March 2014 Redacted

La Capra Associates

NEEDS FOR AND ALTERNATIVES TO (NFAT) REVIEW OF MANITOBA HYDRO'S PROPOSAL FOR THE KEEYASK AND CONAWAPA GENERATING STATIONS

Technical Appendix 4

Environmental Issues and Policy

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This report contains information that has been deemed Commercially Sensitive Information and is, therefore, subject to a protective order.

PREPARED FOR

The Manitoba Public Utilities Board

PREPARED BY

La Capra Associates, Inc.
One Washington Mall, 9th Floor
Boston, MA 02108

January 24, 2014

La Capra Associates

CONFIDENTIAL

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Technical Appendix 4: Environmental Issues and Policy

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La Capra Associates, Inc.
One Washington Mall, 9th Floor
Boston, Massachusetts 02108

lacapra.com

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Acronyms

Technical Appendix 4

EIS	Environmental Impact Statement
ET	Evapotranspiration
GCM	Global Climate Model
GS	Generating Stations
IRR	Internal Rate of Return
LCA SOW	La Capra Associates Scope of Work
LCA	La Capra Associates
LTFD	Long-Term Flow Data
MH	Manitoba Hydro
MISO	Midcontinent Independent System Operator
M-RETS	Midwest Renewable Energy Tracking System
NFAT	Needs For and Alternatives To
NRIS	Network Resource Interconnection Service
PIAO	Partial Inflow Available for Outflow
RCM	Regional Climate Model
REC	Renewable Energy Certificate
RES	Renewable Energy Standard
US	United States

I. Introduction

The La Capra Associates (LCA) scope of work (SOW) included several items related to environmental issues and policy. Specific scope items addressed in this Technical Appendix include:

Power Resource Planning and Economic Evaluation

4. *Review Manitoba Hydro's NFAT filings with respect to the Lake Winnipeg and Upper Nelson River Water Regime change and the potential mitigation costs to the NFAT project;*
5. *Review the potential global warming impacts on water supply/river flows/lake and reservoir evaporation;*
14. *Comment on climate change impacts on energy supply and demand; and*

Business Case and Risk Assessment

6. *Analyze the market value of clean energy from hydro power during various seasonal and peak or off-peak periods.*

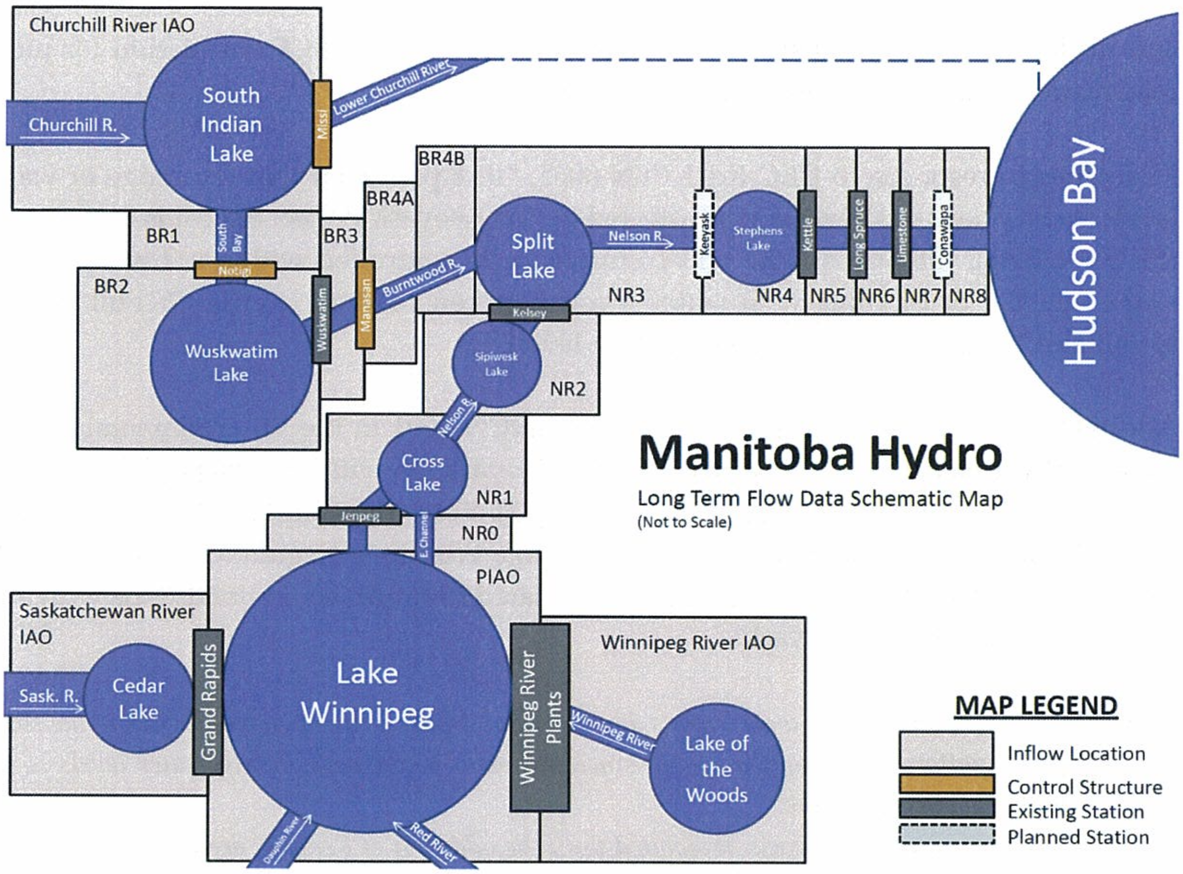
The material contained in this Technical Appendix also relates to information contained in LCA Technical Appendix 6: Export Markets, and Technical Appendix 7: Export Contracts, and the information prepared by Potomac Economics and MNP in their work regarding the Midcontinent Independent System Operator (MISO) markets and macro-environmental issues, respectively.

The specific focus of this Technical Appendix is to assess the reasonableness of Manitoba Hydro's (MH) claims regarding environmental issues and policies that impact the NFAT analysis.

II. Hydro Impacts to Water Regime

In this section, we address the impacts of the Keeyask and Conawapa Generating Stations (GS) on the water regime. We have focused on the effects of the new GS on the operation of the MH hydropower system. In a separate report, MNP has addressed the environmental impacts of Keeyask and Conawapa GS. Impacts addressed by MNP include flooding, water quality, impacts on caribou and impacts on Lake Sturgeon.

