NEEDS FOR AND ALTERNATIVES TO (NFAT)

REVIEW OF MANITOBA HYDRO'S

PREFERRED DEVELOPMENT PLAN (PDP)

REPORT PREPARED FOR

THE MANITOBA METIS FEDERATION

BY

WHITFIELD RUSSELL ASSOCIATES

FEBRUARY 12, 2014

Whitfield Russell Associates
4232 King Street
Alexandria, VA 22302
703-894-2200
www.wrassoc.com

TABLE OF CONTENTS

INTRODUCTION AND CAVEATS

Whitfield Russell Associates ("WRA") was retained to review and analyze Manitoba Hydro's Preferred Development Plan ("PDP" or "Plan") on behalf of the Manitoba Métis Federation ("MMF"). In particular, WRA has focused its examination on the Terms of Reference - Needs For and Alternatives To ("NFAT") Review number 2.g as identified by the Manitoba Public Utilities Board ("PUB") in Procedural Order 67/13. This term of reference is as follows:

> 2. An assessment as to whether the Plan is justified as superior to potential alternatives that could fulfill the need. The assessment will take the following factors into consideration:
>
> . . . .
>
> g. The financial and economic risks of the Plan and export contracts and export opportunity revenues in relation to alternative development strategies;

However, the MMF has been frustrated in its attempts to evaluate the financial and economic risks of the PDP and export contracts by its inability to gain access to the vast majority of information that Manitoba Hydro provided to the Independent Expert Consultants ("IECs"). Because of this lack of access, the MMF has encountered considerable difficulty analyzing the details of the various alternative plans, their underlying assumptions, the costs and benefits of each alternative, and how these relate to the concerns of the Manitoba Métis Community. Many questions asked by the IECs were similar to those that MMF would have asked. And many of the answers came as follows:

> "This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro."[1]

Many other data responses were considered to be commercially sensitive and were therefore not made available to the general public. See, for example, responses to MMF/MH II-015, II-016d and II-019h. The opaqueness is exacerbated by redactions in the IEC evidence.

[1] See, for example, LCA/MH 1-029 thru 032, among many others. Also troubling is the lack of transparency with regard to pricing of exports versus costs of the two proposed hydroelectric generation projects, Keeyask and Conawapa.

Most troubling to the MMF is that, as noted in the Terms of Reference at page 4, the scope of the NFAT does not include the Bipole III high voltage direct current ("HVDC") transmission line and converter station project. Of particular importance is Manitoba Hydro's stance that Bipole III is needed primarily for reliability purposes, and thus (somehow), no NFAT review was needed for this particular facility. One would think that a "Need for and Alternative To" review would have been required for a $3.3 billion facility traversing a large portion of the Province.[2] According to PUB Order 5/12, however, the PUB decided that a needs analysis was not required for Bipole III, and, accordingly, the Terms of Reference in this proceeding exclude Bipole III and its converter stations from the scope of the NFAT.

Manitoba Hydro's underlying assumption that each and every alternative should include Bipole III has the effect of understating the cost of the Preferred Development Plan and greatly overstating the cost and relative economics of certain alternatives—primarily those that do not include future hydro generation or that involve deferrals of Northern hydro development.

In short, the PDP of Manitoba Hydro consists of building two large hydro generating stations on the Nelson River (Keeyask Generating Station in 2019 and the Conawapa Generation Station in 2026), both of which will make use of the additional transmission capacity added by Bipole III. The PDP also includes North-South Transmission Upgrades which involve changes to the alternating current ("AC") collector system of the hydro plants on the Nelson River, as well as additional AC transmission lines. Finally, the PDP includes a transmission link with the United States—the Manitoba-Minnesota Transmission Project, which will enable Manitoba Hydro to export substantial additional bulk power to various utilities in the Midcontinent Independent System Operator, Inc. ("MISO"). As part of the NFAT, Manitoba Hydro analyzed 15 separate alternative plans that could provide the necessary energy and capacity for Manitoba's forecasted domestic loads, as well as planned exports to MISO utilities.

Manitoba Hydro described the need for Bipole III as follows in Chapter 5 of the NFAT (at 25:8 – 26:2).

[2] See PUB/MH I-053a Revised for the estimated cost of Bipole III.

> Approximately 70% of Manitoba's hydro-electric generating capacity is delivered to southern Manitoba via the Bipole I and Bipole II HVDC transmission lines. Bipoles I and II share the same transmission corridor through the Interlake region over much of their length from northern Manitoba to a common terminus at the Dorsey Converter Station. The existing transmission system is therefore vulnerable to the risk of catastrophic outages of either (or both) Bipoles I and II in the Interlake corridor and/or at Dorsey due to unpredictable events, particularly severe weather. This vulnerability, combined with the significant consequences of prolonged major outages, caused Manitoba Hydro to pursue a major initiative to reduce dependence on the Dorsey Converter Station and the existing HVDC Interlake transmission corridor.

However, as will be discussed in more detail below, Manitoba Hydro's reasoning in support of the reliability need for Bipole III is flawed. Indeed, Manitoba Hydro's PDP will put more eggs in the Northern hydro basket, fill the reserve transmission capacity to be provided initially by Bipole III and return Manitoba Hydro to its dependence on the HVDC Interlake transmission corridor.

THE 78-YEAR STUDY PERIOD IS TOO LONG

Manitoba Hydro's use of an extremely long study period (78 years) serves the purpose of tilting its economic analysis in favor of long-lived assets such as hydro projects that are projected to generate substantial off-system sales revenue. Initially, Manitoba Hydro noted that "The next step was to develop and evaluate potential alternative development plans using the short-listed resource options. The number and size of resource options were selected to cover Manitoba's energy and capacity needs for the next 35 years." See Executive Summary at 17:14-16. However, actual economic evaluations were based on the much longer 78-year time period, as described in Chapter 9 at 7:15-18:

> The total study life used in this analysis is 78-years. For the total study life, Manitoba Hydro combines two approaches – a 35-year detailed evaluation and a long-life asset evaluation which extends from the end of the 35-year study period to the end of the service life of hydro-electric generation assets, as representing the longest-lived assets.

Manitoba Hydro's response to LCA/MH 1-189 notes that the 78-year study length was determined by using the weighted average life of the hydro plants (67) years, extending from the 2025, when the Conawapa Project was initially assumed to go into service. Attachment A of the response to PUB/MH 1-020a indicates that other study periods of Manitoba Hydro tend to range from 10 to 35 years. Indeed, Manitoba Hydro's Integrated Financial Forecast ("IFF") uses a 20-year projection, while its Power Resource Plan looks forward 35 years.[3]

As a result, Manitoba Hydro's economic evaluations of its alternative plans mask the negative aspects of the financial burdens associated with capital-intensive hydro plans, and give unwarranted value to exports to the United States. Manitoba Hydro admits that these hydro-intensive plans cause a need for rate increases that, in the "medium" term (if 20 and 35 years are considered medium term), are projected to be higher than the rate increases necessary to support alternative resource plans with no hydro additions, or only one future hydro plant addition. For example, Manitoba Hydro states in Chapter 11 of the NFAT report:

> By 2035, following the in-service of both Keeyask and Conawapa, the cumulative rate increases for the Preferred Development Plan (green) begin to beneficially separate from the alternatives. By 2040, the cumulative rate increases for the Preferred Development Plan are lower than [those required in connection with] all other development plans as measured by the P10, P25, P50, P75 and P90 values.[4]

Therefore, nearly 26 years must elapse before the PDP lowers the cumulative rates paid by Manitoba consumers. Before 26 years, the cumulative rates required to support other alternative plans will be lower. And during these 26 years, many of the favorable conditions assumed to underlie these studies may not develop. Actual conditions could differ drastically from the favorable conditions assumed in Manitoba Hydro's studies. Furthermore, it is during this first quarter century initial period (e.g., until Manitoba loads increase and eat into its ability to export power) that revenues from exports are expected to be most significant in amount and value (as measured on a net present value basis). If assumed margins on export sales turn out to be overestimated, even greater rate increases will be required.

Manitoba Hydro's response to PUB/MH 1-149a REVISED shows the impact on customers of rates based on different alternative resource plans. It states:

---

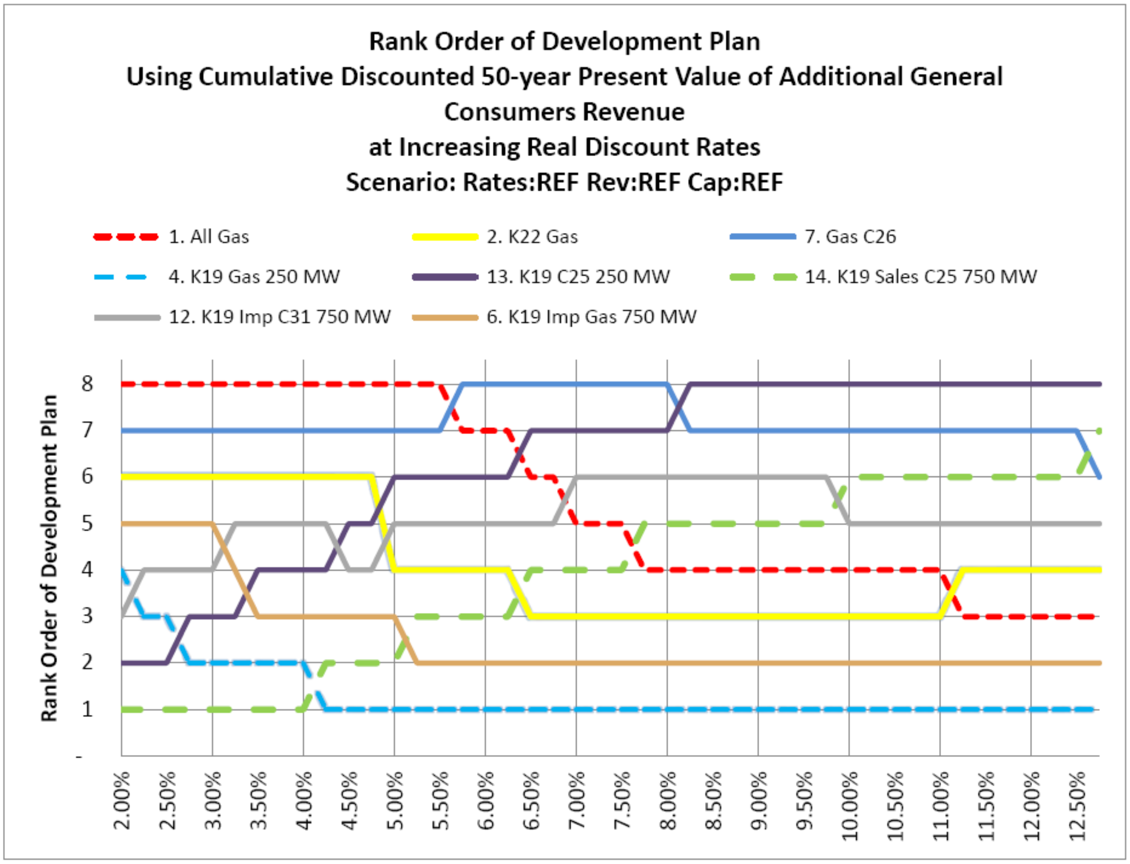
[3] See NFAT Appendix B at 19.

