REPORT ON EXPORT PRICES AND REVENUES RELATING TO THE NEED FOR AND ALTERNATIVES TO (NFAT) MANITOBA HYDRO'S PREFERRED DEVELOPMENT PLAN

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CONTAINS COMMERCIALLY-SENSITIVE INFORMATION

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Executive Summary

A. Overview

Manitoba Hydro is seeking government approval of its preferred development plan for investments in generation and transmission capacity in order to support domestic load growth and expand opportunities in export markets.

The Manitoba Public Utilities Board ("PUB") was asked by the Government of Manitoba to conduct a Needs For and Alternatives To ("NFAT") review of the Manitoba Hydro development plan. A panel of PUB members ("the NFAT Panel") was selected by the PUB Chair to conduct the review. In order to proceed with its review, the NFAT Panel will use evidence presented by Manitoba Hydro, interveners, and independent experts provided by PUB. Potomac Economics is one of the PUB independent experts and our report addresses expected export market conditions in the markets administered by the Mid-Continent Independent System Operator ("MISO"). The MISO markets are the primary source of export revenues for the preferred development plan.

Potomac Economics is the Independent Market Monitor for the MISO. In this role, we closely monitor prices, investments, market structure, and market outcomes. We are also the Independent Market Monitor for ISO-New England, the New York ISO, and ERCOT (Texas). We rely on this broad experience with the development and performance of wholesale electricity markets to conduct this study.

Manitoba Hydro's preferred development plan establishes generation capacity which exceeds the projected domestic load requirements for a significant period of time. The excess capacity, along with other investments in the plan to expand transmission ties to the US, would support export sales. According to the plan, by building larger plants and using the excess capacity to support export sales, the cost of meeting the growing domestic load in Manitoba is lower than if capacity was built to meet load growth alone. The preferred development plan is expected to deliver the expected benefits if actual conditions meet certain critical projections. Among these critical projections is the revenue that can be earned from sales of energy and capacity to the MISO markets in the US. These revenues are based on export price forecasts from six consultants retained by Manitoba Hydro. Our report assesses the price forecasts and other associated issues that form the basis for Manitoba Hydro's projected MISO export revenues.

In order to assess Manitoba Hydro's price forecasts, we developed our own price forecast based on a method and approach that we find to be a reasonable and transparent. Our method is based on forecasts of key drivers of MISO market prices. These key drivers are fuel prices, load growth, generation retirement and additions, new-build generation capital and operating costs, environmental regulations, and congestion.

Manitoba Hydro's six consultants based their forecasts on essentially the same key drivers. However, we believe certain assumptions made by the consultants tended to overstate the level of future prices. Due to limits on the availability of the underlying data from the consultants' models, we were not able to perform a detailed review of the consultants' models nor could we adjust the specific assumptions in the consultants' forecasts to address differences. As result, we provide an alternative forecast and recommend that these forecasts be used to assess revenues projected under the development plans.

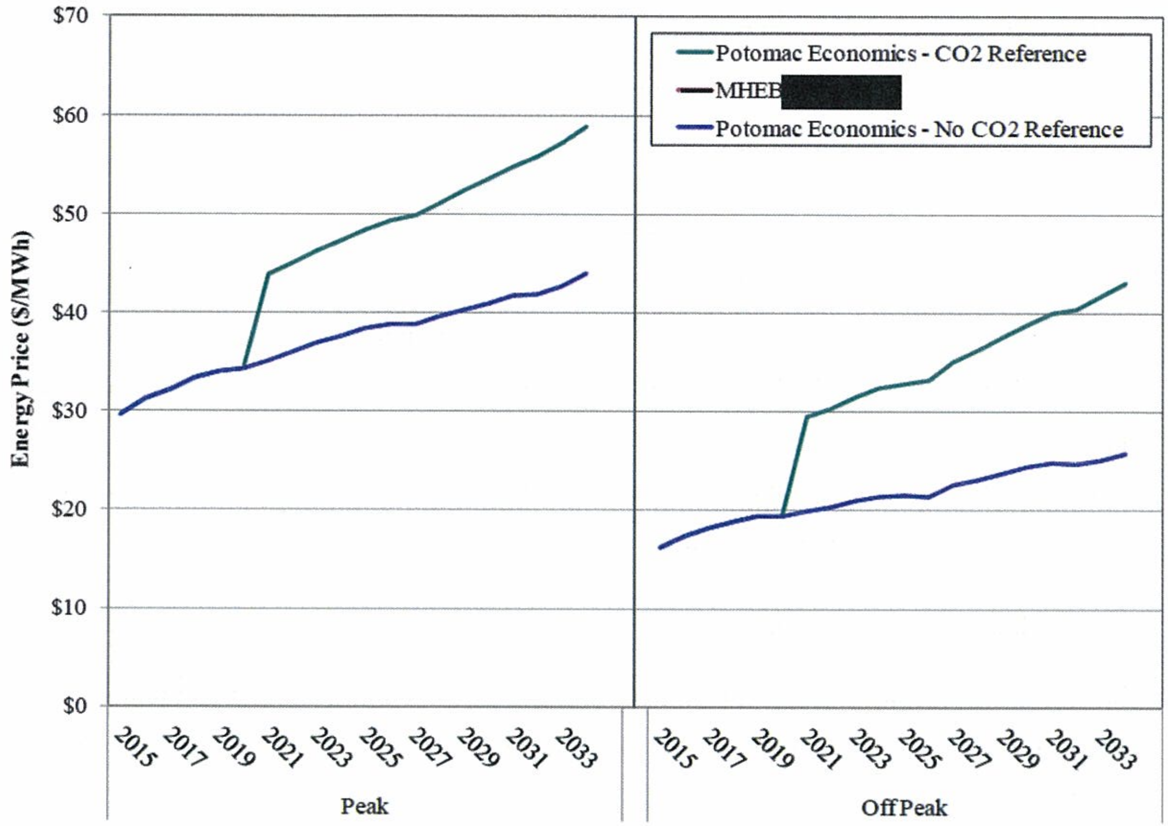
B. Summary of Results

Our forecast is based on MISO supply and demand characteristics and recent market outcomes. Changes in these characteristics and outcomes are forecasted for future years based on assumptions regarding the evolution of key drivers noted above.

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. As explained herein, our point-of-view on these key assumptions is based on the reference case used by the US Energy Information Agency (EIA) in its 2013 Annual Energy Outlook.

Figure 1 shows our two reference case forecasts for on-peak energy and off-peak energy prices compared to the Manitoba Hydro reference price forecasts. Manitoba Hydro's reference price forecast is the composite of its six consultants' forecasts. We produce two reference case forecast in order to reflect two CO2 price scenarios – one scenario is based on the reference forecast of Mr. Craig Sabine of MNP, and the other is a reference case with no CO2 costs. We explain these various cases in Section II.

Figure 1: MH and Potomac Economics Reference Case Energy Forecasts

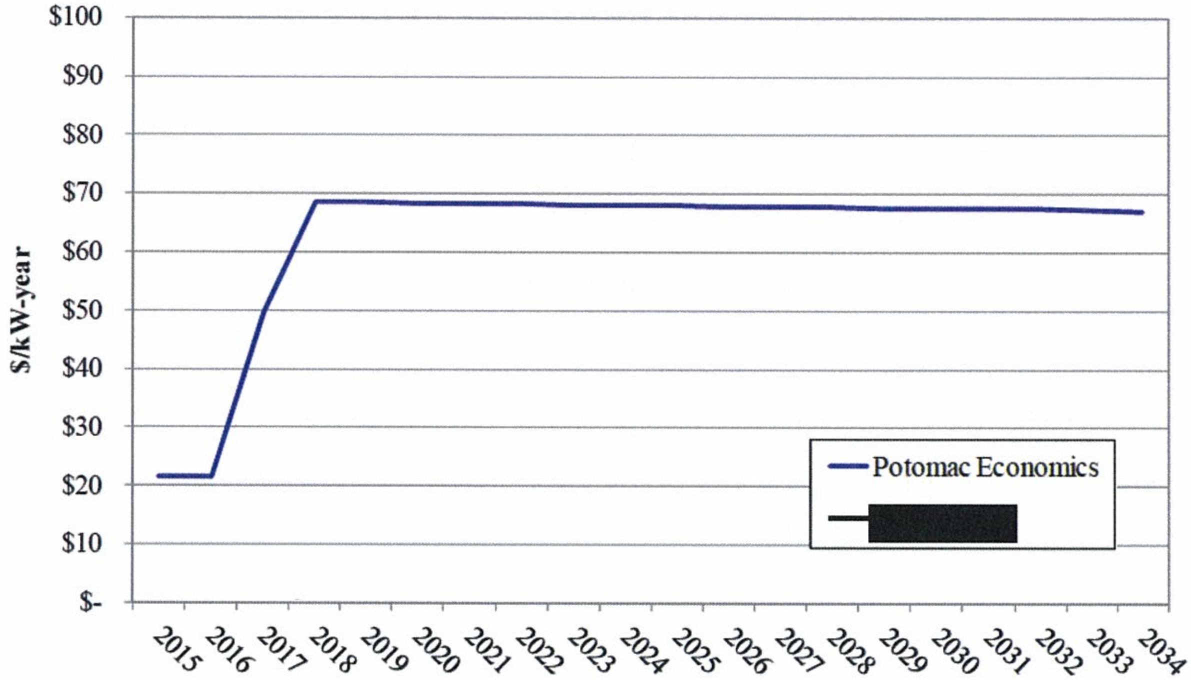


Criteria 3a

As the figure shows, the Manitoba Hydro forecasts are [redacted] for both on-peak and off-peak energy prices, although our reference forecast [redacted] forecast period for on-peak energy. In this report, we will explain how we developed our price series and why they are different from the Manitoba Hydro prices.

We also forecast capacity prices, which are based on our estimate of the net cost of new entry ("net CONE"). We assume that when surplus capacity dissipates, the capacity price will rise to the level necessary to incent the construction of new resources. As we explain herein, this capacity price is at most the net CONE of a new peaking resource, which is equal to the resource's cost of new entry less the variable profit it would earn in the MISO's energy and ancillary services markets. However, in the short-run, we do not expect the market to support the net CONE. Figure 2 shows the comparison of our reference case capacity price forecast and Manitoba Hydro's forecast.

Figure 2: MH and Potomac Economics Reference Case Capacity Forecasts



As the figure shows, our price [redacted] estimates by Manitoba Hydro. The main reason for this is our assumptions regarding the cost of new entry. Our assumptions regarding the costs to build an advanced combustion turbine [redacted] that assumed by Manitoba Hydro consultants. We note that the capacity prices that we forecast [redacted] than that which Manitoba Hydro can actually achieve, due to regulatory and other constraints, discussed herein.

We present forecasts for energy and capacity prices under four scenarios that examine alternative assumptions. In addition to our two reference cases, we examine alternative assumptions concerning natural gas prices and economic growth. Changes in these assumptions can substantially affect Manitoba Hydro's forecasted revenues.

C. Organization of Report

We were asked by the PUB to provide an Independent Expert Report on MISO market conditions that Manitoba Hydro will face under its proposed development plan. Because the critical factor in the MISO markets is prices, the main part of our report is in the following three sections:

Section I discusses the price forecasts used by Manitoba Hydro;

Section II presents our own forecasts for energy prices; and

Section III presents our own forecasts for capacity prices.

In addition to assessing the price forecasts, we also assess issues associated with other expected market conditions that affect future export prospects. These other issues include: (2) developments in neighboring regions; and (3) export volumes and pricing. These other issues are discussed in Section IV.

I. THE CONSULTANTS' PRICE FORECASTS

Manitoba Hydro used six external consultants to produce price forecasts for its financial model. These six forecasts are used on an equal-weight basis to establish a single consolidated forecast. In this section, we review and discuss the six forecasts.

A. Products

The company expects to sell an on-peak energy product, an off-peak energy product, and a long-term "dependable" product. The on- and off-peak products are assumed to be priced based on the consultants' on- and off-peak price forecasts. The long-term dependable product is assumed to include a capacity component. Accordingly, Manitoba Hydro asked the consultants for 20-year forecasts for the period 2015-2034 for on-peak energy, off-peak energy, and capacity prices.

B. Summary of Consultants' Forecasts

The six consultants use variations on a common approach to forecast energy prices. The approach uses a so-called "fundamentals" model that basically attempts to simulate the energy dispatch of the electrical system to determine which units are on margin during each hour of the year. The hourly prices simulated for on-peak periods are the basis for the on-peak prices and the hourly prices simulated in the off-peak periods are the basis for the off-peak prices.

The consultants generally use the forecasted energy prices and the estimated cost of new entry for a new peaking resource to forecast capacity prices. In particular, the forecasted capacity price in each year is generally equal to the annual fixed cost of new entry less the anticipated "net revenues" earned by a peaking unit. Net revenues are the revenues a unit would earn in MISO's energy and ancillary services market in excess of its variable production costs. This net revenue approach is a reasonable way to forecast the capacity price. It is important to recognize that the MISO does not currently have a well-functioning capacity market that would establish prices consistent with this net revenue methodology. Nonetheless, one may assume that Manitoba Hydro may be able to sign bilateral contracts to sell capacity at these price levels to load-serving entities in MISO that would otherwise be short of capacity. There is some uncertainty about this assumption which is discussed in Section III.

The following is the list of consultants and the summary of the results of their analysis and our discussion of their process and results. The consultants each provided forecasts of off- and on-peak energy prices and annual capacity prices. The consultants provided a "reference case" and most consultants provided a "low" and "high" case. Our discussion of the consultants' models is confined to the on-peak energy price and the capacity prices associated with the "reference case." The issues identified with the reference case also tend to adversely affect the consultants "high"- and "low" cases in comparable ways. Similarly, the problems we see with the on-peak energy price estimates, also affect the off-peak estimates in the same manner. Therefore, we focus on the areas of concern associated with the reference case for on-peak energy and capacity.

At the outset, we note that detailed information regarding each of the consultants' models, assumptions, and output was limited. We generally only received high-level representations of the models and inputs. This limited our ability to critically review the consultants' results and ultimately compelled us to produce our own forecast. Nonetheless, we briefly summarize each of the six consultants' forecasts in the following subsections.

1. The Brattle Group

The Brattle Group forecasts reference case on-peak energy prices in the near term just under \$40/MWh until about 2020, then increase to over \$60/MWh by the end of the 20-year forecast period. As indicated above, the forecast is based on a simulated dispatch of the system using a variety of assumptions. Given our limited information regarding the model and assumptions, it is not straightforward to determine exactly what drives the price forecast. However, we note three key assumptions used by the consultant (and which generally are the key assumptions used by all of the consultants). The first is the assumed introduction of carbon taxes in 2020. This starts at \$15/ton and grows until 2034 to about \$24/ton. The second key assumption is the increase in the price of input fuel -- natural gas prices increase by 60 percent over the 20-year period. This has an impact on the on-peak price directly, but is also interconnected with the third key assumption, which is the retirement of coal plants. Lower coal capacity causes natural gas-fired units to be on the margin in more hours. Both the additional hours on the margin and the higher natural gas prices will cause energy prices to be higher. Brattle did not report MISO-wide retirements in its work papers. It reports MRO-West retirements because its forecast model focuses on the MRO West sub-region of MISO. However, a report by Brattle in 2013 indicates between 11 and 16 GW of MISO coal plant retirements. This level of MISO coal plant retirements is substantially above the level we assume in our reference case. As explained below, we assume 6 GW of MISO-wide coal plant retirements. The emissions and fuel cost assumption along with the high level of coal plant retirements are likely to overstate energy prices.

Capacity prices are based on the least-cost capital investment needed to meet planning reserves over the 20-year horizon. The annual fixed cost of this investment (primarily capital carrying costs) net of revenues earned in the energy markets, establishes the capacity price for each year. This is affected primarily by the energy price forecast and the net retirement, but also capital costs of new facilities. As a noted above, this approach assumes Manitoba Hydro will sell capacity to utilities in MISO on a bilateral basis to meet the utilities' planning reserve requirements, rather than selling in the short-term capacity market presently existing in MISO.

Capacity prices estimated by Brattle are zero until 2019, reflecting an assumed capacity surplus in MISO until that time. After 2019, the price rises to over $70/kW-year. The Brattle work papers do not specify what type of unit is setting the capacity price in a given year. However, the capacity price is consistent with the capital cost identified by the consultant for both the natural gas-fired combustion turbine and the natural gas-fired combined cycle plant ($1200/kW net of modest energy market revenues). Both the CT and the CC are assumed to have capital cost of about $1200/kW, which is roughly $120/kW-year in carrying and fixed costs. The lower value of $70/kW-year could reasonably reflect variable profits in the energy markets.

The consultants' assumed capital costs for the combustion turbine are generally higher than those used by the other consultants. In particular, the consultant assumes a cost of $1200/kW for a CT, whereas the EIA has identified an advanced CT as having a capital cost of approximately $700/kW. This would have a significant effect on the consultant's capacity prices. EIA's estimate of the advanced combined cycle plant ($1000) and the conventional combined cycle plant ($900/kWh) are also somewhat lower than the estimated cost used by the consultants.[1]

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1 See, EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants", April 2013, http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

We believe the emissions and fuel cost forecasts assumptions may overstate the expected cost profile of fossil-fuel fired resources and, thus, overstate energy prices. This may also understate capacity prices since net revenues would likely decline under a projection of lower energy prices. But this effect is confounded by the apparent overstatement of generator capital costs. Based on the information provide, we are not able to disentangle these countervailing effects and so we cannot recommend using the Brattle estimates as a basis of future prices.

2. [redacted]

[redacted]

[redacted]

[redacted] As a result, we do not recommend these as the basis for the export revenue forecast.

3. [redacted]

[redacted]

[redacted] Due to the lack of underlying data, we cannot recommend using this forecast for estimating export revenues.

[redacted]

[redacted]

[redacted] Hence, we cannot endorse this forecast as reasonable.

5. [redacted]

[redacted]

[redacted]

[redacted] We do not recommend this forecast as a basis for projecting export revenues.

6. [redacted]

[redacted]

[redacted]

C. Conclusions on Consultants' Price Forecast.

In general, the key assumptions used by the Consultants [redacted] This is particularly the case with respect to (1) natural gas prices, load growth, coal retirements, and cost of new entry. With respect to CO2 prices, our reference case assumptions tend to be [redacted] We explain our forecasting approach in the next section. In the Tables below, we compare our forecasts to the consultants.

The Table below shows a comparison among the six consultants along with our own forecasts of (1) on-peak energy; (2) off-peak energy; and (3) capacity.

Figure 3: Comparison of Reference Case On-Peak Energy Prices

[redacted]

Figure 4: Comparison of Reference Case Off-Peak Energy Prices

[redacted]

Figure 5: Comparison of Reference Case Capacity Prices

[redacted]

Criteria 1, 3a & 4

D. Composite Forecasts and Alternative Cases

Manitoba Hydro used the consultant's price forecast to create a single composite forecast, which is basically an average of the consultants' forecasts. The following three charts show the composite price forecasts for the three power products (1) on-peak energy; (2) off-peak energy; and (3) capacity. In each case, we show the Manitoba Hydro composite forecast the consultants' reference case as well as the composite "high" and "low" forecast cases. We also show our reference case and the "high" and "low" alternatives for each forecast.

The low and high case alternatives were produced by each consultant at the request of Manitoba Hydro. Manitoba Hydro required plausible scenarios that could represent the lower and upper limits of pricing trends. While we also produce two alternative cases, our cases are based on likely alternatives that together with the reference case, represent a large range of probable outcomes. In other words, we expect that future prices are very likely to fall within the bounds of our three forecast scenarios.

Figure 6: Manitoba Hydro On-Peak Energy Price Forecasts

[redacted]

Figure 7: Manitoba Hydro Off-Peak Energy Price Forecasts

[redacted]

Figure 8: Manitoba Hydro Capacity Price Forecasts

[redacted]

II. Potomac Economics Energy Price forecast

Because detailed information regarding the consultants' models, input data, and results was not available to Potomac Economics, we evaluated their reasonableness by comparing their forecasts to a range of forecasts we developed. This section of the report describes our methodology and provides a detailed discussion of the results.

A. Overview of Forecast Model

Our forecast is based on historical publicly-available market outcomes in the MISO markets for 2011 and 2012. Our approach uses these actual day-ahead market results and adjusts them to anticipated changes in future market conditions, such as fuel prices, capacity, carbon taxes, and load growth. The MISO market data we use includes hourly data on system load and capacity, system marginal price, and supply offers. The day-ahead supply offers specify offer price, offered quantity (MW), fuel, and whether the offer was accepted. By stacking the offers in accordance with energy offer price we establish an hourly supply curve. We adjust the hourly supply curves to account for changes in fuel costs, new capacity additions and retirements, and carbon taxes. Hence, we establish a supply curve for all future hours in the twenty-year forecast horizon (2015-2034). Using actual hourly generation demand and assumptions regarding the growth of load, we establish forecasted load in every hour of the forecast horizon. Based on the intersection the hourly supply curve and the hourly system load (along with some operational adjustments described below), we can establish a system marginal price for each hour of the twenty-year forecast period. These hourly prices are the basis for our on-peak and off-peak energy prices.

Locational Marginal Prices. The prices estimated using the hourly supply curves are the system marginal prices ("SMP"). They do not reflect the locational marginal prices (LMP) that would be received by a seller of power at various locations in MISO. Congestion and marginal losses will cause a locational price to be different from the SMP. Therefore, we compute a locational marginal price at the Manitoba interface with MISO by subtracting losses and congestion costs from the SMP. Congestion costs are estimated based on the historical relationship between congestion and factors that tend to explain their level, such as time of day, generation, load levels, and exports from Manitoba Hydro to MISO. We use the historical average marginal losses as the estimate of future losses.

Capacity Prices. Capacity prices are estimated based on the net cost of new entry (net CONE). This net CONE is the annual carrying cost and other fixed cost of a new combustion turbine less the variable profits earned in the MISO energy and ancillary services markets. Based on the heat rate of a new combustion turbine (CT), any hour when the SMP is above the variable energy cost for the CT, the difference in marginal energy cost and the LMP is the net revenue for that hour. The resulting total net revenues are deducted from the annual fixed cost of the new unit to arrive at the estimated capacity price. The estimated price is the amount an investor would need to be paid to profitably enter the market with the prospect of earning MISO energy and ancillary services revenues. However, this price is relevant only if capacity is needed. In times of capacity surplus, the capacity price is likely to be less than this price and, indeed, sometimes close to zero. This presents a substantial risk for Manitoba Hydro that its capacity revenues may be much lower than expected.

B. Specifics of Forecast Model

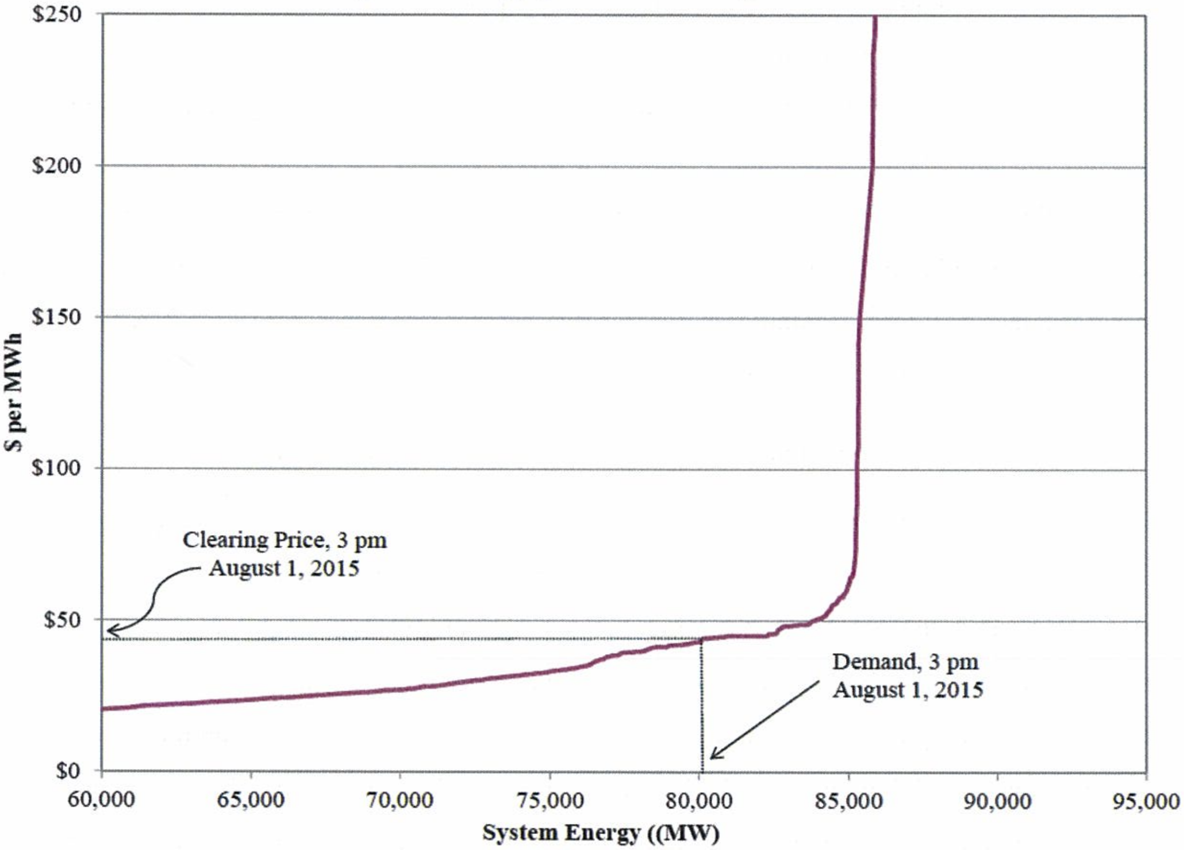
1. Hourly Supply Curves and Demand

Our forecast model uses two years of historical MISO market data and creates two forecasts for each hour for the forecast period 2015-2034. There are two forecast for each hour, one based on 2011 hourly market data and the other on 2012 hourly market data. We average the two forecasts to get the forecast for each future hour.

For each historical hour, the day-ahead MISO data contains an offer curve for each resource that indicates the quantity, fuel type, and offer price (for start-up, energy, and ancillary services). We use these offers to establish an hourly supply curve for each historical hour, which is a simple stack of the MW offers in ascending order of offer price for each MW block.

We next use hourly generation demand to identify where system demand intersects the historical supply curve for each historical hour. Hourly system demand also is publicly available from MISO. It contains day-ahead system demand as well as net imports so that we can identify the hourly load that was served by the available supply in each historical hour. Comparing the hourly load level to the supply curve identifies which unit would supply the last MW of load under the assumption that all units are dispatched fully.

Figure 9: Supply Curve for August 2015



Note: The "clearing price" shown is the basis of the forecast SMP. To arrive at the SMP, the clearing price is increased to reflect operational issues. This increase is derived from the historical clearing price and the historical SMP for each hour.

This marginal unit representing the direct intersection of the hourly supply curve and the hourly load is not likely to be the one that actually sets the system marginal price. This is because of operational constraints. Operational constraints occur as a result of constraints in the operation of generators. There are a number of operating constraints that may cause the strict stacking of units from low to high marginal cost not to match the actual dispatch. First, units may not be fully dispatched due to ramp limits in a given hour. In such a case, units may be dispatched at a higher or lower output level than would be indicated by running costs alone. A high cost unit may also be running because it is meeting a minimum run time. Such a unit may be more expensive than other units not fully running because the more expensive unit is needed in some future hour and needs to be started in advance. Or the more expensive unit was needed in a recent hour and needs some time to turn down or turn off.

In each hour, MISO publishes the day-ahead SMP. With the SMP we can identify the unit that sets the marginal price on the historical hourly supply curves. Because this is rarely the unit that would clear in a "pure" sense from stacking the units against demand, in each historical hour we measure the movement up the supply curve that was necessary for MISO to undertake to dispatch the system in that hour given the operational restrictions it must accommodate. This value is expressed as a percentage increase in the energy "clearing" price. We retain this value, which we call the hourly "operational adjustment," because it is important for estimating the market clearing price for future periods.

2. Clearing the Hourly Forward Market in Future Hours

To clear the hourly market, and establish the forecast price for that hour, we adjust each historical hourly supply curve based on anticipated changes in key supply variables (fuel costs, etc.). We explain the evolution of the supply curve over the time horizon below. We also assume load grows at certain rates. Hence, in every future hour, we have (1) the estimated forecast hour supply curve; (2) the forecast hourly load; and (3) the "operational adjustment" (based on historical movement along the supply curve to clear the market, described above). Matching the estimated supply curve to the forecast demand for each hour, we identify the marginal unit in a "pure" market clearing. We then adjust the forecasted price by a percentage amount equal to the "operational adjustment," discussed above, to account for operating constraints. The resulting price is the forecast SMP for that hour.

3. Formation of Supply Curves

The process of clearing the hourly market described in the previous subsection is based on estimated supply and demand. The estimated supply curves for future hours evolve from the historical supply curves. If all key supply variables remained fixed, then the forecast of each future hour would be identical to the base historical hours from 2011-2012. However, of course, key variables change. In particular, we create new supply curves for each hour based on projections of (1) fuel prices; (2) additions and retirements of generating capacity; (3) load growth; and (4) carbon taxes. In addition, we make assumptions about the cost of new capacity in order to estimate the cost of new entry to support the capacity price forecasts. We discuss the particular projections of these key assumptions in the next subsection. In this section, we describe how the supply curves change as a result of the key assumptions.

Fuel Prices. When fuel prices change, the marginal cost of producing energy from a resource using that fuel will change. In a competitive market, suppliers submit offers that are consistent with their marginal costs. Therefore, the offer prices of the unit will change as fuel prices change. Hence, each hourly supply curve in a given year will change based on the change in fuel prices for that year compared to the historical year.