The Keeyask and Conawapa GS will be installed in the Nelson River which is the last body of water in the MH system before Hudson Bay. The Keeyask GS is just upstream of Stevens Lake and the Conawapa GS will be the most downstream GS in the MH system. This is illustrated in the figure below.



CONFIDENTIAL Figure 4-1: Manitoba Hydro System Schematic[1]

The largest storage reservoir in MH's system is Lake Winnipeg, and most of the generation capacity is some distance from the outlet of the Lake. The MH System is relatively flat geographically and the travel time between the Lake and the major generating stations on the Lower Nelson River is measured in weeks, not days or hours.

Neither Keeyask GS nor Conawapa GS is expected to affect the operation of the other GS owned by MH or the operation of the existing reservoirs. The exception to that, as explained further below, is that the addition of Keeyask will require Kettle to reduce its output slightly. This is not documented in the NFAT, but is documented in several information requests in the Keeyask Environmental Impact Statement (EIS) Proceeding

[1] SP-121 NFAT Confidential – LTFD_DATA_1912-2010(CONFIDENTIAL).

and in the interconnection studies. (See Technical Appendix 8: Transmission for more information related to the interconnection studies.)

MH states in response to CEC Rd 1 PFN-0035, "It is predicted that the range of water levels on Stephens Lake will not be affected by the Keeyask Project once it is operational (PE SV 4.4.2.3). Stephens Lake will continue to be controlled within a 2 m operating range for 90% of the time with water levels between 141.1 m (Kettle GS Full Supply Level) and 139.2 m (5th percentile operating level)."[2]

Additionally in response to TAC Public RD 1 NCN-0001 in the Environmental Impact Statement Proceeding, MH confirms that the Keeyask GS will not change the operation of the Winnipeg River hydroelectric generating stations, the Churchill River Diversion, Grand Rapids GS or Cedar Lake Storage, or Lake Winnipeg Regulation. The response also included the following two conclusions related to future water conditions with and without the addition of Keeyask:

- *The water levels in the waterbodies downstream of Lake Winnipeg would follow the same general pattern as presently exists, since the main factor influencing water levels is the amount of system inflow.*
- *The changes in water levels associated with the addition of Keeyask are not expected to be discernible in the context of existing water level variation in the waterbodies downstream of Lake Winnipeg.*[3]

In the *Final Interconnection Evaluation Study Report for Keeyask Hydropower Limited Partnership*, the owners of the planned Keeyask GS requested Network Resource Interconnection Service (NRIS) from MH. In this document MH also request that Kettle decrease the size of its NRIS by up to 65 MW. The maximum generation at Kettle requires the level of Stephens Lake be at a level that would raise the tailrace level at

[2] EIS proceeding, Manitoba Hydro Response to CEC Rd. 1 PFN-0035, p. 2:38-41, http://keeyask.com/wp/wp-content/uploads/2013/07/CEC-Round-1-Web-Version-July-31-2-pm.pdf.

[3] EIS Proceeding, Manitoba Hydro Response to TAC Public Rd 1 NCN-0001, p. 2:55-60, http://keeyask.com/wp/wp-content/uploads/2012/11/Keeyask-Generation-Project-Responses-to-Requests-for-Additional-Information-Round-1-WEB-VERSION.pdf.

Keeyask and would reduce the generating capacity of Keeyask. For this reason, Keeyask has asked that Kettle reduce its capacity.[4]

Given the later online date of Conawapa GS, there has not been a similar EIS proceeding for that facility yet. However given its position as the most downstream facility in MH's system and its limited pondage, it is not expected to change the operation of MH's other storage reservoirs or generating stations.

Neither Keeyask nor Conawapa add any material pondage capability in the MH system. Each project would operate effectively as "run-of-river" operations, producing energy with water as it comes to the facility with only very limited ability within daily operations to store water at these sites for later production.

In its report, MNP notes that historically Lake Winnipeg Regulation and the Churchill River Diversion have been the most significant contributors to the degradation of First Nations ecosystem and their interaction with the land. MNP further notes that MH has agreed in the Joint Keeyask Development Agreement that operation of the Keeyask GS will not require any changes to the Lake Winnipeg Regulation or Churchill River Diversion licenses and will not affect water levels in Split Lake during open water conditions. [5]

III. Climate Change

As part of the NFAT Business Case economic analysis, MH conducted a sensitivity analysis to see how various potential hydrological changes due to the effects of climate change would impact the economic analysis of some representative portfolios. This section reviews the methodology employed and offers opinions on key strengths and weaknesses.

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[4] SP-041, NFAT Confidential, Manitoba Hydro, *Final Interconnection Evaluation Study Report for Keeyask Hydropower Limited Partnership,* June 8, 2012, p. 4.

[5] MNP, "NFAT Review: A Review of Manitoba Hydro's Macro Environmental Considerations," p. 42.

A. Baseline Hydrology Data

Before understanding how climate change is modeled for the sensitivity analysis, it is necessary to first understand how hydrology is modeled in SPLASH.[6] The hydrology inputs to SPLASH are known as the Long-Term Flow Data (LTFD). LTFD is the average monthly flow at 18 flow points, grouped into five major basins, over the 99-year period from 1912-2010. The five major basins (shown in the figure below) are the Saskatchewan River, Churchill River, Nelson River, Winnipeg River, and PIAO (Partial Inflow Available for Outflow—a grouping of the Assiniboine River, Lake Winnipeg, and Red River basins). MH's climate change modeling is designed to estimate the potential changes to the water inflows for these basins.

CONFIDENTIAL Figure 4-2: Major basins for Long-Term Flow Data[7]

B. Climate Change Adjustment

Global Climate Models (GCM) simulate coarse scale climate dynamics to project temperature, precipitation, evapotranspiration (ET), runoff, and other effects under various emission scenarios. GCMs are typically developed and run by international modeling agencies. For the NFAT analysis, 21 GCMs running three emission scenarios

[6] SPLASH is MH's long-term planning dispatch model. For more on SPLASH operations, see Appendix 9.2 of the NFAT Submission.