[4] See Chapter 11 at 8:14-9:2.

Figure 11.10 shows the impacts on customer rates (seen in Figure 11.1, 1 Chapter 11, page 8) on a present value basis and represents the projected cumulative present value of total general consumers' revenue for the 50 year study period. Figure 11.10 shows that:

- In the near term, by 2020, the cumulative present values for the various alternatives are relatively similar.
- By 2030, the cumulative present value of the capital-intensive plans that include both Keeyask and Conawapa are generally higher than [those associated with] the other alternatives.
- Between 2030 and 2050, K19/Gas/250 (light blue) is projected to have the lowest cumulative present value at the P50 value.
- From 2050 to the end of the study period, the preferred development plan (green) is projected to have the lowest cumulative present value at the P50 value.

This same data response indicates that Manitoba Hydro performed a sensitivity analysis of the discount rate on the various alternatives, and noted that "the Preferred Development Plan provides the lowest customer bill impacts on a present value basis up to a real discount rate of approximately 4.15%." What Manitoba Hydro did not say, however, was that another alternative, the K19 Gas 250 MW alternative was better at every single higher discount rate. See the table below, included in the data response as Figure 11.13:



One of the IECs, Elenchus, submitted a review of Manitoba Hydro's load forecast. In its report, Elenchus noted that (at i) "given the time frame of the NFAT analysis, it is our view that it is more reasonable to anticipate that there will be significant structural changes that could result in dramatically different domestic demand (and presumably export prices) in the coming decades." Elenchus also notes (at iii): "Forecasting over a 20-year time horizon has many associated risks." The fact that Manitoba Hydro has instead performed its economic evaluation of alternatives using a 78-year study period, including forecasting future energy prices and revenues, throws into doubt many, if not all, of its conclusions and plans. Elenchus mentions the possibilities inherent in increased demand side management and energy efficiency measures, as well as the real risk of distributed generation for lowering demand in the future.

The risks that Elenchus (and other IECs) describe are very real. For example, looking back to the decade of the 1990s, it is doubtful that forecasters predicted the recession period of 2008-2012, or the boom of shale gas production. Other recent changes include the rapidly decreasing costs of wind power and solar power, as well as energy efficiency gains through the use of LED lights, which has led to lower load growth.

Manitoba Hydro admits itself that the excessive study period involves a lack of detailed inputs and assumptions, as stated in response to LCA/MH 1-218.

> The financial evaluation in Chapter 11 is a full revenue and cost analysis of Manitoba Hydro's entire electric operations, including the impacts of the current and proposed integrated hydro electric system, as compared to the incremental analysis, which includes the development plan specific inputs only, in the economic and uncertainty evaluations in Chapters 9 and 10. The 50-year period is an extension of the detailed 35-year evaluation period to be consistent with the long-term nature of hydro-electricity assets as well as provide a sufficient timeframe for which to analyze the benefits and costs for each development. Financial evaluation over a longer timeframe is limited due to the lack of availability of the detailed inputs and assumptions required by the financial model related to the entire integrated hydro-electric system both current and proposed rather than the availability of development plan specific inputs and assumptions.

If the economic study period is reduced to 35 years, the PDP is no longer the best plan, although Manitoba Hydro puts the best face on the PDP by stating that the "key conclusions from the probabilistic analysis provided in Chapter 10 do not change significantly whether assuming a total study life of 78 years, as provided in the NFAT submission, or a 35 year study period." See LCA/MH 1-397. This same response notes that "The Preferred Development Plan (Plan 14) and Plan 4 [K19/Gas24/250MW] have essentially the same incremental NPV under the reference scenario. <u>Plan 4 has a higher expected value by $226 million</u>." Emphasis added. Exactly how an amount that is $226 million higher is "essentially the same" as another amount remains unexplained.

La Capra Associates, Inc. ("LCA"), another IEC, has also discussed the risks relating to Manitoba Hydro's 78 year study period. Please see LCA's Technical Appendix 9A "Economic Analysis Part 1" at 9A-24f. In fact, LCA re-ran many studies using shorter study periods in order to better illustrate the impacts of the various alternative scenarios.

DETAILS ON EXPORT REVENUE AND PRICES ARE UNAVAILABLE OR INADEQUATE AND SUBJECT TO RISK

WRA has had a difficult time determining what portion of the net benefits of each alternative are related to the expected future sales to, and prices in, the MISO. Potomac Economics, one of the IECs, has found that Manitoba Hydro's forecast of future gas prices and export sales revenue are overstated, which has the effect of overstating the net benefit of the Preferred Development Plan. Potomac Economics stated at page 5 of its Expert Report on Export Prices and Revenues ("Report"):

> Our results generally forecast lower prices than Manitoba Hydro's consultants due to assumptions on key inputs. In particular, our models generally rely on lower natural gas price forecasts, lower growth rates of demand, and lower quantities of coal plant retirements.

Potomac Economics' Report also states later at page 11 that at least one consultant, the Brattle Group, used a much higher price for a combustion turbine to calculate the Cost of New Entry ("CONE") that was 70% higher than that used by Potomac Economics. Obviously, assuming a higher price for a gas-fired combustion turbine will favor the PDP and place gas-fired alternatives at a disadvantage. However, a prospective buyer of Manitoba Hydro's dependable power will not be misled. It will evaluate a purchase from Manitoba Hydro based on the real, lower cost of a gas-fired combustion turbine.

Importantly, Potomac Economics noted the following at page 45 of its Report:

> Manitoba Hydro's Consultants provide forecasts to 2034. However, Manitoba Hydro projects revenues until 2080. To calculate the forward revenues, Manitoba Hydro assumes a growth rate for the years 2035-2049 based on the compound average growth rate ("CAGR") for the years 2030-2034, but declining to a growth rate of zero by 2049. Basically, growth rates in prices are linearly interpolated between the value equal to the average CAGR for the years 2030-2034 and zero value for 2049. After 2049, growth rates in prices are assumed to be zero.
>
> <u>With regard to capacity prices, we find no basis for assuming the real price will increase after 2034. For reasons stated above, such prices may even decline. For energy prices, we find it difficult to recommend an approach that would be reliable given the long-term nature of this assumption</u>. We recommend that alternative post 2034 growth rates be

> examined in order to understand the sensitivity of the results to alternative growth assumptions. At least one such sensitivity should be a zero real growth rate, which would effectively assume that fuel prices and C02 prices escalate at the rate of inflation after 2034. [Emphasis added]

WRA was not allowed to view any detailed material on Manitoba Hydro's forecast energy and capacity prices. Although Manitoba Hydro's NFAT Appendix 9.3 provides documentation on each alternative (and on each sensitivity study) on an annual basis, the tables show only Net Average Flow Related Gross Revenue (in millions of 2014$). According to Appendix 9.3 at 87, this gross revenue includes only revenues from exports.

> Gross revenue incorporates the revenue from both firm export power sales and the sale of short-term opportunity export energy. Gross revenue does not include domestic revenue as it is common to all development plans. Expected export revenues are generated from the SPLASH model and are a function of the makeup of each development plan within the context of the whole Manitoba Hydro generation and transmission system and the interconnected markets.

Because the energy contract prices from the firm export sales have not been made available in usable form,[5] and because the Electricity Export Price Forecasts are deemed commercially sensitive (see response to PUB/MH 1-056a), WRA has not been able to delve into the details of the economic alternatives. However, material that has been provided makes clear that electric export prices over the past five years have fallen drastically, and that forecasts of export prices over time have demonstrated the same reductions. Although Manitoba Hydro concludes that its PDP, with its long study length and reliance on as-yet-unrevealed amounts of energy at as-yet-unrevealed prices to provide much of its value, is the best for the Province, that conclusion appears to be based upon a shaky foundation.

Recent sales to the United States have suffered the effects of the Great Recession. One table from the response to PUB/MH 1-008 REVISED illustrates how the past exports to the U.S. have fallen in price over the past six years, particularly the opportunity sales (which do not include prices under the firm export contracts). This table compares the revenues per megawatthour ("MWH") average price.

[5] PUB/MH 1-280 provides a summary table of the volumes, term and pricing assumptions used in the Integrated Financial Forecasts ("IFF") for 2009 and 2012 for the export term sheets/contracts.

NFAT PUB/MH I-008 Revised									
TOTAL U.S. SALES									
	U.S. Dependable Sales			U.S. Opportunity Sales			U.S. System Merchant Sales		
Year	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2000/01	4,895	199	40.69	4,511	167	36.95	0	0	0.00
2001/02	4,767	263	55.15	5,083	247	48.66	0	0	0.00
2002/03	4,947	277	56.09	2,713	115	42.30	0	0	0.00
2003/04	5,245	259	49.45	507	35	69.42	0	0	0.00
2004/05	5,633	290	51.44	3,218	171	54.48	109	1	10.64
2005/06	4,044	240	59.25	8,879	401	45.12	0	0	0.00
2006/07	3,654	218	59.67	5,877	270	46.24	0	0	0.00
2007/08	3,921	209	53.22	6,618	289	44.19	0	0	0.00
2008/09	4,087	233	57.12	5,622	237	43.24	0	0	0.00
2009/10	3,263	186	56.99	7,224	160	22.28	33	2	0.00
2010/11	3,377	172	51.09	6,062	146	24.44	5	0.3	37.82
2011/12	3,742	175	46.79	5,616	117	21.13	80	3	35.21
2012/13	3,636	177	48.69	4,690	113	23.62	63	2	29.92

Manitoba Hydro's responses to questions concerning forecast export revenues indicate that its estimates of projected revenues have continually been getting smaller. In almost every case, the prices have dropped, contributing to the drop in expected revenues. Note that these projections only go out 20 years, whereas the NFAT evaluations extend out over a 78-year study period. The response to PUB/MH I-058b illustrates how the prices have fallen over the last few IFFs.