CO2 Prices. CO2 prices are projected for potential changes in law regarding green-house-gas emissions.[2] CO2 prices are based on cost per ton of CO2 output. Coal and natural gas have specific CO2 content. According to the US EPA, Average CO2 output of a coal unit is 1.02 (metric)\tons/MWH and for a natural gas units about 0.516 tons/MWh.[3] This emissions rate is multiplied by the CO2 price forecast for each year to estimate the additional cost to be added to the unit's offer curve. For example, the CO2 price in 2021 is projected to be $13.14/(metric) ton. Therefore, offer curves for coal units have an increased incremental energy component of $13.14/ton x 1.02/tons/MWH = $13.40/MWh. For natural gas units, their incremental energy offers increase by $13.14/ton x 0.516/tons/MWh = $6.78/MWh.

Generating Resources. The historical supply curves for each hour are based on units that are in-service during that particular historical hour in the 2011-2012 historical years. In each subsequent year, the set of in-service units changes based on assumptions regarding *new* additions and retirements. This can result in a re-ordering of the capacity in the supply curve through "re-commitment" discussed in the next subsection. Our base assumptions regarding additions and retirements are based on the EIA Annual Energy Outlook assumptions.[4] We adjust these assumptions as needed to satisfy MISO's resource adequacy needs. When additional

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2 We adopt the CO2 prices developed by Independent Expert Consultant Mr. Craig Sabine of MNP.

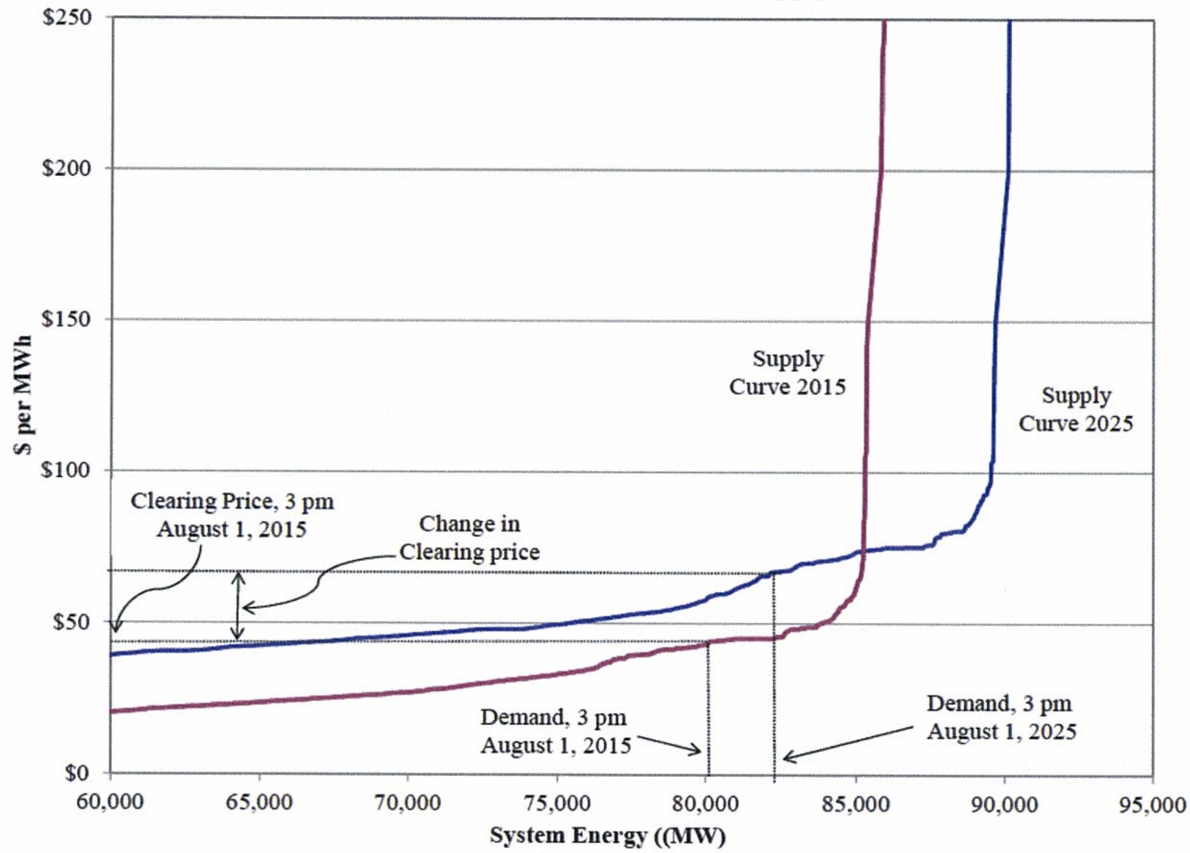
3 See EPA, http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

4 See, http://www.eia.gov/forecasts/aeo/data.cfm

resources are needed, we assume one-half of the new resources are combined cycle natural gas units and one-half are natural gas combustion turbines.

When the EIA data indicates retirements of a unit type for a specific year (e.g., coal units), we choose units to retire based on units net revenue for the previous year. The least profitable are retired first.

Figure 10: Example of Change in Supply Curve



Note: The figure shows the change in forecast clearing price in our model resulting from changes in supply and demand between 2015 and 2025.

4. "Headroom" and Daily Recommitment

The supply curve for each future period also is adjusted to reflect the fact that future periods will have different supply and demand characteristics due to changes in key drivers, mainly load and the composition and quantity of available generating capacity. The supply curve for a historical hour is based on the historical load and the commitment of units in service at the time. When load changes in a future hour, it is not reasonable to simply move along the historical supply curve to a new load level to clear the market for that future hour. Instead, at a new load level, some units that were not committed in the historical hour may be economic for commitment at a higher or lower load level and therefore be added to the supply curve. This type of recommitment may also be appropriate if new units are added or existing units retire - these new units may replace existing units in the stack or existing units not initially committed may replace retired units in the stack.

In order to recommit generation, we seek to ensure the system has adequate resources to meet forecasted load, ancillary services, and the market headroom requirement (the headroom requirement is the additional operating flexibility required by RTOs to meet ramp demands). Much like MISO's day-ahead market, our process for re-committing resources is performed on a daily basis. If headroom is inadequate in some hour, the daily commitment is revised to ensure that sufficient generating capacity is available for dispatch.

The revised commitments are is then used as the basis for the hourly supply curves for that day and the market is cleared in accordance with the process described above.

5. Reference Forecast Assumptions and Alternative Cases

We develop forecasts under three alternative scenarios. Each differs from the other according to different assumptions on key supply and demand inputs. As we discussed above, aside from the historical MISO data that form the base case supply curves, a price forecast depends on assumptions about (1) load growth; (2) fuels costs; (3) retirements and additions; (4) CO_2 prices; and (5) cost of new generation (for capacity prices). Our three scenarios are as follows:

a. Reference Cases

We use two reference cases due to the significant uncertainty regarding the introduction of CO_2 costs. We develop a first case, called simply, the "Reference Case," which includes positive CO_2 costs. Our "Reference No Carbon" case is very similar to the reference Case except CO_2 costs are zero, and the load growth is slightly higher.

Both the Reference Case and the Reference No Carbon case are based on the assumptions used by the EIA in its 2013 Annual Energy Outlook for its own reference case. The EIA reference case assumes CO2 costs are zero. Therefore, the EIA reference case assumptions on load, capacity, and fuel prices are used in our Reference No carbon Case.

For our Reference Case (with Carbon), we depart from the EIA reference case in order to reflect CO2 prices. We introduce a CO2 price in 2021, consistent with the forecast of Mr. Craig Sabine of MNP who is the Independent Expert Consultant for the PUB in this NFAT on matters relating to CO2 pricing. According to Mr. Sabine's reference case, the CO2 price will be zero until 2021, at which point it will be $13.14/ton and increases by 5 percent per year thereafter. We reflect Mr. Sabine's forecast by adjusting offer curves for fossil fuel plants to account for the additional CO2 cost. The adjustment to offer curves to reflect this additional cost was described above.

We also slightly reduce the EIA Reference Case load growth starting in 2021 to reflect non-zero CO2 prices starting in year 2021. In particular, for the years 2015-2021, we use the compound average growth rate (CAGR) from the EIA reference case for those years. Starting in 2022, we adopt the load growth rates envisioned by EIA under a $10/ton CO2 price ("EIA GHG10"), wherein the EIA assumes a 2014 CO2 price of $10/ton. We use the CAGR from EIA GHG10 for the years 2015-2034 for our years 2022-2034 in our reference Case. We use the earlier years in the EIA GHG10 to match the growth rates that would be expected once the non-zero CO2 prices are realized (assumed to be realized in 2021 in our Reference Case).

For both of our reference cases, fuel prices were taken directly from the EIA reference case -- Henry Hub for natural gas prices and Wyoming Powder River Basin for coal. We assumed a further coal transportation cost into MISO of $1.7/MMBTU, a value typically used in the MISO to account for coal transportation. Natural gas transportation costs are assumed to be $0.75/MMBTU. Generation retirements and additions are taken directly from the EIA reference case. We began 2013 with a MISO capacity surplus of 6,200 MW.[5] When load growth together with net capacity retirements resulted in a year with a capacity deficit, some future EIA reference case additions were moved forward or additional natural gas capacity was added beyond that scheduled in the EIA reference series. These key input series are shown in Appendix A.

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[5] See Potomac Economics, "2012 State of the Market Report for the MISO Electricity Markets", p. 18, figure 8. It shows a capacity market surplus for July 2012 of 6200 MW.

For each year, we simulate the SMP for all hours using the historical supply curves adjusted for the assumptions of this case. For the 16 peak hours of each (non-holiday) weekday, we calculate the average SMP to establish the on-peak SMP for that hour of that year. The average price for all other hours establishes the off-peak SMP for that hour of that year.

b. High Resource Production (Low Fuel Price) Case

We believe a credible case is one in which natural gas prices may show little change over the next 20 years. This is credible because of the additional natural gas supply that has been made available through hydraulic fracturing technology, which has already been shown to increase natural gas production in North America. Accordingly, we produce a price forecast using the assumptions associated with EIA's "High Oil and Gas Resource" case, which models the effect of high resource production on fuel prices and the secondary effects on electricity markets.

For load growth in the High Resource Case, we used the levelized growth rate of load for the 2015-2034 period used in EIA's High Resource case. We assume no CO2 costs for this case. Fuel prices were taken directly from the EIA High Resource case (the Henry Hub natural gas and Powder River Basin coal prices).

Generation retirement and addition assumptions are taken directly from the EIA High resource case, but adjusted to ensure that MISO's resource needs are satisfied. Like our reference case, we began 2013 with a MISO capacity surplus of 6,200 MW. When load growth together with net capacity retirement resulted in a year with a capacity deficit, some future EIA reference case additions were moved forward or additional natural gas capacity was added beyond that scheduled in EIA High Resource series. These key input series are shown in Appendix A.

c. High Economic Growth Case

We also believe there is a significant likelihood that economic growth may be higher than assumed in the EIA reference case. Accordingly, we produce a price forecast using the assumptions associated with EIA's "High Growth" case, which models the effect of higher macroeconomic growth on electricity markets. We assume CO2 cost in accordance with the reference case developed by Mr. Sabine (the same CO2 costs as in our reference case above), which start at $13.14/ton in 2021 and increases at a rate of 5 percent per year thereafter. For the years 2022-2034, load grows more slowly than in the EIA High Growth case. We assume a lower growth rate in later years to reflect the effects of the CO2 costs. In particular, the growth rate is the average of (1) the levelized growth rate in the EIA High growth case for 2022-2034 and (2) the levelized growth rate in the EIA GHG10 case for the year 2015-2034.

Fuel prices were taken directly from the EIA High Growth case (Henry Hub natural gas and Powder River Basin coal).

The quantity and timing of generation retirements and additions are taken directly from the EIA High Growth case, adjusted as needed to satisfy MISO's resource needs. Like our Reference Case, we began 2013 with a MISO capacity surplus of 6,200 MW. When load growth together with net capacity retirement resulted in a year with a capacity deficiency, some future EIA High growth case additions were moved forward or additional natural gas capacity was added beyond that schedule in EIA High Growth series. These key input series are shown in Appendix A.

C. Estimates of Losses and Congestion

The previous section described the forecast of the MISO System Marginal Price, which is the underlying commodity price throughout MISO. This price does not include the effects of losses or transmission that can cause locational marginal prices ("LMPs") at a location to be higher or lower than the SMP. Manitoba hydro will settle its energy imports at the Manitoba interface location. Therefore, we forecast the losses and congestion that will be incurred at the Manitoba interface relative to the SMP. We use the historical relationships in the 2011 and 2012 data to forecast future losses and congestion.

1. Losses

For losses, we use the average observed marginal losses calculated by MISO over the two year period 2011-2012 as the marginal loss factor going forward. We do not believe there are any currently known changes to the system that would raise or lower losses significantly going forward. For on-peak hours, we assume an average marginal loss factor of 8.8 percent. For off-peak hours, we assume a marginal loss factor of 9.4 percent.

2. Congestion

Unlike losses, transmission congestion can change substantially as the dispatch of the system or the topology of the network changes. To forecast congestion, we develop an econometric model to estimate how key factors will affect congestion. We use standard linear regression techniques to develop this model. The estimated relationship is then used to forecast the future value of congestion based on projections of future key variables. The results of this estimated model, along with the standard statistical diagnostics, are provided in Appendix B.

We use the hourly data from 2011-2012 and hypothesize that congestion depends on a number of "explanatory" variables. These variables include:

System Marginal Price. The system marginal price is the price calculated by MISO that represents the marginal cost of meeting the next increment of load in MISO. We hypothesize that a higher SMP will result in higher congestion costs at the Manitoba interface with MISO. This hypothesis is based on the fact that at a high SMP, MISO is dispatching high-cost units to serve demand. These same units will be redispatched to manage congestion. All else equal, this should result in higher congestion costs.

Our regression analysis indicates a statistically significant estimate that congestion costs at the Manitoba border with MISO increase by $0.10/MWh for every $1/MWh change in the SMP.

Market Generation. Market generation is the level of generation dispatched within MISO to serve MISO demand. We hypothesize that the congestion cost at the Manitoba interface with MISO will be higher when market generation is higher. This hypothesis is based on the fact that at a higher dispatch, the transmission network is more fully utilized and congestion is more likely to arise.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.04/MWh for every 1,000 MW increase in system generation.

Ramp Requirements. Ramp requirements are the amount of capacity MISO expects to increase or decrease in a given hour to respond to anticipated increases or decrease in market demand or supply. In hours when demand is increasing or decreasing quickly (mid-morning and late evening), MISO may be constrained in responding to congestion and be required to use expensive re-dispatch to manage flows over transmission facilities. We hypothesize that ramp requirements will cause higher congestion.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.21/MWh for every 1000 MW increase in ramp requirements.

Wind Share of Generation. Wind share of generation is the percentage share of dispatched generation that is from wind resources. When output of wind resources increases relative to the rest of the system, there tends to be higher congestion. This occurs because most wind resources are located in Western MISO so higher wind output raises west-to-east flows and congestion on the MISO system. The Manitoba interface is significantly affected because is it located in the western part of MISO. Therefore, we hypothesize that higher wind share will cause higher congestion costs for Manitoba Hydro.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.45/MWh for every one percentage point increase in the share of wind resources on the system.

Manitoba Hydro Exports to MISO. Manitoba Hydro export to MISO is the MW volume of exports from Manitoba Hydro to MISO. When Manitoba Hydro exports power, congestion costs are likely to increase because MISO must manage the additional west-to-east power flow in an area already affected by west-to east-congestion. We hypothesize that higher Manitoba Hydro exports to MISO will cause higher congestion costs for Manitoba Hydro.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.78/MWh for every 1000 MW increase in Manitoba Hydro exports to MISO.

Headroom West. Headroom West is the amount of capacity that is on line in the west (sum of the maximum output level for each unit) in excess of energy being produced from each resource. As discussed above, headroom is used to ensure operational requirements for MISO. When the MISO west headroom requirement increases, flexibility in managing west-to-east congestion decreases, because units have lower limits to which they can be dispatched in order to reduce west-to-east flows. This will tend to result in more expensive redispatch to address congestion.

Accordingly, we hypothesize that higher MISO west headroom will cause higher congestion costs for Manitoba Hydro.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.87/MWh for every 1,000 MW increase in MISO west headroom.

Natural Gas-Coal Price Spread. The ratio of natural gas prices to coal prices spread is used in the regression equation to account for a significant factor that affects redispatch costs. If natural gas prices increase relative to coal prices, the cost of displacing coal with gas to resolve congestion increases. We hypothesize that congestion costs will increase when the natural gas-coal price spread increases.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $1. 37/MWh for every $1/MMBTU increase in the spread between coal and natural gas prices.

Qualitative Variables. The variables described above are the "quantitative" variables used in the regression. These variables can take on a range of values, for example, natural gas prices can have a rather broad range. The regression measures the effect of changes in quantitative variable on the congestion costs. Qualitative variables measure a change in state. They generally reflect the presence or absence of a condition, for example, whether a particular observation is an on-peak hour or an off-peak hour. The following are our qualitative variables used in the regression.

Peak Hour Indicator. The peak hour indicator signals whether the observation is an on-peak hour or not. Peak hours are the 16 hours ending at 11PM on (non-holiday) weekdays. During these hours, load grows in the west and helps to alleviate the usual west-to-east flow that creates congestion. We hypothesize that congestion cost will decrease during on-peak hours.

Our regression analysis indicates a statistically significant estimate that congestion costs are $0.21/MWh lower during on-peak hours.

Winter Indicator. The winter indicator signals whether the hour is during December, January, or February. Like the peak hour indicator, we expect load in the west to grow relative to the rest of MISO in these months and help alleviate the usual west-to-east flow that creates congestion. We hypothesize that congestion cost will decrease during winter months.

Our regression analysis indicates a statistically significant estimate that congestion costs are $1.86/MWh lower for hours in the winter.

Summer Indicator. The summer indicator signals whether the hour is in a summer month. For summer peak hours, we expect load in the rest of MISO grow relative to the west of MISO and aggravate the prevailing west-to-east flow that creates congestion. We hypothesize that congestion cost will increase in these hours.

Our regression analysis indicates a statistically significant estimate that congestion costs are $0.62/MWh higher in the summer peak hours.

The results of the regression equation are shown in Appendix B. The regression is an AR(1) model. For the ordinary least squares model, the Durbin-Watson statistic indicated that the data had a high degree of correlation between the hourly observations, which was not unexpected. Accordingly, we used an AR(1) model to account for this correlation. The results in Appendix B are the AR(1) results.

3. Effect of New Transmission Investment on Congestion.

The future congestion facing Manitoba Hydro in the western part of MISO should take into account two significant transmission expansion projects. The first is Manitoba Hydro's proposal to build additional capacity from the Manitoba Interface to Minnesota and Wisconsin as part of its preferred plan. The second is the investment that MISO initiated in 2011 to integrate wind capacity in western MISO. The regression equation used to forecast congestion is based on the state of the transmission network as it existed in 2011 and 2012. Hence, we adjust the congestion forecast to account for the prospect that congestion will be changing.

a. Wind Integration and MISO's Multi-Value Projects

MISO's planning process includes provisions to plan for and develop projects to facilitate the integration of resources to meet regulatory policies, for example, projects related to renewable energy requirements. MISO's process has resulted in substantial investments aimed at integrating existing and future wind capacity in the western part of MISO. In fact, MISO has approved over $5 billion in projects since 2011. We believe many of these projects will be in service by 2015.

As a result of this new investment, we recognize that the congestion estimated in our forecast is likely to be overstated. In particular, the variable in our regression analysis associated with "Wind Share" measures the higher levels of congestion at the Manitoba Hydro interface when the share of wind in MISO increases. However, with the new investments in MISO aimed at integrating wind, we believe additional congestion from new wind resources is likely to be offset by the additional transmission capability. Therefore, in forecasting the congestion at the Manitoba Hydro interface, we assume changes in wind share above the level projected in 2015 will have no additional effects on congestion by capping the wind share in future years at the 2015 level. In other words, we assume the new MVP projects will completely offset the forecasted increases in output from new wind projects.

b. Manitoba Hydro Transmission Projects

As part of Manitoba Hydro's preferred development plan, Manitoba Hydro proposes to build new transmission into Minnesota and Wisconsin. These investments will help eliminate congestion into the Minnesota Hub caused by additional Manitoba Hydro exports. As our regression indicates, Manitoba Hydro export volumes into MISO create additional congestion costs at the rate of $0.78/MWh for each 1,000 MW of Manitoba Hydro exports. However, this is congestion as measured at the MISO SMP. Some of this is congestion is between Manitoba Hydro interface and the Minnesota Hub and some of it is congestion from the Minnesota Hub into the rest of MISO.

In order to separate the effects, we estimate the same regression model using the Minnesota Hub congestion cost as the dependent variable instead of the Manitoba Hydro interface congestion costs. This could identify the effect of congestion from MISO to the Minnesota Hub. We found this value to be $0.59/MWh for each 1,000 MW increase in Manitoba Hydro exports to MISO. The regression results are in Appendix B.

Therefore, the congestion caused by additional Manitoba Hydro exports is mostly between the Minnesota Hub and the rest of MISO. As a result, for additional exports into MISO after 2021 when the projects are proposed to be ready, we reduce the rate of additional congestion costs caused by imports to the coefficient estimated in the second regression model ($0.59/MWh for each 1000 MW of additional exports, instead of $0.78/MWh).

D. Full Price Forecasts

In this section we present the final results of our price forecasts: the System Margin Price combined with congestion costs and losses.

The following four figures show our estimated prices, including losses and congestion. The top line indicates the SMP. After removing congestion and losses, the bottom line indicates the LMP that Manitoba Hydro is forecasted to receive when exporting energy to MISO.

Figure 11: Potomac Economics Reference Case Energy Prices

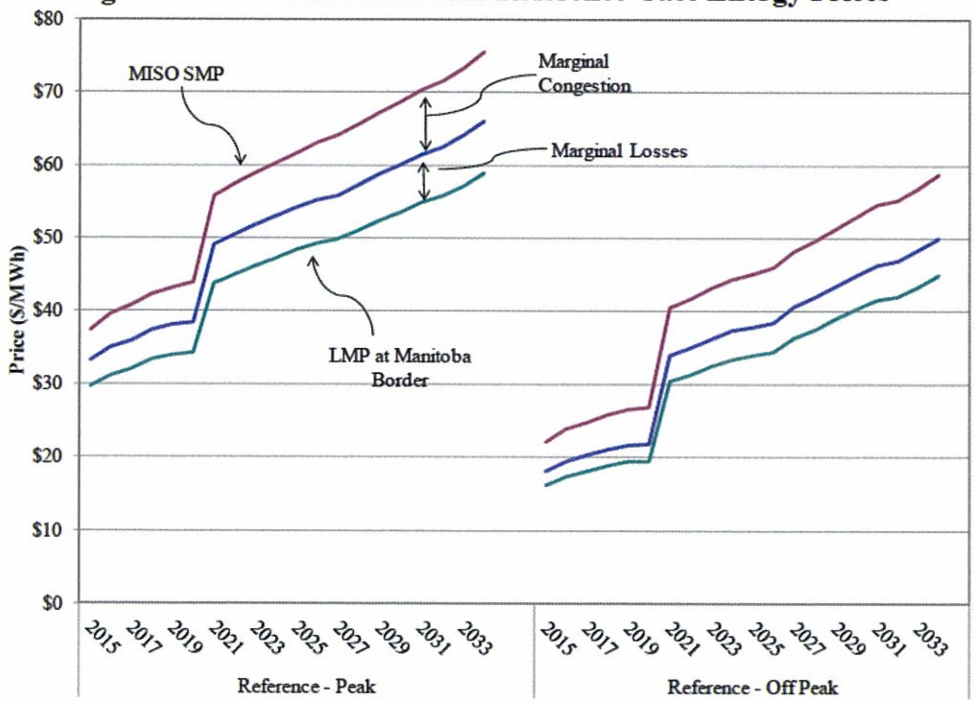


Figure 12: Potomac Economics Reference No Carbon Case Energy Prices

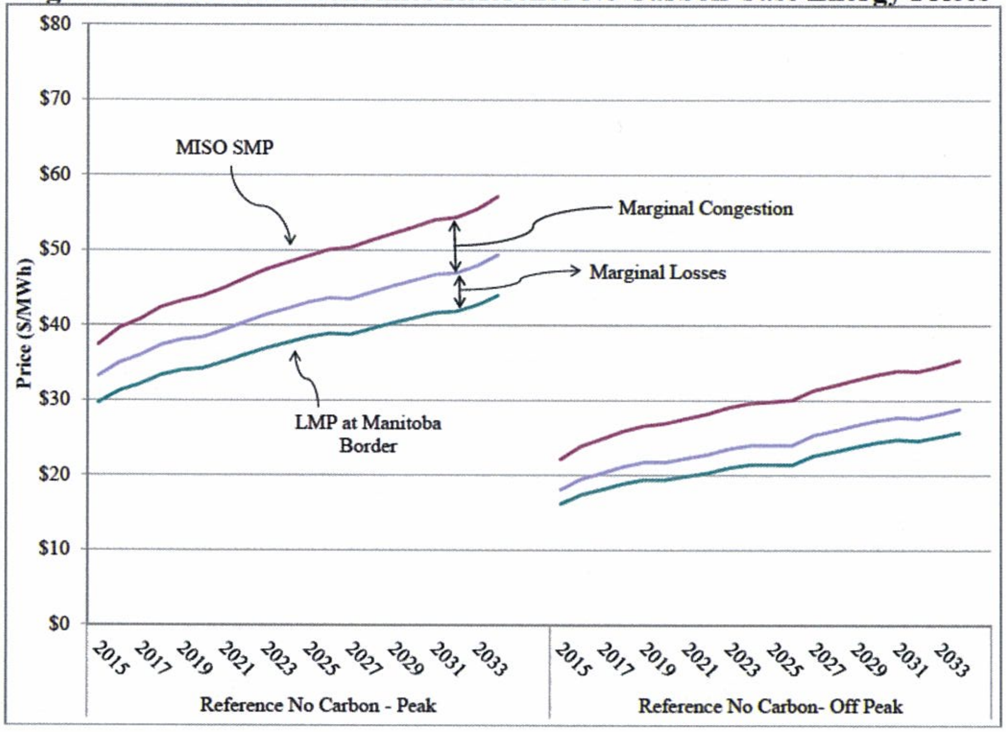


Figure 13: Potomac Economics High Resource Case Energy Prices

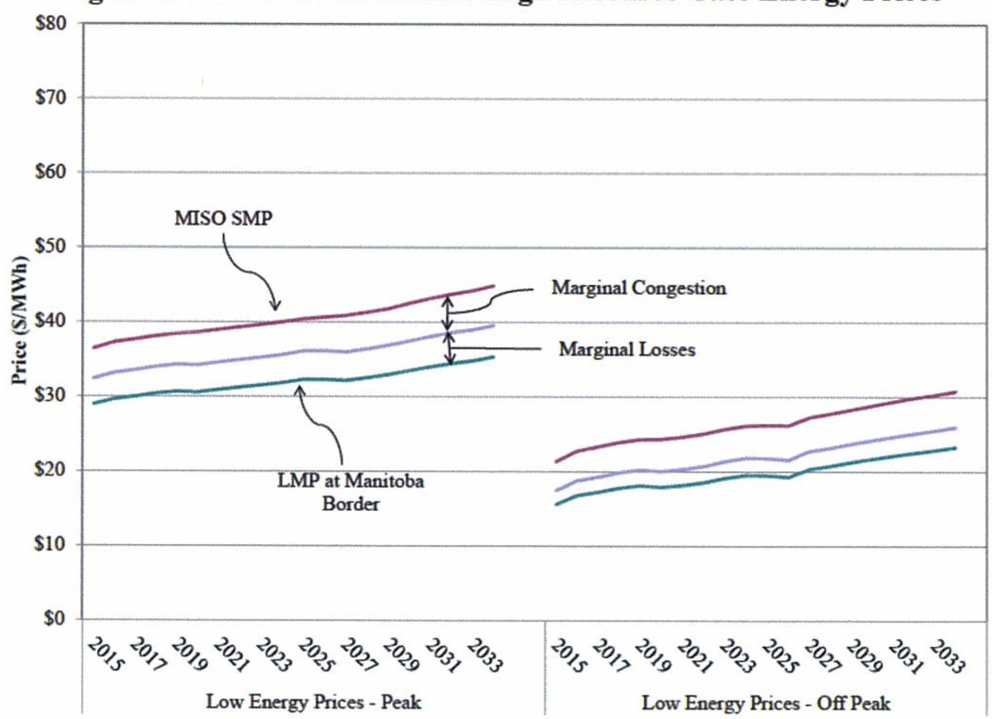
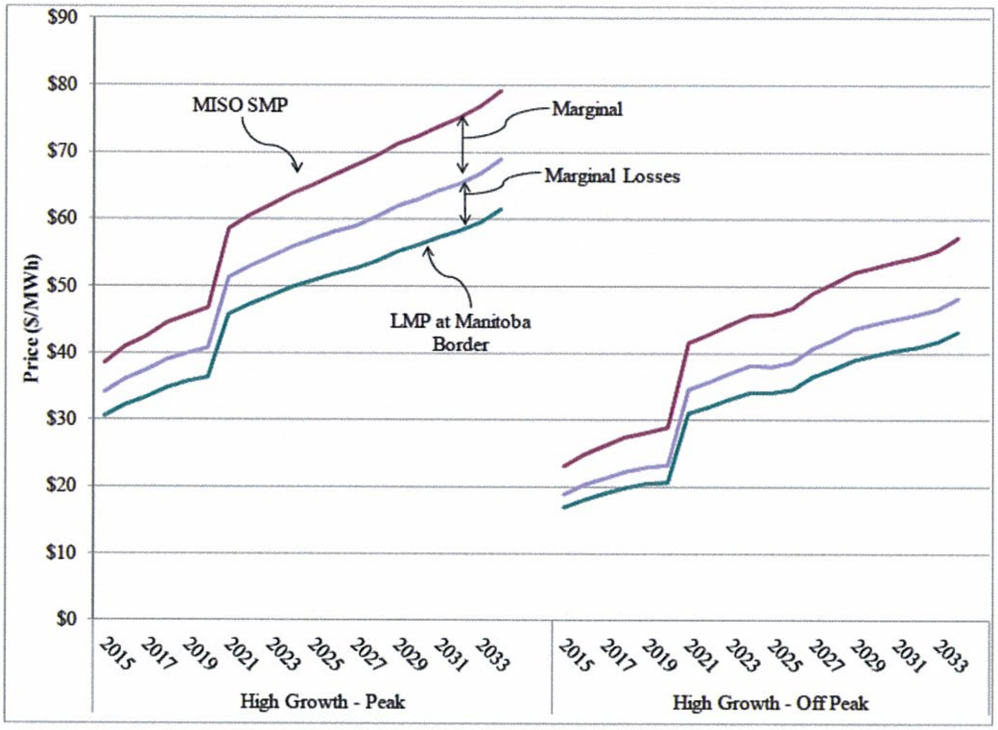


Figure 14: Potomac Economics High Growth Case Energy Prices



III. Potomac Economics Capacity Price Forecast

Capacity prices in MISO's planning reserve auction have been close to zero since its introduction. This has been partly due to the prevailing capacity surplus in MISO and partly due to market design flaws that lead prices to be understated.[6] While these flaws tend to reduce the value of capacity in MISO, load serving entities will still procure capacity through bilateral contracts or build capacity when needed to meet their planning reserve requirements.

