**PUB/MH/RISK-1**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market- Domestic Competition (A1.1)**

**a) Please file the 2010/11 Load Forecast**

**ANSWER:**

Please see Appendix 62.

**<u>PUB/MH/RISK-1</u>**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Market- Domestic Competition (A1.1)**

**b)** **Please indicate what assumptions did MH make in the load forecast with respect to customer migration from**

**i.** **electric to natural gas**
**ii.** **electric to geothermal**
**iii.** **electric to other**

**<u>ANSWER</u>:**

i. MH does not make specific assumptions regarding customer migration from electric to natural gas in the load forecast. The customer forecast for all-electric and standard customers is determined by forecasting the market share (percentage) of all-electric customers using econometric analysis. This forecast assumes to include both new construction (i.e. growth) and all transfers between standard and all-electric customers.

ii. MH does not make specific assumptions regarding customer migration between electric and geothermal customers in the load forecast. The forecast for geothermal customers is determined from past trends and expected adoption rates. This assumes to include both new construction and conversions of existing homes with electric or natural gas heating systems; conversions from electric heat are not specifically forecast within the load forecast.

iii. MH does not make specific assumptions regarding customer migration from electric heat to “other fuels”. It includes “other fuels” with natural gas in the standard customer classification. Only a small percentage of Manitoba Hydro’s residential customers heat with a fuel other than electricity or natural gas, and market share for “other fuels” is not anticipated to change materially.

**<u>PUB/MH/RISK-2</u>**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Market-Export Regulatory Environment A2.1**

**a)** **Please provide the wording for all regulatory approvals and conditions for WPS and MP in the term sheets and an outline on the process to obtain the approvals.**

**<u>ANSWER</u>:**

The terms and conditions of the WPS and MP Term Sheets are subject to a non-disclosure agreement between Manitoba Hydro and the respective parties.

In general, all Manitoba Hydro long-term export contracts require appropriate state/provincial and federal regulatory, final non-appealable approval. It is Manitoba Hydro's responsibility to obtain Canadian approvals whereas it is the purchaser's responsibility for U.S. approvals.

**PUB/MH/RISK-2**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market-Export Regulatory Environment A2.1**

**b) Please indicate the prospects for Hydro—based generation to be considered renewable energy and discuss the implications on MH's Export prospects?**

**ANSWER:**

Hydro based generation is a renewable energy source as it is derived from naturally replenished resources. However, each Renewable Portfolio Standard defines specific technologies that are eligible or qualify under its system. These definitions tend to vary from a true definition of renewability and are often driven by differing and sometimes unstated objectives such as encouraging: non-emitting technologies; emerging technologies; and local economic development.

Although most Renewable Portfolio Standard definitions recognize hydro generation, they often contain limitations related to the size of the facility. MH's small generating stations (less than 100 MW) are eligible under Minnesota's current Renewable Portfolio Standard. While Minnesota's standard is unlikely to change in the near term, there is potential for other state systems to become more inclusive. For instance, in 2010 a bill was promoted in Wisconsin that would have included new hydro regardless of size. While this Wisconsin bill was not voted on in 2010, Wisconsin based utilities are expected to continue to push for these amendments. Vermont recent announced its intention to fully include hydro power from Quebec in its definition of eligible renewable resources.

A more fulsome inclusion of MH's generation under Renewable Portfolio Standards would further enhance the value of our exports. However, despite the current limited eligibility, the inherent renewable and non-emitting natures of hydropower have been a strong marketable characteristic of MH's exports.

**PUB/MH/RISK-2**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market-Export Regulatory Environment A2.1**

**c) Please file the definition utilized by Wisconsin for its Renewable Portfolio Standard and provide a status update on MH's efforts to have the definition to recognize large Hydro.**

**ANSWER:**

*Wisconsin Statute § 196.378 (1)(h)*, shown below, defines the current renewable resources recognized by the State of Wisconsin.

(h) "Renewable resource" means any of the following:

1. A resource that derives electricity from any of the following:
   - a. A fuel cell that uses, as determined by the commission, a renewable fuel.
   - b. Tidal or wave action.
   - c. Solar thermal electric or photovoltaic energy.
   - d. Wind power.
   - e. Geothermal technology.
   - g. Biomass.
   - h. Synthetic gas created by the plasma gasification of waste.
   - i. Densified fuel pellets made from waste material that does not include garbage, as defined in s. 289.01 (9), and that contains no more than 30 percent fixed carbon.
   - j. Fuel produced by pyrolysis of organic or waste material.
   - 1m. A resource with a capacity of less than 60 megawatts that derives electricity from hydroelectric power.

2. Any other resource, except a conventional resource, that the commission designates as a renewable resource in rules promulgated under sub. (4).

MH supported Wisconsin based utilities efforts to expand the definition of renewable resource to include a broader inclusion of hydroelectric generation. In 2010 a Bill was promoted within the State Senate which would have expanded the definition to include new hydro (regardless of its size). However, the bill expired with the end of legislative session without being voted upon. MH will continue to support Wisconsin based utilities efforts to expand the definition of eligible renewable resources.

**PUB/MH/RISK-2**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Market-Export Regulatory Environment A2.1**

**d)** **If for any reason there was a change in the Export Regulatory environment, please provide a 20 Year IFF and CEF that assumes no new export contracts other than the NSP extension and no new Northern Generation and Transmission with any domestic shortfall met through CCT generation. Please provide all supporting assumptions including annual financial targets and annualized rate increases.**

**ANSWER:**

The work to produce an alternative IFF is complex and cannot be completed within the time allotted for responding to these Information Requests.

**PUB/MH/RISK-2**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Market-Export Regulatory Environment A2.1**

**e) Please provide a status update on the US legislation approvals for new transmission associated with MH's term sheets.**

**ANSWER:**

At present, the necessary facilities and their location associated with the proposed new transmission interconnection have not been determined. As a result, it is premature to define if any U.S. legislature approvals are required.

**PUB/MH/RISK-3**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market-Export Transmission (A2.3)**

a) **Please provide a summary of MH's reserved peak hour transmission rights (MW) (time period in force) and off-peak hour transmission constraints (MW) if any during the last three years.**

**ANSWER:**

The following table indicates Manitoba Hydro's current firm seasonal transmission rights for system intact conditions.

| Firm Export Transmission Rights Held by Manitoba Hydro | | |
|---|---|---|
| **Interface** | **Winter** | **Summer** |
| U.S. (within MB) | 1348 MW | 1848 MW |
| US (within US) | 271 MW (2008)<br>471 MW (2009)<br>521 MW (2010) | 271 MW (2008)<br>471 MW (2009)<br>521 MW (2010) |
| Ontario | 200 MW | 200 MW |
| Sask | 0 | 0 |

These firm rights apply continuously and are not subject to off peak constraints.

**PUB/MH/RISK-3**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market-Export Transmission (A2.3)**

**b) Please provide a detailed comparison to the total physical export transmission capacity that might be available to Manitoba.**

**ANSWER:**

The following table indicates Total Transfer Capability at each interface for system intact conditions.

Please note that the total transfer capability is the theoretical limit and higher than the permissible scheduling limit, which is constrained by transmission reliability margins that are set aside to account for system contingencies.

| **Total Transfer Capability** | | |
|---|---|---|
| **Interface** | **Winter** | **Summer** |
| U.S. (within MB) | 2500 MW | 2500 MW |
| US (within US) | 2500 MW | 2500 MW |
| Ontario | 300 MW | 300 MW |
| Sask | 525 MW | 500 MW |

**<u>PUB/MH/RISK-3</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market-Export Transmission (A2.3)**

**c) Please update that summary to reflect the increased level of reserved (or contractually assured) transmission rights (peak and off-peak) that flow from MH's NSP contract extension.**

**<u>ANSWER</u>:**

The NSP agreements utilize the existing transmission rights associated with the existing NSP agreements. The new sale agreements do not require an increase in transmission rights.

**PUB/MH/RISK-3**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market-Export Transmission (A2.3)**

**d) Please provide a status update on potential new transmission rights that MH may acquire through the pending WPS and MP agreements**

**ANSWER:**

The MP 250 MW and WPS 500 MW term sheets require MP and WPS to provide up to 750 MW of additional long term North and South firm transmission capability. Manitoba Hydro, MP and WPS are involved in ongoing transmission studies with the Midwest ISO and others to determine which facilities are required to meet the obligations of the term sheets.

**PUB/MH/RISK-4**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market- Export–Domestic Requirements (A2.6)**

**a) Please explain how domestic load growth from each rate class poses a financial risk to MH.**

**ANSWER:**

A financial risk is posed to the extent that higher priced export sales are displaced with lower priced domestic sales. This will ultimately lead to lower net income and the need for higher domestic rate increases to maintain financial targets.

**PUB/MH/RISK-4**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market- Export–Domestic Requirements (A2.6)**

**b) Please confirm (and explain) how in MH's Power Resource Plan, firm contracted export sales are given equal access with domestic load to all dependable generation resources.**

**ANSWER:**

The Power Resource Plan includes information on the supply resources (capacity and energy) and demand requirements (capacity and energy). The plan does not differentiate between domestic load and contracted exports in regards to access to the Corporation's generation resources. Manitoba Hydro plans its generation resources for these loads in a non-discriminatory manner.

**PUB/MH/RISK-4**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Market- Export–Domestic Requirements (A2.6)**

**c) Please provide an analysis of the 2003/04 drought period showing how MH could have contractually eliminated all or most export sales.**

**ANSWER:**

The 2003/04 drought occurred prior to the commencement of the MISO Day 2 market. Therefore a financial bookout negotiated directly between Manitoba Hydro and its bilateral counterparties would have been the only means to contractually offset its export sales.

**<u>PUB/MH/RISK-5</u>**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**PUB/MH II-172; PUB/MH II-174**
**Risk Issue:** **Market- Export– Commodity Availability (A2.7)**

**a)** **Please confirm that while MH has winter diversity agreements in place for imports, the cost of imports would typically reflect MISO-Day-Ahead market prices.**

**<u>ANSWER</u>:**

To the extent that the cost of imports in diversity agreements were at rates above market, Manitoba Hydro would avoid them and purchase market priced energy from the Midwest ISO.

PUB/MH/RISK-5

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**PUB/MH II-172; PUB/MH II-174**
**Risk Issue:** **Market- Export– Commodity Availability (A2.7)**

**b) With reference to the table below, please confirm that over the last 5 years, the MISO-Day-Ahead average winter prices in these years were 0.5 to 1.5 CDN ¢/KWh higher than the average summer prices during the off-peak and that except for 2008, the same differential existed during the on-peak.**

**PUB/MH II-172; PUB/MH II-174**
**MH's Achieved Export Prices versus**
**MISO Day-Ahead Prices (CDN ¢/KWh)**

| Year | Peak Periods | | | | Off-Peak Periods | | | |
|---|---|---|---|---|---|---|---|---|
| | MH Average Revenue Rates | | MISO Day Ahead Prices | | MH Average Revenues Rates | | MISO Day Ahead Prices | |
| | May-Oct. | Nov.-April | May-Oct. | Nov.-April | May-Oct. | Nov.-April | May-Oct. | Nov.-April |
| 2005 | 6.52 | 6.00 | 5.79 | 4.98 | 2.43 | 3.89 | 1.30 | 2.02 |
| 2006 | 6.01 | 6.54 | 5.50 | 6.50 | 3.45 | 3.57 | 2.03 | 3.86 |
| 2007 | 5.76 | 5.86 | 5.12 | 6.39 | 2.36 | 4.36 | 1.49 | 3.36 |
| 2008 | 6.01 | 6.23 | 4.95 | 3.73 | 2.15 | 3.67 | 1.40 | 2.05 |
| 2009 | 4.07 | 4.67 | 2.31 | 3.31 | 1.36 | 2.67 | 0.87 | 1.82 |

**ANSWER:**

Based on the response provided in PUB/MH II-172c Manitoba Hydro has been unable to duplicate the rates shown in the table. A corrected table is shown below which shows all prices in CDN $.

Based on the corrected numbers in the table below, the MISO Day-Ahead average winter prices in these years were 0.8 to 2.2 CDN ¢/KWh higher than the MISO Day-Ahead average summer prices during the off-peak and that except for 2005 and 2008, the same differential existed during the on-peak hours.

| **Year** | **Peak Periods** | | | | **Off-Peak Periods** | | | |
|---|---|---|---|---|---|---|---|---|
| | **MH Average Revenue Rates** | | **MISO Day Ahead Prices** | | **MH Average Revenues Rates** | | **MISO Day Ahead Prices** | |
| | **May-Oct.** | **Nov.-April** | **May-Oct.** | **Nov.-April** | **May-Oct.** | **Nov.-April** | **May-Oct.** | **Nov.-April** |
| **2005** | **6.68** | **6.02** | **6.97** | **6.17** | **2.86** | **3.65** | **1.57** | **2.45** |
| **2006** | **5.99** | **6.57** | **5.89** | **7.5** | **3.20** | **6.08** | **2.27** | **4.45** |
| **2007** | **5.76** | **5.91** | **5.31** | **6.40** | **2.40** | **3.94** | **1.72** | **3.40** |
| **2008** | **6.05** | **6.09** | **5.22** | **4.62** | **2.18** | **2.97** | **1.49** | **2.54** |
| **2009** | **4.04** | **4.25** | **2.53** | **3.46** | **1.39** | **1.69** | **0.95** | **2.06** |

**<u>PUB/MH/RISK-5</u>**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**PUB/MH II-172; PUB/MH II-174**
**Risk Issue:** **Market- Export– Commodity Availability (A2.7)**

**c) Please provide the typical range of both the overall (fixed and variable) costs and the operating (only) costs currently associated with MISO Day-Ahead market:**

- **Coal-generated energy.**
- **Natural gas (CCCT/generated energy.**
- **Natural gas (SCCT) generated energy.**
- **Wind generated energy.**

**<u>ANSWER</u>:**

MISO does not provide this information.

These costs are dependant upon a number of variables (location and age of the generation unit, capital cost of the generation unit, the cost of fuel supply, the heat rate of the facility and the capacity factor). For a general indication of these costs, please refer to Appendix 56, Attachment 6, Page 10.

**PUB/MH/RISK-6**

**Reference:** **Appendix 12.1 Corporate Risk Management Report/ Appendix 6.1 Debt Management Strategy Page 6**
**Risk Issue:** **Financial- Exchange (B.1)/ Exposure Management Program**

**a)** **Please provide the quantification of the $100 million risk exposure due to a $0.10 change in the CAD/USD exchange rate mentioned in the CRM. Provide supporting calculations.**

**ANSWER:**

The foreign exchange exposure was calculated by taking the IFF07-1 base case and applying a $0.10 increase in the exchange rate to derive a foreign exchange scenario. The net income for the period 2008 to 2018 for the base case was compared to the resultant total net income of the foreign exchange scenario. The modeled difference was the quantification of the risk exposure.

Specifically, the IFF07-1 foreign exchange scenario was filed in CAC/MSOS/MH I-106(b). A copy of the IFF07-1 base case is attached. For the period 2008 to 2018, the foreign exchange scenario resulted in net income of $1.840 billion as compared to net income under the base case scenario of $1.940 billion. This difference of $100 million was the risk exposure reported in Appendix 12.1.

**PUB/MH/RISK-6**

**Reference:** **Appendix 12.1 Corporate Risk Management Report/ Appendix 6.1 Debt Management Strategy Page 6**

**Risk Issue:** **Financial- Exchange (B.1)/ Exposure Management Program**

**b)** **Please provide a schedule summarizing the debt structure indicating the amount and percentage of fixed and floating USD and CAD Debt and average exchange rate used for translation for the fiscal years 2000 through 2009/10 and forecast for each of the years in the 20- Year IFF09.**

**ANSWER:**

Please see the attached schedule.

Note that the actual information for the fiscal years 2003/04 to 2008/09 reconciles to the year end information shown in response to CAC/MSOS/MH I-146(d). Also note that for planning purposes only, all new financings were forecast to be CAD fixed for 30 years in IFF09. Therefore, the modeled percentage of total floating rate debt declines throughout the forecast period. Actual results will vary from forecast and Manitoba Hydro will continue to secure floating rate long term debt such that the percentage of floating rate debt within the total portfolio remains within the Corporation's 15 - 25% target range. As stated in response to CAC/MSOS/MH I-142(b), actual financings "will consider the timing, dollar value, denomination, and fixed versus floating nature of the issue depending on a number of factors including: the cash and liquidity requirements in existence at the time of financing; refinancing requirements on forward interest rate swaps; the term dependent on the current maturity schedule, interest rate expectations and the mitigation of refinancing risk; the management of foreign exchange risk; and the market appetite and economic environment."

Also, as the precise timing and volume of future rebalancings of USD receipts and payments is uncertain, IFF09 assumed for long term planning purposes only that all new financings would be in Canadian dollars. As a result, IFF09 depicts an increasingly long USD position in the outbound years of the forecast even though rebalancing actions to limit net foreign exchange exposures will be undertaken by securing new US long term debt/ interest payments.

IFF10-1 will have enhanced modeling such that all new forecasted long term debt will be 20% floating and 80% fixed. Also, the enhanced modeling will forecast new USD debt in addition to CAD debt.

**PUB/MH/RISK - 6 (b)**
**Manitoba Hydro**
**Summary of Fixed and Floating Debt Structure**

| (in $Millions) | Actual Mar-2004 | Actual Mar-2005 | Actual Mar-2006 | Actual Mar-2007 | Actual Mar-2008 | Actual Mar-2009 | Forecast Mar-2010 | Forecast Mar-2011 | Forecast Mar-2012 | Forecast Mar-2013 | Forecast Mar-2014 | Forecast Mar-2015 | Forecast Mar-2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Canadian: Short Term Notes & Floating Long Term Debt (CAD) | 1,229.8 | 999.5 | 840.3 | 1,053.8 | 1,042.7 | 1,064.8 | 1,146.3 | 1,134.3 | 1,104.5 | 1,032.4 | 705.6 | 605.6 | 596.6 |
| Total US: Short Term Notes & Floating Long Term Debt (USD) | 309.5 | 300.0 | 300.0 | 300.0 | 500.0 | 500.0 | 350.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 |
| Exchange Rate for USD/ CAD at period end | 1.31 | 1.21 | 1.17 | 1.15 | 1.03 | 1.26 | 1.06 | 1.07 | 1.09 | 1.07 | 1.11 | 1.12 | 1.13 |
| Total US: Short Term Notes & Floating Long Term Debt (CAD) | 405.6 | 362.9 | 350.1 | 345.9 | 514.0 | 630.1 | 371.0 | 160.5 | 163.5 | 160.5 | 166.5 | 168.0 | 169.5 |
| **Total Short Term Notes & Floating Long Term Debt (CAD)** | **1,635.4** | **1,362.4** | **1,190.5** | **1,399.6** | **1,556.7** | **1,694.9** | **1,517.3** | **1,294.8** | **1,268.0** | **1,192.9** | **872.1** | **773.6** | **766.1** |
| Total Canadian Fixed Long Term Debt (CAD) | 3,055.7 | 3,322.8 | 3,490.4 | 3,517.6 | 3,851.1 | 4,238.4 | 4,789.3 | 5,466.8 | 6,054.4 | 6,631.0 | 7,978.0 | 9,380.3 | 10,970.7 |
| Total US Fixed Long Term Debt (USD) | 2,131.0 | 2,131.0 | 2,132.0 | 2,132.0 | 2,132.0 | 1,885.5 | 1,788.4 | 1,788.4 | 1,788.4 | 1,788.4 | 1,450.0 | 1,450.0 | 1,450.0 |
| Exchange Rate for USD/ CAD at period end | 1.31 | 1.21 | 1.17 | 1.15 | 1.03 | 1.26 | 1.06 | 1.07 | 1.09 | 1.07 | 1.11 | 1.12 | 1.13 |
| Total US Fixed Long Term Debt (CAD) | 2,792.6 | 2,577.6 | 2,488.3 | 2,458.0 | 2,191.5 | 2,376.1 | 1,895.7 | 1,913.6 | 1,949.3 | 1,913.6 | 1,609.5 | 1,624.0 | 1,638.5 |
| **Total Fixed Long Term Debt (CAD)** | **5,848.3** | **5,900.3** | **5,978.6** | **5,975.6** | **6,042.5** | **6,614.5** | **6,685.0** | **7,380.3** | **8,003.7** | **8,544.6** | **9,587.5** | **11,004.3** | **12,609.2** |
| **Total Debt** (Note 1) | **7,483.7** | **7,262.7** | **7,169.1** | **7,375.2** | **7,599.2** | **8,309.4** | **8,202.3** | **8,675.1** | **9,271.7** | **9,737.5** | **10,459.6** | **11,777.9** | **13,375.3** |
| Canadian Floating Percentage of Total Debt | 16.4% | 13.8% | 11.7% | 14.3% | 13.7% | 12.8% | 14.0% | 13.1% | 11.9% | 10.6% | 6.7% | 5.1% | 4.5% |
| US Floating (CAD) Percentage of Total Debt | 5.4% | 5.0% | 4.9% | 4.7% | 6.8% | 7.6% | 4.5% | 1.9% | 1.8% | 1.6% | 1.6% | 1.4% | 1.3% |
| **Total % Floating** | **21.9%** | **18.8%** | **16.6%** | **19.0%** | **20.5%** | **20.4%** | **18.5%** | **14.9%** | **13.7%** | **12.3%** | **8.3%** | **6.6%** | **5.7%** |
| Canadian Fixed Long Term Debt Percentage of Total Debt | 40.8% | 45.8% | 48.7% | 47.7% | 50.7% | 51.0% | 58.4% | 63.0% | 65.3% | 68.1% | 76.3% | 79.6% | 82.0% |
| US Fixed Long Term Debt (CAD) Percentage of Total Debt | 37.3% | 35.5% | 34.7% | 33.3% | 28.8% | 28.6% | 23.1% | 22.1% | 21.0% | 19.7% | 15.4% | 13.8% | 12.3% |
| **Total % Fixed** | **78.1%** | **81.2%** | **83.4%** | **81.0%** | **79.5%** | **79.6%** | **81.5%** | **85.1%** | **86.3%** | **87.7%** | **91.7%** | **93.4%** | **94.3%** |

**PUB/MH/RISK - 6 (b)**
**Manitoba Hydro**
**Summary of Fixed and Floating Debt Structure**

| (in $Millions) | Forecast Mar-2017 | Forecast Mar-2018 | Forecast Mar-2019 | Forecast Mar-2020 | Forecast Mar-2021 | Forecast Mar-2022 | Forecast Mar-2023 | Forecast Mar-2024 | Forecast Mar-2025 | Forecast Mar-2026 | Forecast Mar-2027 | Forecast Mar-2028 | Forecast Mar-2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Canadian: Short Term Notes & Floating Long Term Debt (CAD) | 376.0 | 100.0 | 172.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| Total US: Short Term Notes & Floating Long Term Debt (USD) | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | - | - | - | - | - | - | - |
| Exchange Rate for USD/ CAD at period end | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 |
| Total US: Short Term Notes & Floating Long Term Debt (CAD) | 171.0 | 171.0 | 171.0 | 171.0 | 171.0 | 171.0 | - | - | - | - | - | - | - |
| **Total Short Term Notes & Floating Long Term Debt (CAD)** | **547.0** | **271.0** | **343.0** | **221.0** | **221.0** | **221.0** | **50.0** | **50.0** | **50.0** | **50.0** | **50.0** | **50.0** | **50.0** |
| Total Canadian Fixed Long Term Debt (CAD) | 12,773.1 | 14,300.8 | 15,291.6 | 16,194.7 | 17,198.6 | 17,797.9 | 18,601.0 | 18,603.9 | 18,605.8 | 18,307.8 | 18,310.1 | 18,312.0 | 18,253.8 |
| Total US Fixed Long Term Debt (USD) | 1,450.0 | 1,450.0 | 1,050.0 | 900.0 | 650.0 | - | - | - | - | - | - | - | - |
| Exchange Rate for USD/ CAD at period end | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 |
| Total US Fixed Long Term Debt (CAD) | 1,653.0 | 1,653.0 | 1,197.0 | 1,026.0 | 741.0 | - | - | - | - | - | - | - | - |
| **Total Fixed Long Term Debt (CAD)** | **14,426.1** | **15,953.8** | **16,488.6** | **17,220.7** | **17,939.6** | **17,797.9** | **18,601.0** | **18,603.9** | **18,605.8** | **18,307.8** | **18,310.1** | **18,312.0** | **18,253.8** |
| **Total Debt** (Note 1) | **14,973.1** | **16,224.8** | **16,831.6** | **17,441.7** | **18,160.6** | **18,018.9** | **18,650.9** | **18,653.9** | **18,655.8** | **18,357.8** | **18,360.1** | **18,361.9** | **18,303.8** |
| Canadian Floating Percentage of Total Debt | 2.5% | 0.6% | 1.0% | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% |
| US Floating (CAD) Percentage of Total Debt | 1.1% | 1.1% | 1.0% | 1.0% | 0.9% | 0.9% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| **Total % Floating** | **3.7%** | **1.7%** | **2.0%** | **1.3%** | **1.2%** | **1.2%** | **0.3%** | **0.3%** | **0.3%** | **0.3%** | **0.3%** | **0.3%** | **0.3%** |
| Canadian Fixed Long Term Debt Percentage of Total Debt | 85.3% | 88.1% | 90.9% | 92.9% | 94.7% | 98.8% | 99.7% | 99.7% | 99.7% | 99.7% | 99.7% | 99.7% | 99.7% |
| US Fixed Long Term Debt (CAD) Percentage of Total Debt | 11.0% | 10.2% | 7.1% | 5.9% | 4.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| **Total % Fixed** | **96.3%** | **98.3%** | **98.0%** | **98.7%** | **98.8%** | **98.8%** | **99.7%** | **99.7%** | **99.7%** | **99.7%** | **99.7%** | **99.7%** | **99.7%** |

Note 1: The calculation of the fixed/ floating rate debt percentages utilized par values of debt. As a result, the total debt beginning in March 2008 does not exactly tie to PUB/MH I - 35 (d) where the reported debt balances are at carrying values (i.e., net of unamortized discounts/premiums/transaction fees).

**<u>PUB/MH/RISK-6</u>**

| | |
|---|---|
| **Reference:** | **Appendix 12.1 Corporate Risk Management Report/ Appendix 6.1 Debt Management Strategy Page 6** |
| **Risk Issue:** | **Financial- Exchange (B.1)/ Exposure Management Program** |

**c) Please indicate what factors the Corporation considers when determining whether it will seek US dollar versus Canadian dollar debt**

**<u>ANSWER</u>:**

Manitoba Hydro considers a number of factors when determining whether it will seek US dollar versus Canadian dollar debt, including:

- <u>Interest Rates</u>. The cost effectiveness of executing a US dollar versus a Canadian dollar issuance for available terms to maturity.
- <u>Foreign Exchange</u>. The mitigation of foreign currency exchange risk through the introduction of additional US denominated interest expense in a natural hedge with US denominated export revenue.
- <u>Liquidity and Access to Capital</u>. The liquidity and interest rate benefits associated with broadened access to capital within a diversified investor base.

As stated in response to response to CAC/MSOS/MH I-142(b), actual financings "will consider the timing, dollar value, denomination, and fixed versus floating nature of the issue depending on a number of factors including: the cash and liquidity requirements in existence at the time of financing; refinancing requirements on forward interest rate swaps; the term dependent on the current maturity schedule, interest rate expectations and the mitigation of refinancing risk; the management of foreign exchange risk; and the market appetite and economic environment."

Note that US dollar issuance typically needs to be at least $500+ million in size. In addition, although provincial borrowers frequently issue long bonds in the Canadian capital markets, due to financial market conditions, provincial issuance of US dollar debt with terms greater than 10 years is unusual because the long end of the US curve has not been cost effective compared to Canada for many years.

**PUB/MH/RISK-6**

**Reference:** **Appendix 12.1 Corporate Risk Management Report/ Appendix 6.1 Debt Management Strategy Page 6**

**Risk Issue:** **Financial- Exchange (B.1)/ Exposure Management Program**

**d) Please explain how and when there is mismatch in US based Cash flow hedges and provide the financial impact of those mismatches during the last five years.**

**ANSWER:**

As long as there are sufficient anticipated US export revenues to meet US long term debt obligations, the cash flow hedges will be in effective hedging relationships and there will be no mismatches in the US based cash flow hedges.

As noted in response to PUB/MH II-11(c), accounting cash flow hedges have been established between the US long term debt obligations and anticipated US export revenues, and the Corporation measures the effectiveness of the accounting hedge relationships on a quarterly basis. Accordingly, foreign exchange translation gains and losses on US long term debt balances in effective cash flow hedge relationships are recognized in Other Comprehensive Income (OCI) until future hedged US export revenues are realized, at which time the respective Accumulated OCI balances are also recognized in net income.

Although a significant portion of the Corporation's transactional foreign currency risk is mitigated through the establishment of a natural hedge between US dollar revenues and expenses, due to the operational variability of these US dollar cash flows, net long or short foreign currency positions will occur and be exposed to transactional foreign currency risk. Please see the response to PUB/MH II-11(c) for a discussion of Manitoba Hydro's Foreign Exchange Exposure Management Program.

**PUB/MH/RISK-6**

**Reference:** **Appendix 12.1 Corporate Risk Management Report/ Appendix 6.1 Debt Management Strategy Page 6**

**Risk Issue:** **Financial- Exchange (B.1)/ Exposure Management Program**

**e) To what extent does IFF09-1 20 year outlook incorporate foreign exchange impacts due to the mismatch of cash flow hedges?**

**ANSWER:**

There are no mismatches within the cash flow hedges as there are sufficient anticipated US export revenues to meet the US long term debt obligations in IFF09.

**PUB/MH/RISK-7**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Interest Rates (B.2)**

**a) Please provide the quantification of the $170 million risk exposure due to a 1% interest rate change mentioned in the CRM. Provide supporting calculations.**

**ANSWER:**

The interest rate exposure was calculated by taking the IFF07-1 base case and applying a 1% increase in the interest rates to derive an interest rate risk scenario. The net income for the period 2008 to 2018 for the base case was compared to the resultant total net income of the interest rate scenario. The modeled difference was the quantification of the risk exposure.

Specifically, the IFF07-1 interest rate scenario was filed in CAC/MSOS/MH I-106(b). A copy of the IFF07-1 base case is attached. For the period 2008 to 2018, the interest rate scenario resulted in net income of $1.773 billion as compared to net income under the base case scenario of $1.940 billion. This difference of $167 million, rounded up to $170 million, was the risk exposure reported in Appendix 12.1.

**<u>PUB/MH/RISK-7</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Interest Rates (B.2)**

**b) Please provide the annual impact of a 1% interest rate increase, over currently forecast rates imbedded in the 20 Year IFF and provide the annual and cumulative financial impact over the 20 year forecast.**

**<u>ANSWER</u>:**

The projected financial statements for the 1% interest rate increase sensitivity was provided in Appendix 14, page 2 and the incremental impacts on the 11-year IFF period to 2019/20 are shown in the table attached to CAC/MSOS/MH I-180(a). The results of the 11-year sensitivity would be identical to the same period in the 20-year sensitivity and the decrease to net income and retained earnings would continue to the end of the 20-year period.

**PUB/MH/RISK-7**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Interest Rates (B.2)**

**c) Please provide a matrix profile illustrating the relationship between various interest rate levels (by 4%/8%/12%) and other factors such as**

- **Exchange rate**
- **Inflations rates**
- **Project Cost Escalation**
- **Debt Levels**
- **OM&A costs**
- **Export revences**
- **Domestic Rate Increase**

**ANSWER:**

Although this question recognizes the interaction of a host of economic and financial variables, the complex inter-relationships among the factors cannot be readily summarized in a matrix profile. There are many combinations of interactions between the factors (including Bank of Canada and US Federal Reserve monetary policies as well as world economic developments and events) that will have some effect on, or relationship with, the stated economic and financial variables.

## PUB/MH/RISK-8 (REVISED)

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Financial- Credit (B.3)**

**a) Please provide the 2009-2010 Credit Rating reports for the Province and MH.**

**ANSWER:**

Manitoba Hydro: Please see the response to PUB/MH I-68 for the following Manitoba Hydro credit rating reports:

- DBRS report dated February 12, 2009.
- Moody's Investors Service report dated February 8, 2010.

No other credit rating reports for Manitoba Hydro have been issued by Moody's subsequent to the aforementioned reports. However, DBRS issued a credit rating report for Manitoba Hydro on November 10, 2010. Please see the attachment for this report to be filed as Appendix 75.

Province of Manitoba: Please see the response to CAC/MSOS/MH I-8(d) for the following Province of Manitoba credit rating reports:

- DBRS report dated September 25, 2009.
- Moody's Investors Service Full Analysis report dated December 24, 2009 and Credit Opinion dated January 25, 2010.

A report was also prepared for the Province of Manitoba by Standard & Poor's dated November 10, 2009. As indicated in response to CAC/MSOS/MH I-8(d), Standard & Poor's has indicated that Manitoba Hydro may file a copy of this report with the regulator in confidence without the need of a permissions agreement, but cannot disclose same to interveners or other parties.

On October 14, 2010, Manitoba Hydro responded to a request from CAC/MSOS for an updated filing and provided the following two additional credit rating reports for the Province of Manitoba:

- DBRS report dated October 8, 2010.
- Moody's Investors Service Full Analysis report dated August 10, 2010.

Canadian Provinces: Please see Appendix 68 for a Special Comment report issued by Moody's Investor Service in February 2010 entitled "*Canadian Provinces: Conditions Remain Challenging.*"

**<u>PUB/MH/RISK-8</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Credit (B.3)**

**b) Please provide the current balance of the Province of Manitoba debt separately defining that portion related to MH.**

**<u>ANSWER</u>:**

As at March 31, 2010, the Province of Manitoba had Net Direct Funded Borrowings of $20.819 billion, of which Manitoba Hydro's portion was $7.479 billion (note these values are net of sinking funds).

**<u>PUB/MH/RISK-8</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Credit (B.3)**

**c) Please provide the Province's long term debt forecast.**

**<u>ANSWER</u>:**

The Province's long term debt forecast is for borrowings to be between $3.4 billion and $4.0 billion per year depending on the capital requirements of both the Province and Manitoba Hydro.

**PUB/MH/RISK-8**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Credit (B.3)**

**d) Please discuss the potential implications to the Provinces Credit Rating if MH does not maintain its key financial targets**

**ANSWER:**

Manitoba Hydro's debt is deemed to be self-supporting by all of the credit rating agencies and it is important for Manitoba Hydro to maintain its key financial targets in order to maintain this status. Not maintaining key financial targets could result in negative implications to the Province of Manitoba's credit ratings.

**PUB/MH/RISK-8**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Credit (B.3)**

**e) Please indicate what would be the financial implications related to a credit rating downgrade (one level)**

**ANSWER:**

Credit rating agencies assign their ratings based upon their assessment of a variety of factors and risk considerations. Each of the rating agencies have their own approaches and may place different weightings on various rating factors or components.

The financial implications related to a credit rating downgrade are difficult to predict. Manitoba Hydro's estimate is that a one tier downgrade may increase average funding costs by 5 to 10 basis points per annum.

**PUB/MH/RISK-8**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Credit (B.3)**

**f) Please provide the relative credit rating scales utilized by Moody's, DBRS and S&P in evaluating MH's debt and MH's current rating on the scales.**

**ANSWER:**

Manitoba Hydro's credit ratings reflect the ratings of the Province of Manitoba.

The following chart shows the credit ratings utilized by Moody's, DBRS and S&P in evaluating provincial debt, and illustrates the Province of Manitoba's long term credit ratings in relation to the other Canadian provinces as at October 25, 2010:

| **Provinces** | **Credit Ratings** (Note 1) | | |
|---|---|---|---|
| | **Moody's** | **DBRS** | **S & P** |
| Alberta | Aaa | AAA | AAA |
| British Columbia | Aaa | AAH | AAA |
| Saskatchewan | Aa1 | AA | AA+ |
| Manitoba | Aa1 | AH | AA |
| Ontario | Aa1 | AAL | AA- |
| Québec | Aa2 | AH | A+ |
| New Brunswick | Aa2 | AH | AA-# |
| Nova Scotia | Aa2 | A | A+ |
| Newfoundland & Labrador | Aa2 | A | A* |
| Prince Edward Island | Aa2 | AL | A * |

Note 1: * = positive outlook; # = negative outlook.

**PUB/MH/RISK-8**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Financial- Credit (B.3)**

**g) Please discuss the credit evaluation process undertaken by MH for Export customers.**

**ANSWER:**

Manitoba Hydro evaluates the most recent financial results and credit rating of export customers to determine the amount of credit that will be extended to the customer. Financial result metrics that are evaluated by Manitoba Hydro to determine the creditworthiness of an export customer includes various liquidity, leverage and performance measures.

**PUB/MH/RISK-8**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Credit (B.3)**

**h) Please describe the credit evaluation process undertaken by MH for Export customers.**

**ANSWER:**

Please refer to Manitoba Hydro's response to PUB/MH/RISK-8(g).

**PUB/MH/RISK-9**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Inflation (B.4)**

**a) Please explain how the Corporation determined that inflation represents a low cost consequence. In the risk matrix given its planned major capital program**

**ANSWER:**

The Corporate Risk Profile Rating for a low financial consequence event is in the range of $0 - $50 million. The annual impact on net income in the general level of inflation is not expected to cause the $50 million limit to be exceeded. Increases or decreases in inflation tend to change export revenues as well as expenses in the same direction. Increases or decreases to capital are not immediately recognized in net income, but rather, are recognized over the life of the asset. The current low inflation levels and the Government of Canada's fiscal policy of maintaining inflation within a target range of 1% to 3% limit the expected impact of changes in inflation.

**PUB/MH/RISK-9**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Financial- Inflation (B.4)**

**b)** **Please provide the estimated annual construction cost escalation utilized in the 20 year CEF 09.**

**ANSWER:**

The 20 year CEF09 utilizes construction cost escalation consistent with IFF09 which assumes the Manitoba Consumer Price Index is 0.6% in 2009/10, 1.9% in 2010/11, and 2.0% thereafter.

**<u>PUB/MH/RISK-9</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Inflation (B.4)**

**c) Please explain how the Corporation intends on mitigating against Construction Cost Escalation risk.**

**<u>ANSWER</u>:**

Long-term firm export contracts contain inflationary adjustments or related provisions to minimize the risk of costs escalating faster than revenues and to reflect opportunity costs in the future. Budgets place inflationary limits on overall spending except where additional increases are necessary to meet safety and service requirements. Prolonged high levels of inflation could begin to jeopardize the achievement of the Corporation's financial targets and necessary capital program and it may be necessary to increase the general rate increases sought to recover cost increases beyond the Corporation's control.

## PUB/MH/RISK-9

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Inflation (B.4)**

**d) Please list the risks that are independent stand alone versus those which have interrelationships with other risks. Please discuss the interrelationships.**

**ANSWER:**

As described in the Corporate Profile B.4 Inflation, the impact of inflation on Manitoba Hydro's financial objectives and the need to raise domestic rates is determined by the interrelationship of the following risk drivers:

- The degree to which export revenues offset increased costs. Export revenues are primarily determined by:
  - Export market prices that are driven by supply and demand and other market conditions.
  - Water conditions that affect energy available for opportunity sales
  - The ability of inflationary adjustments or related provisions in long term firm export to minimize cost escalations.

- The degree to which increases in costs can be minimized which is determined primarily by: the level of expenditures required to effectively maintain, operate and improve the system to meet safety, service, reliability and environmental requirements.

Please also see Manitoba Hydro's response to PUB/MH/RISK-7(c).

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PUB/MH/RISK-9

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Inflation (B.4)**

**e) Please discuss MH's views on the specific major components that Credit Rating Agencies consider in rating and discuss the ratings in the context of the current negative economic.**

**ANSWER:**

Credit rating agencies assign their ratings based upon their assessment of a variety of factors and risk considerations. Each of the rating agencies have their own approaches and may place different weightings on various rating factors or components. Credit rating agencies provide an independent report based on their own analyses and Manitoba Hydro typically does not take issue with the analyses of the agencies.

In February 2010, Moody's Investors Service published a special commentary entitled "*Canadian Provinces: Conditions Remain Challenging*" (see Appendix 68). This commentary described a number of credit rating drivers for Canadian Provinces in the context of the current economic environment.

While reaffirming on page 10 that "Canadian provinces exhibit very strong credit quality," Moody's identified a number of rating drivers that may lead to downward rating pressure. The first issue discussed was the risk of deterioration in debt affordability. The following quote from page 2 reinforces Manitoba Hydro's view pertaining to the over-extended use of floating or variable rate financing as opposed to securing fixed rate financing at historically low interest rates:

> "**Deterioration in debt affordability**. Debt affordability, as measured by the proportion of revenues consumed by interest costs, reflects a government's ability to handle its debt burden. As such, it is perhaps a more informative indicator than the magnitude of the debt burden, as measured by debt-to-revenues or debt-to-GDP. As mentioned above, the sharp rise in debt burdens has so far led to only modest deteriorations in debt affordability. Nevertheless, when interest rates rise, provinces that relied heavily on short-term or variable-rate debt financing will be more affected than those who opted to "lock-in" historically low interest rates for long-dated

> maturities, effectively ensuring debt service certainty for a long period of time. Our global macro risk scenario for 2010-11 points to higher global interest rates and, while not expected, sharp increases in interest rates over short periods of time have occurred in the past and cannot be ruled out. As we saw in the 1990's and early 2000's, governments were faced with high debt burdens and correspondingly low debt affordability and had to make difficult budget choices. If similar conditions were to occur, interest costs would effectively be eating into funds available for public services. Under this scenario, downward rating pressure would emerge."

Also noteworthy was Moody's commentary on page 12 regarding their downgrade of the Province of New Brunswick and the following reference to New Brunswick Power:

> "The rating action also reflected our assessments of the risks associated with New Brunswick Power (NBP). The narrowing of NBP's margins in recent years, in conjunction with high leverage and risks related to the refurbishment of the Point Lepreau nuclear generating station, represents an element of risk for the province."

**PUB/MH/RISK-10**

**Reference: Appendix 12.1 Corporate Risk Management Report PUB/MH II-196**
**Risk Issue: Financial- Capital Structure (B.7)**

**a) Please provide a quantification of the Drought Risk reflected in the CRM with supporting calculations. Please incorporate finance expense impacts if not included.**

**ANSWER:**

Please refer to the response provided to RCM/TREE/MH I-33(a) which responds to PUB Order 117/06 which provides quantification for each of the five years of the drought period.

**PUB/MH/RISK-10**

**Reference: Appendix 12.1 Corporate Risk Management Report PUB/MH II-196**
**Risk Issue: Financial- Capital Structure (B.7)**

**b) Please indicate and discuss how the Drought Risk may change between 2014-2024 when the equity ratio is below the 25% target. (As new G&T projects and additional contracts come into play) Please re-file the table from PUB/MH II-196 including the debt:equity ratio, interest coverage ratio and capital coverage ratio for each year.**

**ANSWER:**

Manitoba Hydro's ability to withstand the financial impact of a severe drought is more directly related to the absolute level of retained earnings then it is to the equity ratio. Despite the equity ratio being below the 25% target, levels of retained earnings are sufficient to absorb the financial impacts of a drought and avoid seeking higher rate increases from customers. Please also see Manitoba Hydro's response to CAC/MSOS/MH II-110(a).

**<u>PUB/MH/RISK-10</u>**

**Reference:** **Appendix 12.1 Corporate Risk Management Report PUB/MH II-196**
**Risk Issue:** **Financial- Capital Structure (B.7)**

**c)** **Please discuss the implications on rates if the Capital Structure falls below an equity ratio of 20%.**

**<u>ANSWER</u>:**

Please see Manitoba Hydro's responses to CAC/MSOS/MH I-8(a), CAC/MSOS/MH I-108(a) and CAC/MSOS/MH II-110(a).

**PUB/MH/RISK-11**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial - Financial Forecasts/IFF09-1**

**a) Please provide an alternate IFF 09-1 that employs natural gas prices of:**

- **$6/GJ in 2014/15 (no CO2 Adder)**
- **$8/GJ in 2019/20 (no CO2 Adder)**
- **$9/GJ in 2024/25 (no CO2 Adder)**
- **$10/GJ in 2029/30 (no CO2 Adder)**

**And assumes that import prices in lower quartile flow years be equal to export prices for the full 20-year forecast and a CAD/USD exchange ratio of 1.0.**

**ANSWER:**

In the response to PUB/MH I-156(a), Manitoba Hydro advised that:

> "…[the] electricity export price forecast is prepared using information from several external price forecast consultants who each have their own electricity price forecast models and assumptions", and

> "…the consultants prepare their own internal estimates for a number of pricing factors. These pricing factors include, but are not limited to, thermal fuel forecasts (coal and natural gas), future load growth forecasts, capital costs and required rates of return, generation retirements and additions, power market rules, future legislative regulations including greenhouse gases, SOx, NOx, and mercury and renewable portfolio standard requirements, and characteristics of the existing generation fleet."

For greater clarity, Manitoba Hydro does not have access to the external price forecast consultants' models nor does Manitoba Hydro stipulate specific pricing factors to the external consultants. As a result, Manitoba Hydro is unable to produce alternative electricity export price forecasts which vary specific pricing factors without incurring significant time and cost.

While Manitoba Hydro is unable to produce alternative electricity export price forecasts, the external price forecast consultants have provided a Low forecast scenario and a High forecast scenario based on their views of the lower and higher bounds of prolonged pricing. Alternative IFF's have been prepared utilizing these electricity export price forecast scenarios. Please see Appendix 15 for the projections supporting these scenarios.

PUB/MH II-49 addresses the impacts of a CAD/USD exchange ratio of 1.0.

**PUB/MH/RISK-12**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Financial Forecasts/IFF09-1 (B.10)**

**a) Please provide alternative IFF 09-1 complete with electricity price assumptions as follows:**

**i. Natural gas supply prices at $5/GJ until 2019/20 rising to $10/GJ by 2029/30 and CO2 price Adders growing from zero to $30/tonne by 2029/30.**
**ii. MH's average export prices cannot exceed the fixed and operating costs of CCCT gas generation.**
**iii. MH's average import prices not less than the operating cost of CCCT gas generation.**
**iv. CAD/USD exchange ratio of 1.0.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-11(a).

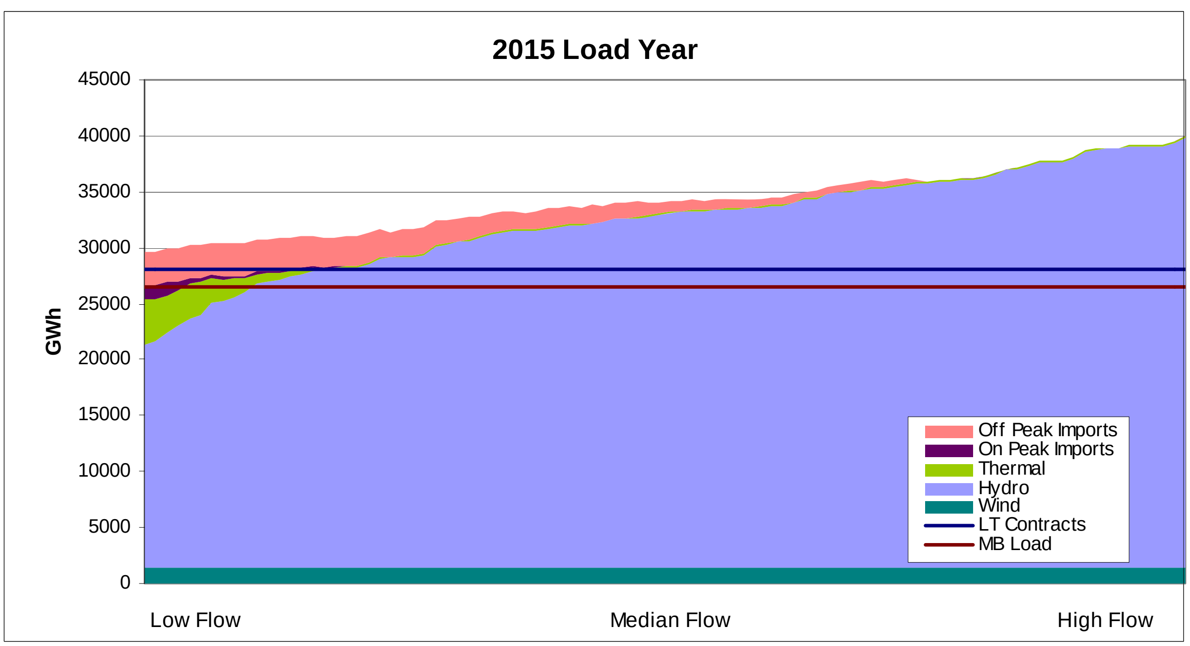
## PUB/MH/RISK-13

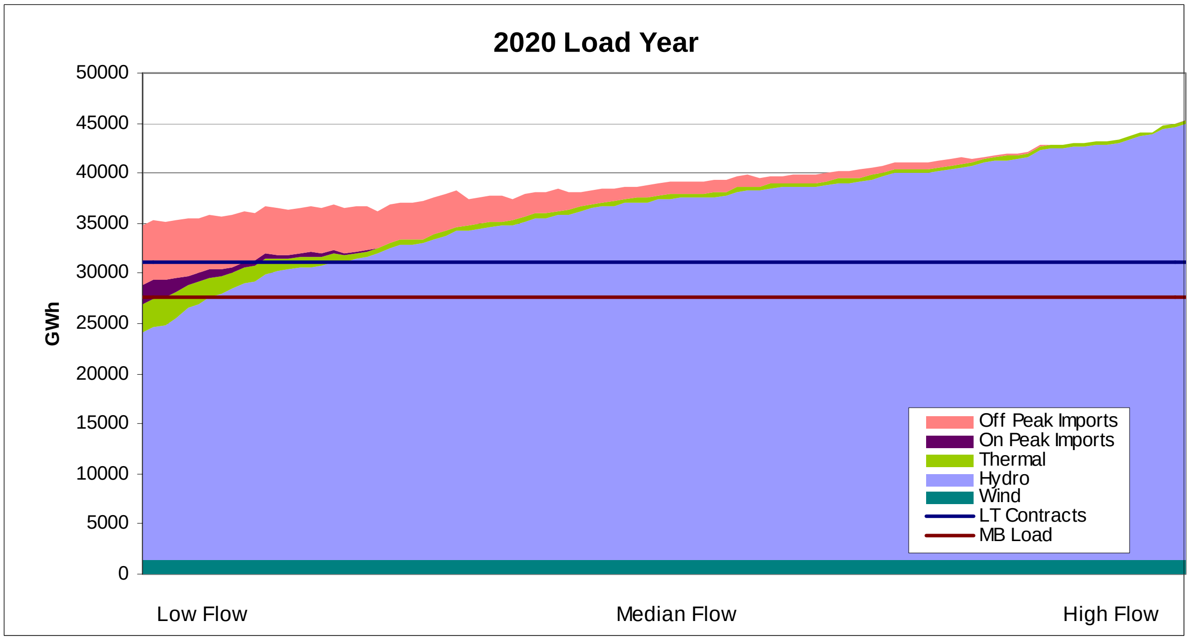
**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Financial - Financial Forecasts/IFF09-1 Export Revenue Rates**

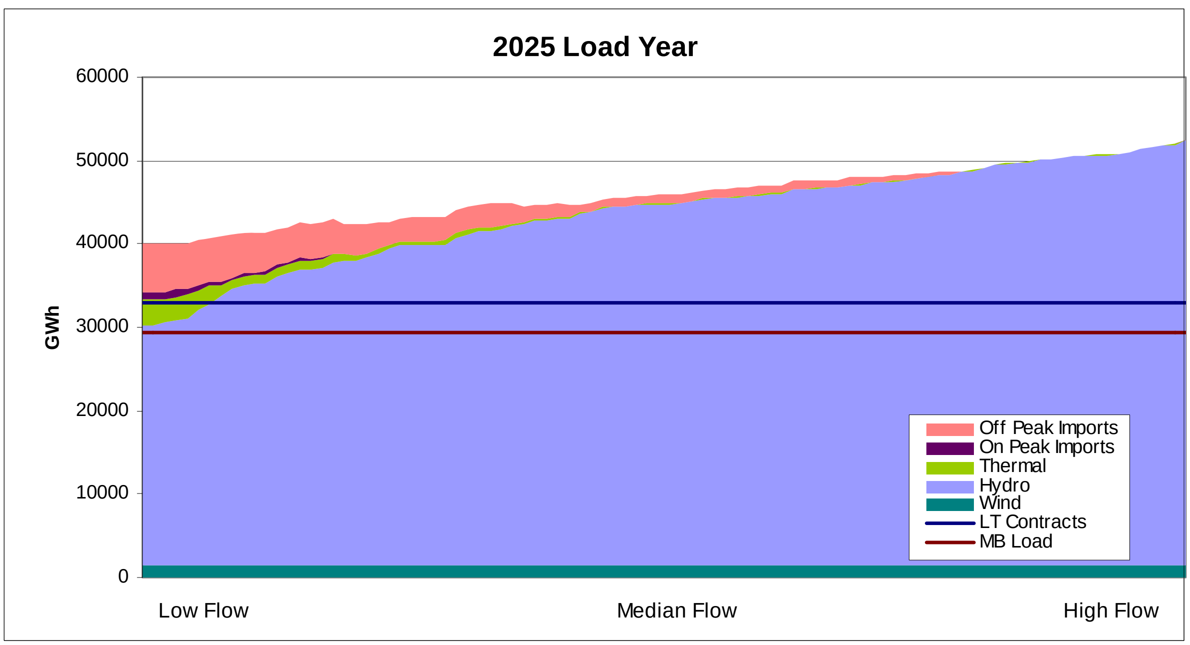
a) **Please confirm that on a historical flow basis, MH's hydraulic generation (post-Wuskwatim until 2024/25) will be adequate to meet domestic load (only) about 25% of the years and that at least 3,000 to 10,000 GWh imports and/or other power purchases will be required to fulfill domestic load and firm contract obligations in those years.**

**ANSWER:**

Manitoba Hydro does not agree with the statements made in this information request. The supply/demand balances change over the study years as domestic load grows, firm contracts are terminated or initiated, and supply resources are added or retired. This results in varying quantities of imports and thermal generation to meet domestic and firm contract obligations. The following graphs are based on resources and contract sales consistent with IFF09-1. These graphs depict the annual energy supply corresponding to a repeat of 94 historical flows for Manitoba Hydro system compared to Manitoba domestic load and long-term contracts obligations under dependable flow conditions for the years 2015/16, 2020/21, and 2025/26.






The relative frequencies of the various generation sources over the range of flow conditions can be observed in the graphs above.

Based on projected annual generation corresponding to historic flows, it is expected that non-hydraulic resources (excluding wind) will be required to meet Manitoba Hydro’s firm obligations to an amount no greater than 7,000 GW.h in 2015 and 2020 and 3,000 GW.h in 2025 during the lowest flow year and decreasing as flows increase.

Manitoba Hydro's dependable energy from all resources is available to serve its firm obligations which include domestic load and firm export sales. As indicated in the graphs, based on projected annual generation corresponding to historical flow records, Manitoba Hydro can expect that energy from all resources will be adequate to meet Manitoba Hydro's firm obligations.

**PUB/MH/RISK-13**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial - Financial Forecasts/IFF09-1 Export Revenue Rates**

**b) Please confirm that in those low flow years, net export revenue cost margins would typically be negative consistent with the difference between export contract prices and winter MISO market prices.**

**ANSWER:**

As shown in the graphs depicted in PUB/MH/RISK-13(a) the vast majority of imports required during low flow years are imported during off-peak periods. Off-peak imports are generally low cost. If on-peak imports are required, they may or may not be at prices higher than the associated revenue depending on market conditions at the time of import.

**<u>PUB/MH/RISK-13</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial - Financial Forecasts/IFF09-1 Export Revenue Rates**

**c) Please confirm that after 2018/19 until 2024/25, with the new NSP/Xcel contracts in place, MH will be faced with importing energy to meet a portion of the export commitments about one year in two (50% of the time).**

**<u>ANSWER</u>:**

Manitoba Hydro does not confirm that after 2018/19 until 2024/25, with the new NSP/Xcel contracts in place, Manitoba Hydro will be faced with importing energy to meet a portion of the export commitments about 50% of the time.

By referring to the graphs supplied in PUB/MH/RISK-13(a) and comparing Manitoba domestic load combined with long-term exports to the annual energy corresponding to the historical flow records for the 2020/21, it is observed that Manitoba Hydro can be expected to require the use of thermal or import energy to meet its firm commitments in about 10% of flow cases.

**PUB/MH/RISK-13**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Financial - Financial Forecasts/IFF09-1 Export Revenue Rates**

**d)** **Please confirm that the existing NSP/Xcel 2005 to 2015 contract price of about 5.5¢ to 6.0¢/KWh did not exceed peak or shoulder period MISO market prices in the first three years and only have exceeded those prices in 2008/09 & 2009/10.**

**ANSWER:**

Without the 2005-2015 500 MW sale to NSP, it is likely that the 529 MW of firm transmission rights NSP holds on the US side of the Manitoba-US interface associated with the sale would not have been extended beyond 2005. That transmission would have been made available to the market and potentially lost from Manitoba Hydro use. Had Manitoba Hydro been successful in purchasing it as firm Point-to-Point transmission the cost would have been approximately US$20 million per year at current prices. Therefore, a strict comparison of energy prices, contract versus spot prices, is inappropriate as it is an apples to oranges comparison.

Given that it is an apples to oranges comparison, Manitoba Hydro confirms that average 5x16 MISO MHEB nodal Day Ahead price has exceeded the contract price from 2005/06 to 2007/08 and that the contract price has exceed the average 5x16 MISO MHEB nodal Day Ahead price in 2008/09, 2009/10 and in 2010/11 to date.

However on a comparable basis, once the US$20 million in avoided transmission costs are considered, Manitoba Hydro can confirm that the contract price has always exceeded the average 5x16 MISO MHEB nodal Day Ahead price.

**PUB/MH/RISK-14**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Financial Forecasts/IFF09-1 Export Revenue Rate Targets**

a) **Please confirm that MH's current embedded cost of G&T is 4.3¢/KWh ($1,213 M / 28,000 GWH) and that current export contracts are priced at 5.5 to 6.0¢/KWh.**

**ANSWER:**

According to PCOSS11 the forecast embedded cost of Generation and Transmission for 2010/11 is 4.0 cents/kWh ($1,116M / 28,189 GWH).

Manitoba Hydro can confirm that the average price of its long term fixed price export contracts for 2009/10 averaged 5.9 cents/kWh.

**PUB/MH/RISK-14**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Financial- Financial Forecasts/IFF09-1 Export Revenue Rate Targets**

**b)** **Please confirm that on an average in-service (interest/depreciation/OM&A) cash flow basis, MH's new G&T projects have incremental cost impacts in the order of:**

**i.** **Wuskwatim - 10¢/KWh (for 1,350 GWh/year at Common Bus).**
**ii.** **Keeyask/Bipole III/Conawapa - 10¢/KWh (for 11,000 GWh/year at Common Bus).**

**ANSWER:**

It is premature for Manitoba Hydro to provide cost impacts related to Keeyask and Conawapa as Manitoba Hydro has not made a commitment to develop Keeyask or Conawapa but is working to protect potential in-service-dates. Any commitment to either Keeyask or Conawapa will depend on the prevailing circumstances at the time. Keeyask and/or Conawapa will be subject to a full examination when the "need for and alternatives to" process is initiated. As well, it should be noted that it was in the 2000/01 timeframe that Manitoba Hydro recognized in its system planning the need for Bipole III based on reliability requirements.

**PUB/MH/RISK-14**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Financial- Financial Forecasts/IFF09-1 Export Revenue Rate Targets**

**c) Please provide on an average Generation & Transmission blended embedded cost basis, the IFF 09-1 average G&T costs expected for:**

**i. 2013/14.**
**ii. 2019/20.**
**iii. 2024/25.**

**ANSWER:**

The average Generation and Transmission cost cannot be provided for the requested years as the necessary details on Operating and Capital costs by Generation, Transmission and Distribution function are not defined for the entire IFF period.

**PUB/MH/RISK-15**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Financial - Export Revenues**

**a) Please provide a tabulation and breakdown of the IFF 09-1.**

**Forecast Exports/Revenues**

| Year | Export Sales (GWh) | Revenue at 'Current' Natural Gas Prices(1) ($M) | Add't Revenue Required from Increased Natural Gas Prices ($M) | IFF 09-1 Export Revenue ($M) | IFF 09-1 Average Unit Revenue Price (¢/KWh) |
|---|---|---|---|---|---|
| 2008/09 | | | | | |
| 2009/10 | | | | | |
| 2010/11 | | | | | |
| 2011/12 | | | | | |
| 2012/13 | | | | | |
| 2013/14 | | | | | |
| 2014/15 | | | | | |
| 2015/16 | | | | | |
| 2016/17 | | | | | |
| 2017/18 | | | | | |
| 2018/19 | | | | | |
| 2019/20 | | | | | |
| 2020/21 | | | | | |
| 2021/22 | | | | | |
| 2022/23 | | | | | |
| 2023/24 | | | | | |
| 2024/25 | | | | | |
| 2025/26 | | | | | |
| 2026/27 | | | | | |
| 2027/28 | | | | | |
| 2028/29 | | | | | |
| 2029/30 | | | | | |
| 20-Year Totals | | | | | |
| (1) 'Current' natural gas prices of $5/GJ rising to $12/GJ by 2029/30. | | | | | |

**<u>ANSWER</u>:**

The table and breakdown above presumes an alternative IFF that varies natural gas prices that cannot be produced. Please see the response to PUB/MH/RISK-11(a) for an explanation as to why the alternative IFF cannot be produced.

**PUB/MH/RISK-16**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**

**Risk Issue:** **Financial- Financial Forecasts/IFF09-1 (B.10) Finance and Depreciation Expense**

**a) Please provide an update to CEF-09 which reflects cost escalations to date or adjustments with respect to:**

- **Jenpeg G.S. Turbines.**
- **Wuskwatim G&T.**
- **Bipole III and Riel.**
- **Enhanced AC transmission from northern generation.**
- **Major G.S. upgrades (Pointe du Bois and other Winnipeg River plants).**
- **Any outstanding Dam Safety upgrades.**
- **Potential new CCCT thermal additions to replace Brandon Coal Plant.**
- **Other NERC mandated enhancements**

**ANSWER:**

Updates to CEF09 will be provided upon approval of CEF10 by the Manitoba Hydro-Electric Board.

**PUB/MH/RISK-17**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Water Rentals**

**a) Please confirm that water rental fees are calculated on the basis of annual hydraulic generation output and not on a generating station capacity.**

**ANSWER:**

Water rentals are paid to the Province of Manitoba in accordance with Article 48(3.2) of the Water Power Regulation. These payments are based on the greater of:

- the installed capacity multiplied by a capacity rate ($/installed horsepower); or
- the fiscal year total energy produced, multiplied by an energy rate ($/horsepower-year).

Water rental payments are typically based on the latter calculation which is dependent on annual generation. Only in severe droughts does annual generation drop to a point where the installed capacity charge governs. This occurred in 2003/04 for the Grand Rapids, Laurie River #1 and Laurie River #2 generating stations and for the Missi Falls house unit.

**PUB/MH/RISK-17**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Financial- Water Rentals**

**b) Please confirm and illustrate that MH does not sell electricity in the export market for less than the water rental fee (plus adjustments for transmission losses to the U.S. border).**

**ANSWER:**

Manitoba Hydro's pricing policy in the export market is commercially sensitive and confidential.

**PUB/MH/RISK-17**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Financial- Water Rentals**

**c)** **Please confirm that water rental fees were last adjusted in 2001 and that current rental revenues have remained at about $100 M since then.**

**ANSWER:**

Manitoba Hydro confirms water rental rates were changed in 2001.

The following table provides water rental payments for 2001/02 through 2009/10.

| | **Manitoba Hydro Water Rental Payment ($M)** |
|---|---|
| 2001/02 | 106.8 |
| 2002/03 | 95.1 |
| 2003/04 | 64.5 |
| 2004/05 | 104.1 |
| 2005/06 | 124.4 |
| 2006/07 | 105.7 |
| 2008/09 | 114.5 |
| 2009/10 | 114.0 |

**PUB/MH/RISK-18**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Environmental- Water Supply/Drought (C.1)**

**Please provide a series of charts illustrating the full detailed financial impacts of various drought scenarios on IFF 09-1. Firstly, a 5-year drought starting in 2011/12 followed by a 7-year drought starting in 2024/25. In each case, assume import prices equal export prices for all energy over and above hydraulic generation during the drought years.**

**ANSWER:**

There are a large number of potential drought related scenarios that could be analyzed. Appendix J of the KPMG Report provides a number of drought scenarios that extensively cover the potential financial impact of drought on the Manitoba Hydro system.

## PUB/MH/RISK-19

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Environmental- Climate Change Kyoto (C.2)**

**a) Please confirm that in the last 90 to 100 years, adjusted historic Lake Winnipeg inflows of <60,000 cfs would have occurred in 25% of those years and that total hydraulic generation (including Wuskwatim G.S.) would likely have been <25,000 GWh and that in IFF 09-1, imported (or thermal generation) energy would need to exceed export energy by increasing amounts (up to 3,000 GWh/year) until 2018/19 (Keeyask in-service).**

**ANSWER:**

Manitoba Hydro confirms that adjusted historic Lake Winnipeg inflows are less than 60,000 cfs in approximately 25% of the years in the last 90 to 100 years. However, Manitoba Hydro cannot confirm the remaining statements made in the information request. The total hydraulic generation (including Wuskwatim G.S.) of 25,000 GWh occurs for about 12% of the flow years, and this is much less frequent than the 25% assumed in the information request. Please refer to the responses to PUB/MH/RISK-13(a) and PUB/MH/RISK-40(b) for graphs and tables of expected energy supply and demand balances for 2015.

Manitoba Hydro cannot confirm the statement that imported and thermal generation in the lower quartile of flow years would need to exceed export energy by increasing amounts (up to 3,000 GWh/year) until 2018/19. Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations. Therefore, it is not appropriate to allocate a specific generation source to a specific requirement such as export sales. The graph in the response to PUB/MH/RISK-13(a) and the table in PUB/MH/RISK-40(b) show that significant quantities of the thermal and import energy are required in about 10% of the flow years to meet the total of all firm commitments.

**<u>PUB/MH/RISK-19</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Environmental- Climate Change Kyoto (C.2)**

**b) Please indicate for those 1 in 4 low flow years, the probable relative average import price to export price differential in ¢/KWh (assuming $8/GJ natural gas supply prices) for post-Wuskwatim hydraulic generation levels:**

- **25,000 GWh.**
- **23,000 GWh.**
- **21,000 GWh or less.**

**<u>ANSWER</u>:**

It should be noted that the market model within SPLASH utilizes a pricing structure for import energy that results in higher prices as the volume of required energy increases. There are a number of factors that influence market prices and natural gas is only one. The requested analysis is inconsistent with the methodology employed in the SPLASH model as a single value for natural gas does not translate into market prices. The requested analysis would require significant new work that Manitoba Hydro declines to undertake.

**<u>PUB/MH/RISK-19</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Environmental- Climate Change Kyoto (C.2)**

**c) Does MH anticipate employing the Brandon coal plant whenever total hydraulic energy generation falls below 25,000 GWh or is that resource expected to be in play on a more infrequent (than 1 year in 4) basis?**

**<u>ANSWER</u>:**

Please see response to PUB/MH I-85(a) for a discussion of the role of Manitoba Hydro's thermal generation. Manitoba Hydro will operate Brandon Unit 5 in accordance with operational restrictions under the recently enacted Climate Change and Emissions Reductions Act and its associated regulation MR 186/2009, which is discussed in more detail in PUB/MH I- 85(b). Also, please refer to the responses to PUB/MH I–85(c) ii, (c) iii, (d) and (e) for additional information.

Manitoba Hydro anticipates that significant operation of Brandon Unit 5 for drought support will occur when annual flows are in the range of the lowest 5 percent of the hydraulic record. It should be noted that in years with average inflow conditions and no major equipment outages, Brandon Unit 5 annual generation is anticipated to be in the order of up to 125 GWh due to requirements for emergency preparedness activities and to accommodate emergency service that may arise.

**PUB/MH/RISK-19**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Environmental- Climate Change Kyoto (C.2)**

**d) Does MH anticipate that domestic load during dry and/or drought years will be higher/same/lower than in the base load forecast?**

**ANSWER:**

Manitoba Hydro does not expect that load would change significantly due to a drought period. There is no obvious relationship between low streamflows in the entire watershed and electricity usage in Manitoba. Manitoba load is affected by temperature and it may be thought that high temperatures may be associated with extreme drought. However, it is lack of precipitation that is the primary cause of drought and not high temperatures. An extreme drought can occur without above normal temperatures. There may be a low correlation between drought and above normal temperature but this would result in a minor impact on electricity consumption.