Price/Volume Components for Unit Revenues for Total Export Sales

(Nominal Canadian Dollars/MWh)

IFF-09 to IFF-10														
Total Export Sales	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**						
IFF 09 ($/MW.h)	66.9	71.7	74.0	90.9	92.3	95.0	105.3	105.6						
IFF 10 ($/MW.h)	58.7	62.0	66.8	81.1	86.4	91.1	95.6	108.4						
% Total Change	-12%	14%	-10%	-11%	-6%	-4%	-9%	3%						
Total Change ($/MW.h)	-8.3	-9.7	-7.2	-9.7	-6.0	-3.9	-9.7	2.8						
Change due to Price ($/MW.h)	-9.8	-11.4	-9.1	-12.7	-12.7	-13.9	-12.7	-9.9						
Change due to Volume ($/MW.h)	2.4	2.6	3.0	3.6	3.8	7.0	-0.7	9.5						
Change due to Other ($/MW.h)	-0.8	-1.0	-1.2	-0.7	2.9	3.0	3.7	3.3						
IFF-10 to IFF-11														
Total Export Sales	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**					
IFF 10 ($/MW.h)		62.0	66.8	81.1	86.4	91.1	95.6	108.4	111.2					
IFF 11 ($/MW.h)		42.5	50.4	61.9	68.8	75.3	81.1	88.1	94.3					
% Total Change		-31%	-24%	-24%	-20%	-17%	-15%	-19%	-15%					
Total Change ($/MW.h)		-19.5	-16.3	-19.3	-17.6	-15.7	-14.5	-20.3	-16.9					
Change due to Price ($/MW.h)		-16.4	-13.9	-15.2	-12.8	-10.7	-9.1	-7.6	-7.5					
Change due to Volume ($/MW.h)		-1.1	-2.1	-4.0	-4.8	-5.0	-5.5	-12.7	-9.5					
Change due to Other ($/MW.h)		-2.0	-0.3	-0.1	0.0	0.0	0.1	0.0	0.2					
IFF-11 to IFF-12														
Total Export Sales	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**
IFF 11 ($/MW.h)			50.4	61.9	68.8	75.3	81.1	88.1	94.3	96.4	99.8	102.5	110.6	106.3
IFF 12 ($/MW.h)			41.4	48.1	52.4	57.2	61.8	66.5	76.5	82.0	85.6	89.6	93.2	90.6
% Total Change			-18%	-22%	-24%	-24%	-24%	-25%	-19%	-15%	-14%	13%	-16%	-15%
Total Change ($/MW.h)			-9.1	-13.7	-16.4	-18.1	-19.4	-21.6	-17.8	-14.5	-14.2	-12.9	-17.4	-15.8
Change due to Price ($/MW.h)			-6.6	-10.5	-12.0	-13.1	-13.8	-14.6	-13.6	-11.3	-10.6	-9.1	-11.0	-11.2
Change due to Volume ($/MW.h)			-1.7	-2.2	-2.4	-2.9	-3.1	-4.3	-2.5	-1.6	-1.9	-1.9	-4.0	-2.4
Change due to Other ($/MW.h)			-0.8	-1.0	-2.0	-2.1	-2.5	-2.7	-1.8	-1.6	-1.6	-1.9	-2.4	-2.2
IFF-12 to NFAT														
Total Export Sales	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**
IFF 12 ($/MW.h)			41.4	48.1	52.4	57.2	61.8	66.5	76.5	82.0	85.6	89.6	93.2	90.6
NFAT ($/MW.h)			40.3	46.7	49.8	53.0	55.5	59.2	72.0	77.9	80.5	82.4	84.8	80.8
% Total Change			-3%	-3%	-5%	-7%	-10%	-11%	-6%	-5%	-6%	-8%	-9%	-11%
Total Change ($/MW.h)			-1.1	-1.4	-2.6	-4.2	-6.3	-7.4	-4.5	-4.0	-5.2	-7.2	-8.4	-9.8
Change due to Price ($/MW.h)			-2.1	-3.5	-5.0	-6.6	-9.1	-11.0	-5.8	-4.3	-5.2	-7.2	-8.2	-9.4
Change due to Volume ($/MW.h)			0.5	1.4	1.7	1.6	2.0	2.5	0.3	-0.6	-0.8	-0.9	-1.2	-1.1
Change due to Other ($/MW.h)			0.5	0.6	0.7	0.8	0.8	1.2	1.0	0.8	-0.8	0.9	1.0	0.7
Source: PUB/MH I-058b														

As noted above, these IFF estimates result from a succession of 20-year forecasts that only go out to 2031/32 (in the most recent cases). As can be seen in the table, expected prices have fallen from an amount estimated for 2019/20 at $105.60/MWH in IFF09 to $66.50/MWH in IFF12 and even further to $59.20/MWH in the NFAT. And, according to Potomac Economics, even these amounts of revenue are based upon unduly high forecasts for energy and capacity prices.

The PUB made the following notable comments about downward trends in export sales in its 2012-13 Annual Report (emphasis added):

> Manitoba Hydro's primary export market is the market operated by the Midwest Independent System Operator (MISO), which, over recent years, has seen reduced load-growth, an increase in subsidized wind power from U.S.-based wind farms, increased utilization of combined-cycle combustion turbine gas generation, imports into the Midwest Independent System Operator market from other U.S.-based utilities, and no increase in exports from Manitoba Hydro. **Since 2008/09, spot market export prices have decreased from about 8.0¢/kWh to an average of 3.2¢/kWh.**

The PUB's 2012-13 Annual Report goes on to state (at 10):

> Opportunity export sales prices have fallen significantly since the onset of the recession in 2008, driven in part by reduced growth in industrial demand, and also the advent of commercial production [of] natural gas from shale deposits.

That Annual Report also states (at 6-7):

> Wuskwatim Generation came on-line in 2012/13 with a Board-calculated (all-in) incremental in-service cost of $160/million/yr (10.5 ¢/kWh). This was estimated by the Board to be about three times the then current average export revenue rate.
>
> . . . .
>
> Because of low export prices, Manitoba Hydro is now forecasting losses for the first ten years of operations of Wuskwatim. At the time of the hearing, those losses were projected to total $341 million as Manitoba Hydro forecasts the project will not be profitable until 2023.

If Wuskwatim will not be profitable until 2023, what does this portend for the profitability of Keeyask in 2019/20, much less Conawapa? As noted by Elenchus, among others, the electric industry may be facing a paradigm shift with the increase in distributed generation, particularly behind-the-meter solar units, on the future loads of utilities themselves. Numerous articles have documented this new trend and its ramifications for electric utilities.[6]

Because of the confidentiality associated with Manitoba Hydro's use of its long-term generation system simulation model (called SPLASH) to simulate its system operations for 35 years[7] into the future, WRA does not have access to the input or output files, nor the actual input assumptions in any detail.[8] Manitoba Hydro describes its economic evaluation process in Appendix 9.3 at 29 as follows:

> Manitoba Hydro's SPLASH model utilizes an optimization technique to maximize net flow related revenue to the system by simulating the operation of reservoirs and hydroelectric generation plants utilizing a monthly time step. The expected price signals

---

[6] See, for example, http://www.forbes.com/sites/pikeresearch/2013/08/26/distributed-generation-poses-existential-threat-to-utilities/ and http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf

[7] See Appendix 9.2 at 2.

[8] For example, prices for export sales have been redacted from the versions of the export contracts provided.

> from the export market are provided to the model for on-peak and off-peak time periods for each month of the year. The capability of the interconnections to each market region is provided in order to limit the rate at which export energy can be transmitted. The SPLASH model determines the net production cost on a monthly basis for a series of years into the future. The net production cost is derived from the variable cost characteristics of the various generation sources and revenue is derived from export sales. A simulation of system operation is undertaken for each of the 99 flow conditions between the years 1912 and 2010 which are assumed to be representative of the range of flow conditions that may occur in the future.

Furthermore, the "components that make up net average flow related revenue are calculated using Manitoba Hydro's system simulation computer model known as SPLASH." See Appendix 9.3 at 87. The SPLASH model provides the detailed economic evaluation for the first 35 years of the study period. See Appendix 9.2 at 2 and Appendix 9.3 at 3, quoted below:

> The total study life used in this analysis is 78 years. For the total study life, Manitoba Hydro combines two approaches – a 35-year detailed evaluation and a long-life asset evaluation which extends from the end of the 35-year study period to the end of the service life of hydro-electric generation assets, as representing the longest-lived assets.
>
> . . . .
>
> Beyond the 35-year study period, replacement capital costs are assumed for assets that reach the end of their economic lives before the end of the long study period (78 years). In addition, a net production cost approximation (also referred to as net average flow related revenue) is used beyond the 35-year study period which includes:
>
> - extending fixed operating and maintenance costs throughout the economic life of all assets (including major capital O&M investments for large hydro-electric resources), and
>
> - extending the average net revenues of the last three years associated with the economics of a development plan to capture the expected ongoing incremental revenues between development plans to the end of the study period.

Therefore, the speculative nature of export prices forecast for the outermost years makes them even more suspect, as Manitoba Hydro just extends a trend line from the last 3 years of the 35-year study period to capture continuing differences between costs and revenues. And as made clear by LCA at Appendix 9A-15, Manitoba Hydro did not forecast its load increasing after the first 35 years of the study. Instead, Manitoba Hydro assumed that demand would remain steady, thereby removing any assumption that Manitoba's loads would increase over time and absorb the hydro power internally, thereby reducing revenues from exports.

Below is an illustration of the export revenues per MWH to U.S. as found in the Ref-Ref-Ref tables for three cases (All Gas, K19 Gas 250 MW, K19 Sales C25 750 MW) from Appendix 11.3. Also note that Manitoba Hydro's financial evaluations used a 50 year life, rather than the 78 year study period assumed in its economic evaluations.

Total Export Sales to USA Average Unit Revenue/Cost ($/MWH)			
	All Gas	K19 Gas 250 MW	K19 Sales C25 750 MW
Year	**Plan 1**	**Plan 4**	**Plan 14**
2013	30.83	30.83	30.83
2014	33.37	33.37	33.37
2015	40.86	40.86	40.56
2016	47.58	47.57	47.13
2017	50.50	50.50	50.15
2018	53.55	53.64	53.44
2019	56.09	56.24	55.95
2020	58.71	60.03	59.69
2021	65.50	71.57	72.54
2022	69.51	77.06	78.50
2023	72.42	79.49	81.05
2024	75.46	81.37	82.96
2025	78.23	84.17	85.35
2026	64.18	75.22	81.05
2027	63.92	76.76	84.00
2028	65.14	77.26	85.45
2029	66.10	79.30	87.75
2030	66.80	81.84	89.81
2031	69.07	84.43	91.87
2032	74.01	86.16	94.09
2033	74.92	90.67	96.17
2034	75.38	93.49	98.16
2035	75.35	96.34	100.15
2036	74.88	93.43	100.97
2037	75.08	94.48	99.67
2038	79.19	96.65	100.54
2039	77.86	102.50	102.18
2040	77.10	105.35	103.86
2041	83.68	107.90	107.19
2042	85.05	113.78	110.64
2043	86.51	117.66	114.02
2044	89.06	121.29	117.46
2045	95.86	123.59	120.93
2046	97.16	130.08	124.63
2047	98.86	133.47	128.27
2048	99.24	137.60	131.65
2049	109.99	147.63	137.78
2050	111.97	150.29	140.26
2051	113.99	152.99	142.78
2052	116.04	155.75	145.35
2053	118.13	158.55	147.97
2054	120.26	161.40	150.63
2055	122.42	164.31	153.34
2056	124.62	167.27	156.10
2057	126.87	170.28	158.91
2058	129.15	173.34	161.77
2059	131.47	176.45	164.69
2060	133.84	179.64	167.65
2061	136.25	182.87	170.67
2062	138.70	186.16	173.74
Source: Appendix 11.3 at 1-2; 164-165; 272-273			
Nominal $, includes dependable sales, plus opportunity sales			