Therefore, we assume that when surplus capacity dissipates, the capacity price will rise to the level necessary to incent the construction of new resources. As a result, our capacity price forecast is based on our estimate of the net cost of new entry ("net CONE"). The net CONE of a resource is equal to the resource's annual fixed cost of new entry less the variable profit it would earn in the MISO's energy and ancillary services markets. Therefore, the estimation of the capacity price requires calculation of (1) the variable profit a new resource can earn in the MISO markets (which requires forecast of the energy and ancillary services prices); and (2) the annual fixed cost of entry for the resource.

We estimate the net CONE of an "advanced" CT, given the parameters published by EIA[7]. Given the typical price duration curve in the MISO market, a CT is generally the most economical way to meet capacity needs. While it conceivable that a CCGT, because it runs longer at lower costs, could overcome its higher capital cost relative to a CT, our analysis indicates that the forecasted energy prices always results in a CT being the most economical addition for capacity (i.e., having the lower net CONE).

A. Cost of New Entry

The cost of new entry is an annual number that reflects carrying cost of the fixed investment plus fixed operating costs (fixed O&M), as well as smaller fixed elements like taxes. We use a value that was published by MISO in support of the capacity auction prices in MISO South. Updating this value to 2013 dollars and incorporating updates in EIA's assumptions for an advanced CT,

6 See, Potomac Economics, "2012 State of the Market Report for the MISO Electricity Markets."

7 See, EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants", April 2013, *supra*.

we estimate the CONE of a CT to be $89.95. The capacity price is estimated as this value less estimated net revenues, as described in the next subsection

B. Net Revenues

Net revenues for a new advanced CT are estimated using the variable production costs of the CT and the prices forecasted for each year. If in a given hour the price is greater than the variable cost of the CT, the unit is assumed to earn the difference in the variable cost and the price. This is part of the net revenue for that hour. We also assume a CT can earn ancillary services revenue by providing off-line supplemental reserves to MISO.[8] The annual net revenues are the annual sum over all hours of the hourly net revenues and the hourly ancillary services revenues.

In the long-run equilibrium, capacity prices together with net revenues from the energy and ancillary services markets must be sufficient to cover the cost of building new resources. This is the basis for our long-run forecast of capacity prices. However, MISO currently has a surplus of capacity and has been exporting capacity to PJM. Most recently, MISO suppliers exported more than 4 GW of capacity to PJM in its auction for 2016/2017. This capacity can be repurchased from PJM in subsequent actions if it is needed to meet MISO's planning reserve needs and its costs are lower than the costs of building new resources. Therefore, we must determine when the MISO capacity market is likely to transition from its current surplus condition (which will produce lower capacity prices) to a long-run equilibrium where capacity prices should cover the cost of building new resources.

Given the current surplus of more than 6 GW and our assumed coal retirements, MISO could experience a shortfall as soon as 2016. However, the ability to repurchase MISO capacity from PJM and fund environmental upgrades that would allow some existing capacity to remain in service will push this date out. Given these factors, we project that MISO will need to begin adding new resources in 2018. Because MISO does not currently have a functional centralized capacity market, we adopt the most recent price from the PJM RPM auction of $57.39/MW-Day as our forecast for 2015 and 2016, which translates to a price of $21.65/kW-Year. In 2017,

8 The ancillary services revenue is earned at the rate of $1/MW when the unit is not operating to provide energy. Although the average operating reserve prices are slightly higher than this level, the $1/MW assumption accounts for (1) the generator being likely to incur some costs in order to be prepared to be deployed and (2) the generator likely to be providing energy in hours when the operating reserve prices are the highest.

MISO's repurchasing of capacity from PJM should increase capacity prices throughout the region to levels similar to those that prevailed prior to the increased sales to PJM. Therefore, we forecast a capacity price comparable to the PJM clearing price in the prior RPM auction of \$160/MW-Day or \$49.64/kW-Year.

In 2018 and beyond, we forecast that prices will rise to the long-run equilibrium level based on the net CONE of a new CT. Table 1 shows the net revenue for each year of the forecast period, along with the annual fixed cost, and the resulting estimated capacity price. We show this for all four of our cases.

Table 1: Summary of Capacity Price Estimates

	Reference Case			Reference Case No Carbon			High Resource (Low Fuel Price)			High Growth		
Year	Net revenue	Fixed Annual Cost	Capacity Price	Net revenue	Fixed Annual Cost	Capacity Price	Net revenue	Fixed Annual Cost	Capacity Price	Net revenue	Fixed Annual Cost	Capacity Price
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2015	$20.23	$89.95	$69.72	$20.23	$89.95	$69.72	$19.76	$89.95	$70.19	$20.97	$89.95	$68.98
2016	$20.51	$89.95	$69.44	$20.51	$89.95	$69.44	$20.56	$89.95	$69.39	$21.12	$89.95	$68.83
2017	$20.92	$89.95	$69.03	$20.93	$89.95	$69.02	$20.84	$89.95	$69.11	$21.53	$89.95	$68.42
2018	$21.32	$89.95	$68.63	$21.32	$89.95	$68.63	$21.10	$89.95	$68.85	$21.84	$89.95	$68.11
2019	$21.51	$89.95	$68.44	$21.51	$89.95	$68.44	$21.26	$89.95	$68.69	$22.12	$89.95	$67.83
2020	$21.61	$89.95	$68.34	$21.61	$89.95	$68.34	$21.37	$89.95	$68.58	$22.31	$89.95	$67.64
2021	$21.59	$89.95	$68.36	$21.78	$89.95	$68.17	$21.59	$89.95	$68.36	$22.15	$89.95	$67.80
2022	$21.66	$89.95	$68.29	$22.03	$89.95	$67.92	$21.81	$89.95	$68.14	$22.35	$89.95	$67.60
2023	$21.77	$89.95	$68.18	$22.24	$89.95	$67.71	$22.00	$89.95	$67.95	$22.52	$89.95	$67.43
2024	$21.85	$89.95	$68.10	$22.38	$89.95	$67.57	$22.24	$89.95	$67.71	$22.69	$89.95	$67.26
2025	$21.99	$89.95	$67.96	$22.50	$89.95	$67.45	$22.40	$89.95	$67.55	$22.70	$89.95	$67.25
2026	$22.05	$89.95	$67.90	$22.62	$89.95	$67.33	$22.60	$89.95	$67.35	$22.84	$89.95	$67.11
2027	$22.08	$89.95	$67.87	$22.72	$89.95	$67.23	$22.59	$89.95	$67.36	$22.94	$89.95	$67.01
2028	$22.19	$89.95	$67.76	$22.90	$89.95	$67.05	$22.63	$89.95	$67.32	$23.03	$89.95	$66.92
2029	$22.31	$89.95	$67.64	$23.04	$89.95	$66.91	$22.76	$89.95	$67.19	$23.24	$89.95	$66.71
2030	$22.42	$89.95	$67.53	$23.20	$89.95	$66.75	$22.46	$89.95	$67.49	$23.20	$89.95	$66.75
2031	$22.49	$89.95	$67.46	$23.34	$89.95	$66.61	$22.29	$89.95	$67.66	$23.29	$89.95	$66.66
2032	$22.47	$89.95	$67.48	$23.37	$89.95	$66.58	$22.25	$89.95	$67.70	$23.26	$89.95	$66.69
2033	$22.59	$89.95	$67.36	$23.56	$89.95	$66.39	$22.24	$89.95	$67.71	$23.35	$89.95	$66.60
2034	$22.79	$89.95	$67.16	$23.88	$89.95	$66.07	$22.19	$89.95	$67.76	$23.60	$89.95	$66.35

Note: The "Capacity Price" column for 2015-2017 shows the estimated net revenue based on a long-run equilibrium. As discussed in the text, this price is not likely to be attained in the short run. The capacity prices for those three years (and all cases) are 2015: \$21.65/kW; 2016: \$21.65/kW; and 2017: \$49.64/kW.

As this table shows, the net revenues from the energy and ancillary services markets do not vary substantially over time or between the various energy price cases. This is expected because the primary changes over time and between cases are related to changes in fuel prices and CO2 prices. Changes in both natural gas prices and CO2 prices will directly increase the CT's marginal costs and, therefore, its assumed offer prices. In most hours that a CT is running, a natural gas-fired unit with similar CO2 emission rates will be the marginal unit setting the price in the energy market. This causes energy prices to increase or decrease at substantially the same rate as the change in the CT's production costs, which in turn causes its net revenue to be relatively unresponsive to these changes.

Likewise, changes in the generator mix over time. as coal plants retire and are replaced by other units, generally changes energy prices at lower load and price levels when the CT would not be forecasted to be running. Therefore, these changes do not tend to affect the CT's net revenues substantially.

Lastly, we assume no real increase over time in the capital cost of building a CT (i.e., capital costs rise at the same rate of inflation). Therefore, the CONE of the CT is flat over time and, when combined with net revenues that are relatively flat as well, we forecast a long-run capacity price trend that is comparably flat.

C. Potomac Economics' Capacity Price Forecast v. Manitoba Hydro's Consultants

Figure 15 shows our reference capacity price forecast compared to the forecasts of Manitoba's consultants. The Potomac Economics forecast rises, as discussed in the prior section, from 2015 to 2017 before achieving a long-run equilibrium that prevails from 2018 to 2034.

Figure 15: Capacity Prices Reference Case Manitoba Hydro v. Potomac Economics

[redacted]

The figure shows that the consultants' forecasts are [redacted] the Potomac Economics forecast after 2020 when most of Manitoba Hydro's new capacity enters the MISO market. As we discussed in Section I, most of the consultants assume capital costs for new resources that [redacted] than the EIA forecast that we assume. Additionally, some of the consultants appear [redacted] that a new resource would earn in MISO's energy and ancillary services markets, without which the forecasted capacity price [redacted]

We were unable to obtain detailed information on the models and inputs used by Manitoba Hydro's consultants to forecast capacity prices. Given that they are [redacted] than the fundamental approach that we used, we do not find them to be credible and recommend that PUB evaluate the business case for the Manitoba Hydro development plans on the basis of Potomac Economics' forecast.

D. Uncertainties

Although the theory underlying our capacity price forecast is sound, there is significant risk associated with these Manitoba Hydro revenues. The capacity prices forecasted for the long run may not be readily attainable by Manitoba Hydro. This is true for at least three main reasons.

First, the capacity price is based on the amount of revenue a new entrant would need to be profitable. This assumes load serving entities are seeking capacity under relatively open and competitive market structures. However, the MISO capacity market is not currently structured to establish efficient capacity prices where capacity is cleared on a multi-lateral basis. Instead, capacity prices under the MISO planning reserve auction tend to be understated. They are likely to be close to zero during periods when even a small surplus of capacity exists. This can put downward pressure on bilateral capacity prices and result in lower revenues for Manitoba Hydro.

Because of this, Manitoba Hydro will likely participate in the bilateral market, as it has in the recent past. The risk that Manitoba Hydro faces in the bilateral market is that regulated utilities may have an incentive to engage in self-build projects when they need capacity rather than purchasing from Manitoba Hydro. We have not quantified this effect in the capacity price, but only cite it as a potential risk.

Second, given the relatively long timeframe of these forecasts, it is plausible that technological advances could reduce the cost or increase the efficiency of the marginal CT, or cause alternative technology to displace the CT. In both cases, the long-run capacity price could fall and reduce the forecast capacity revenues.

A third reason why the capacity price may overstate the revenue Manitoba Hydro may earn is that the capacity price is based on net revenues earned at the MISO system marginal price. If constrained areas emerge where energy prices are much higher than the SMP, the net CONE of units built in these areas will fall. This would potentially reduce the MISO capacity price because units in these areas may be the marginal economic entrant.

IV. Other Export Market Issues

In this section we address other issues that could significantly impact the price forecasts and revenues expectations under Manitoba Hydro's development plans.

1. Regional Issues

MISO South. In December 2013, Entergy transitioned its operation to MISO and began participation in the MISO markets. The Entergy system along with several other nearby smaller systems are part of what is known as "MISO South". The rest of MISO is referred to as "MISO Midwest." MISO Midwest and MISO South are connected by way of a transmission path that is managed on a regional basis through the Operations Reliability Coordination Agreement ("ORCA"). ORCA is an agreement among MISO and other non-MISO regional utilities to coordinate certain operations that may be impacted by the joint dispatch of MISO Midwest and MISO South. Currently, among other things, the agreement limits transfers between MISO Classic and MISO South to 2000 MW in any given hour. In the future, this limit may increase.

While the integration of MISO Midwest and MISO South promises to better allocate resources between the two areas, we do not believe it will have a significant effect on the supply and demand conditions in the western part of MISO where Manitoba Hydro anticipates making sales.

Capacity Exports to PJM. Another regional issue is the current level of MISO capacity exports to PJM. MISO is currently in a capacity surplus and exports to PJM through the PJM capacity auctions. These exports are committed for up to three years in advance As we discussed above, as the MISO capacity surplus declines, capacity exports to PJM from MISO will likely decline and this capacity will be available to meet MISO requirements.

2. Export Volumes

Manitoba Hydro assumes all additional surplus electricity can be sold either as long-term "dependable" (firm) energy or as on- and off-peak opportunity sales. Projected export volumes of long-term dependable energy are based on the surplus dependable capacity that Manitoba Hydro calculates based on historical water conditions and forecast load and resources. Manitoba assumes 100 percent of available dependable energy can be sold as long-term firm.

Manitoba Hydro on-peak and off-peak energy volumes are estimated based on simulations of the Manitoba Hydro system using its "SPLASH" model. The SPLASH model uses anticipated hydro conditions, load, resources, and export prices. The model optimizes the use of the available water to determine the volumes of exports and imports. The reasonableness of the export volumes produced by the SPLASH model was evaluated by Independent Expert Consultant, La Capra Associates.

Our role was to examine whether Manitoba Hydro can actually sell the volumes into MISO. Overall, given the small volume of additional capacity and energy resulting from the development plans relative to the size of the MISO market, we conclude that Manitoba will likely be able to sell the volumes it assumes in its plans. Our price forecasts take into account the additional volumes in estimating the market clearing prices. We also take into account the additional volumes when estimating the congestion component of the location marginal price at the Manitoba Hydro border with MISO.

Aside from the risk associated with selling capacity in the MISO market described above, we have a minor concern that the assumed volumes of long-term dependable energy may be slightly high. Manitoba Hydro assumes all dependable capacity is sold under long-term firm contracts. We do not believe all dependable capacity should be assumed to be sold forward on a long-term basis. Instead, an historical ratio could be applied. Manitoba Hydro has provided an analysis that indicates the value is close approximately 91 percent in recent years. We recommend that nine percent of the Manitoba Hydro projected long term dependable energy be "re-priced" at peak opportunity sales levels. We understand that La Capra will be addressing the effect of this issue.

We also examined Manitoba Hydro's assumption that its on-peak opportunity sales are able to receive prices that exceed the MISO day-head price. Manitoba projects on-peak opportunity sales revenue that averages [redacted] percent above its forecasted on-peak price. We found there is some justification for this premium in the data. However, this premium is not always attained. In 2011, the average day-ahead on-peak price at the Manitoba Hydro border was actually two percent higher than the average on-peak sales price by Manitoba Hydro.[9] In 2012, Manitoba Hydro managed to earn a ten percent premium. We recommend the Company provide additional analysis supporting this premium, preferably one that estimates a premium based on a risk model that values the hedge obtained by the buyers of on-peak energy.

3. Longer-Term Price Forecasts

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.

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. 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 CO2 prices escalate at the rate of inflation after 2034.

4. Probability of Potomac Economics Cases

In this subsection, we provide a discussion of the probability of realizing the various cases we developed. We believe our reference cases are the most likely to represent the future path of prices. We believe our Reference Case and our Reference No Carbon Case are equally likely but will ultimately depend on the direction of future policy in the U.S. Therefore, we assign a probability of 30 percent to each of these two reference cases

9 Manitoba Hydro informed us that relatively high water levels in 2011 allowed them to sell large quantities during on-peak hours in the shoulder load months, bringing down the overall on-peak per-MW sales revenue for that year.

Our high growth case assumptions do not depart significantly from our reference case. Mainly load grows faster and natural gas prices are higher.

We believe our last case reflects on-going progress in developing shale gas, which has proved to substantially increase natural gas supply in the U.S. The high resource case also shows slower load growth, primarily because gas substitutes for electricity for heating and may also become a transportation fuel, lessening load growth in the transportation sector. The slower load growth can also be a proxy for overall slower macroeconomic activity, which is reflected in this case.

We believe the High Growth and the High Resource cases are also equally likely, but less likely than the reference cases. Therefore, we assign a probability of 20 percent each to these two cases.

Appendix A – Summary of Key Assumptions in Potomac Economics Forecasts[10]

Figure A-1: Natural Gas Prices

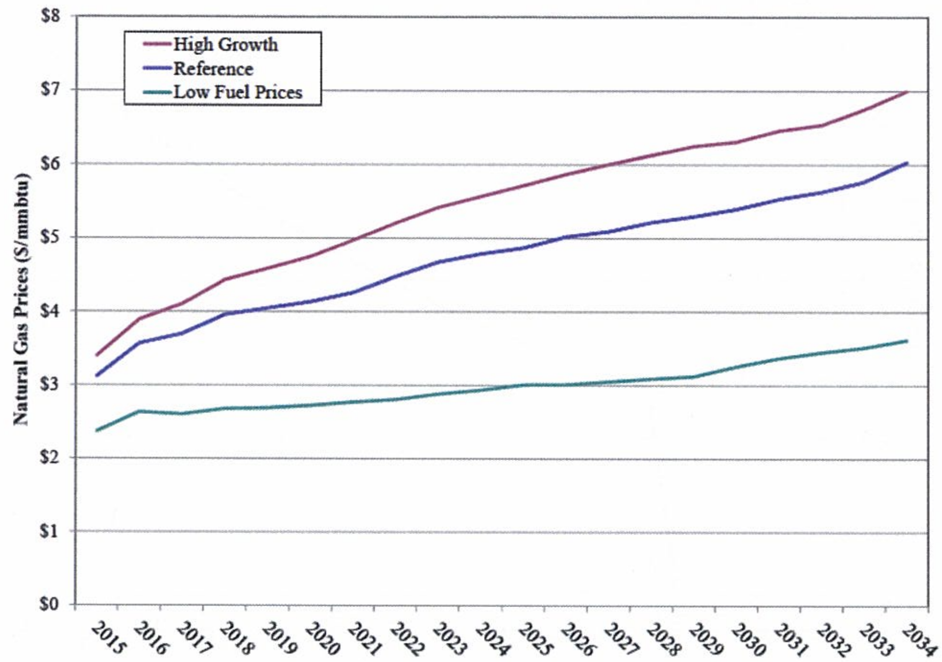
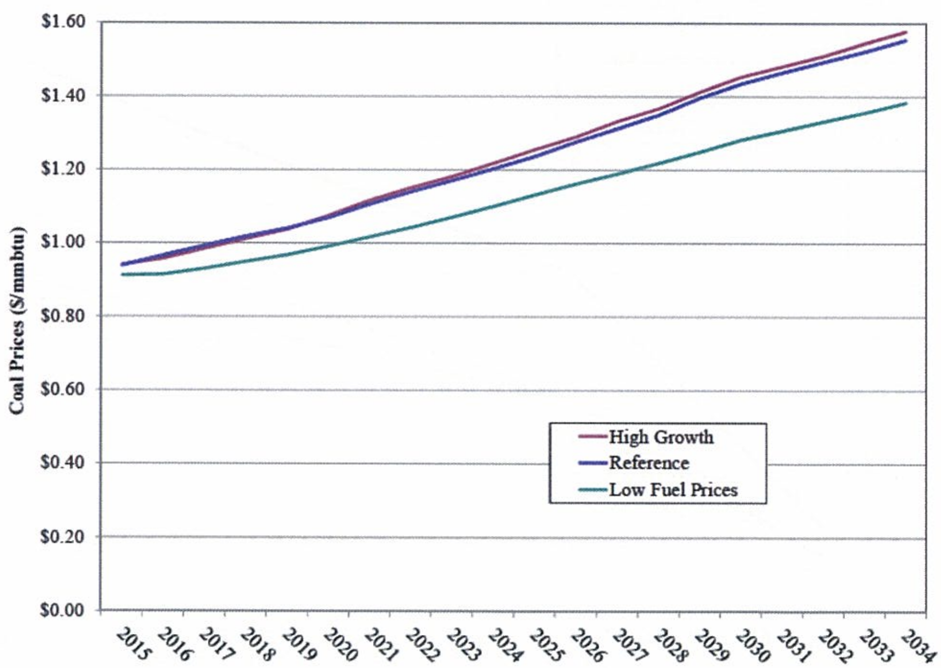


Figure A-2: Coal Prices



10 Unless otherwise indicated, the Reference Case assumptions are also used in the Reference No Carbon Case.

Figure A-3: CO2 Prices

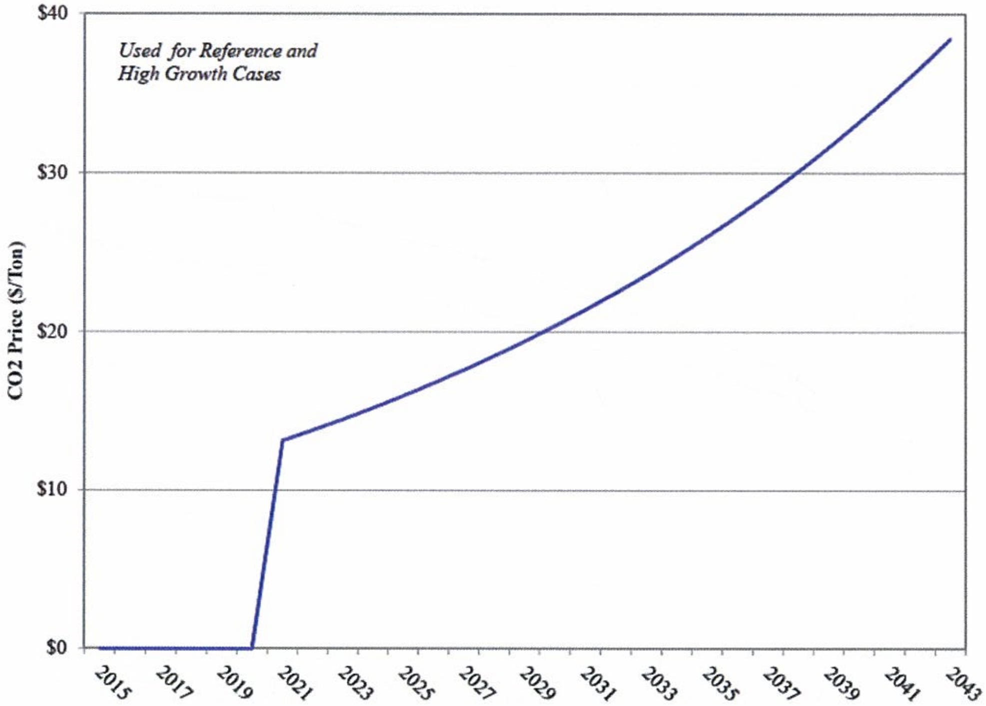


Figure A-4: Load Growth

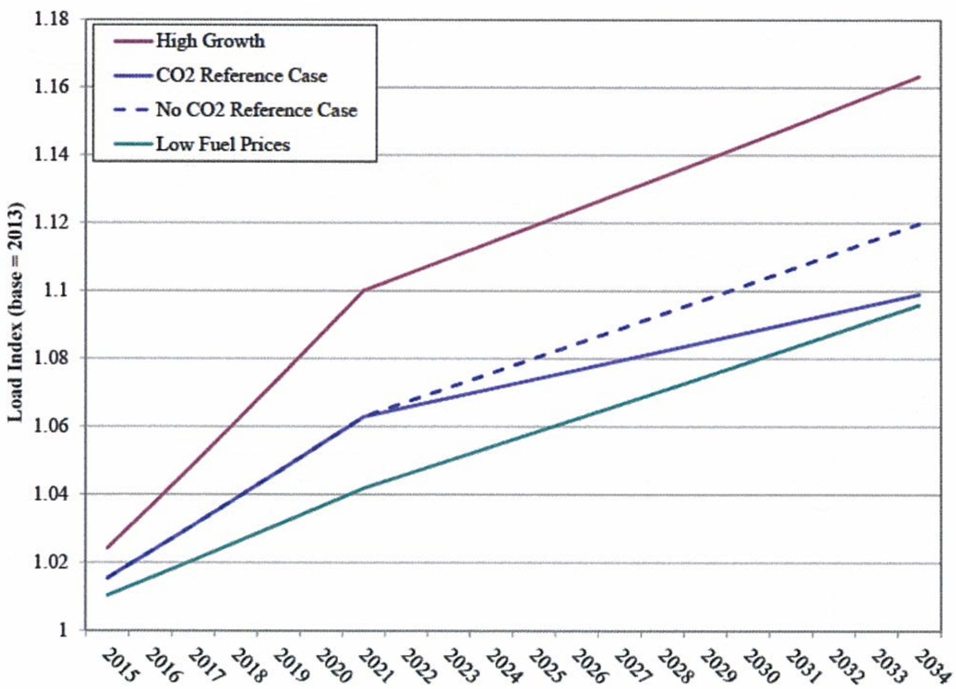
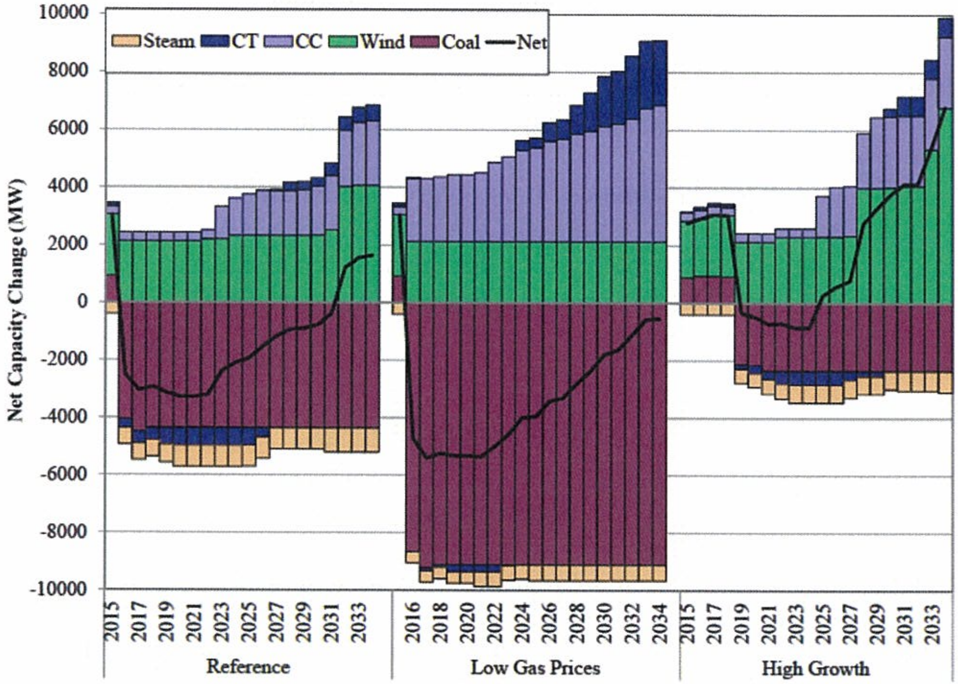


Figure A-5: Capacity Changes



Appendix B -- Regression Result Summaries

B-1: Regression Model used to Estimate the Determinants of Marginal Congestion at the Manitoba Hydro Interface with MISO

Estimates of Autoregressive Parameters

Lag	Coefficient	Std Error	t Value
1	-0.896657	0.003347	-267.88

Regress R-Square	0.1107	Total R-Square	0.8776

Yule-Walker Estimates

Parameter Estimates

Variable	Estimate	Std Error	t Value	Approx. Pr > |t|
Intercept	8.6284	1.0976	7.86	<.0001
MEC	-0.0971	0.005231	-18.56	<.0001
MARKET_GEN	-0.000042	0.0000117	-3.64	0.0003
RAMPDEMAND	-0.000206	9.0498E-6	-22.79	<.0001
WINDSHARE	-45.2384	3.2332	-13.99	<.0001
MHEB_EXPORT	-0.000778	0.0000857	-9.08	<.0001
PEAK	0.2125	0.0738	2.88	0.0040
SUMMER	-0.6233	0.3377	-1.85	0.0650
WINTER	1.8698	0.3580	5.22	<.0001
HEADROOM_WEST	-0.000873	0.0000495	-17.63	<.0001
SPARK	-1.3718	0.5028	-2.73	0.0064

B-2: Regression Model used to Estimate the Determinants of Marginal Congestion at the Minnesota Hub