**PUB/MH/RISK-19**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Environmental- Climate Change Kyoto (C.2)**

**e) Please provide an alternative calculation of MH's overall CO2 footprint forecast going to 2029/30 assuming:**

- **All imports are derived from coal energy.**
- **All exports displace natural gas generation.**

**ANSWER:**

The requested analysis would require significant new work that cannot be undertaken in the allotted timeframe for responses to information requests.

**PUB/MH/RISK-20**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Infrastructure- Loss of Plant (D.1) – All Property/ All Perils**

**a) Please explain what aspects of MH's assets and operations are externally insured or self-insured with respect to:**

- **Generation plant and operations.**
- **Transmission plant and operations.**
- **Distribution plant and operations.**
- **Office/shops/yards/roads/etc.**

**ANSWER:**

Generation plant is externally insured subject to policy terms and conditions, subject to a $5 million deductible. Operations are not insured.

Transmission plant external insurance applies to Radisson, Henday and Dorsey converter stations and are subject to a $5 million deductible. Operations are not insured.

Distribution plant and operations are not insured.

Offices/shops and other physical property is externally insured subject to a $5 million deductible.

**PUB/MH/RISK-20**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Infrastructure- Loss of Plant (D.1) – All Property/ All Perils**

**b) Please confirm that for MH, domestic supply is paramount. What are MH's obligations to maintain domestic supply and at what cost? Does "Force Majeure" apply to physical failures of power station components in the absence of ice storms floods/tornadoes/earthquakes/ forest fires?).**

**ANSWER:**

Manitoba Hydro is required to supply power adequate for the needs of the province of Manitoba. Manitoba Hydro seeks to utilize all tools available to it (e.g. prudent export market activity, demand side management) in order to provide such power in a cost efficient manner.

The application of Force Majeure is dependent on the facts associated with a particular event. Generally, the causal event must be found to be beyond the control of the party which is unable to perform its obligations under an agreement.

**<u>PUB/MH/RISK-21</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Infrastructure- Insufficient Supply (D.2)**

**a) Please define the various circumstances that could lead to insufficient supply**

**<u>ANSWER</u>:**

The main risk that could lead to insufficient supply is drought. Manitoba Hydro's system is designed and operated such that there is sufficient firm supply to meet firm load demands given a repeat of the worst historic river flows. Should a drought of greater severity or duration occur than the worst historic river flows, there is a risk to Manitoba load of insufficient supply.

**PUB/MH/RISK-21**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Infrastructure- Insufficient Supply (D.2)**

**b) Please discuss the implications of the coincident perils:**

- **Drought events.**
- **Thermal infrastructure outages**
- **DC or transmission outages**
- **High demand domestically**
- **High demand MISO market**

**ANSWER:**

Coincident perils such as those listed in this question would increase the risk of insufficient supply and the cost to Manitoba Hydro. Coal thermal outages, outages on interconnections and high market demand are factors that would cause higher costs. DC outages would have minimal consequences during drought as spare DC capacity would be available due to lack of northern generation.

**PUB/MH/RISK-22**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Infrastructure- Prolonged Loss of System Supply (D.3)**

**a) Please provide an estimate of the power reserve requirement as capacity (MW) and energy shortfall (GWh) for the following events:**

- **Powerhouse fire at one of Kettle/Long Spruce/Limestone generation stations.**
- **Major forest fire on Bipole I and II and AC lines in Grand Rapids area/Kelsey area.**
- **Major tornados in the Interlake and the Red River Valley.**
- **Broad area ice storms in the Interlake and western Manitoba.**
- **Multi-year very broad area high temperature drought conditions in MISO and Canadian Prairies.**

**ANSWER:**

Most of the events that are listed in the information request are force majeure or act of god events that have a very low probability of occurring. However, the consequence of such events can be extremely high. The specific energy and capacity shortfall would be dependent on the timing and duration of such events, the extent of damage (if any), and the ability to forecast the event to minimize impacts. Many of the suggested perils appear to be directed at Bipoles I&II, and form part of Manitoba Hydro's position that Bipole III be in-service for reliability as soon as possible. This requires that Bipole III be on a corridor separate from the existing bipoles.

**PUB/MH/RISK-22**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Infrastructure- Prolonged Loss of System Supply (D.3)**

**b) Please explain how these contingencies are addressed in MH's risk management and reserve determination.**

**ANSWER:**

Manitoba Hydro plans its system to meet the criteria labelled as the "Corporate Policy Statement on Generation Planning (No. G195)", which is found as Appendix A of the attachment to information request RCM/TREE/MH I-30(a). Included in the Corporate Policy Statement are a capacity criterion, for a reserve against breakdown of plant and increase in demand above forecast, as well as a dependable energy criteria to ensure adequate energy resources to supply the firm (dependable) energy demand in the event that the lowest recorded coincident river flow conditions are repeated.

As a bulk power system owner and operator, Manitoba Hydro must comply with approved NERC (North American Reliability Corporation) reliability standards. NERC-compliance addresses the issues of assessing power system performance following normal and contingency conditions.
Most of the events that are listed in the information request PUB/MH/RISK-22(a) are force majeure events that have a very low probability of occurring. However, the consequence of such events can be extremely high. One of the purposes of Manitoba Hydro's financial targets is to allow Manitoba Hydro to maintain a sufficiently strong financial position which recognizes the potential for risks such as those identified in this information request.

**PUB/MH/RISK-22**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Infrastructure- Prolonged Loss of System Supply (D.3)**

**c) Please confirm and explain that these issues are adequately addressed in MH'S Power Resource Plan**

**ANSWER:**

Manitoba Hydro can confirm that it addresses these issues through its internal processes including through the power resource planning process. These processes include the application of NERC criteria, sophisticated monitoring and protection processes and entering into innovative contractual arrangements with export customers. Other initiatives include the planned construction of Bipole III on separate right-of-way, the re-termination of a 500 kV line at Riel Station and the pursuit of the construction of a new 500 kV interconnection.

**PUB/MH/RISK-23**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Infrastructure- Emergency Response/ Business Continuity (D.8)**

**a) Please clarify the nature of this risk in terms of:**

- **Customer loss of service.**
- **Compensation of customer.**
- **Utility loss of revenue.**
- **Utility costs of response**

**ANSWER:**

The Emergency Management Program is one of several activities in place to mitigate and manage the impact of infrastructure failure or impairment from events such as major weather conditions, sabotage, fire, human error and technical failure. The program is designed to comply with numerous industry laws and standards that set out stringent requirements.

Failure to have an appropriate Emergency Management Program in place can exacerbate otherwise manageable events and have, among others, the following impacts:

- **Customer loss of service** - Failure can result in the inability of Manitoba Hydro to provide minimum acceptable energy services.

- **Compensation of customer** - Failure to have an appropriate program in place could result in Manitoba Hydro being liable to compensate customers for losses and damages.

- **Utility loss of revenue -** Failure to have an appropriate program in place could increase the time necessary and the severity to re-establish service. This would increase the revenue loss to the Corporation.

- **Utility costs of response -** Failure to have an appropriate program in place could increase the severity and result in increased costs to the Corporation.

**PUB/MH/RISK-24**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Human- Succession Planning (E.3)**

**a)** **Please describe the perceived risk related to succession Planning and quantify the Risk.**

**ANSWER:**

The electricity and gas industry will be facing significant labour force challenges in the years ahead. Succession planning is utilized by Manitoba Hydro to mitigate the risk associated with these challenges.

Retirements, new requirements resulting from major construction and technology changes, and a changing labour market have the potential to impact Manitoba Hydro's supply of staff. Similar to many employers, retirement will have the most significant impact on Manitoba Hydro's human resource requirements due to the movement of the large cohort of "Baby Boomer" employees into retirement. At Manitoba Hydro, retirements have shifted from a long-term average of 80 employees per year to a new long-term average of twice that or more. This new trend commenced in the year 2005 and is expected to peak in the year 2020.

**<u>PUB/MH/RISK-24</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Human- Succession Planning (E.3)**

**b) Please provide a summary description of the succession plan for key staff within each business unit and indicate which positions have been identified to be addressed in the plan.**

**<u>ANSWER</u>:**

Succession planning is used for Executive, Management and key technical/critical positions within the organization. Leaders responsible for these positions create plans and aide in the development of succession planning candidates. The process is carried out on an annual basis.

## PUB/MH/RISK-24

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Human- Succession Planning (E.3)**

**c) Please indicate the targeted retirement dates for key staff members.**

**ANSWER:**

Historical trends indicate candidates normally provide a minimum of 30 days notice of their intended retirement. Eligibility rates (earliest year of retirement with unreduced pension) indicate 43% of individuals in positions on the succession plan are eligible to retire in five years. In ten years, the retirement eligibility of such candidates increases to 67%. It is important to note that the average retirement age at Manitoba Hydro exceeds retirement eligibility age by several years (average age at retirement was 58.9 years in 2009). Additionally, employees in professional and managerial roles retire older than other employees. Retirement eligibility is thus only one dimension of the retirement equation. The employee's ability and desire to continue working along with their occupation are also factors.

**<u>PUB/MH/RISK-25</u>**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Business Operational- Operational Control (F.2) Front Office/Middle Office**

**a)** **Please define the type and level of information available to the "front office" as a short-term outlook and with a longer-term perspective for:**

- **Surplus energy**
- **Short-term contracts**
- **Pricing targets**
- **Transmission rights**
- **Need for imports**

**<u>ANSWER</u>:**

The front office personnel have detailed information as follows:

- Surplus Energy: All surplus energy information as projected by Manitoba Hydro's HERMES and SPLASH Systems.
- Short-term Contracts: Manitoba Hydro utilizes ICE (Intercontinental Clearing Exchange) and customer communication to identify short term contract opportunities.
- Pricing Targets:
  - Short Term: Manitoba Hydro's marginal cost of supply.
  - Long Term: Manitoba Hydro's electricity price forecast.
- Transmission Rights: Manitoba Hydro's Export Power Marketing Department maintains a portfolio listing of transmission rights used for short term and long term transactions.
- Need for Imports: See "Surplus Energy" above.

**PUB/MH/RISK-25**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Business Operational- Operational Control (F.2) Front Office/Middle Office**

**b) Please provide a full description of the role and activities of the "middle office" in short-term and long-term sale commitments.**

**ANSWER:**

Middle Office role and activities related to short term commitments are:

- Assessing whether potential risk exposures for export power strategies are identified.

- Evaluating risk treatment mitigation activities.
  - Reviewing all formal policy and procedure documents to identify gaps or weaknesses in risk treatment and provide recommendations to improve risk mitigation.
  - Reviewing established risk tolerances to determine whether they provide direction in electric export power activities and operations are within the established limits.

- Evaluating the accuracy of risk exposure / measurement information.
  - Assessing the quantitative methodologies and systems in place to measure risk exposures.
  - Testing methodologies and systems to ensure accuracy and adherence to stated objectives and logic.
  - Determining that measurement information is accurately calculated, prepared in a timely manner and clearly communicated.
  - Performing stress and back testing and when appropriate scenario analysis on risk exposures.

- Monitoring export power activities for adherence to established policy, procedure and guideline and assessing the effectiveness of controls.
  - Reviewing export power activities on an ongoing basis and where possible incorporating exception reporting into those systems used for tracking and reporting of trading activities.
  - Reporting on weaknesses and all non compliance issues.

- Reviewing all new products to confirm that the risks around these new products have been identified and report the results of the review.

The current policy framework for long term contract commitments does not provide for Middle Office participation. Middle Office has reviewed this framework and issues related to pricing of long term contracts in relation to the NYC consultant reports.

**PUB/MH/RISK-25**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Business Operational- Operational Control (F.2) Front Office/Middle Office**

**c)** **Please provide the full complement of the middle office including a description of the roles and responsibilities of the individuals.**

**ANSWER:**

The Chief Financial Officer provides oversight to the functioning of the Middle Office.

Middle Office staff and their respective roles and responsibilities are:

Manager, Corporate Risk Management

- Manages the Middle Office Function
- Represents Middle Office at Export Power Risk Management Committee (EPRMC)
- Resource to Power Sales and Operations Market Committee

Senior Risk Management Officer

Role of this position is risk monitoring and evaluation of policy, procedure compliance, controls and risk reporting.

Responsibilities

- Monitor whether potential risk exposures for export power strategies and products are identified
- Position tracking and monitoring
- Identify policy and procedure gaps, weaknesses and recommend improvements
- Monitor effectiveness of controls and recommend improvements
- Evaluate transactions for policy and procedure compliance
- Monitor risks of export power activities
- Develop and maintain risk reporting for EPRMC
- Undertake other department duties as assigned

Senior Market Risk Analyst

Role of this position is to conduct market risk quantification and analysis.

Responsibilities:

- Assist in the development, documentation and maintenance of forward curve construction for marking to market
- Conduct scenario and stress tests on the export power portfolio
- Conduct market risk analysis necessary to support risk metrics and reporting requirements
- Identify and report material positions that have significant market risks
- Conduct appropriate back-testing and calibration of all risk models.
- Assist in development, documentation and maintenance of forward curve construction and validation for power exposures
- Undertake other department duties as assigned

A Credit Analyst (to be posted and filled)

Role of this position is to perform credit risk analysis, measurement and monitoring.

Responsibilities

- Calculate credit exposures, credit risk metrics.
- Identify credit risk limit violations, losses or other credit issues
- Identify, measure and monitor counterparty risk and credit
- Administer collateral (margins, parental guarantees, letters of credit)
- Determine appropriate credit ratings and related limits
- Undertake other department duties as assigned

**PUB/MH/RISK-25**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Business Operational- Operational Control (F.2) Front Office/Middle Office**

**d)** **What additional [if any] information is available to the "middle office" in assessing risks that isn't available to the "front office"?**

**ANSWER:**

Middle office has access to the same information available to front office.

**PUB/MH/RISK-25**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Business Operational- Operational Control (F.2) Front Office/Middle Office**

**e)** **What authority does the "middle office" have to reverse "front office" decisions on export or import transactions? If so, please describe the decision process to reverse "front office" decisions. If not, why not?**

**ANSWER:**

Middle Office has no authority to reverse front office decisions on export or import transactions.

An Authority Table for power related transactions, approved by the Export Power Risk Management Committee, establishes by duration of the transaction authorization required to enter into wholesale power transactions and related agreements. Wholesale power transactions should not be executed without the proper authorization to bind Manitoba Hydro. Once a transaction is committed it is binding and not reversible in the markets. If a transaction is a bilateral transaction with a counterparty it would require agreement with the counterparty.

**PUB/MH/RISK-26**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Reputation (G)**

**a) Please describe the perceived risk related to MH's reputation.**

**ANSWER:**

Manitoba Hydro can sustain reputational risk from number of different sources as its operating and capital activities impact numerous stakeholders both within and outside the Province. These stakeholders include:

- Domestic Customers / Export Customers – risk of loss of customer confidence/sales;
- Financial Markets / Rating Agencies – risk of higher interest rates and reduced liquidity;
- First Nation Communities – risk of having to develop more expensive generating resources;
- Regulators (NEB, PUB, FERC, NERC, DFO, Transport Canada, Manitoba Conservation, Water Stewardship) – risk of not receiving or having more restrictive license and financial constraints;
- Electricity Markets (AESO, IESO, MISO) – risk of reduced market access.

**<u>PUB/MH/RISK-26</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Reputation (G)**

**b) Please describe MH's actions to mitigate the risks.**

**<u>ANSWER</u>:**

Manitoba Hydro conducts its business activities with high corporate integrity and within the following Operating Principles:

- Provide customers with exceptional value
- Strengthen working relationships with Aboriginal peoples
- Protect the environment in everything that we do
- Promote cost effective energy sustainability, conservation and innovation
- Be recognized as an outstanding corporate citizen and a supporter of economic development in Manitoba

In addition, Manitoba Hydro's corporate goals reflect the high standards to which the Corporation performs and the value placed on external relationships.

**PUB/MH/RISK-26**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Reputation (G)**

**c) To what extent does the Corporation consider maintaining its reputation in financially settling export commitments under drought conditions? Please quantify the financial impact related to maintaining the Corporations reputation during the 2003/04 drought.**

**ANSWER:**

Manitoba Hydro is committed to fulfilling all of its contractual obligations under all conditions including drought. Defaulting on its contractual obligations is not considered an option as this would ruin Manitoba Hydro's reputation as a supplier in the export market.

During drought conditions, such as in 2003/04, Manitoba Hydro may have financially settled some of its export obligations in order to minimize the cost of meeting load or to maximizing the reliability of the energy supply. There were no additional costs incurred during the 2003/04 drought associated with maintaining the Corporation's reputation.

<u>**PUB/MH/RISK-26**</u>

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Reputation (G)**

**d)** **Please confirm MH's reputation in the energy export business relates to:**

- **i.** **Low-price energy surpluses**
- **ii.** **Reliable and consistent supply**
- **iii.** **Clean hydraulic energy**

<u>**ANSWER**</u>**:**

Manitoba Hydro's reputation in the export market relates to the following factors:

1. Manitoba Hydro is a supplier of clean, renewable electricity.
2. Manitoba Hydro provides its customers with exceptional value.
3. Manitoba Hydro is dealing with its past and is working in partnership with Aboriginal peoples.
4. Manitoba Hydro protects the environment in everything it does.
5. Manitoba Hydro meets all of its contractual, license and reliability standards obligations.
6. Manitoba Hydro will meet all of its citizenship obligations to stakeholders.

**PUB/MH/RISK-26**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Reputation (G)**

**e) Please identify and quantify the specific actual supply curtailments than MH has imposed on its Export customers as a result of:**

- **i. Export energy supply shortfalls [e.g. drought];**
- **ii. Generation capacity shortfalls;**
- **iii. Transmission line outages;**
- **iv. Transformer/substation outages; and**
- **v. other.**

**ANSWER:**

i. Manitoba Hydro has never curtailed supply to export customers as a result of drought.

ii. Manitoba Hydro has never curtailed supply to export customers as a result of generation capacity shortfalls. Manitoba Hydro has always had sufficient capacity available to meet its firm load obligations (including exports) and its planning reserve obligations.

Manitoba Hydro has various options available in response to system emergencies within Manitoba such as generator outages, HVdc outages, generator outlet transmission outages, and transformer/substation outages. Firstly, it may have unused available generation that can be dispatched in response to emergency circumstances. Secondly, Manitoba Hydro participates in reserve sharing arrangements that provide for Emergency Power in system emergencies such as the loss of generation or transmission. Thirdly, Manitoba Hydro has curtailable load under Options A and R of the Curtailable Rate Program that can be used to free up generation to serve other load. Fourthly, Manitoba Hydro has curtailment rights for all its export contracts which are activated according to a priority stack. Lastly, in extremely rare circumstances Manitoba Hydro may have to curtail Manitoba load when no other supply option is available.

During forced outages Manitoba Hydro will exercise one or more of these options depending upon the circumstances, always in compliance with the appropriate NERC Standard and its reserve sharing agreement obligations.

Following an emergency event Manitoba Hydro will activate all its immediately available generation and will then call for Emergency Power for the balance of its supply shortfall. As Manitoba Hydro is responsible for the costs of Emergency Power that is being purchased to serve its export contracts Manitoba Hydro will exercise its contractual curtailment rights as soon as possible.

The following table indicates Manitoba Hydro's total Emergency Power purchases from MISO for 2009/10. Note that the energy volumes and costs have not been assigned to domestic or export loads.

| **Date** | **MWHS** | **COST $US** | **AVG PRICE $/MWh** |
|---|---|---|---|
| April 9/09 | 210 | 21,017.02 | 100.08 |
| April 9/09 | 290 | 29,063.59 | 100.22 |
| May 21/09 | 95 | 9,458.30 | 99.56 |
| May 21/09 | 120 | 11,945.57 | 99.55 |
| June 16/09 | 132 | 13,086.60 | 99.14 |
| July 10/09 | 95 | 14,674.34 | 154.47 |
| July 19/09 | 84 | 8,373.09 | 99.68 |
| July 30/09 | 756 | 53,666.23 | 70.99 |
| July 30/09 | 816 | 72,458.14 | 88.80 |
| Aug 19/09 | 169 | 16,621.46 | 98.35 |
| Aug 25/09 | 135 | 13,457.25 | 99.68 |
| Sept 21/09 | 154 | 15,766.63 | 102.38 |
| Sept 21/09 | 283 | 23,098.93 | 81.62 |
| Nov 2/09 | 568 | 55,158.91 | 97.11 |
| Nov 3/09 | 648 | 58,804.59 | 90.75 |
| Jan 19/10 | 7 | 559.69 | 79.96 |
| Feb 20/10 | 25 | 1,946.25 | 77.85 |
| March 31/10 | 511 | 34,543.60 | 67.60 |
| March 31/10 | 121 | 8,179.60 | 67.60 |
| | 5219 | 461,879.79 | 88.50 |

iii. There are occurrences when transmission outages are called by the ISOs which result in a Transmission Loading Relief (TLR) event that curtails exports. To the extent that TRLs curtail export contract deliveries, the risks and associated costs are borne by the export customers.

iv. See response to ii.

v. See response to ii.

**PUB/MH/RISK-26**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Reputation (G)**

**f) Please provide an indication of the relative ratio of these outages to the outages that were avoided at MH's expense**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-26(e).

**PUB/MH/RISK-27**

**Reference:** **Appendix 12.1 Corporate Risk Management Report**
**Risk Issue:** **Governance/Regulatory/Legal- Export Market Access (H2.1)**

**a) Please provide a summary of MH's existing transmission rights reservations and explain the extent to which these are adequate [or not] to serve MH's Firm/Bilateral contracts and the MISO market sales.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-3.

Manitoba Hydro has sufficient firm export rights to meet all its contractual requirements. In addition, Manitoba Hydro has 521 MW of firm rights in the US that can be used as required to minimize the risk of curtailment associated with the use of non-firm transmission service. These additional 521 MW represent only 29% of firm rights in the US. The remaining 71% are controlled by others and may not be available for use by Manitoba Hydro for market sales. As a consequence, Manitoba Hydro is attempting to increase its firm rights in the US in order to limit its exposure to non-firm transmission service and the risk of curtailment.

**PUB/MH/RISK-27**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- Export Market Access (H2.1)**

**b) Please explain how the above rights will be altered under the NSP/Excel contract extension.**

**ANSWER:**

Under the NSP Sale Agreements, Manitoba Hydro will have the right to use the US firm transmission reservations associated with the contract to sell additional energy for a fee.

**PUB/MH/RISK-27**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- Export Market Access (H2.1)**

**c) Please explain how the pending WPS & MP contracts are contingent on new US Transmission system additions and upgrades currently under consideration by these customers.**

**ANSWER:**

MP and WPS are responsible under the Term Sheets for providing for transmission service in the US associated with the capacity amounts. Transmission studies have indicated that in order to provide that level of service, new transmission facilities are required.

**PUB/MH/RISK-27**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- Export Market Access (H2.1)**

**d) Please confirm that MH's US export sales are subject to NEB licensing and approval and explain how and why the NEB could preclude the sales [PUB/MH II-21]**

**ANSWER:**

Pursuant to the National Energy Board Act, all US exports must be approved by NEB either through the issuance of a permit or a license.

When an exporter applies for approval, the Board determines at the outset whether a permitting process will be used (with no public hearing) or whether the Board will recommend to the Governor in Council that a licensing process be initiated with a public hearing. According to the Act, the Board has full discretion in determining whether to recommend a licensing process, taking into account all factors that the Board deems relevant, including the impact of the export on adjoining provinces and the environment, and whether the exporter has offered the electricity to interested parties in Canada. If a permitting process is initiated, the Board has no discretion to refuse the permit, but may impose conditions on the permit. If the Board obtains an Order in Council and a licensing process is initiated, the Board has full discretion to refuse the license and is not confined to specific considerations. Conditions may also be imposed on licenses.

PUB/MH/RISK-27

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- Export Market Access (H2.1)**

**e) Please explain [& quantify] MH's ability to make sales to Ontario which are typically opportunity sales either directly into NW Ontario or indirectly as merchant trading via the US to Southern Ontario.**

**ANSWER:**

Manitoba Hydro is directly able to sell to and buy from the Ontario market on the Manitoba-Ontario interface. Manitoba Hydro holds the rights to 200 MWs of firm transmission service on this interface for sales into Ontario. Manitoba Hydro must purchase non-firm transmission service to make additional sales (up to the scheduling limit) to Ontario.

Manitoba Hydro is also able to sell to and buy from the Ontario market on the Minnesota-Ontario and Michigan-Ontario interfaces. Manitoba Hydro has access to 104 MWs of firm transmission on the Michigan-Ontario interface. This transmission service position allows Manitoba Hydro to increase its market access into Ontario and diversify its export portfolio by benefiting from price spreads between MISO and Ontario. Manitoba Hydro can also effect additional transactions by utilizing non-firm transmission on a short-term daily or hourly basis.

The Ontario market has a Day Ahead Commitment Process (DACP) and a real time market. Market participants can specify an offer price in both timeframes. If MH's energy is accepted in the DACP, Manitoba Hydro is guaranteed to be paid its offer price. If Manitoba Hydro's energy is accepted in the real time market, Manitoba Hydro will realize the higher of the real time market clearing price or its offer price.

Historically, Manitoba-Ontario interface sales make up less than 5% of Manitoba Hydro's total physical sales. Sales via the Minnesota-Ontario and Michigan-Ontario interfaces make up less than 10% of Manitoba Hydro's total physical sales.

## PUB/MH/RISK-27

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- Export Market Access (H2.1)**

**f) Please explain [& quantify] MH's ability to make sales into Alberta via Saskatchewan's open access transmission**

**ANSWER:**

Manitoba Hydro is able to sell to and buy from the Alberta market (AESO) provided it can purchase the required transmission service through Saskatchewan. The AESO market is a real time market. Pool participants are unable to specify a bid or offer price when transacting with the market so in effect they are price takers. When contemplating a sale of surplus energy to the AESO, Manitoba Hydro needs to be confident that all costs can be recovered by the AESO clearing price. Costs include energy and transmission costs and losses through Saskatchewan.

AESO sales make up a small percentage of MH's total sales (historically less than 10% of total Canadian export sales).

**<u>PUB/MH/RISK-28</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- NERC/MRO Reliability Standards (H.5)**

**a) Please provide a listing of MH's 2005 to date Generation & Transmission upgrades and indicate to what extent these were driven by NERC requirements.**

**<u>ANSWER</u>:**

Please see the attached schedule for a listing of Manitoba Hydro's Generation & Transmission upgrades from 2005 to 2010. Of this list, three projects were required to meet NERC requirements:

1. Cyber Security Systems
2. Power Supply Security Installations/Upgrades
3. Station Battery Bank Capacity & System Reliability Increase

**Legend:**

NERC Projects

**Projects for FY2005 to FY2010**

| **Category** | **Description** |
|---|---|
| BASE | 200MW Ontario Hydro Sale - Sync Cond Conversion |
| | 35 MVA Mobile Transformer Purchase |
| | Automatic Meter Reading Implementation |
| | Bipole 1 Chiller Replacement |
| | Bipole 1 DC Filter Capacitor Replacement |
| | Bipole 1 P1 & P2 Battery Bank Separation |
| | Bipole 1 Thyristor Valve Upgrade Project |
| | BP2 Valve Hall Wall Bushing Replacement |
| | Brandon Crocus Plains 115 - 25kV Bank Addition |
| | Brandon G.S. Unit 5 License Review |
| | Brandon G.S. Unit 5 Relicensing |
| | Brandon Generating Station Unit 5 License Review |
| | Brandon Unit 5 License Review |
| | Brandon Unit 5 Rehabilitation |
| | Brereton Lake Station Area |
| | Burrows New 66 - 12 kV Station |
| | Canexus Load Addition |
| | Communication System - Southern MB (Great Plains) |
| | Communications |
| | Communications Upgrade Winnipeg Area |
| | Converter Transformer Bushing Replacements |
| | Cromer North Station & Reston RE12-4 25kV Conversion |
| | Customer Information System |
| | Cyber Security Systems |
| | Defective RINJ Cable Replacement |
| | Distribution PCB Testing & Transformer Replacement |
| | Dorsey - Rosser 230kV Transmission Improvement |
| | Dorsey - US Border D602F 500kV AC T/L Insulator Rplc |
| | Dorsey 230 kV Bus Enhancements |
| | Dorsey 230 KV Relay Building Upgrade |
| | Dorsey 230kV Bus Enhancements |
| | Dorsey 230kV Relay Building Upgrade |
| | Dorsey 500 kV R502 Breaker Replacement |
| | Dorsey Asea Synchronous Condenser Cooler Upgrade |
| | Dorsey EE Synch Condenser Glycol Cooler Upgrade |
| | Dorsey Synchronous Condenser Refurbishment |
| | Enbridge Pipelines Clipper Project |
| | Enterprise GIS Project |
| | Fire Protection Projects |
| | Fire Protection Projects - HVDC |
| | Flin Flon Area Transmission Improvements Phase II |
| | Frobisher Station Upgrade |
| | Gas SCADA Replacement |
| | Generating Station Roof Replacements |
| | Generation South Breaker Replacement |
| | Generation South PCB Regulation Compliance |
| | Generation South Transformer Refurbish & Spares |
| | Generation Townsite Infrastructure |
| | Glenboro - Rugby 230kV T/L |
| | Great Falls 115 kV Indoor Station Safety Improvements |
| | Great Falls 115kV Indoor Station Safety Improvements |
| | Great Falls G.S. 115 kV Indoor Station Safety Improvements |
| | Great Falls G.S. Rehabilitation |
| | Great Falls G.S. Unit 4 Major Overhaul |
| | Great Falls Generating Station Rehabilitation |
| | Great Falls Generating Station Unit 4 Overhaul |
| | Great Falls Unit 4 Overhaul |
| | Halon Replacement Project |
| | Harrow Station Bank 3 Installation |
| | High Voltage Test Facility |
| | Holland 8kV - 25kV Conversion & Dist. Supply Centre |
| | Holland Conversion & DSC |
| | HSC Service Consolidation & Distribution Upgrade |
| | Human Resource Management System |
| | HVDC AC Filter PCB Capacitor Replacement |
| | HVDC Auxiliary Power Supply |
| | HVDC Auxiliary Power Supply Upgrades |
| | HVDC Bipole 1 By-Pass Vacuum Switch Removal |
| | HVDC Bipole 1 Roof Replacement |
| | HVDC Bipole 1 Smoothing Reactor Replacement |
| | HVDC Bipole 2 230 kV HLR Circuit Breaker Replacements |
| | HVDC Bipole 2 Thyristor Module Cooling Refurbishment |
| | HVDC BP1 Converter Station, P1 & P2 Battery Bank Separation |
| | HVDC BP2 HLR Breaker Replacements |

**Legend:**

NERC Projects

**Projects for FY2005 to FY2010**

| Category | Description |
|---|---|
| | HVDC Circuit Breakers Operating Mechanism Replacements |
| | HVDC Stations Ground Grid Refurbishment |
| | HVDC Switchgear Upgrade |
| | HVDC Sys. Transformer and Reactor Fire Protection & Prevention |
| | HVDC Syst Transformer and Reactor |
| | HVDC Syst Transformer and Reactor FP&P |
| | HVDC System Transformer & Reactor Fire Protection & Prevention |
| | HVDC System Transformer and Reactor |
| | HVDC Thyristor Module Cooling Refu |
| | HVDC Transformer Marshalling Kiosk Replacement |
| | HVDC Transformer Replacement Program |
| | Integration of System Control Centres |
| | Interlake Digital Microwave Replacement |
| | Jenpeg G.S. Unit Overhauls (Units 1 - 6) |
| | Jenpeg G.S. Unit Overhauls (Units 1- 6) |
| | Jenpeg Generating Station Unit Overhauls |
| | Jenpeg Transformers Refurbish/Add Spare |
| | Kettle G.S. Unit Re-Wedging |
| | Kettle Transformer Overhaul Program |
| | Kettle Transformer Replacement Program |
| | Laurie River G.S. Plant 1 and 2 Rehabilitation |
| | Laurie River Plant 1 and 2 Rehabilitation |
| | Laurie River/CRD Communication & Annunciation Upgrades |
| | Martin New Outdoor Station |
| | Microwave Frequency Displacement |
| | Mobile Radio System Modernization |
| | Mobile Transformer |
| | Neepawa New 230 - 66kV Station |
| | Neepawa North Feeder NN12-2 & Line 57 Rebuild |
| | Ness Station Feeder Conversions |
| | New Head Office |
| | Niverville Station 66 - 12kV Bank Replacements |
| | Notigi Marine Vessel Replacement & Infrastructure Improvements |
| | Oil Containment |
| | Oil Containment - HVDC |
| | Oil Containment - Power Supply |
| | Perimeter South Distribution Supply Centre Installation |
| | Perimeter South DSC Installation |
| | Pilot Wire Replacement |
| | Pine Falls - Great Falls 115 - 66kV Supply |
| | Pine Falls - Great Falls 115- 66 kV Supply |
| | Pine Falls G.S. Rehabilitation |
| | Pine Falls Generating Station Rehabilitation |
| | Pine Falls Rehabilitation |
| | Portage South 230 - 66 kV Transformer Addition |
| | Power Supply Dam Safety Upgrades |
| | Power Supply Fall Protection Program |
| | Power Supply Hydraulic Controls |
| | Power Supply Security Installations/Upgrades |
| | Power Supply Sewer & Domestic Water Systems |
| | PS Sewer & Domestic Water System Install & Upgrades |
| | Red River Floodway Expansion Project |
| | Richer South 230 - 66 kV Transformer Addition |
| | Rosser - Inkster 115 kV Transmission |
| | Rosser - Silver 230 kV Transmission |
| | Rosser Station 230 - 115 kV Bank 3 Replacement |
| | Rover 4 kV Switchgear Building & Replacement |
| | Rover Substation Replace 4 kV Switchgear |
| | Ruttan - South Indian Lake 66kV Line |
| | Selkirk Enhancements |
| | Selkirk G.S. Ancillary Systems |
| | Selkirk G.S. Fuel Switching Project |
| | Selkirk G.S. License Review |
| | Selkirk G.S. Rehabilitation |
| | Selkirk Generating Station Enhancements |
| | Shamattawa New Diesel GS & Tank Farm |
| | Shoal Lake New 33 - 12.47 kV DSC |
| | Shoal Lake New DSC & Town Conversion |
| | Site Remediation |
| | Site Remediation of Contaminated Corporate Facilities |
| | Site Remediation of Diesel Generating Stations |
| | Slave Falls G.S. Creek Spillway Rehabilitation |
| | Slave Falls G.S. Rehabilitation |
| | Slave Falls Generating Station Rehabilitation |

| Legend: | |
|---|---|
| NERC Projects | |
| Projects for FY2005 to FY2010 | |
| **Category** | **Description** |
| | Slave Falls Rehabilitation |
| | St James 24 kV System Refurbishment |
| | St. Boniface - Plessis Rd 115-25kV Station |
| | St. Boniface - Plessis Rd Bank 2 Addition |
| | St. Boniface 66 kV Line Burial & Salvage |
| | Stanley Station 230-66kV Hot Standby |
| | Station Battery Bank Capacity & System Reliability Increase |
| | Station Battery Bank Replacement & Upgrade |
| | Stony Mountain New 115 - 12 kV Station |
| | Stony Mountain New Station |
| | System Control Centres Improvements & Upgrades |
| | Tadoule Lake DGS Tank Farm Upgrade |
| | TCPL Keystone Project |
| | Teulon East Station Study No. DER-S09-02 |
| | Trans Line Protection & Teleprotection Replacements |
| | Transcona & Ridgeway Station 66kV Bus Upgrades |
| | Transcona Area Distribution Conversion |
| | Transcona New 230 - 66 kV Station |
| | Transcona Station 66 kV Breaker Replacement |
| | Transmission Line Protection & Teleprotection Replacement |
| | Transmission Line Re-rating |
| | Virden Area Distribution Changes |
| | Water Licenses & Renewals |
| | Waverley Service Centre Oil Tank Farm Replacement |
| | Waverley West Sub Division Supply - Stage 1 |
| | WCD U/G Network Transformer Replacement |
| | West Kildonan - Court 115 - 7.2kV Bank Addition |
| | William New 66 - 12 kV Station |
| | Winkler Market Feeder WM25-13 Conversion |
| | Winnipeg Area Transmission Refurbishment |
| | Winnipeg Central 66 kV Breaker Replacement |
| | Winnipeg Central District Oil Switch Project |
| | Winnipeg Central Protection Wireline Replacement |
| | Winnipeg Central U/G Network Asbestos Removal |
| | Winnipeg Distribution Infrastructure Requirements |
| | Winnipeg River Control System |
| | Winnipeg River Riverbank Protection Program |
| | Workforce Management |
| | WorkSmart |
| | Wpg Central 12 & 4 kV Manhole Oil Switches |
| | Wpg Central District Underground Network Asbestos Removal |
| | York Station Bank & Switchgear Addition |
| | Rosser - McPhillips 115 kV Transmission Improvements |
| | Seven Sister Improvements & Upgrades |
| | Winnipeg - Brandon Transmission System Improvements |
| **BASE Total** | |
| MNG&T | Bipole III |
| | Brandon Combustion Turbine |
| | Brandon Combustion Turbine Pipeline Upgrade |
| | Conawapa - Generation |
| | Dorsey - US Border New 500 kV Transmission Line |
| | Firm Import Upgrades |
| | Grand Rapids G.S. Rehabilitation |
| | Herblet Lake - The Pas 230 kV Transmission |
| | Keeyask - Generation |
| | Kelsey Improvements & Upgrades |
| | Kettle Improvements & Upgrades |
| | Northern AC Transmission System Requirements |
| | Point du Bois Improvements & Upgrades |
| | Pointe du Bois - Transmission |
| | Riel 230/500kV Station |
| | Wind Generation |
| | Wuskwatim - Generation |
| | Wuskwatim - Transmission |
| | MB - ON Clean Energy Transfer Init - Phase I |
| **MNG&T Total** | |

**PUB/MH/RISK-28**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- NERC/MRO Reliability Standards (H.5)**

**b) Please provide a similar listing for MH's proposed Generation & Transmission projects in CEF 09.**

**ANSWER:**

Please see the attached schedule for a listing of Manitoba Hydro's Generation & Transmission upgrades in CEF 09. Of this list, three projects were required to meet NERC requirements:

1. Cyber Security Systems
2. Power Supply Security Installations/Upgrades
3. Station Battery Bank Capacity & System Reliability Increase

| Legend: |
| --- |
| NERC Projects |

| Sum of Annual Total | |
| --- | --- |
| **Category** | **Description** |
| BASE | 35 MVA Mobile Transformer Purchase |
| | Automatic Meter Reading Implementation |
| | Bipole 1 Chiller Replacement |
| | Brandon Crocus Plains 115 - 25kV Bank Addition |
| | Brandon Generating Station Unit 5 License Review |
| | Brereton Lake Station Area |
| | Burrows New 66 - 12 kV Station |
| | Communication System - Southern MB (Great Plains) |
| | Communications Upgrade Winnipeg Area |
| | Converter Transformer Bushing Replacements |
| | Corporate Building Program |
| | Cromer North Station & Reston RE12-4 25kV Conversion |
| | Cyber Security Systems |
| | Defective RINJ Cable Replacement |
| | Distribution PCB Testing & Transformer Replacement |
| | Domestic Item - Customer Service & Marketing |
| | Domestic Item - Finance & Administration |
| | Domestic Item - Power Supply |
| | Domestic Item - Transmission & Distribution |
| | Dorsey 230 kV Bus Enhancements |
| | Dorsey 230 KV Relay Building Upgrade |
| | Dorsey 500 kV R502 Breaker Replacement |
| | Dorsey Asea Synchronous Condenser Cooler Upgrade |
| | Dorsey Synchronous Condenser Refurbishment |
| | Enterprise GIS Project |
| | Fire Protection Projects - HVDC |
| | Fleet |
| | Flin Flon Area Transmission Improvements Phase II |
| | Frobisher Station Upgrade |
| | Gas SCADA Replacement |
| | Generating Station Roof Replacements |
| | Generation South Breaker Replacement |
| | Generation South Transformer Refurbish & Spares |
| | Generation Townsite Infrastructure |
| | Great Falls 115 kV Indoor Station Safety Improvements |
| | Great Falls Generating Station Rehabilitation |
| | Great Falls Generating Station Unit 4 Overhaul |
| | Halon Replacement Project |
| | High Voltage Test Facility |
| | Holland Conversion & DSC |
| | HVDC AC Filter PCB Capacitor Replacement |
| | HVDC Auxiliary Power Supply Upgrades |
| | HVDC Bipole 1 By-Pass Vacuum Switch Removal |
| | HVDC Bipole 1 Roof Replacement |
| | HVDC Bipole 1 Smoothing Reactor Replacement |
| | HVDC Bipole 2 230 kV HLR Circuit Breaker Replacements |
| | HVDC Bipole 2 Thyristor Module Cooling Refurbishment |
| | HVDC BP1 Converter Station, P1 & P2 Battery Bank Separation |
| | HVDC Stations Ground Grid Refurbishment |
| | HVDC Sys. Transformer and Reactor Fire Protection & Prevention |
| | HVDC Transformer Replacement Program |
| | Interlake Digital Microwave Replacement |
| | Jenpeg Generating Station Unit Overhauls |
| | Kettle Transformer Overhaul Program |
| | Martin New Outdoor Station |
| | Mobile Radio System Modernization |
| | Neepawa New 230 - 66kV Station |
| | Neepawa North Feeder NN12-2 & Line 57 Rebuild |
| | Ness Station Feeder Conversions |
| | New Head Office |
| | Oil Containment |
| | Oil Containment - Power Supply |
| | Pilot Wire Replacement |
| | Pine Falls - Great Falls 115 - 66kV Supply |
| | Pine Falls Generating Station Rehabilitation |
| | Power Supply Dam Safety Upgrades |
| | Power Supply Emergencies/ Equipment Failures |
| | Power Supply Fall Protection Program |
| | Power Supply Hydraulic Controls |
| | Power Supply Security Installations/Upgrades |
| | PS Sewer & Domestic Water System Install & Upgrades |
| | Red River Floodway Expansion Project |
| | Rosser - Inkster 115 kV Transmission |
| | Rosser Station 230 - 115 kV Bank 3 Replacement |
| | Rover Substation Replace 4 kV Switchgear |
| | Selkirk Generating Station Enhancements |
| | Shoal Lake New 33 - 12.47 kV DSC |
| | Site Remediation |
| | Site Remediation of Contaminated Corporate Facilities |
| | Slave Falls Generating Station Rehabilitation |
| | St James 24 kV System Refurbishment |
| | Stanley Station 230-66kV Hot Standby |
| | Station Battery Bank Capacity & System Reliability Increase |
| | Stony Mountain New 115 - 12 kV Station |
| | System Control Centres Improvements & Upgrades |
| | T&D System Emergencies/Equipment Failures |
| | Transcona & Ridgeway Station 66kV Bus Upgrades |
| | Transcona Area Distribution Conversion |
| | Transcona New 230 - 66 kV Station |
| | Transcona Station 66 kV Breaker Replacement |
| | Transmission Line Protection & Teleprotection Replacement |
| | Transmission Line Re-rating |
| | Water Licenses & Renewals |
| | Waterways Management Program |
| | Waverley West Sub Division Supply - Stage 1 |
| | William New 66 - 12 kV Station |
| | Winkler Market Feeder WM25-13 Conversion |
| | Winnipeg Central 66 kV Breaker Replacement |
| | Winnipeg Central District Oil Switch Project |
| | Winnipeg Central Protection Wireline Replacement |
| | Winnipeg Distribution Infrastructure Requirements |
| | Winnipeg River Control System |
| | Winnipeg River Riverbank Protection Program |
| | Workforce Management |
| | WorkSmart |
| | Wpg Central District Underground Network Asbestos Removal |
| | York Station Bank & Switchgear Addition |
| | Seven Sister Improvements & Upgrades |
| | Winnipeg - Brandon Transmission System Improvements |
| **BASE Total** | |
| MNG&T | Bipole III |
| | Conawapa - Generation |
| | Demand Side Management |
| | Herblet Lake - The Pas 230 kV Transmission |
| | Keeyask - Generation |
| | Kelsey Improvements & Upgrades |
| | Kettle Improvements & Upgrades |
| | Planning Study Costs |
| | Point du Bois Improvements & Upgrades |
| | Pointe du Bois - Transmission |
| | Riel 230/500kV Station |
| | Wuskwatim - Generation |
| | Wuskwatim - Transmission |
| **MNG&T Total** | |

**PUB/MH/RISK-28**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- NERC/MRO Reliability Standards (H.5)**

**c) Please describe (and provide written confirmation if any of ) NERC's reaction to a substantial deferral of Bipole III and Riel .**

**ANSWER:**

Manitoba Hydro does not anticipate a reaction from NERC to a substantial deferral of Bipole III and Riel since a deferral will not constitute a violation of existing NERC standards.

**PUB/MH/RISK-28**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- NERC/MRO Reliability Standards (H.5)**

**d) Please indicate briefly what type of Generation & Transmission shortcomings would trigger NERC interventions.**

**ANSWER:**

Any violation of a NERC reliability standard, whether it is reported through a self-report, audit findings, or otherwise will follow the MRO compliance monitoring and enforcement process. The MRO can make a recommendation to PUB regarding a penalty or other sanction, and NERC must approve a settlement agreement regarding a penalty before MRO can file it for approval with the PUB. When Manitoba Hydro recommends a facility that is driven by load growth, the plan for that facility must meet the performance requirements stipulated in the NERC Standards. Such requirements make provision for voltage levels, acceptable load limits, and prohibitions against loads being tripped. NERC intervention could occur if system assessments of the plans did not meet the performance requirements, or delays in needed projects caused voltages or loading criteria to be violated.

**PUB/MH/RISK-28**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Governance/Regulatory/Legal- NERC/MRO Reliability Standards (H.5)**

**e) Please provide a full listing of penalties, which MH is subject to under NERC.**

**ANSWER:**

A full listing of penalties cannot be provided, since NERC determines penalties based on the Violation Risk Factor of the violated requirement (measures of potential reliability significance designated by NERC as High, Medium, or Lower) and the Violation Severity Level assessed for the violation (the degree to which a violator violated a requirement of a reliability standard). The base penalty amount is then adjusted by the MRO based on mitigating or aggravating factors to reflect the specific facts and circumstances material to each violation and violator. The MRO recommends a penalty that is enforceable only by order of the PUB. All violations require a mitigation plan to rectify the violation and prevent further occurrences. In the US, penalties can reach $1M per violation per day, and in Canada the upper limit is subject to any limitation imposed by Canadian law.

**PUB/MH/RISK-29**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Emerging Energy Technologies (J.1)**

a) **Does MH foresee a significant potential loss [or gain] of export market as a result of:**

- **Renewable energy mandates in Minnesota/Wisconsin and/or Ontario?**
- **Ground source energy supply growth in the same regions?**
- **Trend to electric vehicles**

**ANSWER:**

As noted in the response to PUB/MH I-156(a), "Manitoba Hydro's forecast which is based on a consensus of the five consultants is referred to as the Consensus Price Forecast in the ICF Report. In preparing their forecasts, the consultants prepare their own internal estimates for a number of pricing factors. These pricing factors include, but are not limited to, thermal fuel forecasts (coal and natural gas), future load growth forecasts, capital costs and required rates of return, generation retirements and additions, power market rules, future legislative regulations including greenhouse gases, SOx, NOx, and mercury and renewable portfolio standard requirements, and characteristics of the existing generation fleet."

Current renewable energy mandates for Minnesota and Wisconsin are explicitly considered in the price forecasting process. For a discussion on the impact of renewables on the MISO market, please see response to PUB/MH I-156(c).

In preparing their forecasts, the price forecast consultants prepare their own load growth forecasts. Expected trends in consumption growth and energy conservation are considered in preparing the load growth forecasts. As a general comment, there is limited electric heat in most areas of the MISO market. Thus switching from electric heat to ground source heat pumps might have a limited effect in very slightly reducing load growth. Switching from natural gas heat to ground source heat pumps could have a limited effect in increasing load growth. Any trend to electric vehicle beyond that assumed in the load growth assumptions for the price forecast would increase load growth and put upward pressure on power market prices.

**<u>PUB/MH/RISK-29</u>**

**Reference: Appendix 12.1 Corporate Risk Management Report**
**Risk Issue: Emerging Energy Technologies (J.1)**

**b) Please discuss how each of the above changes could impact MH's export market access.**

**<u>ANSWER</u>:**

Export market access is considered to be freedom from physical restrictions (transmission transfer capability) or legal/regulatory barriers to the export power market. Emerging energy technologies and renewable energy mandates such as those referred to in PUB/MH/RISK-29(a) are not expected to impact Manitoba Hydro's export market access.

Manitoba Hydro monitors emerging energy technologies to determine if they have any potential to become a future supply option for Manitoba and to monitor their potential impact, if any, on the export market. The price forecast consultants also monitor and consider technology trends, emerging energy technologies and energy policy as they forecast changes to the generation mix over the forecast horizon. Hence emerging energy technologies are considered in the preparation of the electricity price forecast.

**PUB/MH/RISK-30**

**Reference: Power Resource Plans (2008 and 2009)**
**Risk Issue: Export Contract Obligations**

**a) At the May 31, 2010/June 2, 2010 workshop, MH provided a revised 2009 Base Load Power Resource Plan showing dependable resources and total energy demand for domestic load and export contracts. Please file the Power Resource Plan that supports these changes.**

**ANSWER:**

The 2009/10 Power Resource Plan is the most recent Power Resource Plan and is included as Appendix 47 to the response to CAC/MSOS//MH I-35(a).

**PUB/MH/RISK-30**

**Reference:** **Power Resource Plans (2008 and 2009)**
**Risk Issue:** **Export Contract Obligations**

**b)** **These workshop numbers differed from the 2008 Base Load forecast (table below), which indicates the Lake St. Joseph sale/NSP sales/pending WPS and MP sales, including transmission losses. Please confirm and explain the changes**

| | May Workshop 2009 (GWh) | 2008 Power Resource Plan (GWh) Lake St. Joseph/NSP/WPS+MP | 2009 Reduction (GWh) |
|---|---|---|---|
| 09/10 | 3,626 | 3,626 | 0 |
| 10/11 | 3,404 | 3,404 | 0 |
| 11/12 | 3,385 | 3,385 | 0 |
| 12/13 | 3,259 | 3,259 | 0 |
| 13/14 | 3,158 | 3,158 | 0 |
| 14/15 | 3,156 | 3,156 | 0 |
| 15/16 | 1,560 | 353+1,920=2,278 | -718 |
| 16/17 | 1,352 | 145+2,062=2,207 | -855 |
| 17/18 | 1,352 | 145+2,062=2,207 | -855 |
| 18/19 | 1,926 | 145+2,062+574=2,781 | -855 |
| 19/20 | 2,614 | 145+2,062+1,262=3,469 | -855 |
| 20/21 | 3,494 | 145+2,062+2,142=4,549 | -855 |
| 21/22 | 3,648 | 145+2,062+2,296=4,503 | -855 |
| 22/23 | 4,992 | 145+2,589+3,350=6,084 | -1,092 |
| 23/24 | 5,086 | 145+2,636+3,444=6,205 | -1,119 |
| 24/25 | 5,086 | 145+2,636+3,444=6,205 | -1,119 |
| 25/26 | 3,589 | 145+Nil+3,334=3,778 | -189 |
| 26/27 | 3,589 | 145+Nil+3,444=3,589 | -- |
| 27/28 | 3,589 | 145+Nil+3,444=3,589 | -- |
| 28/29 | 3,589 | 145+Nil+3,444=3,589 | -- |
| 29/30 | 3,589 | 145+Nil+3,444=3,589 | -- |

**ANSWER:**

The table in the information request is generally accurate with some small differences from what Manitoba Hydro would have provided. This difference in long-term export obligations is due to a change in the presentation of the adverse water clause of the NSP contract in the supply and demand tables. The differences in long-term export obligations are offset by equal differences in dependable imports in each year. The adverse water clause is shown as a decrease to the long-term sales obligation in the 2009 resource plan to reflect the decreased physical obligation under adverse water conditions contained in the contract. The 2008 resource plan showed the total obligation as a long-term sale obligation with a corresponding import amount to reflect the adverse water clause.

## PUB/MH/RISK-31

**Reference: PUB/MH II-75; PUB/MH II-90**
**Risk Issue: Energy from Storage**

**a) Please confirm that in defining dependable energy MH typically assumes every drought year will commence with an April 1st average energy-in-storage of 8,000 GWh; and therefore, MH is targeting to retain at least average energy-in-storage at the end of March.**

**ANSWER:**

Manitoba Hydro cannot confirm that it is targeting to retain 8,000 GW.h of energy in storage. Given that the annual energy from inflow in the most severe drought is approximately 15,500 GW.h and that dependable hydraulic energy is 21,000 GW.h, it could be concluded that Manitoba Hydro requires about 5,500 GW.h in storage at the end on March that can be utilized over the next year of low flows assuming financial settlements and additional market supplied energy are ignored as supply sources.

For operational planning purposes, Manitoba Hydro assumes that a portion of its long term export contracts will be financially settled and that some market supplied energy will be available in determining its energy reserve requirements.

**PUB/MH/RISK-31**

**Reference: PUB/MH II-75; PUB/MH II-90**
**Risk Issue: Energy from Storage**

**b) Please confirm that in above average flow years, it should be almost always possible to sustain an outflow from energy-in-storage of 8,000 GWh over an eight-month (August to March) period.**

**ANSWER:**

Manitoba Hydro cannot confirm that it is able to sustain an 8,000 GWh draw from energy-in-storage in above average flow years from August to March.

In above average inflow years the outflow capability from Lake Winnipeg is insufficient to achieve a significant draw (if any) from storage for power purposes. 2010/11 is a good example of this situation when the draw for power purposes (in spite of maximum outflows at Jenpeg) will be limited to 225 GWh by March 31, 2011 due to ice restrictions in the Lake Winnipeg outlet channels. When storage draws from Cedar Lake and Southern Indian Lake of 2,000 GWh are included the total storage draw is 2,225 GWh.

Manitoba Hydro does not control the storage draw on all the other major reservoirs in the Nelson-Churchill watershed.

**PUB/MH/RISK-31**

**Reference:** **PUB/MH II-75; PUB/MH II-90**
**Risk Issue:** **Energy from Storage**

**c)** **Please confirm that MH should typically be able to recognize above average flow years from the combined winter and spring precipitation within the Winnipeg River, Red River and local Lake Winnipeg watershed's.**

**ANSWER:**

Manitoba Hydro can typically only recognize an above average water year by the end of June by waiting and observing the actual runoff volumes that have occurred as a result of the winter and subsequent spring weather conditions.

2010 was an excellent example of how this year's water conditions could not be characterized as being an above average year until the torrential mid June rainfall occurred across all of western Canada, having been preceded by one of the driest winters and springs on record.

## PUB/MH/RISK-32

**Reference: PUB/MH II-75; PUB/MH II-90**
**Risk Issue: Drought Frequency**

a) **Please confirm that the data in the following table reasonably represents information filed in PUB/MH II-75, PUB/MH II-90, and PUB/MH II-82, with the exception of the last column, which is drawn from other sources.**

| Year | April 1st Energy-in Storage (GWh) | Total Potential Hydraulic Generation (GWh) | Total Nelson River Flow (cfs) | Red River Flow (cfs) | Winnipeg River Flow (cfs) | Winnipeg River No. of Months Flow <20,000 cfs | Accumulated Summer (Theoretical) (Net) Evaporation Loss on Lake Winnipeg |
|---|---|---|---|---|---|---|---|
| 1980-81 | 9,800 | 25,210 | 97,500 | 2,900 | 21,000 | 6 | 22” |
| 1981-82 | 6,000 | 22,201 | 81,100 | 2,500 | 18,000 | 7 | 15” |
| 1982-83 | 3,700 | 29,800 | 106,900 | 8,000 | 35,100 | 4 | 16” |
| 1987-88 | 8,700 | 22,353 | 94,100 | 5,900 | 15,200 | 8 | 14” |
| 1988-89 | 4,800 | 18,850 | 73,900 | 1,900 | 19,700 | 6 | 24” |
| 1989-90 | 4,600 | 24,274 | 90,000 | 4,000 | 32,100 | 1 | 16” |
| 1990-91 | 4,500 | 24,162 | 89,500 | 2,400 | 24,300 | 4 | 18” |
| 1991-92 | 3,800 | 24,658 | 88,600 | 3,600 | 25,700 | 0 | 12” |
| 1994-95 | 8,300 | 28,200 | 103,900 | 10,000 | 34,100 | 2 | 4” |
| 1998-99 | 12,300 | 29,000 | 115,800 | 11,400 | 19,500 | 5 | 9” |
| 2003-04 | 4,200 | 18,500 | 66,400 | 5,100 | 18,100 | 8 | 18” |
| 2006-07 | 12,400 | 31,200 | 132,900 | 12,400 | 22,200 | 10 | 23” |
| 1977-2009 Average | 8,000 | 29,000± | 106,000 | 9,600 | 32,300 | N/A | 12” |

**ANSWER:**

Manitoba Hydro confirms the accuracy of the information provided in response to PUB/MH II-75, PUB/MH II-90, and PUB/MH II-82. However the information contained in this table does not relate to the responses filed for PUB/MH II-75, PUB/MH II-82 or PUB/MH-II-90.

Manitoba Hydro can confirm the following regarding the information provided in this table:

1. “April 1st [*Potential*] Energy in Reservoir Storage (GWh)” values shown in the table are in agreement with Manitoba Hydro records and the response filed for PUB/MH I-82(e).

2. “Total Potential Hydraulic Generation (GWh)” values that are shaded in the table agree with the values provided in the response filed for PUB/MH I-90(b). Manitoba Hydro has not performed similar calculations for the non-shaded values.

3. Manitoba Hydro provided monthly Lower Nelson River flow at Kettle from 1978-2008 in the response to PUB/MH I-75 and confirms the accuracy of that response. The information provided in that response is representative of total Nelson River flows. Average “Total Nelson River Flow (cfs)” values in the above table generally agree with Manitoba Hydro records, with the exception of 1981-82. Manitoba Hydro records indicate annual average flows for 1981-82 were approximately 87,000 cfs (not 81,100 cfs).

4. Manitoba Hydro provided monthly Red River flow for 1978-2005 in the response to PUB/MH I-75 and confirms the accuracy of that response. Average “Red River Flow (cfs)” values in the above table generally agree with Manitoba Hydro records.

5. Manitoba Hydro provided monthly Winnipeg River flow at Slave Falls for 1978-2008 in the response to PUB/MH I-75 and confirms the accuracy of that response. Average “Winnipeg River Flow (cfs)” values in the above table generally agree with Manitoba Hydro records.

6. Manitoba Hydro provided monthly Winnipeg River flow at Slave Falls for 1978-2008 in the response to PUB/MH I-75 and confirms the accuracy of that response. A count of “Winnipeg River No. of Months of Flow <20,000 cfs” was calculated from the information provided in PUB/MH I-75. The results of this count are provided in Table 1 below.

Table 1.

| **Year** | **Winnipeg River No. of Months Flow <20,000 cfs** |
|---|---|
| 1980-81 | 6 |
| 1981-82 | 6 |
| 1982-83 | 0 |
| 1987-88 | 9 |
| 1988-89 | 6 |
| 1989-90 | 1 |
| 1990-91 | 3 |
| 1991-92 | 2 |
| 1994-95 | 2 |
| 1998-99 | 5 |
| 2003-04 | 8 |
| 2006-07 | 7 |

## PUB/MH/RISK-32

**Reference: PUB/MH II-75; PUB/MH II-90**
**Risk Issue: Drought Frequency**

**b) Please confirm that the above table reflects the fiscal years since 1977/78 when Winnipeg River flows were low for all or part of the year and that the list encompasses:**

- **All of MH's low (<25,000 GWh) hydraulic generation output years during the last 30 years.**
- **The nine lowest Winnipeg River flow years in the last 30 years.**
- **The eight lowest Red River flow years in the last 30 years.**
- **The five highest probable net evaporation situations for Lake Winnipeg in those 30 years.**
- **The seven lowest April 1st energy-in-storage levels in those 30 years.**
- **The seven lowest Nelson River flows at Kettle G.S. in those 30 years**

**ANSWER:**

As water from the Winnipeg River generates on average 40% of Manitoba Hydro's hydraulic generation as it flows from the Ontario-Manitoba border to Hudson's Bay, and as river flows on the Red River and from the Eastern Tributaries to Lake Winnipeg are highly correlated to Winnipeg River flows, Manitoba Hydro can confirm that drought on the Winnipeg River generally corresponds to years of low total hydraulic generation.

***first bullet* –** Confirmed.

***second bullet*** - Confirmed.

***third bullet* –** Confirmed.

***fourth bullet*** - Manitoba Hydro does not know the source of the net evaporation data provided and therefore can not confirm this item.

***fifth bullet*** - Not confirmed. The April 1$^{st}$ Potential Energy in Reservoir Storage in 2004 was among the seven lowest in the fiscal years since 1977/78.

***sixth bullet* –** Confirmed.

**PUB/MH/RISK-33**

**Reference:** **PUB/MH II-75; PUB/MH II-90**
**Risk Issue:** **Low Hydraulic Generation**

**a)** **Please confirm that for annual hydraulic generation outputs of 25,000 GWh or less, MH (after meeting domestic load) currently would employ almost one GWh of imports for every GWh of exports (firm and opportunity) and that additional peak export sales would usually achieve a net revenue of less than 2¢/KWh while off-peak sales would yield very little net revenue.**

**ANSWER:**

Manitoba Hydro cannot confirm the premise.

**PUB/MH/RISK-33**

**Reference:** **PUB/MH II-75; PUB/MH II-90**
**Risk Issue:** **Low Hydraulic Generation**

**b) Please confirm that:**

- **With average April 1st energy-in-storage and only lower quartile accumulated winter and spring precipitation within the Winnipeg River watershed, MH should expect to achieve <25,000 GWh of hydraulic generation.**
- **With April 1st energy-in-storage of about 4,000 GWh, MH would need to have at least average accumulated winter and spring precipitation within the Winnipeg River watershed to achieve 25,000 GWh of hydraulic generation.**
- **Lake Winnipeg net evaporation losses as demonstrated in 2006/07 can largely negate favourable winter and spring precipitation and spring runoff volumes.**

**ANSWER:**

Manitoba Hydro cannot confirm any of the above statements.

**PUB/MH/RISK-34**

**Reference: PUB/MH I-82**
**Risk Issue: Export Profitability**

**a) Please confirm that MH's export sales are most profitable when they are derived entirely from hydraulic generation and least profitable when they are derived entirely from imports.**

**ANSWER:**

Manitoba Hydro cannot confirm this statement. There are times when Manitoba Hydro is paid to purchase energy. These would be the most profitable export transactions.

PUB/MH/RISK-34

**Reference:** PUB/MH I-82
**Risk Issue:** Export Profitability

**b) Please confirm that MH's net revenues from export sales and profitability prospects will vary (low-high) substantially with energy-in-storage levels and the April to July inflows of energy into storage as subjectively illustrated below:**

| Energy-in-Storage | Lower Quartile Inflows to Storage | Average Inflows to Storage | Upper Quartile Inflows to Storage |
|---|---|---|---|
| 4,000 GWh | Very Low (Imports >> Exports | Very Low (Imports >> Exports) | Low (Imports = Exports) |
| 6,000 GWh | Very Low (Imports >> Exports) | Low (Imports = Exports) | Low-Medium (Imports < Exports) |
| 8,000 GWh | Low (Imports > Exports) | Low (Imports = Exports) | Medium (Imports << Exports) |
| 10,000 GWh | Low-Medium (Imports < Exports) | Medium (Imports << Exports) | High (No Imports) |
| 12,000 GWh | Low (Imports = Exports) | High (No Imports) | High (No Imports) |

**ANSWER:**

The profitability of Manitoba Hydro's opportunity exports are a function of both volume and price. However, high volumes resulting from favourable water conditions do not lead to significantly increased export revenues as the incremental volumes are sold in low value off peak markets. Profitability is much more influenced by price as price changes affect both on peak and off peak markets proportionally.

**<u>PUB/MH/RISK-34</u>**

**Reference: PUB/MH I-82**
**Risk Issue: Export Profitability**

**c) Please confirm that MH's export-import profitability can also change significantly for the better or for the worse as a result of very high or very low summer precipitation.**

**<u>ANSWER</u>:**

Manitoba Hydro's net export revenues will increase/decrease with very high/very low summer precipitation. Profitability of export-import transactions is a function of market prices.

**PUB/MH/RISK-35**

**Risk Issue: Jenpeg Outage**

**a) Please confirm that currently, MH counts on hydraulic generation resources as follows:**

| | Dependable | Mean | Median | High Flow |
|---|---|---|---|---|
| Fully On-Line | 21,100 | 29,180 | 29,490 | 36,690 |
| Jenpeg G.S. | 680 | 960 | 1,020 | 940 |

**ANSWER:**

Manitoba Hydro confirms that the estimates of hydraulic generation summarized in the information request are derived from information that was provided in the response to PUB/MH I-85(c)(i-iv) as part of the 2008 General Rate Application process. The only exception is the system dependable energy which was listed as 19,750 GWh in the 2008 response. The current estimate is in the range of 21,100 GWh as listed in the current information request. This system dependable energy value is the maximum hydraulic energy production that can be achieved if the generating system output is maximized and energy in storage under Manitoba Hydro control is maximized prior to the low flow year.

**PUB/MH/RISK-35**

**Risk Issue: Jenpeg Outage**

**b) Please provide a status update on the Jenpeg G.S. and explain the potential outages for:**

- **Turbine repair scenarios.**
- **Turbine replacements scenarios.**

**ANSWER:**

Three of six Jenpeg units have been returned to service. The three remaining units are planned to be returned to service on the following schedule:

| Unit | Expected Return to Service Date |
|---|---|
| Generator 4 | 12/02/2010 |
| Generator 6 | 01/10/2011 |
| Generator 5 | 02/18/2011 |

Manitoba Hydro is not considering full turbine replacement of any unit at Jenpeg.

**PUB/MH/RISK-35**

**Risk Issue: Jenpeg Outage**

**c) Please indicate whether with a 1977 in-service date, Jenpeg G.S. turbine replacement was contemplated after 30 to 35 years.**

**ANSWER:**

According to Manitoba Hydro's depreciation studies, the expected service life of hydraulic turbines is 65 years.

**PUB/MH/RISK-35**

**Risk Issue: Jenpeg Outage**

**d) Please provide a tabulation of MH's hydraulic G.S. indicating the probable time frames for turbine replacement and/or major hydraulic retrofits.**

**ANSWER:**

Please see the table below for Manitoba Hydro's current plans for major overhaul of its hydraulic units. The scope or dates are not yet approved and the equipment will require an engineering assessment prior to confirming scope.

| Generating Station | Unit | Date | Recommended work |
|---|---|---|---|
| 00102 - Pointe du Bois | U10 | 2013 | Turbine Replacement |
| 00103 - Great Falls | U2 | 2021 | Major Overhaul (New Turbine, Stator Rewind) |
| 00103 - Great Falls | U4 | 2011 | Major Overhaul (New Turbine, Stator Rewind) |
| 00103 - Great Falls | U5 | 2016 | Major Overhaul (New Turbine) |
| 00103 - Great Falls | U6 | 2022 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | U1 | 2015 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | U2 | 2016 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | U3 | 2016 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | U4 | 2017 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | U5 | 2017 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | U6 | 2018 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | U7 | 2018 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | U8 | 2019 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | HU1 | 2019 | Major Overhaul (New Turbine, Stator Rewind) |
| 00104 - Slave Falls | HU2 | 2020 | Major Overhaul (New Turbine, Stator Rewind) |
| 00105 - Seven Sisters | U5 | 2011 | Stator Rewind |
| 00105 - Seven Sisters | U6 | 2020 | Major Overhaul Stator Rewind |
| 00107 - Pine Falls | U1 | 2013 | Major Overhaul (New Turbine, Stator Rewind) |
| 00107 - Pine Falls | U2 | 2012 | Major Overhaul (New Turbine, Stator Rewind) |
| 00107 - Pine Falls | U3 | 2014 | Major Overhaul (New Turbine, Stator Rewind) |
| 00107 - Pine Falls | U4 | 2014 | Major Overhaul (New Turbine, Stator Rewind) |
| 00111 - Kelsey | U4 | 2010 | Major Overhaul (New Turbine, Stator Rewind) |
| 00111 - Kelsey | U6 | 2011 | Major Overhaul (New Turbine, Stator Rewind) |
| 00111 - Kelsey | U7 | 2012 | Major Overhaul (New Turbine, Stator Rewind) |
| 00113 - Kettle | U1 | 2012 | Major Overhaul (Stator Rewind) |
| 00113 - Kettle | U2 | 2013 | Major Overhaul (Stator Rewind) |
| 00113 - Kettle | U3 | 2014 | Major Overhaul (Stator Rewind) |
| 00113 - Kettle | U4 | 2011 | Major Overhaul (Stator Rewind) |
| 00131 - Laurie River I | U1 | 2012 | Major Overhaul (Stator Rewind) |

**<u>PUB/MH/RISK-36</u>**

**Reference:** **RCM/TREE/MH I-3e (iii., SEP Price History**
**Risk Issue:** **Energy Price Variability**

**a)** **Please confirm that the inflation adjustment of SEP prices should realistically have been applied to U.S. $ prices rather than CDN $ prices to avoid transposing the higher exchange factors in effect prior to 2008 into the inflation adjusted prices.**

**<u>ANSWER</u>:**

The PCOSS uses SEP prices as proxies to reflect relative, not absolute values of energy across the 12 time periods. In this context, the purpose of using a longer, rather than a shorter, time series is to provide assurance that single year anomalies in the relative values are not given undue weight. It is possible that expressing the time series in Canadian dollars at the exchange rates applicable historically may lead to some distortion relative to the current absolute value of energy. But this is not the use to which the time series is being put.