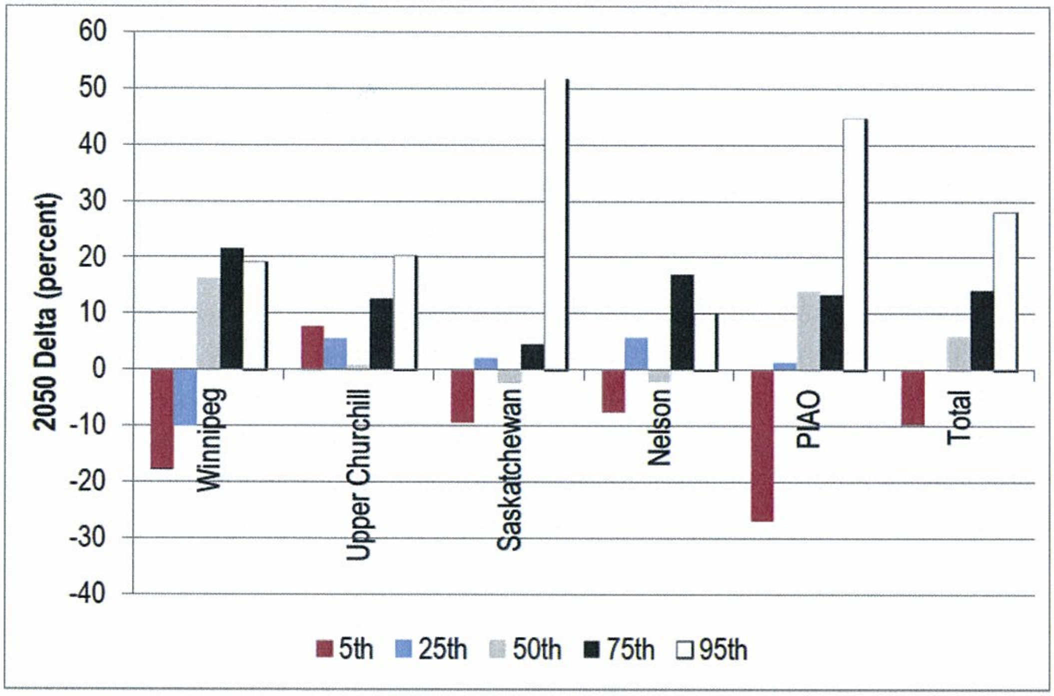
[7] NFAT Confidential – Runoff Methodology Presentation for LCA (SP-079), November 1, 2013, p. 4.

and some "multi-member runs" were used to produce 109 scenarios. MH maps the projected runoff from the GCM output (often with a spatial resolution up to 600 km wide[8]) onto their five major basins. Our understanding is that MH does this based on approximate spatial proportions.[9] Although MH is currently engaged in efforts to develop and calibrate more granular analysis using regional climate change models and hydrological routing studies, these methods were not yet available for this analysis.

For each GCM scenario and basin, the average 1971-2000 runoff is compared to the average 2040-2069 runoff to calculate a percent change in flow, or delta. The overall delta for all five basins combined is used to rank the 109 GCM scenarios, and the 5th, 25th, 50th, 75th, and 95th percentile scenarios are used in the climate change sensitivity analysis. About 70% of simulations project increased annual runoff. The basin specific and overall deltas for the featured scenarios are shown in the figure below.

[8] NFAT Submission, Appendix K (MH Climate Change Report, FY 2012-13), p. 10.

[9] Conversation with Michael Vieira, 11/1/13.



CONFIDENTIAL Figure 4-3: Runoff deltas for featured GCM scenarios[10]

These deltas are applied to the LTFD as follows:

- For each basin, the delta is applied to annual average flows for each flow point.
- The annual average flow change is assumed to apply uniformly in each month of the year.
- For maintained drought periods of 1938-1941, 1987-1989, and 2003 no adjustment (up or down) is made to the LTFD.

C. Economic Impacts

These adjusted LTFD scenarios are run through SPLASH, effectively modeling the full mid-century climate change impact in every year of the study. The impact on annual revenues was adjusted so that it would represent incremental climate change effects

[10] Based on data presented in SP-079 NFAT Confidential – Runoff Methodology Presentation for LCA, November 1, 2013, p. 9.

over time, beginning with no change in 2012/13 and increasing linearly[11] to the full (100%) revenue impact by 2050/51.[12]

The sensitivity analysis compares the NPV under the 5 climate change scenarios for the Preferred Plan, the K22/Gas plan, and the All Gas Plan. The All Gas Plan NPV improved relative to the Preferred Plan in the 5th percentile ($416M) and 25th percentile ($36M) streamflow cases, but worsened relative to the Preferred Plan in the 50th ($154M), 75th ($264M) and 95th ($448M) percentile cases. The benefits relative to the K22/Gas Plan ranged from $328 million less to $339 million more. The change in relative NPV benefits in MH's economic analysis is shown in Figure 4-4.

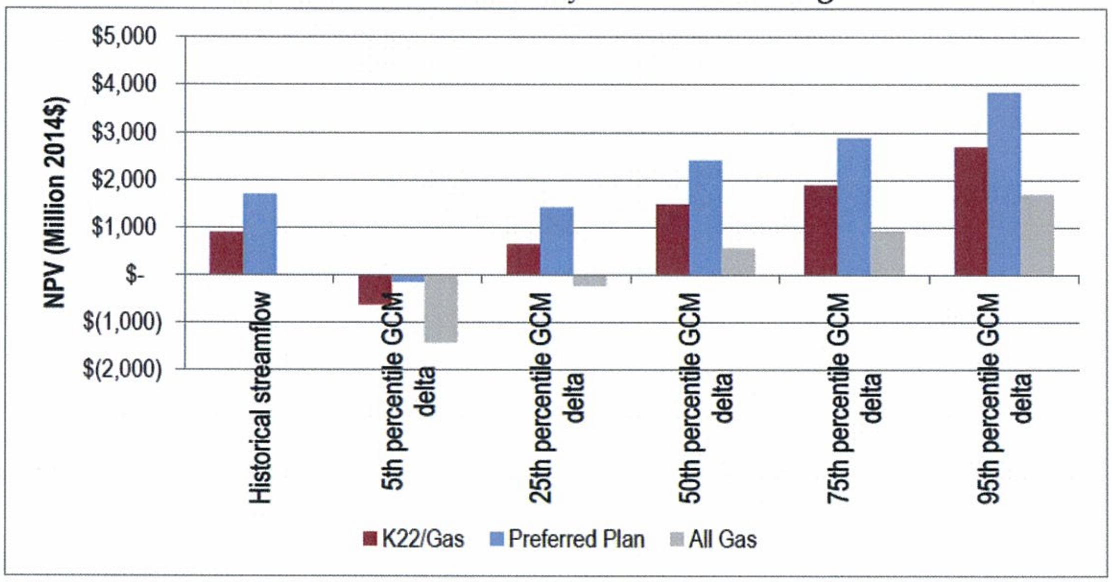


Figure 4-4: Incremental NPV (@ 5.05%) of the Preferred Development Plan and K22/Gas Plan Relative to the All Gas Plan, Reference Scenario [13]