Estimates of Autoregressive Parameters

Lag	Coefficient	Std Error	t Value
1	-0.872090	0.003700	-235.72

Yule-Walker Estimates

Regress R-Square	0.1123	Total R-Square	0.8513

Parameter Estimates

Variable	Estimate	Std Error	t Value	Approx Pr > |t|
Intercept	12.0768	0.9322	12.96	<.0001
MEC	-0.0288	0.005248	-5.49	<.0001
MARKET_GEN	-0.000031	0.0000112	-2.74	0.0062
RAMPDEMAND	-0.000235	9.1225E-6	-25.73	<.0001
WINDSHARE	-38.2088	3.0165	-12.67	<.0001
MHEB_EXPORT	-0.000590	0.0000860	-6.86	<.0001
PEAK	0.1562	0.0745	2.10	0.0361
SUMMER	-0.4452	0.2824	-1.58	0.1149
WINTER	0.9854	0.2979	3.31	0.0009
HEADROOM_WEST	-0.001047	0.0000487	-21.48	<.0001
SPARK	-3.8936	0.4190	-9.29	<.0001

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

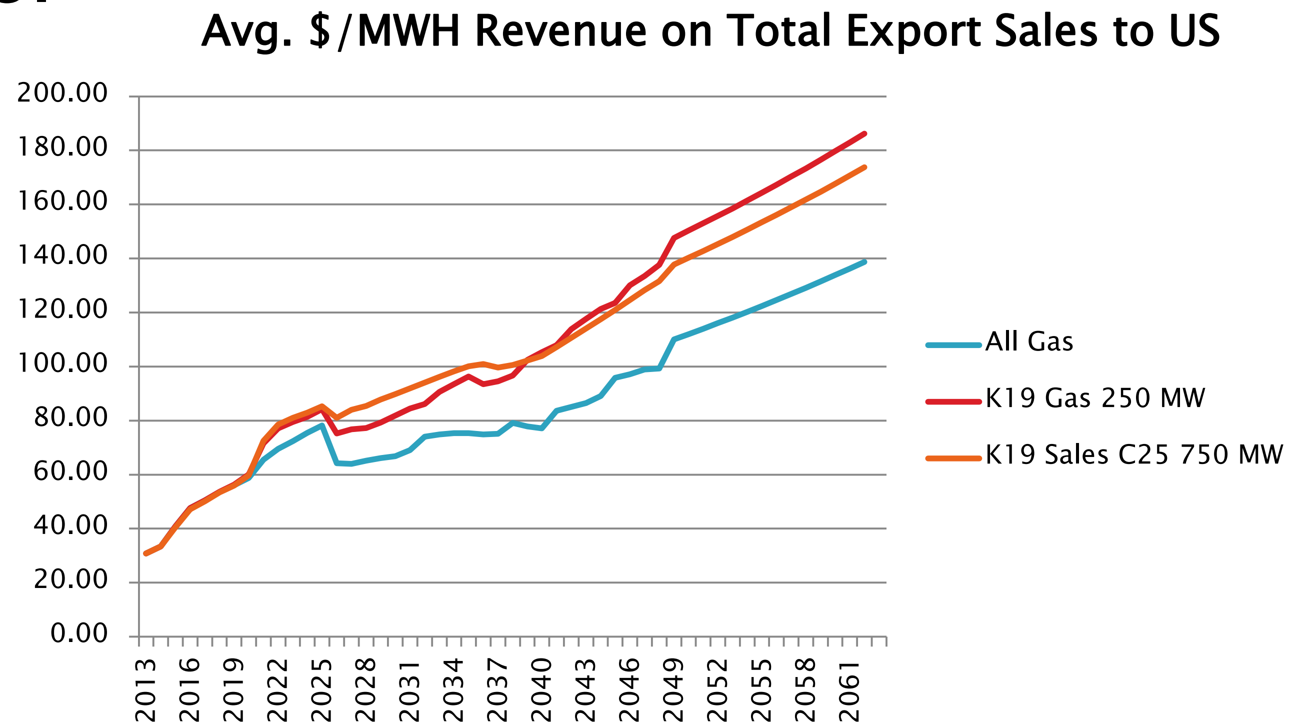
There is a substantial gap between:

- 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

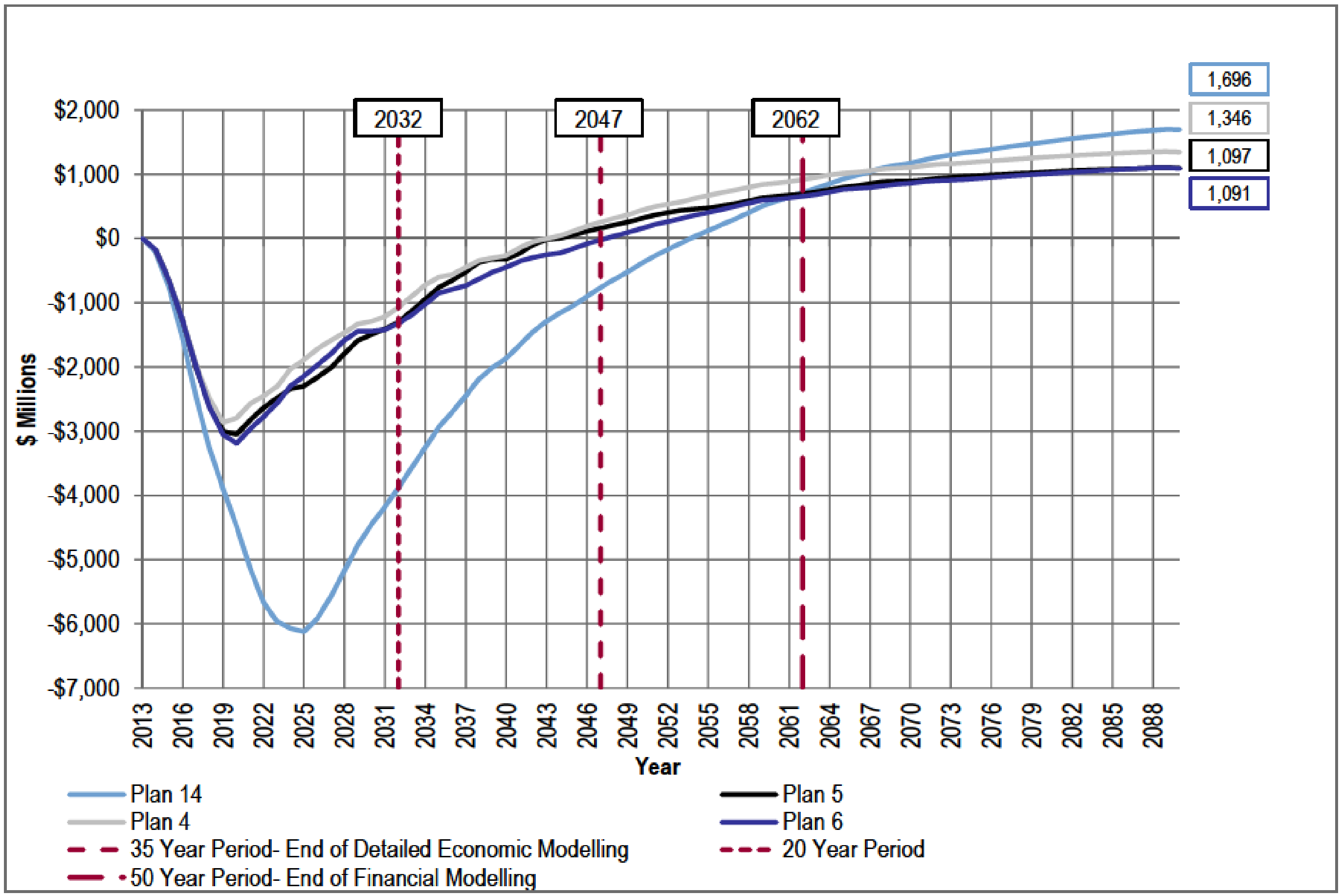
MH has an incentive to maximize firm exports and lock in pricing for firm exports, but is constrained by buyer resistance and the cost of alternatives. As costs escalate and forecasts of export prices fall, the point in time at which export revenues recover increased costs is pushed farther into the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

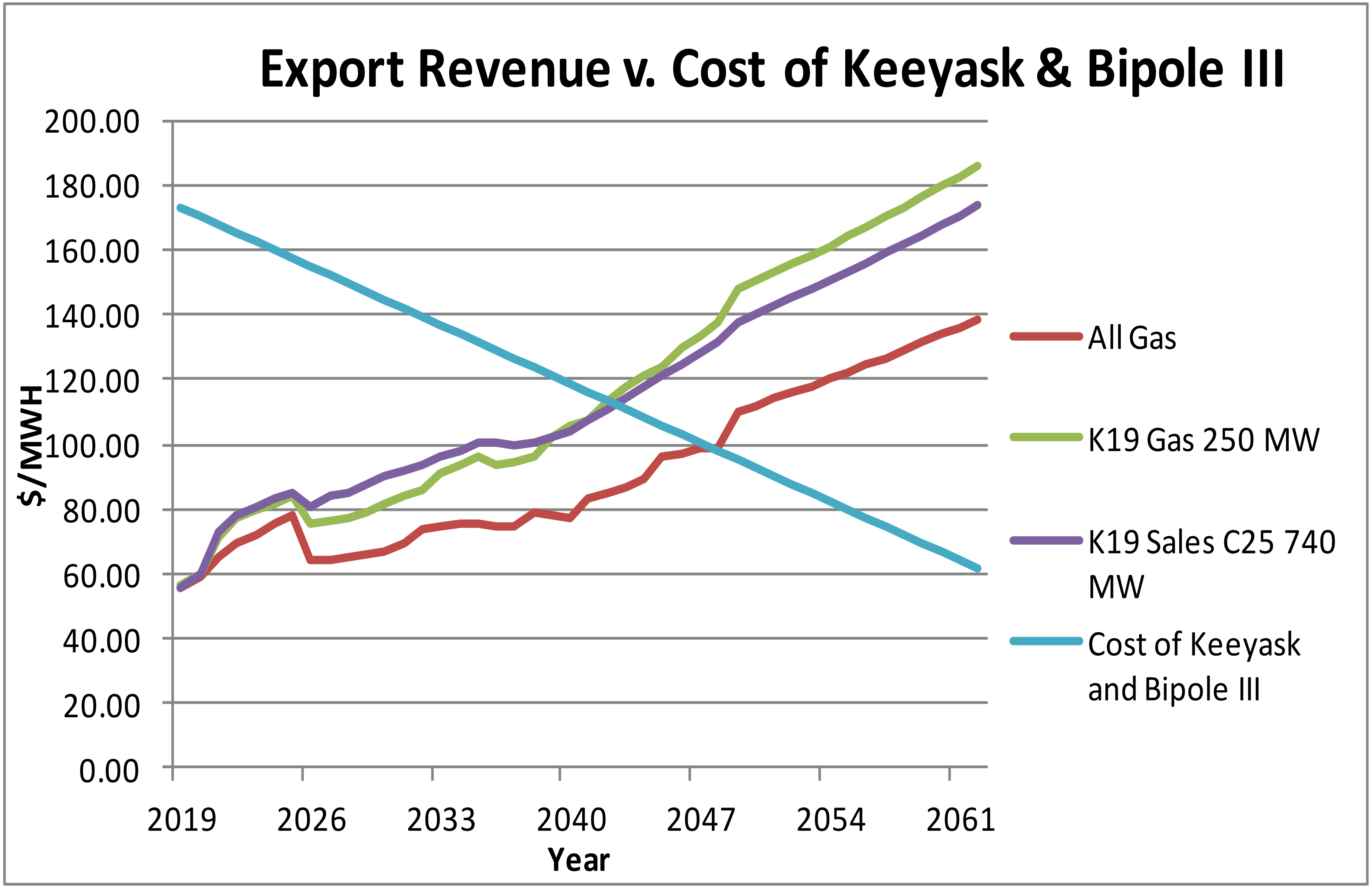
- Favorable economics of hydro erode as capital costs increase, as has been demonstrated in the updated work of MH. The initial $1.696 Billion advantage enjoyed by the Preferred Development Plan (PDP) over the All-Gas Plan diminished to $374 million as a result of an $800 million increase in estimates 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

		Development Plan	1	2	4	8	5	14
			All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas25 /750MW	K19/C25 /750MW
							WPS Sale & Investment	
Energy Prices	Discount Rates	Capital Costs	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 deterministic 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.

[redacted] 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

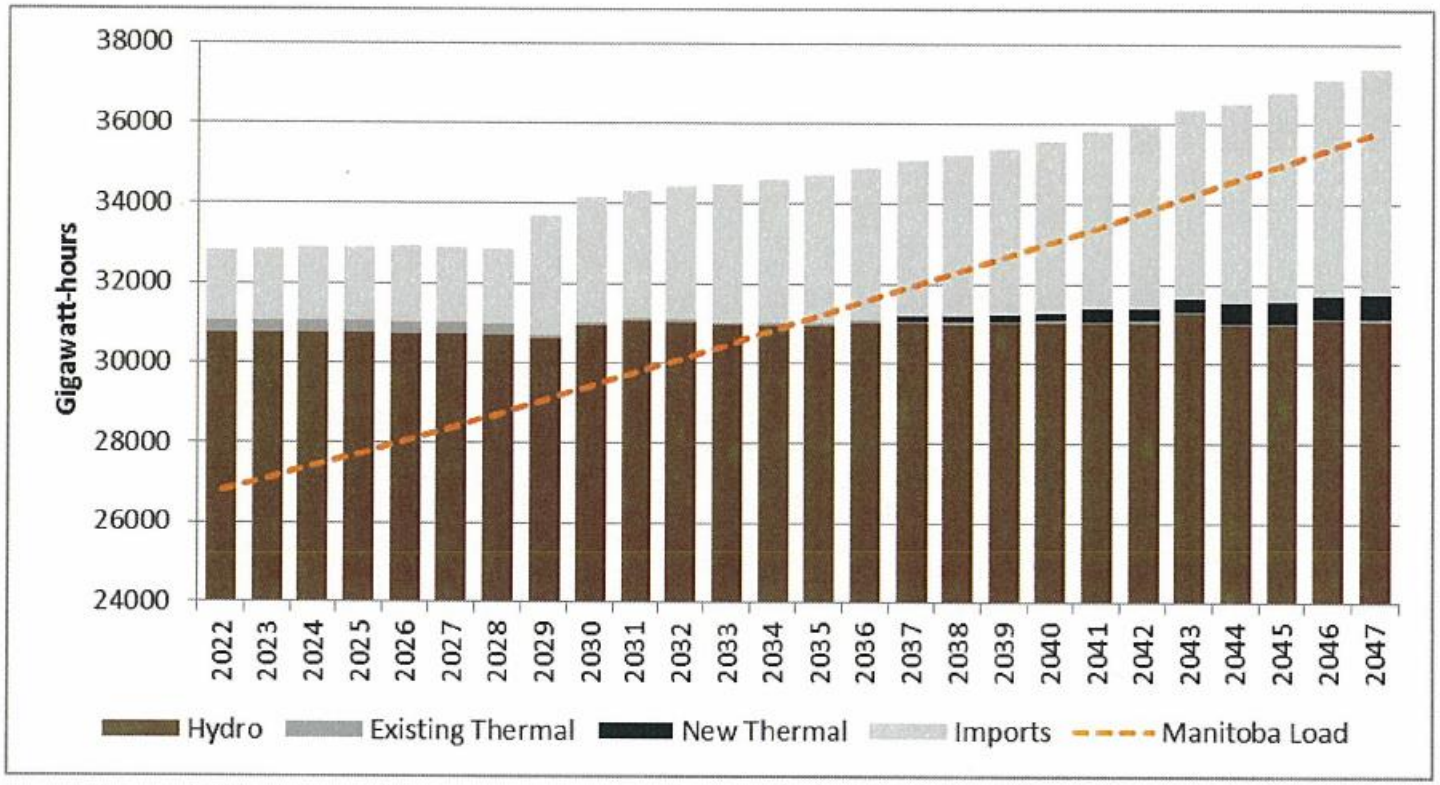


Figure 3-26: Annual resource generation mix in LCA No New Generation Plan

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.

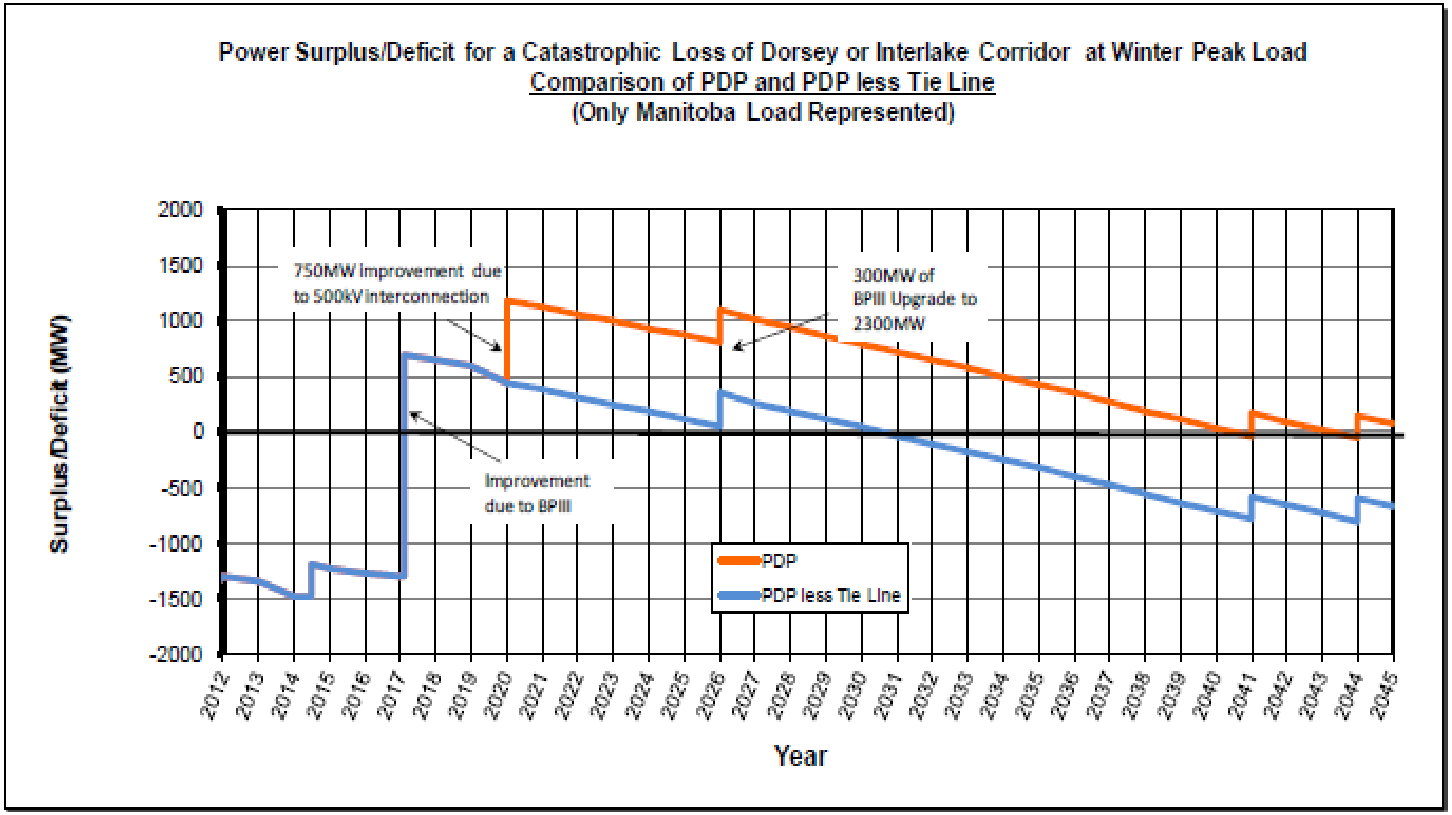
- At pages 1-3, MH challenges our position that it has implemented a less restrictive standard than it did in the CEC proceeding. MH seems to have missed my point because its rebuttal focuses on the adequacy of spare transmission capacity and not upon the adequacy of imported generating capacity to meet 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.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; CAC/MH I-17, 2012 GRA

QUESTION:

Please file each of the determinations of average export prices over the planning horizon based on those used in IFF09,-1, IFF10- , IFF11-2 and IFF12 and that used in the NFAT and provide an analysis demonstrating the changed in assumptions in (a) related to price and that related to export volumes.

RESPONSE:

The attached table provides the unit revenues for total export sales for IFF-09, IFF-10, IFF-11, IFF-12 and NFAT. The change in the unit revenues between respective IFF's is given in terms of an absolute ($/MWh) and percentage change.

The total change in the unit revenues for total export sales is broken into the price, volume and other components. The price and volume components consist of the effect of price and volume changes, respectively, for all long-term export sales and flow-related revenues and costs. The change related to 'other' reflects the factors that are not clearly defined by price and volume (for example, the transmission costs and revenues and MISO membership costs, amongst others).

Price and volume are not independent factors. A change in price will change to some extent the energy volumes. In the attached table, the change due to price for the transition from IFF-09 to IFF-10, as an example, is calculated as the total effect of only changing the prices. The change due to volume includes changes such as Manitoba load, export contracts and deferral of in-service dates for generating stations, amongst others.

Price/Volume Components for Unit Revenues for Total Export Sales

(Nominal Canadian Dollars / MWh)

IFF-09 TO IFF-10

Total Export Sales	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
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	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
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	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
IFF 11 ($/MW.h)	50.4	61.9	68.8	75.3	81.1	88.1	94.3	96.4
IFF 12 ($/MW.h)	41.4	48.1	52.4	57.2	61.8	66.5	76.5	82.0
% Total Change	-18%	-22%	-24%	-24%	-24%	-25%	-19%	-15%
Total Change ($/MW.h)	**-9.1**	**-13.7**	**-16.4**	**-18.1**	**-19.4**	**-21.6**	**-17.8**	**-14.5**
Change due to Price ($/MW.h)	-6.6	-10.5	-12.0	-13.1	-13.8	-14.6	-13.6	-11.3
Change due to Volume ($/MW.h)	-1.7	-2.2	-2.4	-2.9	-3.1	-4.3	-2.5	-1.6
Change due to Other ($/MW.h)	-0.8	-1.0	-2.0	-2.1	-2.5	-2.7	-1.8	-1.6

IFF-12 TO NFAT

Total Export Sales	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
IFF 12 ($/MW.h)	41.4	48.1	52.4	57.2	61.8	66.5	76.5	82.0
NFAT ($/MW.h)	40.3	46.7	49.8	53.0	55.5	59.2	72.0	77.9
% Total Change	-3%	-3%	-5%	-7%	-10%	-11%	-6%	-5%
Total Change ($/MW.h)	**-1.1**	**-1.4**	**-2.6**	**-4.2**	**-6.3**	**-7.4**	**-4.5**	**-4.0**
Change due to Price ($/MW.h)	-2.1	-3.5	-5.0	-6.6	-9.1	-11.0	-5.8	-4.3
Change due to Volume ($/MW.h)	0.5	1.4	1.7	1.6	2.0	2.5	0.3	-0.6
Change due to Other ($/MW.h)	0.5	0.6	0.7	0.8	0.8	1.2	1.0	0.8

Price/Volume Components for Unit Revenues for Total Export Sales (cont'd)

(Nominal Canadian Dollars / MWh)

IFF-09 TO IFF-10

Total Export Sales
IFF 09 ($/MW.h)
IFF 10 ($/MW.h)
% Total Change

Total Change ($/MW.h)
Change due to Price ($/MW.h)
Change due to Volume ($/MW.h)
Change due to Other ($/MW.h)

IFF-10 TO IFF-11

Total Export Sales
IFF 10 ($/MW.h)
IFF 11 ($/MW.h)
% Total Change

Total Change ($/MW.h)
Change due to Price ($/MW.h)
Change due to Volume ($/MW.h)
Change due to Other ($/MW.h)

IFF-11 TO IFF-12

Total Export Sales	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
IFF 11 ($/MW.h)	99.8	102.5	110.6	106.3	107.6	111.4	114.1	117.2	120.3
IFF 12 ($/MW.h)	85.6	89.6	93.2	90.6	91.4	93.5	97.0	100.4	103.7
% Total Change	-14%	-13%	-16%	-15%	-15%	-16%	-15%	-14%	-14%

Total Change ($/MW.h)	-14.2	-12.9	-17.4	-15.8	-16.2	-17.9	-17.0	-16.8	-16.6
Change due to Price ($/MW.h)	-10.6	-9.1	-11.0	-11.2	-10.4	-10.1	-9.0	-8.4	-7.8
Change due to Volume ($/MW.h)	-1.9	-1.9	-4.0	-2.4	-4.4	-6.6	-6.7	-7.0	-7.3
Change due to Other ($/MW.h)	-1.6	-1.9	-2.4	-2.2	-1.4	-1.3	-1.3	-1.4	-1.5

IFF-12 TO NFAT

Total Export Sales	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
IFF 12 ($/MW.h)	85.6	89.6	93.2	90.6	91.4	93.5	97.0	100.4	103.7	106.8
NFAT ($/MW.h)	80.5	82.4	84.8	80.8	83.5	84.8	87.2	89.3	91.4	93.6
% Total Change	-6%	-8%	-9%	-11%	-9%	-9%	-10%	-11%	-12%	-12%

Total Change ($/MW.h)	-5.2	-7.2	-8.4	-9.8	-7.9	-8.7	-9.9	-11.2	-12.3	-13.2
Change due to Price ($/MW.h)	-5.2	-7.2	-8.2	-9.4	-8.3	-9.3	-10.5	-11.8	-12.9	-13.8
Change due to Volume ($/MW.h)	-0.8	-0.9	-1.2	-1.1	-0.1	0.1	0.1	0.0	0.0	0.0
Change due to Other ($/MW.h)	0.8	0.9	1.0	0.7	0.6	0.5	0.6	0.6	0.6	0.7

MANITOBA PUBLIC UTILITIES BOARD

IN THE MATTER OF *Order In Council 128/2013 and attached Terms of Reference Needs For and Alternatives (NFAT) Review*

AND IN THE MATTER OF *Manitoba Hydro's Filing with Respect to the Need For and Alternatives to Manitoba Hydro's Preferred Development Plan*

REBUTTAL EVIDENCE OF MANITOBA HYDRO

WITH RESPECT TO THE WRITTEN EVIDENCE OF:

- **ELENCHUS RESEARCH ASSOCIATES INC., ("Elanchus"); KNIGHT PIESOLD CONSULTING, ("KP"); LA CAPRA ASSOCIATES, INC., ("LCA"); MNP LLP, ("MNP"); MORRISON PARK ADVISORS, ("MPA"); POTOMAC ECONOMICS, LTD., ("POT") and POWER ENGINEERS INC., ("PE"), Independent Expert Consultants ("IECs") retained by the Public Utilities Board ("PUB")**

- **BILL HARPER, ECONALYSIS CONSULTING SERVICES; KYRKE GAUDREAU & ROBERT GIBSON; JILL GUNN & AYODELE OLAGUNJU, DOUGLAS GOTHAM, WAYNE SIMPSON; and WAYNE SIMPSON & DOUGLAS GOTHAM on behalf of Consumers Association of Canada (Manitoba) ("CAC")**

- **PAUL CHERNICK, RESOURCE INSIGHT, INC. and WESLEY STEVENS POWER ADVISORY LLC on behalf of Green Action Centre ("GAC")**

- **PATRICK BOWMAN, INTERGROUP CONSULTANTS LTD. on behalf of Manitoba Industrial Power Users Group ("MIPUG")**

- **WHITFIELD RUSSELL, WHITFIELD RUSSELL ASSOCIATES on behalf of the Manitoba Métis Federation ("MMF")**

- **PHILIPPE U. DUNSKY, DUNSKY ENERGY CONSULTING on behalf of Consumers' Association of Canada (Manitoba) and Green Action Centre ("CAC/GAC")**

February 28, 2014

Manitoba Hydro

TABLE OF CONTENTS

Page

1.0 INTRODUCTION

Manitoba Hydro's Rebuttal Evidence addresses the written evidence filed on behalf of the following parties with respect to Manitoba Hydro's NFAT filing:

William Harper, Econalysis Consulting Services (ECS); Dr. Wayne Simpson; Dr. Douglas Gotham; Dr. Kyrke Gaudreau & Dr. Robert Gibson; Jill Gunn & Ayodele Olagunja on behalf of Consumers Association of Canada (Manitoba) ("CAC");

Mr. Philippe Dunsky, Dunsky Energy Consulting on behalf of the Consumers' Association of Canada/Green Action Centre (CAC/GAC);

Mr. Paul Chernick, Resource Insight, Inc. and Mr. Wesley Stevens, Power Advisory LLC on behalf of the Green Action Centre (GAC);

Mr. Patrick Bowman, Intergroup Consultants Ltd., on behalf of the Manitoba Industrial Power Users Group (MIPUG) and;

Whitfield Russell, Whitfield Russell Associates on behalf of the Manitoba Metis Federation (MMF).

Manitoba Hydro's Rebuttal Evidence also addresses the written evidence of the Independent Expert Consultants (IEC):

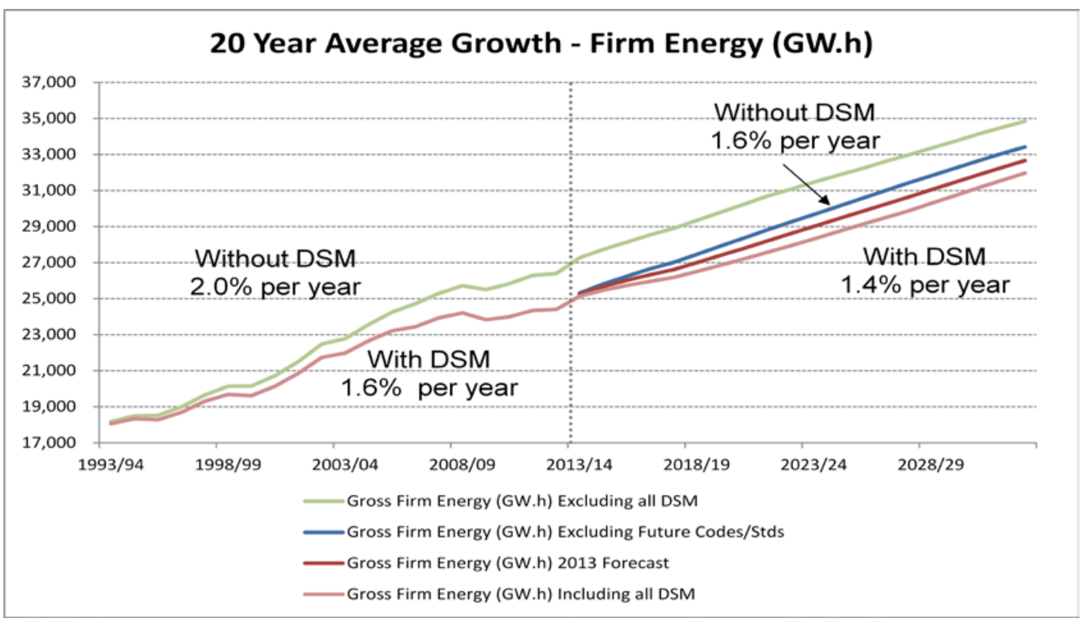
Elanchus Research Associates Inc.(Elanchus), Knight Piesold Consulting (KP), La Capra Associates, Inc. (LCA or La Capra), MNP LLP (MNP), Morrison Park Advisors (MPA), Potomac Economics Ltd (POT or Potomac) and Power Engineers Inc. (PE).