**PUB/MH/RISK-36**

**Reference: RCM/TREE/MH I-3e (iii., SEP Price History**
**Risk Issue: Energy Price Variability**

**b) Please provide a monthly average tabulation of the U.S. $ values of SEP components and the natural gas prices (U.S. $/GJ) in effect from April 2000 to March 2010.**

**ANSWER:**

Please refer to previously submitted Surplus Energy Program reports. The report for November 1, 2007 through October 31, 2008 was provided as Appendix_13.2 Surplus Energy Program.

Historical natural gas prices for the Minnesota gate are provided in the table below.

HISTORIC NATURAL GAS PRICES
Source: Natural gas Citygate Price in Minnesota (Dollars per Thousand Cubic Feet) Source: U.S. Energy Information Administration (www.eia.gov)
Converted to $US/GJ (using conversion of 0.95 thousand cubic feet of natural gas at 1000 Btu/cf)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2000 | 2.83 | 3.06 | 3.45 | 3.16 | 3.46 | 4.96 | 5.36 | 4.67 | 5.39 | 5.65 | 5.38 | 6.98 |
| 2001 | 8.74 | 6.68 | 5.66 | 5.70 | 5.23 | 4.60 | 4.10 | 3.88 | 3.49 | 2.44 | 4.49 | 3.82 |
| 2002 | 3.25 | 3.47 | 3.43 | 3.36 | 3.64 | 3.92 | 3.78 | 3.61 | 3.76 | 3.88 | 4.66 | 4.83 |
| 2003 | 4.82 | 5.60 | 8.05 | 5.28 | 4.82 | 5.24 | 5.68 | 5.36 | 5.08 | 4.78 | 5.67 | 6.50 |
| 2004 | 5.38 | 6.36 | 6.19 | 5.82 | 5.89 | 6.54 | 6.39 | 6.24 | 6.19 | 5.69 | 8.08 | 8.29 |
| 2005 | 6.19 | 6.75 | 6.98 | 7.68 | 6.60 | 6.82 | 7.27 | 6.48 | 9.21 | 10.74 | 11.69 | 10.52 |
| 2006 | 10.03 | 9.07 | 7.51 | 6.71 | 7.66 | 6.24 | 6.55 | 7.25 | 6.92 | 5.39 | 8.18 | 8.05 |
| 2007 | 7.49 | 7.89 | 8.10 | 6.96 | 7.33 | 7.65 | 7.19 | 6.41 | 5.90 | 6.55 | 7.66 | 7.60 |
| 2008 | 7.69 | 8.15 | 8.92 | 8.84 | 9.60 | 10.78 | 11.52 | 8.90 | 7.22 | 5.39 | 6.80 | 6.94 |
| 2009 | 6.69 | 6.02 | 5.62 | 4.28 | 4.05 | 3.85 | 4.21 | 4.14 | 3.67 | 4.43 | 5.76 | 5.27 |
| 2010 | 5.96 | 5.84 | 5.70 | 4.27 | 4.44 | 4.84 | 5.21 | | | | | |

**PUB/MH/RISK-36**

**Reference:** **RCM/TREE/MH I-3e (iii., SEP Price History**
**Risk Issue:** **Energy Price Variability**

**c)** **Please confirm that prior to 2004/05, the predominant driver for SEP peak prices was SCCT natural gas generation and that post-2004/05 the pre-dominant driver for SEP peak prices was CCCT natural gas generation.**

**ANSWER:**

Manitoba Hydro cannot provide confirmation to the question asked as it does not collect the data associated with the marginal supply source for peak prices.

**<u>PUB/MH/RISK-36</u>**

**Reference: RCM/TREE/MH I-3e (iii., SEP Price History**
**Risk Issue: Energy Price Variability**

**d) Please confirm that prior to 2008/09, the predominant driver of SEP off-peak prices was coal generation.**

**<u>ANSWER</u>:**

Manitoba Hydro cannot provide confirmation to the question asked as it does not collect the data associated with the marginal supply source for peak prices.

**<u>PUB/MH/RISK-37</u>**

**Reference: NSP/Xcel Contracts – Publicly Available Redacted Version**
**Risk Issue: New Base Contract Implications**

**a) Please confirm that the NSP/Xcel 375/325 MW contract (2015-2025) will provide MH with assured sales and revenues as follows:**

| Summer | Winter |
|---|---|
| **375 MW (7x16)<br>1,080 GWH/year<br>Escalating fixed price / kW.h** | **325 MW (7x12)<br>700 GWh/year @<br>Escalating fixed price / kW.h** |

**<u>ANSWER</u>:**

Manitoba Hydro does not confirm the sale volumes identified above. The fixed price energy under the NSP/Xcel 375/325MW contract is a 375MW 5x16 product in the summer season and a 325MW 5x12 product in the winter season. The volume of fixed priced energy is approximately 790 GWh per year in the summer season and approximately 580 GWh per year in the winter season.

MH confirms that the fixed price energy is an escalating price per MWh.

**PUB/MH/RISK-37**

**Reference: NSP/Xcel Contracts – Publicly Available Redacted Version**
**Risk Issue: New Base Contract Implications**

**b) Please confirm that these prices for this energy reflect both capacity and energy payments within the contract.**

**ANSWER:**

The contract contains prices for the capacity and energy components of the power being sold to NSP.

**PUB/MH/RISK-37**

**Reference: NSP/Xcel Contracts – Publicly Available Redacted Version**
**Risk Issue: New Base Contract Implications**

**c) Please confirm the these prices also include transmission costs incurred by both MH and NSP/Xcel.**

**ANSWER:**

The prices do not include transmission costs. Each party is responsible for transmission costs incurred on their respective sides of the Canada/United States border.

**<u>PUB/MH/RISK-37</u>**

**Reference: NSP/Xcel Contracts – Publicly Available Redacted Version**
**Risk Issue: New Base Contract Implications**

**d) Please confirm that the capacity charge within the contract covers all time periods during the day and that NSP/Xcel is entitled to draw energy at any time (off-peak as well as peak) during the day providing the daily additional uptake is limited to four consecutive hours.**

**<u>ANSWER</u>:**

Manitoba Hydro confirms that the capacity being sold covers all time periods during the day and that the capacity charge is based upon it being continuously supplied.

Hours of delivery are specified in the contract (5x16 during the summer, 5x12 during the winter).

**PUB/MH/RISK-37**

**Reference: NSP/Xcel Contracts – Publicly Available Redacted Version**
**Risk Issue: New Base Contract Implications**

**e) Please confirm that when there is peak or off-peak energy surplus to domestic load and the "Must Supply" NSP/Xcel obligations, MH may:**

- **Offer this into the MISO market day-ahead market employing and paying for firm transmission rights (largely controlled by NSP/Xcel).**
- **Obligate NSP/Xcel to accept this energy at a discounted day-ahead MISO price.**
- **Price this energy above the day-ahead market price and as a result, not sell this energy.**

**ANSWER:**

Manitoba Hydro confirms that Must Offer energy in the NSP contract is offered into the MISO day-ahead market however NSP is responsible for paying any firm transmission rights on the US side of the delivery point.

Manitoba Hydro confirms that NSP is obligated to accept any energy offered by Manitoba Hydro and accepted into the MISO market. Manitoba Hydro cannot confirm the price of the energy as this is considered trade secret and confidential.

Manitoba Hydro confirms that the price of offered energy is at MH's discretion and that the energy may not be accepted by the market if it is above the day-ahead clearing price.

**<u>PUB/MH/RISK-38</u>**

**Reference: NSP/Xcel Contracts - Publicly Available Redacted Version**
**Risk Issue: New Diversity Contract Implications**

a) **Please confirm that MH is obligated in each year to supply 350 MW of capacity (no charge) and 1,020 GWh/year of 7x16 energy to NSP/Xcel during the 6 summer months (at MISO day-ahead market prices).**

**<u>ANSWER</u>:**

Manitoba Hydro confirms that it is obligated to provide 350MW of capacity for each summer season during the contract term. Manitoba Hydro cannot confirm the price for the capacity as this is trade secret and confidential.

During the summer season, Manitoba Hydro has a daily obligation to offer energy into the MISO market for the four consecutive hours in which the MISO load is expected to peak. The must offer obligation amounts to approximately 260 GWh per summer season.

**PUB/MH/RISK-38**

**Reference: NSP/Xcel Contracts - Publicly Available Redacted Version**
**Risk Issue: New Diversity Contract Implications**

**b) Please confirm that NSP/Xcel is obligated to accept the above 7x16 energy and also 7x8 off-peak energy (at a discount off MISO day-ahead market prices) if MH chooses to offer this energy (510 GWh/year) into the MISO market.**

**ANSWER:**

Manitoba Hydro confirms that NSP is obligated to accept any energy that is offered by Manitoba Hydro and accepted into the MISO market. Manitoba Hydro cannot confirm the price for this energy as it is trade secret and confidential.

**PUB/MH/RISK-38**

**Reference:** **NSP/Xcel Contracts - Publicly Available Redacted Version**
**Risk Issue:** **New Diversity Contract Implications**

**c)** **Please confirm (explain) that MH is precluded from marketing the 350 MW of capacity during the summer off-peak hours.**

**ANSWER:**

Manitoba Hydro is obligated to reserve the 350MW of capacity for NSP during all hours of the summer season. However, Manitoba Hydro may use the capacity to supply energy to others when not required to provide service under the Diversity contract.

**<u>PUB/MH/RISK-38</u>**

**Reference: NSP/Xcel Contracts - Publicly Available Redacted Version**
**Risk Issue: New Diversity Contract Implications**

**d) Please confirm (explain) that MH may not require the winter diversity energy in about one year in three.**

**<u>ANSWER</u>:**

It can be confirmed that Manitoba Hydro may not utilize the import of diversity energy in about 33% of the flow conditions due to sufficient availability of hydraulic energy.

Manitoba Hydro may call on diversity energy in order to optimize operations and maximize revenue. Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations. As a result, Manitoba Hydro generally imports energy under all but the highest flow conditions for economic purposes. Please refer to the response to PUB/MH/RISK-13(a) for an indication of the relative frequency for utilization of thermal and import energy that is derived from the analysis of 94 possible flow conditions. It is observed in the graphs in the response to PUB/MH/RISK-13(a) that there is little to no utilization of import energy in the highest 33% of flow conditions. The import energy utilized in the remaining 67% of flow conditions may be imported under the diversity contract or sourced directly from the MISO market.

The seasonal diversity contract is a capacity swap with Manitoba Hydro receiving capacity in the winter season in exchange for providing capacity in the summer season. As noted above, Manitoba Hydro will make use of the energy available under the seasonal diversity contract in the context of operating the integrated system.

**<u>PUB/MH/RISK-39</u>**

**Reference: NSP/Xcel Contracts - Publicly Available Redacted Version**
**Risk Issue: Clean Energy Stipulations**

a) **Please confirm that MH is obligated to provide NSP/Xcel with clean energy (Primarily from hydraulic and wind resources).**

**<u>ANSWER</u>:**

Manitoba Hydro is obligated in the NSP contracts to allocate and transfer environmental attributes for energy that is supplied by Manitoba Hydro to NSP. The facilities from which the environmental attributes will be allocated and transferred to NSP is trade secret and confidential.

**PUB/MH/RISK-39**

**Reference: NSP/Xcel Contracts - Publicly Available Redacted Version**
**Risk Issue: Clean Energy Stipulations**

**b) Please confirm that prior to 2021, the clean energy supply would be:**

- **3,500 GWh (minimum year).**
- **6,000 GWh (maximum year.**

**ANSWER:**

Manitoba Hydro cannot confirm the quantity of environmental attributes to be transferred to NSP as this information is trade secret and confidential.

**<u>PUB/MH/RISK-39</u>**

**Reference: NSP/Xcel Contracts - Publicly Available Redacted Version**
**Risk Issue: Clean Energy Stipulations**

**c) Please confirm that in about one year in three, MH would be buying in excess of 3,500 GWh of market energy (coal and natural gas generated) to meet domestic load and NSP/Xcel contract obligations.**

**<u>ANSWER</u>:**

Manitoba Hydro does not confirm the statement in this information request. Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations.

Please refer to the response to PUB/MH/RISK-13(a) which presents graphs that show the relative frequencies of the various generation sources over the range of flow conditions in three different years into the future. As may be observed from the graphs, the frequency of relying on Manitoba Hydro thermal or imports would be significantly less than one year in three.

## PUB/MH/RISK-40

**Reference:** NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s
**Risk Issue:** Energy Supply-Demand Balance

**a) Please confirm that with the new NSP/Xcel contracts in place, MH would be looking at a 2016/17 energy balance (order of magnitude) as follows:**

| | Historical Minimum (GWh) | Lower Decile (GWh) | Lower Quartile (GWh) | Median (GWh) | Upper Quartile (GWh) | Practical Maximum (GWh) |
|---|---|---|---|---|---|---|
| **Year 2016/17** | | | | | | |
| Hydraulic Generation | 18,500 | 20,000 | 25,000 | 29,500 | 34,000 | 36,500 |
| + Wuskwatim G.S. | 1,300 | 1,300 | 1,400 | 1,500 | 1,500 | 1,500 |
| + Kelsey Improvement | -- | 200 | 500 | 800 | 800 | 800 |
| Total Hydraulic Gen. | 19,800 | 21,500 | 26,900 | 31,800 | 36,300 | 38,800 |
| Domestic Load | 27,500 | 27,500 | 27,500 | 27,500 | 27,500 | 27,500 |
| NSP - Firm | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 |
| NSP - Optional | -- | -- | -- | 1,500 | 3,000 | 3,000 |
| MP | -- | -- | -- | -- | -- | -- |
| WPS | -- | -- | -- | -- | -- | -- |
| Other MISO Opportunity | -- | -- | -- | --(2) | 3,000(2) | 5,500(2) |
| Total Load (including losses) | 31,000 | 31,000 | 31,000 | 32,500 | 37,000 | 39,500 |
| Required F&PP | (11,200) | (9,500) | (4,100) | (700) | (700) | (700) |
| Wind | 700 | 700 | 700 | 700 | 700 | 700 |
| Fossil Fuel Purchase(1) | (10,500) | (8,800) | (3,400) | Ø | Ø | Ø |

**Notes:**

**(1) Fossil fuel purchase includes MH's diversity exchange purchases and DSM resources**

**(2) DSM resources could potentially increase MH's opportunity exports in average or above years.**

**<u>ANSWER</u>:**

Manitoba Hydro does not agree that the table presents an accurate energy supply and demand balance for 2016/17. The following are areas of concern that have been addressed in the revised tables in the response to PUB/MH/RISK-40(b):

- The energy quantity for the NSP sale is too high. Please refer to the response to PUB/MH/RISK-67(c) for the appropriate quantity.

- With reference to Note (2), the DSM load reduction would reduce the dependency on fuel purchases during the low flows and increase the opportunity exports during high flows.

- The "Historical Minimum" energy is not an appropriate quantity to include in this energy balance overview as a lower bound. The historic energy generation is not representative of the dependable energy because the system was not stressed in the same way it would be in a dependable energy determination. Greater use of storage would increase the hydraulic generation compared to the historic experience. The estimates of dependable energy should be used to denote the lower bound for energy supply instead of "Historical Minimum".

- The line items denoting optional energy (such as, 'NSP Optional' and 'Other MISO Opportunity') appear to imply a dispatch order in the use of surplus energy. This ordering would not occur in practice and it is inappropriate to differentiate this energy in the table. All export sales should be combined into a single export quantity.

**PUB/MH/RISK-40**

**Reference: NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue: Energy Supply-Demand Balance**

**b) Please explain any differences or revisions that MH would see as appropriate.**

**ANSWER:**

Please refer to the response provided to PUB/MH/RISK-40(a) which outlines Manitoba Hydro's areas of concern with the tables of the type provided in this information request.

Please refer to the graphs provided in PUB/MH/RISK-13(a) which depict the annual energy supply corresponding to a repeat of 94 historical flows for Manitoba Hydro's system compared to Manitoba domestic load and dependable long-term contracts obligations for the fiscal years 2015/16, 2020/21, and 2025/26. The following tables represent energy demand and resources based on the flow conditions depicted. The tables are in a format that is generally consistent with supply/demand tables in Manitoba Hydro's power resource plan.

**System Energy Demand and Resouces**
**2015/16 Load Year**

| | Dependable GW.h | Lower Decile GW.h | Quartile GW.h | Median GW.h | Upper Quartile GW.h | Maximum GW.h |
|---|---|---|---|---|---|---|
| **Resources:** | | | | | | |
| Hydro* | 22,100 | 24,000 | 27,600 | 31,400 | 34,400 | 38,400 |
| Wind | 1,300 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 |
| DSM | 800 | 800 | 800 | 800 | 800 | 800 |
| Thermal & Imports | 6,400 | 4,900 | 3,300 | 1,200 | 200 | 100 |
| **Total Resources** | **30,600** | **31,200** | **33,200** | **34,900** | **36,900** | **40,800** |
| **Demand:** | | | | | | |
| Manitoba Load | 27,200 | 27,200 | 27,200 | 27,200 | 27,200 | 27,200 |
| Long Term Contracts | 1,500 | 1,500 | 1,900 | 1,900 | 1,900 | 1,900 |
| **Total Demand** | **28,700** | **28,700** | **29,100** | **29,100** | **29,100** | **29,100** |
| Oppportunity Sales | | 500 | 4,100 | 5,800 | 7,800 | 11,700 |
| **Surplus Energy** | **1,900** | **2,000** | **-** | **-** | **-** | **-** |

* Includes Wuskwatim

**System Energy Demand and Resouces**
**2020/21 Load Year**

| | Dependable GW.h | Lower Decile GW.h | Quartile GW.h | Median GW.h | Upper Quartile GW.h | Maximum GW.h |
|---|---|---|---|---|---|---|
| **Resources:** | | | | | | |
| Hydro* | 25,400 | 31,000 | 35,900 | 38,700 | 41,300 | 43,400 |
| Wind | 1,300 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 |
| DSM | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| Thermal & Imports | 7,100 | 4,300 | 1,600 | 1,100 | 300 | 300 |
| **Total Resources** | **34,800** | **37,800** | **40,000** | **42,300** | **44,100** | **46,200** |
| **Demand:** | | | | | | |
| Manitoba Load | 28,900 | 28,900 | 28,900 | 28,900 | 28,900 | 28,900 |
| Long Term Contracts | 3,800 | 5,200 | 5,200 | 5,200 | 5,200 | 5,200 |
| **Total Demand** | **32,700** | **34,100** | **34,100** | **34,100** | **34,100** | **34,100** |
| Oppportunity Sales | | 3,000 | 5,900 | 8,200 | 10,000 | 12,100 |
| **Surplus Energy** | **2,100** | **700** | **-** | **-** | **-** | **-** |

* Include Wuskwatim, Keeyask & new interconnection

**System Energy Demand and Resouces**
**2025/26 Load Year**

| | Dependable GW.h | Lower Decile GW.h | Quartile GW.h | Median GW.h | Upper Quartile GW.h | Maximum GW.h |
|---|---|---|---|---|---|---|
| **Resources:** | | | | | | |
| Hydro* | 29,600 | 33,100 | 37,900 | 43,300 | 46,700 | 49,200 |
| Wind | 1,300 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 |
| DSM | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 |
| Thermal & Imports | 7,300 | 6,600 | 3,300 | 1,100 | 400 | 300 |
| **Total Resources** | **39,300** | **42,300** | **43,800** | **47,000** | **49,700** | **52,100** |
| **Demand:** | | | | | | |
| Manitoba Load | 30,700 | 30,700 | 30,700 | 30,700 | 30,700 | 30,700 |
| Long Term Contracts | 3,600 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 |
| **Total Demand** | **34,300** | **35,700** | **35,700** | **35,700** | **35,700** | **35,700** |
| Oppportunity Sales | | 6,600 | 8,100 | 11,300 | 14,000 | 16,400 |
| **Surplus Energy** | **5,000** | **-** | **-** | **-** | **-** | **-** |

* Includes Wuskwatim, Keeyask, new interconnection & Conawapa

Notes:

1. Thermal and import resources are shown as one quantity, since either resource can be dispatched based on economics and regulations in place at the time of dispatch. Imports associated with opportunity sales are included.
2. Opportunity sales are based on system flow conditions and the amount of imports purchased for export opportunities.
3. The resources depicted under dependable flow conditions represent the total available to Manitoba Hydro under this flow condition. Firm demand under the dependable flow condition is less than the total available supply.

4. Surplus energy is defined as energy that would not be dispatched during the lowest 10% of flow years due to the unavailability of economic opportunities to export energy because the marginal generation resource in Manitoba has a higher cost relative to market price.
5. Manitoba Hydro has an obligation to purchase wind energy in all flow conditions. The dependable wind energy is assumed to occur in a year that is coincident with the dependable flow condition. Dependable wind generation is assumed to be about 85% of the expected long-term quantity.
6. The energy requirement for long-term contracts is lower in dependable and lower decile flows due to the ability to curtail a portion of energy contract obligations if Manitoba Hydro declares that it is in adverse water conditions.
7. DSM is not a dispatchable resource and a constant quantity is available in all flow conditions.

## PUB/MH/RISK-40

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue:** **Energy Supply-Demand Balance**

**c) Please confirm that in at least 1 year in 4, MH could be faced with fossil fuel imports (or own thermal generation) for the entire energy supply to NSP/Xcel.**

**ANSWER:**

Manitoba Hydro does not agree with the statement made in this information request. Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations. Therefore, it is not appropriate to allocate a specific generation source to a specific requirement such as a particular export sale.

Please refer to the responses to PUB/MH/RISK-13 and PUB/MH/RISK-40(b) for information on the distribution of the various energy quantities over the range of flow conditions.

**PUB/MH/RISK-40**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue:** **Energy Supply-Demand Balance**

**d) Please confirm that in 1 year in 4, MH would be importing either coal or natural gas generated energy which could attract CO2 emissions "penalty" pricing in order to supply clean energy to NSP/Xcel.**

**ANSWER:**

Manitoba Hydro does not agree with the statement made in this information request. Manitoba Hydro's dependable energy from all resources is available to serve its firm obligations which include domestic load and firm export sales. Therefore, it is not appropriate to allocate a specific generation source to a specific requirement such as a particular export sale.

Please refer to the responses to PUB/MH/RISK-13 and PUB/MH/RISK-40(b) for information on the distribution of the various energy quantities over the range of flow conditions.

Manitoba Hydro's long-term electricity export price forecast already incorporates considerations for emissions premiums and hence Manitoba Hydro's view of CO2 emissions pricing is already considered in the evaluation regardless of whether Manitoba Hydro is exporting to or importing from the MISO market.

**PUB/MH/RISK-41**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**
**Risk Issue:** **Energy Supply-Demand Balance**

**a)** **Please confirm that in the absence of new G&T and with the new NSP/Xcel contracts (375/325 MW and 350 diversity) in place, MH would be looking at a 2021/22 energy balance (order of magnitude) as follows:**

| | Historical Minimum (GWh) | Lower Decile (GWh) | Lower Quartile (GWh) | Median (GWh) | Upper Quartile (GWh) | Practical Maximum (GWh) |
|---|---|---|---|---|---|---|
| Year 2021/22 (No New G&T) Hydraulic Generation (including Wuskwatim G.S. and Kelsey Improvement) | 19,800 | 21,500 | 26,900 | 31,800 | 36,800 | 38,800 |
| Total Hydraulic Gen. | 19,800 | 21,500 | 26,900 | 31,800 | 36,300 | 38,800 |
| Domestic Load, including Losses | 29,200 | 29,200 | 29,200 | 29,200 | 29,200 | 29,200 |
| NSP - Firm | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 |
| NSP - Optional | -- | -- | -- | -- | 3,000 | 3,000 |
| MP - Firm | N/A | N/A | N/A | N/A | N/A | N/A |
| WPS - Firm | N/A | N/A | N/A | N/A | N/A | N/A |
| Other MISO | -- | -- | -- | --(2) | 1,800(2) | 3,800(2) |
| Total Load | 32,700 | 32,700 | 32,700 | 32,700 | 37,500 | 39,500 |
| Required F&PP | (12,900) | (11,200) | (5,800) | (900) | (700) | (700) |
| Wind | 700 | 700 | 700 | 700 | 700 | 700 |
| Fossil Fuel Purchase(1) | (12,200) | (10,500) | (5,100) | (200) | Ø | Ø |

**Notes:**

**(1)** **Fossil fuel purchase includes MH's diversity exchange purchases and DSM resources.**

**(2)** **DSM resources could potentially increase MH's opportunity exports in average or above years.**

**ANSWER:**

There are an unlimited number of development plans that could be analyzed in terms of energy supply-demand balances. In the 2009/10 power resource plan, which was provided in response to CAC/MSOS/MH I-35(a), Manitoba Hydro has provided the supply/demand tables for the recommended development plan and the alternative development plan under dependable conditions. In addition, the responses to PUB/MH/RISK-13 and PUB/MH/RISK-40(b) provide additional information related to the recommended development plan for a range of flow conditions. The information provided in the aforementioned responses allows for analysis and for observations to be made on the energy supply-demand balance on Manitoba Hydro's recommended and alternative development plans. It is important to note that Manitoba Hydro's recommended development plan along with alternatives will be subject to a full examination when the "need for and alternatives to" process is initiated.

Please refer to the response provided to PUB/MH/RISK-40(a) which outlines the Manitoba Hydro's areas of concern with the type of table provided in this information request.

**PUB/MH/RISK-41**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**
**Risk Issue:** **Energy Supply-Demand Balance**

**b)** **Please explain any differences or revisions to the "Must Supply" obligations that MH would see as appropriate.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-41(a).

**<u>PUB/MH/RISK-41</u>**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue:** **Energy Supply-Demand Balance**

**c)** **Please confirm that in the absence of new G&T, the magnitude and frequency of substantial fossil fuel imports (or own thermal generation) would increase going from October to 2026; to almost one year in two frequency.**

**<u>ANSWER</u>:**

Please see Manitoba Hydro's response to PUB/MH/RISK-41(a).

**PUB/MH/RISK-42**

**Reference:** NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s

**Risk Issue:** Energy Supply–Demand Balance

**a)** **Please confirm that after Keeyask G.S. and Bipole III come on-line (circa 2018/19), the NSP/Xcel contract commitments will be increased from 375/325 MW to 500/450 MW in 2021 and that MH would be looking at a 2021/22 energy balance (order of magnitude) as follows:**

| | Historical Minimum (GWh) | Lower Decile (GWh) | Lower Quartile (GWh) | Median (GWh) | Upper Quartile (GWh) | Practical Maximum (GWh) |
|---|---|---|---|---|---|---|
| Year 2021/22 (New G&T, 125 MW NSP) | | | | | | |
| Hydraulic Generation | 19,800 | 21,500 | 26,900 | 31,800 | 36,800 | 38,800 |
| (including Keeyask/Bipole III/ Wuskwatim/Kelsey) | 3,100 | 3,600 | 4,100 | 4,600 | 4,800 | 5,000 |
| Total Hydraulic Gen. | 22,900 | 25,100 | 31,000 | 36,400 | 41,600 | 43,800 |
| Domestic Load, including Losses | 29,200 | 29,200 | 29,200 | 29,200 | 29,200 | 29,200 |
| NSP - Firm | 4,200 | 4,200 | 4,200 | 4,200 | 4,200 | 4,200 |
| NSP - Optional | | | | 3,700 | 4,000 | 4,000 |
| MP - Firm | | | | | | |
| WPS - Firm | | | | | | |
| Other MISO | | | | --(2) | 4,900(2) | 7,100(2) |
| Total Load | 33,400 | 33,400 | 33,400 | 37,100 | 42,300 | 44,500 |
| Required F&PP | (10,500) | (8,300) | (2,400) | (700) | (700) | (700) |
| Wind | 700 | 700 | 700 | 700 | 700 | 700 |
| Fossil Fuel Purchase(1) | (9,800) | (7,600) | (1,700) | Ø | Ø | Ø |

**Notes:**

**(1)** **Fossil fuel purchase includes MH's diversity exchange purchases and DSM resources.**

**(2)** **DSM resources could potentially increase MH's opportunity exports in average or above years.**

**ANSWER:**

Please see Manitoba Hydro's responses to PUB/MH/RISK-40(a) and PUB/MH/RISK-41(a).

**<u>PUB/MH/RISK-42</u>**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue:** **Energy Supply–Demand Balance**

**b)** **Please explain any differences or revisions to the must supply obligations that MH would see as appropriate.**

**<u>ANSWER</u>:**

Please refer to the response provided to PUB/MH/RISK-40(a) which outlines Manitoba Hydro's areas of concern with the tables of the type provided in this information request.

**PUB/MH/RISK-42**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue:** **Energy Supply–Demand Balance**

**c) Please confirm that transmission inter-tie constraints could result in substantial off-peak export sales in above average flow years.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-41(a).

It should be noted that no new additional transmission capacity is required to provide service to NSP under the new NSP System and Diversity Sale Agreements.

**PUB/MH/RISK-43**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue:** **Energy Supply–Demand Balance**

**a)** **Please confirm that with Keeyask G.S. and Bipole III on-line and export agreements in place (NSP/Xcel 500/450 MW, WPS 500 MW, and MP 250 MW), MH would be looking at a 2021/22 energy balance (order of magnitude basis) as follows:**

| | Historical Minimum (GWh) | Lower Decile (GWh) | Lower Quartile (GWh) | Median (GWh) | Upper Quartile (GWh) | Practical Maximum (GWh) |
|---|---|---|---|---|---|---|
| Year 2021/22<br>New G&T 125 NSP/ 500 WPS/250 MP | | | | | | |
| Hydraulic Generation | 19,800 | 21,500 | 26,900 | 31,800 | 36,800 | 38,800 |
| + Wuskwatim/Kelsey/ Keeyask/Bipole III | 3,100 | 3,600 | 4,100 | 4,600 | 4,800 | 5,000 |
| Total Hydraulic Gen. | 22,900 | 25,100 | 31,000 | 36,400 | 41,600 | 43,800 |
| Domestic Load, including Losses | 29,200 | 29,200 | 29,200 | 29,200 | 29,200 | 29,200 |
| NSP - Firm | 4,200 | 4,200 | 4,200 | 4,200 | 4,200 | 4,200 |
| NSP - Optional | -- | -- | -- | -- | 4,000 | 4,000 |
| MP - Firm | 1,100 | 1,100 | 1,300 | 1,300 | 1,300 | 1,300 |
| WPS - Firm | 2,300 | 2,300 | 2,700 | 2,700 | 2,700 | 2,700 |
| Other MISO Opportunity | -- | -- | -- | --(2) | 900(2) | 3,100(2) |
| Total Load | 36,800 | 36,800 | 37,400 | 37,400 | 42,300 | 44,500 |
| Required F&PP | (13,900) | (11,700) | (6,400) | (1,000) | (700) | (700) |
| Wind | 700 | 700 | 700 | 700 | 700 | 700 |
| Fossil Fuel Purchase(1) | (13,200) | (11,000) | (5,700) | (300) | Ø | Ø |

**Notes:**

**(1)** **Fossil fuel purchase includes MH's diversity exchange purchases and DSM resources.**

**(2) DSM resources could potentially increase MH's opportunity exports in average or above years.**

**<u>ANSWER</u>:**

Please see Manitoba Hydro's responses to PUB/MH/RISK-40(a) and PUB/MH/RISK-41(a).

**PUB/MH/RISK-43**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue:** **Energy Supply–Demand Balance**

**b) Please explain any differences or revisions that MH would see as appropriate.**

**ANSWER:**

Please refer to the response provided to PUB/MH/RISK-40(a) which outlines Manitoba Hydro's areas of concern with the tables of the type provided in this information request.

**PUB/MH/RISK-43**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**
**Risk Issue:** **Energy Supply–Demand Balance**

**c)** **Please identify the additional transmission inter-tie capacities that will have to be in place to achieve the must serve components of these contract sales in summer periods and in winter periods going to 2026 (assuming Conawapa G.S. is deferred).**

**ANSWER:**

No new additional transmission capacity is required to provide service to NSP under the new NSP System and Diversity Sale Agreements.

**PUB/MH/RISK-44**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue:** **Energy Supply–Demand Balance**

a) **Please confirm that with Keeyask G.S./Bipole III/Conawapa G.S. in-service and export agreements in place (500/450 MW - NSP/Xcel, 500 MW - WPS and 250 MW-MP), MH would be looking at a 2025/26 energy balance (order of magnitude) as follows**

| | Historical Minimum (GWh) | Lower Decile (GWh) | Lower Quartile (GWh) | Median (GWh) | Upper Quartile (GWh) | Practical Maximum (GWh) |
|---|---|---|---|---|---|---|
| **Year 2025/26** | | | | | | |
| **Hydraulic Generation,** | **19,800** | **21,500** | **26,900** | **31,800** | **36,800** | **38,800** |
| **including Wuskwatim + Kelsey** | **3,100** | **3,600** | **4,100** | **4,600** | **4,800** | **5,000** |
| **Keeyask/Conawapa + Bipole III** | **4,500** | **5,000** | **6,000** | **7,000** | **8,500** | **9,800** |
| **Total Hydraulic Gen.** | **27,400** | **30,100** | **37,000** | **43,400** | **50,100** | **53,600** |
| **Domestic Load, including Losses** | **30,700** | **30,700** | **30,700** | **30,700** | **30,700** | **30,700** |
| **NSP - Firm** | **4,200** | **4,200** | **4,200** | **4,200** | **4,200** | **4,200** |
| **NSP - Optional** | | | | **4,000** | **4,000** | **4,000** |
| **MP - Firm** | **1,100** | **1,100** | **1,300** | **1,300** | **1,300** | **1,300** |
| **WPS - Firm** | **2,300** | **2,300** | **2,700** | **2,700** | **2,700** | **2,700** |
| **Other MISO Opportunity** | | | | **1,200(2)** | **7,900(2)** | **11,400(2)** |
| **Total Load** | **38,300** | **38,300** | **38,900** | **44,100** | **50,800** | **54,300** |
| **Required F&PP** | **(10,900)** | **(8,200)** | **(1,900)** | **(700)** | **(700)** | **(700)** |
| **Wind** | **700** | **700** | **700** | **700** | **700** | **700** |
| **Fossil Fuel Purchase(1)** | **(10,200)** | **(7,500)** | **(1,200)** | **Ø** | **Ø** | **Ø** |

**Notes:**

**(1)** **Fossil fuel purchase includes MH's diversity exchange purchases and DSM resources.**

**(2) DSM resources could potentially increase MH's opportunity exports in average or above years.**

**<u>ANSWER</u>:**

Please see Manitoba Hydro's responses to PUB/MH/RISK-40(a) and PUB/MH/RISK-41(a).

**PUB/MH/RISK-44**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**
**Risk Issue:** **Energy Supply–Demand Balance**

**b)** **Please confirm that MH's "Must Supply" obligations in 2025/26 could require as much as 10,000 GWh of imports or thermal generation under drought conditions.**

**ANSWER:**

Manitoba Hydro cannot confirm the requirement for 10,000 GW.h of imports or thermal generation under drought conditions. Please refer to the 2009/10 Power Resource plan System Firm Energy and Dependable Resources Table (GW.h) provided as Appendix 47 in response to CAC/MSOS/MH I-35(a). The amount of imports and thermal resources required in 2025/26 to meet total demand under dependable flow conditions is about 2,000 GW.h. The estimate corresponding to minimum flows as provided in the table of information request PUB/MH/RISK-44(a) is too high for various reasons as explained in that response.

**PUB/MH/RISK-44**

**Reference:** **NSP/Xcel Contracts (Redacted); Various Power Resource Plans and Energy Supply I.R.'s**

**Risk Issue:** **Energy Supply–Demand Balance**

**c) Please confirm that in lower quartile flow years, MH's "must supply" export obligations would involve a comparable amount of fossil fuel imports (likely coal based) with CO2 emissions being assigned to domestic customers.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-41(a).

Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations. Therefore, it is not appropriate to allocate a specific generation source to a specific requirement such as export sales.

**PUB/MH/RISK-45**

**Reference: Appendix 56 - Attachment #6 Various Power Resource Plans**
**Risk Issue: Market Price Constraints**

**a) Please confirm that with natural gas prices currently under $5/GJ, Combined Cycle Combustion Turbine (CCCT) generation can be displacing coal as a base load supply and also depressing prices during peak and shoulder periods.**

**ANSWER:**

Manitoba Hydro does not confirm the statements made in this information request. Low gas prices can cause natural gas to displace coal generation, but this would occur first in areas of the eastern U.S. which use Central Appalachia coal rather than the much less expensive Powder River Basin coal used in the western part of the MISO market region.

**<u>PUB/MH/RISK-45</u>**

**Reference: Appendix 56 - Attachment #6 Various Power Resource Plans**
**Risk Issue: Market Price Constraints**

**b) Please explain why MH has been and still could be considering CCCT natural gas generation as an interim supply option.**

**<u>ANSWER</u>:**

As part of its resource planning process, Manitoba Hydro considers a range of supply options for serving its firm obligations, including CCCT natural gas generation. Should the potential in-service date for hydro options be delayed for any reason, or should there be a need for new resources due to rapid load growth in Manitoba, some form of natural gas fired generation (CT or CCCT) would be considered as a supply option.

**PUB/MH/RISK-45**

**Reference: Appendix 56 - Attachment #6 Various Power Resource Plans**
**Risk Issue: Market Price Constraints**

**c) Please confirm that a new 400 MW CCCT could supply dependable energy at:**

- **5.5¢/KWh (variable operating costs with $8/GJ natural gas).**
- **1.5¢/KWh (fixed costs).**

**ANSWER:**

Manitoba Hydro can not confirm the costs per kWh in the information request. These values will vary significantly based on the assumptions used. Manitoba Hydro estimates that the variable plus fixed cost for a CCCT is in the order of 8 - 9¢/kW.h assuming a mid-range capacity factor, natural gas priced at $8/GJ and no allowance for carbon costs.

**PUB/MH/RISK-46**

**Reference: SEP/NEB Prices Power Resource Plan**
**Risk Issue: Market Price Constraints**

a) **Please confirm that in the next five to ten years, the MISO day-ahead market price will typically reflect:**

- **CCCT generation costs (fixed and variable) for 5x16 and 2x16 energy.**
- **CCCT or coal generation costs (variable only) for off-peak (night time) sales.**

**ANSWER:**

Manitoba Hydro does not confirm the statements made in the information request. The Components of Electricity Market Prices slide of the Manitoba Hydro Market Considerations for Planning presentation (Attachment 6 of Appendix 56 of the 2010 GRA Application) explains that the Variable Production Cost is the "Cost of producing the energy and is the market clearing price in a power market [emphasis added]. In a thermal system, this is largely fuel (gas or coal) cost, and in the future will include the cost of carbon."

Therefore, MISO day-ahead market price does not include any value for fixed or capacity costs. The fixed or capacity costs are currently recovered through bilateral contracts such as Manitoba Hydro's long-term export contracts which include capacity revenue.

The marginal generator which sets the market clearing price varies continually as the weather, load, time of day, seasons, generation outages, transmission outages and fuel costs change. For on-peak hours, the marginal generator is likely to be coal, gas CCCT and gas CT during the highest load hours. During off-peak hours, the marginal generator is likely to be coal, with a small, but increasing amount of CCCT over the longer term.

**<u>PUB/MH/RISK-46</u>**

**Reference: SEP/NEB Prices Power Resource Plan**
**Risk Issue: Market Price Constraints**

**b) Please confirm that for natural gas prices under $8/GJ, MISO day-ahead market prices are unlikely to exceed:**

- **6.5¢/KWh in peak (7x16) period.**
- **4.5¢/KWh in off-peak.**

**<u>ANSWER</u>:**

Manitoba Hydro can not confirm that MISO day-ahead market prices are unlikely to exceed those listed in this information request. With gas at $8 GJ ($7.58/ MMBTU), the variable production cost of energy from an efficient CCCT is on the order of 6.5¢/KWh, before carbon costs are considered. During higher load periods, less efficient CCCT units and CTs will be the marginal generation units, and day-ahead market will be higher than 6.5¢/KWh. In addition, there are fixed or capacity costs to be recovered through bilateral markets outside of the MISO day-ahead market.

During off-peak hours, the marginal generator is likely to be coal, with a small, but increasing amount of CCCT over the longer term. In the event that combined cycle generation is the marginal generator during the higher load hours of the off-peak period, the day-ahead market price is likely to exceed 4.5¢/KWh, even before carbon pricing is factored in over the long term.

The information request refers to a 7x16 peak period. It should be noted that prices in the 2x16 period are typically lower than those in the 5x16 period which is the industry standard for definition of peak.

**PUB/MH/RISK-46**

**Reference: SEP/NEB Prices Power Resource Plan**
**Risk Issue: Market Price Constraints**

**c) Please confirm that at current natural gas prices of $4.50/GJ, MISO day-ahead market prices are likely to be:**

- **Less than 4.0¢/KWh in peak periods.**
- **Less than 2.0¢/KWh in off-peak periods.**

**ANSWER:**

Manitoba Hydro can not confirm that, at natural gas prices of $4.50/GJ, MISO day-ahead market prices are likely to be less than those listed in this information request. With gas at $4.50 GJ ($4.26/ MMBTU), the variable production cost of energy from an efficient CCCT is on the order of 4.0-4.5¢/KWh, before carbon costs are considered. There are a significant number of higher load hours during the on-peak period, where less efficient CCCT units and CTs will be the marginal generation units, and day-ahead market prices will be higher than 4.5¢/KWh. In addition, there are fixed or capacity costs to be recovered through bilateral markets outside of the MISO day-ahead market.

During off-peak hours, the marginal generator is likely to be coal, with a small, but increasing amount of CCCT over the longer term. In the event that combined cycle generation is the marginal generator during the off-peak period, the day-ahead market price is likely to exceed 2.0¢/KWh, even before carbon pricing is factored in over the long term. Coal generators in the MISO market have varying efficiencies and varying coal costs. Some of the less efficient coal, or that coal generation with higher delivered coal costs, will have variable production costs higher than 2.0¢/KWh, again resulting in market price likely to exceed 2.0¢/KWh, even before carbon pricing is factored in over the long term.

**PUB/MH/RISK-47**

**Reference:** **Energy Resource**
**Risk Issue:** **Market Price Comparisons with High Price Jurisdictions**

**a)** **Please confirm (and file excerpts as appropriate) that a California Energy Commission Staff Report (January 2010) on "Comparative Costs of California Central Station Electricity Generation" provided the following (extracted) forecasts:**

| | Natural Gas Combined Cycle (U.S.¢/KWh) | Average Natural Gas Supply Price (U.S./$MMBTU) |
|---|---|---|
| 2009 | 10.79-11.48 | 6.56 |
| 2012 | | 7.87 |
| 2015 | | 9.01 |
| 2018 | 15.03-15.85 | 12.66 |
| 2022 | | 13.64 |
| 2026 | N/A | 15.35 |

**ANSWER:**

The referenced California Energy Commission Staff Report has not been reviewed by Manitoba Hydro and consequently Manitoba Hydro is not in a position to interpret or confirm any information contained in the report.

**PUB/MH/RISK-47**

**Reference: Energy Resource**
**Risk Issue: Market Price Comparisons with High Price Jurisdictions**

**b) Please confirm that the above 2008-09 forecasted pricings of electricity and natural gas would suggest fixed costs make up 30% (about 4¢/KWh) of the California NGCC costs.**

**ANSWER:**

The referenced California Energy Commission Staff Report has not been reviewed by Manitoba Hydro and consequently Manitoba Hydro is not in a position to interpret or confirm any information contained in the report.

**<u>PUB/MH/RISK-47</u>**

**Reference: Energy Resource**
**Risk Issue: Market Price Comparisons with High Price Jurisdictions**

**c) On a comparative basis, please explain how a 400 MW CCCT plant in Manitoba could have fixed cost under 1.5¢/KWh?**

**<u>ANSWER</u>:**

As discussed in PUB/MH/RISK-47(b), the referenced California Energy Commission Staff Report has not been reviewed by Manitoba Hydro and consequently Manitoba Hydro is not in a position to interpret or confirm any information contained in the report.

To illustrate the importance of understanding the assumptions within the report, Manitoba Hydro notes that if a CCCT plant has a very high capacity factor (90%), its unit fixed costs (i.e., per MWh or kWh) would be half that for a moderate capacity factor (45%) CCCT plant.

**PUB/MH/RISK-48**

**Reference:** **Energy Resource Rates IFF 09-1 Assumptions; Appendix 56 - Attachment 6**
**Risk Issue:** **Market Price Comparisons**

**a)** **Please confirm (and file excerpts as appropriate) that the Washington PUD Association (August 2008 report by EES Consulting) "Rate Comparison PSE and New Washington Power Utility" provided the following (extracted) forecast of new resource costs:**

| | Wind (U.S.¢/MWh) | CCCT (U.S.¢/MWh) | SCCT (U.S.¢/MWh) | Natural Gas Supply $/MMBTU |
|---|---|---|---|---|
| 2010 | 96.3 | 77.6 | 94.1 | 7.60 |
| 2020 | 117.3 | 97.4 | 119.0 | 9.80 |
| 2029 | 141.1 | 120.2 | 147.7 | 12.30 |

**ANSWER:**

The referenced Washington PUD Association report has not been reviewed by Manitoba Hydro and consequently Manitoba Hydro is not in a position to interpret, confirm or compare any information contained in the report.

**PUB/MH/RISK-48**

**Reference:** **Energy Resource Rates IFF 09-1 Assumptions; Appendix 56 - Attachment 6**

**Risk Issue:** **Market Price Comparisons**

**b)** **Please indicate whether (or define otherwise) these forecast prices are relatively consistent with projected pre-downturn all-in prices in MH's MISO market area.**

**ANSWER:**

The referenced Washington PUD Association report has not been reviewed by Manitoba Hydro and consequently Manitoba Hydro is not in a position to interpret, confirm or compare any information contained in the report.

**PUB/MH/RISK-48**

**Reference:** **Energy Resource Rates IFF 09-1 Assumptions; Appendix 56 - Attachment 6**

**Risk Issue:** **Market Price Comparisons**

**c) Please compare and discuss the above resource costs with MH's IFF 09-1 assumptions and Appendix 56 - Attachment 6.**

**ANSWER:**

The referenced Washington PUD Association report has not been reviewed by Manitoba Hydro and consequently Manitoba Hydro is not in a position to interpret, confirm or compare any information contained in the report.

**PUB/MH/RISK-48**

**Reference:** **Energy Resource Rates IFF 09-1 Assumptions; Appendix 56 - Attachment 6**

**Risk Issue:** **Market Price Comparisons**

**d)** **Can MH confirm that MH's own future wind projects would also experience price escalations that track/parallel CCCT prices?**

**ANSWER:**

Manitoba Hydro cannot confirm what changes in project costs there will be for specific generation types or what changes there may be in the relationship between different generation types. Capital costs are influenced by numerous variables including technological advancements which may affect one source of generation and not another.

It should be noted that wind generation and natural gas generation from CCCTs have different components that determine their energy costs. Wind generation has high fixed costs due to high capital cost and very low variable costs while CCCTs have lower fixed costs and high variable costs arising from use of natural gas. There is no obvious reason that wind energy costs should parallel the costs of energy from CCCTs.

**PUB/MH/RISK-49**

**Reference:** **Natural Gas Generation Appendix 56 - Attachment 6, Graphs on Page 8.**
**Risk Issue:** **Energy Price Factors**

**a)** **Please confirm that the variable electricity production costs without CO2 Adders are approximately:**

| Natural Gas Supply Costs ($/GJ) | CCCT ¢/KWh | SCCT ¢/KWh |
|---|---|---|
| 3.00 | 2.9 | 3.8 |
| 7.00 | 5.9 | 7.5 |
| 12.50 | 10.1 | 13.0 |
| (1) | 15.0 | (1) |

**(1)** **Please complete the table where indicated.**

**ANSWER:**

For the illustrative graph titled "CCCT Gas Fired Generation - Recent Range of Variable Production Costs" in Appendix 56 - Attachment 6, Manitoba Hydro notes the units for the X axis are US$ / MM BTU and not $/ GJ, and the response uses units consistent with the original graph.

Manitoba Hydro confirms that the variable electricity production costs without CO2 Adders in this information request are generally representative of very efficient CCCT generation and appear to be extracted from Manitoba Hydro's information provided in Appendix 56 - Attachment 6.

The assumptions for the example are detailed in the slide titled "Typical Variable Production Costs from Existing Generation". The fuel efficiency or heat rate of each CCCT and CT is not the same and varies significantly based on the turbine model and age of the unit. Therefore, the variable electricity production costs are given for two values, that of a very efficient CCCT/CT, and that for a lower efficiency CCCT/CT, which cover most of the range of such gas fired units operating in the market.

Manitoba Hydro notes that the MISO day-ahead market price does not include any value for fixed or capacity costs. The fixed or capacity costs are recovered through bilateral contracts such as Manitoba Hydro's long-term export contracts which include capacity revenue. Generators within the MISO market are not obligated to offer their generation into the MISO market at exactly their variable production costs, and there typically is some degree of mark up on their offers into the market, depending on operating and competitive considerations.

The particular marginal generator which actually sets the market clearing price, varies continually as the weather, load, time of day, seasons, generation outages, transmission outages and fuel costs change.

| | Very Efficient CCCT | Lower Efficiency CCCT | Very Efficient CT | Lower Efficiency CT |
|---|---|---|---|---|
| Heat Rate (MMBTU/ MWh) | 7.5 | 10.0 | 9.5 | 13.5 |
| Variable O&M Cost ($/ MWh) | $7.00 | $7.00 | $10.00 | $10.00 |
| | | | | |
| Gas Cost (US$/ MMBTU) | $3.00 | $3.00 | $3.00 | $3.00 |
| Variable Production Cost (US$/ MWh) | $29.50 | $37.00 | $38.50 | $50.50 |
| Gas Cost (US$/ MMBTU) | $7.00 | $7.00 | $7.00 | $7.00 |
| Variable Production Cost (US$/ MWh) | $59.50 | $77.00 | $76.50 | $104.50 |
| Gas Cost (US$/ MMBTU) | $12.50 | $12.50 | $12.50 | $12.50 |
| Variable Production Cost (US$/ MWh) | $100.75 | $132.00 | $128.75 | $178.75 |
| Gas Cost (US$/ MMBTU) | $14.30 | $14.30 | $14.30 | $14.30 |
| Variable Production Cost (US$/ MWh) | $114.25 | $150.00 | $145.85 | $203.05 |

## PUB/MH/RISK-49

**Reference:** **Natural Gas Generation Appendix 56 - Attachment 6, Graphs on Page 8.**
**Risk Issue:** **Energy Price Factors**

**b) Please confirm that CO2 cost Adders would increase the above costs by approximately:**

| CO2 Price | CCCT ¢/KWh | SCCT ¢/KWh |
|---|---|---|
| $15/tonne | 0.6 | 0.8 |
| $30/tonne | 1.2 | 1.6 |

**ANSWER:**

Manitoba Hydro confirms that the CO2 cost Adders in this information request are generally representative of very efficient CCCT generation and appear to be extracted from Manitoba Hydro's information provided in Appendix 56 - Attachment 6.

Please refer to the response to PUB/MH/RISK-49(a) for comments applicable to this illustrative calculation.

| | Very Efficient CCCT | Lower Efficiency CCCT | Very Efficient CT | Lower Efficiency CT |
|---|---|---|---|---|
| Emissions Rate (Tons CO2/MWh) | 0.43 | 0.59 | 0.52 | 0.82 |
| Carbon Value (US$/ ton) | $15.00 | $15.00 | $15.00 | $15.00 |
| Carbon Emissions Cost Adder (US$/ MWh) | $6.45 | $8.85 | $7.80 | $12.30 |
| Carbon Value (US$/ ton) | $30.00 | $30.00 | $30.00 | $30.00 |
| Carbon Emissions Cost Adder (US$/ MWh) | $12.90 | $17.70 | $15.60 | $24.60 |

**PUB/MH/RISK-49**

**Reference:** **Natural Gas Generation Appendix 56 - Attachment 6, Graphs on Page 8.**
**Risk Issue:** **Energy Price Factors**

**c)** **Please provide the appropriate fixed cost components for additional generation options:**

| | CCCT ¢/KWh | SCCT ¢/KWh |
|---|---|---|
| 200 MW | 70% on-line | 20% on-line |
| | 50% on-line | 40% on-line |
| 400 MW | 70% on-line | 20% on-line |
| | 50% on-line | 40% on-line |

**ANSWER:**

The requested analysis would require significant new work that cannot be undertaken in the timeframe allotted for responses to information requests. Some representative fixed costs for a CCCT are provided in response to PUB/MH/RISK-45(c).

**PUB/MH/RISK-50**

**Reference: NSP/XCEL Contracts Publicly Available Redacted Version**
**Risk Issue: Energy Price Factors**

**a) Please confirm that MH's contracts with NSP/Xcel include:**

- **"Must Supply / Must Buy" energy that typically displaces baseload coal on natural gas (CCCT) generation.**
- **"Optional Supply - Must Buy" energy that typically displaces peak natural gas (CCCT and SCCT) generation and off-peak natural gas (CCCT) and coal generation, or that may support wind energy when the wind isn't blowing.**

**ANSWER:**

Manitoba Hydro confirms that the new PPA with Xcel includes a "must sell / must buy" obligation for energy and capacity and "optional supply / must buy" energy. Manitoba Hydro cannot confirm the type of resources that the contract energy will displace.

**PUB/MH/RISK-50**

**Reference: NSP/XCEL Contracts Publicly Available Redacted Version**
**Risk Issue: Energy Price Factors**

**b) Please discuss within the context of the NSP/Xcel contracts what displacement role MH's exports would play during:**

- **Peak summer periods.**
- **Off-peak summer periods.**
- **Peak winter periods.**
- **Off-peak winter periods.**

**ANSWER:**

Please see Manitoba Hydro's responses to PUB/MH II-179(c) and (d) which discusses displacement factors for imports and exports.

**PUB/MH/RISK-51**

**Reference: Competitive Bidding for consultant Services**
**Risk Issue: Competitive Bidding for consultant Services**

**a) Please define the situations when MH, in seeking consulting services, elects to go to:**

- **Public tenders.**
- **Short list invitations.**
- **Sole Source.**

**ANSWER:**

- Public tenders.

  – Public or Open Tendering for consulting services is considered when there is limited knowledge of the bidder expertise in a specific field,
  – To broaden the supplier base to ensure an adequate level of competition is achieved, and
  – To allow all qualified and interested Bidders the opportunity to participate on Manitoba Hydro's tenders.

- Short list invitations.

  – Invited Tendering for consulting services is considered when there is an existing list of qualified Bidders to ensure an adequate level of competition is achieved, and
  – Bidders have pre-qualified to submit a bid,
  – Based on requirements, there are only a limited number of qualified bidders.

- Sole Source.

  – Sole Sourcing for consulting services is considered when the consultant, in a specialized field, has a wide knowledge on the subject matter based on skill, knowledge, reputation, ethics and previous work experience.

**PUB/MH/RISK-51**

**Reference: Competitive Bidding for consultant Services**
**Risk Issue: Competitive Bidding for consultant Services**

**b) Does MH maintain an up to date inventory of consulting firms whose expertise may be required at various times. Explain. Please file a summary listing.**

**ANSWER:**

MH maintains a vendor master data base of all suppliers, including consultants who have registered to do business with MH. At time of registering, suppliers complete a questionnaire indicating the areas of business in which they specialize. The vendor master database is updated on an ongoing basis, and MH also refers to the Consulting Engineers of Manitoba for specialized services.

**PUB/MH/RISK-51**

**Reference: Competitive Bidding for consultant Services**
**Risk Issue: Competitive Bidding for consultant Services**

**c) Please provide a tabulation by professional discipline of the top five dollar level (in each) consultants employed on major projects and/or major studies, in the last ten years, indicating:**

- **Firm (including affiliations).**
- **Annual payments (fees/disbursements).**
- **Overall years of service to MH.**
- **Selection basis/process/fee limit.**
- **Services renewal process.**
- **Role (prime/sub).**
- **Responsible MH division.**

**ANSWER:**

Manitoba Hydro is unable to provide the requested information. In many cases, the contracts for services will require that information as to payments be maintained as confidential, and a determination of such confidentiality would require a review of each of the individual contracts to determine whether such confidentiality provision apply to that particular contract. The exclusion of some contracts on the basis of confidentiality may result in the remaining information being unrepresentative. The significant time required to analyze and extract the information, and develop a response is not warranted given the questionable relevance and limited value of this information.

**PUB/MH/RISK-51**

**Reference: Competitive Bidding for consultant Services**
**Risk Issue: Competitive Bidding for consultant Services**

**d) Please discuss the rationale employed when seeking "Independent Reviews" pursuant to PUB Directives on:**

- **Risk.**
- **Drought.**
- **IFRS.**
- **Benchmarking.**
- **Asset condition evaluation.**
- **COSS/MC.**

**ANSWER:**

Manitoba Hydro typically considers the following factors when seeking consulting assistance:

- Qualifications and reputation of consulting firm;
- Qualifications of specific consultants to be assigned to the project;
- References from other clients;
- Experience in the energy consulting business;
- Experience with the regulatory environment;
- Directly related experience with the issues to be reviewed;
- Hourly rates of key personnel and projected hours to be devoted to the project;
- Total projected cost including travel and expenses (including pricing of specific components of project as applicable);
- Detailed plan for addressing assignment including scheduled start and completion dates; and
- Manitoba content.

**PUB/MH/RISK-51**

**Reference: Competitive Bidding for consultant Services**
**Risk Issue: Competitive Bidding for consultant Services**

**e) Please provide a tabulation of consulting contracts and fees since 2003/04 paid by consultant relative to**

- **Overall corporate Risks**
- **Planning & operational**
- **Drought Risks**
- **Infrastructure Risk**

**ANSWER:**

Please refer to the tabulation provided with the response to PUB/MH/RISK-104(b).

Please also see Manitoba Hydro's response to PUB/MH/RISK-51(c).

**PUB/MH/RISK-52**

**Reference: PUB/MH II-208**
**Risk Issue: Export-Import Pricing**

**a) Please confirm it is MH's position that WPS/MP related transmission capacity increases would:**

- **Allow more peak period sales if additional G&T projects proceed.**
- **Achieve lower import prices relative to export prices (improved margin).**
- **Preclude drought shortage pricing.**

**ANSWER:**

Manitoba Hydro can confirm that the new transmission will increase on-peak sales and increase the availability of off-peak purchases.

The US transmission facilities associated with the US Term Sheets will improve Manitoba Hydro's firm import capability. However it is not yet known the extent to which this improvement will result in lower pricing at the MB-US border under high import conditions such as during drought. This is because other regional transmission upgrades are proceeding regardless of the transmission facilities associated with the WPS and MP Term Sheets and price improvements through reduced congestion may occur anyways.

**<u>PUB/MH/RISK-52</u>**

**Reference:** **PUB/MH II-208**
**Risk Issue:** **Export-Import Pricing**

**b)** **Please explain in detail how MH, as a net importer in drought years, will avoid shortage import pricing when total available energy in the MISO market is reduced substantially.**

**<u>ANSWER</u>:**

The firm transmission service reservations associated with Manitoba Hydro's long-term contracts provide the Corporation with an increased ability to import energy at market based prices from the MISO market. Anytime Manitoba Hydro purchases energy from the market, prices will rise as incrementally more expensive generation is dispatched to serve the demand. However Manitoba Hydro's import requirements are relatively small in relation to MISO load and the increased import capability (of at least 700 MW) from the new transmission line will be utilized first during the off-peak periods which will reduce the need for on-peak energy purchases which are generally more expensive.

## PUB/MH/RISK-52

**Reference: PUB/MH II-208**
**Risk Issue: Export-Import Pricing**

**c) Please define the circumstances when MH may be import capacity constrained during:**

- **Summer 7x16 peak periods.**
- **Summer 7x8 off-peak periods.**
- **Winter 7x12 peak periods.**
- **Winter 7x12 off-peak periods.**

**ANSWER:**

Please refer to the response to CAC/MSOS/MH I-62(g) which indicates that Manitoba Hydro's firm transmission import capacity of 700 MW from the MISO market represents less than 1% of the peak MISO market load. The MISO footprint, consisting of approximately 138,000 MW of generation capacity owned by many suppliers, is currently very large relative to the Manitoba Hydro system.

Given the large size of the MISO market relative to the current 700 MW firm import limit, or with an import limit on the order of twice that size in the future, Manitoba Hydro does not anticipate that there would be any hours in which there would be insufficient available capacity in the MISO market to serve Manitoba Hydro's import requirements during winter hours and during summer off-peak hours. However, during the summer on-peak period, Manitoba Hydro has capacity obligations to the MISO market, and Manitoba Hydro does not anticipate importing from MISO during the highest summer load hours.

**<u>PUB/MH/RISK-52</u>**

**Reference: PUB/MH II-208**
**Risk Issue: Export-Import Pricing**

**d) Please illustrate (graphically) the duration of such circumstances in c) and when the actual constraint is related to generation capacity.**

**<u>ANSWER</u>:**

As discussed in the response provided to PUB/MH/RISK-52(c), Manitoba Hydro does not anticipate that there would be any hours in which it would be expecting to import from the MISO market that there would be insufficient available capacity in the MISO market to serve Manitoba Hydro's import requirements.

**PUB/MH/RISK-53**

**Reference: Alternative IFF Scenarios NSP/Xcel Contracts (Redacted) IFF 09-1**
**Risk Issue: Alternative IFF Scenarios**

**a) Please file an updated 20-year IFF that reflects the following scenario:**

- **Current MISO market prices out to 2014/15.**
- **NSP/Xcel contracts from 2015/16 to 2025/26.**
- **Pending 500 MW WPS and 250 MW MP contracts with NSP/Xcel pricing levels.**
- **Projected (no carbon Adder) day-ahead market pricing for all opportunity export sales and non-contract imports.**
- **Keeyask/Conawapa/Bipole III being on-line as per 2008 Power Resource Plan.**

**ANSWER:**

The question posed requires Manitoba Hydro to produce an alternative forecast of export revenues and generation costs and re-employ such information in producing an alternative IFF. This work is complex and cannot be completed within the time allotted for responding to these Information Requests. While an alternate IFF cannot be produced, Manitoba Hydro can advise that it would expect that the IFF09 Low export price scenario would provide a directional indication of the impacts of the lower bound of export prices. The proposed in-service schedule for Keeyask, Conawapa and Bipole III did not change from the 2008 Power Resource Plan to the 2009 Plan and is assumed in the IFF09 Low export price scenario. Please see Appendix 15 for the projected financial statements supporting the IFF09 Low export price scenario.

**<u>PUB/MH/RISK-53</u>**

**Reference: Alternative IFF Scenarios NSP/Xcel Contracts (Redacted) IFF 09-1**
**Risk Issue: Alternative IFF Scenarios**

**b) Please file an updated 20-year IFF that reflects the a) above market conditions, but without the WPS/MP contracts and without any of the major G&T projects.**

**<u>ANSWER</u>:**

As in the response to PUB/MH/RISK-53(a), an alternative forecast of export revenues and generation costs and corresponding alternative IFF cannot be produced. An alternative IFF scenario assuming no WPS/MP contracts, the Alternative Development Sequence, has been provided in Appendix 15. This scenario assumes no Keeyask, no new US interconnection and Conawapa in 2021/22. A scenario with no major G&T projects as requested is not feasible as new resources are required to meet Manitoba requirements and the other major new generation and transmission projects identified in CEF09 are required for load, reliability or safety.

**PUB/MH/RISK-53**

**Reference: Alternative IFF Scenarios NSP/Xcel Contracts (Redacted) IFF 09-1**
**Risk Issue: Alternative IFF Scenarios**

**c) Please file an updated 20-year IFF that reflects the same b) market situation, but with addition of Keeyask G.S. and Bipole III.**

**ANSWER:**

The question posed requires Manitoba Hydro to produce an alternative capital plan, generation estimate and forecast of export revenues and generation costs and re-employ such information in producing an alternative IFF. This work is complex and cannot be completed within the time allotted for responding to these Information Requests.

## PUB/MH/RISK-53

**Reference:** **Alternative IFF Scenarios NSP/Xcel Contracts (Redacted) IFF 09-1**
**Risk Issue:** **Alternative IFF Scenarios**

**d) Please file an updated 20-year IFF that reflects above c) market conditions, NSP/Xcel contracts, and pending WPS/MP contracts with Keeyask G.S. and Bipole III, but not Conawapa G.S. on-line.**

**ANSWER:**

The question posed requires Manitoba Hydro produce an alternative capital plan, generation estimate and forecast of export revenues and generation costs and re-employ such information in producing an alternative IFF. This work is complex and cannot be completed within the time allotted for responding to these Information Requests. The resource development plan identified in the question is not feasible as the WPS/MP contracts require the construction of both Keeyask G.S. and Conawapa G.S. and associated transmission.

**PUB/MH/RISK-54**

**Reference:** **Appendix 56, Attachment #1 Reliability/Existing Interconnections**
**Risk Issue:** **Workshop**

**a)** **Please confirm (or otherwise revise) that in terms of bulk energy supply. MH's dependable energy supply in 2010/11 is expected to serve:**

| Energy | GWh |
|---|---|
| **Domestic load at Generation** | **24,000** |
| **Export contract obligations** | **3,500** |
| **Opportunity export sales and transmission losses** | **6,000** |
| **Total** | **33,500** |

**ANSWER:**

As indicated in Table 2 of Tab 8 of the Application, Manitoba Hydro's dependable energy supply for 2010/11 is 29,262 GWh compared to firm demands of 28,163 GWh.

**<u>PUB/MH/RISK-54</u>**

**Reference: Appendix 56, Attachment #1 Reliability/Existing Interconnections**
**Risk Issue: Workshop**

**b) Please explain from what resources (and why) MH would expect to serve these GWh obligations (and additional sales) during the six summer months and subsequently the six winter months of 2010/11.**

**<u>ANSWER</u>:**

Please see Table 2, Tab 8 of the Application for the Manitoba Hydro resources available to serve firm demands. In addition to these resources, Manitoba Hydro has access to additional market resources which it will utilize when it's more economical that its own resources to serve firm load or to maximize net export revenues.

**PUB/MH/RISK-54**

**Reference: Appendix 56, Attachment #1 Reliability/Existing Interconnections**
**Risk Issue: Workshop**

**c) Please explain from what resources (and why) MH would expect to meet the bulk system reliability or capacity requirements (MW) during peak winter months and during peak (export) summer months of 2010/11.**

**ANSWER:**

Please see Table 1, Tab 8 of the Application for the Manitoba Hydro capacity resources available to serve firm demands. In addition to these resources, Manitoba Hydro has access to additional market resources which it will utilize when more economic that its own resources to serve firm loads.

**PUB/MH/RISK-54**

**Reference: Appendix 56, Attachment #1 Reliability/Existing Interconnections**
**Risk Issue: Workshop**

**d) Please confirm that MH's installed capacity of 5,600 MW (1,900 MW - AC and 3,700 MW - DC) amounts to about 125% of 2010-11 domestic winter demand;**

**ANSWER:**

As shown on page 121 of Appendix 4.1 of the Application, Manitoba Hydro's installed capacity is 5490 MW.

As per Table 1 of Appendix 7.1 of the Application, Manitoba Hydro's Net Total Peak Demand for 2010/11 is 4407 MW.

The ratio of installed capacity to demand is 125%.

**PUB/MH/RISK-54**

**Reference: Appendix 56, Attachment #1 Reliability/Existing Interconnections**
**Risk Issue: Workshop**

**e) Please confirm that with maximum imports in the absence of Bipoles I and II, available capacity would be reduced to 80% of domestic winter demand.**

**ANSWER:**

Confirmed.

**PUB/MH/RISK-54**

**Reference: Appendix 56, Attachment #1 Reliability/Existing Interconnections**
**Risk Issue: Workshop**

**f) Please indicate (explain) the extent to which MH could serve domestic and export obligations with and without Bipoles I and II during peak summer months of 2010/11.**

**ANSWER:**

With Bipoles I and II in service, Manitoba Hydro can serve both domestic load and export obligations during expected peak summer months entirely with its own generation.

In the event Bipoles I and II were forced out of service, Manitoba Hydro would not be obligated to supply its export contracts. Manitoba Hydro could supply its expected summer peak load using its AC generation and firm and non-firm imports.

