to the annual forecast of the consensus survey. The long-term forecast of Manitoba RGDP beyond year 2018, however, is set to a value such that the average over the forecast period from 2019 – 2033 (red line in above figure) is equal to the average over the forecast period of the consensus survey (blue line in above figure). For example, the long-run average over the forecast period 2019-2033 as projected by the three long term forecasters - Spatial Economics, Conference Board and Informetrica – was 1.9%. This "smoothed" 1.9% value was set as Manitoba's forecast of Manitoba RGDP for 2019 and beyond.

SUBJECT: Socio-economic impacts: employment

REFERENCE: MMF/MH 1-056

PREAMBLE: Further to MMF-056 asking the Proponent to "Provide the definition of a "Manitoban" for the purposes of assigning employment benefits, including the criteria used to determine this definition", the Proponent responded that a "Manitoban refers to residents of Manitoba". The definition does not distinguish Manitobans who move to the Province to take up work versus those who are already resident in the Province and obtain work.

QUESTION:

Please describe the criteria required by the Province of Manitoba to be considered a "resident" of the Province.

RESPONSE:

According to the the Government of Manitoba, generally, you are a resident of the Province if Manitoba is where you lived for the last 12 consecutive months. This would include workers who move to the Province to take up work, provided these workers lived in Manitoba for the past 12 months.

SUBJECT: Socio-economic impacts: employment

REFERENCE: MMF/MH 1-056

PREAMBLE: Further to MMF-056 asking the Proponent to "Provide the definition of a "Manitoban" for the purposes of assigning employment benefits, including the criteria used to determine this definition", the Proponent responded that a "Manitoban refers to residents of Manitoba". The definition does not distinguish Manitobans who move to the Province to take up work versus those who are already resident in the Province and obtain work.

QUESTION:

Please indicate for the Wuskwatim Project (as a most recent example), how many person-years of direct employment for the construction phase of the Project were obtained by Manitobans and by non-Manitobans, and the total person-years of direct employment for that Project on an annual (or preferably monthly) basis.

RESPONSE:

From start of construction to end of November 30, 2012, direct total person years of employment for Wuskwatim were estimated at 2859. This is based on an employee working 2000 hours in a year. Of this total, 2001 person years and 858 person years represent employment by Manitobans and non-Manitobans, respectively. Cumulative year totals for person years of employment were provided in Annual Monitoring Overview reports available at the following link: http://wuskwatim.ca/reports.html#monitor.

Note that the total person years may be understated as a full validation of the employee database to end of December 31, 2012 is ongoing.

SUBJECT: Macro-environmental

REFERENCE: MMF/MH I-060

PREAMBLE: In MMF-60, MH was asked to "Explain the declining effect in Figure 13.8 of the hydro development plans on reduction of GHG emissions in export markets over time, making reference to relevant legislation in these markets and any targets for GHG emissions reduction at the municipal, state, regional and federal levels or within certain industries or corporations producing electricity within these markets."

In its response, MH indicates that "This figure assumes a constant GHG displacement factor of 0.75 kg CO2e/kWh was applied to the Manitoba Hydro exports (and imports) associated with the selected development plans."

It is unclear why Manitoba Hydro would apply the same GHG displacement factor over time given commitments to reduce greenhouse gases in the target markets.

QUESTION:

Please explain and justify why a constant GHG displacement factor was assumed for the duration of the planning period (shown as 2010 to 2048 in Figure 13.8), when GHG emissions will need to be reduced substantially over that period in order to achieve climate change objectives.

RESPONSE:

Please refer to the response to PUB/MH II-376a.

SUBJECT: Macro-environmental

REFERENCE: MMF/MH I-060

PREAMBLE: In MMF-60, MH was asked to "Explain the declining effect in Figure 13.8 of the hydro development plans on reduction of GHG emissions in export markets over time, making reference to relevant legislation in these markets and any targets for GHG emissions reduction at the municipal, state, regional and federal levels or within certain industries or corporations producing electricity within these markets."

In its response, MH indicates that "This figure assumes a constant GHG displacement factor of 0.75 kg CO2e/kWh was applied to the Manitoba Hydro exports (and imports) associated with the selected development plans."

It is unclear why Manitoba Hydro would apply the same GHG displacement factor over time given commitments to reduce greenhouse gases in the target markets.

QUESTION:

Please explain how Manitoba Hydro accounts for the potential for exports to displace demand-side management or other renewables, as opposed to fossil-fuel generation, in the export markets.

RESPONSE:

Manitoba Hydro's exports primarily displace fossil fuel generation rather than other renewables or demand side management programs. In a market like MISO, generation unit dispatch decisions are made by the system operator based on marginal energy production cost. Renewable generation like wind, solar and hydro are very rarely on the margin because they have very low dispatch costs relative to the fuel costs associated with coal and natural gas generation. Similarly demand-side management programs affect load and have no marginal energy cost and therefore are not affected by resource dispatch decisions.

Further, the construction of wind generation in the MISO market has been primarily driven by state renewable portfolio standards and the federal US production tax credits (See Chapter 3, Section 3.3.4 State and Provincial Policy Perspectives, page 21 of the Application). Wind generation in MISO has grown to 11,857 MW registered wind capacity at June 2012 (Appendix 5.1 – MISO Corporate Information Fact Sheet) with these incentives, and while Manitoba Hydro was exporting into the MISO market. Similarly, demand side management is often driven by legislative requirements. For example, Minnesota passed an energy efficiency resource standard in 2007 requiring electric and gas utilities to spend and invest for energy conservation improvements a specified percentage of its gross operating revenues (Minnesota Statute 216B.241 Energy Conservation Improvement).