2.0 LOAD FORECAST

In this section of Manitoba Hydro's Rebuttal Evidence, Manitoba Hydro addresses the written evidence of IECs Elanchus and LCA as well as Intervenor witnesses Wayne Simpson and Douglas Gotham on behalf of CAC and Patrick Bowman on behalf of MIPUG.

2.1 Overview of Forecast Growth

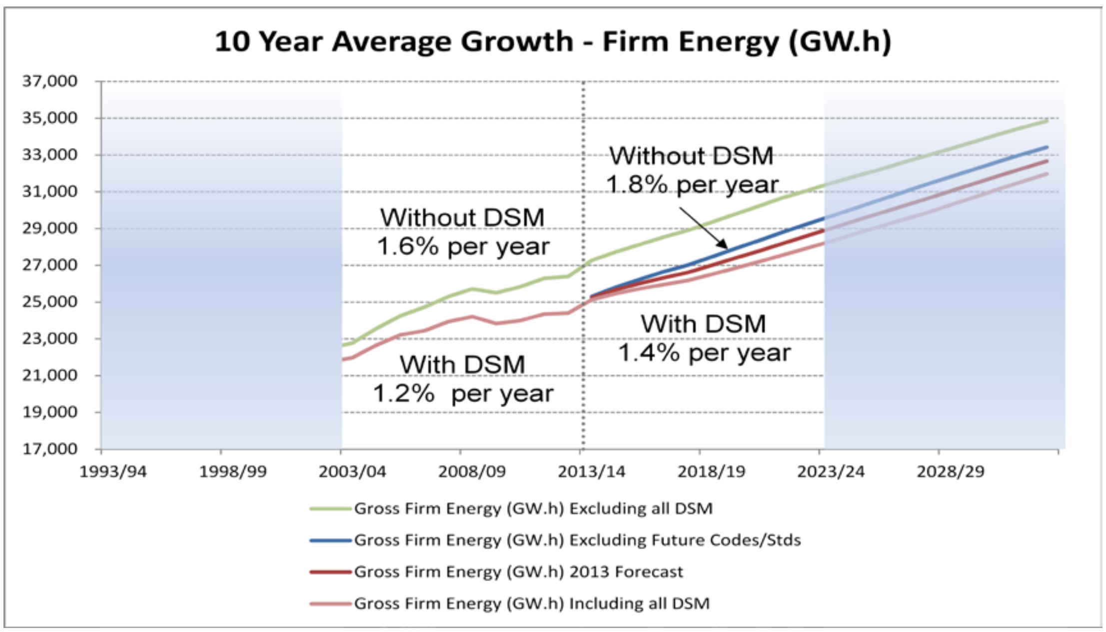
The purpose of the load forecast is to present the best estimate of long term future energy requirements for Manitoba. The following figure presents a 40 year summary of the historic and future energy requirements in Manitoba. Over the last 20 years, reflecting periods of both economic growth (beginning 1992) and economic downturn (beginning 2008) and the influence of past Demand Side Management (DSM) initiatives and changes to codes and standards Manitoba load has grown at an average rate of 1.6% per year. Without Manitoba Hydro's efforts both provincially and nationally to support DSM, Manitoba's energy requirements would have grown at an average rate of 2.0% per year over last 20 years.



Looking forward over the next 20 years under the 2013 load forecast and incorporating projections from the 2013 Power Smart Plan, energy requirements are projected to grow at an average rate of 1.4% per year. Manitoba Hydro is continuing to expand its DSM efforts and expects to be increasing its targets. As outlined during the September 5, 2013

Technical Conference and in Manitoba Hydro's response to PUB/MH I-265, with the completion of the DSM Potential Study, Manitoba Hydro revisited its Power Smart portfolio with the objective of seeking to reach higher levels of savings. Please refer to Section 3.0 Demand-Side Management for a detailed discussion of the enhanced levels of DSM assessed. Manitoba Hydro is now in the process of finalizing an update to its Power Smart Plan to be released by March 31, 2014 after consultation with the Minister Responsible for Manitoba as outlined under s. 7 of *The Energy Savings Act.*

The evidence of Elenchus and Drs. Simpson & Gotham focus their review on Manitoba load growth over the last ten years. This period is heavily influenced by a significant economic downturn which affected jurisdictions around the world including North America. The following figure presents a ten year summary of Manitoba's energy growth and forecast. Actual average annual growth in energy requirements over the last ten years has been 1.2% even with the loss of one Top Consumer and the economic downturn beginning in 2008; without DSM, the average annual growth would have been 1.6%.



In Manitoba, the impact of this downturn was predominately observed in the Top Consumers sector where, with the loss of one Top Consumer, the load reduced from 2007/08 to 2010/11 by an average of 4.3% per year while the weather adjusted Residential Basic and General Service Mass Market sectors experienced average annual growth of 1.9% and 1.5%, respectively, during this period.

2.2 Manitoba Growth Compared to Other Jurisdictions

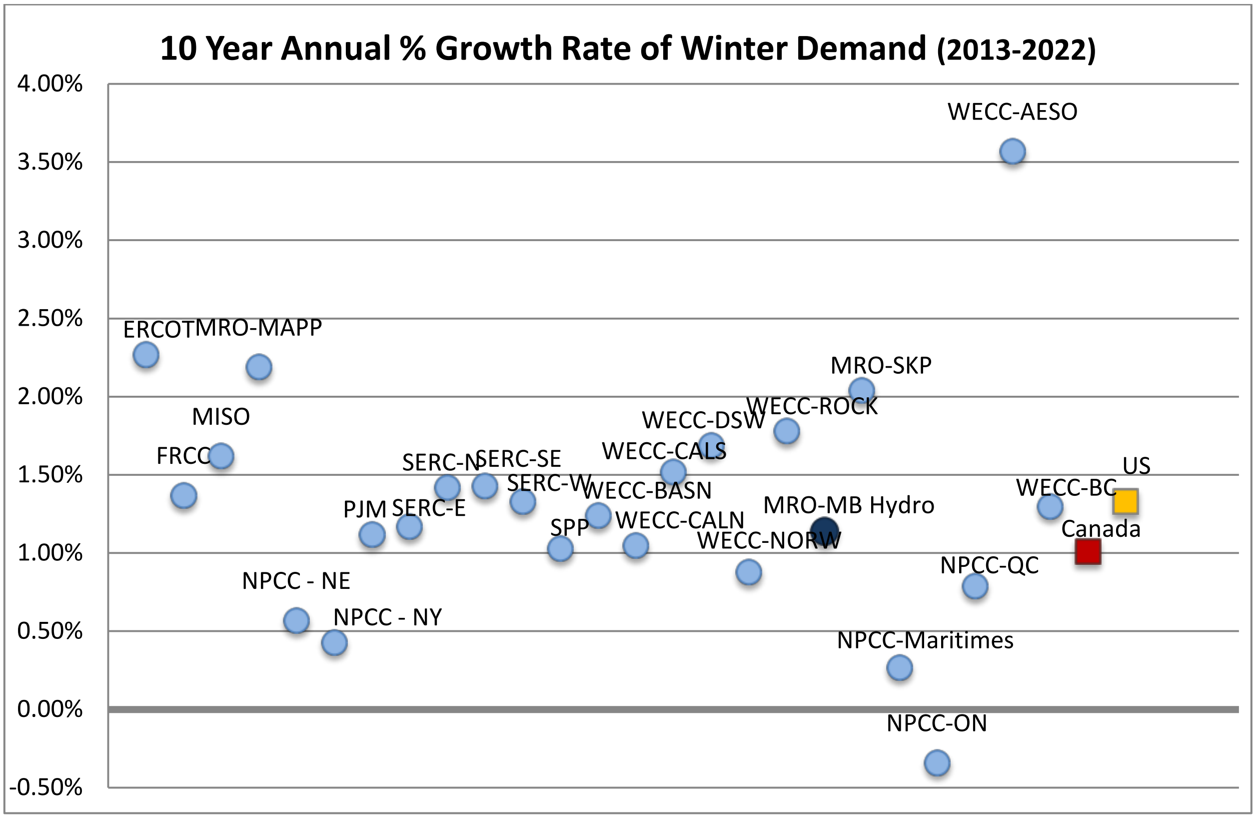
On page 8 of their evidence, Drs. Simpson and Gotham, on behalf of CAC, express puzzlement as to Manitoba Hydro's projection of 1.6% load growth (1.5% under the 2013 Load Forecast) exceeding the load growth forecast for the U.S. at 0.9%. As noted in response to CAC/MH I-171 the 0.9% US load growth forecast was drawn from the U.S. Energy Information Administration's Annual Energy Outlook 2013 (AEO13) and represents an average for the United States. The AEO13 compares the AEO13 forecast with the forecast of three other agencies with the other agencies are all forecasting electricity sales to have a higher growth rate[1]. National Renewable Energy Laboratory's forecast is 0.2% per year higher, Energy Ventures Analysis' forecast is 0.4% per year higher, and IHS Global Insight's forecast is 0.7% per year higher than AEO13. These three agencies are forecasting U.S. electricity growth rates to be between 1.1% and 1.6% per year. Manitoba Hydro's 20 year forecast average annual growth of 1.4%, including the influence of DSM savings, is within these bounds.

The AEO13 does not give specific details regarding the construct of these forecasts. Such comparisons of load growth rates between jurisdictions cannot be presumed to compare equivalent measures. Definitions of load differ and treatment of losses vary. Recent data may not be available and older data is compared to newer data. Further, when comparing a specific jurisdiction to an overall average, it is important to recall that the average represents an average of the expectations of a number of unique jurisdictions some of which will be projecting higher or lower growth than the average.

A more appropriate comparator is the data assembled from utilities by the North American Electric Reliability Corporation (NERC). Table 3.1 of Chapter 3, is produced below in graphic format for the benefit of the reader, presented in the order given in Table 3.1. The data contained therein is collected by NERC using a specific definition of load (Total Internal Demand) to compare forecasts. What is to be included and excluded is specified, as are time periods, and the data is required to be submitted by all utilities subject to NERC jurisdiction to NERC. So this is the best source of comparing projected growth in relationship to other jurisdictions. NERC reports a Total Internal Demand figure that reports Summer and Winter peak demand excluding Station Service and including DSM programs and specific system improvements. Because of this, NERC reports Manitoba Hydro's Total Internal Demand growth rate for 2012 to 2022 to be 1.14%. This

[1] Table 11 page 98 of http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf

corresponds to the 1.7% forecast annual peak growth during the same ten year period noted under Manitoba Hydro's 2012 Load Forecast.



In Mr. Dunsky's response to PUB/CAC-GAC-008a, he highlights four regions projecting flat to limited growth. The above figure demonstrates that Manitoba Hydro's forecast growth rate is only slightly higher than the "Total Canada" growth rate of 1.01%, but lower than the "Total U.S." growth rate of 1.33%. Ontario (NPCC-ON) and the Maritimes (NPCC-Maritimes), noted by Mr. Dunsky, do project flat growth over the next ten years. However, Table 3.1 also demonstrates that there are many jurisdictions with higher projected growth rates than Manitoba, including SaskPower (MRO-SKP) at 2.04%, Alberta (WECC-AESO) at 3.57%, and British Columbia (WECC-BC) at 1.30%. In the United States, the majority of jurisdictions have higher growth rates than Manitoba. Even the nearby MAPP region (MRO-MAPP) projects a higher growth rate at 2.19%. NERC presents all growth rates as including the influence of projected DSM savings.

2.3 Growth by Sector

As outlined in Section 4.2.1.1 of Chapter 4 of the NFAT filing, Manitoba Hydro's forecast is influenced by population growth, growth in GDP and average use per customer.

2.3.1 Residential Customer Growth

Manitoba Hydro's forecasts are "…based on a consensus view of several independent sources…" all of whom are known and respected (2013 Economic Outlook, Page 5). This consensus view is used to determine the long-term population forecast, and the estimate of 2.79 people per household is based on analysis of historical and forecasted data and judgment by Manitoba Hydro staff.

2.3.2 The Residential Customer Forecast – Number of Customers per Household

Both Elenchus and Simpson & Gotham took issue with the assumption of "simple arithmetic" used by Manitoba Hydro to determine the 2.79 estimate of people per household:

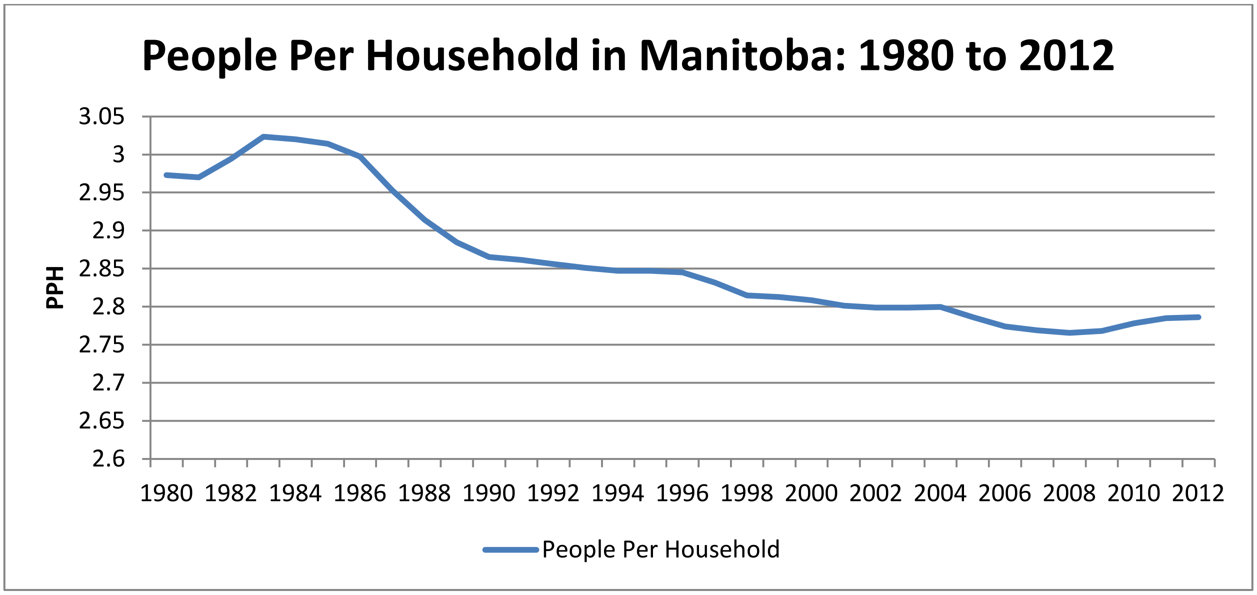
> *What is slightly more unusual about Manitoba Hydro's approach is how it determines its residential customer forecast. Residential customers are forecast based on an arithmetic identity between a "people per household" factor, which is determined through an historical simple arithmetic average and is held constant for the duration of the forecast horizon, and a consensus forecast which is a simple average of several forecasting agencies' population forecasts for the province. As shown above, the annual "people per household" as calculated by Manitoba Hydro is not constant. It has trended downwards from the 1980s until about 2007 and has now started to trend upwards. (Elenchus, Page 10)*

> *It is unclear how realistic it is to assume that use per customer for each of the GS Mass Market classes remains static for the 20-year forecast horizon. Embedded within the GS Mass Market forecast is also the assumption of a fixed 2.79 persons per household in the Residential forecast over the forecast horizon. (Elenchus, 21)*

> *Manitoba Hydro assumes the number of customers will change proportionately with population. This relies on the assumption that the number of people per household will not change. This has not been true in the past and is unlikely to hold true in the future. The number of occupants per household will be affected by not only the number of people, but the relative ages of the population. For instance, if the fastest growing segment of the population is over 50, there will usually be fewer people per household in the future. Another factor affecting the number of occupants per household is personal income. As income increases, the number of occupants per household generally decreases. (Simpson and Gotham, Page 6*)

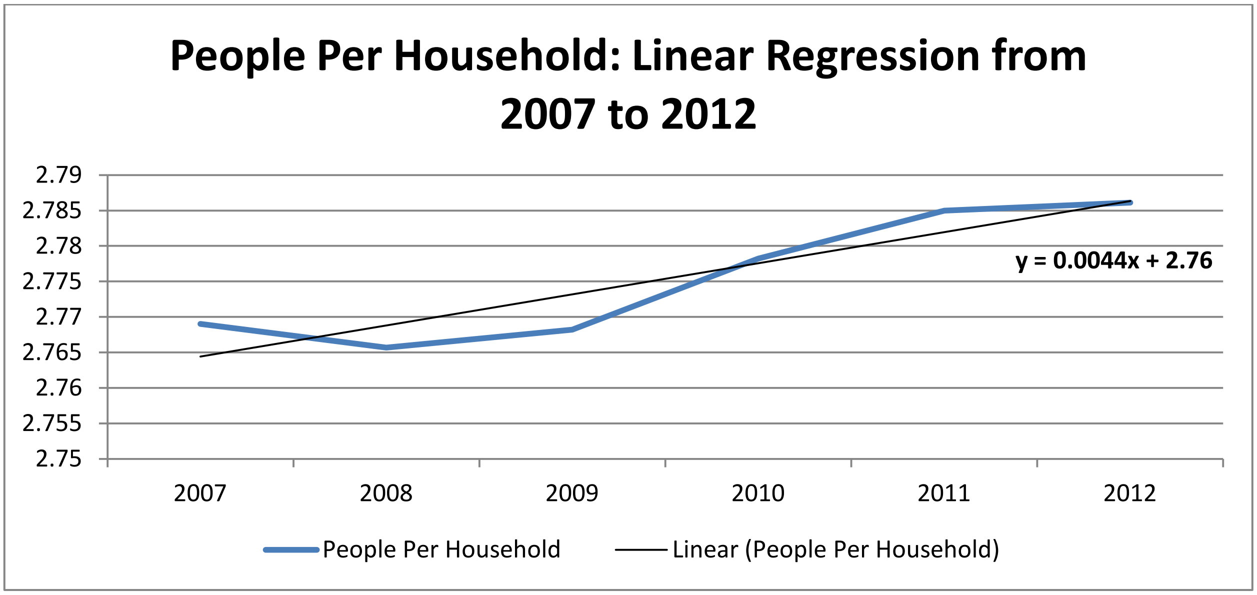
Manitoba Hydro recognizes and endorses the value of statistical analysis, including regressions, and that additional analysis strengthens decision making. Manitoba Hydro remains confident that the assumption that 2.79 people per household is reasonable as a constant for the residential customer forecast used by the NFAT submission on the basis that the average number of people per household has not changed materially since 1997. By rejecting Manitoba Hydro's assumption and instead assuming a growth in average number of people per household based on the trend since 2007 as advocated by Elenchus (Page 10), Manitoba Hydro emphasizes two points: almost any statistical technique will require the application of judgment to make assumptions; and even an aggressive assumption used in the residential customer forecast has a marginal impact on the overall long-run load forecast.

From 1980 until 2012 the actual number of people per household has declined from 2.97 to 2.78, a reduction of 6.3% in absolute terms. In 2000 there were 2.8 people per household and in 2012 there were 2.79, a reduction of 0.007% in absolute terms.

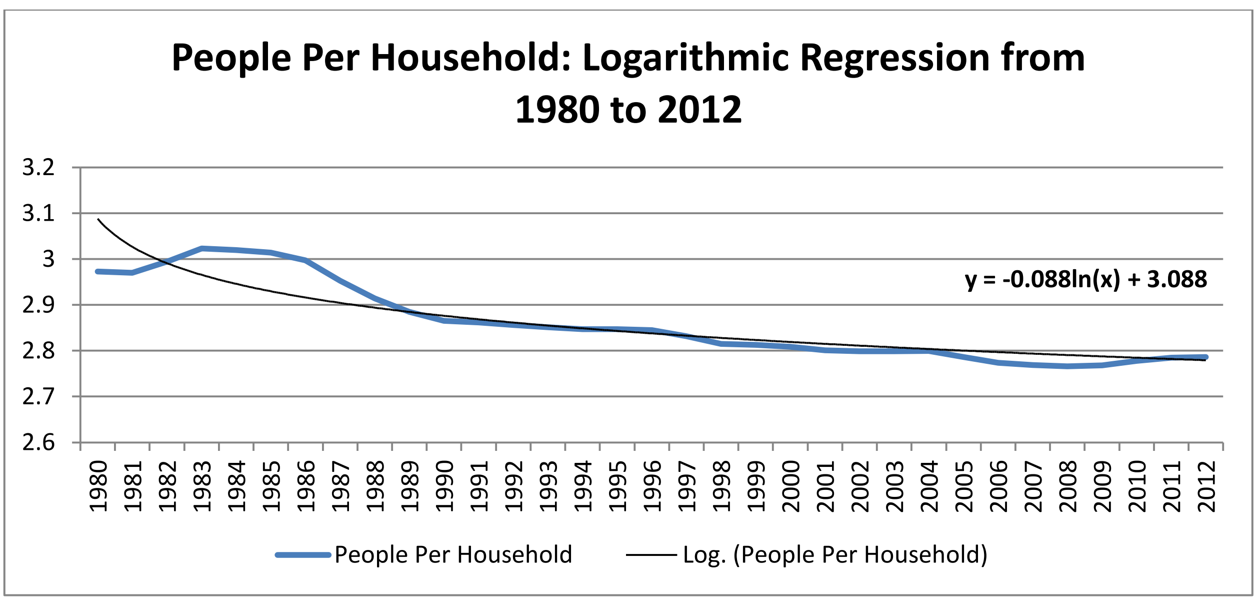


From 1980 to 2012, the highest value of people per household was 3.02 in 1983. Comparatively, the lowest value of people per household was 2.76 witnessed in 2008.

If Manitoba Hydro dismissed all historical record in favour of only the most recent past from 2007 where Elenchus (Page 10) noted there had been an upward trend, and then extrapolated this assumption through a time series linear regression, the result would be a continued annual increase of 0.0044 people per household; the 20 year forecast would be 2.86 people per household, and this new residential customer forecast would be 557,800, compared to the 572,600 projected by Manitoba Hydro. The difference between these cases is 14,800 residential customers, which assuming 30 GWh per 1,000 customers decreases the load forecast by approximately 450 GWh 20 years from now.



This is an unrealistic analysis because one needs to examine the broader historical trend. This trend has clearly demonstrated an overall decline and levelization of people per household to around 2.79. Indeed, when looking at the most recent trend, this value has been the average for 15 years from 1997 to 2012, and while it may have slightly increased, it is in fact again leveling off since 2010.



Similarly, a simple logarithmic fit to the entire dataset back to 1980, would project a continued downward trend, down to 2.417 people per household 20 years out, with a corresponding increase in the number of residential customers.

2.3.3 Residential Growth in Average Use per Dwelling

The electricity use of Manitoba Hydro's Residential Basic sector has grown 121 GWh per year (1.8%) for the past ten years. The growth reflects the effect of past Demand Side Management initiatives, including both programs and improved codes & standards. During this time, the number of Residential Basic customers has grown by 4,232 customers (1.0%) per year for the past ten years with average use growing 0.8% per year.

Over the next 20 years Residential Basic electricity use is expected to grow at 112 GWh (1.4%). This growth excludes the effect of future DSM programs which are forecast separately for planning purposes. The number of customers, based on population forecasts, is expected to grow at a slightly higher rate than it has in the past at 5,423 customers (1.1%) per year. The average use per customer is forecast to continue to grow at 0.3% for the next 20 years. One example demonstrating this would be that high efficiency natural gas furnaces are generally installed with multi speed fans that consume approximately 1,750 kWh/year when operated at a reduced speed on a continuous basis to enhance ventilation and comfort. The result is an increase in average electricity use of approximately 790 kWh/year relative to conventional furnaces with single-speed fans that operate only during heating/cooling cycles, using approximately 960 kWh/year.

There are several substantive considerations that must be referenced when examining the average consumption within the residential sector in Manitoba as compared to other jurisdictions that have projected a decreasing average use.

1. Manitoba has colder winters than many other jurisdictions. Building codes with an energy component are in place to ensure improved energy efficiency for Manitoba dwellings while ensuring adequate ventilation for maintenance of air quality. Part 9 of the Building Code requires that all new dwellings must install a heat recovery ventilator (HRV). HRVs save 313 kWh/year on heating in electrically heated dwellings, but increase electricity use in natural gas heated dwellings by 1,895 kWh/year. While this requirement decreases the average use of an electrically heated dwelling, it causes an increase in the average electricity use of a new natural gas heated dwelling.

2. Currently 36.3% of all dwellings in Manitoba use electricity for space heating. The percentage of new dwellings installing electric heat in Manitoba is increasing such that the overall percentage of electrically heated dwellings is expected to rise to

39.3% by 2032/33. An average electrically heated dwelling uses much more electricity in Manitoba than other jurisdictions even with improved energy requirements under the Manitoba Building Code due to Manitoba's climate, recognizing Winnipeg is one of the coldest cities of its size in the world. An average dwelling using electricity for heat in Manitoba in 2012/13 used approximately 25700 kWh compared to 10200 kWh for a dwelling not using electricity for heat. The difference implies that by 2032/33, approximately 3% of Manitoba's residential customers will be using over 15000 kWh/year more for space heat, contributing to an increase in the average use per dwelling in Manitoba.

3. Currently 49.0% of all dwellings in Manitoba use electricity for water heating. New dwellings are almost all built with electric water heaters, and some existing natural gas water heaters are being replaced with electric water heating. This combination is expected to increase the percentage of electric water heaters in Manitoba to 62.5% by 2032/33. A typical electric water heater uses approximately 3500 kWh/year. The increase in the percentage of electric water heating is contributing to an increase in the average use in Manitoba.

These differences reflecting Manitoba's unique market are contributing to the overall 1.4% growth projected for the residential sector.

2.3.4 General Service Mass Market – Growth in Average Use per Customer

The electricity use of Manitoba Hydro's General Service Mass Market sector has grown 107 GWh per year (1.4%) for the past ten years. The growth reflects the net effect of past Demand Side Management initiatives and some influence from the economic downturn. The number of General Service Mass Market customers has grown 571 customers (0.9%) per year with average use growing 0.5% per year for the past ten years.

Manitoba Hydro realizes that energy efficiency measures (DSM programs and codes & standards) have been and will continue to reduce the average energy intensity (kWh / square foot) in the General Service Mass Market sector. Notwithstanding all the measures that have been implemented, historical average use per customer has increased at 0.5% per year.

Average use per customer in the General Service Mass Market sector is affected by floor space, i.e.:

Total customer kWh = Building floor space (sqft) * Energy intensity (kWh/sqft)

Even though buildings are becoming more efficient, the average floor space per customer is growing at a faster rate offsetting the energy intensity reduction. Some examples include:

1. The construction of one prominent facility in Winnipeg at 550,000 square feet replacing the older 400,000 square feet facility. The new facility is 38% larger; overall electricity use has increased by 27%.

2. The Winnipeg Convention Centre is expanding from 492,000 square feet to 832,000 square feet, but remains as one "customer" with increased projected electricity requirements.

3. The IKEA store built in Winnipeg in 2012 at 400,000 square feet with geothermal space conditioning in line with the company's sustainability mandate[2] is much larger than other retail stores and despite being very energy efficient, uses more electricity than the average retail store in Manitoba.

4. A portion of a city block in downtown Winnipeg with two customers representing a total of 40,000 square feet is replaced by one 19 storey office/retail/hotel tower of 300,000 square feet, increasing the average floor space and energy use per customer, a trend that is anticipated to continue based on future plans for construction of new multi-use residential/commercial towers in downtown Winnipeg.

5. Expansions to hospitals, schools and public buildings do not add to the number of customers but do add to the average use per customer. For example, a rural school, originally built in 1964, added 36,000 square feet in 2012 increasing in size from approximately 20,200 square feet to 56,200 square feet; a 178% increase in floor space accompanied by a 120% increase in overall energy use.

6. New apartment buildings, nursing homes and offices are typically larger than those built in the past. For example, recently constructed head offices for a community

[2] http://www.ikea.com/ms/en_CA/pdf/sustainability_report/group_approach_sustainability_fy11.pdf, page 7.

organization and a health services organization are 82,000 and 71,000 square feet respectively using approximately 14 kWh/sqft, compared to the overall average office size of 12,000 square feet using an average 16 kWh/sqft.

These trends are expected to continue, with the average use per customer increasing compared to that of past customers.

Through the econometric model used to create the General Service Mass Market forecast, Manitoba Hydro has found a significant relationship between customer growth in the Residential Basic sector and growth in GDP to customer growth in the General Service Mass Market sector, and forecasts using this relationship. The significance (t statistics) of these two variables are 3.72 and 4.05 respectively as displayed at p.62 of the 2013 Load Forecast document, indicating that these variables are both relevant. The level of forecast accuracy in this sector has proven to be acceptable as noted by Elenchus in their assessment at page 21 of their evidence.