**PUB/MH/RISK-55**

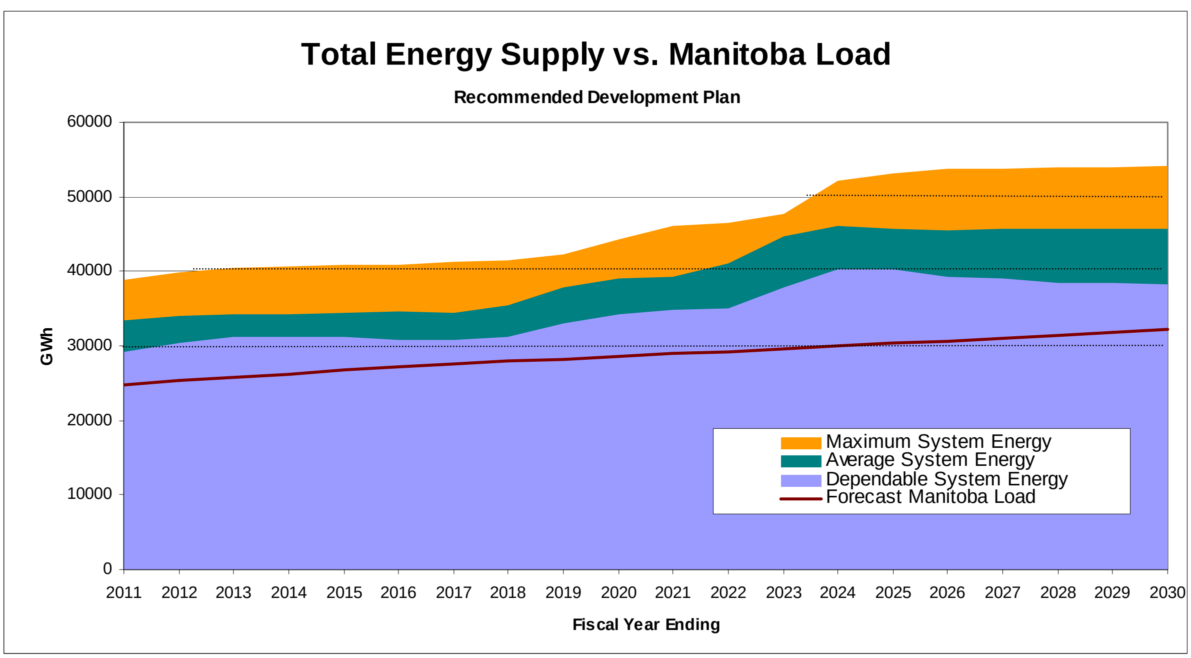
**Reference: Appendix 56, Attachment #1 Reliability/Need for New Inter-Connections**
**Risk Issue: Workshop**

**a) Please provide a true-scale graphical illustration of MH's current and post-new G&T energy supplies and surpluses to domestic load (GWh) under:**

- **Dependable flow conditions;**
- **Average flow conditions; and**
- **Maximum flow conditions.**

**ANSWER:**

The following graph provides the total generation capability relative to the 2009 forecast of Manitoba load for dependable, average and maximum flow conditions. The total generation capability includes thermal generation, import and wind energy purchases. The difference between Manitoba load and each generation capability estimate indicates the surplus dependable, average and maximum energy for the years 2010/11 to 2029/30. In-service dates for new generation and transmission are consistent with the recommended development plan in the 2009/10 Power Resource Plan.



**<u>PUB/MH/RISK-55</u>**

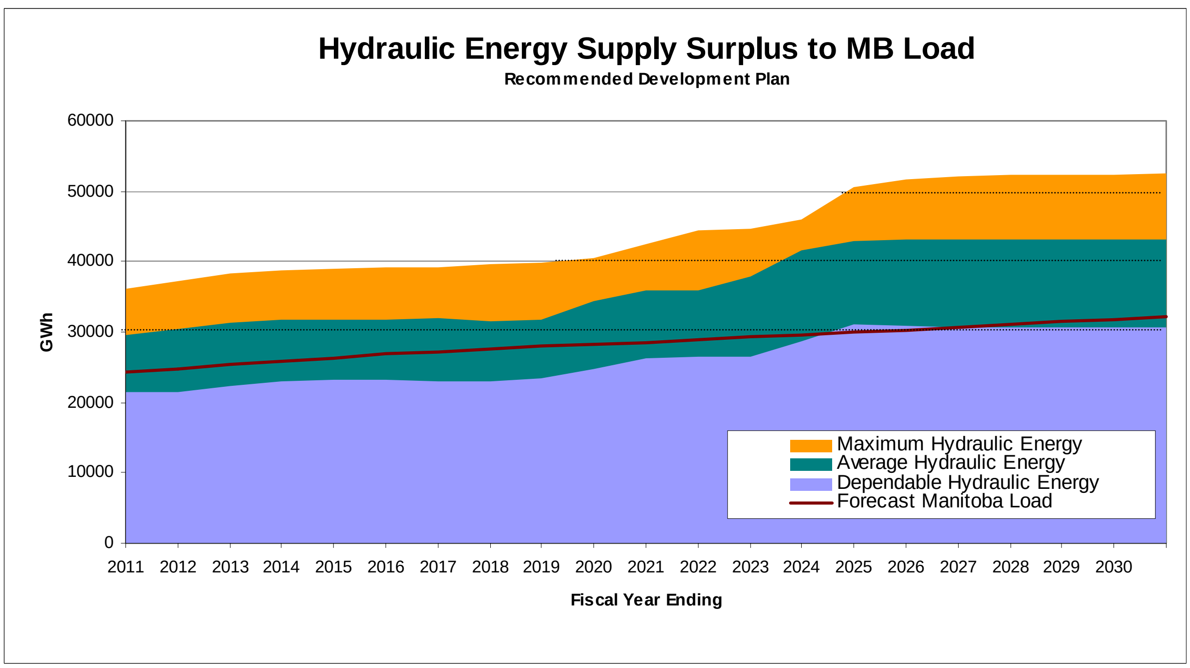
**Reference:** **Appendix 56, Attachment #1 Reliability/Need for New Inter-Connections**
**Risk Issue:** **Workshop**

**b)** **Assuming domestic load has priority on dependable hydraulic generation, please indicate the corresponding hydraulic energy surplus component (GWh) in each of the above a) cases.**

**<u>ANSWER</u>:**

Please see the response to PUB/MH/RISK-55(a) which provides the assumptions for the information that is provided. It is noted that the energy supply in the response to PUB/MH/RISK-55(a) includes thermal generation, import and wind energy purchases. Manitoba Hydro's dependable energy from all resources are available to serve its firm obligations which include domestic load and firm export sales.

The following graph illustrates the forecast of Manitoba load relative to the dependable, average and maximum hydraulic energy that is available for the years 2010/11 to 2029/30.



**PUB/MH/RISK-55**

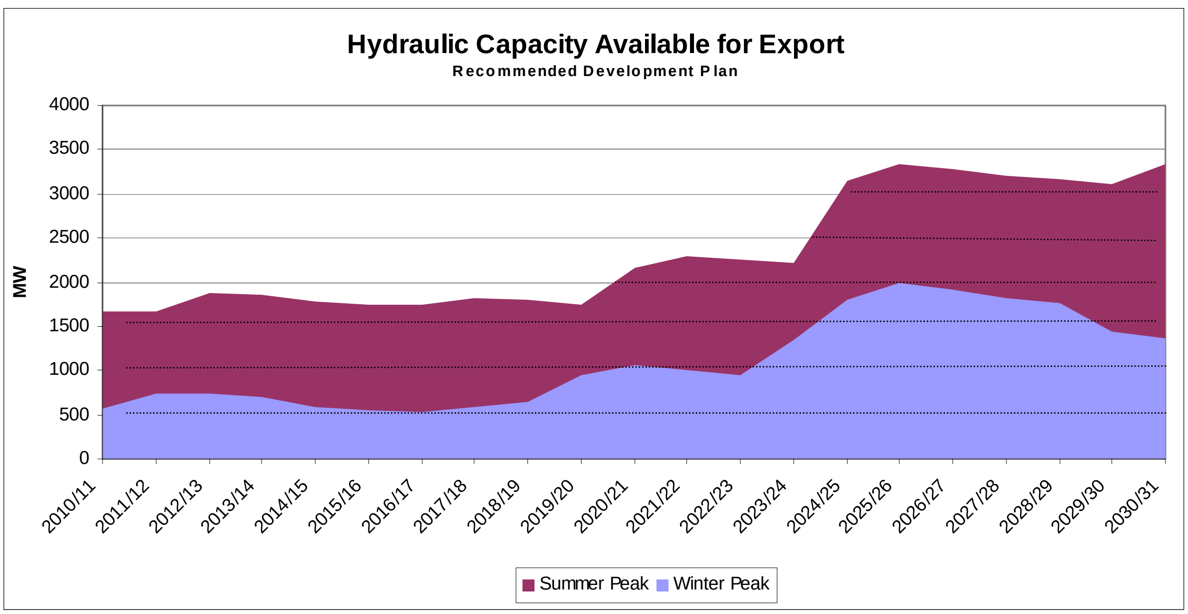
**Reference: Appendix 56, Attachment #1 Reliability/Need for New Inter-Connections**
**Risk Issue: Workshop**

**c) Please indicate the installed hydraulic capacity component (MW) that is available to exports in the summer and in the winter in each of the above a) cases.**

**ANSWER:**

The following graph shows installed hydraulic capacity surplus to Manitoba Load under average flow conditions for the years 2010/11 to 2029/30. The In-service dates for new generation and transmission are consistent with the 2009/10 Power Resource Plan.

It should be noted that Manitoba Hydro's capacity from all resources is available to serve its firm obligations which include domestic load and firm export sales.



**<u>PUB/MH/RISK-55</u>**

**Reference: Appendix 56, Attachment #1 Reliability/Need for New Inter-Connections**
**Risk Issue: Workshop**

**d) Please indicate the Manitoba constraints (current and post-Bipole III. on exports and imports (GWh and MW).**

**<u>ANSWER</u>:**

Please refer to the response to CAC/MSOS/MH I-63 which details Manitoba Hydro's current transfer limits through its interconnections.

The addition of Bipole III to Manitoba Hydro's system will not affect these limits since it is planned that all northern generation will be able to be transmitted to southern Manitoba both pre and post Bipole III.

PUB/MH/RISK-55

**Reference: Appendix 56, Attachment #1 Reliability/Need for New Inter-Connections**
**Risk Issue: Workshop**

**e) Please indicate the MISO market constraints (current and post-WPS/MP) and Canadian market constraints on exports and imports (GWh and MW).**

**ANSWER:**

The current transfer limits on Manitoba Hydro's export interconnections during system intact conditions were detailed in response to CAC/MSOS/MH I-63(d).

The current transfer limits on Manitoba Hydro's import interconnections during system intact conditions are as follows:

| Interconnection | Maximum Non-Firm Import Capability | Firm Import Schedule Limit | Potential maximum annual import based on Firm Limit |
|---|---|---|---|
| U.S. | 850 MW | 700 MW | 6,132 GWh/yr |
| Ontario | 240 MW | 0 MW | 0 GWh/yr |
| Saskatchewan | 150 MW | 0 MW | 0 GWh/yr |

As stated in Appendix 47 of the 2010/11 & 2011/12 General Rate Application Filing, the 2009/10 Recommended Power Resource Development Plan includes "A 1000 MW export and 750 MW import interconnection".

**PUB/MH/RISK-56**

**Reference: Appendix 56, Attachment #2 Planning Cycle**
**Risk Issue: Workshop**

**Please confirm that electricity market price assumptions IFF 09-1 are no longer valid and will significantly be revised in the next IFF.**

**ANSWER:**

Manitoba Hydro cannot confirm that the electricity market price assumptions used in the preparation of IFF09-1 are no longer valid but can confirm that the 2010 forecast reduces on-peak prices 8% on average in the 2012 to 2021 time period. Short-term cycles of economic conditions, such as the current downturn in the economy in the U.S., can be expected to depress market prices in some periods in the future. However, such short-term cycles should not have an impact in the long term as long as the long-term fundamentals that drive electricity prices do not change. As part of the process for developing the 2010 power resource plan and the input for the Integrated Financial Forecast, Manitoba Hydro has undertaken a 2010 update to the electricity price forecast utilizing the process outlined in PUB/MH I-156(a).

In comparison with the forecast used for IFF09-1, the 2010 forecast reduces on-peak prices 8% on average in the 2012 to 2021 time period. The price decrease is not uniform over the 2011 to 2021 time period, but is greatest in 2011. The difference between the two forecasts narrows such that they are very similar by 2022 and continue to be similar for the 2022 through to 2036 period. The 2010 forecast of export prices in the early years is lower in comparison with the forecast used for IFF09-1 due to a combination of the carry over of reduced demand from 2008/09 recession, reduced capacity values due to a near-term capacity surplus, and lower natural gas prices. In conclusion, Manitoba Hydro has revised export prices somewhat downward in the years up to 2020 but the long-term outlook has not had a significant adjustment.

## PUB/MH/RISK-57

**Reference:** **Appendix 56, Attachment #3 PUB/MH II-188a) PUB/MH II-193c)**
**Risk Issue:** **Incremental F&PP Costs**

**a) Please confirm that the $68 M fixed and variable costs reflect only the first three quarters of 2009/10.**

**ANSWER:**

The $68 M fixed and variable costs reflected preliminary annual numbers for 2009/10.

**PUB/MH/RISK-57**

**Reference:** **Appendix 56, Attachment #3 PUB/MH II-188a) PUB/MH II-193c)**
**Risk Issue:** **Incremental F&PP Costs**

**b) Please confirm that the $33 M "Power" item reflects:**

- **250 GWh of wind (Q1/Q2/Q3).**
- **200 GWh of scheduled imports (Q1/Q2/Q3).**
- **600 GWh of merchant trading (Q1/Q2/Q3).**

**ANSWER:**

The $33 M "Power" amount included only energy purchased from the market and wind generation for fiscal year 2009/10. It did not include the costs associated with merchant trading.

**PUB/MH/RISK-57**

**Reference:** **Appendix 56, Attachment #3 PUB/MH II-188a) PUB/MH II-193c)**
**Risk Issue:** **Incremental F&PP Costs**

**c)** **Please confirm that the $29 M "TX" item reflects about 300 GWh of non-scheduled bilateral imports and about 400 GWh of day ahead and real time market purchases in the first three quarters of 2009/10**

**ANSWER:**

The $29 M indicated as "TX" or Transmission Charges is for fixed transmission costs for 2009/10 and does not include energy purchase costs. The energy purchase costs were included in the $33 M for Power referenced in part b) of this response.

**Reference: Appendix 56, Attachment #4**
**Risk Issue: Workshop - Drought Research**

a) **Please file all internal reports prepared by (or for) MH dealing with drought frequencies.**

**ANSWER:**

To date, there are no final internal reports that have been approved by Manitoba Hydro dealing with drought frequencies for the Nelson-Churchill basin.

The statistical studies to date have been projects by post graduate researchers investigating methods of evaluating joint probability of concurrent multi-year drought in Manitoba Hydro's major sub-basins. The research projects have had limited success in reproducing the mean and variance of the parent record, due in part to lack of streamflow records in several of the sub-basins in Manitoba Hydro's watershed. The Nelson-Churchill water supply is complex and spatially diverse, comprised of inflow from four major river systems in four different climatic regions and three different physiographic regions. Consequently, the joint probability of concurrent droughts in each major watershed is still not well understood. Therefore, the confidence in the predicted return period of droughts of varying duration and severity is quite low.

Manitoba Hydro also supported post-graduate research projects investigating paleo-climatic data such as tree-rings and lake sediments as indicators of past drought events in a number of sub-basins within the Nelson-Churchill watershed. These studies were intended to investigate whether paleo-climatic data could provide information about past climate extremes (both flood and drought), which could be used by Manitoba Hydro to reconstruct basin-wide droughts in past centuries. While some inference of past extreme droughts was evident in some of the regions studied, in most cases, the correlation between tree-rings or lake sediments and streamflow was poor and would not provide enough data to represent past streamflow for the entire basin on a continuous basis. In addition, it was found that tree-rings in the Prairie region do not respond well to winter precipitation, making this type of information difficult to use in drought probability analyses.

**<u>PUB/MH/RISK-58</u>**

**Reference: Appendix 56, Attachment #4**
**Risk Issue: Workshop - Drought Research**

**b) Please file Table of Contents/Executive Summary/ Conclusions sections of relevant external reports relied on by MH in its drought research.**

**<u>ANSWER</u>:**

Manitoba Hydro has participated in various collaborative initiatives and reviewed a variety of technical external documents over an extended period of time on the subject of water supply and climate change. The majority of this work does not specifically address the probability of drought for the Manitoba Hydro system.

**PUB/MH/RISK-59**

**Reference: Appendix 56, Attachment #4, Page 18**
**Risk Issue: Workshop - Energy Import Capability**

**a) Please confirm that MH's firm import capability is limited to 700 MW (mainly 500 MW Diversity Agreement) with a maximum energy flow of:**

- **1,600 GWh winter off-peak.**
- **1,400 GWh winter peak.**

**ANSWER:**

Potential maximum winter imports based on long-term Firm USA import capability translates to 1,322 GWh and 1,719 GWh in the on-peak and off-peak, respectively. These figures do not account for any other restrictions (for example transmission outages or minimum generation levels in Manitoba). Note that these figures were based on the number of on-peak and off-peak hours in Winter 2010/2011.

**PUB/MH/RISK-59**

**Reference: Appendix 56, Attachment #4, Page 18**
**Risk Issue: Workshop - Energy Import Capability**

**b) What is the firm import capability:**

- **____ GWh summer off-peak?**
- **____ GWh summer peak?**

**ANSWER:**

Potential maximum summer imports based on long-term Firm USA import capability of 700 MW translates to 1,422 GWh and 1,669 GWh in the on-peak and off-peak, respectively. These figures do not account for any other restrictions (for example transmission outages or minimum generation levels in Manitoba). Note that these amounts are based on the number of on-peak and off-peak hours in Summer 2011.

In addition, Manitoba Hydro has the ability under almost all of its export contracts to serve them from the MISO market. In effect, this ability increases Manitoba Hydro's supply capability by the amount of its firm contract obligation.

**PUB/MH/RISK-59**

**Reference: Appendix 56, Attachment #4, Page 18**
**Risk Issue: Workshop - Energy Import Capability**

**c) What is MH's potential non-firm import capability in drought years?**

**U.S.**

- **_____ GWh _____ MW - winter**
- **_____ GWh _____ MW - summer**

**Ontario**

- **_____ GWh _____ MW - winter**
- **_____ GWh _____ MW - summer**

**Saskatchewan**

- **_____ GWh _____ MW - winter**
- **_____ GWh _____ MW – summer**

**ANSWER:**

Note that transmission capability is affected by many factors, hence import scheduling limits change from time to time, particularly non-firm import limits. They change over the long term as the transmission system evolves and in the short term due to issues such as outages of individual transmission lines or conditions in adjacent power systems.

Non-firm transmission limits will change from year to year. Based on current conditions, Manitoba Hydro does not expect to maximize imports for drought in this fiscal year. Due to the changing nature of non-firm limits, it would be speculative to provide non-firm energy imports during drought for some future year.

Based on the currently posted interface scheduling guides, the hypothetical maximum import energy values, by interface, are as follows:

| | Maximum interface scheduling limit (Import) in MW | | | Maximum Import Energy (GWh) | | |
|---|---|---|---|---|---|---|
| Interface | USA | ON | SPC | USA | ON | SPC |
| Notes | 1 | 2 | 3 | | | |
| Winter | 850 | 257 | 350 | 3692 | 1116 | 1520 |
| Summer | 850 | 22 | 175 | 3754 | 97 | 773 |

Notes:

1. Scheduling Limit plus CRSG release with System Intact
2. Dynamic Scheduling Limit
3. Dynamic Scheduling Limit

Also note that the non-firm limits are not additive in all three directions due to transmission reliability considerations.

The Summer period is May 1st through October 31st and the Winter period is November 1st through April 30th. Interface operating guides are posted on Manitoba Hydro's Open Access Same-time Information System (OASIS) page:

http://oasis.midwestiso.org/documents/mheb/ops_guide.html

## PUB/MH/RISK-59

**Reference:** **Appendix 56, Attachment #4, Page 18**
**Risk Issue:** **Workshop - Energy Import Capability**

**d) If the new G&T does not proceed, what additional import requirements will be needed within the next 20 years.**

**ANSWER:**

Over the next 20 years new sources of supply will be required to serve the Manitoba load. Manitoba Hydro has not determined what alternatives would be required to serve firm load should Keeyask, Conawapa and the new US interconnection not proceed.

**PUB/MH/RISK-60**

**Reference:** **Appendix 56, Attachment #4, Page 13**
**Risk Issue:** **Workshop - Energy Export Capability**

**a)** **Please confirm that under median flow conditions, MH expects to achieve annual on-peak (5x16) exports of about 6,000 GWh (7,000 declining to 5,000) over the next seven to eight years and about 8,000 GWh annual on-peak (7x16) after Keeyask G.S. comes on-line circa 2018/19.**

**ANSWER:**

Please refer to the response provided to PUB/MH/RISK-40(b) which provides tables with energy demand and resources based on a number of flow conditions.

**PUB/MH/RISK-60**

**Reference:** **Appendix 56, Attachment #4, Page 13**
**Risk Issue:** **Workshop - Energy Export Capability**

**b) Please define the existing transmission constraint on annual exports with respect to:**

- **U.S. (2,175 MW - _____ GWh).**
- **Ontario (300 MW - _____ GWh).**
- **Saskatchewan (450 MW - _____ GWh).**

**ANSWER:**

Please also see Manitoba Hydro's response to PUB/MH II-130.

The amount of exports that can be scheduled on interfaces to neighbouring markets is dependent on a number of factors, including: the time of year; Manitoba Load, the configuration of transmission lines and other transmission elements both inside Manitoba and its neighbouring systems; and the status of some Manitoba Hydro generation.

Based on the currently posted interface scheduling guides, the hypothetical maximum export energy values are as follows:

| | **Maximum interface scheduling limit (Export) in MW** | | | **Potential maximum export energy based on interface scheduling limit in GWh** | | |
|---|---|---|---|---|---|---|
| Interface | USA | ON | SPC | USA | ON | SPC |
| notes | 1 | 2 | 3 | | | |
| Winter | 1950 | 263 | 400 | 8611 | 1161 | 1766 |
| Summer | 1950 | 262 | 275 | 8471 | 1138 | 1195 |

1. Scheduling Limit plus CRSG release with System Intact
2. Maximum Dynamic Scheduling Limit with System Intact
3. Maximum Dynamic Scheduling Limit with System Intact

Transmission capability is affected by many factors and hence these values change from time to time. They change over the long term as the transmission system evolves and in the short term due to issues such as outages of individual transmission lines. Also note that the limits are not additive in that even if supply were available, exports could not be maximized in all three directions at one time due to transmission reliability considerations.

Transmission limits are one of three key limits or constraints on the Manitoba Hydro system. Two other key limits which also affect and limit exports are availability of supply (i.e. water conditions), and the availability of surplus generation capacity beyond the Manitoba load. In winter, when the Manitoba load is higher, Manitoba Hydro has reduced surplus capacity, and exports are significantly limited by this factor in comparison with the summer period.

Manitoba Hydro has not performed detailed studies of the maximum possible total exports assuming ideal water conditions. However, Manitoba Hydro experienced very favourable water supply conditions in 2005/06, which provides a reasonable proxy for maximum exports with the current transmission system and the aforementioned practical limitations. Manitoba Hydro's physical exports in 2005/06 totaled 13,839 GWh.

Note that the Summer period is May 1$^{st}$ through October 31$^{st}$ and the Winter period is November 1$^{st}$ through April 30$^{th}$.

Please also see Manitoba Hydro's response to CAC/MSOS/MH I-63.

## PUB/MH/RISK-60

**Reference:** **Appendix 56, Attachment #4, Page 13**
**Risk Issue:** **Workshop - Energy Export Capability**

**c) Please define the maximum total exports (in b)).**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-60(b).

**PUB/MH/RISK-60**

**Reference: Appendix 56, Attachment #4, Page 13**
**Risk Issue: Workshop - Energy Export Capability**

**d) Please explain and quantify (MW and GWh) how the WPS/MP related U.S. transmission interconnection enhancement will increase MH's on-peak export capability by about 4,400 GWh.**

**ANSWER:**

The graph in Appendix 56 Attachment #6 page 13 was presented for illustration only. However, a 1000 MW interconnection operating during on-peak hours can deliver in the order of 4400 GW.h of energy each year.

**PUB/MH/RISK-60**

**Reference: Appendix 56, Attachment #4, Page 13**
**Risk Issue: Workshop - Energy Export Capability**

**e) Please explain how the new combined generation (Keeyask and Conawapa) will increase MH's total on-peak exports to 12,400 GWh from 5,000 GWh circa 2017 and indicate how this is constrained by available transmission interconnections to U.S./Ontario/Saskatchewan markets.**

**ANSWER:**

The 12400 GW.h stated in this information request is in the order of the quantity that can be exported over the existing 1950 MW interconnection to the US, plus a new 1000 MW interconnection, both being fully utilized during the on-peak period all year. Please refer to the response provided to PUB/MH/RISK-40(b). It should be noted that Manitoba Hydro has excess capacity that enables significantly higher generation during the on-peak.

**PUB/MH/RISK-61**

**Reference: Appendix 56, Attachment #4, Page 16**
**Risk Issue: Alternative Development Plan**

**a) Please confirm that a Conawapa G.S. in-service of 2021/22 (instead of Keeyask G.S.) has not been entirely ruled out.**

**ANSWER:**

Manitoba Hydro has not made a commitment to develop either Keeyask or Conawapa but is working to protect potential in-service-dates. Current plans that include Keeyask as the next plant are based on the successful conclusion of the sales with Wisconsin Public Service and Minnesota Power. Any commitment to either Keeyask or Conawapa will depend on the prevailing circumstances at the time and therefore it is confirmed that Conawapa G.S. as first plant has not been ruled out in favour of Keeyask G.S.

**PUB/MH/RISK-61**

**Reference: Appendix 56, Attachment #4, Page 16**
**Risk Issue: Alternative Development Plan**

**b) Please confirm that in the absence of substantial new transmission interconnections, the added generation output would not be fully employed during upper quartile flow scenarios (flow spillage would be substantial about one year in four).**

**ANSWER:**

Manitoba Hydro can confirm that in the absence of substantial new transmission interconnections in the order of 1000 MW, the added generation output would not be fully utilized in the early years after the in service of Conawapa, during upper quartile flow scenarios under Manitoba Hydro's alternative development plan. It is not expected that spill would be substantial even in these early years.

**PUB/MH/RISK-62**

**Reference:** **Appendix 56, Attachment #1 (Page 25) and Attachment #4 (Page 21)**
**Risk Issue:** **Reliability**

**a)** **Please provide an Alternative Power Resource scenario that would employ new CCCT thermal generation (in lieu of Keeyask G.S. and Bipole III. with a 2017/18 in-service to:**

- **Add 1,000 MW to AC supply capacity.**
- **Add about 5,000 to 8,000 GWh to energy supply.**

**ANSWER:**

The requested analysis would require significant new work that cannot be undertaken in the timeframe allotted for responses to information requests.

**PUB/MH/RISK-62**

**Reference: Appendix 56, Attachment #1 (Page 25) and Attachment #4 (Page 21)**
**Risk Issue: Reliability**

**b) Please provide a comparative annual cost and net revenue analysis ($M/¢/KWh) of:**

- **Keeyask G.S. and Bipole III.**
- **1,000 MW CCCT.**

**ANSWER:**

Manitoba Hydro interprets this information request as requesting a new development plan with a new IFF scenario which compares Keeyask G.S. to a 1000MW CCCT. The requested analysis would require significant new work that cannot be undertaken in the timeframe allotted for responses to information requests. In addition, Manitoba Hydro's recommended development plan along with alternatives will be subject to a full examination when the "need for and alternatives to" process is initiated.

It should be noted that in the 2000/01 timeframe, Manitoba Hydro recognized in its system planning the need for Bipole III based on reliability requirements.

**PUB/MH/RISK-62**

**Reference:** **Appendix 56, Attachment #1 (Page 25) and Attachment #4 (Page 21)**
**Risk Issue:** **Reliability**

**c) Please separately indicate the $CO_2$ emissions cost impact on a CCCT scenario for:**

- **$15/tonne.**
- **$30/tonne.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-49(b) for the impact of $CO_2$ emissions cost on CCCT variable production costs.

**PUB/MH/RISK-63**

**Reference: Appendix 56, Attachment #5, Page 45**
**Risk Issue: Workshop - Export Energy Pricing**

**a) Please confirm that with natural gas prices under $7/GJ, any energy needs in excess of hydraulic and wind generation likely to be experienced by MH in below average flow years could be cost effectively supplied by imports of MISO area CCCT natural gas thermal generation as opposed to:**

- **MH's own SCCT.**
- **MH's Selkirk.**
- **MH's Brandon Coal.**
- **New DSM.**

**ANSWER:**

It cannot be confirmed that all of Manitoba Hydro's resource alternatives listed in the information request are more costly than imports derived from CCCT generation corresponding to natural gas prices of $7/GJ. It should be noted that any power that Manitoba Hydro imports, regardless of reason or natural gas prices will be economically dispatched by MISO from the fleet of generation resources in the MISO market on a least cost basis, based on available supplies and constraints, without regard to sourcing from a particular generation technology such as CCCT. However, CCCT generation may be the marginal resource that sets the marginal clearing price in the MISO market.

For most hours of the year (other than during very high load periods in the summer and winter), it is likely that the economic resources from the MISO market are less expensive than Manitoba Hydro's own gas generation at Selkirk G.S. and the Brandon SCCT generation.

The operation of Brandon Unit 5 on coal is no longer based on market economics but rather restricted under the *Climate Change and Emissions Reductions Act* as discussed in the responses to PUB/MH I-85(a), (b), and (c). If the operation of this plant were not restricted, the cost of CCCT generation corresponding to natural gas prices of $7/GJ would clearly be greater than generation from the coal-fired plant.

DSM load reduction, such as from energy efficiency improvements, are not dispatchable resources but rather are long-term reductions in the Manitoba load. Once implemented, DSM load reduction cannot be turned off in response to market pricing. Since DSM is a long-term energy resource, new DSM is justified on the basis of long-term marginal cost which may be different than the short-term marginal cost proxy being discussed in this information request and in PUB/MH/RISK-63(b). In addition, it is possible that there may be new DSM initiatives that are less costly than the cost of CCCT generation corresponding to natural gas prices of $7/GJ.

**PUB/MH/RISK-63**

**Reference: Appendix 56, Attachment #5, Page 45**
**Risk Issue: Workshop - Export Energy Pricing**

**b) Please confirm that CCCT generation with its moderate CO2 footprint could at least in the short-term be reasonably viewed as a marginal cost / price proxy for MH's thermal or DSM energy resources.**

**ANSWER:**

It can be confirmed that CCCT generation is indeed the marginal generation resource for the MISO market during a portion of the operating hours during a given year. Therefore, during those hours, subject to system constraints, the marginal cost of a CCCT may be reasonably viewed as a marginal cost proxy for the Manitoba Hydro system.

Manitoba Hydro does not understand the meaning of how such a short-term marginal cost could apply to "MH's thermal or DSM energy resources". Please refer to the response to PUB/MH/RISK-63(a) for a discussion on the determination of levels of DSM.

**<u>PUB/MH/RISK-63</u>**

**Reference: Appendix 56, Attachment #5, Page 45**
**Risk Issue: Workshop - Export Energy Pricing**

c) **Please provide a status update on the Corporations understanding of current or proposed carbon legislation in the United States and Canada.**

**<u>ANSWER</u>:**

MH's understanding is that North American greenhouse gas (GHG) emissions will ultimately be significantly constrained through federal legislative and regulatory means, and/or through state and provincial actions.

Over the past two years, the United States Congress promoted several GHG reduction bills but was unable to move legislation. Uncertainty remains around the final format and timing of any federal GHG rules, but the U.S. Administration has stated its ongoing commitment to addressing emissions linked to climate change.

As part of the U.S. Administration's strategy, the Environmental Protection Agency (EPA) is expected to regulate GHG emissions from major stationary sources beginning in 2011. These regulations are expected to put significant constraints on electricity sector emissions. However, the EPA is facing a variety of legal challenges to these regulations from some members of Congress.

In Canada, the federal government has aligned its GHG reduction targets with those of the U.S. and expectations are that it will not independently legislate economy-wide GHG emissions. However, Environment Canada has been directed to move ahead with the development of regulations that will phase-out conventional coal-fired generation. Scheduled to begin in mid-2015, the proposed regulations would apply the GHG emissions performance standard of a natural gas combined cycle generator to new coal-fired electricity generation units, and to units that have reached the end of their economic life.

In addition to federal legislation and regulation, state- and provincially-led GHG cap-and-trade initiatives are also in various stages of development and operation. The Western Climate Initiative (WCI) and Midwestern Greenhouse Gas Reduction Accord (MGGRA) have been under development and include the Province of Manitoba as a partner jurisdiction.

Discussions are ongoing between the WCI, MGGRA, and the Regional Greenhouse Gas Initiative (RGGI) relating to a potential collaboration between these cap-and-trade systems.

**PUB/MH/RISK-64**

**Reference: Appendix 56, Attachment #5, Pages 46-51**
**Risk Issue: Workshop - Transmission Rights**

**a) Please confirm that transmission rights (going from MH into MISO) are held as follows:**

- **NSP 500 MW**
- **NSP 213 MW**
- **WPS 100 MW**
- **MP 50 MW**
- **MMPA 30 MW**
- **OTP 50 MW**
- **OTP 55 MW**
- **Diversity 300 MW**
- **ATC 450 MW**

**ANSWER:**

The following table indicates the firm transmission reservations on the US side of the boarding going into MISO:

- NSP 500 MW
- NSP 213 MW
- WPS 100 MW
- MP 50 MW
- MMPA 30 MW
- OTP 50 MW
- OTP 55 MW
- GRE 50 MW
- Diversities 300 MW
- Point-to-Point 471 MW

**PUB/MH/RISK-64**

**Reference: Appendix 56, Attachment #5, Pages 46-51**
**Risk Issue: Workshop - Transmission Rights**

**b) Please define and explain the ownership and role of the Diversity and ATC components**

**ANSWER:**

The 300 MW Diversity transmission is associated with the 150MW diversity contracts with NSP and GRE.

The 471 MW Point to Point transmission is firm transmission service that is owned by Manitoba Hydro. The role of firm point-to-point transmission service is to provide Manitoba Hydro with the ability to export electricity at any time into the MISO market independent of the control of any customer.

**Reference:** **Appendix 56, Attachment #5, Pages 46-51**
**Risk Issue:** **Workshop - Transmission Rights**

**c) Please indicate how MH's 17% control is arrived at and what constraints does the Corporation have on access on use thereof.**

**ANSWER:**

Since the workshop, Manitoba Hydro acquired 50 MW of firm point to point transmission. Therefore Manitoba Hydro currently controls approximately 30% not 17% of the firm transmission capability on the US side of the border during the summer season. This 30% is determined by dividing the 521 MW of point-to-point transmission (471 MW + 50 MW) that is held by MH in the US by the total ATC level of 1743 MW.

**Reference:** **Appendix 56, Attachment #5, Pages 46-51**
**Risk Issue:** **Workshop - Transmission Rights**

**d) Please indicate and explain which of the above transmission services were involved in MH's 2009/10 sales.**

**ANSWER:**

Manitoba Hydro utilized all the transmission services identified in PUB/MH/RISK-64a to provide contracted power sales to counterparties and with MISO for dependable and opportunity sales agreements in 2009-10.

**PUB/MH/RISK-65**

**Reference: Appendix 56, Attachment #6, Pages 3 and 4**
**Risk Issue: Workshop - Export Energy Quantities**

**a) Please confirm that in the MISO region, the August 8, 2008, October 3, 2008, and December 3, 2008 is a typical capacity offering of capacity for a hot summer day, fall day, and cold winter day.**

**ANSWER:**

Manitoba Hydro does not confirm the statement made in the information request. Generation capacity offered into the MISO market varies somewhat from hour to hour and day to day based on forced outages (equipment breakdown) and planned outages (regular maintenance). In addition, wind generation and net interchange are shown on the graph based on average daily values but in reality vary significantly from hour to hour, which impacts the total quantity of offered capacity on an hourly basis.

The Load versus Offered Capacity graphs in the "Manitoba Hydro Market Considerations for Planning" presentation in Appendix 56 were intended for educational purposes to illustrate the point that different technologies (which have different variable costs structures) would be the marginal generation unit at different times of the day, and different times of the year as the load changes through the day and year.

**<u>PUB/MH/RISK-65</u>**

**Reference: Appendix 56, Attachment #6, Pages 3 and 4**
**Risk Issue: Workshop - Export Energy Quantities**

**b) Please indicate the corresponding peak and off-peak market clearing prices for those dates.**

**<u>ANSWER</u>:**

The average MISO Day Ahead (DA) market prices, at the Minnesota Hub, in U.S. dollars, were:

| | **Aug 8 2008 DA** | **Oct 3 2008 DA** | **Dec 3 2008 DA** |
|---|---|---|---|
| On-Peak | 67.23 | 46.39 | 48.51 |
| Off-Peak | 15.73 | 17.94 | 22.08 |

**PUB/MH/RISK-65**

**Reference: Appendix 56, Attachment #6, Pages 3 and 4**
**Risk Issue: Workshop - Export Energy Quantities**

**c) Please define any non-market price mechanisms (subsidies/mandates/etc.) that could pre-empt minimum prices in determining the on-line percentage of:**

- **Nuclear.**
- **Wind.**
- **Coal.**

**ANSWER:**

Manitoba Hydro interprets this information request to relate to subsidies and mandates that would affect the dispatch of generation in the MISO market. MISO economically dispatches the fleet of generation resources in the MISO market on a least cost basis, based on available supplies and constraints, without regard to sourcing from a particular generation technology.

Most wind generation in the MISO market benefits from the U.S. Production Tax Credit. The PTC is a credit of about 2.1 cents per kilowatt-hour of wind generation. Except for a minimal number of low-load hours each year, which result in minimum generation alert conditions, the PTC does not affect the dispatch of wind generation in the MISO market.

Manitoba Hydro is not in a position to comment on the range of subsidies available to nuclear, wind and coal generators.

## PUB/MH/RISK-65

**Reference:** **Appendix 56, Attachment #6, Pages 3 and 4**
**Risk Issue:** **Workshop - Export Energy Quantities**

**d) Please indicate the percentage which bilateral agreements operate outside of the MISO market price framework for each of the following competing energy sources:**

- **Nuclear.**
- **Coal.**
- **Wind.**
- **Natural gas (CCCT's).**
- **MH exports.**

**ANSWER:**

Most bilateral contracts are confidential and hence the specific data is not publicly available to respond directly to this request. However, Manitoba Hydro exports, and the other generating resources listed in this information request, generally operate within the context of the MISO market framework and economics - otherwise, there would be no market.

As a general comment, bilateral contracts within the MISO market are treated as financial bilateral contracts, which means the contracts are used for financial settlement in accordance with contracts terms. The actual generation dispatch is determined by MISO based on the economics of the generation offers as required to meet the load without regard to the existence of the bilateral contracts. Bilateral contracts for capacity play an important role to ensure generation is made available to the market should it be required or economic.

**PUB/MH/RISK-66**

**Reference:** **Appendix 56, Attachment #5**
**Risk Issue:** **Workshop - Exports/Energy Supply**

**a)** **Please provide MH's export sales/export supply breakdown as per the following table:**

| | Total MISO Sales (Gwh) | Net MISO Sales (GWh) | Thermal Generation (GWh) | Manitoba Hydraulic & Wind Surplus (GWh) | Canadian Energy Purchases (GWh) |
|---|---|---|---|---|---|
| 2004/05 | | | | | |
| 2005/06 | | | | | |
| 2006/07 | | | | | |
| 2007/08 | | | | | |
| 2008/09 | | | | | |
| 2009/10 | | | | | |

**ANSWER:**

Manitoba Hydraulic & Wind Surplus numbers have not been supplied in the table below as this number would be based on an arbitrary allocation of generation to serve load.

| | Total Physical MISO Sales GWh | Net Physical MISO Sales GWh | Thermal Generation GWh | Canadian Physical Energy Purchases GWh |
|---|---|---|---|---|
| **2004/05** | 0 | 0 | 414 | 79 |
| **2005/06** | 6,613 | 6,568 | 401 | 12 |
| **2006/07** | 3,799 | 3,642 | 522 | 227 |
| **2007/08** | 5,831 | 5,753 | 457 | 124 |
| **2008/09** | 4,675 | 136 | 335 | 523 |
| **2009/10** | 4,647 | 4,532 | 143 | 114 |

**<u>PUB/MH/RISK-66</u>**

**Reference:** **Appendix 56, Attachment #5**
**Risk Issue:** **Workshop - Exports/Energy Supply**

**b) Please confirm (and define, how and why) that MH is unable to:**

- **Buy MISO market energy for direct resale into MISO market.**
- **Buy IESO or AESO energy for direct import into the MISO market.**

**<u>ANSWER</u>:**

Manitoba Hydro confirms that it is unable to buy MISO market energy for direct resale into the MISO market. Manitoba Hydro requires market-based rate authorization from the Federal Energy Regulatory Commission in order to perform this activity.

Manitoba Hydro confirms that it is able to import energy from the IESO for direct import into the MISO market.

Manitoba Hydro confirms that it is unable to buy energy from the AESO for direct import into the MISO market because the AESO market is not directly connected to the MISO market.

**PUB/MH/RISK-66**

**Reference: Appendix 56, Attachment #5**
**Risk Issue: Workshop - Exports/Energy Supply**

**c) Please confirm (and define, how and why) that MH is able to:**

- **Buy MISO market energy for direct resale to bilateral agreement customers in the MISO region.**
- **Buy MISO market energy for direct resale into Ontario.**

**ANSWER:**

Manitoba Hydro confirms it utilizes market settlement mechanisms to provide bilateral agreement customers with MISO market energy. Manitoba Hydro utilizes this market settlement mechanism whereby the bilateral agreement customer receives MISO market energy primarily when Manitoba Hydro's energy offer that is associated with a bilateral agreement does not clear the MISO day-ahead market.

Manitoba Hydro confirms that it is able to purchase MISO market energy for direct resale into Ontario.

**PUB/MH/RISK-67**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**a) Please confirm (or revise) the following contract commitments:**

**i. 375/325 MW**

**a) Must supply in 6 summer months (5x16/2x16/5x4 energy at 375 MW).**

**b) Must supply in 6 winter months (5x12/2x12/5x4 energy at 325 MW).**

**c) Guaranteed capacity at those levels for every day in the year (24 hours per day).**

**d) Optional supply (NSP must take) of energy in all remaining off-peak hours.**

**e) Optional supply (NSP must take) of additional capacity (up to 154 MW/204 MW summer/winter) and energy in both peak and off-peak periods.**

**ANSWER:**

a&b) Manitoba Hydro does not have a must supply commitment under the NSP 375/325 MW System Power Sale. Manitoba Hydro's commitment under the NSP 375/325 MW System Power Sale is to offer energy on a daily basis (375 MW during the summer season and 325 MW during the winter season) for a minimum of four consecutive hours in which the MISO load is expected to peak.

The 375/325 MW System Power Sale contains Fixed Price Energy (375 MW of 5x16 energy during the summer season, 325 MW of 5x12 energy during the winter season) for which NSP has a take or pay obligation. Manitoba Hydro will supply this energy to the extent that Manitoba Hydro's energy offers clear the MISO day-ahead market.

c) Manitoba Hydro confirms that capacity provided under the contract is 375 MW throughout the summer season and 325 MW throughout the winter season.

d) Manitoba Hydro has the option to supply and NSP has an obligation to take all energy supplied outside of the 5x16 period in the summer season and outside the 5x12 period in the winter season. This energy is defined as MH's Additional Energy in the contract.

e) Manitoba Hydro has the option to supply and NSP has an obligation to take all energy supplied by Manitoba Hydro (up to 154 MW in the summer season and up to 204 MW in winter season) up until the 125 MW System Power Sale commences. Once the 125 MW System Power Sale commences, the quantity reduces to 29 MW in the summer season and 79 MW in the winter season). This energy is defined as MH's Firm LD Energy in the contract. The total of all Fixed Priced Energy under the 375/325 MW and the 125 MW System Power Sale Agreements, MH's Additional Energy and MH's Firm LD Energy cannot exceed 529 MW for any given hour during the contract term.

**PUB/MH/RISK-67**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**a) Please confirm (or revise) the following contract commitments:**

**ii.. 350 MW Diversity**

**a) Must supply in 6 summer months (5x16/2x16 diversity energy at 350 MW).**

**b) Guaranteed capacity at 350 MW for every day in the year (24 hours per day).**

**c) Optional supply (NSP must take) of energy at 350 MW in all remaining (off-peak) hours.**

**d) Optional supply (NSP must take) of additional capacity (13 MW summer/ 213 MW winter) and energy in both peak and off-peak periods.**

**ANSWER:**

a) Manitoba Hydro does not have a must supply commitment under the NSP 350 MW System Diversity Sale. Manitoba Hydro's commitment during the summer season under the NSP 350 MW System Diversity Sale is to offer 350 MW of energy on a daily basis for a minimum of four consecutive hours in which the MISO load is expected to peak (MH's Must Offer Energy). Manitoba Hydro will supply this energy to the extent that Manitoba Hydro's energy offers clear the MISO day-ahead market.

b) Manitoba Hydro's capacity commitment is to provide 350 MW throughout the summer season. Manitoba Hydro does not have a capacity commitment during the winter season.

c) Manitoba Hydro has the option to supply and NSP has an obligation to take all energy supplied outside of the 7x4 must offer period. This energy is defined as MH's Additional Energy in the contract.

d) Manitoba Hydro has the option to supply and NSP has an obligation to take all energy supplied by Manitoba Hydro (up to 13 MW in the summer season and up to 213 MW in winter season). This energy is defined as MH's Firm LD Energy in the contract. The total of all MH's Must Offer Energy, MH's Additional Energy and MH's Firm LD Energy cannot exceed 363 MW for any given hour during the contract term.

**PUB/MH/RISK-67**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**a) Please confirm (or revise) the following contract commitments:**

**iii. 125 MW**

**a) Must supply (if new G&T proceeds) after 2021, additional 125 MW 5x16/2x16/5x4 energy in the summer; additional 125 MW 5x12/2x12/5x4 energy in the winter.**

**b) Guaranteed capacity at 125 MW for every day of the year (24 hours per day).**

**c) Optional supply (NSP must take) of energy at 125 MW in all remaining (off-peak) hours.**

**ANSWER:**

a) Manitoba Hydro does not have a must supply commitment under the NSP 125 MW System Power Sale. Manitoba Hydro's commitment after 2021 (if new G&T proceeds) under the NSP 125 MW System Power Sale is to offer energy on a daily basis for a minimum of four consecutive hours in which the MISO load is expected to peak.

The NSP 125 MW System Power Sale contains Fixed Price Energy (125 MW of 5x16 energy during the summer season, 125 MW of 5x12 energy during the winter season) for which NSP has a take or pay obligation. Manitoba Hydro will supply this energy to the extent that Manitoba Hydro's energy offers clear the MISO day-ahead market.

b) Manitoba Hydro confirms that capacity provided under the contract is 125 MW throughout the contract term (subject to new G&T).

c) Manitoba Hydro has the option to supply and NSP has an obligation to take all energy supplied outside of the 5x16 period in the summer season and outside the 5x12 period in the winter season (MH's Additional Energy).

**<u>PUB/MH/RISK-67</u>**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**b) The combined contracts commit MH to make available to NSP/Xcel:**

- **A minimum of 725 MW at all times during the 6 summer months; but would enable up to 892 MW to be supplied to NSP/Xcel in that time period.**
- **A minimum of 325 MW at all times during the 6 winter months; but would enable up to 742 MW to be supplied to NSP/Xcel in that time period.**

**<u>ANSWER</u>:**

Manitoba Hydro confirms the capacity commitment to NSP is as stated above. Manitoba Hydro's energy commitment is to offer energy associated with the minimum capacity levels stated above on a daily basis for a minimum of four consecutive hours in which the MISO load is expected to peak.

**PUB/MH/RISK-67**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**c) Please confirm that the contracts require MH to supply at least:**

- **3,200 GWh/year from 2016 to 2026.**
- **3,900 GWh/year after 2021 (if new G&T is in place).**

**ANSWER:**

Manitoba Hydro's energy supply requirements under the NSP contracts is 1,696 GWh per contract year and this amount increases to 2,205 GWh per year once the 125 MW System Power Sale commences.

These energy volumes are determined as follows:

Prior to 125 MW System Power Sale

| | |
|---|---|
| 375 MW * 184 days * 24 hours per day * 52.38% capacity factor = | 867 GWh |
| 325 MW * 181 days * 24 hours per day * 40.48% capacity factor = | 571 GWh |
| 350 MW * 184 days * 24 hours per day * 16.67% capacity factor = | 258 GWh |
| Total | 1,696 GWh |

Including 125 MW System Power Sale

| | |
|---|---|
| 375 MW * 184 days * 24 hours per day * 52.38% capacity factor = | 867 GWh |
| 325 MW * 181 days * 24 hours per day * 40.48% capacity factor = | 571 GWh |
| 125 MW * 184 days * 24 hours per day * 52.38% capacity factor = | 289 GWh |
| 125 MW * 181 days * 24 hours per day * 40.48% capacity factor = | 220 GWh |
| 350 MW * 184 days * 24 hours per day * 16.67% capacity factor = | 258 GWh |
| Total | 2,205 GWh |

The capacity factors used in the calculations above were determined as follows:
52.38% = 5x16 product (Monday to Friday HE7:00 to HE22:00) + 2x4 product (4 hour must offer on Saturday and Sunday)
40.48% - 5x12 product (Monday to Friday HE9:00 to HE20:00) + 2x4 product (4 hour must offer on Saturday and Sunday)
16.67% - 7x4 product (4 hour must offer on Monday to Sunday)

**PUB/MH/RISK-67**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**d) Please confirm that additionally, the contracts would enable MH to supply up to another 1,360 GWh/year of peak energy to NSP/Xcel when water flows permit and to supply up to 2,600 GWh/year (2016-2021) or 3,200 GWh/year (2021-26) of off-peak (night-time) energy to NSP/Xcel when water flows permit.**

**ANSWER:**

The NSP contracts will enable Manitoba Hydro to supply an additional 1,933 GWh/year (2016-21) and 1,477 GWh/year (2021-26) of on-peak energy and 3,532 GWh/year (2016-21) and 3,480 GWh/year (2021-26) of off-peak energy to NSP when water flows permit.

**<u>PUB/MH/RISK-67</u>**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**e) Please confirm that theoretically, MH could supply up to 7,000 GWh/year until 2021 and 8,400 GWh/year thereafter, with NSP/Xcel obligated to accept all of this energy.**

**<u>ANSWER</u>:**

Manitoba Hydro could theoretically supply and NSP would be obligated to accept 7,162 GWh/year over the contract term.

**PUB/MH/RISK-67**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**f) Please confirm that practically, MH will rarely be able to sell much winter peak period energy to NSP/Xcel until after Conawapa G.S. comes on-line.**

**ANSWER:**

Manitoba Hydro interprets the winter peak period to be the 5x16 on-peak hours through the months of November to April.

Manitoba Hydro does not confirm the statement made in this information request. Please refer to the supply/demand tables in the 2009/10 power resource plan provided as Appendix 47 in response to CAC/MSOS/MH I-35(a) which provide information on “System Firm Capacity (Winter Peak) Demand (MW) and Resources” relative to the highest single hour of demand. Over the winter on-peak period, which consists of all of the 5x16 on-peak hours (of which all but one is less than the peak hour), surplus winter generating capacity is available in all years from 2015 to 2025.

In its planning process, Manitoba Hydro ensured that supply was available to meet the terms of the NSP 375/325 System Power Sale including during the winter on-peak period.

**PUB/MH/RISK-67**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**g) Please confirm that some 900 GWh of optional winter peak sales will not be achievable before 2024 because of generation capacity constraints during the winter.**

**ANSWER:**

For clarification, please refer to the response to PUB/MH/RISK-67(a) which indicates that under the NSP 375/325 MW System Power Sale, Manitoba Hydro has the option to supply up to 204 MW of Additional Energy in the winter season. This translates into a maximum of approximately 400 GW.h of winter on-peak energy and not 900 GW.h as assumed in the information request.

Please also refer to the response to PUB/MH/RISK-67(f) which indicates that surplus winter capacity is available in all years from 2015 to 2025. Manitoba Hydro anticipates that in most years prior to Conawapa, total on-peak winter opportunity exports will exceed 400 GWh, which is the limit under the Additional Energy provision of the NSP 375/325 MW System Power Sale.

**PUB/MH/RISK-67**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**h) Please confirm that the average revenue rate for these contracts will be about 1.5-2.0¢/KWh lower than IFF 09-1 average price assumptions.**

**ANSWER:**

Manitoba Hydro cannot confirm the pricing information as it is trade secret and confidential.

**PUB/MH/RISK-67**

**Reference: NSP/Xcel 2015-2025 Contracts - Publicly Available Redacted Version**

**i) Please confirm that MH will be obligated to supply the energy in each year from hydraulic and wind resources to the maximum extent possible and a "Clean Energy" guarantee will apply to energy supplied under each of the three contracts over the life of the contracts.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-39(a).

**PUB/MH/RISK-68**

**Reference:** **Base and Alternative Development Sequence**
**IFF 09-1/2009/10 Power Resource Plan/CEF 09 1**
**Risk Issue:** **PUB/MH (Risk) - Deferral of Major G&T Projects**

**a)** **Please provide an alternative development scenario (including a new CEP, a new Power Resource Plan, and a new IFF 09-1), which consists of:**

- **A 1,000 MW CCCT coming on-line in 2017/18.**
- **Deferral until after 2030 of Bipole III, Keeyask G.S. and Conawapa G.S.**
- **NSP/Xcel contracts, but no WPS/MP contracts.**
- **Market energy prices that reflect natural prices going from $5/GJ (2010 to $10/GJ (2030), and CO2 Adders going from $15/tonne (2010) to $45/tonne (2030).**
- **Import prices in lower quartile flow years equal to export contract prices, including CO2 Adders.**

**ANSWER:**

In the 2009/10 power resource plan, which was provided in response to CAC/MSOS/MH I-35(a), Manitoba Hydro has provided the supply/demand tables for the recommended development plan and the alternative development plan under dependable conditions. In addition, the responses to PUB/MH/RISK-13 and PUB/MH/RISK-40(b) provide additional information related to the recommended development plan for a range of flow conditions. The information provided in the aforementioned responses allows for analysis and for observations to be made on Manitoba Hydro's recommended and alternative development plans. It is important to note that Manitoba Hydro's recommended development plan along with alternatives will be subject to a full examination when the "need for and alternatives to" process is initiated.

**<u>PUB/MH/RISK-69</u>**

**Reference: KPMG Report**
**Risk Issue: Model Verification**

**a) Please confirm that the HERMES July forecasts of annual hydraulic generation are relatively accurate for higher energy surplus years (deviation about 500 GWh), but show greater deviations (1,500 to 2,500 GWh) in years with drought conditions.**

**<u>ANSWER</u>:**

Confirmed.

**PUB/MH/RISK-69**

**Reference: KPMG Report**
**Risk Issue: Model Verification**

**b) Please confirm that with this deviation, the impacts for drought years would be magnified when energy prices (particularly imports) are factored in.**

**ANSWER:**

Manitoba Hydro cannot confirm this statement as the financial effects from volume deviations may or may not be offset in price variations.

Only when both price and volume forecasts are unfavourable will the impact be magnified. In circumstances when the volume forecast variance is unfavourable but the price forecast is favourable, there may be no net impact on net revenues.

**Reference:** **KPMG Report**
**Risk Issue:** **Model Verification**

**c) Please confirm that the HERMES over-statement of hydraulic generation in drought periods could be in addition to the greater (total) use of storage (in SPLASH) during these same drought periods.**

**ANSWER:**

Manitoba Hydro cannot confirm this statement.

**PUB/MH/RISK-69**

**Reference: KPMG Report**
**Risk Issue: Model Verification**

**d) Please confirm that MH views lake levels and hence energy-in-storage as output and not an input to the HERMES**

**ANSWER:**

Current lake levels are observed and are input to the HERMES model as a starting condition. Water in lake storage and water from inflows form the water supply. The optimization process in HERMES converts this water supply to hydraulic generation. One of the outputs of HERMES is a forecast of reservoir levels. There is no forecast of energy in storage in HERMES.

The HERMES model is used to project water levels in the future. Future water levels are determined based on the starting water level and future reservoir inflows and outflows. Inflows and outflows to a given reservoir are forecast using HERMES, therefore a *forecast* of energy in reservoir storage at some point in the future is an output of HERMES.

**<u>PUB/MH/RISK-70</u>**

**Reference:** **KPMG Report – Page 57-59 (Exhibit 3.5)**
**Risk Issue:** **Antecedent Forecasting**

**a) Please explain and illustrate for 2006-07 the time-step process employed by MH to define the seasonal (and monthly) flows of:**

- **Winnipeg River @ Pine Falls.**
- **Red River @ Lockport.**
- **Saskatchewan River @ The Pas.**
- **Burntwood River @ Thompson.**
- **Local inflows and lake or reservoir evaporation.**
- **Upper Nelson River @ Kelsey G.S.**
- **Lower Nelson River @ Kettle G.S.**

**<u>ANSWER</u>:**

In general, the time-steps used in antecedent inflow forecasting consist of weekly time-steps leading up to the end of the first future month and monthly time-steps thereafter. The independent variable is the average actual flow for the previous week which is used in the regression model to project the future flow for the forecast period.

In general, Manitoba Hydro repeats its inflow forecasting process every week throughout the year. Inflow forecasts may be reviewed more frequently if warranted by system conditions, for example if inflows are changing rapidly as a result of a major rainstorm.

This process was used in 2006/07. Of the locations listed above, regression models are only used for the Red River and local inflows. Flows at the other locations are predicted from the routing of inflows and reservoir operations at upstream locations.

**<u>PUB/MH/RISK-70</u>**

**Reference: KPMG Report – Page 57-59 (Exhibit 3.5)**
**Risk Issue: Antecedent Forecasting**

**b) Please explain how the antecedent forecasting deals with the flow attenuation due to (artificial) reservoir regulation by MH or other jurisdictions.**

**<u>ANSWER</u>:**

Reservoir regulation and reservoir routing (attenuation) within the Manitoba Hydro system and the Winnipeg River system upstream of Manitoba is dealt with outside of antecedent forecasting, using Manitoba Hydro's hydraulic simulation models.

In some instances for flows arriving in Manitoba, antecedent regression relationships are based on historic flow data which embeds the 'attenuation' effects due to reservoir regulation by other jurisdictions.

**PUB/MH/RISK-70**

**Reference:** **KPMG Report – Page 57-59 (Exhibit 3.5)**
**Risk Issue:** **Antecedent Forecasting**

**c)** **Please confirm that within various licence constraints, MH's hydraulic system does not transfer substantial quantities of water from one water year to the next (unlike the St. Lawrence River system).**

**ANSWER:**

Manitoba Hydro can confirm that on average it does not transfer significant quantities of water from one year to the next.

**<u>PUB/MH/RISK-70</u>**

**Reference:** **KPMG Report – Page 57-59 (Exhibit 3.5)**
**Risk Issue:** **Antecedent Forecasting**

**d)** **Please explain with hindsight how MH might have further minimized the financial consequence of the drastically lower late summer and fall flows/hydraulic output**

**<u>ANSWER</u>:**

Manitoba Hydro does not control the water supply. It is a natural process that depends upon the weather and the weather cannot be predicted accurately much more that a few days in advance. Over 70% of Manitoba Hydro's water supply is regulated upstream from Manitoba by other reservoir operators. Manitoba Hydro does not control these reservoirs especially those on the Winnipeg River which are completely dependent upon regulation in Ontario. During 2006/07 Manitoba Hydro believes its reservoir regulation practices were appropriate given the constraints on operating the power system and that the power system was operated in a least cost manner.

**PUB/MH/RISK-71**

**Reference: KPMG Report – Appendix J (J-10 Page 57-59**

**Risk Issue: Alternative Development Sequence**

**a) Please confirm that the Alternative Development Sequence would involve:**

- **375/325 MW NSP Agreement.**
- **350 MW NSP Diversity Agreement.**
- **125 MW additional NSP Agreement.**
- **Conawapa G.S. in 2021/25.**
- **Bipole III in 2018/19.**
- **A CCCT in 2033/34.**

**but would not include:**

- **Keeyask G.S.**
- **500 WPS/250 MP sales.**
- **Any new transmission access in U.S.**

**ANSWER:**

Based on Manitoba Hydro's evaluations in the 2009/10 timeframe, it is confirmed that the Alternative Development Plan includes the 375/325 NSP Agreement, the 350 MW NSP Diversity Agreement, the 125 MW additional NSP agreement, Conawapa G.S. in 2021/22 ISD, Bipole III in 2018/19, and a CCCT in 2033/34. It does not include the Keeyask G.S., the WPS/MP Sale or any new transmission into the U.S.

PUB/MH/RISK-71

**Reference:** **KPMG Report – Appendix J (J-10 Page 57-59**
**Risk Issue:** **Alternative Development Sequence**

**b)** **Please confirm that this Alternative Scenario would result in debt ratios (%) and retained earnings levels (approximately from graphical illustrations) as follows:**

| Year | Debt Ratio (%) | | Retained Earnings ($M) | |
|---|---|---|---|---|
| | Alt. Base Scenario | Base Forecast | Alt. Base Scenario | Base Forecast |
| 2012 | 75 | 75 | 2,300 | 2,300 |
| 2017 | 78 | 81 | 2,800 | 3,000 |
| 2022 | 74 | 77 | 4,300 | 4,500 |
| 2027 | 56 | 62 | 7,600 | 8,500 |

**ANSWER:**

Based on the reference cited for this question, Manitoba Hydro is unable to confirm the debt ratios and retained earnings in the table. However, the "Base Forecast" is consistent with IFF09 and 20 Year Financial Outlook provided in Appendix 5.2 and Appendix 16, respectively, and the "Alt. Base Scenario" is consistent with the Alternative Development Sequence provided in Appendix 15.

**PUB/MH/RISK-71**

**Reference: KPMG Report – Appendix J (J-10 Page 57-59**
**Risk Issue: Alternative Development Sequence**

**c) Please rationalize the directional significance of the above debt ratios and retained earnings in defining MH's financial health.**

**ANSWER:**

Based on the response to PUB/MH/RISK-71(b), debt ratios are slightly lower under the Alternative Development Sequence compared to the 20 Year Financial Outlook until 2033/34. Over the same period, retained earnings are conversely lower under the Alternative Development Sequence compared to the 20 Year Financial Outlook. The apparent counter-intuitive impact on debt ratio and retained earnings is related to the significant growth in net assets under the 20 Year Financial Outlook compared to the Alternative Development Sequence. As the benefits from hydro development and additional US tie-line capability are realized under the 20 Year Financial Outlook, the growth in retained earnings keeps pace with the growth in net assets and maintains roughly the same proportionate amount of debt and equity to net assets.

**PUB/MH/RISK-71**

**Reference: KPMG Report – Appendix J (J-10 Page 57-59**
**Risk Issue: Alternative Development Sequence**

**d) Please identify the export and import volumes and average prices that were employed for the NSP/Xcel contract(s) in the Alternative Development Sequence**

**ANSWER:**

Manitoba Hydro declines to provide this information as contract specific information is commercially sensitive and therefore confidential.

**PUB/MH/RISK-72**

**Reference:** **KPMG Report – Appendix J Page 27`**
**Risk Issue:** **Debt: Equity**

**a)** **Please confirm or otherwise explain that contrary to the statement on P. J-27, Alternative Base (No Sale) scenario has a favourable debt ratio compared to the Base Forecast and that the differential is not negated under various drought events as illustrated in Exhibits J-31/J-32/J-33.**

**ANSWER:**

KPMG Response:

On page Appendix J-27, KPMG stated that "the sale scenario provides MH with improved Retained Earnings and Debt Ratios compared to the No Sale Scenario."

Exhibits J-31 to J-33 show that the Sale case debt ratios are lower than under the No Sale case debt ratios for the 9 scenarios presented (three different price forecasts under each of the three different drought commencement year runs) by the end of the period shown in the exhibits (i.e., 2033). Further, the MH data provided to KPMG is for a longer period (to 2042) than depicted in the exhibits J-31, J-32 and J-33 in the KPMG report (to 2033) and demonstrate a further continuation of this trend - under all cases, debt ratios under the Sale case continue to be much lower than the No Sale case over the long term.

**PUB/MH/RISK-72**

**Reference: KPMG Report – Appendix J Page 27`**
**Risk Issue: Debt: Equity**

**b) Please confirm or otherwise provide the debt ratios for respectively 2017/2022/2027 for drought events commencing in:**

| Drought Commences | | Debt Ratios % | | |
|---|---|---|---|---|
| | | Low Price | Expected Price | High Price |
| 2013 | Alt.<br>Base | 90/92/76<br>90/92/78 | 92/93/89<br>94/92/88 | 100/107/102<br>99/105/97 |
| 2019 | Alt.<br>Base | 80/80/75<br>80/82/76 | 78/83/83<br>81/85/83 | 79/86/95<br>81/86/93 |
| 2025 | Alt.<br>Base | 78/75/59<br>80/78/64 | 78/75/60<br>81/78/65 | 79/62/62<br>81/66/66 |

**ANSWER:**

Manitoba Hydro confirms that the debt ratios provided in the table in this information request are approximately correct.

**<u>PUB/MH/RISK-72</u>**

**Reference:** **KPMG Report – Appendix J Page 27`**
**Risk Issue:** **Debt: Equity**

**c)** **Please reconcile the debt ratios for the Sale and alternative "No Sale" scenarios on P. J-26 and J-27 with the debt ratios shown on P. J-4/J-7/J-10 and J-14/J-17/J-20.**

**<u>ANSWER</u>:**

The Exhibits J-4/J-8/J-12 and J-31/J-32/J-33 have been reproduced in colour for reference and are attached (Attachments #1-5). Exhibits J-16/J-20/J-24 are redacted from the public KPMG report and debt ratios cannot be reconciled to Exhibits J-31/J-32/J-33.

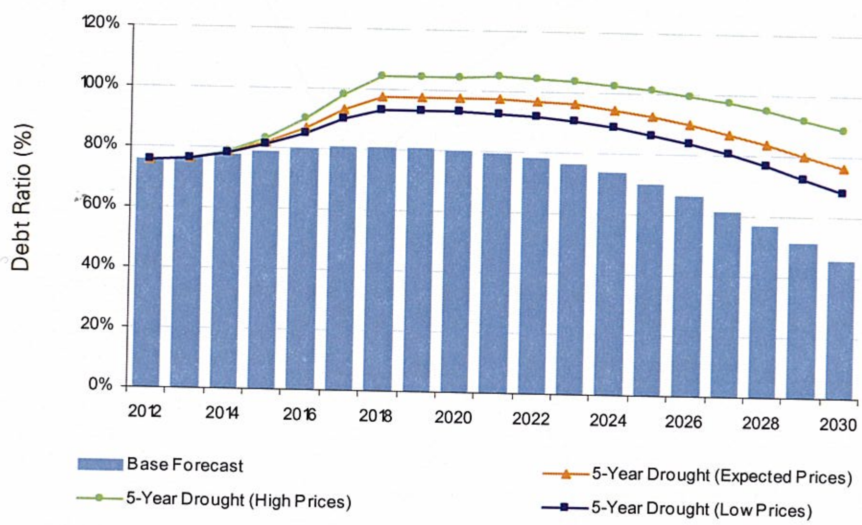
<u>Exhibit J-4 (p. J-4)</u>:
5-Year Drought High Prices (green line circle marker) corresponds to Exhibit J-33 (p. J-27) Commencing 2013 (Sale) (light blue line square marker).
5-Year Drought Expected Prices (orange line triangle marker) corresponds to Exhibit J-32 (p. J-26) Commencing 2013 (Sale) (light blue line square marker).
5-Year Drought Expected Prices (dark blue line square marker) corresponds to Exhibit J-31 (p. J-26) Commencing 2013 (Sale) (light blue line square marker).

<u>Exhibit J-8 (p. J-7)</u>:
5-Year Drought High Prices (green line circle marker) corresponds to Exhibit J-33 (p. J-27) Commencing 2019 (Sale) (red line triangle marker).
5-Year Drought Expected Prices (orange line triangle marker) corresponds to Exhibit J-32 (p. J-26) Commencing 2019 (Sale) (red line triangle marker).
5-Year Drought Expected Prices (dark blue line square marker) corresponds to Exhibit J-31 (p. J-26) Commencing 2019 (Sale) (red line triangle marker).

