Whitfield Russell Associates Report on the NFAT for the MMF

Whitfield Russell Associates
May 13, 2014

WRA Presentation Focuses on:

- Lack of transparent data
- Study Period of 78 years is too long
- Export revenues forecasts unavailable, risky
- Exports will not recover the full costs of Keeyask/Conawapa
- Hydro's analysis and conduct indicates a predisposition to build hydro
  - Bipole III's $3.3 billion costs is deemed sunk and ignored in economic comparison analysis
  - Other sunk costs for Keeyask and Conawapa similarly prejudice analysis
  - 78-year study period favors hydro
- Reliability analysis that Hydro relied on to expand the HVDC system
- An additional transmission line to the U.S. will lower costs and risks and improve reliability for Manitoba

The Lack of Transparent Data

- Much of the data on financial and economic risks of the PDP, transmission planning and export contracts has been restricted as commercially sensitive information.
- 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  - “This Information Request has been withdrawn by the IEC as no longer required, having been satisfied through discussion with Manitoba Hydro.”

TOR Lacks Bipole III Review

As noted in the TOR 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. This portion of the TOR caused the parties to treat future investments in Bipole III as sunk costs (even though much of that investment has not yet been made and some of that investment may be avoidable). This element of the TOR distorted the analyses to favor hydro-centric alternatives.

The 78-Year Study Period Is Too Long

1. Is longer than typical even for Manitoba Hydro which uses a 20-year projection for its Financial Forecast and a 35-year period for its Power Resource Plan.
2. Favors high-risk, hydro-centric plans that have near-zero energy costs but add generating capacity in large capacity blocks, require export sales of surpluses until needed by domestic loads (thus exposing MH to a risk of suppressed export prices), require large capital investments, take a long time to build and are projected to generate savings only after much of their initial cost is paid down through depreciation.

The 78-Year Study Period Is Too Long

3. Makes plans susceptible to difficult-to-predict structural changes such as those that could alter relative costs of assets and lower domestic demands (e.g., from DG and new technology) and export prices.
4. Masks the need for near-term rate increases (and the associated burdens) to support hydro projects before they begin to generate savings and achieve lower costs decades from now. MH showed that 26 years must elapse before the PDP lowers cumulative rates to Manitoba consumers. This creates inter-generational inequity.

Risk Associated with Export Revenue

The net benefits claimed for plans involving Keeyask and Conawapa are highly dependent upon the magnitude of future exports and the future level of export prices. Publicly available data on the historical magnitude of exports and the average price per kWh sold revealed a disturbing trend of considerable volatility (particularly in opportunity sales volumes and prices) and a decline in export prices since 2006/7.

Reduced Export Revenues/MWH

NFAT PUB/MH I-008 Revised								
TOTAL U.S. SALES								
	U.S. Dependable Sales			U.S. Opportunity Sales			Total	Weighted
Year	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	AvgPrice
2000/01	4,895	199	40.69	4,511	167	36.95	9,406	38.90
2001/02	4,767	263	55.15	5,083	247	48.66	9,850	51.80
2002/03	4,947	277	56.09	2,713	115	42.30	7,660	51.21
2003/04	5,245	259	49.45	507	35	69.42	5,752	51.21
2004/05	5,633	290	51.44	3,218	171	54.48	8,851	52.55
2005/06	4,044	240	59.25	8,879	401	45.12	12,923	49.54
2006/07	3,654	218	59.67	5,877	270	46.24	9,531	51.39
2007/08	3,921	209	53.22	6,618	289	44.19	10,539	47.55
2008/09	4,087	233	57.12	5,622	237	43.24	9,709	49.08
2009/10	3,263	186	56.99	7,224	160	22.28	10,487	33.08
2010/11	3,377	172	51.09	6,062	146	24.44	9,439	33.97
2011/12	3,742	175	46.79	5,616	117	21.13	9,358	31.39
2012/13	3,636	177	48.69	4,690	113	23.62	8,326	34.57

Risk Associated with Export Revenue Forecasts

The overall forecast of weighted average export prices has dropped in each successive forecast since 2009, often by large amounts.

IFF Forecasts of Revenues/MWH

	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-058

MH's Intent to Build Hydro

- Manitoba Hydro's selection of the PDP seems to reflect a predisposition to build high-cost hydro resources largely for export in the initial period of the life of those resources.
- The market for firm exported power is primarily determined by the marginal cost of alternative thermal resources which presently tend to have capital costs ($750/kW for SCGTs and $1350/kW for CCGTs) far below those of hydro ($9000/kW for Keeyask before the recent escalation).