By relying primarily on surplus capacity additions of large, costly hydro plants based on its expectation of benefits arising from potentially unrealistic high export energy prices, Manitoba Hydro would forgo the flexibility it might otherwise have (i) to adjust to a situation in which loads turn out to be much smaller than those it currently forecasts, (ii) to locate plants where they would be more useful and valuable in reducing losses and the needs for transmission additions, and (iii) to reduce exposure to long transmission lines needed to deliver the output of remote hydro additions to Winnipeg and the US. Indeed, Manitoba Hydro's initial rationale for building Bipole III is that, because so much of its generation is located on the Nelson River, far from the major loads in Winnipeg, it needed a backup path to cover the simultaneous loss of Bipoles I and II. By building Keeyask and Conawapa in the same general area, Manitoba Hydro will fill up its backup transmission path and put even more of its eggs in one remote basket, creating the potential for trapping even more generating capacity in the North after an extreme combination of HVDC transmission outages and creating the need for even more backup transmission capacity on Manitoba Hydro's interconnections with the United States. A less risky approach would involve building gas plants in locations closer to the Winnipeg load center where power is needed and the transmission system is networked. Plus, gas plants could be distributed across its service area, reducing the concentration of large blocks of generation in a single transmission-constrained region. Indeed, by planning to build natural gas plants closer to Winnipeg, Manitoba Hydro would avoid any "need" to build Bipole III, which is driven by its high-risk plan to build excess hydro capacity and move even more hydro power to the U.S. market in the hope of making profitable sales.

If Manitoba Hydro insisted that it needed a backup for the simultaneous loss off Bipoles I and II, it could reinforce the capability of its interconnection with the U.S. instead of building Bipole III.

THE COSTS OF BIPOLE III SHOULD BE ATTRIBUTED ONLY TO THOSE ALTERNATIVES WHICH REQUIRE THE EXTRA TRANSMISSION CAPACITY IT PROVIDES

In its Environmental Impact Statement ("EIS") before the Clean Environment Commission ("CEC"), Manitoba Hydro attributed the need for, and the cost of, Bipole III primarily to system reliability. This reliability-based need for Bipole III will be discussed in a later section. But now the real purpose for Bipole III has become apparent. Based upon the economic evaluations of alternatives provided in the NFAT, it is clear that Bipole III is being built primarily to carry the output of Keeyask and Conawapa to both Manitoba loads and to loads in the United States, not to enhance reliability. The long period of negotiation over the export contracts indicates a longstanding intent to build additional hydro on the Nelson River.

Manitoba Hydro's decision to attribute the need for, and the cost of, Bipole III primarily to system reliability has had the effect - advantageous in Manitoba Hydro's eyes - of laying the groundwork for - and diverting attention from - its longstanding plans to build Keeyask and Conawapa. Those plans in fact depend upon Bipole III. Pre-building Bipole III supports the ostensible economic rationale for those plans by attributing a zero cost for Bipole III, and therefore much reduced transmission costs, in those plans. That attribution lowers the ostensible cost below that which Manitoba Hydro will actually incur under the PDP when building Keeyask, Conawapa and Bipole III together. The PDP is Alternative 14 of the NFAT, which calls, in part, for:

i. 2,180 MW (2,025 MW net) of new hydroelectric generation to be constructed at the northern end of the Nelson River (i.e., the 695 MW (net 630 MW) Keeyask Generating Station in 2019 followed by the 1485 MW (net 1395 MW) Conawapa Generating Station) in 2025 and

ii. the output of that new hydroelectric generation to be delivered to the Winnipeg load center by means of Bipole III and the existing HVDC system, as well as upgrades to the collector system and upgrades to the North-South AC transmission system. Much of that output will be redelivered to wholesale buyers in the United States through a new interconnection with the United States (the 750 MW, 500 kV AC Manitoba-Minnesota Transmission Project).

Manitoba Hydro ignores the cost of Bipole III when assessing its preferred plan through a simple cost allocation sleight of hand: by assuming that the cost of Bipole III will represent a sunk cost under every alternative resource expansion plan. Through this sleight of hand, Manitoba Hydro has given its preferred plan, which must have Bipole III to work, the appearance of being more cost-effective than it really is by not including the costs for Bipole III and has added unwarranted costs to the plans that do not need Bipole III. The cost of Bipole III should instead be attributed only to those plans (including the PDP) that call for the Conawapa Project alone, or both the Keeyask and Conawapa Projects.

A prior 35-year analysis of the expected benefits of proposed northern hydro generation combined with construction of the Bipole III transmission line indicated that the All Gas scenario would be preferred at a 10% real discount rate (assuming that the in-service date ("ISD") of Bipole III was delayed to the 2024 ISD of new hydro generation (Conawapa or Gull), and that the costs of Bipole III were added to the costs of the new hydro generation).[9] See Attachment PUB/MH 1-024, Manitoba Hydro's 2004/05 Power Resource Plan ("PRP") at pages 10-11, attached as Appendix 1. While the hydro generation assumptions in that prior study are different from those in the NFAT (e.g., Conawapa or Gull versus Keeyask and/or Conawapa), the results of those analyses indicate that delaying Bipole III and adding the Bipole III costs to the hydro generation makes the hydro alternatives less desirable. The first part of the study (at 10), assumed Bipole III was built East of Lake Winnipeg. The second part of the study assumed Bipole III's costs were 46% higher with a Western route around Lake Winnipeg, and showed that the All Gas alternative was preferable. In addition, these studies were run using very different assumptions from those in the NFAT (e.g., lower cost estimates for Conawapa and Bipole III, as well as export prices presumably much higher than those used today).

[9] At a 6% discount rate, Conawapa (with 5 units or 10 units) or Gull (including SCGT1X-35, 39) were more favorable than an "all SCCT Sequence."

By adopting the analytical approach for the NFAT that Bipole III is a sunk cost, Manitoba Hydro has biased its analysis in favor of the PDP. Under the PDP, Bipole III will be built first (for commercial service by 2017/2018 and ostensibly for reliability reasons alone), but, in a happy coincidence for Manitoba Hydro, the capacity of Bipole III will be treated as if it is a "free good," available free of charge (although paid for by Manitoba Hydro customers) to accept the output of Keeyask in 2019 and of Conawapa in 2026.

However, the cost of Bipole III is not a "sunk cost." Bipole III has not yet been built but is instead presumably in the early stages of construction with an estimated in-service date of 2017/2018. Much could undoubtedly be saved by cancelling it or deferring its in-service date.[10]

It is not correct to assume that the cost of Bipole III is a neutral factor in assessing all resource plans because not all resource plans require construction of Bipole III in 2017/2018. Many resource plans will not require Bipole III until much later - or at any time. For example, an "all gas" alternative would not need Bipole III at all because that alternative involves adding thermal generation near the Winnipeg load center instead of adding new hydroelectric generation at locations remote from the Winnipeg load center along the Nelson River. Yet the cost of Bipole III is included in Manitoba Hydro's Plan 1, its "all gas" alternative. In a proper analysis, the cost of Bipole III would not be needed at all in the "all gas" alternative (and should not be attributed to that alternative). On the other hand, the cost of Bipole III should be explicitly added to the cost of the PDP because the transmission line is necessary for that alternative to work.

RECOGNIZING THE COST OF BIPOLE III AND OTHER SUNK COSTS WOULD UNDERMINE THE PREFERRED DEVELOPMENT PLAN

Bipole III is projected to cost $3.3 billion and enter service in 2017/2018. See the response to PUB/MH I-053a Revised. Moreover, about $1.0 billion of the projected total cost of Keeyask has also been ignored in Manitoba Hydro's analysis because those costs are also considered sunk

[10] A twelve (12) year delay of a $3.3 billion investment amortized over 30 years at 5% (assuming a 2% annual escalation in the investment cost) would save $970 million, about the cost of a new 500 kVAC Manitoba-U.S. interconnection.

costs.[11] The $3.3 billion in outlays for Bipole III are projected to be incurred early in Manitoba Hydro's study period (from the present through 2017/2018), and thus the NPV of those outlays will be roughly equal to their $3.3 billion cost.[12]

The $3.3 billion cost of Bipole III exceeds the incremental benefits which the Preferred Development Plan is said to produce under many scenarios as compared to the benefits of the "All Gas Plan." Accordingly, adding the $3.3 billion cost of Bipole III to the NPV of the PDP will make it less attractive than the all-gas plan in many scenarios. See the tabulation of relative benefits in Table 2 at page 23 of 42 of the NFAT Executive Summary. The PDP is Plan 14. In only a third of the scenarios studied does the PDP yield incremental benefits that are more than $3.3 billion greater than the benefits associated with the "All Gas Plan." Those scenarios are based on assumptions of low discount rates and/or high energy prices - both of which assumptions give greater value to off-system sales of power to the United States made possible by adding Keeyask and Conawapa. That is, use of the low discount rate will lend greater value to off-system sales projected to be made at high prices far into the future than would a high discount rate. If the study period were 35 years instead of 78 years, the Preferred Development Plan would produce fewer benefits than would Plan 4 (K19/Gas25/250 MW).[13]

Bipole III has a similar effect on the other resource plans. For example, the $3.3 billion cost of Bipole III exceeds the incremental benefits which the Preferred Development Plan will produce

[11] As noted in Chapter 11 at 5:20-27:

> As such, all costs (incurred or estimated) prior to June 2014 that were required to protect the in-service dates for Keeyask and Conawapa are considered as "sunk" in the economic evaluation. The financial evaluation, however, recognizes these costs need to be included in the revenue requirement at an appropriate point in time.

By expending $1.0 billion on Keeyask even before it was formally selected and approved as an element of the PDP, Manitoba Hydro has provided further support for the notion that development of Keeyask was pre-ordained. Manitoba Hydro's decision to ignore those potentially imprudent expenditures on Keeyask (because they are sunk costs) obviously favors any alternative that includes Keeyask. By not including expenditures on Keeyask to date in its analysis, Manitoba Hydro has further biased that analysis in favor of the PDP.