<u>Exhibit J-8 (p. J-7)</u>:
5-Year Drought High Prices (green line circle marker) corresponds to Exhibit J-33 (p. J-27) Commencing 2025 (Sale) (dark green line circle marker).
5-Year Drought Expected Prices (orange line triangle marker) corresponds to Exhibit J-32 (p. J-26) Commencing 2025 (Sale) (dark green line circle marker).
5-Year Drought Expected Prices (dark blue line square marker) corresponds to Exhibit J-31 (p. J-26) Commencing 2025 (Sale) (dark green line circle marker).

MH's ability to withstand the financial impact of a five year drought will be dependent on the Retained Earnings available to MH during the drought periods. As indicated above, the estimated financial impact of a five year drought commencing in 2013 will result in nominal Retained Earnings assuming low and expected prices, and Deficits of up to $1.3 billion in the periods 2018 to 2026 assuming high prices.

**Exhibit J-4: Sale Scenario Impact on Debt Ratio of 5-Year Drought Commencing in 2013**




*Source: derived from Manitoba Hydro data and model runs.*

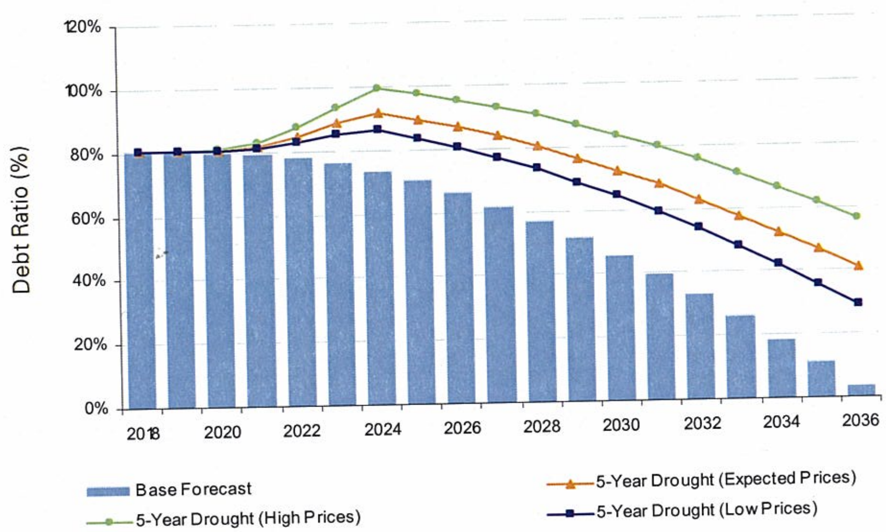
As indicated, assuming low and expected prices, the Debt Ratio will exceed the 75% target beginning in 2014 and will reach 93% and 97% in 2018 for low and expected prices respectively, returning to target levels by 2029/2030. Assuming high prices, the Debt Ratio will exceed the target beginning in 2014 and will reach 105% in 2021 and return to target levels in 2034.

## *Five Year Drought Sale Scenario 2*

This scenario assumes a recurrence of the worst five year drought on record (1937 – 1941) commencing in 2019, coinciding with the in service date for Keeyask and construction stage of Conawapa, returning to average revenues for all 94 flow conditions in the periods preceding and following the drought period assuming expected, high and low prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

As indicated, the estimated financial impact of a five year drought commencing in 2019 will result in sufficient Retained Earnings to withstand the drought assuming both low and expected price, and a nominal Deficit in 2024 and Retained Earnings immediately thereafter assuming high prices.

**Exhibit J-8: Sale Scenario Impact on Debt Ratio of 5-Year Drought Commencing in 2019**




*Source: derived from Manitoba Hydro data and model runs.*

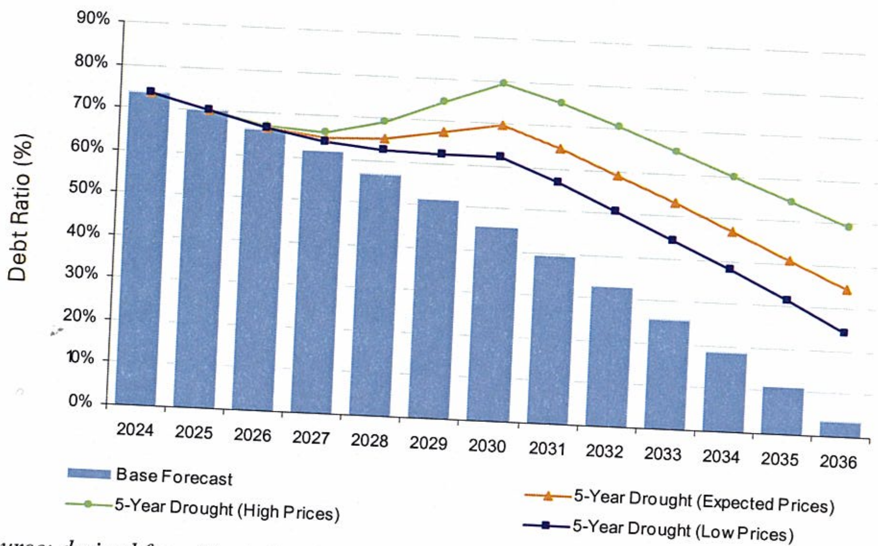
The Debt Ratio will reach highs of 86%, 91% and 99% in 2024 assuming low, expected and high prices respectively.

## *Five Year Drought Sale Scenario 3*

This scenario assumes a recurrence of the worst five year drought on record (1937 – 1941) commencing in 2025, coinciding with the in service date of Conawapa, returning to average revenues for all 94 flow conditions in the periods preceding and following the drought period assuming low, expected and high prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

As indicated, assuming low, expected or high prices, there should be sufficient Retained Earnings to withstand the estimated financial impact of a five year drought commencing in 2025.

**Exhibit J-12: Sale Scenario Impact on Debt Ratio of 5-Year Drought Commencing in 2025**




*Source: derived from Manitoba Hydro data and model runs.*

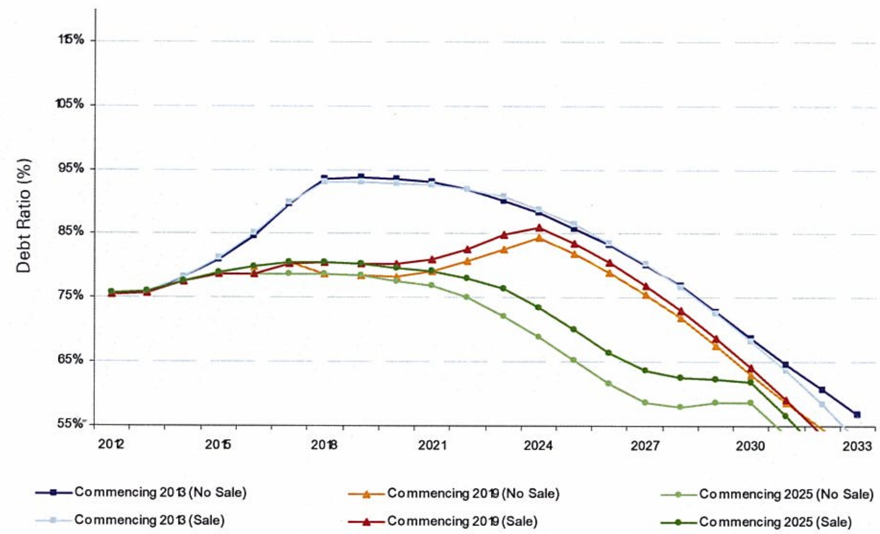
The Debt Ratio and will be below the target debt ratio of 75% in all years for both low and expected prices, and will reach 80% in 2030 assuming high prices.

## Alternative Development Plan Sequence Analysis

In this section we consider the impact of drought risk related to the new generation development sequence and the related long-term export contracts.

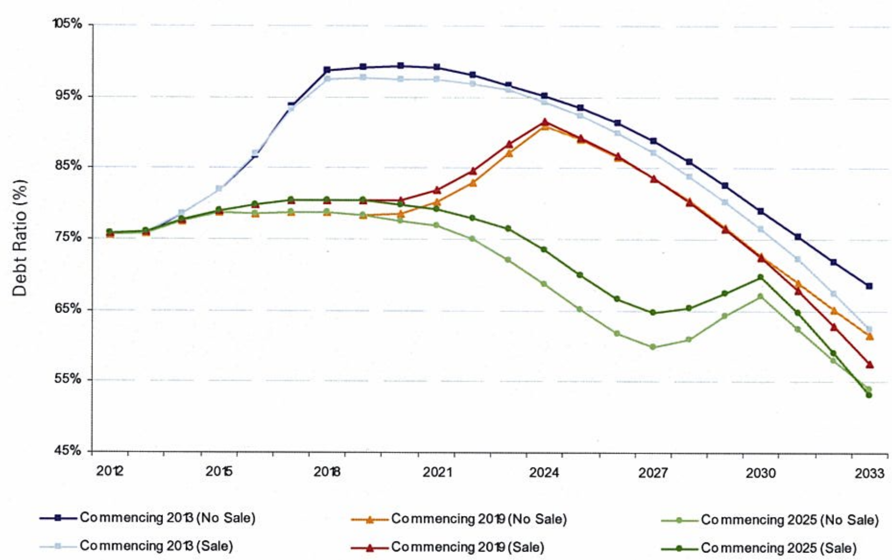
We asked MH to consider the impact of five year droughts commencing at various times in a situation where new generation capacity is only added as required to meet Manitoba load growth. The development sequence required to meet Manitoba load growth includes Conawapa in 2021/22 (advanced one year from 2022/23 in the IFF09 and 20 Year Financial Outlook) and a combined cycle combustion turbine in 2033/34. This sequence excludes the export sales related to the WPS and MP contracts, the construction of Keeyask, and the planned US transmission interconnection (herein defined as the "No Sale Scenario").

**Exhibit J-31: Comparison of Sale vs. No Sale Scenarios (Low Prices)**



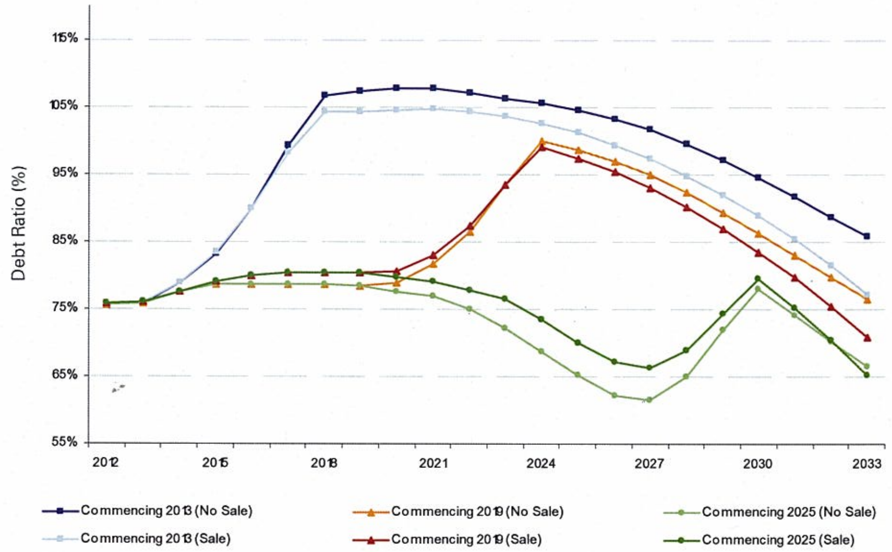

*Source: derived from Manitoba Hydro data and model runs.*

**Exhibit J-32: Comparison of Sale vs. No Sale Scenarios (Expected Prices)**




*Source: derived from Manitoba Hydro data and model runs.*

**Exhibit J-33: Comparison of Sale vs. No Sale Scenarios (High Prices)**




*Source: derived from Manitoba Hydro data and model runs.*

As previously stated, the Sale Scenario provides MH with improved Retained Earnings and Debt Ratios compared to the No Sale Scenario. The improved Retained Earnings and Debt Ratios are due primarily to the increased surplus export sales associated with the new generation and US transmission interconnection capabilities. The new US transmission interconnection capabilities also provide for increased import capabilities in low flow periods, which should reduce costs required to run the thermal gas units in order to meet Manitoba load requirements.

Accordingly, the Sale Scenario appears to reduce the overall risk of a five year drought compared to a No Sale Scenario, since it provides greater Retained Earnings and improved Debt Ratios to withstand the financial impact of a five year drought.

## Additional Low Flow Scenarios

In this section we considered additional low water flow conditions to supplement the analysis and determine the financial impact for a reoccurrence of the worst ten years of historical low flows on record (1932 to 1941), and the worst fifteen years of historical low flows on record (1927 to 1941), as illustrated in the graph below, in a Sale Scenario commencing at various times.

**PUB/MH/RISK-72**

**Reference: KPMG Report – Appendix J Page 27`**
**Risk Issue: Debt: Equity**

**d) Please explain why Additional Low Flow scenarios did not examine a low price impact for drought situations.**

**ANSWER:**

In the context of the financial impact of drought, low prices will not result in a financial impact as severe as that under expected or high prices. Therefore, an analysis of low prices was not undertaken.

## PUB/MH/RISK-73

**Reference:** **KPMG Report – Appendix J**
**Risk Issue:** **Energy Purchase Assumptions**

**a)** **Please provide the inputs/assumptions employed in each of the various drought scenarios with respect to:**

| | Average Export | | Average Imports | | Other Power Purchases | |
|---|---|---|---|---|---|---|
| | Volumes (GWh) | (¢/KWh) | Volumes (GWh) | (¢/KWh) | Volumes (GWh) | (¢/KWh) |
| F2012<br>F2017<br>F2022<br>F2027 | | | | | | |

**ANSWER:**

The inputs and assumptions related to the drought scenarios are considered to be confidential based on rationale #7 for Manitoba Hydro redactions to the KPMG Report and Appendices. Rationale #7 relates to economic and financial benefits including retained earning calculations that are confidential and therefore, if released publicly, can harm Manitoba Hydro in negotiation of export sales.

Furthermore, the market model within SPLASH does not use singular or average prices but utilizes a pricing structure for different volumes.

**<u>PUB/MH/RISK-73</u>**

**Reference: KPMG Report – Appendix J**
**Risk Issue: Energy Purchase Assumptions**

**b) Please indicate what import shortage pricing (premiums) if any were applied to the drought years in each scenario.**

**<u>ANSWER</u>:**

No specific shortage pricing premiums were applied to imports for the analysis. As discussed in the response to CAC/MSOS/MH/RISK-41(b): “While a drought is a significant event for Manitoba, in the context of the large size of the MISO market, it is not such a significant event. Therefore, overall MISO market prices are largely independent of drought conditions in Manitoba.” For further information, please see the responses to CAC/MSOS/MH/RISK-41(b) and CAC/MSOS/MH I-62(g).

It should be noted that the analysis in Appendix J includes low, expected and high price scenarios. The high price scenario accommodates assumptions related to shortage pricing.

**PUB/MH/RISK-73**

**Reference: KPMG Report – Appendix J**
**Risk Issue: Energy Purchase Assumptions**

**c) Please compare the relationship of above pricing assumptions with actual experiences in the second half of 2002/03 and the full year 2003/04 and again in 2006/07.**

**ANSWER:**

The requested analysis would require significant new work that cannot be undertaken in the timeframe allotted for responses to information requests.

Manitoba Hydro notes that the centrally operated MISO energy market became operational on March 31, 2005, substantially improving the regional dispatch, transmission operation and a significantly more liquid and competitive real-time and day-ahead markets. Thus the market environment has changed significantly since 2002/03 and 2003/04, limiting the applicability of the suggested historical comparisons. As well, the MISO market has not remained static and new generation and transmission resources have been added.

**<u>PUB/MH/RISK-73</u>**

**Reference: KPMG Report – Appendix J**
**Risk Issue: Energy Purchase Assumptions**

**d) Would MH agree that "shortage pricing" would constitute a more "conservative" approach to resource management?**

**<u>ANSWER</u>:**

It is unclear to Manitoba Hydro what is meant by this information request. However, Manitoba Hydro offers the following comments:

The analysis in Appendix J includes low, expected and high prices. The high prices provided would accommodate assumptions related to shortage pricing as well as any other potential drivers for high prices, and therefore provides a more robust analysis than focussing only on shortage pricing. It should be noted that the market model within SPLASH utilizes a pricing structure for import energy that results in higher prices as the volume of required energy increases. Please also see the response to CAC/MSOS/MH I-62(g) which discusses shortage pricing.

**PUB/MH/RISK-74**

**Reference: KPMG Report – Main Report/End of May 2010 MH Workshop**

**a) Please advise whether MH shared the end of May 2010 Workshop Presentation contents (in whole or in part) with KPMG prior to their April 15, 2010 submission of the main report.**

**ANSWER:**

Manitoba Hydro did not share the Workshop Presentation contents with KPMG. However, many of the materials provided to KPMG were similar in nature to the Workshop materials.

**PUB/MH/RISK-74**

**Reference: KPMG Report – Main Report/End of May 2010 MH Workshop**

**b) Please indicate whether KPMG was asked to and/or did provide any critique on the Workshop Presentation material.**

**ANSWER:**

KPMG was not asked to provide any critique on the Workshop Presentation material.

**PUB/MH/RISK-74**

**Reference: KPMG Report – Main Report/End of May 2010 MH Workshop**

**c) Please indicate the time frame and extent that the KPMG review was intended to capture in their analysis of MH's forecasting procedures:**

- **2009/10 +/ or**
- **2004/05 to 2008/09 +/or**
- **1999/00 to 2003/04.**

**ANSWER:**

KPMG was not asked to review a particular time frame. Rather, their mandate was to review the assertions made by the NYC which included the period from approximately 2006 to 2008.

**PUB/MH/RISK-74**

**Reference: KPMG Report – Main Report/End of May 2010 MH Workshop**
**Risk Issue: MH Workshop**

**d) Please explain why KPMG (or MH) did not do a model verification run employing the actual drought event data (GWh/¢/KWh/etc.) for the 2002/03 and 2003/04 period.**

**ANSWER:**

KPMG was not asked to do a model verification run for 2002-2004 as it was prior to the initial NYC engagement. KPMG reviewed Manitoba Hydro's drought management strategies, the validity of its models and forecasting technique. The results of that review found:

- Manitoba Hydro's process for forecasting water flow is reasonable; the process is statistically sound and is a standard industry approach.
- The use of historical water flow data for forecasting is reasonable.
- Manitoba Hydro has taken appropriate care and due diligence in developing, operating and maintaining the models.

Manitoba Hydro's drought management strategies, models and forecasting technique were all in place in 2002-2004 and testing them against that specific year with perfect hindsight with regard to prices would not have changed the conclusions.

**PUB/MH/RISK-75**

**Reference: KPMG Report – Main Report**
**Risk Issue: Reliability of Export Supply**

**a) Please confirm that prior to 2003-04, MH's annual hydraulic generation had always exceeded annual domestic load requirements and that off-peak imports were essentially used to achieve peak exports.**

**ANSWER:**

Manitoba Hydro cannot confirm that prior to 2003/04, annual hydraulic generation always exceeded annual domestic load and that off peak imports were only used to serve export sales.

**PUB/MH/RISK-75**

**Reference:** **KPMG Report – Main Report**
**Risk Issue:** **Reliability of Export Supply**

**b)** **Please confirm that the increasing domestic load did exceed 2003/04 hydraulic generation and going forward will continue to exceed dependable hydraulic generation until at least 2018 with ever greater price risks.**

**ANSWER:**

As shown in the graph provided in response to PUB/MH/RISK-55(b), Manitoba Hydro confirms that domestic load will continue to exceed Manitoba Hydro's dependable energy from hydraulic generation. Manitoba Hydro has the obligation to serve firm commitments and therefore must ensure that adequate resources are available. At those points in time when new resources are required, Manitoba Hydro's development plan along with alternatives will be subject to a full examination when the "need for and alternatives to" process is initiated.

**PUB/MH/RISK-75**

**Reference: KPMG Report – Main Report**
**Risk Issue: Reliability of Export Supply**

**c) Please confirm that firm export contracts now rely entirely on a combination of energy supplies from:**

- **Wind.**
- **Thermal generation.**
- **Diversity imports.**
- **Non-firm imports.**

**ANSWER:**

Manitoba Hydro does not confirm the statement in this information request. Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations.

Please refer to the response to PUB/MH/RISK-13(a) which presents graphs that show the relative frequencies of the various generation sources over the range of flow conditions in three different years into the future.

**PUB/MH/RISK-75**

**Reference: KPMG Report – Main Report**
**Risk Issue: Reliability of Export Supply**

**d) Please confirm that in about one third of the next 8-10 years, MH could reasonably expect to purchase all of the energy to meet firm export commitments.**

**ANSWER:**

Manitoba Hydro does not confirm the statement in this information request. Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations.

Please refer to the response to PUB/MH/RISK-13(a) which presents graphs that show the relative frequencies of the various generation sources over the range of flow conditions in three different years into the future. As may be observed from the graphs, the frequency of relying on Manitoba Hydro thermal or imports would be significantly less than one year in three.

**<u>PUB/MH/RISK-75</u>**

**Reference:** **KPMG Report – Main Report**
**Risk Issue:** **Reliability of Export Supply**

**e)** **Please explain how this situation constitutes "conservative" practices in energy management when:**

- **Wind energy is intermittent.**
- **SCCT thermal generation is uneconomical.**
- **Diversity imports usually command significantly higher prices than diversity exports.**
- **Non-firm imports in drought periods may command peak market prices reflecting a capacity guarantee.**
- **DSM is ill-defined and may not be dispatchable.**

**<u>ANSWER</u>:**

Please refer to the information provided in responses to PUB/MH/RISK-75(c) and (d), and the information provided in PUB/MH/RISK-13(a) regarding the relative frequency of Manitoba Hydro's reliance on non-hydraulic generation.

Please also refer to the response to PUB/MH/RISK-126(b) for comments regarding the specific resources listed in this information request.

**PUB/MH/RISK-76**

**Reference: KPMG Report – Appendix J – Sale/No Sale Analysis**
**Risk Issue: Alternative Scenarios**

a) **Please explain why the pricing approach used for export-import impact calculations for various drought sequences did not employ the same purchase prices for the "No Sale" as for the "Base Case" for later drought events.**

| | Drought Years | | |
|---|---|---|---|
| | **2013-18** | **2019-24** | **2025-30** |
| **Lost Exports/(Purchases) – Sale Scenario** | | | |
| **¢/KWh** | | | |
| • **Low** | **5.3 (6.7)** | **5.6 (7.2)** | **6.6 (8.4)** |
| • **Expected** | **7.1 (9.0)** | **7.8 (10.2)** | **9.8 (12.0)** |
| • **High** | **9.9 (12.1)** | **11.5 (14.0)** | **14.0 (16.3)** |
| **Lost Exports/(Purchases) – No Sale Scenario** | | | |
| • **Low** | **5.3 (6.7)** | **5.6 (8.2)** | **6.4 (9.2)** |
| • **Expected** | **7.1 (9.0)** | **7.8 (11.3)** | **9.6 (13.0)** |
| • **High** | **9.9 (12.1)** | **11.2 (15.4)** | **14.7 (17.4)** |

**ANSWER:**

Manitoba Hydro assumes that the unit prices in this information request were determined from the volumes and revenues and cost differences provided in Appendix J. These estimates have not been verified by Manitoba Hydro.

As stated in Appendix J "This appendix presents the results of the detailed runs conducted by Manitoba Hydro". The runs provided by Manitoba Hydro used the same market prices for both "No Sale" and "Base Case". As explained in the response to PUB/MH II-208(c), Manitoba Hydro does not assume that there is a single price for export and import energy and the impact of the new interconnection assumed in the Sale Scenario along with other factors affects the average pricing. A new interconnection allows more energy to be purchased during periods when prices are lower, resulting in a lower average purchase price.

**PUB/MH/RISK-76**

**Reference: KPMG Report – Appendix J – Sale/No Sale Analysis**
**Risk Issue: Alternative Scenarios**

**b) Please provide the rationale employed for defining lost export revenues in drought years when IFF 09-1 appears to assume:**

- **Opportunity export prices that on average will be higher than firm contract prices.**
- **Little, if any, off-peak sales in mean flow years.**
- **Average export revenue rates higher than prevailing/potential firm contract rates.**

**ANSWER:**

Manitoba Hydro does not agree that IFF-09 incorporates the assumptions stated in this information request. It is unclear to Manitoba Hydro what the relationship is between the statements in this information request and the calculation of lost export revenue in Appendix J of the KPMG Report.

For clarification, revenues in the IFF are based on the average of revenues from all 94 historic flow conditions and not the revenues from a single flow condition, such as the median flow. Lost export revenue is the difference between the revenue stated in the IFF, which consists of all 94 flow conditions, and the revenue from each of the five drought years.

Please refer to the response provided to PUB/MH/RISK-78(b) which addresses the relative value of opportunity energy.

**PUB/MH/RISK-76**

**Reference: KPMG Report – Appendix J – Sale/No Sale Analysis**
**Risk Issue: Alternative Scenarios**

**c) Please define the impacts on the "No Sale" alternative IFF 09-1 (and supporting assumptions) of significantly reducing MH's reliance on imports of high CO2 fossil fuel generation by:**

- **Minimal, if any, imports in average (or above) flow years.**
- **No off-peak overnight sales except in upper quartile flow years.**

**ANSWER:**

The requested analysis would require significant new work that cannot be undertaken in the timeframe allotted for responses to information requests.

**PUB/MH/RISK-77**

**Reference: KPMG Report – Appendix J – Page J-10**
**Risk Issue: Power Resource Plan**

**a) Please confirm that both the Base Case and the Alternate Development Sequence employed by KPMG were identical to that provided in the MH's Power Resource Plan.**

**ANSWER:**

It is confirmed that the Base Case Development Plan and the Alternative Development Plan used by KPMG are identical to those provided in the 2009/10 Power Resource Plan.

**PUB/MH/RISK-77**

**Reference: KPMG Report – Appendix J – Page J-10**
**Risk Issue: Power Resource Plan**

**b) Please identify and supply any other alternative development scenarios that MH shared with KPMG, e.g.:**

- **i. No NSP/WPS/MP contracts**
- **ii. Keeyask G.S./Bipole III/no Conawapa**
- **iii. CCCT generation in lieu of Bipole III/Keeyask and Conawapa G.S.**

**ANSWER:**

There were no other development plans provided to KPMG as part of the drought risk analysis detailed in Appendix J of the KPMG Report.

**<u>PUB/MH/RISK-77</u>**

**Reference: KPMG Report – Appendix J – Page J-10**
**Risk Issue: Power Resource Plan**

**c) Please indicate (and explain) in the absence of new – U.S. transmission connections whether either Keeyask G.S. or Conawapa G.S. is financially viable.**

**<u>ANSWER</u>:**

Based on the 2009/10 Power Resource Plan, new resources are required to serve Manitoba load by 2022/23. The Alternative Development Sequence described in the 2009, 20-Year Financial Outlook (provided as Appendix 16 in response to PUB/MH I-2(a)) includes the Conawapa G.S. and does not include a new transmission interconnection with the U.S. This Alternative Development Sequence would provide the resources required to serve Manitoba Hydro's firm obligations.

It should be noted that Manitoba Hydro has not made a commitment to develop Keeyask or Conawapa but is working to protect potential in-service-dates. Current plans that include Keeyask as the next plant are based on the successful conclusion of the sales with Wisconsin Public Service and Minnesota Power. Any commitment to either Keeyask or Conawapa will depend on the prevailing circumstances at the time. Keeyask and/or Conawapa will be subject to a full examination when the "need for and alternatives to" process is initiated.

**PUB/MH/RISK-77**

**Reference:** **KPMG Report – Appendix J – Page J-10**
**Risk Issue:** **Power Resource Plan**

**d)** **Please indicate (and explain) in the absence of Bipole III whether either Keeyask G.S. or Conawapa G.S. is financially viable.**

**ANSWER:**

In the 2000/01 timeframe Manitoba Hydro recognized in its system planning the need for Bipole III based on reliability requirements. Therefore, an analysis which excludes Bipole III as it relates to the potential development of the Keeyask G.S or the Conawapa G.S. has not been undertaken.

## PUB/MH/RISK-78

**Reference:** **KPMG Report – Appendix J – Page J, PUB/MH I-206**
**Risk Issue:** **Drought Pricing**

**a)** **Please confirm that MH's IFF 09-1 anticipates export revenues in the next 5 years (2011/12 to 2015/16) that are based on average export prices rising from 6.0¢ to 9.0¢/KWh for predominantly peak period energy.**

**ANSWER:**

As provided in the response to PUB/MH I-209, calculated average export prices based on IFF-09 are in the range stated in this information request. It should be noted the average export prices provided in PUB/MH I-209 are for both on-peak and off-peak energy.

**PUB/MH/RISK-78**

**Reference: KPMG Report – Appendix J – Page J, PUB/MH I-206**
**Risk Issue: Drought Pricing**

**b) Please confirm that because firm contract sales will continue (until 2016) at prices in the 5.5 to 6.0¢ range for 2,000 to 3,000 GWh of energy, opportunity sales prices applying to the other 3,500 to 4,500 GWh of energy in mean years will have to run at 6.5¢ to 12.0¢ in that same period.**

**ANSWER:**

Manitoba Hydro does not confirm the statements related to firm contract prices in this information request. As indicated in PUB/MH II-216(b) Manitoba Hydro cannot confirm the opportunity sale price.

It should be noted that the 3500 to 4500 GWh of energy referenced in the information request would not all be opportunity energy but would also include dependable energy which is valued at the forecasted long-term firm price. In addition, the 5.5¢ to 6¢ range referenced in the information request appears to be a historical price which is being compared with prices in future dollars. As well, the overall average price of energy exported will increase over time until major new supply is added, because a greater portion of energy will be exported during higher valued hours.

**PUB/MH/RISK-78**

**Reference: KPMG Report – Appendix J – Page J, PUB/MH I-206**
**Risk Issue: Drought Pricing**

**c) Please confirm that in a 5 year (2011/12 to 2015/16) drought situation the lost export energy could involve much higher priced energy than the 6.0 to 6.6¢/KWh MH used in PUB/MH I-206 and that instead of a $1.1 B lost export revenue, the actual lost revenue could be $1.6 B.**

**ANSWER:**

Manitoba Hydro does not confirm the conclusion reached in this information request. The reduced export revenue in a drought is derived predominantly from the loss of export sales at opportunity export prices. Please refer to the response provided to PUB/MH/RISK-78(b) which indicates that incorrect assumptions are being made related to future prices for opportunity energy.

## PUB/MH/RISK-78

**Reference: KPMG Report – Appendix J – Page J, PUB/MH I-206**
**Risk Issue: Drought Pricing**

**d) Please confirm that based on the 2003/04 and 2006/07 experiences, import costs in a drought situation would approach peak opportunity sales prices (shortage pricing).**

**ANSWER:**

Please see responses to CAC/MSOS/MH/RISK-41(b) and CAC/MSOS/MH I-62(g) for comments on how overall MISO market prices are largely independent of drought conditions in Manitoba. Please refer to PUB/MH/RISK-13(a) which shows that a large quantity of energy purchased during a drought would be during the lower priced off-peak period.

**PUB/MH/RISK-79**

**Reference:** **KPMG Report – Diversity Revenues/Costs Page 171, Drought Scenarios Appendix J, MH's Price History 2007 Hearing ( PUB/MH I-23, I-29)**

**Risk Issue:** **2003/04 Drought**

**a)** **Please confirm that in 2003/04, MH imported about 9,000 GWh of energy, but only bought 30 GWh from NSP/Xcel under it's Diversity Agreement.**

**ANSWER:**

In 2003/04 MH imported 9,627 GWh of energy, of which 31 GWh were purchased under the NSP/Xcel Diversity Agreement.

**PUB/MH/RISK-79**

**Reference:** **KPMG Report – Diversity Revenues/Costs Page 171, Drought Scenarios Appendix J, MH's Price History 2007 Hearing ( PUB/MH I-23, I-29)**
**Risk Issue:** **2003/04 Drought**

**b) Please explain why in 2003/04 MH did not purchase most of the energy shortfall under the Diversity Agreement.**

**ANSWER:**

Manitoba Hydro did purchase a significant amount of energy using the firm transmission reservations associated with the Seasonal Diversity contracts in 2003/04. However, only a small portion of these purchases were for Seasonal Diversity Energy.

The Seasonal Diversity contracts allow Manitoba Hydro to use the firm transmission reservations associated with the Seasonal Diversity contracts to purchase several types of energy including;

1. Seasonal Diversity Energy,
2. Tertiary Energy

Seasonal Diversity Energy is backed with reserves on the supplier's system and as a result is significantly more expensive than market priced Tertiary Energy.

In 2003/04, Manitoba Hydro needed to purchase energy as a result of the drought. It was not capacity deficient. Therefore it was unnecessary in most instances to purchase more expensive Seasonal Diversity energy when there were sufficient supplies of Tertiary Energy available in the market.

**PUB/MH/RISK-79**

**Reference:** **KPMG Report – Diversity Revenues/Costs Page 171, Drought Scenarios Appendix J, MH's Price History 2007 Hearing ( PUB/MH I-23, I-29)**

**Risk Issue:** **2003/04 Drought**

**c)** **Please define the 2003/04 specific sources and nature (GWh/¢/KWh) of purchase transactions that MH used to offset the energy shortfall.**

**ANSWER:**

In 2003/04 MH purchased 9,616 GWh at an average price of 5.2 /¢/KWh to offset the energy shortfall.

**PUB/MH/RISK-79**

**Reference:** **KPMG Report – Diversity Revenues/Costs Page 171, Drought Scenarios Appendix J, MH's Price History 2007 Hearing ( PUB/MH I-23, I-29)**

**Risk Issue:** **2003/04 Drought**

**d)** **Please define the quantity and cost of energy buybacks MH was able to achieve in 2003/04.**

**ANSWER:**

In 2003/04 MH had energy buybacks of 2,542 GWh for a purchase cost of $158,214,563.

**<u>PUB/MH/RISK-79</u>**

**Reference:** **KPMG Report – Diversity Revenues/Costs Page 171, Drought Scenarios Appendix J, MH's Price History 2007 Hearing ( PUB/MH I-23, I-29)**
**Risk Issue:** **2003/04 Drought**

**e)** **Please define the quantity and price of MH's 2003/04 exports under must supply and optional supply categories.**

**<u>ANSWER</u>:**

In 2003/04, Manitoba Hydro had long term dependable sales obligations ("must supply") and opportunity sales (those sales made in the short term and spot markets).

The following table summarizes Dependable and Opportunity Exports for 2003/04.

| | **GWh** | **Average Price (Cdn$)** |
|---|---|---|
| USA Dependable | 5245 | $49.45/MWh |
| Canadian Dependable | 986 | $36.63/MWh |
| USA Opportunity | 506 | $69.42/MWh |
| Canadian Opportunity | 228 | $74.60/MWh |

**PUB/MH/RISK-80**

**Reference:** **KPMG Report – Drought Scenarios Appendix J, MH's Price History-2007 Hearing PUB/MH I-23, I-29**

**Risk Issue:** **2006/07 Energy Supply**

a) **Please confirm that in 2006/07, MH purchased about 3,500 GWh of energy at 5.2¢/KWh and sold about 11,300 GWh @ 5.0¢ energy.**

**ANSWER:**

We confirm the volume and prices quoted above.

**PUB/MH/RISK-80**

**Reference:** **KPMG Report – Drought Scenarios Appendix J, MH's Price History-2007 Hearing PUB/MH I-23, I-29**

**Risk Issue:** **2006/07 Energy Supply**

**b)** **Please confirm that in 2006/07 Q1, MH achieved an average price of 3.7¢/KWh, 3,000 GWh opportunity sales (and 4.2¢/KWh for all sales) and in 2006/07 Q2, achieved an average price of 5.2¢/KWh for 2,500 GWh opportunity sales (5.4¢/KWh for all sales), but was faced with the purchase of 1,500 GWh of energy at 5.5¢/KWh in 2006-07 Q3 resulting in what could be viewed as an energy marketing loss.**

**ANSWER:**

The numbers provided above for 2006/07 Q1 and Q2 sales are approximately correct, however the numbers provided for 2006/07 Q3 purchases include System Merchant whereas the sales numbers provided do not include System Merchant. Please see table below which reflects the sales as reported above as well as the purchases excluding the System Merchant.

Manitoba Hydro does not agree these results indicate an energy marketing loss.

| | Q1 | | | Q2 | | | Q3 | | | Q4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | GWh | $ | ¢/KWh | GWh | $ | ¢/KWh | GWh | $ | ¢/KWh | GWh | $ | ¢/KWh |
| Opportunity Sales | 3,039 | 115,964,988 | 3.8 | 2,317 | 118,507,997 | 5.1 | 486 | 30,306,466 | 6.2 | 407 | 30,434,180 | 7.5 |
| Dependable Sales | 695 | 52,273,287 | 7.5 | 1,078 | 60,748,703 | 5.6 | 842 | 52,030,229 | 6.2 | 838 | 52,961,583 | 6.3 |
| **Total Sales** | 3,734 | 168,238,275 | 4.5 | 3,396 | 179,256,700 | 5.3 | 1,329 | 82,336,695 | 6.2 | 1,246 | 83,395,763 | 6.7 |
| **Total Purchases** | 191 | 5,206,042 | 2.7 | 280 | 14,386,983 | 5.1 | 1,116 | 54,490,114 | 4.9 | 662 | 38,606,759 | 5.8 |

**PUB/MH/RISK-80**

**Reference:** **KPMG Report – Drought Scenarios Appendix J, MH's Price History-2007 Hearing PUB/MH I-23, I-29**

**Risk Issue:** **2006/07 Energy Supply**

**c)** **In light of the above, please explain how MH's summer operation could have been modified to avoid this loss and increased net revenues.**

**ANSWER:**

Manitoba Hydro is confident that its summer operations in 2006/07 were appropriate given the state of its reservoirs and the water supply.

**PUB/MH/RISK-80**

**Reference:** **KPMG Report – Drought Scenarios Appendix J, MH's Price History-2007 Hearing PUB/MH I-23, I-29**

**Risk Issue:** **2006/07 Energy Supply**

**d)** **In light of the above, please explain why MH does not employ drought import prices at least equal to average forecast export prices.**

**ANSWER:**

Manitoba Hydro's forecast of spot market import prices exceeds or is equal to its forecast spot market export prices for any hour of the forecast.

**<u>PUB/MH/RISK-80</u>**

**Reference:** **KPMG Report – Drought Scenarios Appendix J, MH's Price History-2007 Hearing PUB/MH I-23, I-29**

**Risk Issue:** **2006/07 Energy Supply**

**e)** **In light of the above, please explain how KPMG could view MH's drought risk costing as "conservative."**

**<u>ANSWER</u>:**

Manitoba Hydro and KPMG are unable to find a reference to a statement that Manitoba Hydro's drought risk costing is "conservative". The closest reference to such a conclusion can be found on page 245 of the KPMG report which states:

> *MH has not assigned a probability to a drought period equivalent to 1937 – 1941, but views a drought event as high likelihood. As a result, MH may have adopted a conservative view in defining an extreme drought by selecting the period from 1937 – 1941 (the worst drought in historical record) as its scenario criteria for an extreme drought period.*

In the above discussion KPMG implies that the selection of the extreme drought period may be a conservative approach to defining a drought scenario when compared to utilizing a probabilistic (VAR) framework. The utilization of the most extreme drought in a one hundred year period might be found to have a lower probability than specifically trying to find a 5%, or other, percentile level of outcome, particularly if the extreme drought is combined with a particular adverse energy pricing scenario. The above discussion indicates that KPMG does not go as far as concluding that Manitoba Hydro's drought risk costing is "conservative".

PUB/MH/RISK-81

**Reference:** KPMG Report – Main Report, Page 171 (including Exhibit 4-17); MH's 2006/07 and 2007/08 Price History

**Risk Issue:** Summer/Winter Pricing

a) Please confirm that in 2006/07 and 2007/08, MH's export sales consisted of:

| | 2006/07 | | 2007/08 | |
|---|---|---|---|---|
| | GWh | ¢/KWh | GWh | ¢/KWh |
| **Summer Energy Exports** | | | | |
| (a) Dependable Peak | 1,920 | 5.79 | 2,170 | 5.34 |
| • Dependable Off-Peak | 180 | 2.07 | 260 | 2.27 |
| | 2,100 | 5.47 | 2,430 | 5.01 |
| • Opportunity Peak | 2,140 | 6.25 | 2,530 | 6.42 |
| (b) Opportunity Off-Peak | 2,610 | 3.19 | 2,870 | 2.41 |
| | 4,750 | 4.57 | 5,400 | 4.29 |
| • Peak Total | 4,060 | 6.0 | 4,700 | 5.9 |
| • Off-Peak Total | 2,790 | 3.1 | 3,130 | 2.4 |
| | 6,850 | 4.9 | 7,830 | 4.5 |
| **Winter Energy Exports** | | | | |
| (b) Dependable Peak | 1,610 | 6.29 | 1,500 | 5.56 |
| • Dependable Off-Peak | 140 | 1.69 | 70 | 2.40 |
| | 1,750 | 5.92 | 1,570 | 5.41 |
| • Opportunity Peak | 760 | 6.42 | 1,250 | 6.88 |
| (c) Opportunity Off-Peak | 750 | 4.00 | 1,160 | 4.28 |
| | 1,510 | 5.21 | 2,410 | 5.63 |
| • Peak Total | 2,370 | 6.3 | 2,750 | 6.2 |
| • Off-Peak Total | 890 | 3.6 | 1,230 | 4.2 |
| | 3,260 | 5.6 | 3,980 | 5.6 |
| **Annual Energy Exports** | | | | |
| | 10,110 | 5.1 | 1,810 | 4.9 |
| Net Exports (from Annual Report) | 8,217 | | 10,590 | |
| Imports | 1,893 | | 1,220 | |
| Diversity Purchases from NSP | 20 | 8.9 | 10 | 2.1 |

**<u>ANSWER</u>:**

The prices and volumes reported above for the Summer and Winter Energy Exports are correct and represent both physical and financial sales.

The Net Exports (from Annual Reports) represent Net Metered Interchange. Net metered interchange includes transactions by other companies wheeling energy through Manitoba. Therefore it cannot be used to determine MH's net exports (Physical exports less physical imports). Physical Imports for 2006/07 were 1,574 GWh and for 2008/09 275 GWh.

**PUB/MH/RISK-81**

**Reference:** **KPMG Report – Main Report, Page 171 (including Exhibit 4-17); MH's 2006/07 and 2007/08 Price History**

**Risk Issue:** **Summer/Winter Pricing**

**b)** **With reference to the above table, please confirm that:**

**i.** **Average winter revenue rates tend to be significantly higher (~20%) than average summer revenue rates.**

**ii.** **Contrary to KPMG's assertion, on-peak MISO market prices are also higher in the winter than in the summer.**

**iii.** **Deferring some summer off- peak sales in average or below average flow years would typically result in greater revenues during the winter period.**

**iv.** **That overnight (7x8) summer off-peak exports typically achieve revenues in the 1.0 to 2.0¢/KWh range.**

**ANSWER:**

i. Manitoba Hydro can not confirm this statement.

ii. Manitoba Hydro can not confirm this statement. Although this may be the case in a given year due to weather changing economic conditions or other reasons, this is not necessarily true for all years, or on average. The following table summarizes the price patterns for electricity exports, expressed as a percentage of the respective yearly on-peak and off-peak prices. The price patterns are based on historic MISO Day-Ahead Locational Marginal Price data for 2006/07, 2007/08 and 2008/09 at the Minnesota Hub Commercial Pricing Node (MINN_HUB).

Monthly price distribution as percent of annual average (2006/07-2008/09) MHEB Node.

| | **On Peak** | **Off Peak** |
|---|---|---|
| Apr | 103% | 105% |
| May | 89% | 71% |
| Jun | 101% | 73% |
| Jul | 139% | 106% |
| Aug | 112% | 95% |
| Sep | 77% | 74% |
| Oct | 88% | 90% |
| Nov | 96% | 103% |
| Dec | 106% | 125% |
| Jan | 93% | 117% |
| Feb | 107% | 131% |
| Mar | 89% | 110% |

Note that pricing factors for any particular month are significantly influenced by weather deviations from normal.

iii. Manitoba Hydro can not confirm this statement as it ignores that Manitoba Hydro's costs of supplying incremental energy are higher in the winter when consideration is given to hydraulic constraints resulting from ice. Effective head at the generation stations are lower in the winter and outflows from Lake Winnipeg are restricted by up to 50% compared to summer. Of relevance to Manitoba is the profitability or net revenue from a winter sale vs. a summer sale. In addition available reservoir storage room needs to be considered. If reservoirs are full during the summer no additional water can be stored which effectively forces Manitoba Hydro to export power off peak or spill.

iv. Monthly average summer off-peak day-ahead (DA) and real-time (RT) prices for the 7x8 period from 2005 through 2010 are generally within the 1.0 to 2.0¢/KWh range as shown in the table below. However, note that the average revenue Manitoba Hydro receives while exporting in to either the DA or RT markets will differ from the monthly average clearing prices because deliveries will not be uniform in volume over the entire 7x8 period.

Monthly Average 7x8 MISO LMP at MHEB Node (¢US/KWh)

| Month | DA | RT |
|---|---|---|
| Jun-05 | 1.4 | 0.6 |
| Jul-05 | 1.9 | 0.5 |
| Aug-05 | 1.2 | 0.4 |
| Jun-06 | 1.3 | 0.9 |
| Jul-06 | 2.3 | 2.2 |
| Aug-06 | 2.0 | 2.2 |
| Jun-07 | 1.7 | 1.3 |
| Jul-07 | 1.7 | 1.6 |
| Aug-07 | 1.7 | 1.5 |
| Jun-08 | 1.3 | 0.9 |
| Jul-08 | 1.3 | 1.5 |
| Aug-08 | 1.4 | 1.5 |
| Jun-09 | 0.7 | 0.5 |
| Jul-09 | 0.8 | 0.8 |
| Aug-09 | 0.8 | 0.6 |
| Jun-10 | 1.5 | 1.2 |
| Jul-10 | 1.5 | 1.5 |
| Aug-10 | 1.7 | 1.6 |
| **Average** | **1.5** | **1.2** |

**PUB/MH/RISK-81**

**Reference:** **KPMG Report – Main Report, Page 171 (including Exhibit 4-17); MH's 2006/07 and 2007/08 Price History**

**Risk Issue:** **Summer/Winter Pricing**

**c) Would MH agree that a potential area of "overselling" in 2006/07 would in part relate the seasonal choice on whether to either maximize summer off-peak sales or maximize storage of energy for the winter?**

**ANSWER:**

No. Summer off peak sales were not maximized with the intent to trade-off against reduced winter export sales and/or increased on-peak winter imports, rather Manitoba Hydro was managing above average spring storage levels on its reservoirs, and operating in consideration of all its operating priorities, including economics. Please see Manitoba Hydro's response to PUB/MH/RISK-80.

Also note that winter 2006/07 was characterized with above forecast domestic load and below normal reservoir releases from externally regulated reservoirs which resulted in reduced net export revenues over the winter months. As examples:

1. Manitoba Hydro was experiencing the 2$^{nd}$ lowest flows in the past 43 years on the Winnipeg River. These extreme low flows limited the energy production and sustainable capacity from Manitoba Hydro's stations on this river. Flows supplying Manitoba Hydro's generating stations on this river are regulated by the Lake of the Woods Control Board.

2. Manitoba domestic load was well above average in February 2007 due to extreme cold weather. February 2007 was the 8$^{th}$ coldest February in the past 51 years. On February 5$^{th}$, the temperature dropped to -42.2 C which was the coldest day in 31 years. Manitoba energy demand was approximately 150 GWh higher and its peak load for the month was approximately 275 MW higher due to well below normal temperatures.

**<u>PUB/MH/RISK-82</u>**

**Reference: KPMG Report – Appendix J**
**Risk Issue: Drought Scenarios**

**a) In alternative drought scenarios, did KPMG only consider export and import energy pricing as defined by MH?**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

In alternative drought scenarios, KPMG asked Manitoba Hydro to run cases based on expected, high and low export and natural gas prices as determined by the 2008 Price Forecast.

**PUB/MH/RISK-82**

**Reference:** **KPMG Report – Appendix J**
**Risk Issue:** **Drought Scenarios**

**b) Did KPMG independently develop or examine any IFF's that employed:**

- **Different (lower) average export prices?**
- **Different import prices more equal to export prices?**

**ANSWER:**

KPMG Response:

As described in section 4.10 and Appendix J, KPMG asked Manitoba Hydro to run various drought scenarios on its development plans in the 2009/10 Power Resource Plan (PRP). The various drought scenarios were run not only for the preferred development sequence but also for an alternative development sequence using expected, low and high export and natural gas pricing and several different water flow conditions.

**<u>PUB/MH/RISK-82</u>**

**Reference:** **KPMG Report – Appendix J**
**Risk Issue:** **Drought Scenarios**

**c) Did KPMG explore alternate:**

- **Retained earnings versus debt ratios relationships?**
- **Specified retained earning targets?**
- **Debt ratio targets?**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

As described in section 4.11 and Appendix J, KPMG asked Manitoba Hydro to run various drought scenarios, the results of which include impacts on:

- Retained earnings,
- debt ratios,
- retained earning targets, and
- debt ratio targets.

**PUB/MH/RISK-83**

**Reference:** **KPMG Report – Appendix J (J-12, J-15, J-18, J-26, J-27) 2007/08 Power Resource Plan,**

**Risk Issue:** **Power Resource Plan**

**a)** **Please confirm that MH's decision to proceed with the Bipole III/Keeyask and Conawapa sequence was made subsequent to the 2007/08 Power Resource Plan being released when export prices were 6 ¢/KWh and trending upward and project cost estimates were:**

- **Keeyask G.S. $3.7 B (CEF 2008).**
- **Conawapa G.S. $5.0 B (CEF 2006)**
- **Bipole III $1.9 B to $2.2 B (CEF 2007)**

**ANSWER:**

It is confirmed that the recommended development plan in the 2008/09 Power Resource Plan was the first to include both Conawapa and the advancement of Keeyask to facilitate a major new interconnection which requires major export sales. In the 2000/01 timeframe, Manitoba Hydro recognized in its system planning the need for Bipole III based on reliability requirements.

It should be noted that Manitoba Hydro has not made a commitment to develop Keeyask or Conawapa but is working to protect potential in-service-dates. Current plans that include Keeyask as the next plant are based on the successful conclusion of the sales with Wisconsin Public Service and Minnesota Power. Any commitment to either Keeyask or Conawapa will depend on the prevailing circumstances at the time. Keeyask and/or Conawapa will be subject to a full examination when the "need for and alternatives to" process is initiated.

**PUB/MH/RISK-83**

**Reference:** **KPMG Report – Appendix J (J-12, J-15, J-18, J-26, J-27) 2007/08 Power Resource Plan,**

**Risk Issue:** **Power Resource Plan**

**b) Please confirm that the financial viability of these projects is now less certain in light of:**

- **Lower export prices reflecting much lower natural gas prices/CO2 considerations and a higher CDN $.**
- **Higher construction costs for:**

  - **Keeyask G.S. $4.6 B (CEF 2009).**
  - **Conawapa G.S. $6.3 B (CEF 2009).**
  - **Bipole III $2.2 B (CEF 2007)**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-83(a).

**PUB/MH/RISK-83**

**Reference:** **KPMG Report – Appendix J (J-12, J-15, J-18, J-26, J-27) 2007/08 Power Resource Plan,**

**Risk Issue:** **Power Resource Plan**

**c)** **Please confirm that MH has recently re-examined an Alternate Development Sequence (with no WPS or MP sales) deferring Keeyask G.S. indefinitely and advancing Conawapa G.S. to 2021 (as per 2007/08 Power Resource Plan), which does have more favourable debt ratios, but with lower retained earning; and reduced export risk.**

**ANSWER:**

Manitoba Hydro has recently evaluated an Alternative Development Plan which is included in the 2009, 20 Year Financial Outlook provided as Appendix 16 in response to PUB/MH I-2(a).

**PUB/MH/RISK-83**

**Reference:** **KPMG Report – Appendix J (J-12, J-15, J-18, J-26, J-27) 2007/08 Power Resource Plan,**

**Risk Issue:** **Power Resource Plan**

**d) Please file the 2007/08 Power Resource Plan and MH's most recent Power Resource Plan.**

**ANSWER:**

The 2009/10 power resource plan is the most recent power resource plan available, and is included as Appendix 47 in response to CAC/MSOS/MH I-35(a), and forms the basis of the KPMG Report. The 2007/08 power resource plan is provided as Appendix 67.

**PUB/MH/RISK-84**

**Reference:** **KPMG Report – Appendix J**
**Risk Issue:** **Alternative Development Scenario**

**a) Please file the IFF assumptions employed for electricity operations under the Alternative Development "No Sale" Scenario.**

**ANSWER:**

Please refer to the 2009, 20-Year Financial Outlook provided as Appendix 16 in response to PUB/MH I-2(a) for a description of the Alternative Development Sequence.

**PUB/MH/RISK-84**

**Reference: KPMG Report – Appendix J**
**Risk Issue: Alternative Development Scenario**

**b) Please confirm that the achievement of a 75% debt ratio would come earlier with the "No Sale" than in IFF 09-1 despite lower retained earnings.**

**ANSWER:**

Confirmed. The "No Sale" case returns to a 75% debt ratio in 2021/22 compared to 2023/24 in IFF09. However, the growth in net assets is significantly greater in IFF09 compared to the "No Sale" case and is "paid for" by roughly the same proportionate amount of debt.

**<u>PUB/MH/RISK-84</u>**

**Reference:** **KPMG Report – Appendix J**
**Risk Issue:** **Alternative Development Scenario**

**c) With the “No Sale” scenario, would it also be appropriate for a lower defined target for retained earnings? Explain.**

**<u>ANSWER</u>:**

The response to CAC/MSOS/MH I-8(a) states:

> “The adequacy of this target and the level of equity (or retained earnings) at any given time depends upon the risks the Corporation faces and the tolerance that the Board of Manitoba Hydro has for risk in consideration of the current and projected circumstances,” and
>
> “The absolute level of equity is also an important consideration in determining its adequacy. With drought being one of the most significant risks faced by Manitoba Hydro, retained earnings should be sufficient to withstand a recurrence of the worst drought on record.”

These statements would also be true under the “No Sale” scenario and adjustments to financial targets under this type of scenario would have to take current circumstances into consideration at that time.

**PUB/MH/RISK-85**

**Reference:** **KPMG Report – Page 98 -100, Drought Probability**
**Risk Issue:** **Drought Risk**

**a)** **Please explain how KPMG's view of the 2002/03 and 2003/04 as a 2-year drought with a minimum hydraulic generation of 18,500 can be reconciled with MH's 21,000 GWh dependable hydraulic generation.**

**ANSWER:**

It is Manitoba Hydro's interpretation that a reconciliation of dependable hydraulic generation quantities as requested in this information request is unnecessary. A search of the KPMG Report shows that the only reference to the quantity of 18,500 GWh appears in the footnote on Page 158 which is a reference to the PUB Order 32/09 and therefore is not KPMG's view. The 18,500 GWh quantity was not provided by Manitoba Hydro and is not considered to be representative of hydraulic system dependable energy; it appears to be a quantity which originates from the PUB.

**PUB/MH/RISK-85**

**Reference:** **KPMG Report – Page 98 -100, Drought Probability**
**Risk Issue:** **Drought Risk**

**b)** **Please confirm that as a 2-year drought, MH would have entered 2003/04 with an April 1st energy-in-storage level of 4,200 GWh and with only 15,000 GWh of inflow, would not achieve 21,000 of dependable hydraulic generation.**

**ANSWER:**

Manitoba Hydro cannot confirm the statement made in this information request. Manitoba Hydro's dependable energy is determined as the maximum amount of energy that can be supplied under lowest flow conditions. It is not appropriate to utilize the historic operations during 2002/03 and 2003/04 as an indicator of maximum hydraulic generation.

Manitoba Hydro operates its hydraulic reservoirs such that there will be sufficient hydraulic energy when combined with other dependable resources to serve domestic and export loads. These firm commitments require physical delivery under assumed severe weather conditions including drought. If it is not necessary to have full reservoirs at the onset of the drought to ensure the supply of electricity, reservoirs will be operated to a lower level. This was the case in 2003/04.

During 2002/03 and 2003/04, Manitoba Hydro planned its operations such that firm commitments would be met through the use of hydraulic generation, thermal resources and imports and financial settlements. With the reservoir storage that existed on April 1, 2003, Manitoba Hydro's planned hydraulic generation for 2003/04 was sufficient to meet load demands, and all obligations were met in actual operations. If it had been determined that 21,000 GW.h of hydraulic energy was required to satisfy all obligations, Manitoba Hydro would have ensured that there would have been additional storage in reservoirs at the beginning of 2003/04.

**<u>PUB/MH/RISK-85</u>**

**Reference:** **KPMG Report – Page 98 -100, Drought Probability**
**Risk Issue:** **Drought Risk**

**c)** **Please confirm that MH's 2002/03 Annual Report dealt at length with the successful survival of a late summer drought in 2003. Please file related pages.**

**<u>ANSWER</u>:**

The following pages contain highlighted references to reduced water flows in the 2002-03 Manitoba Hydro annual report.

*Success on the export market has allowed electricity rates in Manitoba to remain unchanged for six consecutive years for residential customers. For large industrial customers, rates have not changed since 1992.*

become increasingly important as our awareness of these interactions has grown. I have been very proud of Manitoba Hydro's performance in environmental issues in recent decades and we continue to work hard to ensure that these high standards are maintained. As part of this effort, Manitoba Hydro received corporate certification by the British Standards Institute for having an environmental management system that conforms to the international ISO 14001 standard. This certifies that the Corporation has in place a vigorous system of management controls for implementing, achieving and maintaining its environmental standards. Having such a management system in place has become mandatory for utilities belonging to the Canadian Electricity Association.

I am also pleased to report that in March 2003, Manitoba Hydro received the Leadership Award in the electric utilities category from the Voluntary Challenge and Registry Inc.. This award recognizes organizations for their commitment, action and leadership in meeting Canada's commitment to reduce greenhouse gas emissions.

After a number of years of negotiation and regulatory review, in January 2003, Manitoba Hydro received the approval of the National Energy Board for the sale of 500 megawatts of electricity to Northern States Power, a subsidiary of Xcel Energy. This 10-year arrangement, worth $1.7 billion, has also received regulatory approval in Minnesota and will commence in 2005. This long-term contract will provide ongoing revenues to Manitoba and a clean renewable electricity supply to our Minnesota neighbours and we are extremely pleased that we were able to conclude this agreement.

The success on the export market has allowed electricity rates in Manitoba to remain unchanged for six consecutive years for residential customers. For large industrial customers, rates have not changed since 1992. These low rates are of direct benefit to all customers but also add significantly to the competitiveness of the industrial and manufacturing sectors.

Reduced water flows in Manitoba in 2002-03 resulted in lower hydroelectric production, which in turn resulted in a drop in net revenues to $71 million compared to $214 million in the previous fiscal year. We also expect the effects of these conditions to carry over into the next fiscal year but do not anticipate an impact on electricity rates—the extent of this reduction in net export revenue is not known at this time as we hope to experience significant rain this spring and summer.

I want to thank all employees in their efforts to integrate the two utilities and for their ongoing commitment to service and achieving our goals in a year with many challenges. Again I welcome the former Winnipeg Hydro employees to the Corporation.

I would like to express my appreciation to the Chairman of the Manitoba Hydro-Electric Board, Vic Schroeder, and his colleagues on the Board for their support and guidance during the year.

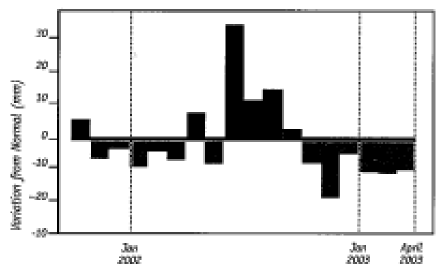
R.B. Brennan FCA
President and Chief Executive Officer

*Manitoba Hydro has been able to effectively and efficiently maximize its available water resources in the province's various watersheds.*

◂ *Duane Kabaluk and his co-workers remove built-up ice from the spillway gates at the Slave Falls Generating Station on the Winnipeg River. The ice is chainsawed into blocks for ease of removal.*

# Power Supply

*Nelson-Churchill Drainage Basin Precipitation 2002-03*




## MANAGING OUR WATER RESOURCES

Manitoba Hydro closely monitors the water flows on key rivers and lakes that affect Manitoba's production of electricity. As of fiscal year end, precipitation in Manitoba's major drainage basin, the Nelson-Churchill, has been at below normal levels in 12 of the last 18 months. Clearly we have been experiencing a period of low water flows.

While these conditions generally signal a reduction in export revenues and an increase in imports, as experienced in 2002-03, Manitoba Hydro has been able to effectively and efficiently maximize its available water resources in the province's various watersheds. This prudent management is reflected in the achievement of this fiscal year's consolidated net income of $71 million and extraprovincial sales of $463 million.

Through carefully managing levels in reservoirs, increased use of thermal resources, and importing power overnight to replace or supplement production, Manitoba Hydro ensures that the electricity supply to its customers continues to be maintained in the most responsible and efficient way under some very challenging conditions.

## BRANDON GAS-FUELLED GENERATION IN SERVICE

The two units of the natural gas combustion turbine plant at the Brandon Generating Station came into service in June and July 2002, respectively. Built over two years at a cost of $191 million, the new plant will help Manitoba Hydro maximize export revenues while strengthening the security of the electricity system in southern Manitoba. The combustion turbine units add approximately 254 megawatts to our system. Combined with the existing coal-burning unit at the Brandon Generating Station, the additional capacity improves the station's overall rating to approximately 346 MW, making it the fifth largest station in the province.

# Management's Discussion and Analysis

## FINANCIAL REVIEW

Manitoba Hydro's consolidated net income for the year ended March 31, 2003, amounted to $71 million compared to $214 million in the previous fiscal year. Low water flows had the most significant influence on the reduction in earnings. The decline in hydraulic generation resulting from the reduced water conditions led to a reduction in electricity sales to extraprovincial customers and an increase in the volume of energy purchases required to meet firm supply commitments. While domestic electricity and gas distribution rates did not increase again during the year, domestic energy growth partially offset the impact of reduced export sales.

Net income of $71 million for the year was almost identical to the forecast amount of $70 million. After adjusting for the cost of gas sold, revenues were higher than forecast by $34 million largely due to increased consumption in both the electric and gas sectors as a result of the colder than normal temperatures. Expenses were higher than forecast by $33 million, the net result of higher power purchases and depreciation expense, partially offset by lower than forecast finance expense.

| **Consolidated Financial Results** | **2002-03** | 2001-02 | Change (%) |
|---|---|---|---|
| Gross revenues | *millions of dollars* | | |
| Electricity sales within Manitoba | **891** | 797 | 12 |
| Extraprovincial electricity sales | **463** | 588 | (21) |
| Natural gas sales | **515** | 479 | 8 |
| Total | **1 869** | 1 864 | — |
| Expenses | | | |
| Electric | **1 277** | 1 159 | 10 |
| Gas (including cost of gas sold) | **502** | 472 | 6 |
| Corporate | **19** | 19 | — |
| Total | **1 798** | 1 650 | 9 |
| Net Income | **71** | 214 | (67) |
| **Electrical Operations** | *billions of kilowatt-hours* | | |
| Generation – interconnected system | **29.2** | 32.6 | (10) |
| Energy sales – Manitoba customers | **22.0** | 20.4 | 8 |
| Extraprovincial customers | **9.7** | 12.3 | (21) |
| | *thousands of kilowatts* | | |
| Manitoba peak load | **3 916** | 3 760 | 4 |
| **Gas Operations** | *millions of cubic metres* | | |
| Gas Sales | | | |
| Residential | **714** | 645 | 11 |
| Commercial and industrial | **980** | 899 | 9 |
| | **1 694** | 1 544 | 10 |
| Transportation | **640** | 502 | 27 |
| Total | **2 334** | 2 046 | 14 |

Consolidated net income of $71 million is projected for 2003-04. This projection is based on normal precipitation over the forecast period. While the water supply condition is the most significant factor affecting projected financial results, other variables such as market prices for electricity and natural gas, weather, and interest rates can also influence the Corporation's projected net income.

Consolidated net income for the year ended March 31, 2003, includes the results and operations of Winnipeg Hydro that was acquired by the Corporation on September 3, 2002. Winnipeg Hydro formerly serviced approximately 94 000 customers in the central part of the City of Winnipeg. The acquisition allows the Corporation to take advantage of cost savings by combining the operations of the utilities. In addition, Manitoba Hydro will improve customer service through the coordination and streamlining of such programs as Power Smart, the one-call emergency response system and billing, metering and collection processes. Since the date of acquisition, the former Winnipeg Hydro operation has become an integrated operation of Manitoba Hydro.

Revenue from sales to residential customers for 2002-03 increased by $40 million to $354 million. The increase in sales was primarily due to increased usage as a result of colder weather experienced this year, especially in the third and fourth quarters, and the additional sales associated with the acquisition of Winnipeg Hydro. The number of residential customers increased by 84 284 during the year, of which 81 609 related to the acquisition of Winnipeg Hydro, and totaled 439 757 at March 31, 2003.

Revenue from general service customers, encompassing the commercial and industrial sector, increased by $76 million to $501 million for 2002-03. The increase was mainly attributable to the acquisition of Winnipeg Hydro and to increased demand in the industrial sector. The total number of general service customers increased by 12 156 to 62 218 at March 31, 2003, of which 11 768 is attributable to the acquisition of Winnipeg Hydro.

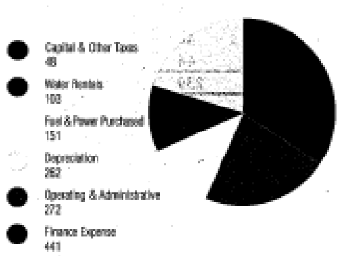
## EXTRAPROVINCIAL POWER SALES

For the first time in six years, Manitoba Hydro experienced a decline in revenue from extraprovincial sales. Revenues declined to $463 million, $125 million lower than revenues reported in 2001-02. The decrease was attributable to the reduction in hydraulic generation and reduced energy available for sale to the export market. Energy sold outside Manitoba was 9.7 billion kilowatt-hours in 2002-03, 2.6 billion kilowatt-hours less than in 2001-02. Of the total extraprovincial revenue, $379 million or 82% was derived from the U.S. market, while $84 million or 18% was from sales to other Canadian provinces.

## EXPENSES

Total expenses of the electrical operations amounted to $1 277 million, an increase of $118 million or 10% from the previous fiscal year. Higher fuel and power purchases attributable to lower water supply conditions accounted for the majority of the total increase in expenses with the balance mainly attributable to the acquisition of Winnipeg Hydro. The incremental impact of the acquisition on electrical expenses was approximately $41 million for the seven-month period since acquisition. In addition, there was an increase in depreciation expense due to the implementation of revised depreciation rates, the acquisition of Winnipeg Hydro and capital additions during the year. Decreases in water rental costs associated with reduced hydraulic generation partly offset the increase in expenses.

*Distribution of Expenses Electrical*
*millions of dollars*



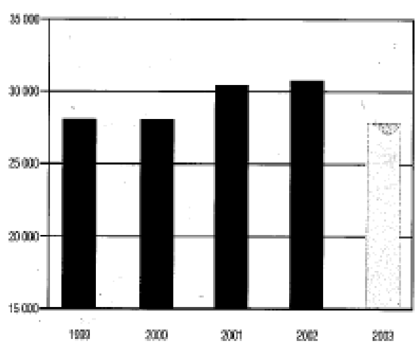
## FUEL AND POWER PURCHASED

Fuel and power purchased amounted to $151 million in 2002-03, an increase of $80 million from the previous year. The increase was comprised of increased power purchases of $69 million and increased thermal generation costs of $11 million. An increase in the volume of energy purchases required as a result of reduced hydraulic generation and increased domestic demand accounted for $62 million of the increase in power purchases. Higher market prices created by rising gas prices and increased purchases during peak periods accounted for the remaining $7 million. In total, power purchases and thermal generation amounted to 3.6 billion kilowatt-hours compared to 2.0 billion kilowatt-hours in the previous year.

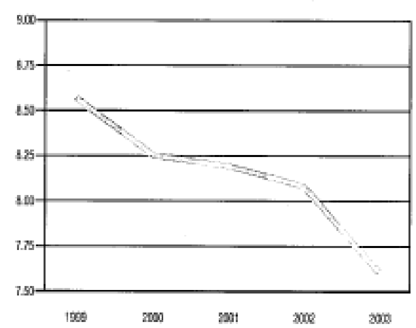
## FINANCE EXPENSE

Finance expense totaled $441 million in 2002-03, a decrease of $4 million compared to the previous year. The decrease reflects the net impact of reduced interest rates and gains on the sale of sinking fund investments. Overall, the Corporation's weighted average interest rate declined from 8.06% in 2001-02 to 7.59% in 2002-03. This marks the sixth consecutive year that the average interest rate on embedded debt has declined.