Export Revenues Will Not Fully Recover Costs of New Hydro

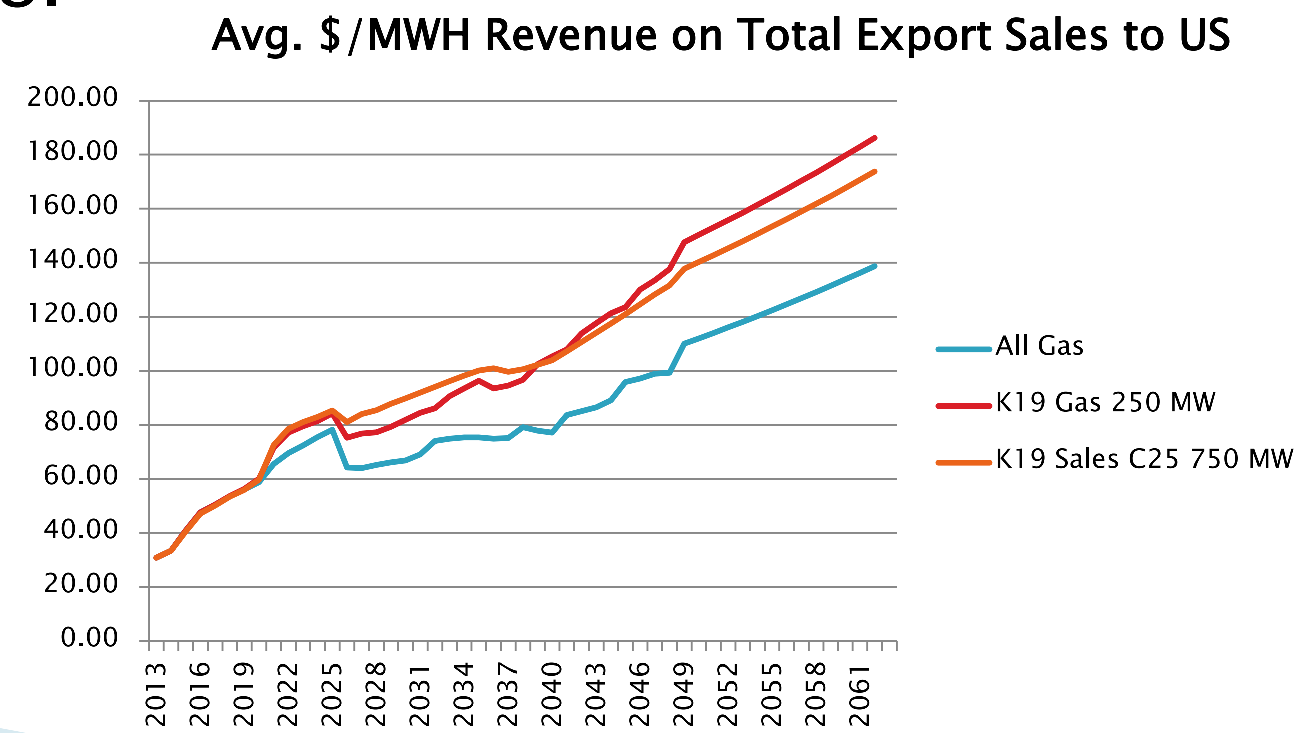
There is a substantial gap between:

- The high initial in-service annual revenue requirement to recover the cost of power for Wuskwatim, Keeyask and Conawapa (approximately $100/MWH or 10¢/kWh – See BO 5/12 at 8, 54) and

- The much lower prices at which MH can expect to sell its firm and surplus hydro power in export markets (resulting in unit sales prices of no more than 6-7¢/kWh on average for firm sales and opportunity sales combined – See BO 5/12 at 55).

PDP and Other Plans Revenue/MWH

The weighted average forecast of firm exports and opportunity sales is below 10¢/kWh until 2038.



Impact of Prices and Study Length

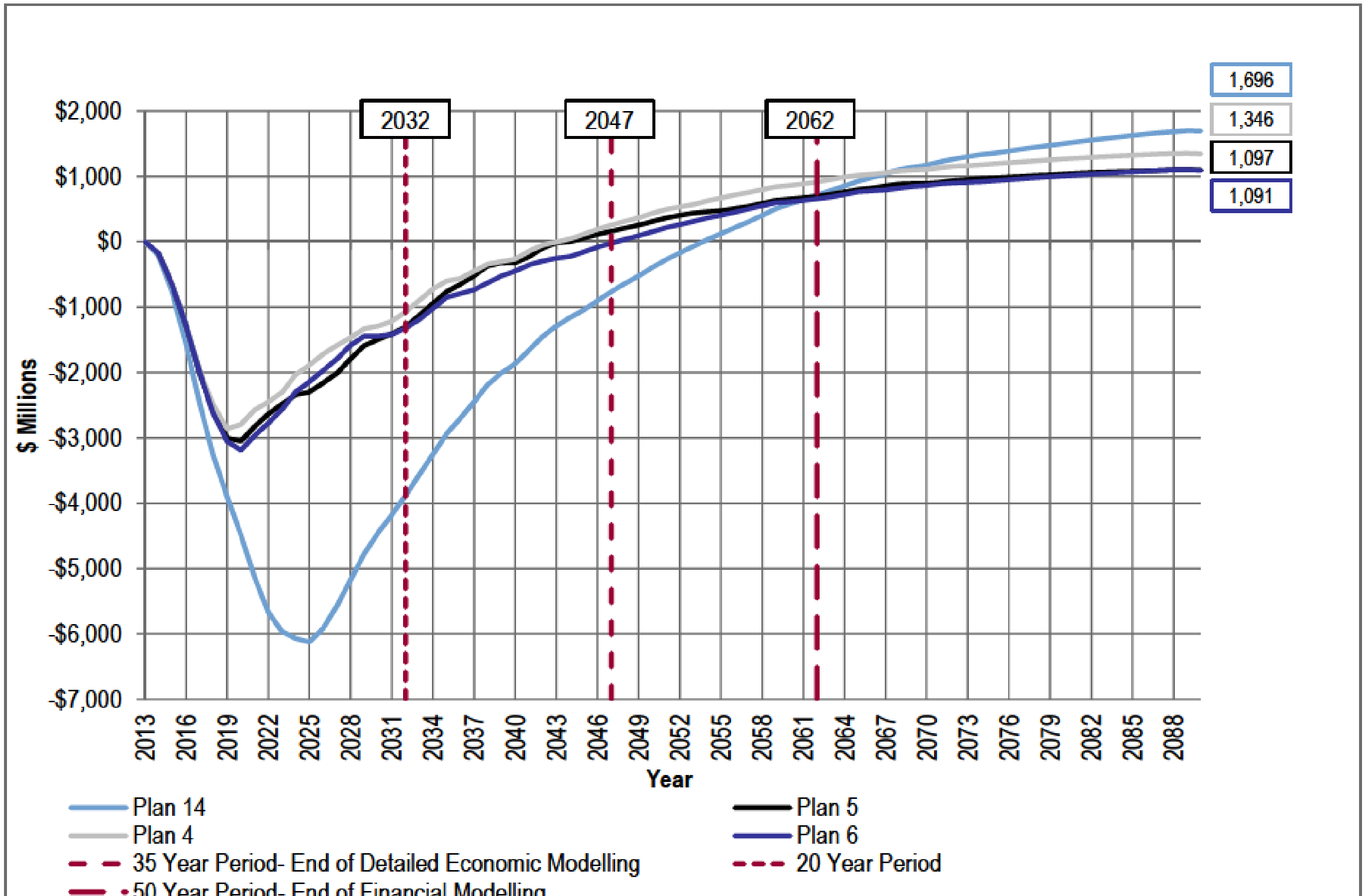
MH has an incentive to maximize firm exports and lock in pricing for firm exports, but is constrained by buyer resistance and the cost of alternatives. As costs escalate and forecasts of export prices fall, the point in time at which export revenues recover increased costs is pushed farther into the future. This set of constraints has provided a powerful incentive to lengthen the study period.