2.3.5 Growth in Top Consumers

Elenchus expressed concerns regarding Manitoba Hydro's forecast for Top Consumers, with Drs. Simpson and Gotham simply echoing this statement at page 7 of their evidence. However, in their response to MIPUG/Elenchus-1, Elenchus clarifies that their concern is primarily in regards to the long term forecast, stating that:

> *"Elenchus is of the opinion that Manitoba Hydro has as good a handle on the short term forecast of these customers as can be expected."*

Drs. Simpson and Gotham discount Manitoba Hydro's use of "informed opinion" and "time series" in its forecast of Top Consumers on the basis that such approaches are deemed unacceptable under MISO's list of forecasting methods (Simpson and Gotham, page 1). However, the concern raised by MISO in their Review is that the utility may not be able to identify the qualifications of the "expert" providing the forecast information. This is not the case in Manitoba Hydro's practice where use of this information is restricted to short term projections based upon the plans provided by the customers themselves. In these circumstances the customer is in the best position to offer advice on their planned future short term operations. Energy is an important consideration for customers included in the Top Consumers category. Efficiency and unit energy costs are generally evaluated relative to key performance indicators established by customers to assess the effectiveness of their operations. As such, energy requirements are generally one of the key considerations related to expansions of existing facilities or location of new facilities. Given the risks associated with the shortfall of a suitable energy supply, it is in the best interests of customers to provide Manitoba Hydro with accurate information regarding their future energy needs. Given the construct of Manitoba Hydro's Top Consumers sector (relatively few customers within each industry), using other approaches such as end-use or econometric analyses will not improve the accuracy of the Top Consumers' forecast.

2.3.5.1 Short Term Forecast: Top Consumers

The Top Consumers sector is made up of just 17 companies comprising of 31 electric accounts in the Primary Metals, Chemicals, Petrol/Oil Natural Gas, Pulp/Paper, Food/Beverage and Colleges/Universities sectors.

In the short term, each company's energy requirement is forecast individually based on committed plans and stated expectations over a three to five year period, which excludes longer term plans that are either uncommitted or subject to change. Forecast energy requirements use the past energy use as a baseline, which is supplemented with information from individual customers regarding their committed plans.

Elenchus at page 23 line 15 states that Manitoba Hydro's Top Consumers "is consistently over forecast". This assessment is based upon only the most recent five year period and is dominated by the unexpected closure of one Top Consumer and by the recent economic downturn. Selecting a different or broader period to perform this analysis presents a different perspective.

By way of example, the following table produced for a period just seven years earlier shows more under-forecasting than over-forecasting (negative numbers indicate actual consumption exceeded forecast):

Top Consumers % Error from Actual
(GWh Forecast)

Forecast Fiscal Yr	Year of Electric Load Forecast 2001	2002	2003	2004	2005	2006	2007
2001/02	-2.1%						
2002/03	-3.2%	-1.0%					
2003/04	-0.7%	-2.9%	2.2%				
2004/05	-3.3%	-6.4%	2.3%	-1.4%			
2005/06	-4.8%	-8.7%	-0.2%	0.3%	0.0%		
2006/07	-2.6%	-8.3%	0.7%	4.9%	3.2%	1.0%	
2007/08	-3.9%	-8.7%	-0.7%	6.1%	7.5%	3.7%	1.6%

2.3.5.2 Long Term Forecast: Top Consumers

Elenchus states in their evidence at page 45 under Summary of Scope of Work Responses, Number 7, that *"…confidence in the load forecast is justified except for the Top Users. Top User loads can change significantly in unanticipated ways since their demands are driven by many idiosyncratic factors that cannot be known to Manitoba Hydro."* Manitoba Hydro agrees that Top Consumer loads can be difficult to forecast in the long term as their energy requirements are driven by many distinct factors.

As a result, Manitoba Hydro forecasts long term energy requirements for Top Consumers as a sector overall, rather than by individual customer or industry sector. Manitoba Hydro forecasts long term energy requirements of its Top Consumers using growth patterns that do not solely reflect short term recent history which may be heavily weighted by a period of economic downturn or by a period of substantial growth. Instead, Manitoba Hydro uses a longer period that includes periods of both economic growth and economic downturn to account for both possibilities.

The table below presents the Top Consumers energy use over the past 20 years. The average annual growth over that period is 91 GWh (2.0%) per year.

Fiscal Year	Top Consumers GW.h	Annual Change
1993/94	3836	
1994/95	3825	-11
1995/96	4021	196
1996/97	4173	152
1997/98	4493	320
1998/99	4632	139
1999/00	4299	-333
2000/01	4515	216
2001/02	4818	303
2002/03	5282	464
2003/04	5423	141
2004/05	5714	291
2005/06	5948	234
2006/07	5989	41
2007/08	6075	86
2008/09	6065	-10
2009/10	5461	-604
2010/11	5342	-119
2011/12	5531	189
2012/13	5560	29
Average		91
Std Dev		244

The five year period Elenchus selected for their analysis includes four years with lower than average growth and one year with a large reduction due to the loss of one Top Consumer. At page 23 of their evidence, Elenchus notes that this period was influenced by the 2008/09 economic downturn. Basing conclusions on solely the last five years does not acknowledge that the last five years includes this referenced significant economic downturn, one that has been characterized as the "greatest financial crisis since the Great Depression"[3] nor does it acknowledge the need to look at the longer term in order to capture a more balanced perspective of growth, recession and recovery over the long term.

In their response to MIPUG/Elenchus-1, Elenchus states that they are concerned the long term forecasts may be over optimistic by not factoring in some consideration for recession cycles. Manitoba Hydro's long term forecast for Top Consumers is reviewed annually based upon past activity over a 20 year horizon, a horizon which contains periods of both growth and recession, including the significant economic downturn just described.

[3] – The Financial Crisis Inquiry Report, Final Report of The National Commission on The Causes of The Financial and Economic Crisis in The United States, The Financial Crisis Inquiry Commission, January 2011, page xv. (http://www.gpo.gov/fdsys/pkg/GPO-FCIC/pdf/GPO-FCIC.pdf)

Over the past twenty years, there were four new customers totaling 1100 GWh of consumption, nine instances of customers with major expansions totaling 1400 GWh, and two existing customers who closed operations reducing consumption by 700 GWh. These types of changes cannot be forecast on an individual basis and are more readily captured in considering the historical average. On this basis, the Potential Large Industrial Load (PLIL) category was set projecting an average of 100 GWh (1.5%) of growth per year starting in the fourth year of the forecast period.

The amount included for PLIL of 100 GWh per year under the 2013 Load Forecast amounts to 1700 GWh over the 20 year forecast. The PLIL represents projected growth that may arise from a single major addition or a combination of growth and contraction from a larger cross-section of Top Consumers, both existing and/or new.

Manitoba Hydro acknowledges that the exact timing and growth of expansions/contractions by Top Consumers will most likely not occur at a rate of 100 GWh per year. It is anticipated that these changes will arrive intermittently causing step changes in consumption by Top Consumers. This is consistent with the comments of Mr. Bowman's evidence, on behalf of MIPUG, at lines 10 – 14 on page 3-12 and in regard to Manitoba Hydro's response to MIPUG/MH I-43b requesting analysis based on the advancement of the full forecast PLIL to 2019/20:

> *"It is important to note that such a high degree of industrial load growth is uncommon, but it might represent only 1-2 loads arriving in the next 5-7 years – there are at least 1-2 major potential loads (and likely more) that could credibly require power from Manitoba Hydro over this period which are not yet contained within the Load Forecast."*

Manitoba Hydro is currently examining the impact of significant potential growth in consumption from the Top Consumer sector arising from recent public announcements by major pipeline transportation companies[4]. The magnitude of the projected load growth remains subject to continued analysis by the proponents of the various proposals, regulatory approvals, and negotiation of long-term contracts between the proponents and

[4] http://www.energyeastpipeline.com/wp-content/uploads/2013/08/Energy-East-News-Release-2013-08-01.pdf
http://www.enbridge.com/MainlineEnhancementProgram/Canada/Alberta-Clipper-Capacity-Expansion.aspx
http://www.enbridge.com/MainlineEnhancementProgram/Canada/Alberta-Clipper-Capacity-Expansion-Phase-II.aspx

their customers. As sufficient information was unavailable during the preparation of the 2013 forecast to provide reasonable certainty regarding the energy requirements of those projects, no projections beyond the PLIL were included in the 2013 forecast.

In one of its information requests (MIPUG/MH I-43b) and further outlined in MIPUG's response to MH/MIPUG I-4, Mr. Bowman suggests that Manitoba Hydro should consider an alternate load growth scenario that advances 13 years of PLIL growth (1300 GWh) to 2019/20. Manitoba Hydro considers the impact of this 1300 GWh advancement, combined with the four prior years of PLIL (400 GWh) included in the 2013 forecast, to be a conservative approximation of the anticipated net load growth for projects being considered by the pipeline sector in respect to both timing and magnitude. The analysis of the energy requirements for these projects is still ongoing and therefore subject to change as the proponents move forward with preparation of their regulatory filings. It is important to recognize that this allocation of the PLIL does not preclude considerations for other Top Consumers from moving forward with expansions to existing facilities or additions of new facilities that are included within the scope of the PLIL projection.

Since long term changes to the Top Consumers sector are difficult to predict reasonably on an individual consumer basis, the PLIL attempts not to capture the specific timing of these events, but to include a forecast of the cumulative load likely to be added by any given year – with the expectation, using the average growth experienced in the past 20 years, that there is an equal chance of the forecast being too high as there is of it being too low. The use of a trend line that is based on past periods of economic expansion as well as economic contraction enables Manitoba Hydro to produce a reasonable midpoint projection that is most likely to be unbiased as either high or low.

2.4 Price Elasticity in Manitoba

Elenchus, at page 44 of their evidence, and Drs. Simpson and Gotham, at page 9 of their evidence, have suggested that Manitoba Hydro's forecast ought to specifically recognize the potential demand response which may result from forecast future rate increases. Several Information Requests posed to Manitoba Hydro have also questioned the future effect of Manitoba Hydro's proposed long term price increases of 3.95% each year on demand. The current Manitoba Hydro long term plan forecasts electricity price increases of 3.95% per year for the next 20 years, compared to 2% per year increases in the CPI. This amounts to a real increase in electricity prices of 1.95% annually.

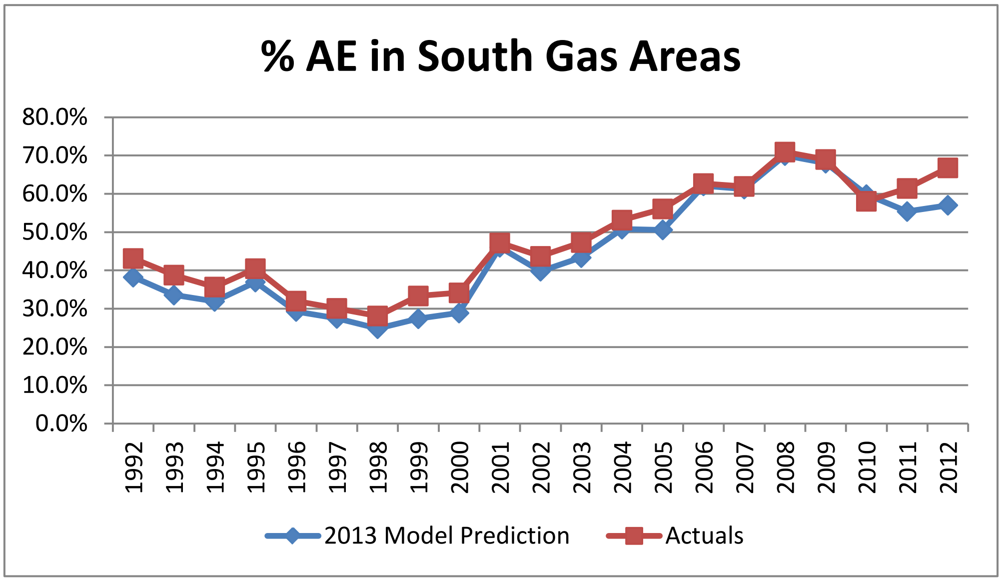
A price elasticity measure is expressed as a number such as -0.1, representing the ratio of the percentage change of the price response to the percentage change of the price. For example, with a price elasticity of -0.1, if the price of a product went up 50%, then the consumption of that product should correspondingly go down 5%.

Manitoba Hydro has among the lowest electricity prices in North America. As outlined in Manitoba Hydro's response to PUB/MH I-256, electricity prices have increased slowly at or close to the rate of inflation. As a result, the effect of price changes on customers' use of electricity would have been largely overwhelmed by the effect of other factors that affect demand for electricity, such as population increases, economic growth, improvements in residential construction, appliance efficiency, and the underlying random year-to-year variation in load.

Manitoba Hydro has previously investigated the possible relationship between energy use and price as noted in Manitoba Hydro's responses to PUB/MH I-256 and more recently in response to an interrogatory by Consumers Association of Canada (CAC) and Green Action Centre (GAC) (GAC-CAC/MH II-001a). These analyses have not provided estimates of elasticity that can be relied upon.

Manitoba Hydro formerly incorporated the effect of electricity and natural gas prices in relation to new homes selecting either electricity or natural gas for space heat into its load forecast. The analysis was based upon natural gas to electricity price ratios, and not electricity price alone. In 2012, the model incorporating the Price of Gas/Price of Electricity ratio predicted a decline in the percentage of New Electric Heat customers to the total number of new customers while the price of natural gas continued to fall. However, the actual market penetration of electric heat billed homes increased in 2011 and 2012. This was indicative that some other factor was being more determinative of the change in the percentage of electric heat billed customers than the price ratio, and the price ratio factor was removed from the model.

The following graph shows how the model built with the 2012 data would predict the historical data, and clearly shows that the model was not performing as expected in 2011 and 2012.



Every jurisdiction is different and will have electricity price elasticity effects that reflect the unique combination of different characteristics of that jurisdiction. While Manitoba Hydro's experience indicates the difficulty in isolating the price effect from other factors, studies from other jurisdictions provide a wide range in elasticity values, from -0.05 to -0.25 and higher. As well, price increases on higher starting prices, which result in a greater absolute expense to a consumer, may result in higher price elasticity than in jurisdictions with low and stable electricity prices.

In comparison to the information from U.S. jurisdictions, BC Hydro in 2008 adopted a price elasticity of -0.05 in their load forecast which has been reviewed and accepted by their regulator[5].

2.5 Adjusting for Weather in Manitoba

2.5.1 Weather Adjustment has Minimal Effect on Load Forecast

Manitoba Hydro has adjusted its definition of weather normal and degree day since 2007 in order to align approaches between forecasting for future electricity and natural gas needs and improve the overall approach. Elenchus noted in its evidence at lines 23-25, page 27, that a sensitivity analysis that outlined the impact of changes in base temperature and definition of normal on Manitoba Hydro's weather adjustment calculation would be useful.

[5] http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/2008_ltap_appendix_e.pdf, page 22.

Manitoba Hydro was previously using 18 degree base for calculating degree day heating for the electric weather adjustment and 14 degree base for calculating degree day heating for the natural gas weather adjustment. Manitoba Hydro analyzed and determined that the 14 degree base provided essentially the same fit as the 18 degree base for both electricity and natural gas, and the former was chosen for both weather adjustments.

Manitoba Hydro has filed such sensitivity analysis in prior Public Utilities Board hearings including: 2011/12 Centra Gas Cost of Service Application, 2012/13 & 2013/14 General Rate Application, and 2013 Centra Gas Cost of Service Application. The following table presents a summary of the findings of the impact of changes to the definition of "normal" on Manitoba Hydro's weather adjustment calculation, as originally presented in the 2011/12 Centra Gas Cost of Service Application:

Normal DDH Calculation Methodology
Impact on Normal DDH

Methodology	Average Change	Maximum Change	Years between Changes	Avg 1 Yr Forecast to Actual	Worst Case 1 Yr Forecast to Actual
25 Year Average	21	54	1	325	989
Olympic Average	32	100	1	300	998
10 Year Average	43	146	1	301	1057
Environment Canada	86	251	10	332	944
Five Year Fixed	104	160	5	306	1050
Statistical Significance Method	364	485	37	315	970

The result of moving from ten year to 25 year averages was a significant improvement in year-to-year stability with only a small reduction in accuracy. The analysis examined degree days and is relevant to both electricity and natural gas.

2.5.2 Necessary Changes to Weather Adjustment Methods

Manitoba Hydro's weather adjustment methodology has evolved from its early methods to meet current requirements. Elenchus noted at page iv of its evidence that *"the weather coefficients appear to fluctuate with observed weather and may not yield appropriate weather results"*. Elenchus is *"unclear why Manitoba Hydro has restricted the regression analysis to such a short time series." (page 28)*

Differing weather adjustment methodologies will have little if any effect on the load forecast. The weather adjustment is used to normalize the historical annual usage such that the historical usage can be viewed assuming a "normal" year as defined by our 25 year average. Any change in weather adjustment methodology will only affect the starting point of the forecast. The growth rate forecast will not be affected by this since both Residential growth rates and General Service growth rates are based on the customer forecast and are added to the weather adjusted starting point. Any variance produced by various methodologies to perform the weather adjustment will cause all years of the forecast to change up or down by a same small amount, not more than +/- 50 GWh overall.

Prior to 2009, Manitoba Hydro had used a regression-based method incorporating many years of data to determine the weather effect as Elenchus recommends. The regression model was:

Monthly GWh = $base_y$ + $base_m$ + ddh_y*(DDH – normal DDH) + ddc_y*(DDC – normal DDC)

Where

$base_y$ = the baseload in year y
$base_m$ = the baseload in month m of any year
ddh_y = the Degree Day Heating coefficient in year y
DDH = the actual DDH in the month
normal DDH = the long term normal DDH for the month
ddc_y = the Degree Day Cooling coefficient in year y
DDC = the actual DDC in the month
normal DDC = the long term normal DDC for the month

The base, ddh and ddc coefficients all have to be dependent upon the year, since they all change over time. But calculation of the coefficients for all years results in large fluctuations from year to year that are even greater than what Elenchus noted in Manitoba Hydro's new model. Therefore stepwise regression was used, so that a new coefficient value would be determined for only the years in which the cumulative change of the coefficient was significant. This results in each coefficient changing approximately every four or five years, not necessarily in the same years as the other coefficients.

These stepwise regression coefficients have fewer fluctuations, but with that they are less accurate, and have some disadvantages:

1. The coefficients would remain constant for several years and then jump, so smooth growth of the parameters was not being modeled, and

2. All the values of the coefficients and the years that they would jump would change whenever another year of data was added.

The primary purpose of weather adjustment at Manitoba Hydro is to explain monthly revenue variance between forecast revenue and actual, with the majority of the variance being due to weather. Reliable methods are needed to estimate the variance in GWh due to weather which then can be converted into a dollar value. The stepwise procedure prevented the best weather adjustment from being made for the current year.

In order to effect the best possible weather adjustment in the current year, weather coefficients need to be determined from the most recent data, ideally, the previous year. However, 12 monthly data points were found to be insufficient to produce good estimates of the base, ddh and ddc coefficients. Using more years of data produced more stable coefficients, but each year added resulted in less accuracy due to the coefficients changing over time. Manitoba Hydro analyzed different time periods to calculate the coefficients and found with using two previous years of data to best represent the current year's coefficients.

By determining the coefficients in advance, the weather adjustments for each month of the current year could be determined and reported as they happen. The coefficients would be set and not change at the end of the year, and all weather adjustment reporting at Manitoba Hydro would be consistent.

Starting 2009, the new model was used. The equation became simpler:

Monthly GWh = base + ddh*(DDH – normal DDH) + ddc*(DDC – normal DDC)

The base, ddh and ddc coefficients for each year are determined using the previous 24 months of data.

The advantages of this methodology are:

1. Historic coefficients do not change with new data,

2. Coefficients of sectors are additive and equal the coefficients of the total of the sectors,

3. This methodology can be used down to the individual customer, and

4. The resulting change in coefficients over time provide insight to customer heating and cooling usage pattern differences over time.

Elenchus expressed concern that the coefficients of this method fluctuate. However, the earlier regression model was less accurate and had some disadvantages, including having coefficients that changed when new data was added, and new data is added every year when a new forecast is produced.

Manitoba Hydro continues to work to improve its methodologies, recognizing however that for weather adjustment, future improvements will only have a minor effect. The inherent random variation in monthly energy use caused by non-weather dependent events limits the accuracy that is possible by any method.

The methodology chosen for weather adjustment has minimal effect on the overall Load Forecast with only a potential variation of +/- 50 GWh throughout the forecast due to a change in the weather adjusted starting point. This represents up to a 0.2% variation in Manitoba Hydro’s forecast overall at any point and is insignificant in that context.

2.6 Forecast Variability and Accuracy – Unpredictable Variation Limits Accuracy

Drs. Simpson and Gotham state at page 5 of their evidence that:

> *Regardless of the methodology used to develop the load forecast, having an accurate forecast is an important factor in resource planning. An inaccurate forecast can have significant reliability and cost implications. … While a perfectly accurate forecast is unattainable, it is important to avoid a forecasting methodology and assumptions that are likely to introduce a bias in either direction.*

Manitoba Hydro agrees that "a perfectly accurate forecast is unattainable", and as such presents a forecast created to be a midpoint for the potential range of variability. The expectation is that there will be a 50% chance that actual growth will be higher than the forecast, and a 50% chance that it will be lower.

On page 44 of the 2013 Electric Load Forecast, the load variability that is inherent in Manitoba's load growth is discussed:

> *The load will vary both year to year and long term because of underlying changes in population growth, economic growth, changes in the operations of Top Consumers, and overall use patterns.*

The variation that appears in the load is then quantified and probability-based ranges are produced. These ranges are based on year-to-year historic variation of weather adjusted load and the correlation between years. They illustrate the expected variation of future load that can occur based on any manner of random events that can occur. The actual load that will occur is unpredictable, but the expected range can be probabilistically estimated.

The analysis on load variability in the Load Forecast gives the information to put a measure on how accurate the forecast can be. For the 2013 forecast for 2022/23, the base forecast is 28605 GWh, and the standard deviation expected on this forecast is 1202 GWh. This defines the achievable level of accuracy to be 28605 +/- 1540 GWh, 8 times out of 10. There is an 80% chance that the weather adjusted actual will be within 5.4% of the base forecast. For 2032/33, the same calculation states that there is an 80% chance that the weather adjusted actual will be within 7.6% of the base forecast. These ranges, as outlined at page 48 Section 10.2.3 of Chapter 10, were used to assess sensitivity to high load and low load growth under this submission.

The five and ten year forecast accuracy, starting on page 47 of the 2013 Electric Load Forecast provides the evaluation of accuracy of past forecasts. It states:

> Manitoba Hydro's objective is that a five year forecast is within 5% and a ten year forecast is within 10%.

These are achievable levels of accuracy based on the analysis of load variability.

Manitoba Hydro understands what level of accuracy is achievable and updates its forecast annually with the most current information available to ensure it becomes the best forecast that is possible at the time it is produced.

2.7 Scenarios and Probability – A Scenario Selects Just One Possible Future

Manitoba Hydro has in the past produced Medium High and Medium Low Load Forecast Scenarios based on various economic and demographic assumptions. This requires the selection of inputs for such scenarios. Manitoba Hydro adopted its probabilistic analysis as it allows quantifiable risk-analysis to be done, where the desired likelihood of the case can be selected for the study. By comparison, arbitrarily constructed scenarios must assume a likelihood of occurring.

Elenchus recommends that Manitoba Hydro returns to its alternative economic scenarios of the past. However, during Manitoba Hydro's Electric GRA 2010/11 & 2011/12, the Public Utilities Board set forth an independent review of Manitoba Hydro Risks by Drs. Kubursi and Magee. The Load Forecast was part of this review, and Drs. Kubursi and Magee stated the following with regards to Manitoba Hydro's use of probabilistic analysis:

> *A probabilistic framework is worked out to identify the load given the probability of the actual load will be less than the forecast load. … This is an improvement on using arbitrary pessimistic or optimistic forecasting to bracket the forecast.(page 113)*

Drs. Kubursi and Magee recommended that the probabilistic methodology be continued and expanded upon. In line with this recommendation, this methodology was used in setting the ranges to assess sensitivity to high load and low load growth under this submission, as outlined at page 48 Section 10.2.3 of Chapter 10.

Manitoba Hydro has provided in the Load Forecast the data needed to understand the potential impact of possible future events and their respective impact on Manitoba energy and peak. These possible events (found on pages 50 to 54 of the 2013 Load Forecast) include the effect of climate change, the addition or loss of a large industrial customer, increased saturation of electric vehicles, increased saturation of electric space heat, and increased saturation of electric water heat. Weather effects are also included on page 43 of the Load Forecast. The effects of economic and demographic changes have been included in the “Changes between the 2012 and 2013 Forecasts” section, pages 12 to 16 of the 2013 Load Forecast.

Combined with the probabilistic analysis that is provided on pages 44 to 46 of the 2013 Load Forecast document, this information allows planners to derive any number of scenarios they wish to analyze.

3.0 DEMAND SIDE MANAGEMENT

In this section of Manitoba Hydro’s Rebuttal Evidence, Manitoba Hydro addresses the written evidence of IEC Elanchus as well as Intervenor witness Philippe Dunsky of Dunsky Energy Consulting on behalf of CAC/GAC.

3.1 Overview

Generally, Manitoba Hydro updates its DSM plans on an annual basis to reflect new and updated information. In the past, the update was aligned with the Manitoba Hydro’s overall planning cycle and the update was completed during the summer months. With the passing of the Energy Saving Act, Manitoba Hydro is now required to update its DSM Plan by March 31 of each year and the plan is to be developed in consultation with the Minister Responsible for Manitoba Hydro. Under this new process, Manitoba Hydro developed its first DSM plan in consultation with the Minister which involved a three year time horizon and included only those programs which were approved. To meet Manitoba Hydro’s resource planning process and requirements, a supplementary 2013-16 Power Smart Plan, 15 Year Supplementary Analysis Report was prepared. Manitoba Hydro recognizes that the targets in this plan are conservative as some programs and opportunities which could reasonably be expected to be achieved within the planning horizon were excluded (e.g. LED applications for Roadway lighting, residential and commercial applications; load displacement opportunities, fuel switching opportunities and energy conservation rates). These and other programs are expected to be added in future Power Smart Plans.

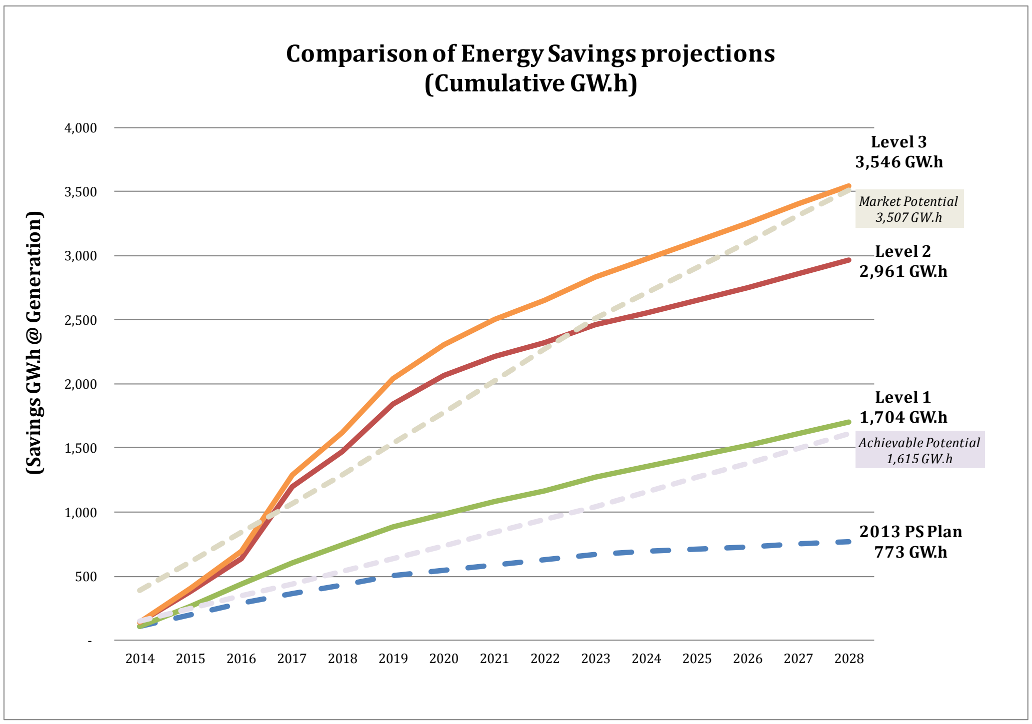
Manitoba Hydro is currently in the process of updating its DSM Plan in accordance with the Energy Savings Act and in consultation with the Minister responsible for Manitoba Hydro. The DSM Plan will likely continue to be a three year plan and Manitoba Hydro will subsequently be developing a longer term DSM Plan to meet the needs of the Corporation's resource planning process and requirements. To reflect DSM targets for resource planning purposes, the Corporation intends to forecast its expectation of DSM savings which will most likely be achieved, and therefore may include energy savings from emerging technologies or other initiatives such as load displacement, energy conservation rates and fuel switching.

For the purposes of undertaking evaluations as part of the NFAT process, Manitoba Hydro developed three levels of DSM. The DSM options were developed at a high level and without in-depth assessment for the purpose of evaluating various levels of DSM, whether economic or not. The three levels of DSM include the following broad categories:

- DSM Level 1 – Energy Efficiency Programming which include extending some existing programs beyond the approval periods (e.g. insulation), emerging technologies which were now economic (e.g. LED applications in roadway, residential and commercial lighting applications), and modifying some existing programs with a more aggressive design and approach. Opportunities included with this option were considered to be generally economic subject to more in-depth analysis and review.
- DSM Level 2 – This option includes additional opportunities which have been and are still under consideration by the Corporation but which are of a different nature than the traditional energy efficiency initiatives. These initiatives include Conservation Rates, Load Displacement opportunities and Fuel Switching. Based on a high level assessment, these opportunities are considered to be economic, however they involve broader considerations beyond simply energy savings objectives.
- Level 3 – This option includes all of the DSM Level 2 initiatives and modifies the energy efficiency programs to achieve greater energy savings, but with a commensurate higher cost. These higher cost programs would be considered uneconomic relative to the Level 2 programs when evaluated against the marginal costs but were included here to test more fully the viability of a higher level of DSM.