*Hydraulic Generation*
*(GW.h)*




*Weighted Average Interest Rate*
*(%)*



**PUB/MH/RISK-86**

**Reference: KPMG Report – Page 112**
**Risk Issue: SPLASH Model**

**a) Please explain and quantify the impact of "Perfect Foresight" on the export volumes determined in MH's SPLASH model for IFF purposes.**

**ANSWER:**

Manitoba Hydro intends to assess the potential impact of perfect foresight on the results of the SPLASH model. A specific plan has yet to be developed and approved along with associated timeframes and resource requirements.

**PUB/MH/RISK-86**

**Reference: KPMG Report – Page 112**
**Risk Issue: SPLASH Model**

**b) In the absence of "Perfect Foresight", would MH's dependable hydraulic energy be reduced and by how much?**

**ANSWER:**

Manitoba Hydro intends to assess the potential impact of perfect foresight on the results of the SPLASH model. A specific plan has yet to be developed and approved along with associated timeframes and resource requirements. At this preliminary stage of assessment, Manitoba Hydro does not expect that the determination of dependable hydraulic energy will be affected by the absence of perfect foresight.

**<u>PUB/MH/RISK-86</u>**

**Reference: KPMG Report – Page 112**
**Risk Issue: SPLASH Model**

**c) Would the absence of "Perfect Forecast" result in lower export volumes and necessitate higher import price assumptions?**

**<u>ANSWER</u>:**

Manitoba Hydro intends to assess the potential impact of perfect foresight on the results of the SPLASH model. A specific plan has yet to be developed and approved along with associated timeframes and resource requirements.

**PUB/MH/RISK-87**

**Reference: KPMG Report Section 1.3.4 Page 9**

**a) Please file copies of the engagement letters and representation letter related to the KPMG Risk assignment.**

**ANSWER:**

Appendix 69 includes copies of the following:

Attachment 1 – Letter dated November 10, 2009, from R.B. Brennan to R.J. Owen of KPMG.

Attachment 2 – Letter dated November 20, 2009, signed on behalf of KPMG and Manitoba Hydro.

Attachment 3 – Revised letter dated December 15, 2009, signed on behalf of KMPG and Manitoba Hydro. The letter was revised following the receipt by KPMG from the New York Consultant of threats of legal action and injunction.

The name of the New York Consultant has been redacted from the attached letters, in keeping with previous Board rulings.

**<u>PUB/MH/RISK-87</u>**

**Reference: KPMG Report Section 1.3.4 Page 9**

**b) Please provide a full listing of communications and presentations made by KPMG to MH related to the Risk assignment**

**<u>ANSWER</u>:**

Communications and presentations between Manitoba Hydro and KPMG were continuous throughout the term of the risk engagement.

**PUB/MH/RISK-87**

**Reference: KPMG Report Section 1.3.4 Page 9**

**c) Please file a copy of all draft KPMG Risk reports.**

**ANSWER:**

KPMG did not provide Manitoba Hydro with a draft risk report.

**PUB/MH/RISK-88**

**Reference: Risk Studies Project Management**

**a) Please provide a full copy of the RFP, to undertake the risk study completed by KPMG, indicate the number of proponents which responded to the RFPs, a copy of the selection criteria matrix employed to evaluate the proposals with the relative ranking of each proponent against that criteria. If an RFP was not tendered for these assignments, please explain why, how and by whom the consultant was selected.**

**ANSWER:**

The decision to engage KPMG was made by the Board of Manitoba Hydro.

**PUB/MH/RISK-88**

**Reference: Risk Studies Project Management**

**b) Please provide all documentation between MH and KPMG that related to all the changes between MH's original terms of reference and KPMG's "Proposal/ Engagement" to undertake the Risk Review. Please provide a black lined version of the proposed services included in the proposal with the actual terms of reference used to undertake the study and explain each difference.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-88(a).

**PUB/MH/RISK-88**

**Reference: Risk Studies Project Management**

**c) Please provide a table with a full listing of the KPMG staff that worked on the Risk Review, the sections worked on, the total budgeted hours per the proposal for service by section/topic, total hours actually worked on the assignment, the respective charge out rates for each individual and the fees charged for the assignment by individual and disbursements billed.**

**ANSWER:**

Manitoba Hydro declines to provide this information on the basis that it is not readily available and not relevant to the findings of the KPMG report.

**PUB/MH/RISK-88**

**Reference: Risk Studies Project Management**

**d) Please provide a detailed schedule of the hours spent by MH employees and other external consultants (by individual) related to the KPMG Risk assignment and the related O&M and disbursements.**

**ANSWER:**

Manitoba Hydro did not maintain a detailed schedule of hours related to the Risk assignment. The Manitoba Hydro employees working on this assignment were senior employees who do not typically timecard hours worked on specific assignments. Any related O&M disbursements by Manitoba Hydro employees would have been minimal. Manitoba Hydro did not engage any other consultants related to the KPMG Risk assessment.

**PUB/MH/RISK-88**

**Reference: Risk Studies Project Management**

**e) Please indicate which KPMG staff will be made available to speak to each section of the report, if required, and file the respective CV's for those individuals.**

**ANSWER:**

Manitoba Hydro expects that all KPMG staff who worked on the KPMG report will be available to speak to their respective sections of the report.

Please see Manitoba Hydro's response to MIPUG/MH/RISK-1(a) for the CV's of KPMG staff.

**PUB/MH/RISK-88**

**Reference: Risk Studies Project Management**

**f) Please indicate the proposed billed rates by KPMG individual for involvement in the hearing process, including the preparation of interrogatories and attendance at the hearing.**

**ANSWER:**

The following KPMG personnel were involved in the interrogatory response process and may be further involved in the hearing process:

| | **Billing Rates (per hour)** |
|---|---|
| Beatty, Stephen | $490 |
| Cassells, Elizabeth | 375 |
| Chen, Frank | 315 |
| Clement, Patrick | 185 |
| Duncan, Stuart | 275 |
| Erling, Jonathon | 375 |
| Farrugia, Christine | 275 |
| Fossay, Craig | 490 |
| Gupta, Amurag | 315 |
| Lipson, Will | 490 |
| Mackey, Glen | 315 |
| Murphy, William | 490 |
| Owen, Robert | 315 |
| Peters, Helen | 375 |
| Ross, Michael | 450 |
| Wolfe, Eric | 180 |
| Woltmann, Norman | 275 |

**<u>PUB/MH/RISK-89</u>**

**Reference: Risk Studies ICF Project Management**

a) **Please provide a full copy of the RFP, to undertake the risk study completed by ICF, indicate the number of proponents which responded to the RFPs, a copy of the selection criteria matrix employed to evaluate the proposals with the relative ranking of each proponent against that criteria. If an RFP was not tendered for these assignments, please explain why, how and by whom the consultant were selected.**

**<u>ANSWER</u>:**

A copy of the RFP is provided as Attachment 1. A copy of the selection criteria matrix is provided as Attachment 2. Ten proponents responded to the RFP. The ranking of each proponent against the criteria is provided as Attachment 3.

Manitoba Hydro

# REQUEST FOR TENDER 029523

# CONSULTING SERVICES - INDEPENDENT REVIEW OF EXPORT POWER SALES AND ASSOCIATED RISKS



**FEBRUARY 3, 2009**

# MANITOBA HYDRO DISCLAIMER

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# INVITATION TO TENDER

To be accepted, one original of the responding Tender must be received and date and time stamped until 16:00 hours, Manitoba local time, **February 25, 2009** by Manitoba Hydro, complete as described in Request for Tender 029523. One photocopy of the Tender is also requested.

The Tender shall be enclosed in a sealed envelope marked: "CONSULTING SERVICES – INDEPENDENT REVIEW OF EXPORT POWER SALES AND ASSOCIATED RISKS" at Manitoba Hydro. If the Tender is to be mailed, it should be addressed to Mr. Glenn W. Gray, Manager, Purchasing Department, Manitoba Hydro, and P.O. Box 1287, Winnipeg, Manitoba, R3C 2Z1, Canada. If the Tender is to be delivered by hand, it should be brought to the Security Officer, 1st Floor, 820 Taylor Avenue, Winnipeg, Manitoba, R3M 3T1, Canada.

# ENQUIRIES

Any enquiry concerning the technical content should be directed in writing only until:

**February 20, 2009**
**12:00 (noon) Manitoba local time**

Mr. Vince Warden,
Vice-President of Finance and Administration and CFO,
Manitoba Hydro,
P.O. Box 1287,
Winnipeg, Manitoba, R3C 2Z1, Canada
FAX number is (204) 474-4114
Email address is **vawarden@hydro.mb.ca**

Any enquiry concerning the tender procedures should be directed in writing only to:

Peter Buscemi, C.P.P.
Purchasing Department
Manitoba Hydro
P.O. Box 1287
Winnipeg, Manitoba R3C 2Z1, Canada
Telephone number: (204) 474-3564
FAX number: (204) 474-4972
Email address: **pbuscemi@hydro.mb.ca**

The Tenderer shall not be entitled to rely on any response or interpretation received in respect of an enquiry unless that response or interpretation was provided via an addendum to this Request for Tender.

# INSTRUCTIONS

## FORM OF TENDER

The Tenderer is required to use the Form of Tender attached hereto. If any Form of Tender page is found to have insufficient space, the Tenderer is requested to attach a sheet or sheets immediately after such page.

The Tenderer is encouraged to include in their Tender thorough and sufficient information concerning matters under evaluation.

Where in the Form of Tender attached hereto the word "shall" is used, the requirement identified is mandatory.

Where in the Form of Tender attached hereto the word "requested" is used, the requirement identified is advisory and is not mandatory.

## ADDENDA

The Purchaser may, at any time prior to the date and time of closing, issue addenda changing Request for Tender 029523, and such addenda shall be an integral part of Request for Tender 029523.

## SIGNING OF TENDERS

A Tender submitted by an individual shall be signed by the individual in the presence of a subscribing witness.

A Tender submitted by a corporation shall be signed by the properly authorized signing officer or officers and the corporate seal affixed or by the properly authorized signing officer or officers in the presence of a subscribing witness or witnesses.

A Tender submitted by a partnership or joint venture shall be properly signed by all partners or joint ventures in the presence of a subscribing witness or witnesses. The Purchaser may require evidence of the authority of any person purporting to sign a Tender on behalf of a person, firm or corporation, whether as principal, agent or attorney. Each signature shall be accompanied by a printed name.

## WITHDRAWAL/AMENDMENT OF TENDER

A Tenderer may withdraw its Tender any time prior to the time and date of closing by way of written notice of withdrawal to the Purchaser received by the Purchaser prior to said time.

A Tenderer may amend its Tender any time prior to the time and date of closing by providing a clear and detailed written notice to the Purchaser of such amendment as follows:

| | |
|---|---|
| To the Attention of: | Mr. Glenn W. Gray, Manager<br>Purchasing Department, Manitoba Hydro |
| If mailed: | P.O. Box 1287<br>Winnipeg, Manitoba R3C 2Z1, Canada. |
| If Personal delivery: | Security Officer<br>1st Floor, 820 Taylor Avenue, Winnipeg, Manitoba, R3M 3T1, Canada.. |
| If Faxed: | (204) 474-4972 |

All amendments must be signed in accordance with the Instructions to Tenderers, and marked "Amendment of Tender 029523"

## TENDERS

The Tender shall be irrevocable by the Tenderer until a date **60 days** after the closing date for the receipt of sealed Tenders.

Notwithstanding any industry or trade custom or past practices of the Purchaser to the contrary, the Purchaser does not represent that it will necessarily, and the Purchaser shall not be obliged to, accept any Tenders, accept the lowest Tenders, or be precluded from accepting any Tenders or other offer further in respect of any Tenders submitted. The Purchaser reserves the right in its sole discretion to accept any Tenders or to reject any and all Tenders received.

The Purchaser reserves the right in its sole discretion to cancel and / or re-tender this Request for Tender at any time regardless of whether or not any Tender(s) have been received for any reason whatsoever.

If any Tender is accepted, in whole or in part, the Purchaser shall notify the successful Tenderer in writing. The successful Tenderer cannot rely upon oral acceptance.

# TENDERER'S EXPENSES

The Tenderer shall be responsible for all expenses concerning or related to the preparation of its Tender, including any proof of concept demonstration(s) and any subsequent discussions and/or negotiations.

# LANGUAGE, DIMENSIONS AND WEIGHTS

All communication, including without limitation all notices, documents, notes on drawings, and submissions, required or permitted under the Contract, shall be in English.

Any Work shall be executed in the SI (Metric) System of Units. Dimensions shall be shown in metres and millimetres and weights shall be shown in kilograms and metric tonnes.

# PROPOSED PRICES

Proposed prices shall be stated in Canadian ***currency*** and shall include all customs duties, surcharges, insurance premiums, permit and licence fees, Workers Compensation and vacation pay assessments, and all other payroll benefits. Canadian Goods and Services Tax (GST) and Manitoba provincial retail sales tax (PST) shall be treated as specified in the Form of Tender for each ITEM. All other applicable taxes shall be included and shall not be subject to any adjustment.

No payment shall be made to the Contractor for sales tax (if any) which may be imposed by Canada or Manitoba in respect of the Contractor's plant, tools and any other items not included in the Work.

Prices in the accepted Tender, if any, shall be firm and not subject to adjustment for changes or unexpected contingencies of any kind whatsoever, including without restricting the generality of the foregoing, changes in wages, material costs, or taxes which may in future be imposed by lawful authority within or outside of Canada.

# ERRORS AND OMISSIONS

The Tenderer shall be solely responsible for any errors, omissions or misunderstandings resulting from the Tenderer's failure to make a thorough examination of this Request for Tender. The Tenderer shall obtain all required information and shall not claim at any time after the submission of the Tender or the subsequent execution of a Contract, if any, that there was any misunderstanding with regard to the conditions imposed by the Contract.

# EVALUATION CRITERIA

Tenders received will be evaluated in accordance with the following criteria (in no particular order of preference):

(a) Proposed fees, total hours and hourly rates.
(b) Proposed key personnel.
(c) Experience and qualifications of proposed key personnel to conduct the work.
(d) Experience and work performed by the key personnel at Manitoba Hydro or at other hydro-based electrical utilities.
(e) Quality, relevance and completeness of the Tender.
(f) Perceived ability to recommend best practices and feasible, valuable and proven opportunities of improvement to add value to Manitoba Hydro.
(g) Availability to expedite a timely completion of the engagement.

# PROVISION OF CONSULTING SERVICES

## GENERAL INFORMATION

Manitoba Hydro is requesting an independent review of the Corporation's export power sales function with specific emphasis on the risks associated with long-term firm contracts and short-term firm opportunity sales.

## BACKGROUND

Manitoba Hydro is a provincial Crown Corporation, providing electricity to 522,000 customers throughout the province of Manitoba and natural gas service to 261,000 customers in various communities in the province. The Corporation also exports electricity to approximately 40 electric utilities through its participation in four wholesale markets in Canada and the mid-western United States. In a typical year, Manitoba Hydro derives approximately 35% of its total electricity revenues from the export market.

Nearly all of Manitoba Hydro's electricity is generated from self-renewing waterpower. On average, about 30 billion kilowatt-hours of electricity are generated annually with 98% of the total produced from the existing 14 hydroelectric generating stations. A new 200 megawatt hydraulic generating station is currently under construction with a scheduled in-service date in 2011. Licencing activities are also underway for major new hydraulic resources that are planned to be added to the system over the next decade.

Manitoba Hydro offers its customers a wide range of energy services, either directly or through its subsidiaries and promotes energy conservation and savings through its many Power Smart programs.

The nature of the Corporation's business involves significant environmental and societal obligations, capital-intensive projects with long lead times, price-regulation and rate-recoverable costs.

Additional information can be found at Manitoba Hydro's website **www.hydro.mb.ca.**

# SCOPE OF THE WORK

Manitoba Hydro is requesting Tenders for consulting services to provide Manitoba Hydro with an independent assessment of the Corporation's risks associated with its export power sales transactions. The deadline for final submission of the consultant report is May 29, 2009.

# SPECIFIC REQUIREMENTS

The purpose of the review is to provide comments and conclusions with respect to the risks associated with Manitoba Hydro's existing and proposed long-term firm export sale contracts and short-term firm opportunity sales.

The review will provide comments and conclusions with respect to:

(a) The appropriateness, from a long-term business strategy and risk exposure perspective, of Manitoba Hydro entering into long-term firm contracts 20 or 30 years into the future;

(b) the adequacy of price that Manitoba Hydro derives (or will derive) from export sale transactions (both long-term firm and short-term opportunity sales);

(c) the risks assumed by Manitoba Hydro in selling long-term firm energy from dependable resources (in consideration of the requirements to meet firm sale commitments during periods of drought);

(d) the extent to which Manitoba Hydro should be involved in pure merchant energy trading transactions;

(e) the reasonableness of Manitoba Hydro's quantification of risk exposure related to an extended (5-year) drought; and

(f) the adequacy of Manitoba Hydro's drought risk mitigation measures.

## SUCCESSFUL TENDERER

The Successful Tenderer shall represent and warrant that it understands Manitoba Hydro's requirements under this Request for Tender, that it possesses the expertise to properly perform the services and work described, and that it has sufficient independence so as to not conflict with work performed for other electrical utilities.

The Successful Tenderer shall comply with all reasonable directions and requests of Manitoba Hydro.

## TENDER FORMAT

The Tender should be written in a concise manner and organized utilizing labelled tabs using the following headings:

(a) Introduction.

(b) Completed Form of Tender.

(c) Profile of Firm.

(d) Proposed fees, total hours and hourly rates (including disbursements).

(e) Work plans and methodology for the project.

(f) Personnel profiles/ resumes (which includes qualifications, formal education, previous experience and references).

**NOTE:** All personnel proposed and accepted for the work shall not be removed without the written permission of Manitoba Hydro. Manitoba Hydro shall have final approval of any replacements that become necessary.

# TERMS AND CONDITIONS OF THE CONTRACT

The Consultant shall comply with all reasonable directions and requests of Hydro.

**CONFLICTS** - While this Agreement is in effect, the Consultant and its agents shall not provide services to any other person in a manner which conflicts with this agreement.

**INVOICES** - Invoices shall be satisfactory to Hydro in both form and content. The Consultant shall also provide supporting documents, and receipts as requested by Hydro. Approved invoices are due 30 days after receipt.

**RECORDS** - The Consultant shall keep proper records related to provision of the Services, and retain them for three years after this Agreement ends. The Consultant shall make the records available for review by Hydro or its auditors during normal office hours.

**CONFIDENTIALITY** - The Consultant and its agents shall:

(a) treat as confidential all Hydro information, data, documents and materials ("Information") acquired or to which access has been given pursuant to this Agreement;
(b) not disclose, or permit to be disclosed, to any person the Information without prior permission from Hydro; and
(c) comply with any reasonable directions given by Hydro with respect to safeguarding or ensuring the confidentiality of the information.

**OWNERSHIP** - All reports, documents, research notes, data, photographs, materials and drawings produced by the Consultant in the course of the Services shall become the property of Hydro. The Consultant hereby grants to Hydro and any third party authorized by Hydro a perpetual and unlimited licence to use, amend, or modify the same for any purpose.

Any equipment and supplies provided by Hydro to the Consultant for use pursuant to this Agreement shall remain the property of Hydro and be returned to Hydro upon request.

**LIABILITY** - The Consultant shall use due care in the performance of this Agreement to ensure that no person is injured, no property damaged or lost and no rights are infringed.

Hydro shall not be liable for any injury, property loss or damage suffered by the Consultant arising out of this Agreement, unless caused by wrongful or negligent acts or omissions by Hydro.

The Consultant shall indemnify and save harmless Hydro against all claims and suits by third parties, resulting from breach of this Agreement or wrongful or negligent acts or omissions by the Consultant or its agents.

**SUSPENSION** - Hydro may, in writing and at its sole option, from time to time suspend the Services for such period of time as Hydro determines. Hydro shall reimburse the Consultant for costs and expenses actually incurred by the Consultant by reason of the suspension, but not for lost profit, up to a maximum of 25% of the total contract price.

**TERMINATION** - Hydro may terminate this Agreement at any time on 30 days written notice. Hydro shall pay for fees and expenses incurred to the date of termination.

Without restricting its other remedies, Hydro may immediately terminate this Agreement in writing if the Services are unsatisfactory, inadequate, or improperly performed, the Consultant fails to comply with this Agreement, or the Consultant becomes bankrupt or insolvent.

**SURVIVAL OF TERMS - CONFIDENTIALITY, OWNERSHIP, AND LIABILITY** shall survive termination or expiration of this Agreement.

**INDEPENDENT CONTRACTOR** - The Consultant is an independent contractor. This Agreement does not create the relationship of employer - employee or principal - agent, between Hydro and the Consultant. The Consultant is responsible for any deductions or remittances required by law.

**INSURANCE** - The Consultant shall maintain Comprehensive General Liability Insurance and Professional Liability Insurance in the minimum amount of $2,000,000.00 for the duration of this Agreement. The Consultant shall supply a Certificate of Insurance to Hydro.

**ASSIGNMENT** - Neither party shall assign or transfer this Agreement or any rights or obligations hereunder without prior written permission from the other party.

**TIME OF ESSENCE** - Time is of the essence of this Agreement.

**APPLICABLE LAW** - This Agreement shall be governed by the laws of Manitoba.

**ENUREMENT** - This Agreement shall enure and be binding upon the parties and their executors, administrators, heirs, successors and permitted assigns.

# FORM OF TENDER

The Tenderer indicated below hereby submits a tender and offers to enter into a contract to do all the work that is set out, described, or called for in Manitoba Hydro Request for Tender subject to the terms and conditions set forth therein and in this tender.

COMPANY LEGAL NAME: ______________________________
hereinafter called the "Tenderer", a company duly incorporated under the laws of:

ADDRESS: ______________________________

______________________________

TELEPHONE: ______________ FAX : ______________

Enquiries to the TECHNICAL CONTACT of this tender should be directed to:

Name: ______________________________

TELEPHONE: ______________ FAX : ______________

Email: ______________________________

Enquiries to the NON-TECHNICAL CONTACT should be directed to:

Name: ______________________________

TELEPHONE: ______________ FAX : ______________

Email: ______________________________

# SIGNATURE PAGE

The words used in this Request for Tender have the meanings ascribed to them in Manitoba Hydro's Request for Tender No. 029523.

We/I the undersigned, having examined all of Request for Tender No. 029523 together with all addenda issued prior to close of tenders, and having attended all mandatory meetings and mandatory site visits (if required), hereby submit this tender with all necessary enclosures, and hereby offer to enter into a contract to do all the work that is set out, described, or called for in Manitoba Hydro Request for Tender upon and subject to the terms and conditions set forth therein.

This tender is irrevocable and open for acceptance by the Purchaser at any time within **60 days** after the date on which tenders close, whether any other tender has previously been accepted or not.

If the Purchaser awards a Purchase Order to the Tenderer based on this tender, it shall constitute and be an acceptance of all or any stated portion of this tender without further communication with, or notice to, the Tenderer.

Dated ______________ this ______ day of __________________, 2009

Witness ______________________

Tenderer's Signature and Corporate Seal (if applicable) ______________________

Name ______________________ Name ______________________

Print Name in Full Under Each Signature

**Request for Tender 029523** **Consulting Services - Independent Review of Export Sales and Associated Risks**

## Evaluation Matrix

| | Company Name | Price | Relevant Experience/ Qualifications | Hydro Experience | Quality/Completeness of Tender | Availability |
|---|---|---|---|---|---|---|
| Criteria Weighting | | 10% | 35% | 35% | 10% | 10% |
| 1 | | | | | | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |

**Request for Tender 029523** **Consulting Services - Independent Review of Export Sales and Associated Risks**

## Evaluation Matrix

| | Company Name | Price | Relevant Experience/ Qualifications | Hydro Experience | Quality/Completeness of Tender | Availability | Total Score |
|---|---|---|---|---|---|---|---|
| Criteria Weighting | | 10% | 35% | 35% | 10% | 10% | |
| | ICF International | 5.5 | 9 | 9.5 | 10 | 9 | 8.93 |
| | Proponent Number 2 | 9 | 8 | 8.5 | 10 | 10 | 8.68 |
| | Proponent Number 3 | 3.5 | 8.5 | 8 | 9.5 | 3.5 | 7.43 |
| | Proponent Number 4 | 0 | 5.75 | 8 | 4.5 | 6.5 | 5.91 |
| | Proponent Number 5 | 8 | 5 | 5 | 5.5 | 10 | 5.85 |
| | Proponent Number 6 | 6 | 4.5 | 3.5 | 7.5 | 9 | 5.05 |
| | Proponent Number 7 | 10 | 4 | 3 | 5.5 | 6.5 | 4.65 |
| | Proponent Number 8 | 1.5 | 3.5 | 3.5 | 7.5 | 8 | 4.15 |
| | Proponent Number 9 | 4 | 3.5 | 1.5 | 1.5 | 9.5 | 3.25 |
| | Proponent Number 10 | 7 | 2.5 | 1 | 5 | 6 | 3.03 |

Note : Rate of 1 lowest to 10 highest

**PUB/MH/RISK-89**

**Reference: Risk Studies ICF Project Management**

**b) Please provide all documentation between MH and ICF that related to all the changes between MH's original terms of reference and ICF's "Proposal/ Engagement" to undertake the Risk Review. Please provide a black lined version of the proposed services included in the proposal with the actual terms of reference used to undertake the study and explain each difference.**

**ANSWER:**

There were no changes between the original terms of reference and ICF's Proposal Engagement. A blacklined version of ICF proposed services from their response to the RFT is provided as Attachment 1 and the scope of work included in the RFT is provided as Attachment 2.

# Section V: Work Plan and Methodology for the Project

This section summarizes our approach and work plan to providing Manitoba Hydro with an assessment of the strategies and risks associated with Manitoba Hydro's existing and proposed long-term firm export sale contracts and short-term firm opportunity sales. Specifically, we will assist Manitoba Hydro in determining the extent to which their strategies, procedures, analysis, and policies are consistent both with standard industry practice and the specific challenges facing Manitoba Hydro's decision makers.

The work plan will include the following tasks, each described in further detail in the remainder of this section.

- Task 1 – Identifying Risk Factors Associated with Power Exports
- Task 2 – Review and Understand Manitoba Hydro's Current Approach with Respect to Export Sales and Associated Risks
- Task 3 – Analysis of the Appropriateness of Entering into Long-Term Contracts
- Task 4 – Analysis of the Adequacy of Exports Sale Transaction Pricing
- Task 5 – Analysis of the Risks in Selling Long-Term Firm Energy
- Task 6 – Analysis of MH's Target Involvement in Shorter-Term Merchant Trading Transactions
- Task 7 – Analysis of Reasonableness of MH's Quantification and Mitigation of Risk Related to Extended Drought

## Task 1 – Identifying Risk Factors Associated with Power Exports

We understand that earnings derived from electricity exports are one of the most critical factors influencing financial performance for MH. The utility has planned significant capital expenditures based on estimates for export earnings and therefore, identifying and quantifying risks associated with these export sales is essential for Manitoba Hydro.

As part of this task, ICF will identify key risk factors that should be considered in determining the long-term business strategy and risk management approach for export sales. We will provide an overview of these risk factors along with any market information to highlight the nature of these risks. This will be the basis for review in Task 3, which includes a comparison of ICF identified risk factors with Manitoba Hydro's assessment. The following summary provides some background on these potential risk factors.

- **Market Risk**

  Manitoba Market -- Future generation available for export is a function of native load growth rates, and Manitoba Hydro faces significant uncertainty regarding its expected native load levels. This is due to several factors including (i) uncertainly surrounding the current economic conditions (and the timing and duration of the economic recovery period), (ii) the outlook for implementation of DSM programs, (i) the potential for switching from gas to electricity for base space heating (electric prices in the recent past were lower than gas prices), and (iv) the outlook for growth in industrial load (in part of function of the degree to which local rates are more attractive than in neighboring regions).

MISO Market -- MH's principal export market is the MISO marketplace in the US. In the event that MH contracts to deliver firm supply and cannot do so, it would presumably be expected to purchase replacement power. The recent changes in the MISO market explicitly require two main purchases to make up for unavailable firm supply: (1) electrical energy supply, and (2) capacity.

Electrical energy prices are driven heavily by fuel prices, including increasingly by natural gas prices, and are determined location by location using an LMP methodology. Other important drivers are coal prices (Powder River Basin minemouth prices and rail transportation rates), emission allowance prices including the potential for $CO_2$ emission allowance prices, and transmission congestion on the gird, and renewable portfolio standards. In light of the consideration of long term sales, and the potential advantages of long term sales (lower financing costs, revenue stability and predictability), it is important to note that there exists large potential for the future pricing to be substantially different than recent pricing conditions. This potential derives from: (1) continuing load growth in the US portions of MISO which when combined with preference for non-base load incremental supply (i.e. mostly natural gas), can increase the hours in which gas is on the margin, (2) $CO_2$ emission regulations which could raise prices, and (3) renewable portfolio standards which could oppose these trends and decrease brown power prices, especially off peak. This has large implications for MH's strategy including the potential that future prices can be higher.

In addition, MISO has just adopted a system which limits the maximum capacity deficiency charge to approximately $220/kW–yr on an annual basis, with deficiency charges varying by month. However, below this level, prices would be determined by supply and demand balance at the peak, the costs of new equipment, energy prices, etc.

- **Hydrological Risk**

Risk of Drought -- Historically, MH has faced a total of 23 droughts in the last 94 years, with the shortest lasting one year (2003-04) and longest drought lasting seven years (1936-42). Based on the frequency of droughts that have occurred in past, one might be able to roughly conclude that MH has the possibility of facing a drought once in every four years. In the 2003-2004 drought period, MH had to operate their highly inefficient natural gas plants like the Brandon SCCT and buy high cost power from the market to meet the local and contractual obligations. It is estimated that for every year of drought the retained earnings will be reduced on the order of $ 500 to $ 600 million.[4]

- **Transmission Risk**

The existence of locational marginal pricing (LMP) in MISO in combination with the existence of transmission congestion creates the potential for transmission risk, notably the potential for pricing at different locations to be substantially different.

[4] Manitoba Public Utilities Board – Board Order 116/0

- **Infrastructure Risk**

  Delay in Construction -- Recently singed PPA contracts assume specific operation dates for hydro expansion projects. Any delay in construction could force MH to run its fossil fired units and/or buy from the market to serve local and export requirements.

- **Regulatory Risk**

  Environmental and renewables regulations in the US and Canada could significantly impact levels and pricing for MH's exports. While MH is expected to benefit from US carbon regulation (through high resultant power pricing in the US), regulations that impose significant renewable capacity expansion may negatively affect MH.

- **Financial Risk**[7]

  Capital Investment and Inflation Risks: To meet its export obligation and domestic demand, MH has started Mega projects such as Wuskwatim, Conawäpa, etc. at a total of close to $18 billion capital expenditure. MH has faced a high inflation year thus increasing the cost of projects. In the near-term, the instability of the financial market has raised concerns with respect to the ability to meet the timeline for these projects. In case of not meeting the export requirement at reasonable cost under various risky scenarios the retained earnings will be affected hence, the construction program may also get delayed, resulting into further loss.

  Exchange Rate Risk: Long-term revenue assumptions for exports to MISO are linked to USD/CND =1.16 exchange rate, and thus in the case of Canadian dollar appreciation, MH will face erosion of profit due to exchange rate differentials. In the recent past, the exchange rate was as close as CND/USD =0.95, and this resulted in substantial loss to MH.

  Credit Rating Risks: MH has planned significant capital expenditure of $18 billion over the next 15 years with projected debt to equity ratio of 75:25. It is necessary that MH should make progress towards achieving this goal to avoid a negative implication for province rating, which may ultimately put negative impacts on both Province and MH by increasing the cost of borrowing for MH, for which the Province provides the guarantee. This may affect the implementation of projects required to support new export contracts and in turn export earnings.

To summarize we find that MH needs to account for market risks, environmental risks, infrastructure risks, regulatory risks, and financial risks inside and outside of Manitoba province. While all of these risks are always present in the market, they will have varying impact on Manitoba Hydro under different business strategies and risk mitigation measures.

**Task 2 – Review and Understand Manitoba Hydro's Current Approach with Respect to Export Sales and Associated Risks**

As part of this task, ICF will research, review, and analyze Manitoba Hydro's current situation with respect to contracting for export sales and risk management. Primary activities that we will undertake will include the following:

- Interview Manitoba personnel who will provide insight on the historical / current business strategy with respect to exports and processes behind the current risk mitigation strategy
- Define current risk management strategy, policies, procedures, and systems and current risk exposure in the marketplace (e.g. percent of the portfolio in each year under contract, the extent and use of delta hedging, etc.)
- Assess MH's existing quantification of the effects of hydro related risks, market risks and the effects of existing hedging and portfolio strategy
- Summarize historical / current profit margins and any outlook on future power pricing and profitability
- Review current and future supply contracts obligations, structure, and pricing
- Quantify current power, fuel and gas volumes being hedged (current capacity) and review historical and future hydroelectric generation estimations
- Perform an analysis on previous "deals" (over the past 12 to 24 months) to examine profit and cost

**Task 3 – Analysis of the Appropriateness of Entering into Long-Term Contracts**

❖ *The appropriateness, from a long-term business strategy and risk exposure perspective, of Manitoba Hydro entering into long-term firm contracts 20 or 30 years into the future*

Long-term firm contracts are a standard practice in the power industry. For both buyers and sellers, forward contracts guarantee the exchange of a known quantity of electricity at a known price structure and for a given time frame. Long-term power contracts, if properly structured, provide significant benefits to both sellers and buyers. They provide the means to reduce price volatility risk by providing a known stream of revenue/costs. They often reduce the cost of capital and simplify the energy marketing and procurement operations. However, if not properly structured with respect to the risk, long term contracts can become a financial burden with catastrophic consequences.

A typical commercially oriented power company (e.g. an Independent Power Producer) will seek to have large portions of its existing supply position contracted forward over the next 3 to 5 years, and will accept a much smaller portion subject to very long contracts. However, the entity would be very reluctant to build new units without significant long term contracting. A typical integrated utility would manage much of its position by owning its own supply, with focus on long-term fuel contracting and delta hedging in some cases. Transmission and distribution utilities in deregulated areas have, at a minimum, rolling power contracts (e.g. 3-year supply, one third contracted each year).

However, in recent years we have seen an increase in long-term power contracts in the US, primarily to reduce risks associated with market volatility. In recent months, this has become critical for securing financing for new projects. The Pennsylvania Public Utilities Commission, for example, has recently requested all their utilities to include long-term contracts in their resource supply options.

MH does not neatly fall into the typical category of utility organizations due to it very large off-system sales position, currency risk, ownership of non-Greenhouse Gas Generation (GHG) generation sources, exposure to locational pricing risks even though it is a Canadian utility, and the potential for capacity expansion. Nonetheless, we expect that it will be useful to set our review in the context of best practices across the industry, as modified by the special circumstances of MH.

The appropriateness of long-term contracts should be evaluated in conjunction with the business strategy, risk mitigation measures and risk tolerance of the signing parties. We envision the following activities to assist Manitoba Hydro in evaluating the appropriateness and extent of additional / total long-term contracting. Several of these activities will augment / supplement those identified in Task 2:

- Interview key current personnel (executive, risk management) who will provide insights on the long-term targets and risk management strategy
- Review existing long-term contracts
- Compare the risk factors identified in Task 1 with those identified by the Corporation
- Assess the likelihood and the potential effect of the risk factors (using our integrated approach and sophisticated modeling tools as discussed in Task 4)
- Review the existing risk mitigation programs and quantify their impacts and as appropriate, propose modification and additional risk mitigation measures (the extent of the quantification will be a function of the extent of the material already available)
- Benchmark our assessment of residual risk (risk not fully covered by the existing risk mitigation programs) with that of the company
- Compare MH's approach and strategies with that of other similarly situated utilities, to the extent information is available
- Conclude on the appropriateness of the long-term contracts

**Task 4 – Analysis of the Adequacy of Exports Sale Transaction Pricing**

❖ *The adequacy of price that Manitoba Hydro derives (or will derive) from export sale transactions (both long-term firm and short-term opportunity sales)*

Historical power pricing and recent spot pricing is a critical guide to future pricing, especially volatility. However, this can only be part of an assessment of likely future power pricing. As noted, this is because the MISO market has historically had coal on the margin in a significant number of hours, but going forward, with demand growth, gas will increasingly displace coal on the margin. Additionally, in hours when coal and gas are on the margin, CO2 regulations (very likely in ICF's view) will dramatically alter the pricing profile in the medium and long-term. It is our view that, all else equal, prices will be higher due to these fundamental changes. This will be partially mitigated by RPS induced capacity expansion that may place some downward pressure on western MISO wholesale power pricing, particularly off-peak. As such, fundamentals-based modeling that considers these and other key factors in an integrated manner is important. ICF's IPM modeling framework is ideally suited for this analysis. This is because it does not assume future conditions will necessarily repeat historical conditions, but rather will over time follow long term supply and demand fundamentals with volatility superimposed on these underlying trends.].

To the extent off-the-shelf materials will be supplemented, ICF will initially focus on developing a Base Case by which to assess adequacy of long term pricing. Additionally, to the extent this option is chosen by MH, based on the identification of risk factors in Task 1, the analysis of long-term contracts in Task 2, and in consultation with Manitoba Hydro personnel, we will develop (as appropriate) various scenarios to analyze quantitatively using sophisticated modeling tools (described in more detail later). These scenarios could include modification to the following parameters:

- Fuel pricing (natural gas primarily, possibly coal)
- Canadian and US environmental regulations including various US and Canadian Carbon policies
- Water conditions (i.e. drought) and other resource availability
- Canadian and US demand growth
- US renewable energy policies
- Transmission

Our models will provide price projections for up to 3 neighboring markets (within the US and Canada as appropriate), with focus on MISO markets where MH currently has delivery locations under a Base Case outlook. This will be derived using our IPM modeling framework, with zonal representation of markets over a twenty-year forecast horizon. ICF will compare these price projections to the prices specified in existing contracts and identify potential risks associated with price spreads, i.e. through review of the spreads under the various scenarios. We can also create probability distributions for pricing based on the scenario analysis, where we combine historical and forecast information to assess volatility. The advantage of these distributions is that they allow for analysis of the effects of hedging and portfolio strategy on volatility of earnings (and thus, MH rates).

ICF will additionally compare its price projections with those of MH to further address the issue of pricing adequacy.

ICF can provide recommendations on structuring for these contracts such as the potential for re-openers in the event of CO2 pricing, indices for fuel pricing, etc. Such mechanism can provide protection against changing conditions.

**Task 5 – Analysis of the Risks in Selling Long-Term Firm Energy**

- ❖ *The risks assumed by Manitoba Hydro in selling long-term firm energy from dependable resources (in consideration of the requirements to meet firm sale commitments during periods of drought)*

One risk that is likely to be faced is that the higher price and the availability of long-term sales opportunities typically associated with firm supply (as compared with non-firm supply) is not sufficient to cover the costs of replacing power during periods in which MH supply is low. The risk of low output in conjunction with runaway prices in MISO for replacement power would be of particular concern to MH.

We understand that MH has a probability distribution for drought conditions and hydroelectric supply. It is also our understanding the Manitoba Hydro is involved in research evaluating the probability and severity (timeline and regional range) of potential droughts (Paleo Research). This research includes not only conclusions based on historical records, but also incorporates possible effects from global warming. ICF will utilize any provided information from this ongoing research, and analyze the impact of drought on MH's risk exposure to droughts of long duration.

An important objective will be to compare the expected value of firm versus non-firm sales, and the cost of drought (e.g. replacement supply). In addition to expected values, some sense of the risks (e.g. percent chance of particular outcomes would also be useful).

This analysis needs to include the likely cost of physical and financial hedges and the impact of portfolio construction on this risk. For example, the cost of peaking supply is much lower than the MISO capacity price cap, and hence, owning peaker and/or other capacity in the delivery areas could be useful if it is determined that the risk of firm supply is too high.

Based on risk identification from previous tasks and the above considerations, we will opine on the appropriateness of MH entering into long-term firm contracts.

**Task 6 – Analysis of MH's Target Involvement in Shorter-Term Merchant Trading Transactions**

- *The extent to which Manitoba Hydro should be involved in pure merchant energy trading transactions*

Most power producers include a combination of contracts (long-term and short-term) and merchant (open) positions as well as combinations of commodities in their risk portfolio. The risk portfolio is continuously adjusted based on current and expected market conditions – e.g. delta hedging for some period of time. This policy, if implemented properly, can maximize revenues while keeping risk at acceptable levels.

There is no single solution for all parties since tolerance of volatility varies. However, utilities are often expected to minimize volatility more than many other businesses. Thus, in most cases the financial benefits from a well managed risk portfolio outweighs the implementation and running costs for portfolio management. For Manitoba hydro though one should consider that fact that there are significant capabilities for storage of excess energy that can be used as a (partial) hedge for periods of short droughts.

ICF will consider all above factors in providing a response to this question. In opining on this issue, ICF will review available estimates of the extent and incremental costs of trading operations and stress testing to determine collateral requirements, e.g. the costs of the systems and individuals necessary to undertake trading. There may also be a history of regulatory review of hedging and trading, which we can review. ICF will also provide illustrative scoping level estimates of the costs of such programs.

**Task 7 – Analysis of Reasonableness of MH's Quantification and Mitigation of Risk Related to Extended Drought**

- *The reasonableness of Manitoba Hydro's quantification of risk exposure related to an extended (5-year) drought; and*
- *the adequacy of Manitoba Hydro's drought risk mitigation measures.*

We will opine on MH's quantification and the adequacy of risk management strategies through review of work that Manitoba Hydro has already conducted in this area. We describe in the next section, some of the elements that will likely form a quantitative approach. Additionally, we can provide ICF quantification as a benchmark and as a basis for determining the reasonableness of MH's quantification and mitigation. This can be structured with the following options:

- Option 1: We will review MH's portfolio of contractual and merchant positions and existing strategies and risk mitigation measures. We will focus our efforts on review of the available materials already being used by MH. To the extent we rely on ICF forward price projections, we will use off-the-shelf forecasts to the extent possible (plus some refinement to the Base Case for MISO) that reflect ICF's expected Base Case for most of the parameters (demand growth, fuels, emissions etc). We will compare MH's treatment of risk to other similarly situated organizations.
- Option 2 – In addition to what is outlined in Option 1, under this option ICF, in conjunction with MH, will model and analyze additional scenarios (up to 6 scenarios for 3 zonal markets using IPM) involving different hydro conditions (including extended drought), fuel prices, emission and CO2 prices, demand growth rates, etc.
- Option 3 – Under this option, ICF will utilize the scenario analysis performed in Option 2 to derive appropriate probability distributions for electricity prices. We will employ Monte Carlo simulation techniques to investigate the profitability of exports and the performance of existing and potential mitigation measures. ICF will provide probability distributions for export revenues and will investigate two portfolio / mitigation measure sets on this distribution. This will assume the provision of a hydro output probability distribution from Manitoba Hydro.

The remainder of this section describes the modeling that ICF might perform under Options 2 and 3. Even if ICF does not perform any modeling, but reviewed MH's existing analysis, this

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## SCOPE OF THE WORK

Manitoba Hydro is requesting Tenders for consulting services to provide Manitoba Hydro with an independent assessment of the Corporation's risks associated with its export power sales transactions. The deadline for final submission of the consultant report is May 29, 2009.

## SPECIFIC REQUIREMENTS

The purpose of the review is to provide comments and conclusions with respect to the risks associated with Manitoba Hydro's existing and proposed long-term firm export sale contracts and short-term firm opportunity sales.

The review will provide comments and conclusions with respect to:

(a) The appropriateness, from a long-term business strategy and risk exposure perspective, of Manitoba Hydro entering into long-term firm contracts 20 or 30 years into the future;

(b) the adequacy of price that Manitoba Hydro derives (or will derive) from export sale transactions (both long-term firm and short-term opportunity sales);

(c) the risks assumed by Manitoba Hydro in selling long-term firm energy from dependable resources (in consideration of the requirements to meet firm sale commitments during periods of drought);

(d) the extent to which Manitoba Hydro should be involved in pure merchant energy trading transactions;

(e) the reasonableness of Manitoba Hydro's quantification of risk exposure related to an extended (5-year) drought; and

(f) the adequacy of Manitoba Hydro's drought risk mitigation measures.

**PUB/MH/RISK-89**

**Reference: Risk Studies ICF Project Management**

**c) Please provide a table with a full listing of the ICF staff that worked on the Risk Review, the sections worked on, the total budgeted hours per the proposal for service by section/topic, total hours actually worked on the assignment, the respective charge out rates for each individual and the fees charged for the assignment by individual.**

**ANSWER:**

The table below lists each ICF staff and their respective charge rate. There is no breakdown available of what sections/topic each ICF staff worked on or budgeted hours by section or topic or total hours worked on the assignment. Services provided by ICF were a fixed cost basis excluding travel and related expenses.

| ICF Staff | | Charge Rates |
|---|---|---|
| Judah Rose | Managing Director | $565 |
| Shanthi Muthiah | Director | $475 |
| Nainish Gupta | Director | $475 |
| Sunita Surana | Sr Consultant | $265 |
| George Katsigiannakis | Principal | $415 |

**PUB/MH/RISK-89**

**Reference: Risk Studies ICF Project Management**

**d) Please provide a detailed schedule of the hours spent by MH employees and other external consultants (by individual) related to the ICF Risk assignment and the related O&M and disbursements.**

**ANSWER:**

Manitoba Hydro did not maintain a detailed schedule of hours related to the Risk assignment. The Manitoba Hydro employees working on this assignment were senior employees who do not typically timecard hours worked on specific assignments. Any related O&M disbursements by Manitoba Hydro employees would have been minimal. Manitoba Hydro did not engage any other consultants related to the KPMG Risk assignment.

**<u>PUB/MH/RISK-89</u>**

**Reference: Risk Studies ICF Project Management**

**e) Please indicate which ICF staff will be made available to speak to each section of the report, if required, and file the respective CV's for those individuals.**

**<u>ANSWER</u>:**

It is expected that any member or members of ICF staff referenced in PUB/MH/RISK-89(c) will be available to speak to the ICF Report.

The CV's for ICF personnel are attached.

# JUDAH L. ROSE

## EDUCATION

1982 M.P.P., John F. Kennedy School of Government, **Harvard University**

1979 S.B., Economics, **Massachusetts Institute of Technology**

## EXPERIENCE

Judah L. Rose joined ICF in 1982 and currently serves as a Managing Director of ICF International. Mr. Rose has 30 years of experience in the energy industry. Mr. Rose's clients include electric utilities, financial institutions, law firms, government agencies, fuel companies, and IPPs. Mr. Rose is one of ICF's Distinguished Consultants, an honorary title given to three of ICF's 3,500 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative.

Mr. Rose has supported the financing of tens of billion dollars of new and existing power plants and is a frequent counselor to the financial community.

Mr. Rose frequently provides expert testimony and litigation support. Mr. Rose has provided testimony in over 100 instances in scores of state, federal, international, and other legal proceedings.

Mr. Rose has also addressed approximately 100 major energy conferences, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies. Mr. Rose has also appeared in TV interviews.

Mr. Rose received a M.P.P. from the John F. Kennedy School of Government, Harvard University, and an S.B. in Economics from the Massachusetts Institute of Technology.

## PRESS INTERVIEWS

**TV:** "The Most With Allison Stewart," MSNBC, "Blackouts in NY and St. Louis & ongoing Energy Challenges in the Nation," July 25, 2006
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Financial Times Energy
LA Times
Arkansas Democratic Gazette
Galveston Daily News
The Times-Picayune
Pittsburgh Post-Gazette
Power Markets Week

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Associated Press
Dow Jones Newswires

**TESTIMONY**

104. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 29, 2010.

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102. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line Oklahoma LLC to conduct Business as an Electric Utility in the State of Oklahoma, Cause No.PUD 201000075, July 16, 2010.

101. Supplemental Testimony on Behalf of Entergy Arkansas, Inc., In the Matter of Entergy Arkansas, Inc., Request for a Declaratory Order Approving the Addition of the Environmental Controls Project at the White Bluff Steam Electric Station Near Redfield, Arkansas, Docket No. 09-024-U, July 6, 2009.

100. Rebuttal Testimony on Behalf of TransEnergie, Canada, Province of Quebec, District of Montreal, No.: R-3669-2008-Phase 2, FERC Order 890 and Transmission Planning, July 3, 2009.

99. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line LLC for a Certificate of Public Convenience and Necessity to Operate as an Electric Transmission Public Utility in The State of Arkansas, Docket No. 10-041-U, June 4, 2010.

98. Surrebuttal Testimony – Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, before the Missouri Public Service Commission, In the Matter of the Application of KCP&L GMO, Inc. d/b/a KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2009-0090, April 9, 2009.

97. Hawaii Structural Ironworkers Pension Trust Fund v. Calpine Corporation, Case No. 1-04-CV-021465, Assessment of Calpine's April 2002 Earnings Projections, March 25, 2009.

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Anker Coal Group, etc., Civil Action. No. GD-06-30514, In the Court of Common Pleas, Allegheny County, Pennsylvania.

95. Supplemental Direct Testimony of Judah Rose, on behalf of Southwestern Electric Power Company, In the Matter of the Application of Southwestern Electric Power Company for Authority to Construct a Natural-Gas Fired Combined Cycle Intermediate Generating Facility in the State of Louisiana, Docket No. 06-120-U, December 9, 2008.

94. Rebuttal Testimony of Judah Rose on behalf of Kelson Transmission Company, LLC re: Application of Kelson Transmission Company, LLC For A Certificate of Convenience and Necessity For the Amended Proposed Canal To Deweyville 345 kV Transmission Line Within Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, And Orange Counties, SOAH Docket No. 473-08-3341, PUCT Docket No. 34611, October 27, 2008.

93. Testimony of Judah Rose, on behalf of Redbud Energy, LP, in Support of Joint Stipulation and Settlement Agreement, In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Granting Pre-Approval of the Purchase of the Redbud Generating Facility and Authorizing a Recovery Rider, Cause No. PUD 200800086, September 3, 2008.

92. Direct Testimony of Judah L. Rose on behalf of Duke Energy Carolinas, In the Matter of Advance Notice by Duke Energy Carolinas, LLC, of its Intent to Grant Native Load Priority to the City of Orangeburg, South Carolina, and Petition of Duke Energy Carolinas, LLC and City of Orangeburg, South Carolina for Declaratory Ruling With Respect to Rate Treatment of Wholesale Sales of Electric Power at Native Load Priority, Docket No. E-7, SUB 858, August 15, 2008.

91. Affidavit filed on behalf of Public Service of New Mexico pertaining to the Fuel Costs of Southwest Public Service for Cost-of-Service and Market-Based Customers, August 11, 2008.

90. Direct Testimony of Judah L. Rose on behalf of Duke Energy Ohio, Inc., Before the Public Utilities Commission of Ohio, In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of an Electric Security Plan, July 31, 2008.

89. Rebuttal Testimony, Judah L. Rose on Behalf of Duke Energy Carolinas, in re: Application of Duke Energy Carolinas, LLC for Approval of Save-A-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs, Docket No. E-7, Sub 831, July 21, 2008.

88. Updated Analysis of SWEPCO Capacity Expansion Options as Requested by Public Utility Commission of Texas, on behalf of SWEPCO, June 27, 2008.

87. Direct Testimony of Judah L. Rose on Behalf of Nevada Power/Sierra Pacific Electric Power Company, Docket No. 1, Public Utilities Commission of Nevada, Application of Nevada Power/Sierra Pacific for Certificate of Convenience and Necessity Authorization for a Gas-Fired Power Plant in Nevada, May 16, 2008.

86. Rebuttal Testimony of Judah L. Rose on Behalf of the Advanced Power, Commonwealth of Massachusetts, Before the Energy Facilities Siting Board, Petition of Brockton Power Company, LLC, EFSB 07-7, D.P.U. 07-58 & 07-59, May 16, 2008.

85. Supplemental Rebuttal Testimony on Commissioner's Issues of Judah L. Rose for Southwestern Electric Power Company, on behalf of Southwestern Electric Power Company, PUC Docket No. 33891, Public Utilities Commission of Texas, May 2008.

84. Supplemental Direct Testimony on Commissioners' Issues of Judah Rose for Southwestern Electric Power Company, for the Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization for a Coal-Fired Power Plant in Arkansas, SOAH Docket No. 473-07-1929, PUC Docket No. 33891, Public Utility Commission of Texas, April 22, 2008.

83. Rebuttal Testimony of Judah Rose, In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, April 1, 2008.

82. Rebuttal Report of Judah Rose, Ohio Power Company and AEP Power Marketing Inc. vs. Tractebel Energy Marketing, Inc. and Tractebel S.A. Case No. 03 CIV 6770, 03 CIV 6731 (S.D.N.Y.), January 28, 2008

81. Proposed New Gas-Fired Plant, on behalf of AEP SWEPCO, 2007

80. Rebuttal Report, Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 21, 2007.

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78. Application of Duke Energy Carolina, LLC for Approval of Energy Efficiency Plan Including an Energy Efficiency Rider and Portfolio of Energy, Docket No. 2007-358-E, Public Service Commission of South Carolina, December 10, 2007.

77. Independent Transmission Cause No. PUD200700298, Application of ITC, Public Service of Oklahoma, December 7, 2007.

76. Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code š8-1-2.5-1, et. Seq. for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance With Ind. Code šš8-1-2.5-1 et seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the PowerShare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Cause Earnings and Expense Tests, Indiana Utility Regulatory Commission, Cause No. 43374, October 19, 2007.

75. Rebuttal Testimony, Docket No. U-30192, Application of Entergy Louisiana, LLC For Approval to Repower the Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery, October 4, 2007

74. Direct Testimony of Judah Rose on Behalf of Tucson Electric Power Company, In the matter of the Application of Tucson Electric Power Company for the Establishment of

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70. Responsive Testimony, Causes No. PUD 200500516, 200600030, and 200700012 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, May 2007.

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68. Rebuttal Testimony, Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, May 2007.

67. Direct Testimony for Southwestern Electric Power Company, Before the Louisiana Public Service Commission, Docket No. U-29702, in re: Application of Southwestern Electric Power Company for the Certification of Contracts for the Purchase of Capacity for 2007, 2008, and 2009 and to Purchase, Operate, Own, and Install Peaking, Intermediate and Base Load Coal-Fired Generating Facilities in Accordance with the Commission's General Order Dated September 20, 1983. Consolidated with Docket No. U-28766 Sub Docket B in re: Application of Southwestern Electric Power Company for Certification of Contracts for the Purchase of Capacity in Accordance with the Commission's 'General Order of September 20, 1983, February 2007.

66. Second Supplemental Testimony on Behalf of Duke Energy Ohio Before the Public Utility Commission of Ohio, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA, February 28, 2007.

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57. Cost of Service and Fuel Clause Issues, Rebuttal Testimony on behalf of Public Service of New Mexico, Docket No. EL05-151, November 2005.

56. Cost of Service and Peak Demand, FERC, Testimony on behalf of Public Service of New Mexico, September 19, 2005, Docket No. EL05-19.

55. Cost of Service and Fuel Clause Issues, Testimony on behalf of Public Service of New Mexico, FERC Docket No. EL05-151-000, September 15, 2005.

54. Cost of Service and Peak Demand, FERC, Responsive Testimony on behalf of Public Service of New Mexico, August 23, 2005, Docket No. EL05-19.

53. Prudence of Acquisition of Power Plant, Testimony on behalf of Redbud, September 12, 2005, No. PUD 200500151.

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50. New Air Emission Regulations and Investment in Coal Power Plants, rebuttal testimony on behalf of PSI, April 18, 2005, Causes 42622 and 42718.

49. Rebuttal Report: Damages due to Rejection of Tolling Agreement Including Discounting, February 9, 2005, CONFIDENTIAL.

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43. Rebuttal Testimony of Judah Rose on behalf of the Hopi Tribe, Case No. A.02-05-046, Mohave Coal Plant Economics, June 4, 2004.

42. Supplemental Testimony "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, May 20, 2004.

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40. "Appropriate Rate of Return on Equity (ROE) TransAlta Should be Authorized For its Capital Investment Related to VAR Support From the Centralia Coal-Fired Power Plant", for TransAlta, April 30, 2004, FERC Docket No. ER04-810-000.

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35. "Valuation of Power Contract," January 2004, confidential arbitration.

34. "In the matter of the Application of the Union Light Heat & Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources, etc.", before the Kentucky Public Service Commission, Coal-Fired and Gas-Fired Market Values, July 21, 2003.

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30. "IPP Power Purchase Agreement," confidential arbitration, April 2003.

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28. "Power Supply in the Pacific Northwest," contract arbitration, December 5, 2002. CONFIDENTIAL

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26. “Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants, rebuttal testimony on behalf of PSI. Filed on 8/23/02.”

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14. “Wholesale Power Prices, A Cost Plus All Requirements Contract and Damages”, Cajun Bankruptcy, July 1999. Testimony to U.S. Bankruptcy Court.

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12. “Horizontal Market Power in Generation.” Testimony to New Jersey Board of Public Utilities, May 22, 1998.

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9. “Future Rate Paths and Financial Feasibility of Project Financing.” Cajun Bankruptcy, Testimony to U.S. Bankruptcy Court, April 1998.

8. “Stranded Costs of PSE&G.” Market Valuation of a Fleet of Coal, Nuclear, Gas, and Oil-Fired Power Plants, Testimony to New Jersey Board of Public Utilities, February 1998.

7. “Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code.” Market Value of Fleet of Nuclear, Coal, Gas, and Oil Power Plants, Rebuttal Testimony filed July 1997.

6. “Future Wholesale Electricity Prices, Fuel Markets, Coal Transportation and the Cajun Bankruptcy.” Testimony to Louisiana Public Service Commission, December 1996.

5. “Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets.” Testimony on a contract arbitration, Las Vegas, Nevada, June 1996.

4. “Future Rate Paths and the Cajun Bankruptcy.” Testimony to the U.S. Bankruptcy Court, June 1997.

3. “Fuel Prices and Coal Transportation.” Testimony to the U.S. Bankruptcy Court, June 1997.

2. “Demand for Gas Pipeline Capacity in Florida from Electric Utilities.” Testimony to Florida Public Service Commission, May 1993.

1. **“**The Case for Fuel Flexibility in the Florida Electric Generation Industry.” Testimony to the Florida Department of Environmental Regulation (DER), Hearings on Fuel Diversity and Environmental Protection, December 1992.

**SELECTED SPEAKING ENGAGEMENTS**

98. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Crystal City, Arlington, VA, June 29-30, 2010.

97. Rose, J.L., Economics of PC Refurbishment, Improving the Efficiency of Coal-Fired Power Generation in the U.S., DOE-NETL, February 24, 2010.

96. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Orlando, FL, January 25-26, 2010.

95. Rose, J.L., $CO_2$ Control, “Cap & Trade”, & Selected Energy Issues, Multi-Housing Laundry Association, October 26, 2009.

94. Rose, J.L., Financing for the Future – Can We Afford It?, 2009 Bonbright Conference, October 9, 2009.

93. Rose, J.L., EEI’s Transmission and Market Design School, Washington, D.C., June 2009.

92. Rose, J.L., ICF’s New York City Energy Forum - Market Recovery in Merchant Generation Assets, June 10, 2008.

91. Rose, J.L., Southeastern Electric Exchange – Integrated Resource Planning Task Force Meeting, Carbon Tax Outlook Discussion, February 21-22, 2008.

90. Rose, J.L., AESP, NEEC Conference, Rising Prices and Failing Infrastructure: A Bleak or Optimistic Future, Marlborough, MA, October 23, 2006.

89. Rose, J.L., Infocast Gas Storage Conference, “Estimating the Growth Potential for Gas-Fired Electric Generation,” Houston, TX, March 22, 2006.

88. Rose, J.L., “Power Market Trends Impacting the Value of Power Assets,” Infocast Conference, Powering Up for a New Era of Power Generation M&A, February 23, 2006.

87. Rose, J.L., “The Challenge Posed by Rising Fuel and Power Costs”, Lehman Brothers, November 2, 2005.

86. Rose, J.L., “Modeling the Vulnerability of the Power Sector”, EUCI – Securing the Nation’s Energy Infrastructure, September 19, 2005

85. Rose, J.L., “Fuel Diversity in the Northeast, Energy Bar Association, Northeast Chapter Meeting, New York, NY, June 9, 2005.

84. Rose, J.L., “2005 Macquarie Utility Sector Conference”, Macquarie Utility Sector Conference, Vail, CO, February 28, 2005.

83. Rose, J.L., “The Outlook for North American Natural Gas and Power Markets”, The Institute for Energy Law, Program on Oil and Gas Law, Houston, TX, February 18, 2005.

82. Rose, J.L. “Assessing the Salability of Merchant Assets – What’s on the Horizon?” Infocast – The Market for Power Assets, Phoenix, AZ, February 10, 2005.

81. Rose, J.L. “Market Based Approaches to Transmission – Longer-Term Role”, National Group of Municipal Bond Investors, New York, NY, December 10, 2004.

80. Rose, J.L. “Supply & Demand Fundamentals – What is Short-Term Outlook and the Long-Term Demand? Platt’s Power Marketing Conference, Houston, TX, October 11, 2004.

79. Rose, J.L. “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast’s Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.

78. Rose, J. L. “After the Blackout – Questions That Every Regulator Should be Asking,” NARUC Webinar Conference, Fairfax, VA, November 6, 2003.

77. Rose, J. L., “Supply and Demand in U.S. Wholesale Power Markets,” Lehman Brothers Global Credit Conference, New York, NY, November 5, 2003.

76. Rose, J.L., “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?”, Infocast’s Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.

75. Rose, J.L., “Asset Valuation in Today’s Market”, Infocast’s Project Finance Tutorial, New York, NY, October 8, 2003.

74. Rose, J.L., “Forensic Evaluation of Problem Projects”, Infocast’s Project Finance Workouts: Dealing With Distressed Energy Projects, September 17, 2003.

73. Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.

72. Rose, J.L., “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?”, Infocast’s Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.

71. Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New York, NY, “Spark Spread Outlook”, July 17, 2003.

70. Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., “Trends in U.S. Energy and Economy”, June 24, 2003.

69. Rose, J.L., “Power Markets: Prices, SMD, Transmission Access, and Trading”, Bechtel Management Seminar, Frederick, MD, June 10, 2003.

68. Rose, J.L., Platt’s Global Power Market Conference, New Orleans, LA, “The Outlook for Recovery,” March 31, 2003.

67. Rose, J.L., “Electricity Transmission and Grid Security”, Energy Security Conference, Crystal City, VA, March 25, 2003.

66. Rose, J.L., “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast’s Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.

65. Rose, J.L., Panel Discussion, “Forensic Evaluation of Problem Projects”, Infocast Conference, NY, February 24, 2003.

64. Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).

63. Rose, J.L., “The Merchant Power Market—Where Do We Go From Here?” Center for Business Intelligence’s Financing U.S. Power Projects, November 18-19, 2002.

62. Rose, J.L., “Assessing U.S. Regional And The Potential for Additional Coal-Fired Generation in Each Region,” Infocast’s Building New Coal-Fired Generation Conference, October 8, 2002.

61. Rose, J.L., “Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, ”Infocast’s Product Structuring in the Real World Conference, September 25, 2002.

60. Rose, J.L., “PJM Price Outlook,” Platt’s Annual PJM Regional Conference, September 24, 2002.

59. Rose, J.L., “Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies,” New York Venture Group’s Investing in the Power Industry—Targeting The Newest Trends Conference, July 31, 2002.

58. Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.

57. Rose, J.L., “Locational Market Price (LMP) Forecasting in Plant Financing Decisions,” Structured Finance Institute, April 8-9, 2002.

56. Rose, J.L., “PJM Transmission and Generation Forecast”, Financial Times Energy Conference, November 6, 2001.

55. Rose, J.L., “U.S. Power Sector Trends”, Credit Suisse First Boston’s Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.

54. Rose, J.L., “Dealing with Inter-Regional Power Transmission Issues”, Infocast’s Ohio Power Game Conference, September 6, 2001

53. Rose, J.L., “Where’s the Next California”, Credit Suisse First Boston’s Global Project Finance Capital Markets Conference, New York NY, June 27 2001

52. Rose, J.L, “U.S. Energy Issues: What MLA Members Need to Know,” Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001

51. Rose, J.L., “How the California Meltdown Affects Power Development”, Infocast’s Power Development and Finance Conference 2001, Washington D.C., June 12, 2001

50. Rose, J.L., “Forecasting 2001 Electricity Prices” presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001

49. Rose, J.L., “Power Crisis in the West” Generation Panel Presentation, San Diego, California, February 12, 2001

48. Rose, J.L., “An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000” Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.

47. Rose, J. L., “An Analysis of the Power Markets, summer 2000” Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000

46. Rose, J.L., “An Analysis of the Merchant Power Market, Summer 2000” presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000

45. Rose, J.L., “Understanding Capacity Value and Pricing Firmness” presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

44. Rose, J.L., “Implementing NYPP’s Congestion Pricing and Transmission Congestion Contract (TCC)”, Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

43. Rose, J.L., “Understanding Generation” Pre-Conference Workshop, Powermart, Houston, Texas, October 26-28, 1999.

42. Rose, J.L., “Understanding Capacity Value and Pricing Firmness” presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.

41. Rose, J.L., “Comparative Market Outlook for Merchant Assets” presentation, Merchant Power Conference, New York, New York, September 24, 1999.

40. Rose, J.L., “Transmission, Congestion, and Capacity Pricing” presentation, Transmission The Future of Electric Transmission Conference, Washington, DC, September 13, 1999.

39. Rose, J.L., “Effects of Market Power on Power Prices in Competitive Energy Markets” Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.

38. Rose, J.L., “Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity” presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.

37. Rose, J.L., “Transmission Solutions to Market Power” presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.

36. Rose, J.L., “Repowering Existing Power Plants and Its Impact on Market Prices” presentation, Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.

35. Rose, J.L., “Transmission and Retail Issues in the Electric Industry” Session Speaker, Gas Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.

34. Rose, J.L., “Peak Price Volatility in the Rockies and Southwest” presentation at Repowering the Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.

33. Rose, J.L., “Understanding Generation” presentation and Program Chairman at Buying & Selling Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.

32. Rose, J.L., “Buying Generation Assets in PJM” presentation at Mid-Atlantic Power Summit, Philadelphia, Pennsylvania, April 12, 1999.

31. Rose, J.L., “Evaluating Your Generation Options in Situations With Insufficient Transmission,” presentation at Congestion Management conference, Washington, D.C., March 25, 1999.

30. Rose, J.L., “Will Capacity Prices Drive Future Power Prices?” presentation at Merchant Plant Development conference, Chicago, Illinois, March 23, 1999.

29. Rose, J.L., “Capacity Value – Pricing Firmness,” presentation at Market Price Forecasting conference, Atlanta, Georgia, February 25, 1999

28. Rose, J.L., “Developing Reasonable Expectations About Financing New Merchant Plants That Have Less Competitive Advantage Than Current Projects,” presentation at Project Finance International’s Financing Power Projects in the USA conference, New York, New York, February 11, 1999.

27. Rose, J.L., “Transmission and Capacity Pricing and Constraints,” presentation at Power Fair 99, Houston, Texas, February 4, 1999.

26. Rose, J.L., “Peak Price Volatility: Comparing ERCOT With Other Regions,” presentation at Megawatt Daily’s Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.

25. Rose, J.L., “The Outlook for Midwest Power Markets,” presentation to The Institute for Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.

24. Rose, J.L., “Developing Pricing Strategies for Generation Assets,” presentation at Wholesale Power in the West conference, Las Vegas, Nevada, November 12, 1998.

23. Rose, J.L., “Understanding Electricity Generation and Deregulated Wholesale Power Prices,” a full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.

22. Rose, J.L., “The Impact of Power Generation Upgrades, Merchant Plant Developments, New Transmission Projects and Upgrades on Power Prices,” presentation at Profiting in the New York Power Market conference, New York, NY, October 22, 1998.

21. Rose, J.L., “Capacity Value – Pricing Firmness,” presentation to Edison Electric Institute Economics Committee, Charlotte, NC, October 8, 1998.

20. Rose, J.L., “Locational Marginal Pricing and Futures Trading,” presentation at Megawatt Daily’s Electricity Regulation conference, Washington, D.C., October 7, 1998.

19. Rose, J.L., Chairman’s opening speech and “The Move Toward a Decentralized Approach: How Will Nodal Pricing Impact Power Markets?” at Congestion Pricing and Tariffs conference, Washington, D.C., September 25, 1998.

18. Rose, J.L., “The Generation Market in MAPP/MAIN: An Overview,” presentation at Megawatt Daily’s MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16, 1998.

17. Rose, J.L., “Capacity Value – Pricing Firmness,” presentation at Market Price Forecasting conference, Baltimore, Maryland, August 24, 1998.