Another takeaway is that the Preferred Plan, under reference scenario assumptions at least, had the greater upside potential and the greater downside risk compared to other development plans. The expected net benefits of the Preferred Plan relative to other

[11] Confirmed with MH that the phase-in of incremental revenue was done linearly on 10/25/13 Climate Change and Hydrology conference call. See also SP-129 NFAT Confidential – Climate Change sensitivity revenue calc.xlsx.

[12] NFAT Submission, Chapter 10, p. 45.

[13] Based on data from NFAT Submission, Chapter 10, Tables 10.9 and 10.10.

plans in most climate change scenarios is accompanied by a greater exposure to risk. The range of climate change impacts on NPV benefits of the three plans is shown in Figure 4-5.

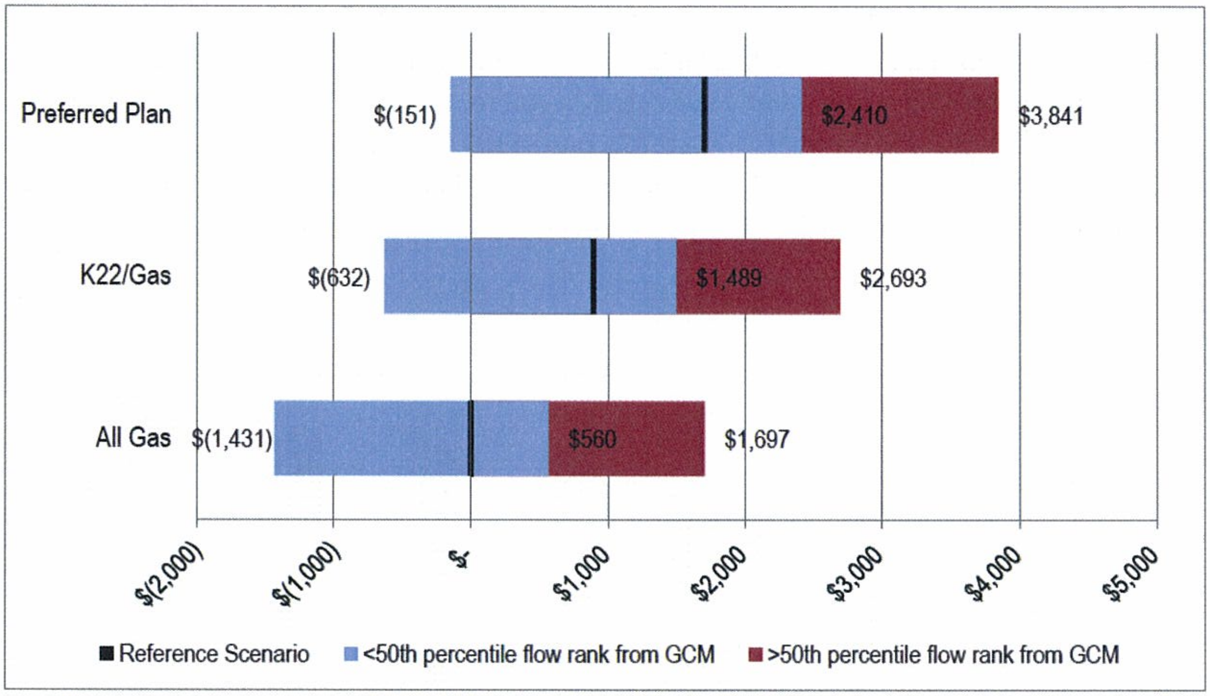
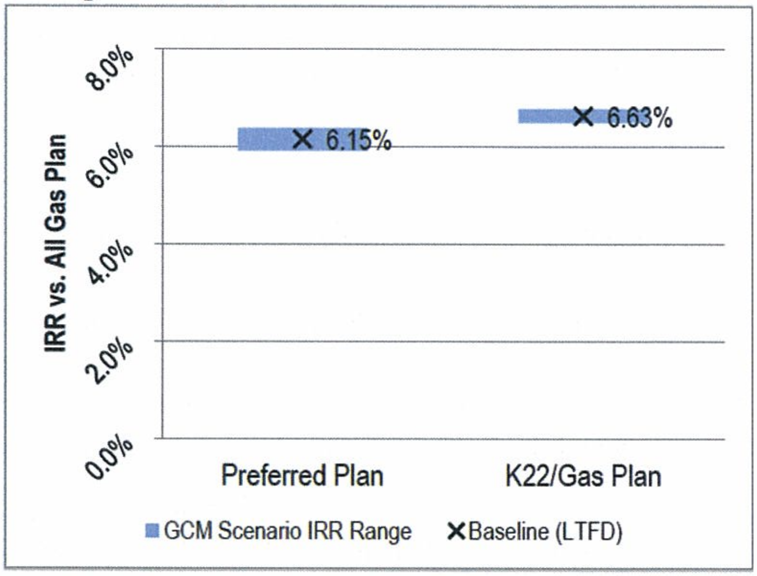


Figure 4-5: Incremental NPV (@ 5.05%) of the Preferred Development Plan and K22/Gas Plan Relative to the All Gas Plan, Reference Scenario [14]

Another way to put in perspective the potential impact of climate change on the economics of the various plans is with the Internal Rate of Return (IRR) metric. This metric is described in greater detail in Technical Appendix 9: Economic Analysis. LCA has developed an IRR metric that measures the IRR necessary for a development plan to have the same 78-year NPV as the All Gas plan. In the Reference Scenario with baseline (LTFD) streamflows, the Preferred Plan has an IRR relative to the All Gas Plan of 6.15%, and the K22/Gas Plan has an IRR relative to the All Gas Plan of 6.63%. La Capra Associates' analysis of MH's projected economic impacts of climate change shows very little impact on the IRRs. In the 5th percentile (low streamflow) GCM case, the plans' IRRs fell to 5.92% and 6.50%, respectively. In the 95th percentile (high streamflow) GCM case, the plans' IRRs rose to 6.39% and 6.78%, respectively. CONFIDENTIAL Figure 4-6

[14] Based on data from NFAT Submission, Chapter 10, Tables 10.9 and 10.10.

below illustrates the relatively tight range of IRRs for the two plans between all GCM cases (5th through 95th percentile).