PDP Benefit is Long in Coming

As Keeyask and Conawapa are depreciated over their 67-year useful lives, their costs will decline to a level that is projected to fall below the market price of exports, but that crossover will not happen for a long time. In the meantime, losses on exports will accumulate before eventually being reduced. In comparison to the All-Gas benchmark case, LaCapra's analysis showed negative cumulative NPVs for the first 30 years for Plans 4, 5 and 6, and for the first 41 years for the PDP.

LCA Figure 9-17 Corrected

- Figure 9-17 *Incremental CPV Plan 4, 5, 6 and Plan 14 Relative to All Gas Case*
  Changed 20 year period to end at 2032 rather than 2033 and the 35 year period to end at 2047 rather than 2048.



Increased Costs Will Reduce Benefits of Exports

- MH's failure to incorporate up-to-date cost estimates in its analyses and negotiation of export contracts harms ratepayers (BO at 65).
- The recent increase in the estimated capital costs of Keeyask and Conawapa were apparently not known at the time MH negotiated the Term Sheets and export contracts.

Erosion of Benefits Impacts Plan Choice

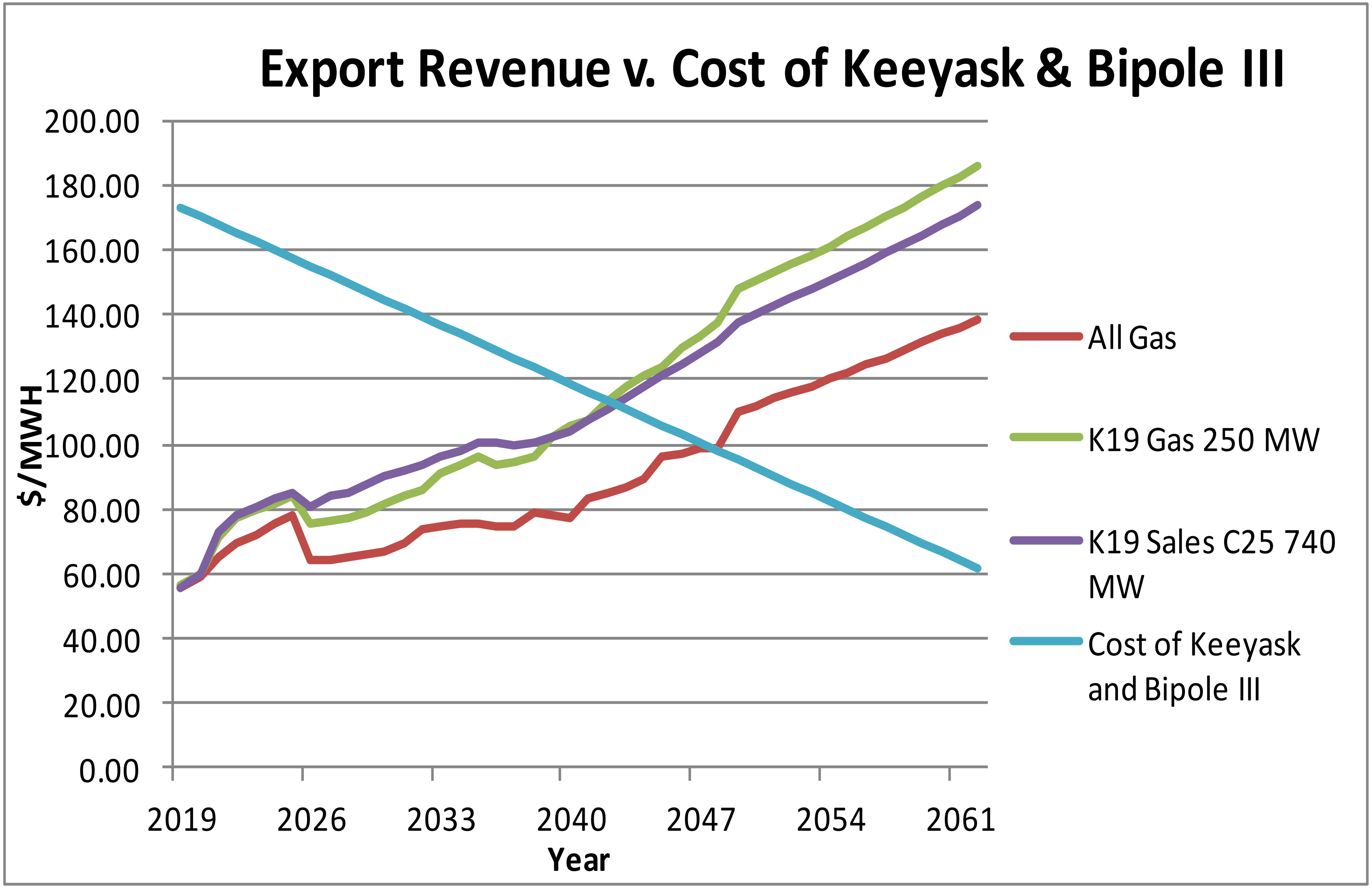
- Favorable economics of hydro erode as capital costs increase, as has been demonstrated in the updated work of MH. The initial $1.696 Billion advantage enjoyed by the Preferred Development Plan (PDP) over the All-Gas Plan diminished to $374 million as a result of an $800 million increase in estimates of capital costs associated with Keeyask and Conawapa and the removal of the WPS investment decision (See MH Exhibit 95 at slide 123).
- With the addition of DSM at level 2, the PDP's NPV advantage over the All Gas Plan falls to only $45 million (MH Exh. 95 at slide 130).