Demand Response was investigated as a DSM opportunity but not actively pursued beyond the present Curtailable Rates Program offering as Manitoba Hydro's focus under the present plan is on relieving energy constraints rather than capacity constraints, which is the primary benefit of demand response initiatives. The rationale behind this decision is provided in the response to Information Request CAC-GAC/MH I-30b.

The following figure presents the energy savings projections under the three levels of enhanced DSM in comparison to the 2013 Power Smart Plan and the Market and Achievable Potentials identified in the DSM Potential Study.



Level 1 DSM represents approximately 2.2 times the level of savings identified under the 2013 Power Smart Plan and is in line with the Achievable Potential identified under the DSM Potential Study.

Level 2 DSM, which includes conservation rates, fuel switching and load displacement, represents approximately 3.8 times the level of savings identified under the 2013 Power Smart Plan.

Level 3 DSM and including Level 2 DSM represents approximately 4.6 times the savings outlined under the 2013 Power Smart Plan.

3.2 More DSM Energy Savings Can be Achieved

In Mr. Dunsky's evidence, he suggests Manitoba Hydro can achieve greater energy savings through DSM. Manitoba Hydro expects that its 2014 – 2017 Update to its Power Smart Plan will include additional future DSM initiatives. The Corporation has already approved a number of initiatives which were included within Level 1 DSM, such as:

- Community Geothermal Program
- Residential Home Insulation Program – extended and more aggressive;
- Roadway LED Lighting
- Commercial Lighting – extended and more aggressive

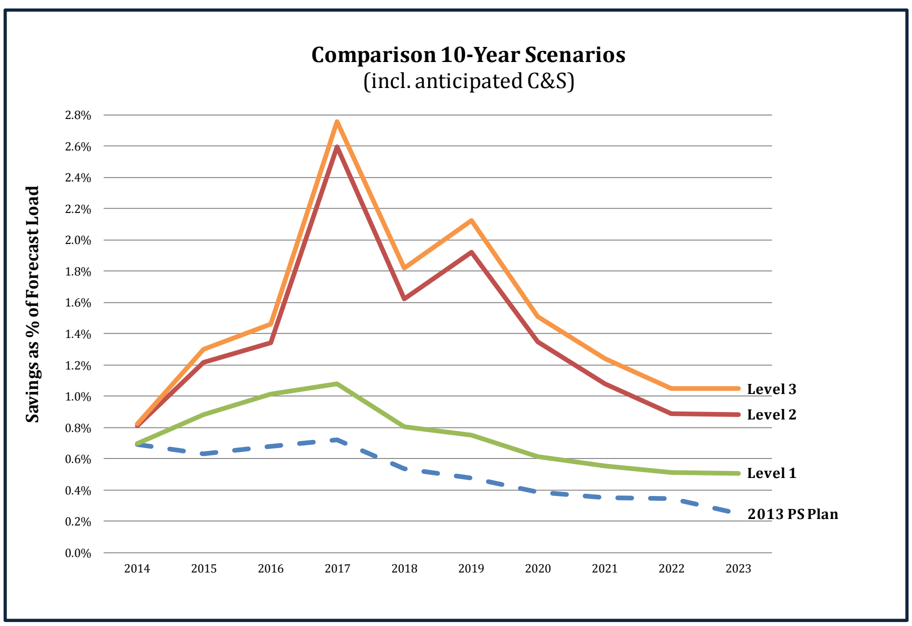
that were not included in its 2013 – 2016 Power Smart Plan.

In addition, subject to further analysis and internal approvals, it is anticipated that most of the initiatives identified in Level 1 DSM will be included in Manitoba Hydro DSM plans. Further work will need to be undertaken prior to making a decision on the initiatives included in Level 2 DSM.

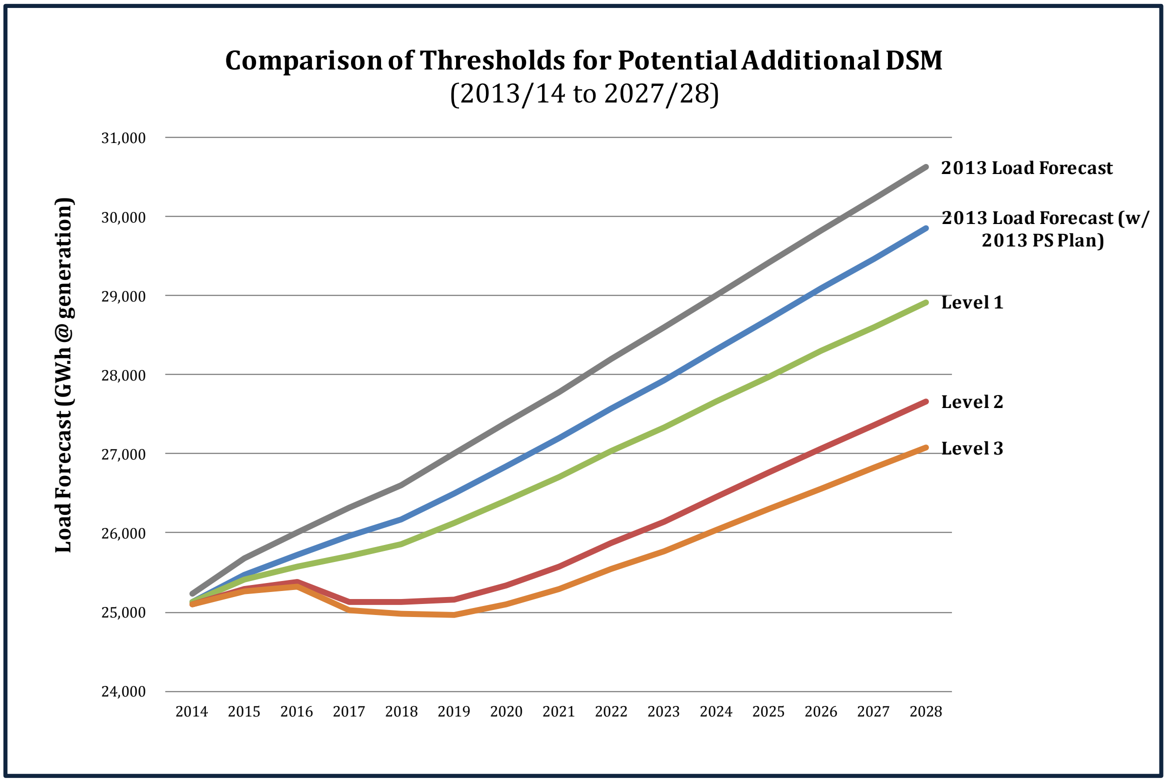
For illustrative purposes, the table below provides the DSM program-driven savings associated with each enhanced level of DSM both as a percentage of forecast sales and in GW.h/year. The table also presents the average annual savings over an initial 10 year period (2013/14 to 2023/24) for DSM programs alone and for non-program savings, specifically those savings currently anticipated to be achieved through codes and standards.

		2014	2015	2016	2017	2018	2019	10 YEAR AVG 2014-2023 (programs only)	10 -yr Avg. 2014-2023 (prog's + C&S)
Level 1 0.5%	%/yr:	0.4%	0.6%	0.7%	0.6%	0.5%	0.5%	0.5%	0.7%
	GWh/yr:	110	160	170	167	138	137	1,272 GW.h/yr (cumulative)	1,918 GW.h/yr (cumulative)
Level 2 1.1%	%/yr:	0.5%	1.0%	1.0%	2.1%	1.3%	1.6%	1.1%	1.3%
	GWh/yr:	138	244	255	559	352	445	2,459 GW.h/yr (cumulative)	3,104 GW.h/yr (cumulative)
Level 3 1.2%	%/yr:	0.6%	1.0%	1.1%	2.3%	1.5%	1.8%	1.2%	1.5%
	GWh/yr:	141	266	285	601	403	499	2,833 GW.h/yr (cumulative)	3,478 GW.h/yr (cumulative)

The following figure illustrates the cumulative savings of the enhanced levels of DSM as a percentage of load reduction compared to Manitoba Hydro's 2013 Power Smart Plan.



The enhanced levels of DSM represent a significant potential reduction to Manitoba Hydro's load forecast. The following figure presents graphically the 2013 Forecast adjusted for the enhanced levels of DSM examined.



Under the 2013 Load Forecast, energy requirements are projected to grow at an average rate of 1.5% per year over 20 years with energy savings projected under the 2013 Power Smart Plan reducing average annual growth to 1.4%. Under the enhanced DSM scenarios, average annual load growth declines to 1.2% under Level 1, 0.9% under Level 2 and 0.8% under Level 3 over the 20 year forecast horizon.

3.3 DSM Planning as a Resource

Mr. Dunsky is concerned that Manitoba Hydro *"risks locking itself into a path of new supply that, as a result, will lock out the much less expensive option of more efficient demand"*. (Dunsky Report, page 16)

Manitoba Hydro has not locked itself into a new supply path. The purpose of this NFAT process is to assess and make recommendations as to which future resources will be developed. The selection of resources and any commitment will depend on the outcome of the NFAT process and subsequent government decisions.

Manitoba Hydro's Power Smart Plan is an integral component of the Corporation's resource plan. Manitoba Hydro's DSM strategy is to pursue all economic DSM opportunities. The Power Smart Plan is developed following this principle, and results in DSM being a preferred option relative to alternative supply side options within the integrated resource planning process. This has been the case for many years and as a result, the Power Smart plan has and continues to be a component of the Corporation's strategy to meet the future electricity needs of Manitoba.

All the NFAT development plans and the pathways include DSM and whichever plan or pathways is pursued will involve expanding DSM.

We concur with Mr. Dunsky that the 1.5x DSM and 4x DSM sensitivity evaluations in Chapter 12 do not provide an integration of DSM and supply which determines the optimum level of DSM. Instead, as stated in the submission, the sensitivities were intended to assess the impact on the supply option selection arising from different levels of DSM which potentially would be developed by Manitoba Hydro.

An integrated evaluation of DSM and supply options to determine the optimum level of DSM could not be provided in the August submission because of the delay in the DSM Potential Study. The DSM options are currently being assessed with the supply options in development plan evaluations and will be provided to the NFAT process as soon as complete.

These evaluations with different levels of DSM will be input into the decisions on:

- DSM expansion
- Selection of development pathway
- Selection of generation options over time (e.g. If Keeyask developed first; would subsequent generation be Conawapa or gas fired generation)
- Timing of these generation options.

The planning for DSM programs and integration with supply options will not stop with the NFAT analysis but carry on in further stages. The DSM program option chosen will evolve in conjunction with supply option planning and not be locked out.

There is a risk when evaluating DSM Option levels, which are packages of programs, that the chosen DSM Option level could include individual programs which are individually not economic. There is also the converse risk that a DSM Option level not chosen contained DSM programs which individually were economic.

Manitoba Hydro is not opposed to including uneconomic opportunities as an overall DSM package; however, there should be rationale to support the inclusion of the uneconomic opportunities (e.g. lower income programming, and demonstration projects on emerging technologies).

Once a DSM Option level is chosen, a further stage of development will involve more detailed program planning which will use updated marginal values to optimize the programs in that Option.

It is particularly useful to undertake a full scale development and evaluation of DSM Option levels where there are significant differences in the characteristics of the development plans. The NFAT situation where there are choices to be made between significantly different development plans is such a situation and why Manitoba Hydro is undertaking the DSM Options review at this time. Once the pathway is chosen, the need for full scale option evaluation is diminished and more effort is placed on refining the programs within the chosen DSM Option level.

3.4 Comparisons with Other Jurisdictions – Savings

In Mr. Dunsky's analysis, there is a substantial focus on the metric of savings as a percentage of load. Such a savings ratio metric is generally valid for comparing efforts among regions with similar load characteristics and having similar marginal cost considerations using similar criteria to define and assess DSM initiatives and their savings, including the assessment of codes and standards regulation, natural conservation and the impact of interactive effects. However, caution must be exercised in using this metric for comparisons among regions where load characteristics and marginal cost considerations differ. A more accurate assessment would involve assessing a region's overall energy conservation efforts which goes beyond just what is achieved through programming. For example sustainable energy savings can be achieved through the implementation of codes and standards, claimed energy savings can be substantially impacted by a region's judgment on free riders and the baseline used for measuring and claiming energy savings.

Mr. Dunsky specifically focused on five regions he chose as representing comparable characteristics of Manitoba markets. These regions were compared on individual characteristics, not in combination of multiple "similar" characteristics. Mr. Dunsky did not include the region which most closely resembles Manitoba's load characteristics;

Quebec. Although Quebec and Manitoba do differ in some ways, Quebec is a more relevant comparator to Manitoba given that it has a combination of comparable characteristics, such as high number of heating degree days (3,100 in Montreal and 4,500 in Winnipeg) combined with a high penetration of electric heat, lower electricity rates, plus a long standing and recognized energy conservation initiative. This is especially interesting given Quebec's ratio of savings to load of 0.55% for 2010[6].

Mr. Dunsky specifically cites Minnesota as another good example of DSM leadership. Mr. Dunsky fails to note however, that Xcel Energy, a large utility that delivers DSM programs in Minnesota, reports their targeted and actual energy savings on a gross basis. Similar to 29% of utilities in a recent report conducted by ACEEE[7], Xcel has adopted a "gross savings" methodology which does not adjust savings by key factors such as free ridership and naturally occurring energy savings whereas Manitoba Hydro adopts a "net savings" methodology which reduced claimed energy savings by these same factors. The report characterizes this issue as follows; "..these substantial discrepancies between states in the use of net vs. gross savings (and the approaches used to calculate net savings) clearly underscore the difficulty of making "apples to apples" comparisons…"[8]. The report concludes with a recommendation on the issue of net vs. gross that; "…whichever approach a state uses, its methodologies and assumptions on this issue should be fully disclosed, so that others seeking to interpret reported results will have that understanding, and be able take that into consideration when comparing results across states." [9]. Notwithstanding other market characteristic differences such has climatic conditions, saturation of electric heat, and rural remote populations, a comparison to Xcel based on the reporting methodology of savings alone, is an oversimplification and does not serve as a fair basis of comparison.

3.5 DSM Potential Study

At page 17 of Mr. Dunsky's evidence, he opines that the DSM Potential Study has likely materially understated the achievable cost-effective potential in the province. Notwithstanding Mr. Dunsky's critic of EnerNoC's DSM Potential Study, Manitoba Hydro is satisfied with the results of market potential study recognizing:

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[6] 2012/13 & 2013/14 Manitoba Hydro General Rate Application, Exhibit GAC&CAC#4, slide 13.
[7] A National Survey of State Policies and Practices for the Evaluation of Ratepayer-funded Energy Efficiency Programs: February 2012. Report Number U122, page 33.
[8] A National Survey of State Policies and Practices for the Evaluation of Ratepayer-funded Energy Efficiency Programs: February 2012. Report Number U122, page 33.
[9] A National Survey of State Policies and Practices for the Evaluation of Ratepayer-funded Energy Efficiency Programs: February 2012. Report Number U122, page 38.

- these studies are undertaken as a high level assessment of the potential in a region; and
- the market potential study results are used for the basis of more detailed analysis of specific energy efficient opportunities. This is the process which is currently being undertaken by Manitoba Hydro with some existing programs now modified and new programs launched. With regard to new opportunities (e.g. LED street lighting), Manitoba Hydro's staff have been monitoring these technologies and are aware of their potential in Manitoba. Regarding opportunities where a program already exists, the study affirms the remaining market opportunity and serves as a basis for program managers to reassess their market and savings assumptions and adjust program strategies.

The potential in Manitoba varies by sector. The following table summarizes the potentials as a percentage of load forecast by sector.

	2022/23				2031/32			
Potential	Residential	Commercial	Industrial	Overall	Residential	Commercial	Industrial	Overall
Technical	27.3%	37.4%	11.5%	23.8%	34.4%	45.2%	15.7%	30.2%
Economic	18.1%	33.9%	10.4%	19.3%	24.4%	41.0%	13.7%	24.8%
Market	9.7%	21.2%	6.3%	11.4%	14.7%	28.8%	8.8%	16.2%
Achievable	3.6%	10.7%	1.5%	4.7%	6.5%	17.1%	2.7%	7.9%

Interactive effects will also have an influence on potential in jurisdictions which are heat dependent, such as Manitoba. Energy savings arising from implementation of energy efficiency measures are decreased when heating systems are required to "make up" heating; this has a greater effect for measures in the residential sector.

The unique characteristics of Manitoba's industrial sector have a significant impact upon the overall potential in Manitoba. An assessment of the industrial sector needs to reflect the nature and characteristic of consumption within the sector and assess the potential savings of major load sources. In Manitoba's instance, it was determined that energy intensive processes within some of Manitoba's largest energy consuming industries were either saturated from an energy efficiency perspective (significant efficiency upgrades already implemented) or subject to significant constraints related to operational impacts, cost and/or technology limitations that restricted future energy efficiency savings opportunities (pipeline transportation). As a result, these loads were removed from consideration for the determination of technical, economic, market and achievable potential.

At page 20 of his evidence, Mr. Dunsky postulates a series of aspects that limit the DSM Potential Study, which as he characterizes "limiting the estimated savings potential". The first area of concern is possible exclusions from the study. Manitoba Hydro acknowledges that load displacement and fuel switching to natural gas were not included within the scope of this study. Conservation Rates were not explicitly modeled within the study; however the Corporation notes that conservation rates may be a possible program strategy used to pursue the higher level market potential, as contained in DSM Level 2.

The following evidence was prepared in collaboration with EnerNOC Utility Solutions in regards to the other exclusions identified in Mr. Dunsky's report:

- *Individual Measures* – The measure list for this study was developed in late 2011 and represents an extensive list of measures compiled by EnerNOC that underwent a qualitative screening process for relevance to Manitoba and also a thorough review by Manitoba staff. For example, Mr. Dunsky specifically referenced the exclusion of air-source heat pumps. In determining the measures relevant to Manitoba, EnerNOC excluded air-source heat pumps in the qualitative screening process as they are not well-suited to Manitoba's very cold climate. EnerNOC's research at the time indicated that air source heat pumps do not work well in cold climates. There was one manufacturer of a "cold-climate" heat pump, but EnerNOC considered this to be an emerging technology that was not proven. Ductless heat pumps were also excluded as an emerging technology. It should be noted that both of these technologies are load-building technologies since they would add cooling to homes that do not currently have it. Geothermal heat pumps were assessed at Manitoba Hydro's request. Air source heat pumps are an electric heat technology which compete with ground source heat pumps. In cold climates, such as Manitoba, the seasonal coefficient of performance (SCOP) of an air source heat pump is lower than a ground source heat pump as the earth retains a larger quantity of heat throughout the winter compared to the air. Pages 6-8 of the Demand Side Management Potential Study note that for the residential market sector, "Heating offers the highest technical potential, which reflects the across the board-installation of geothermal heat pumps". With air source heat pumps having a lower SCOP than ground source heat pumps, including the technology in the Study at the technical level would not have increased the technical potential. The approximate installed cost of a whole home air source heat pump that can operate in Manitoba's cold climate is $14,000 to $16,000 installed, with an approximate SCOP of 1.5.

- *Miscellaneous loads* – Mr. Dunsky states that assuming zero efficiency savings from miscellaneous loads is understating potential. EnerNOC goes to great lengths to enumerate end uses and technologies in the development of market profiles. For the residential sector, for example, EnerNOC identified 44 uses (end-use/technology combinations), which account for almost 96% of residential electricity use (see Report, pages 3-5). The remaining use, which is labeled as Miscellaneous-Miscellaneous, includes all the remaining uses of electricity including things like power tools, coffee makers, hair dryers, and exercise equipment. Similarly, for the commercial sector EnerNOC identified 32 end-use/technology combinations, which account for 96% of commercial electricity use (see Report, pages 3-13). The remaining use, also labeled Miscellaneous-Miscellaneous, includes all other uses such as medical equipment, coffee makers, power tools and miscellaneous plug loads. It is EnerNOC's standard practice not to speculate on energy-efficiency improvements for these uses, and has been consistent in this in more than 30 potential studies completed in the last five years. That being said, whenever a use within this category becomes significantly large and high-efficiency options become available, EnerNOC isolates this end use outside of the miscellaneous category. Two examples of this in the residential sector are lighting and home electronics, both of which were part of the miscellaneous end use in the past and have been isolated in recent years.
- *Early retirement* – Mr. Dunsky states that the potential study ignored the potential for early replacement. In EnerNOC's experience performing more than 30 potential studies in the last five years, early replacement of appliances and equipment is simply not cost effective. Early replacement measures must consider the full cost of the measure rather than the incremental cost. Any additional savings that might accrue from early replacement should only be counted until the expected life of the measure is reached or a standard goes into effect. These savings do not, in EnerNOC's experience, support the full cost of the equipment. It is also important to recognize that early replacement affects the timing of savings rather than absolute savings.
- *Future technologies* - It is EnerNOC's practice to include only those measures that are commercially-available or very near commercialization. In recent years, this has included LED lamps and heat pump water heaters. In order to include the measures, EnerNOC must have performance data (e.g., energy use/savings, measure lifetime) and costs. The LoadMap model allows for the inclusion of declining measure costs during the forecast period. In the more than 30 studies conducted by EnerNOC over the last five years, none have speculated about new measures that cannot be identified.
- *Industrial loads* - Mr. Dunsky expressed concern that a large portion of industrial loads have been excluded from the study. The largest industrial customers, who

consume the majority of the industrial process energy use, assess economically viable energy conservations measures for process equipment during major upgrades and replacement cycles. The costs associated with changing out site-specific process equipment and revenue lost during production outages cannot generally be justified solely on energy savings alone. Therefore major advances in energy efficiency related to industrial processes are generally addressed when new facilities or major upgrades and expansions to existing facilities are being considered, which was not foreseen in the period of the potential study.

In addition, a large share of the energy consumed in Manitoba's large industrial processes has been minimized and can therefore be considered "saturated" for the purposes of the DSM Potential Study. DSM savings achieved within these sectors are dominated by several large companies that have participated in Manitoba Hydro's industrial programs and should be considered mature and transformed for the DSM planning period.

Major advances in energy efficiency related to industrial processes are generally addressed when new facilities or expansions to existing facilities are considered. This consideration is often related to efforts to maximize production at the lowest available unit cost rather than an intention to lower absolute energy consumption. Such expansions are also subject to a large number of considerations of which energy is often only one component. As a result, forecasting the future impact of technology advancement in industrial processes is particularly challenging. Any load expansions or major refurbishments that are not specifically foreseen in the load forecast would most likely have relatively insignificant DSM potential due to the higher base-case associated with newly installed industrial processes.

The second area of concern noted by Mr. Dunsky is a perceived limitation in the approach to the economic screening process.

- *Benefit cost threshold* - Mr. Dunsky states in his evidence at page 52 that "potential studies commonly apply a Benefit/Cost (B/C) threshold below 1". None of the DSM Potential Studies completed by EnerNOC have used a Benefit/Cost (B/C) ratio of less than 1.0 to assess measure cost-effectiveness. In many studies, EnerNOC includes an estimate of program administration costs in the economic screening of measures, usually as a percentage of the measure cost. However, at Manitoba Hydro's request, no program administration costs were included, keeping the costs to a minimum and producing a higher B/C ratio.

Under the LoadMap model used for determining cost effective measures, each measure is assessed each year within the study horizon such that a measure that is not cost effective in years 1 or 2 may become cost effective in year 3 and is accounted for in the potential.

- *Non-energy benefits* - As Mr. Dunsky notes at page 53 of his report, it is difficult to assess the value of non-energy benefits (NEBs) and, for this reason, EnerNOC states that most of their clients do not require the analysis to consider NEBs. The only NEBs EnerNOC has considered are water savings from low-flow showerheads and horizontal-axis washers. If these measures do not pass the economic screen (B/C ratio < 1.0) on energy savings alone, EnerNOC looks at the B/C ratio. If it is close to 1.0, then the client may direct EnerNOC to include the measure in economic potential. EnerNOC's LoadMap model has a "B/C kicker" variable that allows them to augment the B/C ratio so it is greater than 1.0. EnerNOC has not considered other NEBs such as productivity in their potential studies.

- *Measure bundling* – Measures in the DSM potential study were screened on an individual basis. However, when designing programs, Manitoba Hydro does bundle measures where it makes sense to do so such as with insulation measures or under its Affordable Energy Program targeted to lower income customers.

The third area of concern noted by Mr. Dunsky is related to the approach to determining the baseline projection and achievable market adoption rates.

- Mr. Dunsky states concern that the baseline projection in the study is lower than the load forecast used by Hydro for its overall energy planning. The EnerNOC baseline projection in the Manitoba potential study is lower than the corporate load forecast because EnerNOC uses an end-use forecasting approach that focuses on describing end-use energy for purposes of estimating potential energy efficiency savings. This approach explicitly accounts for numerous factors, including appliance standards, building codes, and customer response to energy prices, some of which are not included in the same way in utility forecasts. In addition, EnerNOC's modeling of growth in the commercial sector is driven by floor space and in the industrial sector is driven by employment and this approach for modeling growth is also different than what utilities typically use to develop their load forecasts and is better for DSM analysis. The purpose of EnerNOC's projection is to identify and quantify the likely projection for each technology included in the study so that the analysis of potential savings through energy-efficiency programs start in an appropriate place. The baseline projection is a stepping stone rather than a key deliverable of the potential study.

In most of EnerNOC's potential studies, the baseline projection is lower than the official utility forecast. This is not of great concern to EnerNOC or to many of their clients as the development of the baseline projection is separate and distinct from the process utilities use to develop their load forecast. Different methods produce different results. In cases where EnerNOC's clients have wanted the baseline projection to align with the utility load forecast, the difference between the baseline projection and the utility forecast is allocated to the miscellaneous-miscellaneous category which does not have any energy-efficiency savings associated with it; either approach results in the same outcome.

- *Adoption Rates* – Mr. Dunsky states that the adoption rates appear far lower than is found in many other regions, including those that served as the basis for the study. EnerNOC routinely adjusts the adoption rates used as a starting point to reflect local results and circumstances (in this case the starting rates are from the Pacific Northwest U.S and adjusted for Manitoba). This information is incorporated into estimates of Market and Achievable Potential. The Market Potential estimates provide an upper bound of potential. Achievable Potential and Market Potential provide a range of potential that could be reached through increased funding, program design, and other actions.

3.6 Solar and Grid Parity

The evidence of both Manitoba Hydro and Mr. Dunsky points to considerable long-term uncertainty over the future costs of solar PV. Such uncertainty provides a challenging framework within which to establish the timing of solar PV as a cost-effective supply option in Manitoba.

In his evidence supporting the near-term grid parity of solar PV installations, Mr. Dunsky provides an estimated time frame for grid parity based on high and low price considerations, using Manitoba Hydro's information as the low price scenario. The estimates for grid parity are based upon solar installations across a number of jurisdictions, not only Manitoba. Costs in each jurisdiction will be impacted by a number of factors including variations in retail rates, incentives, rebates, tax credits, and installations costs.

This analysis therefore incorporates assumptions with regard to current and future consumer rates, incentives, rebates, and tax credits available to support solar installations and their projected decline over the next decade. Mr. Dunsky's suggestions of near-term grid parity rely heavily on incentives, tax credits and rebates to support near-term grid parity, even in jurisdictions with higher cost rates structures. As an example, the feed-in-tariff provided in Ontario at $0.396 per kWh coupled with the 100 percent exemption from sales tax referenced in Mr. Dunsky's response to MH/CAC_GAC 5(b) is significantly higher than the current marginal value of many alternate supply options.

It must be recognized that Mr. Dunsky's evidence does not consider the expectation customers (both businesses and homeowners) may have about obtaining a reasonable return on their investment relative to other opportunities that may be pursued. While customers in jurisdictions where solar contributes to reduced greenhouse gas production may see value in this investment from perspectives other than purely financial ones, a reasonable return on investment is likely to be of greater importance to customers in Manitoba where hydraulic generation already provides those environmental benefits and other measures such as home insulation may provide greater long-term economic benefits.

Manitoba Hydro's current Bioenergy Optimization Program has the flexibility to allow for adoption and integration of many different types of emerging renewable energy measures, including solar PV. In allowing for such measures, Manitoba Hydro is prepared to adopt and support solar PV as long-term costs and benefits gain greater clarity and provide for improved cost/benefit ratios. The design of this program and future load displacement programs will account for the many influences that determine grid parity and the cost-effectiveness of load displacement opportunities that may contribute to future supply options. As noted in its application, Manitoba Hydro's projections include declining costs of solar PV that are anticipated to support improved economics for all types of solar installations in the future. It is anticipated that new homes, commercial facilities and community developments may provide the first opportunities for implementation as the incremental costs will be lower and therefore more attractive.

3.7 DSM Load Factor and Relationship to System Load Factor

The assertion made by Elenchus in regards to the relationship between System Load Factor and DSM load Factor (Page 13, Lines 13 – 26) suggests that DSM demand and energy savings must be in the same proportions as system load originating with the residential, commercial and industrial sectors unless load shifting is a specific objective.

While there may be some validity in suggesting that such a relationship may occur on a sector basis over a period of time with saturation of DSM initiatives, factors such as the seasonal influence on energy and demand savings, diversity of program offerings and available savings opportunities must be considered when evaluating the relationship between savings load factor and system load factor. The authors of the Elenchus report appear to have based their load factor comparisons on an annualized basis only, which does not recognize the sector and measure specific nature of various DSM initiatives pursued by Manitoba Hydro.

A common understanding of load shifting initiatives implies that curtailed energy use within a time period (often on-peak) is usually recovered in another time period (often off-peak) on a daily or weekly basis. Based on this definition, load shifting initiatives do not generally provide for a net reduction in energy use, although some system peak coincident demand savings may be achieved through shifting of load from on-peak periods to off-peak periods. Such a savings characteristic will result in a typically low savings load factor similar to that achieved through demand response or curtailment programs. Given industry-wide acceptance of demand response as a recognized DSM initiative, it would also appear to be reasonable to then also consider Manitoba Hydro's Curtailable Rates Program as a DSM initiative.

DSM initiatives that save both demand and energy may not necessarily have an annualized savings load factor that correlates to the annualized system load factor on either a sector or system-wide basis. Given that the savings load factor of any particular initiative is a function of the ratio between energy and demand savings, it is important to understand the relationship between these two desired outcomes of any DSM initiative.