CONFIDENTIAL Figure 4-6: 78-year IRR Relative to All Gas Plan for Baseline vs. GCM Scenario Streamflows (Reference Scenario)[15]

D. Methodological Shortcomings

Drought

One major shortcoming of MH's approach is that it fails to study climate change's potential impact on the probability and severity of future droughts. About 30% of the GCM scenarios project total average runoff to decline by mid-century, but no analysis is shown of whether the likelihood and severity of droughts may increase. It is also possible that even in scenarios with increases in average runoff expected, increased year-to-year variability could result in an elevated probability of a severe drought in any given year. This issue is also explored in MNP's report, when MNP notes that GCM's tend to predict both increased precipitation *and* increased instances of drought for northern locations such as Manitoba.[16]

[15] Based on data from SP-129 NFAT Confidential – Climate Change sensitivity revenue calc.

[16] MNP, "NFAT Review: A Review of Manitoba Hydro's Macro Environmental Considerations," p. 9.

The GCM results relied upon in MH's analysis reflect only changes to long-term averages rather than specific annual flows, so the streamflows during the more severe droughts in the LTFD are "hard-wired" into this analysis without change.[17] The impact of climate change on drought risk is essentially assumed away in the MH analysis framework.

Monthly/Seasonal and Geographic Granularity

MH has already recognized some of the shortfalls in its climate change modeling, and has begun on a three- to 5-year project to significantly improve its ability to model granular climate change impacts on the Nelson-Churchill watershed, particularly as it relates to the streamflow inputs that go into SPLASH.[18] The plan includes the following:

- Move to more granular forms of Global Climate Models (GCMs), or Regional Climate Models (RCMs), that capture more local effects (50km^2 resolution) not resolved in GCMs;
- Set up detailed hydrologic models (using WATFLOOD) of each river basin within the Nelson-Churchill watershed;
- Develop runoff scenarios to understand uncertainties within larger trends, such as changes in timing of spring freshet, frequency/magnitude of extreme events, etc.; and
- Translate new modeling into streamflow inputs for SPLASH.

MH's plan addresses some of the key critiques that we would offer of their methods, including the following:

- The method depends on the allocation of outputs in very large-resolution GCMs to smaller-resolution river basins. MH admits that not only the overall change in runoff, but the distribution of that runoff (how much falls in the Winnipeg River basin vs. the Saskatchewan, for example) can be very important to the results. Given the disparate impacts predicted for the five basins within each GCM scenario, this has to be considered a major assumption in the analysis.

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[17] NFAT Submission, Chapter 10, p. 45.

[18] NFAT Submission, Appendix K (Climate Change Report, FY 2012-13), pp. 10-15.

- The method depends on a single output from GCMs – runoff. No hydrological routing analysis is done.
- The deltas are estimated at the annual level, and no consideration is made for seasonal variation, storm intensity, and other factors that may be hidden within annual averages.

MH's climate change analysis for the NFAT submission does not provide conclusive findings on the economic advantages of the plans considered. Though MH's economic analysis shows positive economic value for the Preferred Development Plan in most GCM scenarios, it also displayed the greatest risk from climate change compared to two other development plans. However, the relative impact on different plans is minimal when compared to the scale of the investments over MH's 78-year economic study period. Furthermore, the analysis focuses only on long-term average flows and ignores climate change's potential impact on drought risk.

IV. Environmental Policy

MH's proposal to build new hydro resources is supported in part by claims that it results in lower environmental impact compared to building fossil-fired resources such as new combined cycle natural gas plants. This section explores MH's claims of environmental benefits provided by the Preferred Development Plan and the risks of changes in environmental policy.

A. Renewable Energy Certificate sale potential for new hydro

In its NFAT submission, MH states that it does not expect sales of unbundled Renewable Energy Certificates (RECs) to become a significant source of revenue in the future.[19] However, it does claim that long-term power sales often include bundled RECs and that this is an important feature of such contracts.[20] This section explores the potential for US Renewable Portfolio Standard (RPS) requirements to create a significant source of value for future hydro development in Manitoba.

RPS Requirements and Eligibility

The two current RPS policies that would be most relevant to MH are Minnesota and Wisconsin. Iowa has already met its RPS target and North Dakota and South Dakota have voluntary goals only.[21]

Minnesota's Renewable Energy Standard (RES) was established in 2007. Minnesota's RES requires electric utilities to procure 12% of retail sales from eligible renewable sources by 2012, escalating to 25% by 2025. Xcel Energy (Xcel), the state's largest utility and owner of Northern States Power, is held to a different standard: 15% by 2010, escalating to 30% by 2025. Xcel is further required to meet at least five-sixths of the 2025 requirement specifically with wind generation.

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[19] NFAT Submission, Chapter 5, p. 54:25-27.

[20] *Id.*, p. 55:4-9. For more on treatment of environmental attributes in Manitoba Hydro's long-term contracts, see Technical Appendix 7: Export Contracts.

[21] Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/rpsdata/index.cfm.

For Minnesota's RES, new or existing hydroelectric resources qualify with capacity up to 100MW. Some MH resources qualify, but a large percentage of the Minnesota RES must be met specifically with wind, so the amount that can be met with hydro is limited.

MH currently receives a small amount of REC revenue from selling Minnesota RECs from hydro assets less than 100 MW and also selling wind RECs.[22]

Wisconsin's RPS sets a target of 6% of statewide energy from renewable sources now, and 10% by 2015. Hydro resources less than 60MW are eligible now.[23] Beginning at the end of 2015, new large hydro (online after December 31, 2010) qualifies as well.[24] For MH to qualify, Manitoba must replace the interim licenses under which the Lake Winnipeg Regulation Project and the Churchill River Diversion Project currently operate with final licenses.[25]

RPS Markets

Based on the latest available information, it appears that neither Minnesota nor Wisconsin will be short of renewable supply under current policies.