Hydro's Levelized Cost Comparison Obscures Impact of Upfront Cost of Hydro Plans

- MH reports a 67-year life-cycle levelized cost of 6-7¢/kWh for Keeyask and Conawapa. See Chapter 7 Table 7.3 and LCA/MH I-308. These costs do not include the sunk costs of Keeyask and Conawapa up through June 2014.
- These numbers are far different from those found in BO 5/12 at 54, which showed starting (non-levelized) costs of 9-10¢/kWh for Keeyask and Conawapa before MH made its new cost estimates known in this proceeding.
- Neither of these starting cost estimates includes approximately 3¢/kWh cost of Bipole III (per BO 5/12 at 54).

Adding Bipole III Costs to Hydro Plans Drives Up Their Costs

- The 10¢/kWh cost of power from Keeyask and Conawapa (from BO 5/12) is forecast to be above the overall weighted average forecast price of exports for many years into the future (See Slide 13).
- When fully loaded, the cost of Bipole III is estimated to add 3¢/kWh to the cost of power delivered (BO 5/12).
- When the cost of Bipole III is added to the cost of Keeyask alone, the deficit is even larger because the incremental costs of the 2000 MW of Bipole III must be recovered on the incremental energy produced from only 630 MW of Keeyask output.
- This drives the incremental cost of Keeyask to about 17.3¢/kWh <u>before</u> potential cost escalations are considered.


Export Revenue v. Cost of Keeyask & Bipole III
$/MWH
200.00
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2019
2026
2033
2040
2047
2054
2061
Year
All Gas
K19 Gas 250 MW
K19 Sales C25 740 MW
Cost of Keeyask and Bipole III

PUB Board Order States:

"To the extent MH's real costs with respect to these projects are not recovered from export customers, it will fall to Manitobans to bear financial responsibility through reduced annual net income of MH (and reduced overall retained earnings) and increased electricity rates for Manitobans." BO 5/12 at 63.

Sunk Costs Disadvantage Non-Hydro Alternatives

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 to accept the output of Keeyask in 2019 and of Conawapa in 2026.

Bipole III's Sunk Costs

The $3.3 billion cost of Bipole III exceeds the incremental benefits which the PDP 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 and to the other hydro plans, while removing it from non-hydro plans, would make a vast difference in the probability analysis.

The next slide shows MH's Quilt Table for Several Plans with Updated Capital Costs from MH Exhibit 95 at 125.

Probabilistic Analysis Updated Capital Costs – Keeyask and Conawapa

Probabilistic Analysis
Updated Capital Costs – Keeyask and Conawapa

Energy Prices	Discount Rates	Capital Costs	1 All Gas	2 K22/Gas	4 K19/Gas24 /250MW	8 CCGT/C26	5 K19/Gas25 /750MW WPS Sale & Investment	14 K19/C25 /750MW WPS Sale & Investment
			Millions of 2014 NPV Dollars					
Low	Low	H	-1062	-1401	-851	-1501	-516	-1583
		Ref	-68	16	646	106	906	632
		L	734	1205	1898	1449	2086	2539
	Ref	H	-463	-1751	-1512	-2398	-1331	-3755
		Ref	208	-677	-334	-1085	-172	-1827
		L	750	232	658	15	795	-167
	High	H	-88	-1782	-1761	-2625	-1675	-4640
		Ref	416	-891	-748	-1480	-651	-2876
		L	823	-133	110	-519	205	-1356
Ref	Low	H	-2033	-120	543	325	236	2111
		Ref	-1039	1296	2040	1932	1658	4326
		L	-237	2486	3292	3275	2837	6233
	Ref	H	-671	-585	-260	-910	-492	-1130
		Ref	0	489	917	403	667	798
		L	542	1397	1910	1503	1634	2458
	High	H	17	-716	-620	-1343	-837	-2562
		Ref	520	175	393	-198	187	-798
		L	927	933	1251	762	1043	722
High	Low	H	-3454	892	1647	2005	645	5631
		Ref	-2460	2309	3143	3612	2066	7846
		L	-1658	3498	4396	4955	3246	9752
	Ref	H	-1158	402	797	469	112	1340
		Ref	-487	1476	1974	1782	1271	3268
		L	55	2384	2967	2882	2238	4928
	High	H	-82	210	368	-156	-186	-627
		Ref	422	1101	1381	989	837	1137
		L	828	1859	2239	1949	1694	2657