[12] NPV, or Net Present Value, is "the difference between the present value of the revenue and the present value of the cost. It is the amount of money, if invested today at a stated discount rate, that would grow to an amount sufficient to finance and to provide a return on the investment over the life of the project. When comparing alternatives, the incremental NPV represents the incremental net benefits (or net costs) associated with the increment of investment made for a higher cost investment option,…" See NFAT Chapter 9 at 3:17-22

[13] See LCA/MH 1-397.

under many scenarios as compared to the benefits of Plan 7 (SCGT/C26 - composed of simple cycle gas turbines plus Conawapa in 2026) and Plan 8 (CCGT/C26 - composed of more efficient gas-fired combined cycle generation plus Conawapa in 2026). Again, see the tabulation of relative benefits in Table 2 at page 23 of 42 of the Executive Summary. The incremental benefit of the PDP over the benefits produced by either the SCGT or the CCGT alternatives exceeds $3.3 billion for even fewer scenarios: only those based on assumptions of low discount rates AND high energy prices. Bipole III would be needed in these gas-fired scenarios but not until eight years later than now planned - in 2026 when Conawapa enters commercial service. Pursuing either of those combination Conawapa/gas-fired scenarios would enable Manitoba Hydro to:

1. Defer for eight years the in-service date of Bipole III (or longer depending upon demand growth and trends in export prices), potentially leading to a further deferral and/or cancellation of Bipole III and Conawapa and

2. Build lower-cost SCGTs ($770/kW - See NFAT Chapter 7 at 31 of 39) and/or CCGTs ($1,295/kW - See NFAT Chapter 7 at 31 of 39) instead of Keeyask ($9,048/kW- See the response to PUB/MH I-053a Revised) and share reserves with MISO over the existing 500 kV interconnection; and thereby

3. Reduce economic risk.

As noted previously, Manitoba Hydro's economic analysis does not include other sunk costs already expended for other projects (particularly Keeyask and Conawapa) in its economic evaluations of alternatives. See NFAT Chapter 9 at 2:4-6. Therefore, considerable amounts of money are ignored when comparing alternatives. For Keeyask, the effect of sunk costs is pronounced as its sunk costs total approximately $1 billion. See Appendix 9.3 at 5. Manitoba Hydro ignored sunk costs in its economic evaluation because it claims that Manitoba Hydro’s customers will need to pay these costs no matter what plan is chosen, whether or not Keeyask or Conawapa come to fruition. It appears that the sunk costs of Keeyask were incurred as a result of Manitoba Hydro’s decision to "to protect the in-service dates for Keeyask and Conawapa."

As noted in NFAT Chapter 11 at 5:20-27:

> As such, all costs (incurred or estimated) prior to June 2014 that were required to protect the in-service dates for Keeyask and Conawapa are considered as "sunk" in the economic evaluation. The financial evaluation, however, recognizes these costs need to be included in the revenue requirement at an appropriate point in time. For plans in which a decision is made to proceed with Keeyask or Conawapa, the sunk costs form part of the cost to acquire the asset and are amortized over the life of the asset. For plans in which Keeyask or Conawapa is deferred beyond the evaluation period, sunk costs are assumed to be amortized over an 18-year period to 2031-32.

If Manitoba Hydro is allowed to recover these sunk costs (projected to be more than $1 billion) from its customers, no matter whether it sought approval for incurring these costs or incurred them without review by the PUB, this allowance will encourage Manitoba Hydro to continue to make resource decisions prior to receiving input from the public and its regulators. WRA notes that LCA also made reference to concerns about the sunk costs, as provided in Technical Appendix 9A at 9A-49.

DESCRIPTION OF NORTHERN HYDRO AND HVDC SYSTEM

The basic facts on the existing Northern hydro generating capacity (both before and after addition of the net capacity of Keeyask and Conawapa) are set forth as follows in the NFAT Business Plan at NFAT Chapter 5:

Hydro Project	Rated Capacity MW
Kettle	1220
Long Spruce	1007
Limestone	1335
SUBTOTAL	3562
Net Keeyask	630
SUBTOTAL	4192
Net Conawapa	1395
TOTAL	5587

Source: NFAT Table 5.1 and Executive Summary p. 4

The capability of the HVDC system is contained in various interrogatory responses, such as MMF/MH II-018a:[14]

HVDC Transmission MW Capacity

Bipole I	1854
Bipole II	2000
SUBTOTAL	3854
Bipole III	2300
TOTAL	6154

Source: MMF/MH II-018a

The comparison of the existing and planned capability of the HVDC system is also addressed in many of Manitoba Hydro's Responses to data requests, including MMF/MH II-017a, -018a and -019a.

For example, the response to MMF/MH II-017a states:

> The existing HVdc system was designed with the reserve criteria of “a dc pole spare over load”. Bipole I and II have a total rating of 3854MW, which can carry power of the existing generation [3562 MW, which Manitoba Hydro characterizes as "about 3600 MW"] under normal conditions [but not in a contingency condition involving outage of a d.c. pole].

Response to MMF/MH II-019a states (emphasis added):

> The existing Bipole I & II HVdc system is rated at 3854 MW and can accommodate the capability of Kettle, Long Spruce and Limestone [about 3600 MW] under normal operating conditions, but does not meet the spare valve over generation criterion. **The existing HVdc system cannot provide transmission capacity for Keeyask power.** Please also refer to the response to MMF/MH II-016e.

It is not precise for Manitoba Hydro to state that "The existing HVdc system cannot provide transmission capacity for Keeyask Power." It is more precise to state, as Manitoba Hydro did in

[14] These Bipole capacities are thermal capacities that do not take account of (i) the reconfigurations that Manitoba Hydro has developed in order to account for outages of valve groups or (ii) possible upgrades to the North-South AC Transmission System.

the response to MMF/MH II-007b (emphasis added) that "No **firm** capacity is available to transfer power from Keeyask or Conawapa over the existing HVdc system." Non-firm transmission capability is available.

According to Manitoba Hydro, Bipole III must be added before the existing HVDC will be able to meet reserve criteria. However, once Keeyask and Conawapa are added, the transmission capacity of the three-Bipole HVdc system will be nearly filled, and, once again, Manitoba Hydro will be unable to meet the reserve criteria of "a dc pole spare over load." Manitoba Hydro has introduced a different concept for assessing the reliability and firmness of the three-bipole system with Keeyask and Conawapa, the "spare valve over generation criterion."

The net effect upon reserve capacity of the three-Bipole system after the additions of Keeyask and Conawapa is as follows:[15]

Comparison of Northern Hydro and Capacity of Bipoles

Bipoles I and II	3854
Existing Generation	3562
Remaining Cap	292
Keeyask	630
Needed Cap	-338
Bipole III	2300
Excess Cap	1962
Conawapa	1395
Remaining Cap	567

Note that the rated capability of Bipoles I and II exceed the capability of the existing generation connected to those HVDC lines by 292 MW, whereas loss of a DC pole (rated 1000 to 1150 MW) would wipe out that 292 MW spare capacity. Accordingly, the existing system does not meet the reserve criteria of "a dc pole spare over load."

[15] The response to MMF/MH II-020c states:

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

Approximately 300 MW of Kettle's generating capacity could be disconnected from the HVDC system and reconnected to the North-South AC system for transmission south to the Winnipeg load center. See NFAT Chapter 2 at 53-54, the response to PUB/MH 1-042f and the response to MMF/MH II-003. Thus, the existing system should be able to accommodate about 592 MW of the 630 MW of generation that is planned to be added at Keeyask without upgrading either Bipole I or II or adding Bipole III.[16]

In addition, the rated capability of both Bipoles I and II could be upgraded to carry the additional generating capacity that would be added at Keeyask. Note that the capacity of Bipole I is 1854 MW while operating at +/-465 kV whereas the ultimate capacity of Bipole III will be 2300 MW while operating at +/-500 kV. If there is sufficient ampacity in the Bipole I conductors, its capacity could conceivably be increased by 446 MW to 2300 MW by upgrading its terminal equipment (converters) to operate at higher voltages and to carry greater currents.[17] Such an upgrade of Bipole I plus the spare capacity in the existing system would provide 738 MW of capacity, more than the 695 MW needed for delivering Keeyask. Another 300 MW of transmission capacity could theoretically be obtained by upgrading the rating of Bipole II from 2000 MW to 2300 MW. HVDC transmission line capacity can be increased with installation of new valves, higher rated conductors, and other features.[18]

---

[16] According to several sources, such as NFAT Chapter 2 at 4, Keeyask's net generation will be 630 MW, rather than 695 MW.

[17] There is likely considerable ampacity available because the design was based on some level of losses. However, using that ampacity may mean excessive sag, and higher voltage may not be possible without first upgrading towers and insulators.

[18] In order to provide one with a sense of what Manitoba Hydro may be able to do with Bipoles I and II, it is worthwhile to examine what has been accomplished over the period since the early 1970s on the HVDC line of the Pacific Northwest-Pacific Southwest Intertie ("PDCI"). This HVDC line extends 846 miles from the Celilo Converter Station on the Columbia River in Oregon south through Nevada to Sylmar, near Los Angeles.

The PDCI was initially designed as +/-400 kV and 1800 amps, a transmission rating of 1440 MW at the sending end. The original mercury arc valves were up-rated to 2000 amps after a few years of operating experience.

The next step was to raise the operating voltage from +/-400 kV to +/-500 kV by adding a 4th valve at each end in order to achieve a 2000 MW transmission rating. Not much in the way of modification was required on the transmission line because it had originally been designed with plenty of insulation margin.

By 1989, the Bonneville Power Administration ("BPA") proposed adding parallel thyristor converters at both ends of the line to raise PDCI's rating to 3100 MW. See http://en.wikipedia.org/wiki/Pacific_DC_Intertie

Apparently, the firm transmission capability of the HVDC system is not critical to Manitoba Hydro's exports to the United States, as described in the response to CAC/MH II-075a (emphasis added).

> Manitoba Hydro's firm export contracts require Manitoba Hydro to provide firm transmission service on the AC network to facilitate energy and capacity transfers according to the system criteria associated with firm transmission service" [e.g., continued deliveries after loss of the single piece of equipment which most limits transfers - a loss referred to as the "most critical contingency"]. However, **Manitoba Hydro is not required to provide a similar level of firmness of transmission service on its HVDC system**.

THE PREFERRED DEVELOPMENT IS INEXTRICABLY LINKED TO, AND DEPENDENT UPON, BIPOLE III—THERE IS NO STANDALONE RELIABILITY FUNCTION OF BIPOLE III

The rationale given for building Bipole III was that Manitoba Hydro has too many eggs in one basket with 70% of its hydro-electric generating capacity being delivered to Southern Manitoba via the Bipole I and Bipole II HVDC transmission lines. Manitoba Hydro asserts that, because Bipoles I and II share the same corridor over much of their length, the existing transmission

---

On February 29, 2012, **Power** reported that

> The Bonneville Power Administration (BPA) last week proposed a $428 million upgrade to the Pacific Direct Current Intertie, an 846-mile overhead transmission line that delivers hydropower and wind power between the Northwest and California. The line is one of the world's longest and highest capacity transmission links.
>
> The BPA said the upgrades would modernize equipment that was "cutting edge when installed more than 40 years ago," but which has since become so outdated that the public service organization had to source parts to repair the line from online auction website Ebay.
>
> The upgrades would also increase the line's capacity from 3,100 MW to 3,220 MW and help it avoid outages and "strengthen it against weather and other threats," the BPA said. Over the past several years, it said, older equipment at Celilo Substation, the northern terminus of the DC Intertie in The Dalles, Ore., has failed with increasing frequency.

system is vulnerable to a common mode failure such as catastrophic outages of either or both of Bipoles I and II. See NFAT at Chapter 5 at 25 of 61.