Both Minnesota and Wisconsin are part of the Midwest Renewable Energy Tracking System (M-RETS), which allows for regional trading of RECs. LCA has broker quotes from Illinois, another M-RETS participant, and they are in the <$1.00/MWh range.[26] The most recent state reports on RPS compliance do not provide specific REC prices,

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[22] NFAT Submission, Chapter 5, p. 54:23-25.

[23] Eligible generation from small hydropower includes: a) all hydropower generation purchased in the reporting year; b) average amounts generated by owned hydropower resources in 2001-2003 adjusted to reflect dam removal or capacity increases since that time; and c) all hydropower generated in the reporting year from owned resources put in service after January 1, 2004. For more see DSIRE.org at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=WI05R&re=0&ee=0.

[24] Per S.B. 81 (2011 WI Act 34) https://docs.legis.wisconsin.gov/2011/related/acts/34.

[25] For more on licensing the Lake Winnipeg Regulation Project and the Churchill River Diversion Project see http://www.hydro.mb.ca/corporate/water_regimes/lake_wpg_regulation_final_licence.shtml; and http://www.gov.mb.ca/waterstewardship/licensing/churchill_river_diversion.html.

[26] MAREX Spectrometer reports.

but they both indicate that obligated entities are complying without difficulty.[27] Based on the schedule of requirement increases and the current pace of renewable project development, there is no reason to believe that Midwestern REC markets will go from oversupply to undersupply absent policy change. As long as REC markets are oversupplied with price-taking generators (predominantly wind), REC prices can be expected to be minimal.

Wisconsin is opening its RPS to MH *after* its RPS requirement has reached its peak level of 10 percent of retail sales. The most recent Public Service Commission of Wisconsin Strategic Energy Assessment shows that through 2011 renewable energy sales have far outpaced RPS requirements, and are on track to reach 2015 requirement levels years in advance (see Figure 4-7). If the target has been exceeded before the change in eligibility allows new MH units to qualify, then incremental eligible MH generation will drive the market further into oversupply, reinforcing negative REC price pressure.

[27] Minnesota Dept. of Commerce Report to Legislature on Renewable Energy Standard Compliance (Jan 2013): http://mn.gov/commerce/energy/images/2013RESLegReport.pdf ; Public Service Commission of Wisconsin Report on the Rate and Revenue Impacts of the Wisconsin Renewable Portfolio Standard (Docket 5-GF-220): http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=166782.

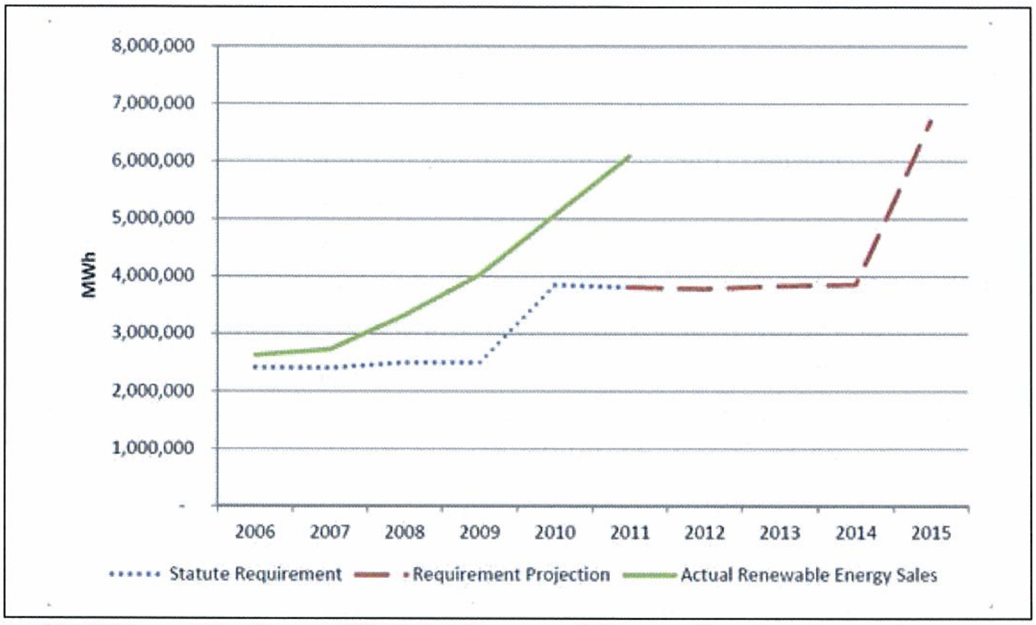

Figure 4-7: Wisconsin Statewide RPS Renewable Retail Sales (Actual vs. Required, 2006-2015)[28]

MH also mentions voluntary credit markets.[29] These have existed for a long time and have never provided significant REC prices. Available broker quotes for Green-e certificates (the US version) are trading in the ~$1.00/MWh range,[30] and have been as long as LCA has tracked these prices.

<u>**RPS policies and the "Window of Opportunity"**</u>

As part of the NFAT Submission, MH discusses a "window of opportunity" for a new transmission interconnection with the US to facilitate expanded exports of surplus hydroelectric power. One of the factors MH discusses is state RPS requirements.[31] As discussed throughout this Section of the Appendix, current US RPS requirements are primarily focused on increasing US wind generation capacity, not Canadian hydro

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[28] Public Service Commission of Wisconsin. (Nov 2012) Final Strategic Energy Assessment: Energy 2018, p. 46. http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=176432.

[29] NFAT submission, Chapter 5, p. 54:14-23.

[30] MAREX Spectrometer reports.

[31] NFAT Submission, Chapter 6, p. 5:5.

capacity. MH argues that MISO has plans to build new transmission to integrate new wind generation to meet RPS requirements and that once this transmission is built, it may become more difficult to find support for additional transmission, including an interconnection between the US and Canada.[32] LCA agrees that significant new transmission will likely be necessary to integrate new wind in MISO. What is less clear is whether such transmission would remove incentives for a new interconnection between the US and Canada. MH discusses the potential for wind-hydro synergy benefits.[33] The determining factor for whether new transmission built to integrate wind will reduce incentives for a new interconnection is whether such transmission will decrease the potential for wind synergy benefits. For more information on wind-hydro synergy and the recent MISO "Manitoba Hydro Wind Synergy Study," see Technical Appendix 8: Transmission.