Process for Approval on Capital Projects Has Prejudiced the Result

- It is apparent that the process by which MH obtains approval for moving forward on capital projects warrants examination with a view to being reformed.
- Although the PUB has regulatory authority over the rates that MH imposes on ratepayers, it does not appear to have authority to approve or disapprove of MH's capital spending – unless requested by the Government (Minister of Energy) to review – and feels constrained to act within any Terms of Reference.
- BO 5/12 at 68: "While this Board's jurisdiction does not extend to the approval of MH's capital expenditures, this Board does have jurisdiction over the approval of MH's rates in which MH seeks to recover the financing, operating and amortization expenses directly attributable to MH's capital expenditures"
- BO 5/12 at 200: "PUB's role as regulator of MH is to make sure rates are justified, and that MH is not seeking increased rates for recovery of losses for mistakes, errors and inefficiencies. MH must ensure efficiencies are maximized, and that it exercises a discipline of maintaining lowest costs."

Process for Approval on Capital Projects Has Prejudiced the Result

- In this case, substantial amounts have been spent by MH prior to the Government asking for this NFAT.
- Although the PUB could deny rate increases to cover these costs, such an action would undermine indicators of financial health.
- New evidence provided in this proceeding appears to demonstrate that much less costly scenarios are possible, but may be coming to light too late to help the ratepayers.
- The remedy is to subject all major capital expenditures to NFAT review before substantial sunk costs are incurred.

LCA's Plan 17 Looks Promising

Plan 17, the LCA No New Generation scenario is a new scenario developed in the reports and testimony of La Capra. Because of Plan 17's low cost, low risk and substantial economic benefits, La Capra makes a strong case for refining this option into a full-fledged plan or an early stage of a long-term plan in order to reduce risk and cost. LaCapra recognizes that Plan 17 is not a fully fleshed out plan, but asserts that its benefits are so significant that its elements warrant serious consideration by the PUB. Transcript at 6071-78.

The LCA No New Generation Scenario Involves:

- DSM at levels 1.5 times the DSM assumed in MH's studies
- Substitution of natural gas heating for electric heating
- Development of a new 750 MW interconnection in 2029/30 with the US that increases import and export capacity.
- Reliance on relaxed import limitations (20% rather than 10% of domestic load plus export obligations) in lieu of developing generation within Manitoba, and
- Continuation of existing diversity exchange agreements with the United States.

Including Sunk Costs, Plan 17 Appears Advantageous

- Plan 17 demonstrates favorable economics despite being burdened by $4.3 billion in sunk costs that Manitoba Hydro incurred in connection with development of new hydro and transmission features that add little or nothing to Plan 17's value.
  - Sunk costs of $1.0 billion are associated with preserving the option to build Keeyask and/or Conawapa.
  - An additional sunk cost of $3.3 billion is associated with Bipole III.

Transmission Planning Standards

- According to Manitoba Hydro, the existing transmission system is vulnerable to a common mode failure such as catastrophic outages of either or both of Bipoles I and II for a period of months or years.
- 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); utilities must evaluate such scenarios for risks and consequences but need not mitigate them.
- 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.
- 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.

MH Reliability Standards Have Changed

- In justifying Bipole III for reliability reasons, Manitoba Hydro adopted a <u>deterministic</u> standard requiring that it be able to meet its peak demand after a loss of both Bipoles I and II for a period of months or years.
- The deterministic reliability standard used to justify Bipole III may not have been carried over in developing plans for comparison in the NFAT.
- That deterministic standard could be met either (1) by strengthening interconnections to the United States or (2) by adding Bipole III.
- Manitoba Hydro chose the more expensive option, adding Bipole III.

Planned Hydro Generation Additions Diminish Claimed Reliability Benefit of Bipole III

- The 2000 MW spare transmission capacity initially created by adding Bipole III will drop when Keeyask is added and virtually disappear once Conawapa is added.
- Under the PDP, Manitoba Hydro plans to upgrade its ability to import capacity from the USA to replace the diminishing spare transmission capacity in Bipole III.
- [redacted]

Too Many Eggs in One Basket

- Each of the hydro plans causes greater concentrations of the Province's hydro resources along the lower Nelson River, even higher than the present high (70%) concentration.

- MH’s failure to evaluate these impacts seems to be an oversight in that the same type of catastrophic events that could take out Bipoles I & II could also take out Bipole III as well, trapping immense portions of Manitoba Hydro's resources without an outlet and cutting off revenues from export sales for extended periods of time. Without sufficient import capacity from the United States, Manitoba could be plunged into darkness under that scenario.

—LCA No New Generation Plan Supports Additional Interconnection

[redacted]

LCA's Plan 17 Promotes Exports and Imports

Addition of another 500 kV US interconnection alone without additional hydro capacity will increase Manitoba Hydro's exports as well as its ability to import power, according to LCA's analysis.