Manitoba Hydro's concern goes further. It contends that an outage of both Bipoles I and II could be a long-term event necessitating reliance on its thermal generation, remaining hydro-electric generation and import capacity in amounts that are insufficient to meet its demand during many times of the year. In Chapter 2.2.1 of its EIS to the CEC, it portrayed the consequences in dire terms:

> The potential consequences of such an outage of the existing HVdc transmission system are exacerbated by the very long estimated repair times. Wide front windstorm, fire, or tornado damage at Dorsey Station could cause an outage that shuts down the HVdc system for up to three years because of the time required to repair or replace equipment of such complexity. The duration of a similar outage of the Bipoles I and II lines, although not as severe and dire as a failure at Dorsey Station, could still easily cause an outage of six to eight weeks.
>
> In the event of an extended HVdc outage, supply would be restricted to the generation connected to the ac system and the possible imports on the ac interconnections with the United States and neighbouring provinces. Such a restricted supply of power would be significantly inadequate to meet provincial demand, particularly in the winter, and could necessitate rotating blackouts for months. The potential shortfall has been growing steadily over the years, as increased demands for power from new and existing customers have increased the system load requirement.[19]

There are several major flaws in Manitoba Hydro's arguments for the reliability need for Bipole III. They are as follows:

A. Under industry reliability standards, utilities do not need to design their systems to withstand a catastrophic event, such as loss of four elements of a transmission system at the same time (such as a total loss of Bipoles I and II), which is considered an N-4 event under North American Electric Reliability Corporation standards.
B. If Manitoba Hydro's major concern is the length of outage of both existing Bipoles, then it could plan for outages by clearing brush and placing equipment (such as

---

[19] The Riel Station, scheduled to enter service in 2014, is designed in part to preserve Manitoba Hydro's system import capability if there is a major outage at Dorsey. See NFAT Chapter 5 at 24 of 61. This upgrade mitigates one of Manitoba Hydro's major reliability concerns with the present configuration of Bipoles I and II.

cranes, other construction equipment and replacement towers, wires, switchgear, transformers, valves, etc.) in areas along the length of the lines and at the converter stations, so that reconstruction could begin immediately. Switchgear, transformers and valves should be protected from physical damage at their present location. The cost of staging equipment and supplies for Bipoles I and II would be far less than the cost of building Bipole III.

C. If Manitoba Hydro first built a second 500 kV interconnection to the United States, it could import more power during outages of one or more of the Bipoles, which is cheaper than building Bipole III. [20] Furthermore, the cost of building a second 500 kV interconnection has been estimated at approximately the same cost as would be saved by deferring Bipole III for twelve years.

A. Transmission Planning Standards

The North American Electric Reliability Corporation ("NERC") is responsible for developing standards that ensure the reliability of the bulk power system in North America. For transmission planning, NERC has established various standards, including the ability of a transmission system to withstand the loss of a single element (N-1) so that none of the equipment exceeds its applicable ratings and the system does not inappropriately drop firm load. If there is a loss of two elements at the same time, or one right after the other (an N-2 or N-1-1 event), the bulk power system may reach emergency ratings for short periods of time, and load can be dropped in a planned or controlled manner.[21] An extreme event, such as a catastrophic failure of both Bipoles I and II would involve the simultaneous outage of all four single poles of Bipoles I and II (called an N-4 event), and utilities need only evaluate such scenarios for risks and consequences.

[20] In the Manitoba Hydro Bipole III EIS, December 2012, the cost of an additional 1500 MW interconnection to the United States was estimated at $1.5 billion. See Section 2.3.4 at 2-12. The cost of 500 MW of gas-fired generation was estimated to cost $750 million. Bipole III was then estimated to cost $3.28 billion. See Section 2.3.2 at 2-10.

[21] See Standard TPL-001.01 at
http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

Loss of a single pole of a Bipole is considered an N-1 event which has a less-than-1% probability of occurring (i.e., less than 1×10^{-2}). See the response to CAC/MH II-013b.[22] Although industry reliability criteria require that Manitoba Hydro continue to serve all firm load obligations after the occurrence of any single contingency (an N-1 event), those criteria do not require that it continue serving all firm load after an N-2 event, let alone, after an N-4 event. Nevertheless, Manitoba Hydro contended before the CEC that the risk posed by the contingency loss of both poles of both Bipoles I and II was an unacceptable risk justifying the expenditure of $3.3 billion.

Manitoba Hydro's contention before the CEC was never tested because of the CEC's limited mandate and terms of reference in relation to Bipole III (which the Manitoba Minister for Conservation and Water Stewardship clarified did not include an NFAT review).[23] However, while the Bipole III hearings were ongoing, the Manitoba Government announced that it had "asked the Public Utilities Board to conduct a Needs For and Alternatives To (NFAT) review of upcoming Manitoba Hydro projects including the Keeyask and Conawapa generating stations and their associated transmission facilities."[24] Despite this public commitment, and the reality that Bipole III is clearly an associated transmission facility for Keeyask and Conawapa, Bipole III was subsequently scoped out of the NFAT process for the PDP which is currently before the PUB.

The MMF has repeatedly raised concerns about the need for Bipole III, its selected route down the west side of the province that dissects the Manitoba Métis Community's "breadbasket" as well as the project's non-mitigatable impacts on the Métis community's rights, culture, economy and way of life on the west side corridor of the province (which have not been addressed).[25] As

[22] An N-4 event involving four independent events would have a probability of 1×10^{-8} or one chance in 100,000,000. However, Manitoba Hydro proposed to build Bipole III to guard against a common mode failure such as tornados or severe ice storms affecting all four poles which its studies determined could be expected to occur once every 17 years. In a common mode failure case, loss of each pole is not considered an independent event.

[23] See letter from Manitoba to CEC Chair dated August 23, 2012 with respect to the conduct of a NFAT in relation to Bipole III. Letter available at: http://www.cecmanitoba.ca/resource/hearings/36/Motion%20Decision2%20-%20Coalitionandencl1.pdf.

[24] Manitoba Government http://news.gov.mb.ca/news/index.html?item=15563.

a result of the Manitoba Government's approach, Bipole III has been segmented from the PDP and other plans related to Keeyask and/or Conawapa and was not examined in an NFAT proceeding. This creates a significant gap. Moreover, Manitoba Hydro did not and has not engaged in meaningful discussions with the MMF about mitigation of the impact of, or Métis benefit from Keeyask and/or Conawapa despite their being inextricably linked to and dependent upon Bipole III. Consequently, the need for Bipole III as well as the social and economic cost of the PDP on the Manitoba Métis Community remains unknown and has not been addressed in any process.

Manitoba Hydro has confirmed that it generally designs its system to comply with standard industry reliability criteria but appears to have considered and accepted laxer criteria with respect to the HVDC system upon addition of Keeyask and Conawapa. For example, Response to MMF/MH II-016a states:

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

As noted previously, Manitoba Hydro's existing transmission HVDC system does not meet this N-1 criterion. If Manitoba Hydro loses one of its DC poles, it can no longer transmit all of its existing hydro power from the Nelson River. Indeed, this is why it appears that some (if not all) of its export contracts allow the exports to be dropped under system emergencies. Response to MMF/MH II-016b admits that loss of just one Bipole is a multiple contingency event:

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

[25] For documents outlining the MMF concerns on these issues, see MMF Closing Argument and Affidavit of David Chartrand in CEC hearing on Bipole III at http://www.cecmanitoba.ca/hearings/index.cfm?hearingid=36#3. Further, following the Minister of Conservation and Water Stewardship's issuance of a license to Manitoba Hydro for the construction of Bipole III, the MMF appealed the Minister's decision and the issuance of the license under section 28(1) of the *Environment Act*. This appeal remains pending.

Indeed, NERC criteria state that no firm load should be lost at transmission levels following a single contingency (N-1), while firm load can be dropped following an N-2 contingency (a multiple contingency). Scenarios involving N-4 events (such as loss of both Bipole I and Bipole II) are expected to be catastrophic. Manitoba Hydro is not required by industry standards to design its system to meet such catastrophic N-4 contingencies. However, Manitoba Hydro expressed a concern about living with months of rotating blackouts, which is more of a capacity reliability issue than a transmission reliability issue. Manitoba Hydro chose to address that concern by building new transmission within Manitoba Hydro rather than by building stronger transmission ties to its U.S. neighbors or gas-fired generation near its Winnipeg load center. In its planning, Manitoba Hydro should be seeking the ability to draw upon a more diverse set of generating resources (e.g., those in MISO), not just more reliable access to pre-existing on-system generation.

Other information illustrates how Manitoba Hydro has begun to change its criteria for its transmission system. For example, the response to MMF/MH II-016e states:

> Manitoba Hydro has historically adopted the “a dc pole reserve over load criteria” stated in the 1986 Transmission Planning Criteria (H&TPD 86-1), as quoted “The present Criteria is to maintain a dc pole reserve toward meeting the Manitoba Firm load demand in conjunction with existing southern system generation under median flows”. This criteria was applied to the development of Limestone generation.
>
> The reserve criteria is under continuous review by Manitoba Hydro. The past operating experience (significant outages of HVdc valve groups) and increasing economic benefit received from power exports have led to the criterion of maintaining “on-line valve group spare over generation” to cover value group outages. This “spare valve” criterion is considered to provide optimum reliability and economic benefits. The reserve criteria is currently under further investigation for the split Northern Collector System associated with Conawapa.

Now that it has secured approval for construction of Bipole III, Manitoba Hydro has greatly relaxed its concerns with risks posed by a contingency outage of a single pole of a Bipole, an entire Bipole, or both Bipole I and II. It now contends that

> The loss of 900-1000MW pole is a low probability event (< 1%) as stated in Appendix 13 of the NFAT submission, therefore it is not considered to be an economically attractive

> option to cover for this loss with an additional spare HVdc capability when evaluating the firm transfer capability of the HVdc system.

See the response to CAC/MH II-013b.

Manitoba Hydro admits that the odds of such an event (simultaneous long-term loss of Bipoles I and II) are low. Ordinarily, utility systems are designed to meet load except for one day in every ten years, the 1-day-in-10 year loss-of-load-probability standard. The risk of losing both existing Bipoles is much lower. At Chapter 2.2.2 of its EIS submission to the CEC, Manitoba Hydro stated:

> Studies (Teshmont 2001) have shown that with respect to Dorsey Station, there is a 1 in 29 year probability of outage due to fire and a 1 in 200 year probability of outage due to wide front winds. While mitigation measures have been put in place, which partially address fire vulnerability at Dorsey, there is little that can reasonably be done to mitigate vulnerability to wind and other weather events. The same studies (Teshmont 2001) revealed that the probability of the loss of the Interlake corridor is 1 in 17 years from a tornado, 1 in 50 years from icing and 1 in 250 years from wide front winds.