Potential REC Revenues and Risks

Given the state of the RPS markets in the Midwestern US, MH's conclusion that unbundled REC sales are unlikely to provide a significant stream of future revenue appears reasonable. It is not clear to what extent bundled RECs are assumed to contribute to projected long-term power sale prices. The premium pricing assumed for "non-committed" firm sales should not be dependent on anticipated REC value in the future. For more on non-committed firm sales, see Technical Appendix 6: Export Markets.

B. Emissions pricing impacts

MH has incorporated carbon pricing into its economic analysis. There are two different carbon price forecasts: one used for developing MISO export market prices and one used for determining the costs of dispatching MH's own thermal generation.

MISO Carbon Price Forecast

MH relies on its suite of consultants to create a carbon price outlook in MISO.[34] For the 2012 Adjusted forecast, carbon pricing is assumed to begin in the [redacted] fiscal year for

[32] *Id.* p. 5:22-27.

[33] *Id.* pp. 20:10-24:2.

[34] For more on MISO pricing assumptions, see Technical Appendix 6: Export Markets.

the reference and high price cases. For the low case, carbon pricing is [redacted].[35] The chart below shows the price assumptions.

[redacted]

CONFIDENTIAL Figure 4-8: Manitoba Hydro's MISO carbon price forecast used for 2012 Adjusted forecast.[36]

Because the 2012 Adjusted price forecast is based on a regression, it is possible to chart the exact contribution of carbon price and natural gas price to the total electricity price. The charts below show this for both reference peak, reference off-peak and long-term dependable electricity prices. Carbon prices make up about [redacted] of off-peak electricity prices, about [redacted] of peak opportunity electricity prices, and about [redacted] of long-term dependable electricity prices. This is small compared to the overall spread in prices evaluated in MH's uncertainty analysis in the NFAT Submission, which varied peak electricity prices between 40% and 50% both on the high and low sides and 40% to 50% on the low side for off-peak electricity prices and 40% to 60% on the high side for off-peak electricity prices.[37]

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[35] The EEPF originally had a price of less than $1/ton for the low case.

[36] SP-010 NFAT Confidential 2012 Adjusted Electricity Export Price Forecast.

[37] CONFIDENTIAL PUB/MH I-056b.

[redacted]

CONFIDENTIAL Figure 4-9: Contribution of carbon price and other factors to the 2012 Adjusted off-peak reference export energy price forecast.[38]

[redacted]

CONFIDENTIAL Figure 4-10: Contribution of carbon price and other factors to the 2012 Adjusted peak reference export energy price forecast.[39]

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[38] SP-010 NFAT Confidential 2012 Adjusted Electricity Export Price Forecast.

[39] *Id.*

[redacted]

CONFIDENTIAL Figure 4-11: Contribution of carbon price and other factors to the 2012 Adjusted peak reference export energy price forecast.[40]

MNP has performed an analysis of the value of carbon displacement under certain assumptions regarding the marginal generating unit in MISO and different carbon prices for four separate development plans.[41] MNP examined the value of total carbon displaced.

Using the regression results described above, a similar analysis can be performed, but on the difference between the All Gas and Preferred Development Plan. To get a first order approximation of the impact of carbon prices on the difference in total export revenues between these cases, LCA reduced the difference in export revenues between the All Gas and Preferred Development Plans for the reference case by the amount of the price forecast attributable to carbon as shown in the red areas in CONFIDENTIAL Figures 4-9 to 4-11. Off-peak and peak opportunity sales revenues along with "non-committed" firm sales revenues were all reduced using the percentages for off-peak, peak, and long-term dependable electricity price forecasts respectively.[42] Since the regression to estimate the 2012 Adjusted forecast was only performed for the first

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[40] SP-010 NFAT Confidential 2012 Adjusted Electricity Export Price Forecast

[41] MNP, "NFAT Review: A Review of Manitoba Hydro's Macro Environmental Considerations," pp. 33-35.

[42] For more information on Manitoba Hydro's electricity price forecasting and export modeling process, see Technical Appendix 6: Export Markets.

twenty years of the forecast period, after this period, the percentage reductions were held constant. No change was made to the costs of thermal generation in Manitoba, so the analysis only tests the sensitivity of revenues to carbon price assumptions in export markets. The results are summarized below.

	Off-Peak Opportunity Sales	Peak Opportunity Sales	"Non-Committed" Firm Sales	Contracted Firm Sales	Total Export Sales	Total NPV
NPV of Revenue Difference Attributable to Carbon Pricing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NPV of Total Revenue Difference	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,696
Percent of Total Revenue Difference Attributable to Carbon Pricing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL Figure 4-12: Portion of the difference in export revenues between the All Gas and Preferred Development Plans attributable to carbon pricing. NPVs are through 2090 using Manitoba Hydro's reference discount rate of 5.05%.[43]

Further analysis of the impact of carbon pricing on the economics of the Preferred Development Plan will be presented in Technical Appendix 9B: Economic Analysis.

Manitoba Carbon Price Forecast

The Manitoba carbon price forecast can be found in Appendix S of the Confidential 2012/13 Power Resource Plan. Although it converges on the consensus price forecast used in the MISO region in the long-term, it differs from the forecast in the following ways:

1) There are separate forecasts for coal and natural gas-fired generation. The coal forecast includes [redacted] on CO_2 emissions from coal-fired generation. Since coal-fired generation is restricted to emergency use in Manitoba, this assumption is expected to have virtually no impact on the NFAT

[43] SP-010 NFAT Confidential 2012 Adjusted Electricity Export Price Forecast; SP-011 NFAT Confidential - Economic Cash Flows.

analysis results compared do a case where the same carbon price was used in both Manitoba and in export markets.

2) The reference carbon price for natural gas-fired generation is [redacted]. However, since the All Gas case does not add new natural gas-fired generation until after 2020/21, similar to the case of coal generation, this is also expected to have virtually no impact on the NFAT analysis results.
3) The high carbon price applies [redacted] This means the Manitoba high carbon price is [redacted] This could make a small impact on the NFAT analysis as the All Gas case adds new natural gas-fired generation in 2022. However, the generation added is SCGT capacity, which is not expected to dispatch at a high capacity factor. Combined cycle capacity is added only after 2031 when the carbon price assumptions would be the same.

2013/14 Update Forecast

The 2013/14 Update analysis included a revised electricity price forecast that included an update of carbon assumptions from the consultants.[44] The updated values compared to the values used in the 2012 Adjusted forecast are shown in the figure below. [redacted], but the reference and high forecasts decrease from the 2012 Adjusted forecast levels. The high case also has [redacted] starting earlier than the 2012 Adjusted forecast. However, only the reference case was used in the 2013 Update analysis.