LCA's No New Generation Plan Annual Resource Generation Mix

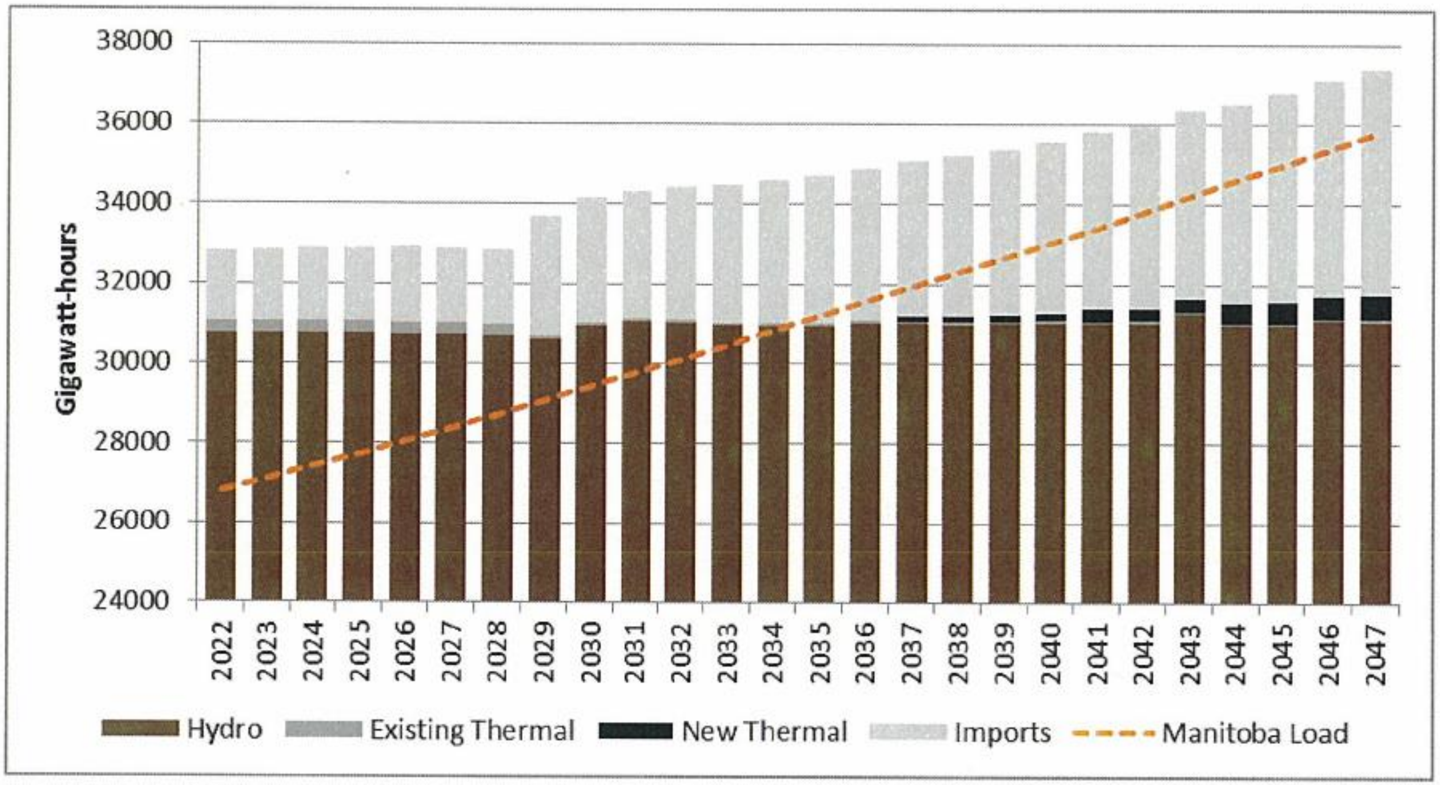


Figure 3-26: Annual resource generation mix in LCA No New Generation Plan

LCA's No New Generation Plan Annual Resource Generation Mix

- This figure indicates that adding a 750 MW line between MH and MISO along with MH's purchasing firm power from generators in the U.S. (but not constructing additional generation in Manitoba) would enable MH to export substantially more power in the annual amounts shown above the dotted line. See the sentence at bottom of first paragraph: "There is also an increase in exports, which is the difference between the load line and the top of the resource mix bar."
- The final paragraph on the page states in part: "More [transmission] import capacity could allow higher imports in off-peak periods allowing exports of hydro during peak price periods. The value of these exports and of the additional capacity in this scenario is likely to be significant, but at this point is unknown, as that analysis has not been conducted by MH."
- This indicates that much of the increase in exportable energy in Plan 17 is the result of energy imported in off-peak hours and stored as elevated water in Manitoba reservoirs until needed as a source of firm capacity and energy for on-peak exports.

MH Objects to LCA's "Import" Line

MH contends that Minnesota regulators would not approve a new transmission line designed for exports to Manitoba and, further, that there is insufficient firm generating capacity in MISO that could be imported cost-effectively by Manitoba. (See MH Rebuttal of Mr. Eric Swanson of Winthrop & Weinstine, P.A.).

I disagree because:

I Disagree Because:

- MISO, PJM and SPP are summer peaking regions that should have substantial surplus capacity and energy available in the winter when Manitoba experiences its peak demand.
- Entities owning generation in the U.S. would have an incentive to increase their sales of firm and non-firm power during the off-peak winter season and engage in diversity exchanges.
- Transmission providers are required to provide transmission service under OATTs at cost-based rates and to build needed upgrades.