In other words, Manitoba found it necessary to expend $3.3 billion on the spare HVDC capability of Bipole III in order to lessen the consequences of an N-4 contingency outage of four poles of Bipoles I and II, which has a probability of one occurrence in seventeen years[26] but has now determined that it is not "economically attractive…to cover . . . with an additional spare HVdc capability" the contingency outage of a single 900-1000 MW pole of any Bipole, an event which has a failure rate of 5.75/year with an outage duration of 1.21 hours (Bipole I), or 6.02 failures per year of 2.16 hours duration (Bipole II). See NFAT Appendix 13.1 at 11.

B. Length of Outage

As described above by Manitoba Hydro in the proceedings before the CEC, Manitoba Hydro's main concern centered on the length of a possible outage of both existing Bipoles. Manitoba Hydro contended that an outage of the Dorsey Substation could last as long as three years, while

[26] Please note that the one in 17 year expectancy is for a tornado, which would not be expected to occur during Manitoba's peak winter months when loads are highest.

outages of the corridors themselves could last from six to eight weeks. However, multiple actions could be taken to reduce the risk of lengthy outages of either the Dorsey Substation or the transmission corridor.

It is notable that the firm that provided the probabilities of losses associated with outages of Bipoles I and II, as well as the Dorsey Substation, has ties to Manitoba Hydro and the Bipole projects themselves. Teshmont Consultants acted as the Owner's Engineer on each of the Bipole projects on behalf of Manitoba Hydro, and has already been hired as Owner Engineer for Bipole III.[27] Therefore, Manitoba Hydro asked the consultant that actually designed the original Bipoles I and II to critique its performance in relation to catastrophic events, and then hired that same consultant to design and build the project that was ostensibly justified via that same consultant's report.

In any event, the probabilities of catastrophic contingencies described by Teshmont are all less than the industry's loss of load probability standard of one day in 10 years. The worst outage for the Dorsey Substation was listed as a 1 in 29 year event for fire, while the worst outage for the Bipoles I and II transmission corridor was a 1 in 17 year event for a tornado. The Interlake corridor was also estimated to be at risk for an icing event of 1 in 50 years.[28]

And for each of these catastrophic events, Manitoba Hydro could take steps to reduce risks for far less money than it would cost to build Bipole III. For example, fire risk could be handled by removing brush in and around the fence of the Dorsey Substation, as well as the transmission corridor. Furthermore, the substation could be reinforced to withstand tornado forces, and Manitoba Hydro could acquire long-lead-time replacement components that cannot be protected and keep these parts in reserve. Equipment necessary in case of icing or wind storms could be purchased in advance, and staged at areas along the transmission lines in order to hasten the recovery of the facilities. Each of these activities would be far less costly than building a third Bipole that will traverse land important to First Nations and Métis people.

---

[27] See http://www.teshmont.com/expertise/hvdc-systems

[28] Manitoba Hydro EIS on Bipole III to the CEC, Chapter 2.2.2.

Finally, adding Bipole III plus Keeyask and Conawapa would put even more eggs in the Northern Hydro basket which would be vulnerable to a single event taking out all three Bipoles of all Northern Hydro generation (i.e., a "common mode" failure such as tornados or ice build-up) or the loss of Bipoles I and II while Bipole III is out of service for maintenance. Today, the simultaneous or overlapping loss of Bipoles I and II would deprive Manitoba Hydro of 3562 MW of Northern hydro generation whereas loss of all three Bipoles would deprive it of 5587 MW of Northern Hydro generation once Keeyask and Conawapa are placed in service. Although constructing Bipole III on a right-of-way ("ROW") separate from that used by Bipoles I and II reduces the risk of a common mode failure of all three Bipoles, some of the common mode events could be widespread enough to take out all three Bipoles.

C. <u>A Second 500 kV Line to the US Provides Reliability</u>

The shortfall that would result from losing both Bipoles I and II was depicted at Chapter 2.2.3 (at 2-6 and 2-7) of Manitoba Hydro's EIS submission to the CEC as about 1500 MW in 2017, growing to 2000 MW in 2025, as illustrated by Manitoba Hydro in the graph below:[29]

---

[29] The 1500 MW deficit in 2017/18 would occur at the time of Manitoba Hydro's winter peak demand which would be unlikely to coincide with a tornado or a brush fire. The load duration curve for 2017/18 shows that Manitoba Hydro's demand can be met with both Bipoles I and II out of service in 68% of the hours of 2017/18. See the Manitoba Hydro EIS on Bipole III, Chapter 2.2.3, Figure 2.2-2.

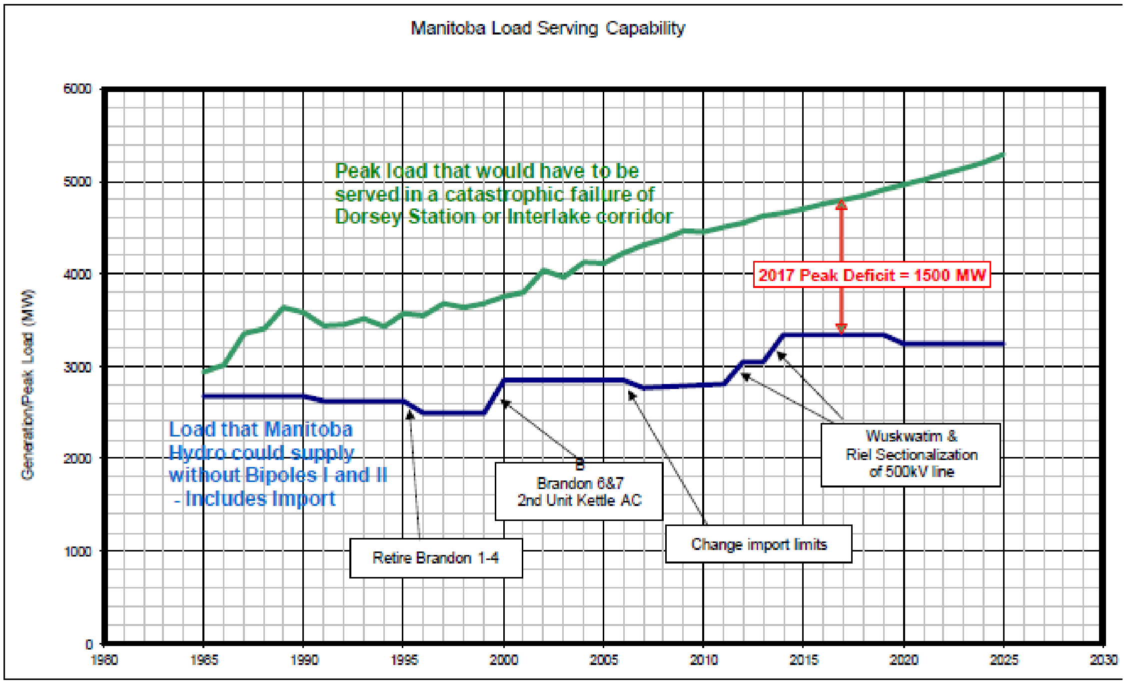


Figure 2.2-1: Load Serving Capability without Bipoles I & II

It appears from Figure 2.2-1 that Manitoba Hydro has been exposed to its alleged susceptibility to loss of Bipoles I and II since 1985 yet it will take more than 30 years to mitigate the impact of such a loss. Manitoba Hydro reports that, at the time of a September 1996 loss of both Bipoles (the only time such a catastrophic loss has occurred in over 35 years), it was able to arrange 985 MW of imports to cover the shortfall,[30] more than the 700 MW existing firm import limit from the United States and other Provinces. See NFAT Chapter 5 at 16 of 61.

Having identified the supposed need for addressing a low-probability event in its presentation to the CEC, Manitoba Hydro proposed two alternatives to building Bipole III (EIS submittal at Chapter 2.3 at 2-9):

2. The addition of up to 2000 MW of gas turbines in southern Manitoba.

3. The addition of up to 1500 MW of new import tie lines to the United States (USA) to provide access to US generation, which is assumed to be comprised mainly of natural gas-fired generation, plus the addition of another 500 MW of natural gas-fired generation in southern Manitoba.

---

[30] See Chapter 2.2.2 of the EIS for Bipole III at 2-4.

Both alternatives to Bipole III were rejected because of cost, but the rejection was not based on an apples-to-apples comparison. The addition of Bipole III brings with it no additional generating capacity, except for a reduction in losses of approximately 90 MW (see NFAT Chapter 4 at 44). That is, Bipole III only provides between 2000 MW and 2300 MW of backup transmission access to already-existing Northern hydro-electric generation in the low-probability event of simultaneous loss of Bipoles I and II. By comparison, each of the two alternatives would have provided 2000 MW of ADDITIONAL generating capacity. The alternatives were determined to be more expensive than Bipole III in large part because they included either (i) 2000 MW of additional firm gas-fired generation in Manitoba or (ii) 1500 MW of firm purchases from the United States plus 500 MW of additional gas-fired generation in Manitoba. Clearly, the two alternatives would have offered 2000 MW more long-term generating capacity value to Manitoba consumers than Bipole III will. In order to make the three alternatives comparable in terms of generating capacity, Manitoba Hydro should have added the costs of Keeyask and Conawapa to the cost of Bipole III, which likely would have made either alternative more attractive than Bipole III in combination with the additional hydro generation.

There were further flaws in Manitoba Hydro's analysis of the alternative that called for building an additional 500 kV AC transmission line to the United States. For example, there would be no need for Manitoba Hydro to line up 1500 MW of firm purchase commitments to cover a simultaneous outage of Bipoles I and II that was estimated to occur no more frequently than once in 17 years. Nevertheless, this alternative was rejected in large part because Manitoba Hydro contended that reliance on additional import capacity would require that, in addition to Manitoba Hydro's building the line to the United States, it would need to line up 1500 MW of costly long-term firm power purchase contracts tied to the cost of gas generation. The imported generation, combined with the 500 MW of gas-fired generation in Manitoba, was estimated to cost \$2.99 billion. See the Bipole III EIS at Section 2.3.4 at 2-12.

In my experience, that contention is inconsistent with industry custom and practice. The right of Manitoba Hydro to rely upon interconnected utilities for support during contingencies – especially such extreme contingencies as outages of four poles of the Bipole HVDC system -- is implicit in the interconnection process and is almost always made explicit in the bulk power contractual arrangements that accompany and govern such interconnections. There are numerous instances in which owners of large blocks of nuclear generation in North America experienced long-term outages or construction delays and obtained replacement power in bulk power markets. Manitoba Hydro could expect to pay a premium in some markets for such power but should obtain some protection from price gouging by MISO oversight of its markets and FERC regulation of interstate commerce in wholesale power.