16. Rose, J.L., “ICF Kaiser’s Wholesale Power Market Model,” presentation at Market Price Forecasting conference, New York, New York, August 6, 1998.

15. Rose, J.L., Campbell, R., Kathan, David, “Valuing Assets and Companies in M&A Transactions,” full-day workshop at Utility Mergers & Acquisitions conference, Washington, D.C., July 15, 1998.

14. Rose, J.L., “Must-Run Nuclear Generation’s Impact on Price Forecasting and Operations,” presentation at The Energy Institute’s conference entitled “Buying and Selling Electricity in the Wholesale Power Market,” Las Vegas, Nevada, June 25, 1998.

13. Rose, J.L., “The Generation Market in PJM,” presentation at Megawatt Daily’s PJM Power Markets conference, Philadelphia, Pennsylvania, June 17, 1998.

12. Rose, J.L., “Market Evaluation of Electric Generating Assets in the Northeast,” presentation at McGraw-Hill’s conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15, 1998.

11. Rose, J.L., “Overview of SERC Power,” opening speech presented at Megawatt Daily’s SERC Power Markets conference, Atlanta, Georgia, May 20, 1998.

10. Rose, J.L., “Future Price Forecasting,” presentation at The Southeast Energy Buyers Summit, Atlanta, Georgia, May 7, 1998.

9. Rose, J.L., “Practical Risk Management in the Power Industry,” presentation at Power Fair, Toronto, Canada, April 16, 1998.

8. Rose, J.L., “The Wholesale Power Market in ERCOT: Transmission Issues,” presentation at Megawatt Daily’s ERCOT Power Markets conference, Houston, Texas, April 1, 1998.

7. Rose, J.L., “New Generation Projects and Merchant Capacity Coming On-Line,” presentation at Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.

6. Rose, J.L., “Projecting Market Prices in a Deregulated Electricity Market,” presentation at conference: Market Price Forecasting, San Francisco, California, March 9, 1998.

5. Rose, J.L., “Handling of Transmission Rights,” presentation at conference: Congestion Pricing & Tariffs, Washington, D.C., January 23, 1998.

4. Rose, J.L., “Understanding Wholesale Markets and Power Marketing,” presentation at The Power Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.

2. Rose, J.L., “Determining the Electricity Forward Curve,” presentation at seminar: Pricing, Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October 23, 1997.

3. Rose, J.L., “Market Price Forecasting In A Deregulated Market,” presentation at conference: Market Price Forecasting, Washington, D.C., October 23, 1997,

1. Rose, J.L., “Credit Risk Versus Commodity Risk,” presentation at conference: Developing & Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16, 1997.

**SELECTED PUBLICATIONS**

Rose, J.L. and Surana, S. “Oil Price Increases, Yield Curve Inversion may be Indicators of Economic Recession.” Oil and Gas Financial Journal, Volume 7, Issue 6, June 2010

Rose, J.L. and Surana, S. “Forecasting Recessions and Investment Strategies.” World-Generation, June/July 2010, V.22, #3.

Rose, J.L., “Should Environmental Restrictions be Eased to Allow for the Construction of More Power Plants? The Costco Connection, April 2001.

Rose, J.L., “Deregulation in the US Generation Sector: A Mid-Course Appraisal”, Power Economics, October 2000.

Rose, J. L., “Price Spike Reality: Debunking the Myth of Failed Markets”, *Public Utilities Fortnightly,* November 1, 2000.

Rose, J.L., “Missed Opportunity: What’s Right and Wrong in the FERC Staff Report on the Midwest Price Spikes,” *Public Utilities Fortnightly,* November 15, 1998.

Rose, J.L., “Why the June Price Spike Was Not a Fluke,” *The Electricity Journal*, November 1998.

Rose, J.L., S. Muthiah, and J. Spencer, “Will Wall Street Rescue the Competitive Wholesale Power Market?” *Project Finance International*, May 1998.

Rose, J.L., “Last Summer’s “Pure” Capacity Prices – A Harbinger of Things to Come*,” Public Utilities Fortnightly,* December 1, 1997.

Rose, J.L., D. Kathan, and J. Spencer “Electricity Deregulation in the New England States,” *Energy Buyer*, Volume 1, Issue 10, June-July 1997.

Rose, J.L., S. Muthiah, and M. Fusco, “Financial Engineering in the Power Sector,” *The Electricity Journal,* Jan/Feb 1997.

Rose, J.L, S. Muthiah, and M. Fusco, “Is Competition Lacking in Generation? (And Why it Should Not Matter)*,” Public Utilities Fortnightly,* January 1, 1997.

Mann, C. and J.L. Rose, “Price Risk Management: Electric Power vs. Natural Gas,” *Public Utilities Fortnightly,* February 1996.

Rose, J.L. and C. Mann, “Unbundling the Electric Capacity Price in a Deregulated Commodity Market,” *Public Utilities Fortnightly,* December 1995.

Booth, William and J.L. Rose, “FERC's Hourly System Lambda Data as Interim Bulk Power Price Information,” *Public Utilities Fortnightly,* May 1, 1995.

Rose, J.L. and M. Frevert, “Natural Gas: The Power Generation Fuel for the 1990s.” Published by Enron.

**EMPLOYMENT HISTORY**

| | | |
|---|---|---|
| ICF Resources Incorporated | Managing Director | 1999-Present |
| | Vice President | 1996-1999 |
| | Project Manager | 1993-1996 |
| | Senior Associate | 1986-1993 |
| | Associate | 1982-1986 |

**PUB/MH/RISK-89**

**Reference: Risk Studies ICF Project Management**

**f) Please indicate the proposed billed rates for ICF by individual for involvement in the hearing process, including the preparation of interrogatories and preparation for and attendance at the hearing.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-89(c).

**PUB/MH/RISK-90**

**Reference: KPMG Engagements**

**a) Please provide full listing of all assignments undertaken by KPMG or its predecessor firms for Manitoba Hydro or any of its subsidiaries during the last 10 years, including a description of the assignments, the title of any reports prepared, fees charged for the assignment, and KPMG staff members involved [ including those that were engaged in the Risk study].**

**ANSWER:**

The table below summarizes the significant assignments undertaken by KPMG over the last ten years. Fee and staff information pertaining to these engagements are not provided for the reasons stated in PUB/MH/RISK-51(c).

| Assignment | Description of assignment | Report Titles |
|---|---|---|
| IFRS Conversion/Consulting | Provide guidance with respect to accounting gap analysis, identification of system and process impacts, and the interpretation of IFRS standards. | *IFRS Status Update Report* (produced by Manitoba Hydro with commentary provided by KPMG), February 2010 |
| IT Internal Controls Assessment | Assisted with the development of an IT systems assessment including:<br><br>(1) IT risk assessment of IT systems to use as one input for audit planning purpose,<br><br>(2) webTrader IT general control review of technical IT processes supporting the webTrader application, and<br><br>(3) Banner IT general control review of technical IT processes supporting the Banner application. | (1) *Information Technology Risk Assessment on Critical Information Technology Systems*<br><br>(2) *webTrader Power Application Control Review* - Review of Business Processes and IT General Controls (KPMG's involvement was only in the detail testing of the IT General Controls)<br><br>(3) *Banner Billing System* - IT General Control (ITGC) Review |
| Manitoba Hydro External Quality Review | Carry out an independent assessment of Manitoba Hydro's risk management practices in its hydroelectric operations and to address assertions raised by a NY consultant pertaining to Manitoba Hydro's export power sales and associated risk management practices. | *Manitoba Hydro - External Quality Review*, April 2010 |
| Manitoba Hydro-Centra Gas Integration Review | Consultation and review on the appropriateness of estimates and accounting for Centra Gas acquisition costs, integration costs, and synergy savings; and the integrated cost allocation methodology process. | *Manitoba Hydro-Centra Gas Integration Review Engagement*, December 2001 |
| Provision of EMS Registration Services | Conduct an assessment of Manitoba Hydro's environmental management system in accordance with ISO 14001 and the registration requirements of the Standards Council of Canada, including an examination of documentation and implementation assessment. | Not Applicable |

**Note: In addition to these assignments, KPMG audited the Corporation's financial statements until 2002.**

**PUB/MH/RISK-90**

**Reference: KPMG Engagements**

**b) Please provide a full listing of current, ongoing or future known or potential [ RFP/ current proposal /retained but not yet started] assignments undertaken or to be undertaken by KPMG including a full description of each assignment and the fees by assignment.**

**ANSWER:**

The IFRS Conversion/Consulting assignment is the only undertaking by KPMG that is currently in process. Fee information pertaining to this engagement is not provided for the reasons stated in PUB/MH/RISK-51(c). As well KPMG is currently engaged to respond to Information Requests related to the Manitoba Hydro External Quality Review.

Manitoba Hydro does not have any additional RFPs outstanding with KPMG, however it is expected that further IFRS consultation and further work with respect to the Manitoba Hydro External Quality Review may be required.

**PUB/MH/RISK-91**

**Reference: ICF Engagements**

**a) Please provide full listing of all assignments undertaken by ICF or its predecessor firms for Manitoba Hydro or any of its subsidiaries during the last 10 years, including a description of the assignments, the title of any reports prepared, fees charged for the assignment, and ICF staff members involved [ including those that were engaged in the Risk study].**

**ANSWER:**

The table below summarizes the significant assignments undertaken by ICF over the last ten years. Fee and staff information pertaining to these engagements are not provided for the reasons stated in PUB/MH/RISK-51(c).

| Assignment | Description of assignment | Report Titles |
|---|---|---|
| Consulting Services | Assist with an analysis of natural gas supply re-contracting options and preparation of RFPs. | Not Applicable |
| Greenhouse Gas Measurement/Reporting | Consulting services related to the audit and review of MH's GHG measurement and reporting practices in accordance with current international protocols. | *GHG Emissions Verification & Management System Audit* , October 2002<br><br>CAC (Criteria Air Contaminants) Emission Factor Review & Planning Tool, March 2003 |
| Price Forecasts & Market Assessments | Provide an update of their electricity price forecast, fuel price forecasts and market assessments of the MRO and/or MISO market regions. | *Power Market Assessment of the Midwest Independent System Operator (MISO) Region* , March 2010 |
| | Provide electricity price forecast, fuel price forecasts and market assessments of the MRO and/or MISO market regions. | *Power Market Assessment of the Midwest reliability Organization (MRO) Region* , July 2009 |
| Risk Assessment - Export Power Sales | Risk assessment and associated work with export power sales transactions | *Independent Review of Manitoba Hydro Export Power Sales and Associated Risks* , September 2009 |

**PUB/MH/RISK-91**

**Reference: ICF Engagements**

**b) Please provide a full listing of current, ongoing or future known or potential [ RFP/ current proposal /retained but not yet started] assignments undertaken or to be undertaken by ICF including a full descriptions of each assignment and the actual or estimated fees by assignment.**

**ANSWER:**

Current Assignment

Gas Portfolio Review

Future/Potential Assignments

Electricity price forecast
Fuel price forecasts
MISO market assessments

The estimated value of future/potential assignments is considered "Confidential" as publically stating the value could compromise the competiveness of the tendering process.

**PUB/MH/RISK-92**

**Reference: KPMG Report Section 1.3.3**

**Please detail steps KPMG undertook to ensure that it had sufficient information to assert that KPMG "understood sufficiently the assertions made by the NYC Consultant, by each assertion analyzed.**

**ANSWER:**

KPMG Response:

KPMG developed a conceptual framework to guide it in its external quality review of Manitoba Hydro, as detailed in Section 1.2. In applying this conceptual framework, KPMG carried out a detailed review of the Consultant's Reports and other documents and in doing so concluded that we understood the assertions made by the Consultant sufficiently to carry out a high quality review.

**<u>PUB/MH/RISK-93</u>**

**Reference: Appendix E**

**Please file a copy of the completed questionnaire instrument used in the survey of 14 utilities.**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

The utilities surveyed provided the information for the questionnaire instrument on a confidential basis and only allowed certain information to be revealed publicly. As mentioned in Appendix E page 3, the utilities that participated did so through a telephone interview process, with the interview questions cited in the section on pages 3-6 of Appendix E.

**<u>PUB/MH/RISK-94</u>**

**Reference: KPMG Page 40 Exhibit 3-2**
**Risk Issue: Export Sales Breakdown**

**Please provide the same level of detail in Exhibit 3-2 for the years 2002/03 through 2009/10.**

**<u>ANSWER</u>:**

The data requested is provided in the table below. Note that in the referenced Exhibit 3-2 the data that was presented as “Hydraulic Generation in 2008/09 as % of Hydraulic Generation in an Average Flow Year” of 114%, this actually represents a percentage of generation in a Median flow year, the percentage of generation in an Average Flow Year for 2008/09 is actually 117%.

| | 2002/03 | | 2003/04 | | 2004/05 | | 2005/06 | | 2006/07 | | 2007/08 | | 2008/09 | | 2009/10 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sales Category | Volumes (MWh) | % | Volumes (MWh) | % | Volumes (MWh) | % | Volumes (MWh) | % | Volumes (MWh) | % | Volumes (MWh) | % | Volumes (MWh) | % | Volumes (MWh) | % |
| **Opportunity Spot (DA and RT)** | 1,315,092 | 13% | 531,277 | 8% | 3,327,716 | 32% | 8,085,539 | 56% | 2,977,409 | 29% | 6,216,880 | 53% | 4,145,046 | 44% | 5,128,774 | 47% |
| **Opportunity Term** | 2,391,479 | 24% | 468,058 | 7% | 1,613,454 | 15% | 2,216,831 | 15% | 3,277,537 | 32% | 1,596,514 | 14% | 1,185,392 | 13% | 2,593,658 | 24% |
| **Dependable** | 6,198,545 | 63% | 5,917,562 | 86% | 5,617,614 | 53% | 4,138,806 | 29% | 3,848,905 | 38% | 4,010,803 | 34% | 4,145,046 | 44% | 3,264,433 | 30% |
| **Total** | 9,905,116 | 100% | 6,916,897 | 100% | 10,558,784 | 100% | 14,441,176 | 100% | 10,103,851 | 100% | 11,824,197 | 100% | 9,475,484 | 100% | 10,986,865 | 100% |
| **Hydraulic Generation as a % of Hydraulic Generation in an Average Flow Year** | 98% | | 63% | | 106% | | 127% | | 108% | | 119% | | 117% | | 116% | |

**PUB/MH/RISK-95**

**Reference: KPMG Report page 28**
**Risk Issue: Financial Model Testing**

**a) Please elaborate on the specifics MH should incorporate in back-testing practices in validating each of its computer models.**

**ANSWER:**

Manitoba Hydro is in the process of assessing the recommendations from KPMG including their applicability, cost and potential implementation timeframe. Therefore, Manitoba Hydro is not in a position at this time to provide information on this specific recommendation.

**PUB/MH/RISK-95**

**Reference: KPMG Report page 28**
**Risk Issue: Financial Model Testing**

**b) Please indicate whether KPMG undertook any back testing in assessing the validity of the models. In particular was any back testing undertaken by KPMG of the 2003/04 drought period. If not, why not?**

**ANSWER:**

KPMG Response:

KPMG did not request any back-testing with respect to the 2003/04 drought period. This period was out of scope for our analysis, because our work was focused on the period covered by the Consultant's Reports. We also noted that the 2003/04 drought had already been the subject of a prior PUB review and of other external consultant reports.

**<u>PUB/MH/RISK-96</u>**

**Reference: KPMG report page 30**

**Risk Issue: HERMES/ SPLASH Model Assumptions**

**a) Please elaborate on which of the NYC listed assumptions are correct and also list the NYC assumptions which are incorrect such that KPMG determined that the implications identified are not meaningful. Please provide reasons for each specific case.**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

KPMG developed a conceptual framework to guide it in its external quality review of Manitoba Hydro, as detailed in Section 1.2. In applying this conceptual framework, KPMG carried out a detailed review of the NYC Consultant's Reports and other documents to group the NYC's assertions into the Issues and Themes as presented in the KPMG report. In assessing the Issues, we took the approach that our work would not necessarily result in a total concurrence with or rejection of the assertions underlying an Issue; in some instances, we have found that we concur with some elements of an assertion and reject other elements. Accordingly, we would suggest that readers of this report focus on the analysis of the Issues as well as any recommendations that relate to the Issues, rather than focusing on whether we concur with or reject any particular assertion. However, the key error made by the NYC was assuming that forecast production schedules lead to corresponding sales of energy in future periods through forward contracts. As a result, the NYC assumes that subsequent changes in production forecasts for these future periods could result in financial losses as MH either attempts to unwind these contracts or ends up being "short" in real-time energy markets.

**PUB/MH/RISK-96**

**Reference: KPMG report page 30**
**Risk Issue: HERMES/ SPLASH Model Assumptions**

**b) Without providing the details of any calculations, please indicate each case where KPMG attempted to replicate the NYC's estimates, and provide detailed KPMG commentary on their findings from the analysis.**

**ANSWER:**

KPMG Response:

We have noted in our report instances where we attempted to duplicate the numbers quoted by the NYC as follows:

- Page 78: As noted in the text, we were able to roughly duplicate NYC's estimate of $50 million for the risks associated with water flow uncertainty.
- Page 75, Exhibit 3-10. We came up with different numbers than NYC with respect to correlations between prices in peak and off-peak periods.

**PUB/MH/RISK-97**

**Reference: KPMG report page 30**
**Risk Issue: SPLASH & PRISM Model Assumptions**

**Did KPMG attempt to comprehensively verify the data and assumptions used in the models? If not, why not?**

**ANSWER:**

KPMG Response:

KPMG focused on the elements of the models that were subject to assertions by the NYC and on the models' general structure and forecasting approach.

We did not attempt to comprehensively verify the data and assumptions used in the models. We note that the SPLASH model, in particular, is a complex model with a large number of data elements and state equations. To undertake a comprehensive review of this model would have been a large undertaking, and was not considered necessary given the nature of the NYC's assertions. In general, the NYC's assertions related to specific model inputs and the general forecasting approach, rather than to the models' computational accuracy or the mechanical implementation of the forecasting logic.

**<u>PUB/MH/RISK-98</u>**

**Reference: KPMG Report section 3.5 page 44**
**Risk Issue: HERMES–Model Validity**

**a) Please elaborate on each of the techniques available to consider uncertainties in future water conditions and discuss how such techniques can result in identifying optimal generation decisions.**

**<u>ANSWER</u>:**

Future water conditions can be assessed by two fundamental methods:

a) modelling the physical processes that underlie the future water supply;
b) statistical modelling of potential future water conditions based on a set of historic records, and the statistical relationship between recent observed inflows and future water supply (i.e. antecedent forecasting).

In the case of Manitoba Hydro, due to the characteristics of its geographically large system, long lead time projections of precipitation and other climate parameters would be required to model physical processes and produce long range inflow forecasts. Given the unpredictability of precipitation, the fundamental forecast necessary to implement physical precipitation/runoff forecasting, method a) is generally not feasible for the Manitoba Hydro system.

Manitoba Hydro's operating plans are developed using method b). The principle is to employ statistical based modelling while using the economic criterion to maximize net revenues in recommending a series of decisions (i.e. an operating plan). Economic planning based on the highest expected value results in decision making that maximizes the utility of the resource.

**<u>PUB/MH/RISK-98</u>**

**Reference: KPMG Report section 3.5 page 44**
**Risk Issue: HERMES–Model Validity**

**b) Please comment on the extent that these techniques have been considered by MH in validating its models.**

**<u>ANSWER</u>:**

Manitoba Hydro continues to explore new approaches to statistical decision making in its modelling. For example, Manitoba Hydro is planning the implementation of a stochastic decision support model that incorporates uncertainty explicitly in the optimization of its operating plan (refer to Section 3.6.4.2 page 52 of KPMG report).

**<u>PUB/MH/RISK-98</u>**

**Reference:** **KPMG Report section 3.5 page 44**
**Risk Issue:** **HERMES–Model Validity**

**c)** **Please elaborate further on how these additional techniques will result in computational complexity.**

**<u>ANSWER</u>:**

Statistical decision making requires a detailed representation of the planning problem with different possible input scenarios. This is in itself requires multiple model runs for each and every of these scenarios. Further, there is a need to compile the information from multiple model runs into a single expected value.

An alternate methodology involves formulating a stochastic model where various input scenarios are combined into a single problem formulation with multiple possible outcomes. This was introduced as the "Tree" model in Section 3.6.4.2 page 52 of KPMG report. This kind of modelling has the potential to increase the computational complexity manifold since there is only a single planning problem formulation but with significantly increased size. The computational time increases exponentially with the problem size.

**PUB/MH/RISK-98**

**Reference: KPMG Report section 3.5 page 44**
**Risk Issue: HERMES–Model Validity**

**d) Please indicate where the techniques referred to in part [a] have been utilized in modeling water flows at other utilities.**

**ANSWER:**

A list of utilities and consultants that service utilities in this area:

British Columbia Hydro, Bonneville Power Authority (USA), Tennessee Valley Authority (USA), Hydro-Québec, Florida Power and Light (Maine division, USA), Statkraft (Norway), Chuck Howard Consulting (Victoria, BC), Hatch Acres (Niagara Falls, Ontario), PSR-INC Consulting (Brasil), Powel ASA (Throndheim, Norway)

**PUB/MH/RISK-98**

**Reference: KPMG Report section 3.5 page 44**
**Risk Issue: HERMES–Model Validity**

e) **Please provide a table detailing all of the model assumptions utilized in HERMES, the source of the assumption, and explain how the assumptions are changed over time.**

**ANSWER:**

The assumptions in HERMES are characterized as forecasts of inputs. By family they can be categorized as follows.

**Load Forecast** - source is historic data and corporate energy forecast, no major structural changes since its original implementation, calibrated annually

**Market Forecast –** sources are historic observed market price profiles and purchased commercial price forecast subscription, methodology change in 2008 in response to recent market changes and the availability of a historic hourly market prices, calibrated monthly

**Flow Forecast** - source is recent observed and historic data, no change since inception, updated weekly

**Hydraulic Performance Forecast** (flow restrictions at lake outlets and station tailwater reaches) - source is recent observed and historic data, no major change since inception, updated weekly

**Maintenance Forecas**t **–** sources are station maintenance planners and generation reliability function of Transmission business unit, no change since inception, calibrated weekly

**PUB/MH/RISK-99**

**Reference:** **page 47 Exhibit 3–4**
**Risk Issue:** **HERMES Model Validation**

**a) Please provide the respective data points for the graph and provide a comparison with actual versus forecast generation.**

**ANSWER:**

See table below. These forecasts were produced in late summer or in the fall; hence early months of the fiscal year forecast contained actuals.

| Fiscal Year | Forecast Date | Forecast Generation GWh | Actual Generation GWh | Variance GWh | Variance % |
|---|---|---|---|---|---|
| 1999/00 | 1999-09-09 | 29347 | 30146 | 799 | 3 |
| 2000/01 | 2000-09-27 | 32265 | 32687 | 422 | 1 |
| 2001/02 | 2001-09-24 | 33419 | 32557 | -862 | -3 |
| 2002/03 | 2002-09-10 | 29924 | 29118 | -806 | -3 |
| 2003/04 | 2003-09-10 | 21820 | 19369 | -2451 | -11 |
| 2004/05 | 2004-10-08 | 30918 | 31534 | 616 | 2 |
| 2005/06 | 2005-08-10 | 36516 | 37629 | 1113 | 3 |
| 2006/07 | 2006-08-22 | 33515 | 32121 | -1394 | -4 |
| 2007/08 | 2007-10-01 | 34330 | 35354 | 1024 | 3 |
| 2008/09 | 2008-09-24 | 34547 | 34528 | -19 | 0 |
| **Average** | | **31660** | **31504** | **-156** | **0** |

**PUB/MH/RISK-99**

**Reference:** **page 47 Exhibit 3–4**
**Risk Issue:** **HERMES Model Validation**

**b)** **Please discuss the implications on the financial loss incurred as a result of the 2003/04 drought with interpretation of the above chart in (a)**

**ANSWER:**

Actual hydraulic generation in 2003/04 was less than forecast in the beginning of September 2003. As a result there were increased costs associated with serving load demands than were forecast for 2003/04. Offsetting these costs were higher than expected carry over storage into 2004/05 which resulted in increased net export revenue in 2004/05 vs. what was forecast in fall of 2003.

**<u>PUB/MH/RISK-99</u>**

**Reference: page 47 Exhibit 3–4**
**Risk Issue: HERMES Model Validation**

**c) Please discuss to what extent KPMG satisfied itself on the accuracy of Exhibit 3–4**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

Exhibit 3-4 was based on a table provided by MH to KPMG that compared actual to forecast generation for each of the fiscal years shown. KPMG verified that the numbers in the table matched numbers provided in the relevant Generation Estimate reports for each year. With respect to Generation Estimate report, we reviewed both the reports containing actual data after the fact and the forecast reports produced in late summer for the purpose MH's financial forecasting process.

**PUB/MH/RISK-99**

**Reference:** **page 47 Exhibit 3–4**
**Risk Issue:** **HERMES Model Validation**

**d)** **Please explain whether an independent review of the model has been undertaken.**

**ANSWER:**

As explained by KPMG in Section 3.5, no comprehensive structured independent review has been undertake for the HERMES model, however on a periodic basis Manitoba Hydro staff have presented the concepts and methodologies used in HERMES at industry forums and received general comments from its peers in the field of hydroelectric operations modeling.

**PUB/MH/RISK-100**

**Reference: KPMG Report Section 3.6.2 Model Revision Process**
**Risk Issue: Model Documentation**

a) **Please indicate whether the MH documentation for model changes is standardized and based on your review comment on the adequacy of the documentation.**

**ANSWER:**

Manitoba Hydro's HERMES model changes follow those described in KPMG Report Section 3.6.2 Model Revision Process. Please refer to the response provided to CAC/MSOS/MH/RISK-10 regarding the adequacy of model documentation.

**Reference: KPMG Report Section 3.6.2 Model Revision Process**
**Risk Issue: Model Documentation**

**b) Please discuss how weekly calibration of the HERMES model would likely identify problems quickly. Please indicate what parameters are utilized to identify whether there are problems with the modeling.**

**ANSWER:**

The HERMES model run provides a set of operating decisions and resultant changes to system operating parameters. These results can be quickly reviewed by the operations planning group through comparison to the near operating history and expected trends in future operation.

Weekly calibration of HERMES consists of:

- updating inflow forecasts, including inflows from upstream regulated reservoirs;
- updating forecast of hydraulic performance (i.e., ice impacts on water conveyance);
- updating current reservoir storage; and
- updating maintenance schedule.

On a weekly basis Manitoba Hydro tracks how actual parameters (e.g. flow, water level, calculated inflows, and energy production) are tracking against its operating forecasts and in comparison to actual operations for similar times in previous years. Graphical and numerical comparisons are used to monitor calibration. If problems are suspected, operations planning engineers can investigate in further detail by using diagnostic reports produced by the HERMES model.

In almost all instances problems encountered in operations planning models trace back to input data. For this reason, dedicated staff in operations perform quality review and checking of operational field data prior to their use in HERMES. A separate suite of tools are used to perform quality control of operational input data. These tools enable visual reviews and programmatic plausibility checking such as evaluating operation data against rate of change, normal minimum, normal maximum limits.

**PUB/MH/RISK-100**

**Reference: KPMG Report Section 3.6.2 Model Revision Process**
**Risk Issue: Model Documentation**

**c) Please indicate what, if any, changes in parameters have been made to the HERMES model since the drought in 2003/04.**

**ANSWER:**

Manitoba Hydro has continued to make improvements and expand the capability of the HERMES model to reflect the changes in the operating environment however the basic principles of the model are unaltered since its original inception. One significant change that has been made since the drought of 2003/04 was the market forecast methodology. As explained in PUB/MH/RISK-98, this change was prompted by changes to the MISO market and the later accrual of historic market clearing price data.

The input data history is constantly accruing with the passage of time and that allows for better inference regarding potential future outcomes. For example the historic inflow record of 2003/04 has now become a valuable actual scenario for evaluating potential planning outcomes of similar severity.

**PUB/MH/RISK-101**

**Reference: KPMG Report – Page 122, Section 4.2 Key Findings/ Page 237 Fn 22**
**Risk Issue: Pricing Methodologies Mark to Model**

a) **Please confirm that the two pricing methodologies for negotiating firm contracts described above, referred to in section 4 of the report is that methodology described on page 21 of the executive summary.**

**ANSWER:**

Manitoba Hydro confirms that the pricing methodology for negotiating firm contracts in section 4 of the report is consistent with the methodology described on page 21 of the executive summary.

**<u>PUB/MH/RISK-101</u>**

**Reference: KPMG Report – Page 122, Section 4.2 Key Findings/ Page 237 Fn 22**
**Risk Issue: Pricing Methodologies Mark to Model**

**b) Please confirm that MH's first methodology employed includes the determination of a price based on averages of price forecast purchased from multiple power price forecasting consultants listed in footnote 22 on page 237 of the KPMG report. If so confirmed, please provide a full listing indicating the vintage of each of the forecast currently employed in the pricing models and an explanation of if or when the price forecasts are refreshed.**

**<u>ANSWER</u>:**

Please see response to PUB/MH I-156(a) for a comment on Manitoba Hydro's long-term electricity export price forecast methodology. An average of the five consultants' forecasts issued in the fall 2007 period through early winter 2008 was used to prepare the electricity export price forecast used for IFF08-1 and IFF09-1.

Updated information was obtained from five external price forecast consultants in the January to March, 2010 period for use in the 2010 power resource plan and the 2010 IFF, which is currently under preparation.

**PUB/MH/RISK-101**

**Reference:** **KPMG Report – Page 122, Section 4.2 Key Findings/ Page 237 Fn 22**
**Risk Issue:** **Pricing Methodologies Mark to Model**

**c) Please confirm that the second methodology used by MH employs a calculation of the avoided cost of the potential counterparties. Please explain why this methodology is employed.**

**ANSWER:**

Manitoba Hydro confirms that the second methodology used employs a calculation of the avoided cost of the potential counterparty. Manitoba Hydro utilizes the avoided cost calculation as a benchmark for evaluating the price that was determined by using Manitoba Hydro's electricity price forecast and for gaining insight into the price of alternative generation /power purchase proposals that may be considered by the customer.

**PUB/MH/RISK-101**

**Reference: KPMG Report – Page 122, Section 4.2 Key Findings/ Page 237 Fn 22**
**Risk Issue: Pricing Methodologies Mark to Model**

**d) Please discuss the merit of incorporating the unit cost of new generation and transmission in support of the new contracts, in establishing the reference price to be negotiated.**

**ANSWER:**

The merits of incorporating avoided cost analysis in establishing the reference price to be negotiated include:

1. Provides a benchmark of the customers alternative self build option and of prices that may be offered by competing suppliers;

2. Provides a cost benchmark that may be considered by regulators when evaluating the feasibility of Manitoba Hydro's proposal; and

3. Provides a benchmark for evaluating the reasonableness of the price calculation based on Manitoba Hydro's electricity price forecast.

**<u>PUB/MH/RISK-101</u>**

**Reference: KPMG Report – Page 122, Section 4.2 Key Findings/ Page 237 Fn 22**
**Risk Issue: Pricing Methodologies Mark to Model**

**e) Please provide KPMG's views of the merits of each of the proposed adjustments to the pricing model suggested by the NYC.**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

KPMG developed a conceptual framework to guide it in its external quality review of Manitoba Hydro, as detailed in Section 1.2. In applying this conceptual framework, KPMG carried out a detailed review of the NYC Consultant's Reports and other documents to group the NYC's assertions into the Issues and Themes as presented in the KPMG report. In assessing the Issues, we took the approach that our work would not necessarily result in a total concurrence with or rejection of the assertions underlying an Issue; in some instances, we have found that we concur with some elements of an assertion and reject other elements. Accordingly, we would suggest that readers of this report focus on the analysis of the Issues as well as any recommendations that relate to the Issues, rather than focusing on whether we concur with or reject any particular assertion. As documented in Section 4.2 KPMG finds that on the basis of its analysis of Manitoba Hydro's pricing process, Manitoba Hydro has an appropriate methodology for arriving at its sales price in its long-term contracts. Further, in various sections of chapter 4, we have analyzed related to the NYC's assertions related to the pricing of long term contracts.

**PUB/MH/RISK-101**

**Reference:** **KPMG Report – Page 122, Section 4.2 Key Findings/ Page 237 Fn 22**
**Risk Issue:** **Pricing Methodologies Mark to Model**

**f)** **Please confirm whether KPMG reviewed the price forecasts from the five consultants to asses whether the prices utilized in the models are still valid. If not provided, please explain how KPMG satisfied itself that the pricing methodology utilized by MH incorporates relevant market pricing forecasts.**

**ANSWER:**

KPMG Response:

As explained in Section 4.6.1, Manitoba Hydro's "Pricing of Long-Term Export Contracts" provides that "Long-term electricity price forecasts and market analyses are usually purchased annually…" As such, the key issue is whether or not Manitoba Hydro is using the most recently purchased price forecasts when it is negotiating a particular long-term contract. KPMG understands that Manitoba Hydro was using the relevant purchased price forecasts for the various long-term contracts it was negotiating.

**PUB/MH/RISK-101**

**Reference:** **KPMG Report – Page 122, Section 4.2 Key Findings/ Page 237 Fn 22**
**Risk Issue:** **Pricing Methodologies Mark to Model**

**g)** **Please explain how KPMG satisfied itself that the proposed adjustments to the pricing model suggested by the NYC would not improve the information utilized in negotiating firm contracts.**

**ANSWER:**

KPMG Response:

Please refer to answer (e) above.

**<u>PUB/MH/RISK-102</u>**

**Reference: KPMG Report - Page 64 & 65, Section 3.7.3 Power Pricing Data Inputs**
**Risk Issue: Pricing Inputs**

**"at the time of the Consultant's initial report, the link between model price assumptions and purchased forecasts was less clear"**

**a) Please elaborate on KPMG's understanding of the process MH followed for incorporating market price outlooks into the production planning process prior to the consultant's initial report.**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

In the period prior to the Consultant's initial report, our understanding is that price versus sales volume relationships for each time strip within HERMES were based on the transaction history associated with MH export sales in prior periods. Current price forecasts influenced the choices made by HERMES model operators in developing scenarios from this history. However, there was not a direct or one to one relationship between model assumptions and the external price forecasts then available.

## PUB/MH/RISK-102

**Reference:** **KPMG Report - Page 64 & 65, Section 3.7.3 Power Pricing Data Inputs**
**Risk Issue:** **Pricing Inputs**

**"at the time of the Consultant's initial report, the link between model price assumptions and purchased forecasts was less clear"**

**b) Please elaborate on what KPMG believes to be significant changes in market price patterns. To what extent did KPMG consider the introduction of shale natural gas impact on current, medium and long-term market prices.**

**ANSWER:**

KPMG Response:

The key change in market price patterns that was noted in our report has been a decline in MISO on-peak prices in 2009 relative to earlier years. This decline in on-peak prices has been accompanied by:

- A reduction in peak versus off-peak differentials (see page 69), and
- A reduction in price differentials between MHEB and MINN nodes.

Reductions in on-peak prices are likely attributable to both a decrease in electricity demand as a result of the economic downturn and a decrease in natural gas prices, which influence the variable operating cost of certain generating units on the margin. The increase in shale gas production has likely contributed to the decrease in natural gas prices. We also note, however, that the economic downturn may have also played a factor, as well as weather patterns.

In the long-term, the introduction of shale gas, and the resulting reduction in expected natural gas prices, should reduce the costs of electricity from combined-cycle natural gas facilities and increase the competitiveness of natural gas as an end-use fuel relative to electricity. These impacts could result in a reduction in the value of MH's export electricity in adjacent US markets.

**PUB/MH/RISK-102**

**Reference: KPMG Report - Page 64 & 65, Section 3.7.3 Power Pricing Data Inputs**
**Risk Issue: Pricing Inputs**

**"at the time of the Consultant's initial report, the link between model price assumptions and purchased forecasts was less clear"**

**c) Please indicate whether MH has undertaken to prepare a more formal analysis and documentation to support that market prices have a limited impact on optimal production schedules**

**ANSWER:**

No formal analysis has been undertaken. Manitoba Hydro recognizes the uncertainty in market price forecasts and regularly evaluates the financial impacts of future price conditions being above or below expected.

**<u>PUB/MH/RISK-103</u>**

**Reference: KPMG Report - Page 145 section 4.5.3**
**Risk Issue: Economic Benefit Analysis of New Facilities**

**a) Please confirm whether KPMG reviewed the economic benefit analysis of hydroelectric facilities, and provide KPMG's analysis.**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

Please refer to sections 4.10, 4.11 and Appendix J for details on the various analyses conducted on Manitoba Hydro's 2009/10 Power Resource Plan that includes the economic benefit analysis of Manitoba Hydro's planned hydro electric facilities in its preferred development sequence.

**PUB/MH/RISK-103**

**Reference:** **KPMG Report - Page 145 section 4.5.3**
**Risk Issue:** **Economic Benefit Analysis of New Facilities**

**b)** **Please file the economic benefit analysis for each of the proposed new G&T projects.**

**ANSWER:**

Manitoba Hydro's recommended development plan along with alternatives will be subject to a full examination when the "need for and alternatives to" process is initiated. The proposed G&T projects will be part of the development plans that will be subject to scrutiny in that process.

**PUB/MH/RISK-104**

**Reference: KPMG Report - Appendix C Page 36 ;Third Party Reports**
**Risk Issue: Risk Reports**

**a) Please provide a comprehensive listing of all risk, risk management or related reports prepared by or for MH since 1999/00.**

**ANSWER:**

Please see the table in the response to PUB/MH/RISK-104(b).

PUB/MH/RISK-104

**Reference:** **KPMG Report - Appendix C Page 36 ;Third Party Reports**
**Risk Issue:** **Risk Reports**

**b) Please provide a detailed table (in the illustrated format below) which indicates the name, author and subject matter , external and internal costs incurred by MH and the total costs incurred by year and since 1999/00 for the production of the reports in (a)**

| 1999/00 | | Specific Subject Matter of Report | External Costs | Internal Costs | Total Costs |
|---|---|---|---|---|---|
| "Report Name" | "Report Author" | | | | |
| 1999/00 Total Costs | | | | | |
| 2000/01 | | | | | |
| " Report Name" | " Report Author" | | | | |
| 2000/01 Total Costs | | | | | |
| | | | | | |
| Total Costs 1999/00 to 2010/11 | | | | | |

**ANSWER:**

Please see the attached table. Manitoba Hydro is unable to provide internal and external costs incurred for the production of the reports since:

- Internal costs to produce reports are not tracked.
- With respect to external costs, in many cases the contracts for services will require that information as to payments be maintained as confidential, and a determination of such confidentiality would require a review of each of the individual contracts to determine whether such confidentiality provisions apply to that particular contract. The significant time required to analyze and extract the information, and develop a response is not warranted given the questionable relevance and limited value of this information.

**MANITOBA HYDRO**
**RISK MANAGEMENT RELATED REPORTS**
**FOR THE YEARS SINCE 1999/00**

| Year | Report Author(s) | Report Name | Subject Matter |
|---|---|---|---|
| 2002/03 | Risk Advisory | Staff Assessment of the Centra Gas Manitoba Derivative Hedging Program for Primary Gas - December, 2002 | External assessment of the staff involved in all aspects of the Centra Derivative Hedging Program |
| 2003/04 | Risk Advisory | Risk Management Review of Power Sales and Operations - April, 2003 | Review of the risk exposures that have arisen from participation in the wholesale electricity markets and fuel procurement activities. |
| | Deloitte | Deloitte Corporate Risk Management - January, 2004 | Independent Review of Corporate Risk Management Program |
| 2004/05 | Corporate Risk Mgmt Dept | Corporate Risk Management Report - June, 2004 | Corporate Risk Management Program |
| | Manitoba Hydro International Inc. | Manitoba Hydro International Inc. (MHI) Risk Management Process - November, 2004 | MHI Risk Management Process |
| | Risk Advisory | 2002-2004 Drought Risk Management Review - January, 2005 | Third party review of MH's response to the 2002-2004 drought as per PUB order 101/04 |
| 2005/06 | Risk Advisory | PSO Division - Trading and Risk Management Org Structure - May, 2005 | Design and operation of a middle office function for the combined requirements of Power Sales & Operations & Gas Supply. |
| | Gas Supply Division | Retrospective Review of Derivative Hedging Program for Primary Gas - July, 2005 | Review of alternatives to the mechanistic hedging approach. |
| | Corporate Risk Mgmt Dept | Corporate Risk Management Report - August, 2005 | Corporate Risk Management Program |
| | Power Sales and Operations Division | Executive Discussion Paper - October, 2005 | Export Power Sales risk management in Manitoba Hydro |
| 2006/07 | Manitoba Hydro International Inc. | Manitoba HVDC Research Centre Inc. Risk Management Process - April, 2006 | Manitoba HVDC Research Centre Inc. risk management process |
| | Corporate Risk Mgmt Dept | Corporate Risk Management Report - September, 2006 | Corporate Risk Management Program |
| | NY Consultant | MH Risk Review 0708 - December, 2006 | NYC risk review |
| | Transmission System Operations (TSO) Division | Transmission System Operations (TSO) Division 2007/08 Risk Profile - March, 2007 | Transmission System Operations risk program |
| 2007/08 | Power Sales & Operations / Power Supply | Comments on NYC Report dated December 4 2006 - May, 2007 | Response to NY Consultant's issues |

**MANITOBA HYDRO**
**RISK MANAGEMENT RELATED REPORTS**
**FOR THE YEARS SINCE 1999/00**

| Year | Report Author(s) | Report Name | Subject Matter |
|---|---|---|---|
| | Dr. Bhattacharyya | Report on Risks Faced by Manitoba Hydro in Power Exports - July, 2007 | Independent Review of Export Power Risks |
| | Resource Planning & Market Analysis | Analysis of Financial Loss Due to Extended Periods Of Drought - July 2007 | Analysis of financial loss due to extended periods of drought |
| | KPMG | IT Risk Assessment on Critical Information Technology Systems - July, 2007 | IT risk assessment on critical IT systems |
| | Corporate Risk Mgmt Dept | Corporate Risk Management Report - October, 2007 | Corporate Risk Management Program |
| | Legal Counsel with assistance by Corporate Risk Management | Legal Compliance Risk Assessment Report - October, 2007 | Privileged Solicitor-Client Communication |
| | NY Consultant | Manitoba Hydro Risk Management Response - January, 2008 | NYC Consultant response to PSO Staff Report |
| 2008/09 | Export Power Middle Office | Middle Office May 2008 Update Preliminary Findings | Review of NYC Reports |
| | NY Consultant | Manitoba Hydro Long Term Contracts Risk Report - July, 2008 | Issues re MH long term export contracts |
| | NY Consultant | Hydraulics Report Update - September, 2008 | Issues re MH hydraulic model |
| | NY Consultant | Long Term Contracts Executive Summary - November, 2008 | Issues re MH long term export contracts |
| | Corporate Risk Mgmt Dept | Corporate Risk Management Report - October, 2008 | Corporate Risk Management Program |
| | Export Power Middle Office | Middle Office Review of NYC Reports - October, 2008 | Review of NYC Reports |
| | Export Power Middle Office | Middle Office Comments on NYC Long Term Contracts Risk Reports - October 2008 | Review of NYC Reports |
| | Finance & Administration | Export Power Sales Risk Management Issues - December, 2008 | Summary of work by NYC and associated risk reports |
| 2009/10 | ICF International | ICF Independent Review of Manitoba Hydro Export Power Sales and Associated Risks - September 2009 | Independent Review of Long Term Sales and Related Risks |
| 2010 | KPMG | KPMG Manitoba Hydro External Quality Review - April, 2010 | Independent assessment of risk management practices in hydroelectric operations. |
| | KPMG | KPMG Middle and Back Office Assessment - May, 2010 | Export Sales middle and back office assessment |

**Reference:** **KPMG Report - Appendix C Page 36 ;Third Party Reports**
**Risk Issue:** **Risk Reports**

**c) Please provide a copy of all 3rd party reports included on the listing in Appendix C Page 36 of the KPMG Report that have not been filed in the current MH GRA.**

**ANSWER:**

Copies of the following 3rd party reports that Manitoba Hydro / Manitoba Water Stewardship commissioned are included in Appendix 74.

| Attachment | Report # | Report Name |
|---|---|---|
| 1 | 4 | PSO Division - Trading and Risk Management Org Structure |
| 2 | 9 | Peer Review of MH SPLASH Model - Government of Manitoba |
| 3 | 10 | Report on SPLASH Model - Slobodan P. Simonovic Consulting |
| 4 | 11 | Review of MH's SPLASH Model - Doering Engineering Inc. |
| 5 | 12 | Summary of SPLASH Model Peer Review - KGS Group |
| 6 | 13 | Risk Management Review of PSO - Risk Advisory |
| 7 | 26 | Risks in Power Markets - Bhattacharyya |

The following reports have not been included for the reasons provided:

| Report # | Report Name | Reason |
|---|---|---|
| 1 | Report on Risks Faced by MH in Power Exports - Bhattacharyya - Summary Version | This is a duplicate listing. See attachment #7. |
| 2 | Report on Risks Faced by MH in Power Exports - Bhattacharyya - Full Version | This report was filed on February 26, 2010 under cover letter by P. Ramage entitled "Manitoba Hydro 2010/11 and 2011/2012 Electric GRA". |
| 3 | Drought Risk Management Review 2002-2004 | Same as (2) above |

| Report # | Report Name | Reason |
|---|---|---|
| 5 | ICF Report - Unredacted Version | This report was filed in Appendix 12.2. Commercially sensitive and confidential information was redacted. |
| 6 | ICF Report - Redacted Version | Same as (5) above |
| 7 | Recommendation and Summary of ICF Report | ICF's Summary of Conclusions forms Chapter One of their report and does not exist as a sand alone report. |
| 8 | Qualifications of ICF Consulting | This information has been provided under PUB/MH/RISK-89(e). |
| 14 | OECM - Risk Assessment and Business Planning Workshop | As per KPMG, this document was referenced by mistake. This is not a Third Party Report and did not directly impact preparation of the KPMG report. |
| 15 | OECM - Risk Assessment Report | Same as (14) above. |
| 16 | National Public Finance Guarantee - Public Power Sector Study | This paper was not commissioned by MH but can be accessed at the following link: http://www.nationalpfg.com/html/sectorStudies.html. |
| 17 | MISO Market Concepts Study Guide | This paper was not commissioned by MH but can be accessed at the following link: http://www.midwestiso.org/publish/Document/20f443_ffd16ced4b_-7fa40a3207d2/Market%20Concepts%20Study%20Guide%2012_05.pdf?action=download&_property=Attachment |
| 18 | Counsel's Argument on behalf of BC Hydro's 2006 IEP and LT Acquisition Plan | This paper was not commissioned by MH but can be accessed at the following link: http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/info_iep_bc_hydro_final_agument.Par.0001.File.info_iep_bc_hydro_final_agument.pdf |

| Report # | Report Name | Reason |
|---|---|---|
| 19 | Electric Power Generation, Transmission and Distribution - 2002 | This paper was not commissioned by MH but can be accessed at the following link: http://dsp-psd.pwgsc.gc.ca/Collection-R/Statcan/57-202-XIB/57-202-XIB-e.html |
| 20 | Electric Power Generation, Transmission and Distribution 2003 | Same as (19) above |
| 21 | Electric Power Generation, Transmission and Distribution 2004 | Same as (19) above |
| 22 | Electric Power Generation, Transmission and Distribution 2005 | Same as (19) above |
| 23 | Electric Power Generation, Transmission and Distribution 2006 | Same as (19) above |
| 24 | Electric Power Generation, Transmission and Distribution 2007 | Same as (19) above |
| 25 | Long-Term Risk Mgmt for Utility Companies - The Next Challenges | This paper was not commissioned by MH but can be accessed at the following link: http://hal.archives-ouvertes.fr/docs/00/41/93/10/PDF/hltrm08-ijtaf-hal.pdf |
| 27 | Short-Term Generation and Transaction Scheduling at MH using the Vista Decision Support System | This paper was not commissioned by MH but can be accessed at the following link: http://www.synexusglobal.com/product_generators_vista_papers_st_plan.html |

**PUB/MH/RISK-105**

**Reference:** **KPMG Report - Appendix J Exhibits J-1, J-5 and J-9 J-12**
**Risk Issue:** **Drought Scenarios**

**a) Please provide a full listing of assumptions utilized in each scenario reflected in Exhibit J-1, J-5, and J-9, including pricing, volume.**

**ANSWER:**

The inputs and assumptions related to the drought scenarios are considered to be confidential based on rationale #7 for Manitoba Hydro redactions to the KPMG Report and Appendices. Rationale #7 relates to economic and financial benefits including retained earning calculations that are confidential and therefore, if released publicly, can harm Manitoba Hydro in negotiation of export sales.

**<u>PUB/MH/RISK-105</u>**

**Reference:** **KPMG Report - Appendix J Exhibits J-1, J-5 and J-9 J-12**
**Risk Issue:** **Drought Scenarios**

**b) For each of the scenarios p reflected in Exhibits J-1, J-5 and J-9 provide the respective 20 year (electric) IFF including financial targets.**

**<u>ANSWER</u>:**

The request requires eighteen low flow and export price cases to be converted into spreadsheet format and Manitoba Hydro is unable to complete this request in a reasonable timeframe.

**<u>PUB/MH/RISK-106</u>**

**Reference: KPMG Report - appendix J Exhibit -13, J-14 and J-15 15**
**Risk Issue: Alternative Development Sequence**

**Assuming the 20 year (electric) IFF for exhibit J-31, J-32 and J-33 have already been prepared, please file including financial targets.**

**<u>ANSWER</u>:**

Please see Manitoba Hydro's response to PUB/MH/RISK-105(b).

**<u>PUB/MH/RISK-107</u>**

**Reference:** **KPMG Report - Section 5.2/ NYC Issue # 183**
**Risk Issue:** **Independence of Middle Office Function**

**KPMG states " The consultant asserts that it is imperative to segregate the duties involved in calculating and reporting the risk and financial exposure of MH from the business unit responsible for operating level decisions, trading and opportunistic deals"**

**New York consultant states that " it is contrary to all best practices, to have PSO Staff issue the "variance" report, since that would place them in a conflict of interest in reporting on their own system errors and system mistakes. Up until now because of the lack of independence on variance reporting no objective Risk Management reports have been issued which would serve as a second set of eyes to alert Hydro to avoidable Front Office internal errors and operational control standards which should be followed."**

**a) Please address directly the NYC's assertion, and provide KPMG's views, on its merits.**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

KPMG developed a conceptual framework to guide it in its external quality review of Manitoba Hydro, as detailed in Section 1.2. In applying this conceptual framework, KPMG carried out a detailed review of the NYC Consultant's Reports and other documents to group the NYC's assertions into the Issues and Themes as presented in the KPMG report. In assessing the Issues, we took the approach that our work would not necessarily result in a total concurrence with or rejection of the assertions underlying an Issue; in some instances, we have found that we concur with some elements of an assertion and reject other elements. Accordingly, we would suggest that readers of this report focus on the analysis of the Issues as well as any recommendations that relate to the Issues, rather than focusing on whether we concur with or reject any particular assertion.

**PUB/MH/RISK-107**

**Reference:** **KPMG Report - Section 5.2/ NYC Issue # 183**
**Risk Issue:** **Independence of Middle Office Function**

**KPMG states " The consultant asserts that it is imperative to segregate the duties involved in calculating and reporting the risk and financial exposure of MH from the business unit responsible for operating level decisions, trading and opportunistic deals"**

**New York consultant states that " it is contrary to all best practices, to have PSO Staff issue the "variance" report, since that would place them in a conflict of interest in reporting on their own system errors and system mistakes. Up until now because of the lack of independence on variance reporting no objective Risk Management reports have been issued which would serve as a second set of eyes to alert Hydro to avoidable Front Office internal errors and operational control standards which should be followed."**

**b) From a of from a leading best practice standpoint should an "independent Middle Office" remain "physically within" PS&O.**

**ANSWER:**

KPMG Response:

From a leading practice standpoint, to the extent warranted by the organization's activities, the process of monitoring and controlling risk should be managed independently of individuals conducting the commercial activities. KPMG is not aware of any leading practice to ensure there is "physical separation" of the Middle Office from the commercial operations. In fact, KPMG's observation would be that many market participants maintain a close physical proximity between the two groups.

**<u>PUB/MH/RISK-107</u>**

**Reference: KPMG Report - Section 5.2/ NYC Issue # 183**
**Risk Issue: Independence of Middle Office Function**

**KPMG states " The consultant asserts that it is imperative to segregate the duties involved in calculating and reporting the risk and financial exposure of MH from the business unit responsible for operating level decisions, trading and opportunistic deals"**

**New York consultant states that " it is contrary to all best practices, to have PSO Staff issue the "variance" report, since that would place them in a conflict of interest in reporting on their own system errors and system mistakes. Up until now because of the lack of independence on variance reporting no objective Risk Management reports have been issued which would serve as a second set of eyes to alert Hydro to avoidable Front Office internal errors and operational control standards which should be followed."**

**c) Please explain what is meant by KPMG when it states "While not ideal from an independence perspective, there are operational efficiencies associated with this approach." Please reconcile with the contradictory finding in section 5.9 that states the Export Power Middle Office is a single, independent, risk management function.**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

From a functional reporting perspective, the Export Power Middle Office reports to the manager of Corporate Risk Management who in turn reports to the Chief Financial Officer. Thus, it is independent from the Power Sales and Operations Division. This finding is stated in both Section 5.2 and Section 5.9 and as such there is no contradictory finding. The KPMG report reference to "operational efficiencies" relates to some utility industry participants, including MH, that have certain market risk assessment responsibilities embedded within their power trading business unit. Consequently KPMG comments are distinguished between functional reporting (independence) and responsibilities (operational efficiencies).

**PUB/MH/RISK-108**

**Reference: KPMG Report - Page 200, Section 5.4.1.7**
**Risk Issue: Power Sales and Operations Market Committee Terms of Reference**

**a) Please provide a the history on the formation of the Power Sales and Operations Market Committee.**

**ANSWER:**

The Power Sales and Operations Market Committee was established in November of 2005. The PSOMC was established to provide coordinated business direction, communication and control regarding strategy, divisional practices and procedures, product sales and purchases, and customer relations for Manitoba Hydro's participation in the export power market.

The PSOMC reviews and approves operational activities within the parameters of the Management Control Plan and the Approval Authority Table for Power Related Transactions through meetings that are held on an as required basis at the call of any Committee member. In addition, the PSOMC reviews and provides recommendations for approval to the Export Power Risk Management Committee.

PSOMC membership is comprised of the PS&O Division Manager (Chair), the Export Power Marketing Manager and the Power Trading Manager. The Committee has a secretary and secures advice from key personnel throughout the Corporation, which includes the Corporate Risk Management Manager and the Business Services Manager.

**PUB/MH/RISK-108**

**Reference:** **KPMG Report - Page 200, Section 5.4.1.7**
**Risk Issue:** **Power Sales and Operations Market Committee Terms of Reference**

**b) Please indicate the committee's terms of reference in detail when formed in 2005 and explain how and why the terms of reference were updated in 2009.**

**ANSWER:**

The terms of reference for the Power Sales and Operations Market Committee in 2005 were as follows:

**POWER SALES & OPERATIONS MARKET COMMITTEE (PSOMC)**
**TERMS OF REFERENCE**

**Scope:**
To provide coordinated business direction, communication and control regarding strategy, divisional practices and procedures, product sales and purchases, and customer relations for Manitoba Hydro's wholesale merchant function.

**Activities:**
The Market Committee will *review, and approve* the following operational issues and activities within the parameters of the Board approved Management Control Plan:

- Energy product sales and purchases implementation plan for transactions
- longer than two weeks for capacity, energy, including ancillary services and transmission products
- Hedging product sales and purchases for transactions longer than two weeks in duration
- General bid and offer strategies for hedging product sales and purchases for transactions two weeks or less in duration
- Pricing mechanisms and processes (such as use of deal analyzer, risk adders, escalation factors)
- New products and transaction types
- Review of monthly activity reports

The Market Committee will *review, and provide recommendations for approval* to the Vice-President, Power Supply on the following issues and activities:

- Export power marketing strategy
- General drought management strategy, including Manitoba Hydro's reliance on and use of the market and hedging tools ;
- General hedging strategies, including objectives, types of instruments, and the establishment of risk tolerances
- New merchant activities
- Marketing and Trading policies and procedures
- Review of monthly risk reports

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**Membership:**

Membership will consist of the following:
Members: PS&O Division Manager (Chair)
Export Power Marketing Manager
Power Trading Manager
Secretary: PS&O Division Manager Secretary

The PSOMC will secure advice as and when required from key personnel throughout the Corporation including but not limited to the following:
Technical Resources: Business Services Manager or delegate
PS&O Risk Oversight Manager or delegate
Corporate Resource: Risk Management Services Manager or delegate

**Quorum:**

Meetings of the PSOMC will be official when at least two of the voting Members are present. The PSOMC will invite Technical and Corporate Resources and others as appropriate.

**Standards of Conduct:**

All meetings, including the information distributed in or for the meetings, shall be held in accordance with Corporation's Board approved Standards of Conduct

**Voting:**

The majority of votes shall determine the Committee's decision on any matter or question with at least two of the voting Members in favour. The Chair shall have the option of voting on any question or matter.

**Meeting Frequency and Minutes**:

Meetings will be held on an as required basis at the call of any Committee member. All meetings will be recorded with formal minutes approved by the Committee. The minutes will record all decisions and actions.

Adopted

November 8, 2005

The 2009 terms of reference were updated and approved by to reflect the current business practices and are as follows (with the red portions being the items that have changed):

**POWER SALES & OPERATIONS MARKET COMMITTEE (PSOMC)**
**TERMS OF REFERENCE**

**Scope:**
To provide coordinated business direction, communication and control regarding strategy, practices and procedures, product sales and purchases, and customer relations for Manitoba Hydro's participation in the export power market.

**Activities:**
The PSOMC will review and approve operational activities within the parameters of the Board approved *Management Control Plan* and the Executive Power Risk Management Committee approved *Approval Authority Table for Power Related Transactions* including but not limited to:

- Development, implementation and modification of business procedures
- Opportunity sales and purchase strategies and forward quantities
- Merchant sales and purchase strategies
- Transmission acquisition and maintenance strategies including the nomination, purchase and sale of Auction Revenue Rights and Financial
- Transmission Rights or equivalent
- System Financial Products strategies

The PSOMC will review and provide recommendations for approval to the Export Power Risk Management Committee on the following activities:

- Export power sales, marketing and associated business policies
- Export power marketing strategies and trading initiatives
- Risk management strategies and hedging activities including drought
- New markets, products and transaction types

The PSOMC Members receive and review monthly export activity and risk reports.

**Membership:**
Members: PS&O Division Manager (Chair)
Export Power Marketing Manager
Power Trading Manager

During absences Members may appoint Alternate Members with written notification to the other Members and the Secretary.

Secretary: PS&O Division Manager Secretary

The PSOMC will secure advice when required from key personnel throughout the Corporation including but not limited to the following:
Technical Resources: Business Services Manager or delegate
Corporate Resources: Corporate Risk Management Manager or delegate

**Quorum:**
Meetings of the PSOMC will be official when at least two of the voting Members (or in a Member's absence, their Alternate) are present. The PSOMC will invite Technical and Corporate Resources and others as appropriate

**Standards of Conduct:**
All meetings, including the information distributed in or for the meetings, shall be held in accordance with Corporation's Board approved Standards of Conduct.

**Voting:**
The majority of votes shall determine the Committee's decision on any matter or question with at least two of the voting Members in favour. The Chair shall have the option of voting on any question or matter.

**Meeting Frequency and Minutes:**
Meetings will be held on an as required basis at the call of any Committee member. All meetings will be recorded with formal minutes approved by the Committee. The minutes will record all decisions and actions.

Revised & Approved:
February 10, 2009

**PUB/MH/RISK-108**

**Reference:** **KPMG Report - Page 200, Section 5.4.1.7**
**Risk Issue:** **Power Sales and Operations Market Committee Terms of Reference**

**c)** **Explain the role on the committee for the Export Power Middle Office Senior Risk Officer**

**ANSWER:**

The role of the Export Power Middle Office Senior Risk Officer on the Power Sales and Operations Market Committee is one of a number of resources to the Committee. The resource role is not a member of the committee, but provides support and professional expertise when requested by the committee members.

**<u>PUB/MH/RISK-108</u>**

**Reference:** **KPMG Report - Page 200, Section 5.4.1.7**
**Risk Issue:** **Power Sales and Operations Market Committee Terms of Reference**

**d) Please provide the history of the Risk Management Function since its inception, and detail the personnel performing risk management functions over the years.**

**<u>ANSWER</u>:**

History of the Risk Management function as it relates to Power Sales and Operations Market Committee is as follows:

- The Export Power Middle Office was created in February, 2007.

- The Corporate Risk Management Department Manager was assigned responsibility for managing the middle office function. The Corporate Risk Management Department Manager reports directly to the Senior Vice-President, Finance & Administration and Chief Financial Officer.

- A Senior Risk Management Officer was hired in February, 2008 to perform responsibilities in the middle office.

- A Senior Market Risk Analyst was hired in July, 2010 to assist in further strengthening the middle office function.

- A Credit Analyst position has been established and will be staffed in November 2010.

- A risk software solution is being studied with a decision on a selected option expected early in 2011.

**PUB/MH/RISK-109**

**Reference:** **KPMG Report - NYC Risk #195/ Risk Governance Leading Practices.**
**Risk Issue:** **Risk Management Best practices /Segregation of Duties**

**NYC states "As Hydro integrates RM in to its corporate framework, it becomes imperative to understand the principles behind segregation of duties. Segregation of duties focuses on segregating the duties involved in calculating the risk and financial exposure to the company from the business units and divisions responsible for operating level decisions, trading and opportunistic deals. It is an internal control element of compliance programs because it mitigates errors and opportunities for corporate fraud, misstatements of financial earnings and the concealment of losses and risks. The business unit [s] responsible for the sales and solicitation of power in the export power marketing, should also not be responsible for the reporting of risk, financial P&L and earnings reports.**

**Results from Front Office self–calculation should not be relied upon and is an oversight on regulators to not demand Middle Office numbers."**

**Please provide, KPMG's and MH's views on the merits of the above noted risk issue, based on the current Risk Management Framework.**

**ANSWER:**

KPMG Response:

KPMG developed a conceptual framework to guide it in its external quality review of Manitoba Hydro, as detailed in Section 1.2. In applying this conceptual framework, KPMG carried out a detailed review of the NYC Consultant's Reports and other documents to group the NYC's assertions into the Issues and Themes as presented in the KPMG report. In assessing the Issues, we took the approach that our work would not necessarily result in a total concurrence with or rejection of the assertions underlying an Issue; in some instances, we have found that we concur with some elements of an assertion and reject other elements. Accordingly, we would suggest that readers of this report focus on the analysis of the Issues as well as any recommendations that relate to the Issues, rather than focusing on whether we concur with or reject any particular assertion.

**PUB/MH/RISK-110**

**Reference: KPMG Report -**
**Risk Issue: Export Power Middle Office Reports**

**Please provide copies of all Middle Office quarterly reports including variance reports issued since the inception of the Middle Office.**

**ANSWER:**

Copies of all Middle Office quarterly reports can be found in Appendix 70 as Attachments 1 to 8. It was necessary to redact some transactional data due to third party confidentiality agreements. The redactions are minimal.

**PUB/MH/RISK-111**

**Reference: KPMG Report - Page 224**
**Risk Issue: Risk Measurement Probabilistic Testing**

**Please provide KPMG's view on how MH should incorporate probabilistic stress testing and explain how the use of such tests will assist management decision-making? Please provide an example of how it should be incorporated.**

**ANSWER:**

KPMG Response:

Probabilistic stress tests are exercises to determine the losses that might occur under unlikely but plausible circumstances. Stress testing allows MH to consider its tolerance for loss and provide reference points for how bad things could get. It is important to note that stress test results do not assume any mitigating tactics are employed and the full effect of a market event are realized. In reality, decisions and mitigating actions would be taken by MH to reduce the impact. Manitoba Hydro could use probabilistic stress tests to quantify and understand the impact of extreme events on the company's earnings and make decisions that help mitigate these potential impacts. For example, MH could stress the market price for power in a specific forward period to determine the potential economic loss of value for a contract or portfolio of contracts. This would provide relevant information for making decisions relating to additional contracting or portfolio management.

**PUB/MH/RISK-112**

**Reference:** **KPMG Report - Page 227 Section 6.4.1 Long- Term Export Contracts– Risk Identification**

**Risk Issue:** **Major Export Contracts MEC**

**Please identify the MEC manager and provide a full description of the individuals role and responsibilities.**

**ANSWER:**

The manager of the Major Export Contracts department is a staff employee of Manitoba Hydro. This individual is responsible for Manitoba Hydro's long-term negotiations with MP, WPS and NSP and the related new US transmission interconnection.

PUB/MH/RISK-113

**Reference: KPMG Report - Page 239, Section 6.5.1.3**
**Risk Issue: Risk Measurement MTM**

**a) Please provide a comparison of the relative strengths and weaknesses of MH's current mark to model approach for long-term contracts versus MTM .**

**ANSWER:**

Manitoba Hydro's mark to model approach for long-term contracts has the following strengths compared to a mark to market approach:

- Pricing data used to calculate a market value is provided by independent consultants based on a long-term view of market fundamentals that will determine future power prices. A lack of market liquidity and adequate price discovery make it very difficult to mark to market Manitoba Hydro's long-term power contracts.
- Mark to model approach allows Manitoba Hydro to evaluate its position versus alternative price scenarios (low, expected and a high price outlook) instead of a single illiquid price used in a mark to market calculation.
- Prices for mark to model approach are determined by an aggregate of price forecasts produced by independent consultants instead of a single illiquid price used in a mark to market calculation.
- Similar to mark to market, the mark to model approach provides the ability to identify hedging opportunities.

Weaknesses and similarities of Manitoba Hydro's mark to model approach for long-term contracts compared to a mark to market approach are:

- The mark to market approach with liquid pricing provides information on the economic and credit risk position of the long-term contract at any given point in time based on actual trades in the marketplace.
- Similar to the mark to market, the mark to model approach ignores the value of firm transmission that is secured by the long-term contracts.
- Similar to mark to market, the mark to model approach ignores the fact that the contracts are physically backed and Manitoba Hydro does not intend on liquidating or trading to capture changes in value of the long-term contract.

**PUB/MH/RISK-113**

**Reference: KPMG Report - Page 239, Section 6.5.1.3**
**Risk Issue: Risk Measurement MTM**

**b) Based on the market scan undertaken please indicate which of the utilities use mark to model versus MTM for valuing long-term contracts.**

**ANSWER:**

KPMG Response:

As mentioned in Appendix E page 3, KPMG contacted the utilities that participated in the market scan telephonically and used the interview questions cited in the section on pages 3-6 of Appendix E. The utilities surveyed provided the information for the questionnaire instrument on a confidential basis and only allowed certain information to be revealed publicly. As such the only information that can be disclosed is contained in Appendix E and KPMG cannot specifically disclose the information sought above.

**PUB/MH/RISK-113**

**Reference:** **KPMG Report - Page 239, Section 6.5.1.3**
**Risk Issue:** **Risk Measurement MTM**

**c)** **Please explain why MH should consider applying MTM to its short-term commodity positions and long-term contracts.**

**ANSWER:**

The KPMG report recommended that MH consider applying MTM to its short-term and thereafter its long-term contracts as it could identify hedging opportunities and facilitate portfolio optimization.

**<u>PUB/MH/RISK-113</u>**

**Reference: KPMG Report - Page 239, Section 6.5.1.3**
**Risk Issue: Risk Measurement MTM**

**d) Please elaborate on the effort required to develop forward price curves for pricing nodes in the long-term contracts. Please describe what would be involved in validating either third-party or internally generated forward price curves.**

**<u>ANSWER</u>:**

Manitoba Hydro's long-term contracts sell electricity at the MHEB MISO pricing node. This pricing node has very limited price discovery that could be used for the valuation of long-term contracts. The development of forward price curves would require statistical and modeling analysis to determine the basis differential of the MHEB MISO node to other more liquid trading nodes.

The validation process for forward price curves would involve monitoring and comparing these price curves against actual transactions that occur in the marketplace in order to be confident in the results produced by the model.

**PUB/MH/RISK-114**

**Reference: KPMG Report - Page 239, NYC Report Issues #204-#210**
**Risk Issue: Risk Analytics VAR**

**a) Please provide a table providing the pros and cons of the three main VAR methodologies and indicate which would be the most appropriate for MH to employ.**

**ANSWER:**

The three methodologies as described by KPMG are; variance-covariance, historical simulation and Monte Carlo simulation. As KPMG stated, each methodology has its own advantages and disadvantages as described on Page 241, and there is no one correct methodology.