I Disagree Because:

- FERC has established incentives to build and own transmission facilities that make such activities quite lucrative.
- FERC Order No. 1000 requires transmission projects for "public purposes" such as renewable energy be considered in developing transmission plans.
- Minnesota utilities have petitioned the Minnesota PUB to consider a competing alternative to the Great Northern Transmission Project. See Megawatt Daily for April 17, 2014.
- Firm power sold during an off-peak season commands only about half the demand charge associated with on-peak firm power during on-peak seasons.

If Plan 17 Had Been Evaluated Earlier:

- [redacted]

- If Bipole III did not already exist, its cost would have had to be added to the cost of any plan for developing Keeyask and Conawapa.

- [redacted]

Response to MH Rebuttal

- The MH Rebuttal to WRA addresses the reliability justification for Bipole III as described in MH/MMF/WRA-004a and b.
- MH proceeded with development of Bipole III to address the risk of an extended loss of both Bipoles I and II, an event expected to occur no more than 1 day in 17 years, a 1-day-in-17-year event. We accepted the proposition that the spare transmission capacity created by Bipole III without Keeyask and Conawapa would lessen risks and costs associated with loss of both Bipoles I and II, [redacted] We also questioned how Bipole III could fulfill its role as backup to Bipoles I and II once it is loaded with Keeyask and Conawapa power. We favored an additional tie line to the US.

Response to MH Rebuttal, cont.

- MH recognized that an additional link to the U.S. was a valid alternative to Bipole III, but, in analyzing alternatives to Bipole III, MH created a different and deterministic reliability standard for judging the adequacy of that alternative in providing reliability. That alternative involved a new 1500 MW AC U.S. interconnection which MH insisted must be backed up with <u>1500 MW of new gas generation</u>. The additional cost of the new generation made an additional link to the US more expensive than Bipole III (without new generation), and that alternative was rejected.
- At page 5 of its new rebuttal, MH states that the alternative to Bipole III considered in the CEC proceeding was a new US interconnection that MH characterizes as a hypothetical "import only" transmission scenario. I am unfamiliar with the notion of an interconnection that would function as an "import only" line. Any new US transmission tie to the US would be no different in this respect from the proposed 750 MW tie to Minnesota and could be expected to provide opportunities for both imports and increased exports. This was supported by LaCapra's presentation on its No New Generation Plan.

Response to MH Rebuttal, cont.

- MH further insisted that it added on the cost of 1500 MW of new gas turbines because an "import only" line must be connected to some form of firm generating capacity. We believe that a new tie to the US would NOT need to be backed up by additional firm gas generation, especially generation needed only once in every 17 years. MH could rely upon its contingency reserves while it shops for longer-term supplies during an extended outage of both Bipoles I & II.
- MH's CEC analysis showed that it would need backup for loss of both Bipoles I & II primarily during the winter peak. With a new tie to the US, MH could expect to call upon winter surpluses of generating capacity in the primarily summer-peaking systems in the US and obtain that power at relatively low cost.

Response to MH Rebuttal, cont.

- MH seems to agree at page 6:2-6 of its latest rebuttal testimony. In speaking of its new US tie, MH states:

  > The proposed transmission line will have the added benefit of providing firm import transmission to Manitoba. As a result, Manitoba Hydro will be able to gain access to surplus energy from the MISO market at essentially no incremental capital or operating costs. There will only be variable costs associated with the cost of energy needed to supply Manitoba load in the times of unexpected outage.

- Moreover, by insisting that a new US tie be accompanied by an additional 1500 MW of gas generation, MH creates an apples-to-oranges comparison because all that Bipole III provides (if Keeyask and Conawapa are not built) is an alternative path for MH to reach its existing Northern Hydro. It does not create an additional 1500 MW of generation. Under MH's logic, Bipole III should also be backed up by 1500 MW of generation. In reality, a 1500 MW tie to the US has access to an array of generation sources while Bipole III can access only existing Northern generation.

Response to MH Rebuttal, cont.