In addition, any outage of both Bipoles I and II would require Manitoba Hydro to trip or back down the 3,562 MW of existing hydro-electric generation at Kettle, Long Spruce and Limestone, (NFAT Chapter 5 at 9 of 61), but this loss of generation represents a relatively small percentage of the 135,000 MW of generation in the MISO market and 167,000 MW of generation in the PJM market to which MISO is strongly interconnected.[31] Furthermore, apart from the position it took in its presentation to the CEC, Manitoba Hydro's position on the value and function of interconnections is consistent with the industry custom and practice I described. That is, Manitoba Hydro relies on its interconnections for just such events as loss of both existing Bipoles. As noted in the NFAT at 5.2.3 Reliability Benefits of Interconnections:

> Manitoba Hydro's interconnections provide significant reliability benefits in several ways:
> - sharing of generation contingency reserves
> - sharing of capacity resources due to load diversity
> - importation of energy during drought conditions or extreme supply loss in Manitoba
> - ability to supply cross-border load when this load is isolated from its system.

Moreover, NFAT Chapter 5 at 18 states:

---

[31] As noted at NFAT Chapter 5 at 40 of 61:

> MISO's July 2012 historic peak load for the market footprint was 98,576 MW; registered generation capacity in July 2012 was 131,581 MW. About 63,000 MW or 48% of the registered generation capacity is coal-fired generation.

Entergy has recently joined MISO and added 23,000 MW of generation. NFAT Chapter 5- at 39 of 61. MISO has strong interconnections with PJM which Wikipedia summarizes as

> More than 830 companies are members of PJM, which serves 60 million customers and has 167 gigawatts [167,000 MW] of generating capacity. With 1,325 generation sources, 59,750 miles (96,160 km) of transmission lines and 6,038 transmission substations, PJM delivered 682 terawatt-hours of electricity in 2009. [Footnote cites 2010 PJM Statistics]

> Imports may also be required for reliability purposes during major supply loss events such as the loss of the entire Interlake HVDC transmission corridor.

Furthermore, Manitoba Hydro has long-established relationships with the opposite parties from the United States in its interconnection agreements. Over the decades since Manitoba Hydro began development of its Nelson River hydro-electric plants, those opposite parties have benefited greatly from their purchases of low-cost power and are well aware of the risks posed by the configuration of Manitoba Hydro's bulk power system. Quite apart from their contractual obligations and industry custom and practice, it would be imprudent of those opposite parties to deny Manitoba Hydro access to reasonably-priced replacement power in the event of a simultaneous contingency outage of both Bipoles I and II. Manitoba Hydro would be in a position to deny those opposite parties' extensions of their present favorable bulk power supply arrangements.

Indeed, the benefits of interconnections provide a basis to include a second interconnection to the United States. And Manitoba Hydro examined the benefits arising from two possible sizes of transmission facilities to the United States. One interconnection upgrade would enable Manitoba Hydro to export an additional 250 MW, while the other would create "750 MW additional transmission interconnection import/export capacity between Manitoba and Minnesota and Wisconsin with an ISD of 2020." See the NFAT Overview at 2 of 13.

Clearly, the 750 MW planned addition to Manitoba Hydro's import limit associated with the second planned 500 kV line to the United States would enable it to cover half the 1500 MW shortfall it could experience in 2017 from loss of both Bipoles, leaving it exposed to a shortfall of capacity in only about 10% of the annual load cycle. It also seems likely that Manitoba Hydro could increase that 750 MW addition to its import capability by adding reactive support to its interconnections with the United States.[32] Nonetheless, Manitoba Hydro rejected that alternative.[33]

[32] The response to MMF-MH I-037 states that "Adding series capacitors to the Richer to Moranville 230 kV line might increase the import limit by 50 to 100 MW." That response also states that the present 700 MW import limit is based on preventing voltage collapse in the United States following loss of the existing 500 kV line between Dorsey and Forbes, suggesting that the 700 MW import limit could be increased by adding reactive support to both

These data suggest that Manitoba Hydro could have achieved the desired level of backup transmission capacity by building the 500 kV Manitoba-Minnesota Transmission Project (with voltage support suitable to avoid voltage collapse in connection with substantial import levels), instead of building Bipole III and - as discussed below - at a cost lower than the $3.3 billion cost of Bipole III. The total cost of the proposed 500 kV Manitoba-Minnesota line is projected to be $1.05 billion, of which some U.S. utilities would pay a share.[34] As noted, the Bipole III EIS estimated the cost of a 1500 MW increase in import capability to be $1.5 billion.

In referring to the Manitoba-Minnesota Transmission Project, the NFAT Executive Summary at 6-7 of 42 states:

> This project is still in the study and negotiation phase. Manitoba Hydro will be responsible for the Manitoba portion of the interconnection, which is estimated to cost $350 million. Manitoba Hydro will also be responsible for some portion of the capital and ongoing operating costs associated with the U.S. portion of the facilities. For the Preferred Development Plan, it is assumed that Manitoba Hydro will be responsible for 40% of the capital and ongoing operating costs associated with the U.S. portion of the 750 MW interconnection facilities, with the remainder of the transmission costs to be borne by MP and WPS. The total cost of the U.S. portion of the 750 MW interconnection is in the order of $700 M (2020 base dollars, not including interest).

CONCLUSION

Manitoba Hydro's Preferred Development Plan has not been supported by Manitoba Hydro's NFAT submission and, if approved and built, will impose unnecessary and excessive risks on ratepayers. Manitoba Hydro's pursuit of a gas-fired alternative and/or imported power

---

the existing and planned 500 kV interconnections with the United States. The cost of reactive support is typically far lower than the cost of a new 500 kV AC interconnection.

[33] "The [230 kV line to Rugby, North Dakota] project increased long-term import capability to 700 MW, and increased the export capability to the U.S. interface system operating limit of 2,175 MW, which is still in effect. It should be noted that 225 MW of the system operating limit is utilized for delivery of operating reserves and transmission reliability requirements and is not available for export purposes." NFAT Chapter 5 at 15 of 61.

[34] The N-2 loss of two 500 kV transmission lines would cause a blackout (or maybe not if an SPS is used and is successful) while the N-4 Bipole outage may or may not cause a blackout, but is primarily of concern because of the possibility of months of rotating blackouts (i.e., two very different kinds of impacts). A blackout is over in a few hours. Rotating blackouts for months are more severe.

(supported by enhanced import capacity on its interconnections with the United States) would be far lower in cost in the years through 2040, and lower in risk, than would pursuit of its PDP. The PDP would exacerbate the concentration of its generating resources along the Nelson River hundreds of kilometers north of its Manitoba Winnipeg load center and put more eggs in that basket.

In addition, Manitoba Hydro should cancel – or at least defer – construction of Bipole III. Manitoba Hydro could more cost-effectively guard against a simultaneous outage of Bipoles I and II by enhancing its import capacity through upgrades of its interconnections with the United States.

POWER PLANNING AND DEVELOPMENT DIVISION

Report on

THE 2004/05 POWER RESOURCE PLAN

Date: July 22, 2004

This report is intended **for internal use** by Manitoba Hydro only. External requests for information contained herein should be referred to Power Planning and Development Division.

3.<u>Conawapa B axis versus DX axis:</u>
The decision on which axis is to be developed for Conawapa would ultimately affect the capacity of the plant. Selection of the DX axis would likely provide 10% more capacity at Conawapa (1250 MW vs 1375 MW) allowing for greater hydro capability in the event the Gillam Island site is not developable. However, this would add additional investment risk to the Conawapa project. The recommendation of Conawapa for an in-service-date of 2024 allows sufficient time to re-evaluate the selection of the preferred axis prior to final commitment.

<u>Other Risks:</u>
<u>Bipole III HVDC Line</u>
Work is ongoing and the routing of the line is yet to be determined. Since the in-service-date of 2010 is not considered to be attainable and 2012 is more likely, the energy and capacity available from reduction in transmission losses resulting from construction and system operation of Bipole III line has been included for an in-service of 2012.

Recognizing that there is a risk of the Bipole III Line not being constructed in advance of new generation, a sensitivity was conducted in which the Bipole III Line is included with new northern generation developed to meet domestic load requirements. The costs and line benefits are now considered as part of the sequence economic analysis. For comparative purposes, all three northern hydro options (Conawapa, 5 unit Conawapa and Gull) have been included as these options would all depend on the Bipole III Line for transmission

Tables 3 below, tabulates the results of this scenario comparison. Under this sensitivity, SCCTs are most economic at the 10% discount rate but the Conawapa -2024 sequence is most economic at 6%.

Table 3
Expected Benefits Relative to all SCCT Sequence
(Bipole III Line costs and benefits included with northern hydro development ISD-2024)
Millions of 2004 PV Dollars, 2004 **EXPECTED** Export Prices

	Conawapa-24	Conawapa -24 (first 5 units of 10)	Gull-24 SCCT1X-35, 39
Incremental NPV @ 6% Discount Rate	589	416	310
Incremental NPV @ 10% Discount Rate	1	-34	-40
Incremental IRR	10.0%	9.4%	9.1%

This sensitivity assumes the Bipole III line being developed in 2024 would still be utilizing the East of Lake Winnipeg route. The loss reduction benefits are included but no monetary value is included for the reliability benefits.

Should the Bipole III line utilize the Interlake or West routes, the capital costs would be higher and the benefits resulting from loss reductions lower. A further sensitivity was conducted to estimate the impact on expected benefits of Conawapa, Conawapa 5 units and Gull should Bipole III Line be constructed on a West route. For this West route sensitivity, costs were estimated to be 46% higher and benefits from reduced losses were estimated to be 41% lower than if the line were construct east of Lake Winnipeg. Table 4 below, tabulates the results of this scenario comparison.

Table 4
Expected Benefits Relative to all SCCT Sequence
(Bipole III Line costs increase by 46% and benefits decrease by 41%, west routing, included with northern hydro development ISD-2024)
Millions of 2004 PV Dollars, 2004 **EXPECTED** Export Prices

	Conawapa-24	Conawapa -24 (first 5 units of 10)	Gull-24 SCCT1X-35, 39
Incremental NPV @ 6% Discount Rate	508	335	229
Incremental NPV @ 10% Discount Rate	-38	-73	-79
Incremental IRR	9.4%	8.7%	8.2%

Inclusion of at least some reliability benefits with the Interlake or West line would reduce or eliminate the cost impacts relative to the SCCT sequence. Thus, the additional costs for the Conawapa and Gull sequences would be larger but probably not sufficient to reverse the recommendation for Conawapa in 2024.

<u>Higher Load Growth</u>

The 2004 Medium High Load Growth scenario would result in deficits in the years 2008/09 and 2009/10, of 280 GWh and 410 GWh respectively. The addition of Wuskwatim in the year 2010/11 provides sufficient additional supply to maintain a net surplus of dependable energy until the year 2019/20. In the 2003/2004 IFF, under the High Load Growth scenario new resources were required (post Wuskwatim) one year earlier in the year 2018/19.

<u>Lower Load Growth</u>

If actual long-term domestic load growth turned out to be lower than the base load forecast, the requirement for new generation would be deferred from the current 2024 date under base load growth. For example, by applying the 2004 Medium Low Load Forecast, the need date for new generation would be 2048/49.