**<u>PUB/MH/RISK-114</u>**

**Reference: KPMG Report - Page 239, NYC Report Issues #204-#210**
**Risk Issue: Risk Analytics VAR**

**b) Please confirm the recommendation to assign probabilities to its drought stress scenarios will improve the understanding of a financial loss associated with a likely extreme event. Please explain.**

**<u>ANSWER</u>:**

Confirmed. Manitoba Hydro is reviewing its current drought stress analytics and is developing a model that uses both, historical and Monte Carlo simulation in order to analyze the financial loss associated with its drought stress scenarios which will assist in combined event drought risk management.

Manitoba Hydro agrees with the recommendation to assign probabilities to scenarios that combine the consequences of multiple risk sensitivities.

Please see the attachment to RCM/TREE/MH I-38 entitled, “Risk Analysis Using PRISM”.

**PUB/MH/RISK-114**

**Reference: KPMG Report - Page 239, NYC Report Issues #204-#210**
**Risk Issue: Risk Analytics VAR**

**c) Please explain whether the Corporation has undertaken a probabilistic risk measurement or VAR since 2003/04. If not. Why not?**

**ANSWER:**

As answered in 114 b), Manitoba Hydro is constantly developing and refining probabilistic-based risk measurement models to evaluate the combined consequences of multiple risks such as; weather, foreign exchange, domestic load growth, market prices.

**PUB/MH/RISK-115**

**Reference:** **NYC/MH Risk Issue #26 (Page 26), Pages 166 to 171**
**KPMG – Main Report, Exhibit 4-17, ICF 2009 Report (Page 92)**
**Risk Issue:** **Diversity Sales/Purchase**

**a)** **Please provide a complete listing on a monthly basis of MH's energy suppliers/purchases (MW/GWh and ¢/KWh) during the August 2002 to June 2004 period.**

**ANSWER:**

| | **Physical Imports** | |
|---|---|---|
| | **MWh** | **c/KWh** |
| Aug-02 | 74,978 | 2.1 |
| Sep-02 | 71,478 | 2.0 |
| Oct-02 | 114,077 | 2.1 |
| Nov-02 | 330,807 | 2.7 |
| Dec-02 | 357,014 | 2.8 |
| Jan-03 | 407,463 | 4.1 |
| Feb-03 | 498,819 | 5.2 |
| Mar-03 | 554,890 | 5.6 |
| Apr-03 | 463,628 | 3.9 |
| May-03 | 389,448 | 2.4 |
| Jun-03 | 616,638 | 3.3 |
| Jul-03 | 524,563 | 5.2 |
| Aug-03 | 638,231 | 5.8 |
| Sep-03 | 606,374 | 4.2 |
| Oct-03 | 626,348 | 4.3 |
| Nov-03 | 684,345 | 4.4 |
| Dec-03 | 659,019 | 4.5 |
| Jan-04 | 765,481 | 6.5 |
| Feb-04 | 584,120 | 7.0 |
| Mar-04 | 515,052 | 6.2 |
| Apr-04 | 260,961 | 3.9 |
| May-04 | 228,523 | 3.9 |
| Jun-04 | 88,350 | 4.3 |

**PUB/MH/RISK-115**

**Reference:** **NYC/MH Risk Issue #26 (Page 26), Pages 166 to 171**
**KPMG – Main Report, Exhibit 4-17, ICF 2009 Report (Page 92)**
**Risk Issue:** **Diversity Sales/Purchase**

**b) Please provide a complete listing of MH's monthly contract buybacks (MW/GWh and ¢/KWh) during the August 2002 to June 2004 period.**

**ANSWER:**

| | **BuyBacks** | |
|---|---|---|
| | **MWh** | **c/KWh** |
| Aug-02 | 10,066 | 3.9 |
| Sep-02 | 1,565 | 5.9 |
| Oct-02 | 240 | 3.5 |
| Nov-02 | 17,443 | 3.6 |
| Dec-02 | 2,880 | 5.0 |
| Jan-03 | 4,416 | 4.6 |
| Feb-03 | 4,390 | 5.7 |
| Mar-03 | 26,075 | 10.5 |
| Apr-03 | 11,535 | 5.3 |
| May-03 | 1,515 | 3.0 |
| Jun-03 | 58,764 | 3.2 |
| Jul-03 | 192,972 | 6.4 |
| Aug-03 | 224,430 | 6.9 |
| Sep-03 | 275,025 | 5.4 |
| Oct-03 | 362,394 | 5.9 |
| Nov-03 | 294,355 | 5.7 |
| Dec-03 | 314,734 | 6.0 |
| Jan-04 | 302,888 | 7.3 |
| Feb-04 | 277,846 | 7.3 |
| Mar-04 | 225,570 | 6.0 |
| Apr-04 | 267,021 | 6.3 |
| May-04 | 132,808 | 4.1 |
| Jun-04 | 44,025 | 3.3 |

**PUB/MH/RISK-115**

**Reference: NYC/MH Risk Issue #26 (Page 26), Pages 166 to 171**
**KPMG – Main Report, Exhibit 4-17, ICF 2009 Report (Page 92)**

**Risk Issue: Diversity Sales/Purchase**

c) **Please provide a monthly tabular comparison (MW/GWh and ¢/KWh) of MH's ongoing exports, buybacks, and energy purchases for the August 2002 to June 2004 period.**

**ANSWER:**

| | **Physical Exports** | | **Physical Imports** | | **Buybacks** | |
|---|---|---|---|---|---|---|
| | **MWh** | **c/KWh** | **MWh** | **c/KWh** | **MWh** | **c/KWh** |
| Aug-02 | 1,037,276 | 5.2 | 74,978 | 2.1 | 10,066 | 3.9 |
| Sep-02 | 939,432 | 4.6 | 71,478 | 2.0 | 1,565 | 5.9 |
| Oct-02 | 780,722 | 4.5 | 114,077 | 2.1 | 240 | 3.5 |
| Nov-02 | 627,373 | 5.0 | 330,807 | 2.7 | 17,443 | 3.6 |
| Dec-02 | 643,451 | 5.1 | 357,014 | 2.8 | 2,880 | 5.0 |
| Jan-03 | 691,954 | 5.0 | 407,463 | 4.1 | 4,416 | 4.6 |
| Feb-03 | 581,182 | 5.4 | 498,819 | 5.2 | 4,390 | 5.7 |
| Mar-03 | 620,172 | 5.3 | 554,890 | 5.6 | 26,075 | 10.5 |
| Apr-03 | 668,671 | 5.1 | 463,628 | 3.9 | 11,535 | 5.3 |
| May-03 | 635,293 | 4.9 | 389,448 | 2.4 | 1,515 | 3.0 |
| Jun-03 | 617,020 | 4.8 | 616,638 | 3.3 | 58,764 | 3.2 |
| Jul-03 | 643,519 | 5.7 | 524,563 | 5.2 | 192,972 | 6.4 |
| Aug-03 | 546,869 | 6.3 | 638,231 | 5.8 | 224,430 | 6.9 |
| Sep-03 | 271,494 | 7.2 | 606,374 | 4.2 | 275,025 | 5.4 |
| Oct-03 | 194,249 | 8.5 | 626,348 | 4.3 | 362,394 | 5.9 |
| Nov-03 | 96,385 | 12.1 | 684,345 | 4.4 | 294,355 | 5.7 |
| Dec-03 | 147,017 | 8.8 | 659,019 | 4.5 | 314,734 | 6.0 |
| Jan-04 | 122,776 | 11.4 | 765,481 | 6.5 | 302,888 | 7.3 |
| Feb-04 | 132,919 | 10.3 | 584,120 | 7.0 | 277,846 | 7.3 |
| Mar-04 | 318,831 | 6.7 | 515,052 | 6.2 | 225,570 | 6.0 |
| Apr-04 | 240,025 | 8.5 | 260,961 | 3.9 | 267,021 | 6.3 |
| May-04 | 472,523 | 7.0 | 228,523 | 3.9 | 132,808 | 4.1 |
| Jun-04 | 717,793 | 5.4 | 88,350 | 4.3 | 44,025 | 3.3 |

**PUB/MH/RISK-115**

**Reference:** **NYC/MH Risk Issue #26 (Page 26), Pages 166 to 171**
**KPMG – Main Report, Exhibit 4-17, ICF 2009 Report (Page 92)**
**Risk Issue:** **Diversity Sales/Purchase**

**d)** **Please reconcile these actual (2002 to 2004) energy sales and purchases with obligations under MH's 500 MW NSP Supply Contract and also MH's Diversity Contracts.**

**ANSWER:**

Manitoba Hydro declines to provide the requested information as it would require an arbitrary allocation of energy purchases and costs between domestic and firm export obligations.

**<u>PUB/MH/RISK-115</u>**

**Reference: NYC/MH Risk Issue #26 (Page 26), Pages 166 to 171**
**KPMG – Main Report, Exhibit 4-17, ICF 2009 Report (Page 92)**
**Risk Issue: Diversity Sales/Purchase**

**e) Please explain why KPMG defined the diversity supply by MH totaling 536 GWh as firm energy when this is not specifically identified in the Power Resource Plan as firm contrary to the ICF 2009 Report which indicated that diversity sales could be considered non-firm.**

**<u>ANSWER</u>:**

<u>KPMG Response</u>:

As indicated in the text following exhibit 4-17, the Diversity Agreements provide Manitoba Hydro with firm energy sales in the Summer Season when Manitoba Hydro has surplus capacity. Specifically, the Diversity Agreements provide for an exchange of capacity and energy between the Summer Season (May 1 to October 31) and the Winter Season (November 1 to April 30) at the option of the holder. The Diversity Agreements require the supplying system to reserve firm capacity to ensure the capacity and energy is available at the request of the counterparty. MH only relies on the Diversity Agreements for firm import capacity in the Winter Season when MH capacity is constrained due to low water flows, or if the seasonal on-peak/off-peak price differential is favourable to MH. In this context, it is worth noting that historically, MISO summer season on-peak energy prices have been greater than the winter season on-peak energy prices. Thus MH has sold more power in the summer and at a higher price than it has bought back in the winter.

**<u>PUB/MH/RISK-115</u>**

**Reference:** **NYC/MH Risk Issue #26 (Page 26), Pages 166 to 171**
**KPMG – Main Report, Exhibit 4-17, ICF 2009 Report (Page 92)**

**Risk Issue:** **Diversity Sales/Purchase**

**f) Please confirm that in the last six years, MH's diversity price to NSP has been 3-4¢/KWh for about 400 GWh/year while MH has not bought back more than 50 GWh/year.**

**<u>ANSWER</u>:**

Manitoba Hydro cannot confirm the energy price or volumes under the NSP diversity agreements as they are covered by a confidentiality agreement.

**<u>PUB/MH/RISK-116</u>**

**Reference: MH March 2007 Comments on 2004 NYC Report (Page 28)**
**Risk Issue: MH Response to NYC Issues**

**a) Please confirm that when MH takes issue with the NYC's perceived differences in year-end water level outputs of HERMES and SPLASH, the problem lies in comparing median flow (HERMES) with mean flow SPLASH generation (GWh) and revenues.**

**<u>ANSWER</u>:**

Manitoba Hydro takes issue with the inappropriate comparison of water levels between:

1) A single decision sequence from an operations model that is based on expected flows in the near term (that transition to median flows) and
2) Average water levels for the same time of year from a planning model that were averaged from multiple decisions sequences (that were based on multiple hydrologic sequences).

Manitoba Hydro notes that the NYC has never provided to Manitoba Hydro a substantive written description of the methodology used in its analysis, nor the key assumptions that were used in its analysis, nor any discussion of limitations of the analysis that led to the conclusions made by NYC.

**PUB/MH/RISK-116**

**Reference: MH March 2007 Comments on 2004 NYC Report (Page 28)**
**Risk Issue: MH Response to NYC Issues**

**b) How would the results differ if MH were to run HERMES with an identical flow to the mean flow reflected by the mean outputs from SPLASH?**

**ANSWER:**

Use of the mean flow will produce higher hydraulic generation, lower thermal generation and lower power purchases compared to the mean hydro, thermal and import associated with each of all the possible flow conditions, regardless of whether HERMES or SPLASH is used in the analysis.

**PUB/MH/RISK-116**

**Reference:** **MH March 2007 Comments on 2004 NYC Report (Page 28)**
**Risk Issue:** **MH Response to NYC Issues**

**c) Please define the specific input assumptions that would preclude a near identical result.**

**ANSWER:**

Both HERMES and SPLASH are mathematical approximations of the Manitoba Hydro system. However, HERMES models the hydraulic, generation, transmission and electrical systems, the export markets and Manitoba load in much greater detail than SPLASH. As a consequence, even with identical inputs, the results from the two models will not be identical.

**<u>PUB/MH/RISK-117</u>**

**Reference:** **MH March 2007 Comments on 2004 NYC Report (Page 28, Schedule 7)**
**Risk Issue:** **MH Response to NYC Issues**

**a) Please explain the process by which adjustment factors are applied to the HERMES model:**

- **As an initial calibration?**
- **As a periodic recalibration?**
- **Relative to seasonal changes in flows and water levels?**
- **Relative to monthly or weekly changes in flows or water levels?**

**<u>ANSWER</u>:**

Calibration of modeled inflow to observed inflows generally occurs on a weekly basis. Outputs of this process include calculated local inflows to key reservoirs and, dependent on the season, lake outlet and station tailrace performance factors that account for ice restrictions. Local inflows encompass un-gauged tributary inflows, direct precipitation, and evaporative losses. Local inflows are affected by the relative accuracy of the flows at gauging stations which are subject to measurement error. The calculated local inflow values are then part of the antecedent condition that is used to project future inflows.

**<u>PUB/MH/RISK-117</u>**

**Reference: MH March 2007 Comments on 2004 NYC Report (Page 28, Schedule 7)**
**Risk Issue: MH Response to NYC Issues**

**b) Please explain how (by whom) an "adjustment factor" is deemed necessary.**

**<u>ANSWER</u>:**

Adjustment factors are used in HERMES to calibrate inputs to the model. Standard factors are assumed in the future but these standard factors are adjusted in the near term to accommodate observed field data.

Manitoba Hydro's Operations Planning staff continuously review recent historic information (e.g. inflows and water levels) and use modeling tools to assist in calibrating the actual observed flows and levels to the modeled flows and levels for the purposes of determining actual wind eliminated lake levels, inflow forecasting and hydraulic rating curve forecasting.

**PUB/MH/RISK-117**

**Reference:** **MH March 2007 Comments on 2004 NYC Report (Page 28, Schedule 7)**
**Risk Issue:** **MH Response to NYC Issues**

**c) Please explain how MH determines the need for adjustment with respect to each of the following:**

- **Water flow time lags.**
- **Precipitation variability.**
- **Evaporation losses.**
- **Ice condition changes.**
- **Hydrometric error.**

**ANSWER:**

Hydrometric errors are typically identified by Manitoba Hydro's hydrometric analysts through a daily visual and/or programmatic review of recently observed operational data. Erroneous data will be estimated or missing data will be in-filled on an as-needed basis. Depending on the priority of the data (i.e. the operational need), Manitoba Hydro may call out field staff to visit the hydrometric site to address the problem (e.g. gauge calibration, re-establish data transmission, etc.).

Calculation and calibration of local inflows is performed on a weekly basis and encompasses effects from un-gauged inflows, direct precipitation, evaporative losses, and un-modeled water flow time lags.

Ice condition changes are calibrated and projected through a separate calibration process each week during the ice season.

**PUB/MH/RISK-118**

**Reference:** **MH March 2007 Comments on 2004 NYC Report (Pages 31/32, Schedule 8)**
**Risk Issue:** **MH Response to NYC Issues**

**a) Please explain the relative value [high, medium, low] and purpose of off-peak energy purchases:**

| Season | High Flow Years | Average Flow Years | Low Flow Years |
|---|---|---|---|
| Spring | ? | ? | ? |
| Summer | ? | ? | ? |
| Fall | ? | ? | ? |
| Winter | ? | ? | ? |

**ANSWER:**

In general, the value of off-peak imports to Manitoba Hydro will increase with decreasing flows and decreasing energy in storage. As storage and inflows decrease, off peak imports are used to supply on peak sales, offset thermal generation, and meet domestic energy demands.

Off-peak imports are generally of no value to Manitoba Hydro when it has surplus off peak hydraulic generation such as in a system spill condition and it is exporting power throughout the off-peak period.

In the winter period, ice restrictions in outlet channels from Lake Winnipeg can limit the flows on the Nelson River to a point where there is insufficient water to maximize on peak generation. In this instance, regardless of the inflow conditions to Lake Winnipeg, Manitoba Hydro can benefit from off-peak imports as this energy can augment on-peak generation from the Lower Nelson River stations.

If Manitoba Hydro is not in a system spill condition and has sufficient generation and transmission capacity to deliver additional on-peak exports, then additional off-peak imports can be used to support additional on-peak sales. The value of these imports to Manitoba Hydro increases with on-peak price increases.

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

**<u>PUB/MH/RISK-118</u>**

**Reference:** **MH March 2007 Comments on 2004 NYC Report (Pages 31/32, Schedule 8)**

**Risk Issue:** **MH Response to NYC Issues**

**b)** **Please indicate the type of circumstances that would see MH buying and selling substantial amounts of off-peak in the same short time frame.**

**<u>ANSWER</u>:**

The following circumstances could result in MH buying and selling substantial amounts of off-peak in the same short time frame:

- Significant price differences within the off-peak. Clearing prices for some hours of the off-peak may be very different from other hours (due to load or other changing conditions in the market. For example, Sunday market conditions can be significantly different that overnight).
- Changes in Manitoba Hydro's available generation or transmission capacity (e.g. a forced outage of a HVDC Pole or a return to service of an HVDC Bipole).
- Day Ahead sales of off peak energy that are subjected to transmission curtailment, resulting in real time purchases to fulfill the Day Ahead commitment.

**<u>PUB/MH/RISK-118</u>**

**Reference:** **MH March 2007 Comments on 2004 NYC Report (Pages 31/32, Schedule 8)**

**Risk Issue:** **MH Response to NYC Issues**

**c) When MH sells or buys off-peak power, how is the profitability of those transactions calculated/determined in:**

- **High flow years?**
- **Average flow years?**
- **Low flow years?**

**<u>ANSWER</u>:**

The large majority of Manitoba Hydro's off peak transactions occur in the MISO Day Ahead or Real Time markets. When Manitoba Hydro sells off peak hydraulic energy, profitability is calculated based upon Manitoba Hydro's marginal cost of production. The cost of production is adjusted from generation to the MHEB pricing node, grossed up to account for Manitoba Hydro's minimum margin requirements and offered into the MISO market through the MISO Day Ahead process.

When Manitoba Hydro purchases energy, profitability is calculated based upon Manitoba Hydro's value of energy in storage. If the market clears below Manitoba Hydro's bid price, Manitoba Hydro will purchase energy up to the desired amount at the market clearing price. The difference between the bid price and the Market Clearing Price is Manitoba Hydro's profitability.

The process described above is independent of water flow. However, Manitoba Hydro's value of energy in storage varies depending on water conditions. In high flow years when spillage is occurring, energy in storage has a very low value. In low water years when on peak purchases are required, energy in storage will have a relatively high value.

**PUB/MH/RISK-119**

**Reference: MH March 2007 Comments on 2004 NYC Report**
**Risk Issue: MH Response to NYC Issues**

**a) Please indicate the MH authors and department(s) responsible for this review.**

**ANSWER:**

Manitoba Hydro's March 2007 comments on the 2004 NYC Report were prepared by the Export Power Marketing Department staff of Manitoba Hydro. Manitoba Hydro declines to provide the names of the authors.

**<u>PUB/MH/RISK-119 (REVISED)</u>**

**Reference:** **MH March 2007 Comments on 2004 NYC Report**
**Risk Issue:** **MH Response to NYC Issues**

**a) Please indicate the MH authors and department(s) responsible for this review.**

**<u>ANSWER</u>:**

Note: Manitoba Hydro assumes the reference should be to the 2006 NYC Report - in 2004 the NYC worked a total of 15 hours over a two week period and this work did not result in the production of a report by the NYC.

Manitoba Hydro's March 2007 comments on the 2006 NYC Report were prepared by the Export Power Marketing Department staff of Manitoba Hydro. Manitoba Hydro declines to provide the names of the authors.

**<u>PUB/MH/RISK-119</u>**

**Reference:** **MH March 2007 Comments on 2004 NYC Report**
**Risk Issue:** **MH Response to NYC Issues**

**b) Please describe the nature and extent of technical analyses by reviewers.**

**<u>ANSWER</u>:**

Manitoba Hydro was unable to undertake a technical analysis of the NYC report as the report did not provide any assumptions or data, nor did it describe the methods or tools used upon which the author drew his/her conclusions. Manitoba Hydro concluded from the report that the NYC did not have a good understanding of Manitoba Hydro, its organization, its business objectives, its business processes or its models. As a result, Manitoba Hydro found the report of no value.

**PUB/MH/RISK-119**

**Reference: MH March 2007 Comments on 2004 NYC Report**
**Risk Issue: MH Response to NYC Issues**

**c) Was the 2003/04 drought specifically addressed by NYC or MH's reviewers? If not. Why not?**

**ANSWER:**

The NYC was engaged in 2006 to assist Manitoba Hydro in the development of risk management policy and procedures and the development of a specification for a risk management system that would be procured at a later date. Manitoba Hydro's efforts in this area were intended to address drought related issues generally however review of the 2003/04 drought was not the task assigned to this consultant. The requested work was not completed nor did the NYC include in its report an analysis of the 2003/04 drought (which work would not have been contemplated by Manitoba Hydro). As a result, there was no material in the December 2006 NYC Report regarding the 2003/04 drought for MH reviewers to address.

**PUB/MH/RISK-120**

**Reference: Middle Office Reviews of 2004 NYC Report**
**Risk Issue: Middle Office Reviews**

**a) Please indicate the authors of these documents.**

**ANSWER:**

The Corporate Risk Management Department authored these documents.

**PUB/MH/RISK-120**

**Reference: Middle Office Reviews of 2004 NYC Report**
**Risk Issue: Middle Office Reviews**

**b) Were these independent reviews of technical issues by middle office or did the middle office compile critiques provided by other offices?**

**ANSWER:**

These were independent reviews conducted by Export Power Middle Office. There were no critiques compiled by other offices.

**PUB/MH/RISK-120**

**Reference:** **Middle Office Reviews of 2004 NYC Report**
**Risk Issue:** **Middle Office Reviews**

**c) Please identify the departments and committees that contributed to the middle office reviews.**

**ANSWER:**

Information and data were collected for the review from relevant departments. Interviews were also held with relevant staff from these departments to address questions and seek clarification of some information. These departments included Power Planning Division - Resource Planning and Market Analysis, Power Sales and Operations Division - Power Trading, Business Services, Export Power Marketing, Major Export Contracts, and Hydraulic Operations.

**<u>PUB/MH/RISK-121</u>**

**Reference:** **Report on Risks Faced by MH in Power Exports (July 4, 2007 – N. Bhattacharyya, Ph.D., Page 31)**

**Risk Issue:** **2006/07 Merchant Trading/ Risks**

**a)** **Please confirm that MH in 2006/07 was engaged in a form of "merchant trading" to supply energy to Ontario (as well as other hedging activities).**

**<u>ANSWER</u>:**

Confirmed. MH sold energy to Ontario utilizing transmission service across the MISO-IESO Michigan and Minnesota interfaces in 2006/07.

**PUB/MH/RISK-121**

**Reference:** **Report on Risks Faced by MH in Power Exports (July 4, 2007 – N. Bhattacharyya, Ph.D., Page 31)**
**Risk Issue:** **2006/07 Merchant Trading/ Risks**

**b) Please confirm that in 2006-07, MH's Ontario merchant trading (system hedging) sales resulted in about $4 M loss.**

**ANSWER:**

Not confirmed. In 2006/07 MH's Ontario merchant trading sales resulted in a $0.05 million loss. The $4 million loss reported by N. Bhattacharyya included a MISO resettlement for Revenue Sufficiency Guarantee (RSG) charges of $4.2 million dollars which was attributable to system merchant trading activity in a prior period (2005/06). However, subsequently MISO again resettled the RSG in 2007/08 and Manitoba Hydro recovered $2.4 million of the $4.2 million.

**PUB/MH/RISK-121**

**Reference:** **Report on Risks Faced by MH in Power Exports (July 4, 2007 – N. Bhattacharyya, Ph.D., Page 31)**
**Risk Issue:** **2006/07 Merchant Trading/ Risks**

**c) Please describe the specific sales operation activities that resulted in this loss.**

**ANSWER:**

There are no specific sales activities that resulted in this loss. As discussed in PUB/MH/RISK-121(b), the market price spreads between MISO and the IESO for 2006/07 were insufficient to cover the firm transmission costs already committed to by MH. Power Trading staff purchased from MISO and sold to the IESO when market price spreads were favourable.

**PUB/MH/RISK-121**

**Reference:** **Report on Risks Faced by MH in Power Exports (July 4, 2007 – N. Bhattacharyya, Ph.D., Page 31)**
**Risk Issue:** **2006/07 Merchant Trading/ Risks**

**d) Please provide a table detailing each of the recommendations made by Dr. N. Bhattacharyya and the Corporations position relative to each.**

**ANSWER:**

Summary of Recommendations Pages 23, 24

| **Recommendation** | **Corporate Position** |
|---|---|
| Should the Corporation increase the volume of merchant transactions it may become advantageous to create a wholly owned subsidiary to manage them. | Manitoba Hydro does not intend to increase the amount of merchant transactions in the foreseeable future. Therefore, there is no need to pursue the creation of a subsidiary at this time. |
| In future it may become advantageous to continue to reduce long term sales as a percentage of total export sales. | Manitoba Hydro will continue to maintain a combination portfolio of spot/short term and long term sales. ICF concluded it was appropriate to enter into long term contracts consistent with business plans. KPMG pointed out the risks of reliance on the spot market as it exposes the Corporation to significant risk during price and demand declines. |
| The Corporation should continue to automate the input processes of these models as much as possible and in future consider a company wide optimization system for operational decisions. | Manitoba Hydro's demand and supply forecasting models have been developed over many years and are unique to Manitoba Hydro's requirements. Manitoba Hydro continues to update and optimize its forecasting models. |
| The Middle Office should be set up under Accounting and Finance Branch. Two persons are required, one a commerce graduate and the other a graduate in quantitative discipline like mathematics or statistics. | The Middle Office reports to Finance & Administration and has evolved considerably since the Bhattacharyya report. The Middle Office continues to pursue best practices in risk monitoring and reporting. It is currently in the process of assessing risk management software to assist with the analytical functions of the Middle Office. Additional staff have been added. |

**PUB/MH/RISK-122**

**Reference:** **KPMG Main Report (Page 22/Page 111), (Page 57/58/59/60); MH March 7 Comment on 2004 NYC Report (Schedule 7/Page 28)**

**Risk Issue:** **KPMG/NYC/MH MH's Antecedent Forecasting of Water Volumes**

**a)** **Please confirm that KPMG has indirectly suggested that the substantial reliance on antecedent forecasting of water volume without employing "Meteorological Data and Modelling of Physical Parameters such as Lake Evaporation." (New York Power Authority) is not practiced by any other hydro utility.**

**ANSWER:**

KPMG Response:

Because KPMG's benchmarking review did not cover all hydro-electric utilities and because, for those utilities that we did study, our research was not complete with respect to all topic areas, we cannot make definitive statements about the uniqueness of MH's forecasting approach.

As noted on page 58 of the report, however, MH does face unique challenges relative to other utilities in its forecasting requirements. The catchment area for MH's production facilities is both large and shallow compared to most other hydro-electric utilities. These characteristics affect the costs and benefits of alternative forecasting approaches and can reasonably result in MH making different choices in these approaches.

**PUB/MH/RISK-122**

**Reference:** **KPMG Main Report (Page 22/Page 111), (Page 57/58/59/60); MH March 7 Comment on 2004 NYC Report (Schedule 7/Page 28)**
**Risk Issue:** **KPMG/NYC/MH MH's Antecedent Forecasting of Water Volumes**

**b) Please explain why MH has not to date employed the direct (ongoing) input to HERMES or a companion model of one/or all of:**

- **Snow pack (net of sublimation).**
- **Spring rains.**
- **Summer rains.**
- **Lake evaporation.**
- **Actual local Lake Winnipeg inflows.**
- **Actual local Upper Nelson River inflows.**
- **Actual lake levels or energy-in-storage.**

**ANSWER:**

Manitoba Hydro uses the historic record of inflows available for outflow for the basis of its seasonal water supply forecasts. The use of actual rainfall, snow pack and evaporation is not possible as the weather network across Manitoba Hydro's watersheds is very sparse and only coarse estimates of these values could be possible. In addition, there are no reliable forecasts of these inputs more than one or two days into the future, whereas Manitoba Hydro requires forecasts up to 16 months in advance. What is important to Manitoba Hydro is the surplus from any water budget calculation that shows up in the rivers/lakes. This surplus can be determined directly from the hydraulic network thus avoiding the complexity and uncertainty of modeling the hydrologic process for the entire watershed.

Manitoba Hydro confirms that it uses actual local inflows to Lake Winnipeg (this includes runoff and the net of precipitation minus evaporation) as well as the actual lake levels in its operation planning process. Manitoba Hydro calculates local Upper Nelson River inflows based upon gauged outflows from Lake Winnipeg and at Kelsey, adjusted for storage changes along the Nelson River.

**PUB/MH/RISK-122**

**Reference:** **KPMG Main Report (Page 22/Page 111), (Page 57/58/59/60); MH March 7 Comment on 2004 NYC Report (Schedule 7/Page 28)**

**Risk Issue:** **KPMG/NYC/MH MH's Antecedent Forecasting of Water Volumes**

**c)** **Please describe how MH does employ and document the above data in the "adjustment factors" that are periodically applied to water volume forecasts.**

**ANSWER:**

Adjustment factors are used to prorate the flow measured at a tributary gauging station to account for the area of that local basin that is not gauged and as a proxy for other tributary inflow that is not gauged.

Adjustment factors are rarely changed. These factors are documented in Manitoba Hydro's model documentation and its database.

**<u>PUB/MH/RISK-123</u>**

**Reference: MH's Internal Audit Department Report (October 2007)**
**Risk Issue: MH Response to NYC Issues**

**a) Please confirm that the intent and scope of this audit did not include issues related to adequacy of water volume forecasts and/or passing judgment on modeling processes.**

**<u>ANSWER</u>:**

Water volume forecasting and modeling processes were not within the intent and scope of this engagement.

**PUB/MH/RISK-123**

**Reference:** **MH's Internal Audit Department Report (October 2007)**
**Risk Issue:** **MH Response to NYC Issues**

**b)** **Did this Committee review MH's operational and planning forecasts and forecasting processes with respect to energy market pricing?**

**ANSWER:**

The focus of the audit was directed toward trading and settlement processes and practices as well as oversight related thereto. The scope of this review audit did not include assurance procedures related to operational and planning forecasting or energy market pricing forecasting processes.

**PUB/MH/RISK-123**

**Reference: MH's Internal Audit Department Report (October 2007)**
**Risk Issue: MH Response to NYC Issues**

**c) Please explain why the Internal Audit Department Report ( October 2007) was undertaken. Was the audit largely a response to various NYC reports and the N. Bhattacharyya, Ph.D. – July 4, 2007 Report?**

**ANSWER:**

The October 2007 Internal Audit Report arose substantially from:

a) the significance of the business activities of the Power Sales and Operations Division, as determined from the Internal Audit Department's standard annual audit planning process; and

b) the need to follow up on the Phase I Audit report.

The Phase I Audit was undertaken by Ernst & Young with the assistance of the Internal Audit Department; the associated report was issued on September 5, 2006. Internal Audit was aware of reports issued by RiskAdvisory, Dr. Bhattacharyya and the December 4, 2006 report of NYC as well as the response thereto. However, the primary driving force behind identifying and performing the referenced audit was the significance of Power Sales & Operations responsibilities and not as a response to the NYC reports and/or the findings of Dr. Bhattacharyya. This and other audits would have been planned and undertaken in the absence of these reports.

**PUB/MH/RISK-124**

**Reference:** **NYC Commentary (Various Pages)**
**Risk Issue:** **Overselling of Energy**

a) **Please explain MH's position on the NYC's apparent contention that overselling of energy into the market during the summer months may result in buy-backs at higher prices.**

**ANSWER:**

Manitoba Hydro disagrees with the assertion that it oversells energy. The NYC failed to understand the factors impacting the physical operations of the Manitoba Hydro system of reservoirs, generation stations, and tielines.

For example, the NYC asserted that Manitoba Hydro oversold summer 2006 which resulted in forced higher priced purchases in winter 2006/07. As explained in PUB/MH/RISK-80 and PUB/MH/RISK-81, the state of Manitoba Hydro's reservoirs in spring and early summer, 2006 required high outflows from Lake Winnipeg, which resulted in off-peak exports. This operation was necessary to avoid reservoir levels rising above licence limits which would then require Manitoba Hydro to effect maximum discharge out of Lake Winnipeg. Such an operation would have resulted in incremental spilled energy and high water impacts on downstream waterway users. Manitoba Hydro was not overselling energy, rather it was managing above average spring storage levels on its reservoirs, and operating in consideration of all its operating priorities, including economics. Please refer to Manitoba Hydro's operating priorities provided in Attachment 1 to PUB/MH I-147(a)(ii).

Manitoba Hydro did purchase power in winter 2006/07 at higher prices than what it was paid for off-peak sales in the prior summer. Winter 2006/07 was characterized with above forecast domestic load and below normal reservoir releases from externally regulated reservoirs:

1. Manitoba Hydro was experiencing the 2$^{nd}$ lowest flows in the past 43 years on the Winnipeg River. These extreme low flows limited the energy production and sustainable capacity from Manitoba Hydro's stations on this river. Flows supplying Manitoba Hydro's generating stations on this river are regulated by the Lake of the Woods Control Board and not Manitoba.

2. Manitoba domestic load was well above average in February 2007 due to extreme cold weather. February 2007 was the 8th coldest February in the past 51 years. On February 5th, the temperature dropped to -42.2 C which was the coldest day in 31 years. Manitoba energy demand was approximately 150 GWh higher and its peak load for the month was approximately 275 MW higher due to well below normal temperatures.

3. Manitoba Hydro, as is usual, operated Lake Winnipeg and the Churchill River Diversion at maximum outflows during the winter season. So, to the extent that Manitoba Hydro was able to minimize energy purchases through the operation of reservoirs under its control, it did so.

**<u>PUB/MH/RISK-124</u>**

**Reference: NYC Commentary (Various Pages)**
**Risk Issue: Overselling of Energy**

**b) Please confirm that overselling of that nature did in fact occur in:**

- **2006/07.**
- **2002/03**

**<u>ANSWER</u>:**

Manitoba Hydro does not confirm that it oversold during 2002/03 and 2006/07.

**<u>PUB/MH/RISK-124</u>**

**Reference:** **NYC Commentary (Various Pages)**
**Risk Issue:** **Overselling of Energy**

**c)** **Would MH agree that overselling can occur when firm export contract commitments exceed hydraulic generation surpluses?**

**<u>ANSWER</u>:**

Manitoba Hydro’s dependable resources include hydraulic, thermal, wind and contracted imports, not just hydraulic resources. Manitoba Hydro only enters into firm export contracts if it has sufficient surplus dependable energy to support the sale at the time the sale commitment is made, therefore overselling is not possible.

**<u>PUB/MH/RISK-125</u>**

**Reference:** **ICF 2009 Report (Pages 72/84/85),NYC Commentary (Pages 105/110)**
**Risk Issue:** **Long-Term Export Contracts**

**a) Does MH agree when ICF suggests that MH is similar to Quebec Hydro in the relative proportion of hydraulic energy that it typically seeks to export?**

**<u>ANSWER</u>:**

Manitoba Hydro does not agree that the ICF report, "suggests that MH is similar to Quebec Hydro in the relative proportion of hydraulic energy that it typically seeks to export."

On average, and in proportion to domestic load, Manitoba Hydro exports more hydraulic energy than Hydro-Québec. This statement was based on a review of publicly available reports for 2004 and 2005.

**<u>PUB/MH/RISK-125</u>**

**Reference: ICF 2009 Report (Pages 72/84/85),NYC Commentary (Pages 105/110)**
**Risk Issue: Long-Term Export Contracts**

**b) Does MH see a logical parallel to Quebec in its approach to long-term contracts as suggested by ICF?**

**<u>ANSWER</u>:**

Manitoba Hydro concurs that there is a logical parallel to Hydro-Québec's approach to long-term contracts as suggested by ICF.

**<u>PUB/MH/RISK-125</u>**

**Reference:** **ICF 2009 Report (Pages 72/84/85),NYC Commentary (Pages 105/110)**
**Risk Issue:** **Long-Term Export Contracts**

**c)** **Further to ICF's statement that Quebec is pursuing a similar strategy to MH on long-term contracting, please explain (with supporting documentation) how Quebec Hydro determines the financial viability of new G&T and the minimum acceptable average contract revenue rate.**

**<u>ANSWER</u>:**

Manitoba Hydro does not have any information on the approach used by Hydro-Québec to determine the financial viability of new G&T and the minimum acceptable average contract revenue rate.

**PUB/MH/RISK-125**

**Reference: ICF 2009 Report (Pages 72/84/85),NYC Commentary (Pages 105/110)**
**Risk Issue: Long-Term Export Contracts**

**d) In light of ICF's statement that existing export contract prices are adequate with respect to production costs, please confirm or otherwise define that MH looks to achieve average contract revenue rates that are:**

- **Greater than MH's future average system cost (¢/kW.h); and/or**
- **Equal to the incremental cost of new G&T (¢/kW.h).**

**ANSWER:**

Manitoba Hydro's export power marketing activities try to achieve an average contract revenue rate that exceeds the Corporation's expected price forecast when the contract is being supplied from existing generating and transmission facilities. When the proposed sale contract is going to require the construction of new generation and transmission in advance of domestic load requirements, Manitoba Hydro has a requirement to achieve net benefits that result in a return on investment that exceeds the Corporation's investment hurdle rate.

**PUB/MH/RISK-125**

**Reference: ICF 2009 Report (Pages 72/84/85),NYC Commentary (Pages 105/110)**
**Risk Issue: Long-Term Export Contracts**

**e) Please confirm that average revenue rates from the three NSP contracts (2015-2025) are likely to be less than the average incremental cost of either Keeyask G.S. or Conawapa G.S. and will not cover any of the additional Bipole III incremental costs of 2.5 to 3.0¢/kWh.**

**ANSWER:**

Manitoba Hydro can not confirm the statement made in this information request.

Under the NSP contracts (2015-2025), Manitoba Hydro is not obligated to construct any new resources. The sales are served from energy that is surplus to Manitoba Hydro's needs, and is valued by comparing to the long-term export price forecast (the alternative opportunity for the energy). In the event that Manitoba Hydro constructs major new hydro resources, the capacity of the sale will increase to 500 MW. The price included in the NSP sales is greater than the long-term export price forecast, and as such they are an attractive sales package to pursue.

It should be noted that in the 2000/01 timeframe, Manitoba Hydro recognized in its system planning the need for Bipole III which was justified on the basis of reliability.

**PUB/MH/RISK-125**

**Reference: ICF 2009 Report (Pages 72/84/85),NYC Commentary (Pages 105/110)**
**Risk Issue: Long-Term Export Contracts**

**f) Please explain ICF's contention that existing long-term contracts will continue to provide a premium over domestic costs when the energy to serve these contracts will within five or six years require the purchase or thermal generation of the entire contract energy amount in average or below average flow years.**

**ANSWER:**

The assumption made in this information request is incorrect. Please refer to the response to PUB/MH/RISK-39(c) and PUB/MH/RISK-13(a) which indicate that thermal and import purchases would be required much less frequently than assumed in this information request.
Although Manitoba Hydro may make energy purchases during years of significantly below average inflow conditions, these are usually during the off-peak period when prices are considerably less than the on-peak market prices.

It should be noted that Manitoba Hydro's dependable energy from all resources is available to serve its firm obligations which include domestic load and firm export sales.

**PUB/MH/RISK-125**

**Reference: ICF 2009 Report (Pages 72/84/85),NYC Commentary (Pages 105/110)**
**Risk Issue: Long-Term Export Contracts**

**g) Can MH confirm that the logical basis for long-term contracts requires that average revenue rates are:**

- **Not lower than average day-ahead market rates?**
- **Adequate to cover a full share of incremental embedded costs of all new G&T that must be in place to serve the contract?**

**ANSWER:**

Some of the advantages and disadvantages (or logical/ strategic considerations) behind long-term contracts are discussed in Sections 5.4 and 5.5 of the September 2009 ICF Report. In addition to these strategic considerations, Manitoba Hydro can confirm that a consideration for entering into long-term contracts is that the contract price is comparable to or better than the long-term forecast for expected average day-ahead market rates for opportunity energy based on the current long-term electricity price forecast.

Manitoba Hydro is uncertain as to the intended definition of "incremental embedded costs" and therefore is not in a position to confirm the second statement. However, when entering into long-term contracts which require advancing a resource for export, Manitoba Hydro performs an economic evaluation of the costs of serving the sale from its entire system, which includes consideration of any costs related to the advancement of resources to serve the sale, as well as any potential imports or thermal generation that may be required in low flow years.

At some point in the future, the Manitoba load will grow to the point that the advanced resources will be required to serve the Manitoba load rather than be available for export. At that time the remaining costs related to those advanced resources would then be borne by the Manitoba load. Hence the export contracts will not pay for the resource over its entire life time - but rather only during the initial exporting years (when the carrying costs are the highest) until the resources are required for the Manitoba load.

**PUB/MH/RISK-126**

**Reference:** **KPMG Main Report (Page 158)**
**NYC Commentary (Page 38)**
**MH's December 2008 Export Power Sales/Mgmt Issue #3 (Page 6)**
**Risk Issue:** **Dependable Flow**

a) **Please confirm that MH's position on defining dependable energy to include wind/thermal generation/DSM/imports effectively allows total firm energy commitments to equal about 115% of dependable hydraulic generation.**

**ANSWER:**

In determining dependable energy capability available to serve firm commitments, Manitoba Hydro includes energy from hydraulic, wind, and thermal resources and from imports. While DSM does not increase generating capability, it reduces system load thereby effectively making available a quantity of dependable energy. The total amount of dependable energy is available to serve Manitoba Hydro's firm commitments.

Based on 2009/10 power resource plan, total firm commitments can be as much as 135% of the dependable hydraulic energy. This ratio will change with the resource mix.

**PUB/MH/RISK-126**

**Reference:** **KPMG Main Report (Page 158)**
**NYC Commentary (Page 38)**
**MH's December 2008 Export Power Sales/Mgmt Issue #3 (Page 6)**
**Risk Issue:** **Dependable Flow**

**b) Please confirm that:**

- **Wind energy is intermittent and may not be available.**
- **MH's SCCT generation is rarely economical.**
- **DSM is not necessarily dispatchable.**
- **Diversity imports may not be economical.**
- **Market imports for firm supply may be at high price.**
- **Non-firm market off-peak imports have historically commanded peak prices during a drought.**

**ANSWER:**

It is unclear in what context the statements in this information request are being made. However, Manitoba Hydro offers the following comments:

Long-term firm contracts can be served primarily from hydraulic resources approximately 90 percent of the time. Therefore it is only during approximately the lowest 10 percent of flow conditions that energy from SCCT, and other natural gas generation, and market purchases or imports may be required to meet firm commitments. SCCT, and other natural gas generation, and market purchases or imports provide a supply of dependable energy as depicted in the response to PUB/MH/RISK-13(a). From an economic perspective serving firm commitments from hydraulic resources is less costly than serving these commitments with SCCT, and other natural gas generation, and on-peak imports/market purchases.

Wind generation is intermittent on an hourly or monthly basis, however over an annual period, generation available from wind power can be counted on as a dependable source of energy.

Manitoba Hydro's SCCTs, and other natural gas generation, are a source of supply available to meet firm commitments and are expected to operate as back-up resources during events such as low flow conditions and system emergencies. Dispatch of the SCCT, and other natural gas generation in non-emergency situations will be based on economics.

DSM is not a source of generation but rather it reduces system load, thereby effectively making available a quantity of dependable energy.

Energy from firm import capability only is included in dependable energy. Energy imports will be based on economics which means the majority of the time they will be purchased in the lower priced off-peak hours. Under the lowest flow conditions, it may be required to also purchase energy during on-peak hours. Please refer to the responses provided to CAC/MSOS/MH/RISK-41(b) and CAC/MSOS/MH I-62(g) for comments on how overall MISO market prices are largely independent of drought conditions in Manitoba. Please refer to the response to PUB/MH/RISK-13(a) which shows that a large quantity of energy purchased during a drought would be during the lower priced off-peak period.

**PUB/MH/RISK-126**

**Reference:** **KPMG Main Report (Page 158)**
**NYC Commentary (Page 38)**
**MH's December 2008 Export Power Sales/Mgmt Issue #3 (Page 6)**
**Risk Issue:** **Dependable Flow**

**c)** **Please confirm that KPMG did raise the exclusion of the 2003/04 hydraulic output of 18,500 GWh and suggested that in effect it was part of a 2-year drought event.**

**ANSWER:**

Manitoba Hydro can not confirm the statement made in this information request. Please refer to the response provided in PUB/MH I-80(a) which describes dependable energy from the existing Manitoba Hydro hydroelectric power resources.

**PUB/MH/RISK-126**

**Reference:** **KPMG Main Report (Page 158)**
**NYC Commentary (Page 38)**
**MH's December 2008 Export Power Sales/Mgmt Issue #3 (Page 6)**
**Risk Issue:** **Dependable Flow**

**d)** **Please confirm that MH's definition of dependable energy involves 21,200 GWh of hydraulic generation achieved from 15,000 GWh of inflows and 6,000 GWh of energy from storage; assumes that the April 1st energy-in- storage was greater than 6,000 GWh and could be fully drawn down .**

**ANSWER:**

Please refer to the response provided in PUB/MH I-80(a) which describes dependable energy from the existing Manitoba Hydro hydroelectric power resources.

**PUB/MH/RISK-126**

**Reference:** **KPMG Main Report (Page 158)**
**NYC Commentary (Page 38)**
**MH's December 2008 Export Power Sales/Mgmt Issue #3 (Page 6)**
**Risk Issue:** **Dependable Flow**

**e)** **Please explain why the above scenario did not work in 2003/04 when the April 1st energy-in-storage was about 4,200 GWh and that 11,000 GWh energy was withdrawn from storage after July.**

**ANSWER:**

Manitoba Hydro operated its system of reservoirs in 2002-04 consistent with its operating and planning criteria. Reservoir storages under Manitoba Hydro control were maintained at levels sufficient that should 1940/41 flows occur in either of 2003/04 or 2004/05 that sufficient hydraulic generation would have been available to meet firm load requirements when thermal, imports and financial settlements were considered.

Although actual hydraulic generation in 2003/04 was below the dependable amount, it was unnecessary to drain reservoirs to increase hydraulic generation as alternative non-hydraulic resources were available. This strategy of not depleting reservoirs allowed Manitoba Hydro to maximize the supply security should sever drought persist into 2004/05. This strategy is prudent given that the severity and duration of drought is only known in hindsight and that the historic hydrologic record does not guarantee that future droughts will never be more severe or longer than the historic record indicates.

Please note that the energy in storage values used in this question include the 18 major reservoirs in Manitoba Hydro's watershed and that only a portion of this storage is under the management of Manitoba Hydro.

**PUB/MH/RISK-127**

**Reference:** **Risk Advisory Report January 18, 2005:**

- **The 2003 Drought**
- **The Drought Management Plan**
- **Operations Planning Criteria/Results**

**Risk Issue:** **2003/04 Drought**

**a)** **Please confirm that the 2003/04 drought actually began in the summer of 2002/03 and that with low fall stream flows, MH's energy-in-storage was moving to a post-LWR/CRD low during that winter; and subsequently dropped to about 4,200 GWh by April 1st, 2003.**

**ANSWER:**

Confirmed.

**<u>PUB/MH/RISK-127</u>**

**Reference:** **Risk Advisory Report January 18, 2005:**

- **The 2003 Drought**
- **The Drought Management Plan**
- **Operations Planning Criteria/Results**

**Risk Issue:** **2003/04 Drought**

**b)** **Please confirm that despite low fall inflows, very little snowpack and reservoir levels at a 27-year low, MH was reluctant to initiate an all-out drought response.**

**<u>ANSWER</u>:**

Manitoba Hydro was quite aware of the water supply situation during the fall and winter of 2002/03 and operated the power system to ensure adequate energy supplies were available in 2003/04 should drought conditions persist. Manitoba Hydro was not reluctant to act but instead, when it became necessary following below average spring rains, acquired gas storage, gas supplies and energy purchases.

**<u>PUB/MH/RISK-127</u>**

**Reference:** **Risk Advisory Report January 18, 2005:**

- **The 2003 Drought**
- **The Drought Management Plan**
- **Operations Planning Criteria/Results**

**Risk Issue:** **2003/04 Drought**

**c)** **Please confirm that on hindsight, the low levels of energy-in-storage, poor snowpack in the Winnipeg River/Red River/Lake Winnipeg local watersheds represented about the only pending drought indicators that MH could have expected.**

**<u>ANSWER</u>:**

Manitoba Hydro cannot confirm that low levels of energy in storage is an indicator of drought. Manitoba Hydro confirms that record low snowpack is one indicator of increased risk of drought. However, as occurred in the late spring of 2010, when accumulated snowpack across Manitoba Hydro watersheds was identical to that in the late spring of 2003, water supplies in the late spring and summer of 2010 were well above average and later developed to near record highs.

**PUB/MH/RISK-127**

**Reference:** **Risk Advisory Report January 18, 2005:**

- **The 2003 Drought**
- **The Drought Management Plan**
- **Operations Planning Criteria/Results**

**Risk Issue:** **2003/04 Drought**

**d)** **Please explain why the withdrawal of energy-in-storage was unusually high in the summer and fall of 2002/03. Please confirm that drought impacts in 2003/04 would have been substantially lower if more energy had been retained in storage.**

**ANSWER:**

Manitoba Hydro utilized surplus energy in storage during the summer and fall of 2002/03 to support hydraulic generation during a period of low inflows. Had additional water been retained in 2002/03, but released in 2003/04 it would have been at the expense of hydraulic generation in 2002/03. Overall, different management of hydraulic storage would have had little impact on the two year hydraulic generation because Manitoba Hydro's storage capability and operability is limited relative to the potential variability of two-year inflow volumes. In other words, management of storage can not avoid the impact of naturally occurring low periods of inflows on total hydraulic generation.

**<u>PUB/MH/RISK-128</u>**

**Reference:** **Risk Advisory Report January 18, 2005 (Various Pages)**
**NYC Commentary (Page 72)**
**KPMG Main Report (Pages 96 to 101)**
**ICF 2009 Report (Page 131)MH Responses to NYC Reports**
**Risk Issue:** **2003/04 Drought**

**a)** **Please confirm that since 2003/04, MH has yet to define a comprehensive Drought Plan for:**

- **Recognizing the onset of a severe drought.**
- **Reducing opportunity export sales as quickly as possible.**
- **Reducing contract export sales as permitted under some contract conditions.**
- **Pre-arranging cost effective import supplies.**

**<u>ANSWER</u>:**

Since 2003/04, Manitoba Hydro has formed the Export Power Risk Management Committee (EPRMC). The EPRMC is chaired by the President and CEO and meets on a regular basis to review water conditions and the status of export markets. Manitoba Hydro is well-prepared to recognize the onset of drought and to take actions appropriate to address current and potential water conditions.

**PUB/MH/RISK-128**

**Reference:** **Risk Advisory Report January 18, 2005 (Various Pages)**
**NYC Commentary (Page 72)**
**KPMG Main Report (Pages 96 to 101)**
**ICF 2009 Report (Page 131) MH Responses to NYC Reports**
**Risk Issue:** **2003/04 Drought**

**b)** **If that comprehensive Drought Plan exists, please file the document/process details.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH/RISK-128(a).

**<u>PUB/MH/RISK-128</u>**

**Reference:** **Risk Advisory Report January 18, 2005 (Various Pages)**
**NYC Commentary (Page 72)**
**KPMG Main Report (Pages 96 to 101)**
**ICF 2009 Report (Page 131)MH Responses to NYC Reports**
**Risk Issue:** **2003/04 Drought**

**c)** **Please confirm that the “antecedent forecasting” process employed by MH assumes a return to mean flows and as such, is not useful in defining the onset of a drought or predicting the continuation or duration of a drought situation.**

**<u>ANSWER</u>:**

No. The conclusion made in this question is incorrect.

Manitoba Hydro’s antecedent forecasting process does not assume a return to mean flows. The forecasting process can be used to define water supplies with various probabilities of exceedence. For example, for preparing the IFF a forecast, a 50% exceedence probability is used. For the purposes of ensuring energy security for future drought conditions, a water supply forecast at the 95% exceedence probability is used in the operating horizon. Please read KPMG report section 3.4.2.3 for more detail and response to CAC/MSOS/MH/RISK-12(a).

**PUB/MH/RISK-128**

**Reference:** **Risk Advisory Report January 18, 2005 (Various Pages)**
**NYC Commentary (Page 72)**
**KPMG Main Report (Pages 96 to 101)**
**ICF 2009 Report (Page 131)MH Responses to NYC Reports**
**Risk Issue:** **2003/04 Drought**

**d)** **Please confirm that in 2003/04 and again in 2006/07, MH did not benefit from the Diversity Agreements and may in fact have been adversely affected by summer sales required in the agreements.**

**ANSWER:**

Manitoba Hydro can not confirm the conclusion implied in this statement. The diversity agreements in the years mentioned and all other years provided Manitoba Hydro with winter capacity, firm export and import transmission capacity, access to dependable energy and opportunity benefits associated with winter/summer price differentials.

**PUB/MH/RISK-129**

**Reference:** **NYC Consultant Commentary (Various)**
**MH Response to NYC Reports (Various)**
**KPMG Main Report (Pages 96 to 101)**
**Risk Issue:** **Risk Adequacy of the Historical Record**

**a) Please confirm that MH is currently employing the best available historically measured data on:**

- **River flows.**
- **Lake levels.**
- **Precipitation.**
- **Evaporation.**

**ANSWER:**

Manitoba Hydro confirms that it uses the best available historical data in its hydraulic system operations and for system planning. Manitoba Hydro ensures that the data is reliable and is generally consistently sourced while also being made available in a timely manner.

**PUB/MH/RISK-129**

**Reference:** **NYC Consultant Commentary (Various)**
**MH Response to NYC Reports (Various)**
**KPMG Main Report (Pages 96 to 101)**
**Risk Issue:** **Risk Adequacy of the Historical Record**

**b)** **Please confirm that the completion and infilling of pre-1940's data by logical relationships (while not precise) does provide a greater and very useful understanding of the longer-term water environment and is not all that dissimilar to adjustments required to integrate the Limestone G.S. into post-LWR/CRD depiction of potential hydraulic generation.**

**ANSWER:**

Manitoba Hydro does not confirm the statement made in this information request. The two processes described are not at all similar. The extension of flow records is undertaken by correlation analysis utilizing statistical techniques, while the determination of potential energy production with the addition of the Limestone G.S. is undertaken through a simulation of system operation.

**PUB/MH/RISK-129**

**Reference:** **NYC Consultant Commentary (Various)**
**MH Response to NYC Reports (Various)**
**KPMG Main Report (Pages 96 to 101)**
**Risk Issue:** **Risk Adequacy of the Historical Record**

**c)** **Please provide a summary discussion and update of the process of back checking and revisions that MH has been and is looking to make on flow inputs and generation outputs.**

**ANSWER:**

Providing a description of the processes as requested in this information request would result in the provision of detailed proprietary information that is considered to be confidential based on rationale #3 for Manitoba Hydro redactions to the KPMG Report and Appendices. Rationale #3 relates to detailed non-standard utility practice solution techniques utilized in short- and long-term planning of capacity, energy and water management with specific reference to the mathematical representation of the hydraulic system.

**PUB/MH/RISK-130**

**Reference:** **ICF 2009 Report (Page 111)**
**KPMG 2010 Main Report (Pages 99/100/101)**
**NYC Commentary (Pages 207/209) MH Responses to NYC Reports (Various)**

**Risk Issue:** **Probability of Drought**

**a) Please confirm that MH is not prepared to define the probability of a 7-year drought or other multi-year droughts even though such events have occurred in the last 100 years.**

**ANSWER:**

Please see Manitoba Hydro's response to PUB/MH I-154(a) which provides information related to frequency analysis of low flows.

**PUB/MH/RISK-130**

**Reference:** **ICF 2009 Report (Page 111)**
**KPMG 2010 Main Report (Pages 99/100/101)**
**NYC Commentary (Pages 207/209) MH Responses to NYC Reports (Various)**

**Risk Issue:** **Probability of Drought**

**b) Does MH agree with or reject the ICF report scenario, that based on the historical record, the probability of the first year of a 5-year drought occurring in any year is 3.1%?**

**ANSWER:**

Manitoba Hydro does not reject the ICF Report scenario and recognizes that ICF's work represents one approach to assigning probability that is similar in concept to work done by Manitoba Hydro in the response to COALITION/MH I-43(e) in the 2008 General Rate Application.

**<u>PUB/MH/RISK-130</u>**

**Reference:** **ICF 2009 Report (Page 111)**
**KPMG 2010 Main Report (Pages 99/100/101)**
**NYC Commentary (Pages 207/209) MH Responses to NYC Reports (Various)**

**Risk Issue:** **Probability of Drought**

**c)** **Would MH agree with KPMG's depiction of drought or low flow events and the related flow shortfalls which would suggest that MH would need some power purchases in 50% of years to serve long-term export contracts?**

**<u>ANSWER</u>:**

Manitoba Hydro generally agrees with the analysis of low flow events done by KPMG on pages 99 to 101 of the KPMG Report. However, Manitoba Hydro does not agree that power purchases are required in 50% of years to serve long-term export contracts.

Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations. Therefore, it is not appropriate to allocate a specific generation source, such as imports or thermal, to a specific requirement, such as export sales.

Please refer to the response to PUB/MH/RISK-13(a) which presents graphs that show the relative frequencies of the various generation sources over the range of flow conditions in three different years into the future. As may be observed from the graphs, the frequency of relying on Manitoba Hydro thermal or imports would be significantly less than 50% of the possible flow conditions.

**PUB/MH/RISK-130**

**Reference:** **ICF 2009 Report (Page 111)**
**KPMG 2010 Main Report (Pages 99/100/101)**
**NYC Commentary (Pages 207/209) MH Responses to NYC Reports (Various)**
**Risk Issue:** **Probability of Drought**

**d) Please confirm and explain why it would be illogical to suggest that drought events that have occurred one or two or three times in the last 100 years have a probability of reoccurrence <<1%.**

**ANSWER:**

It should be noted that the NYC has previously asserted that the five-year drought around 1940/41 period is a stress test scenario that has a likelihood of happening of 1 in 6.9 billion years (The calculation for this is $93^{5}$).

The KPMG Report thoroughly reviewed NYC's assertions in Section 3.7.11 on Drought Risk and concluded:

> "The assumption of time independence by the Consultant is flawed. It is clear that there is serial correlation in the water flow data. This has the effect of expanding the quantum of volume risk, since there is a greater risk that drought conditions will persist than will be calculated under an assumption of time independence." (KPMG Report - 3.7.11)
>
> "However, this is not an appropriate measure of the risk associated with low water flows because:
>
> - Water flows are serially correlated, and low flow years are likely to be followed by additional low flow years.

- Drought risks do not just arise from a single case of the lowest annual flow in the past 93 years happening 5 years in a row. The next lowest flow years are all relatively close together. Even if we accepted the Consultant's assumption of time independence, the probability of drought risks would depend on the various permutation and combinations of the relevant flow years, and this would be much higher than just the single case of the worst year happening 5 years in a row.

MH's use of actual flow sequences to measure drought risk is consistent with practices at other utilities and avoids the need to develop statistical models of underlying water flow processes." (KPMG Report – 3.7.11)

KPMG also reviewed Manitoba Hydro's drought risk quantification and concluded:

"Manitoba Hydro quantifies its drought risk appropriately and currently provides for appropriate levels of reserves of risk capital against its projected drought risk" (KPMG Report – 4.2)

**PUB/MH/RISK-131**

**Reference:** **NYC Consultant (Page 87)**
**ICF 2009 Report (Pages 84/85)**
**Risk Issue:** **Rate Payer Rate Increases**

**a) Please explain how MH's rate increases in IFF 09 1 were determined with respect to net income/retained earnings/debt ratio.**

**ANSWER:**

Please see Manitoba Hydro's response to CAC/MSOS/MH II-109(a).

**<u>PUB/MH/RISK-131</u>**

**Reference:** **NYC Consultant (Page 87)**
**ICF 2009 Report (Pages 84/85)**
**Risk Issue:** **Rate Payer Rate Increases**

**b)** **Please provide alternative rate increase scenarios reflecting average export revenue rates at 75% and 50% of IFF 09-1 export revenue rates while leaving fuel and power purchase costs unchanged and retaining the same debt ratios.**

**<u>ANSWER</u>:**

Manitoba Hydro cannot produce an alternative price scenario in the time allotted for responding to these Information Requests. However, the IFF09 Low Price scenario would provide a directional indication of the impacts of the lower bound of export prices. Please see Appendix 15 for the projected financial statements supporting the IFF09 Low Export Price scenario.

**PUB/MH/RISK-131**

**Reference: NYC Consultant (Page 87)**
**ICF 2009 Report (Pages 84/85)**
**Risk Issue: Rate Payer Rate Increases**

**c) Please indicate whether or not and how Manitoba rate payers will continue to benefit if export prices do come in at those lower levels (suggested in (b)).**

**ANSWER:**

Prolonged lower export price impacts as shown in the Low Export Price scenario provided in Appendix 15 indicate that the debt ratio rises to a peak of 84% and then recovers to the target 75% by 2026/27 (3 years later than the 20 Year Financial Outlook shown in Appendix 16). Retained earnings grow from $2.2 billion in 2009/10 to $6.6 billion by 2028/29, adequate levels to absorb a period of low water flows. When combined with a 5-year drought commencing in various periods, the KPMG report shows that the impacts of drought are less severe under low prices compared to expected and high prices (KPMG Report, Exhibits J-4/J-8/J-12). An adequate level of retained earnings avoids the need to seek higher rate increases from customers. Please also see the response to CAC/MSOS/MH II-105(i).

**PUB/MH/RISK-132**

**Reference: ICF/NYC/KPMG**
**Risk Issue: G&T Capital Costs**

**a) Please explain why none of MH's external consultants (from 2004 onward) have addressed the risk of new G&T capital cost escalation when this could be a very substantial factor in future debt ratios.**

**ANSWER:**

Risk of new G&T capital cost escalation was not a specific part of the terms of reference/scope of the external consultants work. However, ICF did briefly comment on Capital Investment, Inflation Risk and Cost Overrun and these comments can be found on page 63 of their report.

**<u>PUB/MH/RISK-132</u>**

**Reference: ICF/NYC/KPMG**
**Risk Issue: G&T Capital Costs**

**b) Please confirm that the decline of energy price in the MISO market is unlikely to trigger a reduction or easing of G&T capital costs.**

**<u>ANSWER</u>:**

Confirmed.

**<u>PUB/MH/RISK-133</u>**

**Reference:** **Risk Advisory Report, MH's Energy in Storage & Monthly Flow Records, NSP Redacted Contract**

**Risk Issue:** **Reacting to Drought Threat**

**a)** **Please confirm that in 2003/04 MH was alerted to the potential for a low flow in January 2003; below-average Fall River flows and very little snowpack, but a Drought Mitigation Plan did not go into effect until May 2003.**

**<u>ANSWER</u>:**

Please see Manitoba Hydro's response to PUB/MH/RISK-127.

**<u>PUB/MH/RISK-133</u>**

**Reference:** **Risk Advisory Report, MH's Energy in Storage & Monthly Flow Records, NSP Redacted Contract**
**Risk Issue:** **Reacting to Drought Threat**

**b)** **Please indicate whether MH committed to any short-term [summer] firm contract sales in February or March of that year given that energy in storage had fallen to a historic low.**

**<u>ANSWER</u>:**

No, Manitoba Hydro did not commit to any short-term firm contract sales during February and March of 2003 for delivery in the summer of 2003.

**PUB/MH/RISK-133**

**Reference:** **Risk Advisory Report, MH's Energy in Storage & Monthly Flow Records, NSP Redacted Contract**

**Risk Issue:** **Reacting to Drought Threat**

**c) Would MH agree that there was no defined "fast–track" process in place in 2003/04 that power sales and operations could have been employed to cut back sales commitments or Institute substantial energy purchases?**

**ANSWER:**

Manitoba Hydro's sales commitments in place at the time were long term in nature. Manitoba Hydro's long term contracts do not include economic curtailment rights and so curtailment of long term contracts is not a strategy that can by used by Manitoba Hydro when managing its system during low water conditions.

All energy purchases that were necessary during the period had to be arranged bilaterally with Manitoba Hydro's counterparts as there was no standard market in place in the US. Manitoba Hydro was dependent on its counterparts' willingness to sell the required quantities. There is no fast-track process available to cut back sales commitments.

**<u>PUB/MH/RISK-133</u>**

**Reference:** **Risk Advisory Report, MH's Energy in Storage & Monthly Flow Records, NSP Redacted Contract**

**Risk Issue:** **Reacting to Drought Threat**

**d)** **Would MH agree that if the Drought Mitigation Plan had not been put in place until September 2003, the financial consequences might have been substantially greater.**

**<u>ANSWER</u>:**

Manitoba Hydro began taking action in response to failure of the 2003 water supply in April 2003. It would be speculative to assume that the financial consequences would have been different had the action been delayed to September 2003 as no alternative action plan is available for comparative purposes.

**PUB/MH/RISK-134**

**Reference:** **KPMG Report- Page 58 & 158**
**Risk Issue:** **Variability of Winter & Spring Precipitation**

a) **Does MH not consider snowpack as a useful parameter in defining flows for the upcoming summer; because sublimation may significantly reduce the actual snow melt runoff.**

**ANSWER:**

Manitoba Hydro considers snowpack to be a useful indicator regarding the likelihood of drought, especially in years of record high snowpack. However snowpack is poorly correlated to water supply. Variations in snowpack results in a small portion of the overall variations in water supply. Snowpack is a relatively small factor that affects the water supply in comparison to rainfall in the frost free seasons which is the primary factor affecting total water supply.

**PUB/MH/RISK-134**

**Reference: KPMG Report- Page 58 & 158**
**Risk Issue: Variability of Winter & Spring Precipitation**

**b) Would a lack of snow pack [as in 2003/04] not be of very strong indicator of reduced spring runoff [sublimation being a non-issue].**

**ANSWER:**

Snowpack is poorly correlated to the annual water supply.

Well above average snowpack is a good indicator of above average spring flows, hence lower risk of severe drought occurring.

Snowpack is a poor indicator of drought occurring as it amounts to a small portion of the total water supply, however drought risk is increased somewhat following poor snowpack conditions. This point is illustrated by comparing 2003/04 water supply to that of 2010/11 where snowpack from the preceding winter was nearly identical in both years and at near record low over the past 30 years, but 2003/04 was a drought year whereas 2010/11 inflows are projected to be near record highs experienced in the past 30 years.

**<u>PUB/MH/RISK-134</u>**

**Reference: KPMG Report- Page 58 & 158**
**Risk Issue: Variability of Winter & Spring Precipitation**

**c) Please explain & illustrate quantitatively the suggestion by MH that winter snow melt is not as great a component of runoff volume as spring rain.**

**<u>ANSWER</u>:**

Simply comparing the three month annual average system weighted precip for winter versus spring indicates that spring precipitation is more significant that winter precipitation.

| Months | System Precipitation (in mm of water equivalent) | % of annual total |
|---|---|---|
| Dec, Jan, Feb | 60 mm | 11 |
| Mar, Apr, May | 116 mm | 21 |
| Jun, Jul, Aug | 246 mm | 44 |
| Sep, Oct, Nov | 137 mm | 25 |
| Annual Average | 560 mm | - |

Period of record: 1979 through 2010

A portion of snow accumulation will be lost to sublimation prior to the melt period, hence will not runoff into Manitoba Hydro's rivers and reservoirs. Conversely, spring precipitation can fall on frozen ground which impedes infiltrations, hence a relatively larger percentage of precipitation results in runoff (as compared to summer and fall rains, all else being equal).

**PUB/MH/RISK-135**

**Reference: KPMG Report - Recommendations Section 7**
**Risk Issue: MH Responses to KPMG Recommendations**

**Please provide a table detailing each of the recommendations made by KPMG and the Corporations position relative to each.**

**ANSWER:**

Manitoba Hydro is in the process of developing the Corporation's position and schedule for addressing the recommendations contained within the ICF and KPMG reports.

**PUB/MH/RISK-136**

**Reference:** **ICF Report - Recommendations**
**Risk Issue:** **MH Responses to ICF Recommendations**

**Please provide a table detailing each of the recommendations made by ICF and the Corporations position relative to each.**

**ANSWER:**

Please see Manitoba Hydro’s response to PUB/MH/RISK-135.