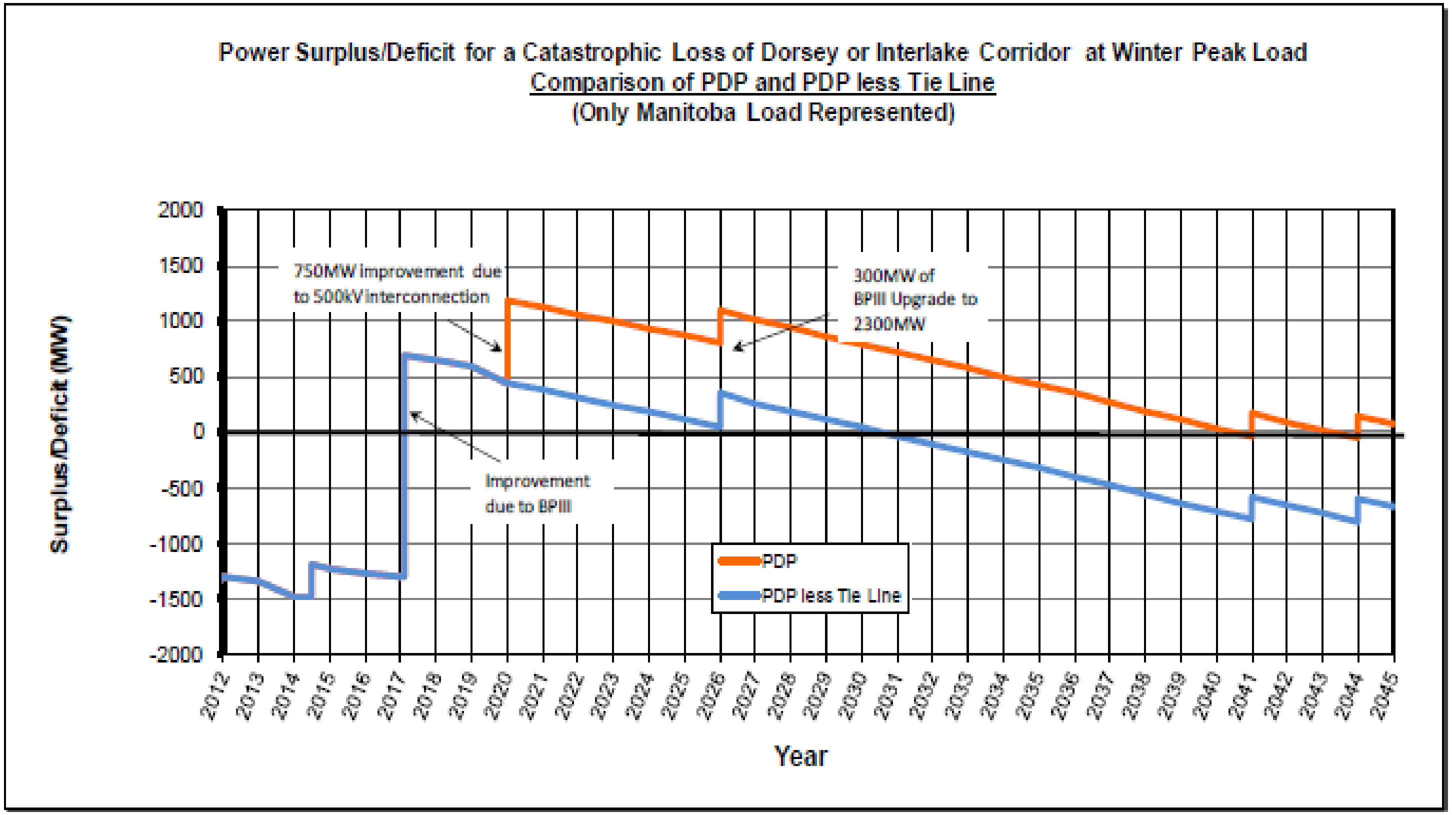
- At pages 1-3, MH challenges our position that it has implemented a less restrictive standard than it did in the CEC proceeding. MH seems to have missed my point because its rebuttal focuses on the adequacy of spare transmission capacity and not upon the adequacy of imported generating capacity to meet the strict new deterministic standard it espoused before the CEC. My calculations indicate that, with Bipole III, MH has not arranged for sufficient firm imports to meet the strict standard it set out in the CEC for covering a loss of both Bipoles I & II.
- The PUB should care about this sequence of events because MH created a stiff reliability standard to support the need for Bipole III and then seemed to back away from it in the NFAT. That stiffer standard occasioned little or no mention until MH filed its most recent rebuttal. As a consequence, Bipole III has been treated as a sunk cost in the NFAT and then repurposed. The result is a distorted economic analysis of alternatives in the NFAT. Moreover, by backing away from the CEC standard in the NFAT proceeding, MH has reduced the needed amount of firm purchases but has not updated the evaluation of a US tie on that same basis.

Response to MH Rebuttal, cont.

- In the NFAT, the hydro-based plans call for filling the spare capacity of Bipole III with the output of Keeyask and/or Conawapa. This would diminish the ability of Bipole III to provide spare capacity to cover the loss of both Bipoles I & II. In those hydro-based plans, MH would rely upon a new tie to the US to replenish the spare Bipole III capacity with capacity on a new US Tie. Thus, MH is planning to obtain backup from the US to replenish the diminishing ability of Bipole III to cover the loss of both Bipoles I & II. One wonders why it did not build a new lower-cost interconnection to the US in the first place [redacted]

MH Rebuttal Figure 1 at 4:

FIGURE 1: POWER SURPLUS/DEFICIT FOLLOWING LOSS OF BP I/II AT WINTER PEAK.



What Does This Show?

- This chart shows that an interconnection to the U.S. provides reliability benefits that are like those provided by Bipole III.

- The amount provided by the 750 MW 500 kV MMTP could have been increased, and built to a higher level [redacted]

MH Rebuttal–TPL-002 Note b

- At 6-7 of its new rebuttal, MH claims that footnote b of NERC Standard TPL-002 allows it to drop firm exports after an N-1 contingency. However, footnote b addresses an exception to the general rule of TPL-002 that Firm Transfers cannot be curtailed for single contingency (N-1) events. Instead, MH employs a number of special protection systems (SPS) to deal with its unique transmission system that cannot meet usual operating reliability levels.
- Note b states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers."

MH Rebuttal–TPL–002 Note b

- MH's SPS, in dropping firm transfers to the US goes well beyond the "radial customers or some local network customers" requirement. The US is not simply a remote load served by a radial transmission line and it is not "local network" on the MH system. Note b is applicable to minor firm load interruptions that are costly to avoid.
- Note b does not preclude the normal practice of system adjustments to prepare for the next contingency. Such adjustments can include dropping firm customers or reducing firm transfer in a controlled manner. However, automatically dropping firm customers or transfers with an SPS does not qualify as an adjustment.

In 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 DSM, imported power (supported by enhanced import capacity on its interconnections with the United States) and future gas generation would be far lower in cost in the years through 2031, 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.