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[44] NFAT Submission, Appendix 9.3, pp. 12-14.

This report contains information that has been deemed Commercially Sensitive Information and is, therefore, subject to a protective order.

[redacted]

CONFIDENTIAL Figure 4-13: Comparison of carbon price forecasts for MISO region used in the 2013/14 Update electricity price forecast and the 2012 Adjusted electricity price forecast.[45]

Since the carbon price forecast decreases relative to the 2012 Adjusted forecast when the total updated price forecast increases compared to the 2012 Adjusted forecast, this indicates that carbon price would be an even smaller part of the total electricity price forecast. Therefore, eliminating the carbon price from the forecast would likely have a lower impact on the export revenues in the 2013/14 Update analysis reference case than is shown in Figure 12 for the 2012 Analysis.

Conclusions

Although not the largest determinant of potential export revenues for new hydro development in Manitoba, carbon pricing is an important assumption with significant uncertainty. The analysis presented here, is only one attempt to quantify the impact of

[45] SP-010 2012 Adjusted Electricity Export Price Forecast spreadsheet and the 2013 Electricity Export Price Forecast document provided on paper as CSI.

MH's carbon pricing assumptions in its NFAT analysis. MNP has developed an independent view of forecasted carbon prices, which is summarized in its report.[46] This view will be incorporated into future price sensitivity analysis of the economics of the Preferred Development Plan performed by LCA, which will be presented in Technical Appendix 9B.

C. Additional clean energy policies

MH assumes that excess hydroelectric generation, but not natural gas generation, can be sold on a firm basis at a premium price because MH "is at a competitive disadvantage in the export of new natural gas-fired generation."[47]. In terms of environmental attributes,[48] hydro power exports have advantages over natural gas generation exports. First, they may qualify to receive REC revenues under US RPS policies as discussed in Section A above. Second, hydro power has lower carbon emissions, which could increase its market value if the US implements a comprehensive carbon tax or cap and trade policy, as discussed in Section B above. In addition to these policies, other clean energy polices in the US create incentives for US utilities to import hydro power from Manitoba.

Minnesota has the most aggressive carbon emission policies of any of potential US market. Minnesota's Next Generation Energy Act of 2007 established statewide greenhouse gas emissions-reduction goals of 15% below 2005 levels by 2015, 30 percent below 2005 levels by 2025, and 80 percent below 2005 levels by 2050 (Minn. Stat. §216H.02). With certain exceptions, the law prohibits the development of or importation from new large energy facilities, or the signing of any long-term PPA,[49] which would increase statewide power sector carbon dioxide emissions (Minn. Stat. §216H.03). Furthermore, the Minnesota Public Utilities Commission is required to establish an estimate of future carbon dioxide regulation costs for incorporation in resource planning and generation acquisition proceedings (Minn. Stat. §216H.03).[50] The most

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[46] MNP, "NFAT Review: A Review of Manitoba Hydro's Macro Environmental Considerations," pp. 28-36.

[47] CONFIDENTIAL PUB/MH II-345a.

[48] For more on other issues related to the feasibility of expanding exports of natural gas-fired generation, see Technical Appendix 6: Export Markets.

[49] Defined as at least 50MW for at least 5 years.

[50] The Next Generation Energy Act of 2007 is discussed in the NFAT Submission, Chapter 3, p. 20.

recent Minnesota Public Utilities Commission order established a range of $9 to $34 per ton as the range of CO_2 costs for utilities to use in resource planning as of 2017.[51]

As a result of the Next Generation Energy Act of 2007 and subsequent implementation actions, a premium is placed on low carbon emission resources by Minnesota utilities. The restrictions also reduce the range of resource alternatives competing with MH contracts as future supply options.

No similar binding carbon emissions-reduction goals exist in Wisconsin or North Dakota.

Any change away from these policies and toward relaxing restrictions on fossil fuel generation would negatively impact MH's ability to export hydro power on a firm basis. For more on the potential impacts of the reduction in firm sales potential, see Technical Appendix 6: Export Markets.

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[51] Order Establishing 2012 and 2013 Estimate of Future Carbon Dioxide Regulation Costs, 11/2/2012, Docket No. E-999/CI-07-1199.

V. Summary and Conclusions

LCA has completed a review of important environmental issues and policies that impact the NFAT analysis in five key areas:

1) Changes to the water regime from new hydro development in Manitoba
2) Climate change impacts on the water regime and economics of the Preferred Development Plan
3) Potential for US REC revenues from Manitoba hydropower exports
4) Impact of MH's carbon pricing assumptions on the economics of the Preferred Development Plan
5) Additional US environmental policies that impact Manitoba hydropower export potential

Manitoba water regime impacts from the development of Keeyask and Conawapa are expected to be minimal. No significant changes in reservoir operations are expected. The only small impact is that the addition of Keeyask may decrease the total potential output from Kettle due to limitations in Stephens Lake water levels. Using MH's current planning assumptions, Kettle's generating capacity would decrease by 65 MW.

Using data from GCMs, MH performed climate change sensitivity modeling to assess the impact of climate change on water inflows and hydro generation. Although most GCM scenarios predict higher runoff levels, increasing potential hydropower generation, the total impact of the increase is not expected to create a meaningful benefit to the overall economics of the Preferred Development Plan. This analysis also has significant shortcomings in that it neither addresses the potential for increased frequency or magnitude of drought nor involves detailed hydrological modeling. MH continues to evaluate the potential impacts of climate change on hydropower generation in Manitoba, which eventually may shed more light on the issue of increased drought.

Although MH does receive some financial benefits from the sales of RECs to US RPS markets, they are not expected to become a significant source of revenue for the Preferred Development Plan. This is mainly due to the fact that US RPS policies focus on wind generation development.

According to MH's electricity pricing forecast methodology, carbon prices are responsible for approximately [redacted] of its assumed export prices starting in [redacted] depending on the year and type of pricing, namely whether off-peak, short-term peak, or long-term firm. More on the impact of carbon pricing assumptions on the economics of the Preferred Development Plan will be presented in Technical Appendix 9B: Economic Analysis.

Finally, although US RPS policy is not a significant direct driver of new Canadian large hydro investment, other US state environmental policies, such as Minnesota's goal to reduce greenhouse gas emissions, are an important factor when considering the potential for exports of clean energy from Manitoba to MISO.