By example:

Residential lighting measures typically achieve lower hours of operation than many other measures due to the low level of occupancy in residential dwellings during mid-day periods. The lower hours of operation reduce the potential energy savings available from such measures but have minimal impact on system coincident demand savings. In Manitoba, energy savings from residential lighting measures will be concentrated towards the winter months due to the shorter hours of daylight that are available during this period. It is important to recognize that demand savings originating from residential lighting measures continue to exhibit a high degree of coincidence with system peak demand despite the lower hours of operation. In a jurisdiction such as Manitoba, where morning and evening winter system peaks dominate annual capacity requirements, excellent correlation with demand savings from residential lighting measures are achieved due to these hours also being peak periods of operation for residential lighting.

This savings characteristic does however dictate that residential lighting measures will provide a much lower annualized savings load factor when compared to either the annualized sector or system load factor. This level of demand coincidence will not occur in a jurisdiction where summer day time peaks dominate annual capacity requirements since residential lighting systems tend not to operate during mid-day periods due to the prevalence of ambient light and a lack of dwelling occupancy during this period. As a result, the annualized savings load factor will be significantly higher in those jurisdictions due primarily to the lower level of system peak coincidence.

Contrasting this behavior, other measures such as building envelope measures will have greater energy savings relative to their demand savings due to their contribution towards reduced energy consumption during both winter and summer periods and the tendency for heating and cooling systems to operate coincidently with peak system demands. As a result, these measures will exhibit a higher savings load factor and better correlation to the annualized sector and system load factor.

Further influences such as the proportion savings available from each measure relative to its baseline consumption also influences the relative contribution of each measure towards the total energy and demand savings available for a specific sector or combination of measures.

These influences can also be extended to the industrial sector.

By example:

While many industrial DSM measures are applicable to a broad cross-section of industrial customers comprising a variety of annual operating hours arising from one, two or three shift operations, the proportional energy and demand savings achieved from DSM measures within these operations relative to their consumption may vary greatly. In aggregate, it can be expected that DSM savings available from measures installed in single-shift operations will generally have a lower savings load factor than the same measures installed at continuous operations. There are differences though in how those energy and demand savings correlate to total energy consumption for these facilities. Resource-based industries that dominate energy consumption in the industrial sector often utilize continuous operations with core processing loads that consume a high percentage of the total energy consumed by operations. Those core processing loads may not have the same opportunity for DSM savings that are available from more common measures related to lighting, ventilation, compressed air, etc, which are available to all industry sectors. In manufacturing operations operating on a single or two shift basis, energy consumption related to lighting, ventilation, ancillary systems, heating and cooling often contributes to a greater percentage of total energy consumption. As a result, smaller industries may have different opportunities to achieve DSM savings that will also typically have a lower annualized savings load factor than the industry sector annualized system load factor.

As with the residential sector, the relationship between available DSM measures, their specific savings load factors, and the frequency of their adoption will also impact the commercial and industrial sectors. In turn, these factors will impact the correlation of the aggregate DSM savings load factor with the system load factor. In Manitoba Hydro's instance, an aggregate annualized DSM savings load factor of approximately 0.54 is considerably lower than the system load factor of approximately 0.63.

Contrary to the assertion provided by Elenchus in its report (Page 13, line 23 – 26), such disparity should not be viewed as a contributing factor to uncertainty in DSM projections provided by Manitoba Hydro. Rather these factors should be viewed as criteria for evaluating the savings contribution of various program options that may be selected by Manitoba Hydro as it reviews and enhances its DSM offerings, thereby improving the quality and reliability of those projections.

3.8 Surplus Energy Program

In its assessment of Manitoba Hydro's demand-side management initiatives, Elenchus makes the following statement in its report (Page 8, Lines 11 – 12) with respect to the Surplus Energy Program:

> *"The Surplus Energy Program is a program whereby customers can choose not to take load in exchange for payments at prices that are posted a week ahead."*

This characterization by Elenchus is not reflective of the intent of the Surplus Energy program. The program is not an initiative aimed at reducing customer load on the Manitoba Hydro system and should therefore not be viewed as a demand-side management initiative.

The Surplus Energy program provides commercial and industrial customers with the opportunity to purchase energy that is otherwise surplus to Manitoba Hydro's domestic and firm export requirements on terms that are comparable to those obtained through opportunity sales or the incremental marginal value of that surplus energy in instances where transmission constraints preclude access to the opportunity market. As such, the terms and conditions of these purchases reflect the nature of an interruptible opportunity sale.

In recent history, such purchases have been made available at a value that has been lower than the firm domestic rates these customers are charged for firm supply due to the lower value of opportunity sales. Typical use of surplus energy is for electric space-heating applications in circumstances where the customer has an available alternate energy supply should surplus sales be interrupted. Customers are not required to nominate energy purchases in advance and prices are posted in advance on a weekly basis.

Manitoba Hydro does not include the Surplus Energy Program in its assessment and development of its Resource Plan or in its DSM savings.

3.9 Curtailable Rates Program

Elenchus appears to have misinterpreted the operation of Manitoba Hydro's DSM Curtailable Rate Program as it asserts in its report (Page 8, Lines 5 – 6) that customers are only approached by Manitoba Hydro during times of constraint caused by low water levels.

The intent and purpose behind the Curtailable Rates Program is to maintain generation reserves, thereby minimizing disruptions to firm customers in the event of loss of generation or transmission, or an unexpected increase in firm load. A secondary objective is to fulfill Manitoba Hydro's commitment to maintain a specific level of planning reserves and operating reserves as part of it reliability obligations with the Mid-Continental Power Pool – Generation Reserve Sharing Pool. The frequency and duration of curtailments allowed under the program do not make it an effective tool for addressing constraints caused by low water conditions, which generally have a longer term influence that cannot be fully addressed with frequency and duration of curtailments allowed under the program.

Elenchus' focus on enhanced export sales as the primary outcome of the Curtailable Rates Program (Page 10, Lines 17 – 20 and Lines 27 – 29) does not reflect the intent and purpose of the program. The quantity of energy that is made available through curtailments facilitated under the program is not sufficient to materially change the amount of energy available for export.

Manitoba Hydro does not include the demand benefits available from the Curtailable Rates Program in the assessment and development of its Resource Plan.

3.10 Time-of-Use Rates and Behind-the-Meter Concepts for Large Customers

In its report (Page 27, Lines 12 – 15) on Manitoba Hydro DSM initiatives, Elenchus indicates that:

> *"Similarly MH has studied the use of Time-of-Use (TOU) rates and does not support their introduction, nor Demand reduction programs or associated concepts ("behind-the-meter" services). (MH does not offer TOU rates to even large consumers, a reflection of the exceptional low cost of electricity in Manitoba)"*

Manitoba Hydro has studied the use of Time-of-Use (TOU) rates for large consumers and submitted an application to introduce Time-of-Use rates for all General Service Large customers served at 30 kV and above during its last General Rate Application (GRA). This will be the subject of a future hearing.

Similarly, Manitoba Hydro is evaluating the implementation of a behind-the-meter self-generation program aimed at capturing cost-effective opportunities for customer-sited load displacement. This initiative is referenced in the Level 2 DSM option provided earlier in Section 3.0 of this Rebuttal Evidence.

4.0 RESOURCE PLANNING

This section addresses the written evidence of IEC's La Capra, MPA and Potomac.

4.1 Manitoba Hydro's Generation Planning Criteria is Appropriate

Manitoba Hydro has a duty to provide for a reliable and dependable supply of power. Planning criteria are the means through which utilities provide reasonable assurance that load can be met over winter peak, during droughts or other contingencies including generation outages, and recognizing that loads can be higher than forecast due to exceptionally cold weather.

La Capra stated, regarding Manitoba Hydro's generation planning criteria that "*MH has provided significant detail on the history and current status of its energy planning criterion. LCA has reviewed the information provided and we find that in some respects MH's planning criteria are reasonable and consistent with industry practice, but in others MH is overly conservative*[10]." Manitoba Hydro believes that its generation planning criteria are reasonable, prudent, and consistent with both industry practice and the duties and responsibilities with which the Corporation is charged.

4.1.1 Capacity Criterion is Appropriate

Manitoba Hydro's generation planning criteria includes a capacity criterion used to determine the minimum quantity of generation capacity required. La Capra did not note any concerns with Manitoba Hydro's capacity criterion, when it concluded "*MH's capacity reserve criterion includes a planning margin that is similar to other similar hydro-dependent systems*[11]." La Capra had also stated "*There is no available evidence upon which to conclude that MH's capacity reserve requirement should be any different than the current 12% standard. LCA believes this to be a reasonable assumption for the NFAT analysis*[12]."

It should be understood that the Capacity Criterion, rather than the Energy Criterion, is at times the governing criterion for adding new resources. Specifically, the need for resources in the All Gas development plan, and the latter years of other development plans

[10] La Capra Associates Technical Appendix 1 - Resource Planning, page 1-17.
[11] La Capra Associates Technical Appendix 1 - Resource Planning, page 1-17.
[12] La Capra Associates Technical Appendix 1 - Resource Planning, page 1-10.

when natural gas fired resources are being added, is generally governed by the capacity criterion.

4.1.2 Energy Criterion is Appropriate for Hydro Resources

In addition to a capacity criterion, Manitoba Hydro has an energy criterion which recognizes the energy-constrained limitation of hydro-electric generating system during a drought. La Capra did not note any concerns with Manitoba Hydro's energy criterion as it is applied to hydro resources, stating *"MH's energy criterion requires dependable resources to be available in the event of a repeat of the driest flow conditions, which is generally consistent with other hydro-dependent systems[13]."* Further, La Capra appears to have taken no issue with the methodology by which Manitoba Hydro determines dependable energy for thermal or wind resources.

4.1.3 Degree of Reliance on Imports in the Energy Criterion is Reasonable and Prudent

La Capra does take issue with the manner in which Manitoba Hydro considers imports as dependable energy in the energy criterion as follows:

- *"The limitation on imports to 10% of Manitoba load plus export obligations has not been supported by any analysis. This threshold does not appropriately incorporate changes in the transmission system or markets since the policy was first established in 1977.*
- *Limiting amount of dependable energy to the quantity that can be imported during the off-peak period similarly is not supported by any analysis and is very conservative[14]."*

La Capra's criticism of Manitoba Hydro's degree of reliance on imports in the energy criterion is unwarranted and based on a number of misunderstandings. Further, if the degree of reliance on imports was increased in accordance with La Capra proposals[15], there could be Manitoba energy shortages under water conditions considered within the hydraulic planning record.

[13] La Capra Associates Technical Appendix 1 - Resource Planning, page 1-17
[14] La Capra Associates Technical Appendix 1 - Resource Planning, page 1-17
[15] See the No Build/ Import Reliance Plan, as discussed in La Capra Technical Appendix 3 Alternative Resources Plan, page 3A-25

Manitoba Hydro has identified the following gaps in the La Capra's analysis of the degree of reliance on imports.

4.1.4 Manitoba Hydro Import Limitations are Consistent with other Predominantly Hydroelectric Utilities

La Capra claims Manitoba Hydro's energy criterion has some "unique and limiting features"[16]. This assertion of uniqueness is not correct, as a number of other Canadian and U.S. jurisdictions consider limitations on external supply or imports when evaluating their system reliability/resource adequacy. La Capra itself recognized that such limitations do exist when it stated "*BC Hydro also has a self-sufficiency component of its planning criteria. The Clean Energy Act requires BC Hydro to be self-sufficient in energy supply by 2016.*"[17]

Other jurisdictions including Ontario, Hydro-Quebec, the Maritimes area, and the U.S. Pacific Northwest region are other examples where there are limitations on external supply or imports.

Ontario does not consider any interconnection support/imports when performing their reliability/resource adequacy analysis:

> Although the NPCC criterion for resource adequacy assessments allows for reliance on interconnection support, imports from Ontario's five interconnected neighbours were not considered in this analysis. This is consistent with the approach used in the development of other IESO reliability assessments (e.g. 18-Month Outlook and the Ontario Reliability Outlook), where imports from neighbouring Planning Coordinator areas are not relied upon to meet peak demand in the planning timeframe but rather left as an additional resource to be used in real-time operations, as required.[18]

Hydro Quebec considers no intertie benefits when it performs a resource adequacy analysis known as a loss of load expectation (LOLE) study even though their estimated intertie

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[16] La Capra Associates Technical Appendix 1 - Resource Planning, page 1-57.
[17] La Capra Associates Technical Appendix 1 - Resource Planning, page 1-9.
[18] Ontario Reserve Margin Requirements 2014-2018 dated October 25, 2013, available at http://www.ieso.ca/imoweb/pubs/marketReports/Ontario-Reserve-Margin-Requirements-2014-2018.pdf

capability is 2900 - 3400 MW. No tie benefit was used to meet the LOLE criterion for all years of the Hydro-Quebec review for the 2011-2016 time period.[19]

For the Maritimes Area (New Brunswick, Nova Scotia, Prince Edward Island and a portion of northern Maine), which has a required reserve margin of 20% of firm peak load, only 300 MW of intertie benefits are considered in their resource adequacy analysis, whereas "the range of estimated annual tie benefit potential for the Maritimes Area for 2011 was 1076 – 1353 MW and 1252 - 1536 MW in the year 2015. Based on this study, the 300 MW of tie benefits assumed for this 2013 Comprehensive Review is conservative. A sensitivity analysis performed for this review shows that the Area does not require interconnection assistance to meet the NPCC resource adequacy criterion[20]". In other words, the Maritimes area assumes intertie benefits at less than 25% estimated annual tie benefit potential and is deemed to have adequate resource adequacy with no reliance on the interconnections whatsoever.

The electricity supply in the U.S. Pacific Northwest Region (primarily the states of Washington, Oregon and Idaho) is governed by federal U.S. legislation called the Pacific Northwest Electric Power Planning and Conservation Act, which requires a 20-year electric power plan for the region[21]. The Pacific Northwest Region has a winter peak load of about 32000 MW, and hydropower provides about 56 percent the region's electricity generating capacity[22]. The Pacific Northwest is interconnected to California which is a summer peaking region. In its resource adequacy analysis, Northwest Power and Conservation Council considers only partial availability of imports from California to meet energy requirements in the Pacific Northwest Region. Specifically, in a manner very similar to what Manitoba Hydro has assumed, zero on peak summer imports are considered, and up to 3000 MW in the off peak period[23]. The Pacific Northwest and California are interconnected through AC and DC transmission interties with approximately 7900 megawatts of maximum transfer capability, including 4800 megawatts

[19] 2011 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, prepared by Hydro-Québec Distribution, approved November 29, 2011, available at: https://www.npcc.org/Library/Resource%20Adequacy/Qu%C3%A9bec%20Comprehensive%20Review%202011.pdf

[20] NPCC 2013 MARITIMES AREA COMPREHENSIVE REVIEW OF RESOURCE ADEQUACY, Approved by the RCC December 3, 2013, page 11.

[21] For information on the Northwest Power and Conservation Council, see http://www.nwcouncil.org/about/

[22] The State of the Columbia River Basin Fiscal Year 2012 DRAFT ANNUAL REPORT, page 4.

[23] Resource Adequacy Advisory Committee of the Northwest Power and Conservation Council, Estimating Availability of Imports from California and Desert Southwest, Technical Committee Meeting November 20, 2013.

on the AC intertie and 3100 megawatts on the DC intertie.[24] Overall, the import supply assumptions of the Northwest Power and Conservation Council are more restrictive of imports from California than Manitoba Hydro is with regard to imports from MISO.

4.1.5 BC Hydro Self Sufficiency Requirements are More Restrictive

La Capra implies that Manitoba Hydro's limitations on imports, which are in relation to dependable energy flow, are more restrictive than BC Hydro's self sufficiency requirements, which are in relation to higher average flow.[25] This is not correct, and in fact the situation is reversed.

BC Hydro specifies a lesser reliance on imports than Manitoba Hydro despite BC Hydro's relatively larger import capability. BC Hydro is interconnected with three 500 kV interconnections, in comparison with Manitoba Hydro's single 500 kV interconnection. BC Hydro's total import capability is up to 4000 MW, described as follows:

- Southern Alberta to Southern British Columbia: East to West 1000 MW[26]
- Pacific Northwest to British Columbia: South to North- Up to 3000 MW all ties

In practice, BC Hydro limits its imports from the Pacific Northwest to 2000 MW[27]. Thus it appears the BC Hydro import capability is around 4 times the 700 MW firm transfer capability for long-term planning used by Manitoba Hydro[28].

As shown in Table 1 below, despite having in excess of 400% more import capability than Manitoba Hydro, BC Hydro has assumed only 33% more dependable import energy (Permitted Imports in Table 1 below: BC Hydro 4100 GWh, Manitoba Hydro 3068 GWh). On a comparable basis, imports as a percent of domestic energy demand is 12% for

[24] Sixth Power Plan, Northwest Power and Conservation Council, March 15, 2013, page 10.
[25] La Capra - Technical Appendix 1 page 1-16 "These data demonstrate that, due to the high hydro capacity and wide variability in water conditions, on an average flow year nearly one-third of MH's generation is excess above dependable energy need. BC Hydro's self-sufficiency standard requires it to have domestic resources to fulfill load during an average flow year. The Figure above demonstrates the significance of that standard versus one based on a minimum flow condition."
[26] WECC 2013 Path Rating Catalogue, Item 1-4, January 2013. The Alberta BC Interconnection consists of a 500 kV line and two 138 kV lines; the BC US interconnection consists of two 500 kV lines and two 230 kV lines; the Manitoba Hydro US interconnection consists of one 500 kV line and three 230 kV lines.
[27] BC Hydro Operating Order Operating Order 7T – 18, page 18, which states "…operating tools and procedures will observe a hard limit of 2000 MW (south to north)."
[28] NFAT Submission, Chapter 5, page 16.

Manitoba Hydro and only 7% for BC Hydro, demonstrating that Manitoba Hydro's criteria for reliance on imported energy is considerably less restrictive than that of BC Hydro.

Table 1 – Permitted Energy Imports

	Manitoba Hydro	**BC Hydro**[29]
Import Capability	700 MW	3000 MW
BC Hydro increase over MB Hydro		4.28x
Permitted Imports (GWh)	3068 GWh[30]	4100 GWh[31]
BC Hydro increase over MB Hydro		1.33x
Domestic Energy Demand Net of DSM (2016/17)	25960 GWh[30]	58874 GWh[32]
Permitted Imports as Percent of Domestic Energy Demand	12%	7%

As shown in Table 2 below, when the size of the drought, as represented by the Critical Drought Energy Deficit is considered, it is evident that the drought in the Manitoba Hydro system has a significantly greater impact. BC Hydro's Dependable Hydro Energy is almost twice that of Manitoba Hydro, and the BC domestic energy demand is more than twice that of Manitoba's. Despite the much larger system, BC Hydro's Critical Drought Energy Deficit is roughly half that of Manitoba Hydro's. In other words, a drought equivalent to a dependable energy year is four times more severe for Manitoba Hydro than BC Hydro. La Capra failed to account for this significant difference in the relative size of the Critical Drought Energy Difference when comparing BC Hydro's self sufficiency requirements with Manitoba Hydro's import limitations.

[29] BC Hydro data from the 2013 IRP, available at http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/irp-chap-2-20130802.pdf
[30] Manitoba Hydro Appendix 4-2, page 122
[31] For BC Hydro, this is equivalent to the Energy Deficit in Dependable Hydro Energy vs Average Hydro Energy
[32] BC Hydro Integrated Resource Plan, Appendix 8A Page 5, dated August 2013.

Table 2 – Critical Drought Hydro-Electric Energy Deficit

	Manitoba Hydro[33]	**BC Hydro**[29]
Domestic Energy Demand Net of DSM (2016/17)	25,960 GWh[30]	58,874 GWh
Average Hydro Energy (GWh)	30,808 GWh[34]	48,200 GWh[35]
Dependable Hydro Energy (GWh)	22,754 GWh[30]	44,100 GWh[36]
Critical Drought Energy Deficit: Average Hydro Energy minus Dependable Hydro Energy	8,054 GWh	4,100 GWh
Critical Drought Energy Deficit, expressed as a percent of Domestic Energy Demand	31%	7%

4.1.6 Degree of Reliance on Imports Must Recognize Capacity Export Contracts

An important consideration in Manitoba Hydro's degree of reliance on imports is that because Manitoba Hydro has surplus capacity, it has entered into contracts with capacity export obligations during its winter peak through 2025. Consequently, Manitoba Hydro currently has capacity export obligations over the on-peaks hours during the time when no new resources are required and it would not be appropriate to assume, on the planning horizon, that Manitoba Hydro is importing during on peak hours when in fact it has export obligations. In many of the development plans Manitoba Hydro will have capacity export obligations during the winter beyond 2025 related to firm export sales.

4.1.7 Energy Contingencies are Likely

Manitoba Hydro notes that its Capacity Criterion has a "minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand."[37] The energy criterion has no similar reserve margin. However, like the capacity calculations which have uncertainty due to forced generation outages

[33] Manitoba Hydro NFAT Submission, Appendix 4.2 Page 122.
[34] Manitoba Hydro data from NFAT Submission, 2012/13 Power Resource Plan, page 43
[35] BC Hydro Integrated Resource Plan, Section 2.3.1 Heritage Hydro, page 2-18, dated August 2013
[36] BC Hydro Integrated Resource Plan, Section 2.3.1 Heritage Hydro, page 2-19, dated August 2013.
[37] Chapter 4, Section 4.3.1.1 Capacity Criterion, page 36.

("breakdown of plant") and weather driven load forecast uncertainty ("increase in demand above forecast"), there is also uncertainty in the energy supply situation.

There are a number of sources of uncertainty in the dependable energy supply situation:

1. transmission outages which may restrict imports to less than the 100% of the assumed 700 MW US firm transfer capability for the planning horizon;

2. the ability of the thermal generation units to perform over the longer term at the projected capacity factors;

3. actual average annual wind generation;

4. increased Manitoba load, for example due to an unusually cold winter; and

5. timing of water flows during a critical flow period.

Further, there is always the possibility of a drought occurring worse than the drought of record, particularly given the increasing impacts of climate change. Although Manitoba Hydro does not explicitly plan for such energy contingencies, including a drought worse than the drought of record, the ability to import on-peak if necessary serves as the reserve margin to protect against loss of load during such energy contingencies.

In any given year, the total energy demand in Manitoba is impacted by the actual weather experienced. As discussed in the 2012 Electric Load Forecast, in regards to extreme weather, "a record cold winter will increase load 4% and a record warm winter will decrease it 3%[38]". Extreme weather impacts are larger on a monthly basis and even larger on a daily basis. On an annual basis for the 2012/13 load year, the potential increase in annual energy demand due to extreme cold weather impacts could be as much as 921 GWh[39]. The base load forecast assumes there is a 50% chance that the load will be higher than forecast due to weather related variations and a 50% chance that it will be lower than expected due to weather variations.

[38] Manitoba Hydro 2012 Electric Load Forecast, External Version, approved July 2012, page 44.
[39] Manitoba Hydro 2012 Electric Load Forecast, External Version, approved July 2012, page 44, Table titled Effect of Weather due to Winter Extremes on Gross Firm Energy

The result of these energy contingencies is that having exactly the quantity of energy needed in a dependable energy situation does not provide any flexibility to manage energy contingencies. As a result, there could be Manitoba energy shortages if these energy contingencies occur at or near a dependable energy situation, unless there is some provision for such energy contingencies. The limitations on the degree of reliance provides such a provision to manage energy contingencies and is a prudent practice exercised by Manitoba Hydro in meeting its mandate of providing a reliable and dependable supply of power for the Province of Manitoba.

4.1.8 Import Limitations Are Justified

La Capra states "*First, the limitation on import energy to 10% of Manitoba load plus export obligations is not fully justified in the NFAT or in MH's criteria review*[40]." This conclusion fails to recognize Manitoba Hydro's explanation as contained in its September 2013 Review of Generation Planning Criteria: "This wording is intended to be generally consistent with the 1977 Report that observed a break point on a flow duration curve for which imports above 10% of the Manitoba load required disproportionally more flow years in which imports would be required[41]." The 1977 Report considered the addition of Limestone, Long Spruce, Burntwood River generation and Conawapa to the system as it existed in 1977 in establishing the import limitations. Further, the design and planning of the major new 500 kV Dorsey – Chisago County (Winnipeg – Minneapolis) transmission line was already well underway in 1977[42] and energy guarantees associated with this major new interconnection were explicitly discussed in the 1977 Report. Thus, the conclusions of the 1977 report remain valid today.

4.1.9 Implications of Energy Shortages

Manitoba Hydro notes that the implications of a shortage of energy in an energy limited hydro system is a more serious situation than capacity shortage in a non energy limited system (i.e. a predominately thermal system such as the MISO market). In a thermal system, a capacity shortage would likely appear as power alerts during periods of extreme demand (caused by extreme hot or cold weather), and might result in rotating blackouts for

[40] La Capra Associates Technical Appendix 1 - Resource Planning, page 1-10.
[41] Review of Generation Planning Criteria, September 2013 page 25; provided in response to CAC/MH I-051.
[42] Manitoba Hydro made an application to the National Energy Board for the 500 kV interconnection on August 12, 1976 and the application was approved by the Governor in Council on August 31, 1977.

a period of hours, possibly for several consecutive days. For example, such an event occurred in Alberta on July 9, 2012[43], and more recently in Newfoundland.

An energy shortage in an energy limited hydro system is not a short term event. An energy shortage could begin with one or two dryer than normal years, followed by a particularly dry summer and cold winter. Potentially, should adequacy of the energy supply be a real concern, there could be an appeal for energy conservation, not just for a period of hours or for several consecutive days but for the entire winter, with the real threat of rotating blackout due to a lack of energy at any time during the winter. Such an event nearly occurred in New Zealand in 2008[44] and is currently being experienced in South America.

Given the greater potential for economic impact from a longer term energy shortage event in comparison with a capacity shortage event, it is entirely appropriate that Manitoba Hydro carefully evaluates the availability of all types of energy sources under a wide range of conditions before relying on the source as dependable energy. An energy shortage in the middle of a long cold Manitoba winter is a situation to be avoided.

In consideration of the above discussion, Manitoba Hydro reaffirms that the degree of reliance of imports in the energy criterion is reasonable and necessary to ensure an adequate supply of energy for the province of Manitoba.

4.2 Generation System Modelling

4.2.1 System Production Cost Based on the Average of 99 Flow Years

In section 3.3.2 of the MPA report (page 34), the following statement is made, "*Critically, Manitoba Hydro assumed average hydroelectric performance in every year throughout their models.*" MPA has misinterpreted how Manitoba Hydro utilizes the 99-year streamflow record to incorporate variability into the long term simulations.

Manitoba Hydro does not assume average hydro-electric performance in any year but uses its historic inflow record of 99 years to derive an average value that is representative of each one of the 99 flow years.

[43] http://www.cbc.ca/news/canada/edmonton/alberta-hit-by-rolling-power-blackouts-1.1178711
[44] http://www.theguardian.com/environment/2008/jun/09/alternativeenergy.energy

The inflows to the integrated Manitoba Hydro hydro-electric system are the primary fuel for energy generation. Long-term hydrologic inflows have been developed for the entire Manitoba Hydro watershed for the flow years 1912/13 to 2010/11, inclusive (99 flow years). The historic flow record on a year by year basis varies in the volume of water and in the distribution of these inflows across river basins. For example within this long-term record are consecutive years in which the inflows are below-average. These years constitute drought conditions throughout the system. Manitoba Hydro's production-costing model inherently incorporates the variability of the long-term hydrologic inflows.

The SPLASH model is used to simulate the operation of the Manitoba Hydro system for the 35-year planning horizon (load years 2014/15 to 2047/48, inclusive). For each load year, system operation is simulated individually for each of the 99 flow cases which are averaged to derive production costing data that is representative of all of the 99 flow years. The average values incorporate drought and flood flows. Analysis of the impact of drought is undertaken separately and focuses on specified consecutive years of below average flow (eg 1988-1992).

Therefore, the methodology employed by Manitoba Hydro does incorporate the variability inherent to the long-term flow data. The production-costing results are not based on system simulation using a (single) average flow condition.

4.2.2 Export Price Assumptions

[redacted] premium for long term firm export sales is appropriate

Manitoba Hydro assumes in its Electricity Export Price Forecast that dependable on-peak energy and capacity resources sold on a long-term basis [redacted] can achieve a [redacted] premium over the base bundled energy and capacity product. La Capra Associates has requested evidence for this assumption, having explicitly stated that "*MH provides little justification for the amount of the* [redacted] *premium*" [45].

The table below provides an analysis of the contracted versus forecasted revenues for all long term export contracts signed since 2005. Specifically the table compares the revenues contracted for On-Peak products (i.e. On-Peak energy and capacity) relative to the forecasted values for those products, inclusive of the [redacted] premium applied by Manitoba Hydro for long term dependable On-Peak sales (i.e. Long Term Dependable product).

[45] La Capra IEC Report – Appendix 6 Page 6-61

This analysis will demonstrate whether or not the On-Peak products sold by Manitoba Hydro via firm export contract achieved the Long Term Dependable product price [redacted] as indicated in the NFAT filing.

[redacted]

Table Notes:

[redacted]

[2] Only the [redacted] contract revenue is included for [redacted]

[3] [redacted] This value is for comparison purposes only.

[4] [redacted] This value is for comparison purposes only.

An analysis of the on-peak energy and capacity prices for long-term export contracts signed since [redacted] relative to the forecast of the long-term dependable product was completed. This analysis demonstrates that for contracts signed since [redacted], the average price negotiated for the on-peak component of the sale is [redacted] of the Long Term Dependable forecast price, which [redacted] premium. In other words, there is a [redacted] premium over the [redacted]. Manitoba Hydro considers the use of a [redacted] [redacted].

This historical contract review since [redacted] provides a solid basis for Manitoba Hydro's assumption that it will achieve a [redacted]. It is of note that the period reviewed encompassed both high and depressed energy price environments (i.e. pre and post 2008 economic downturn).

4.2.3 Value of Opportunity Energy

Potomac Economics on Pages 44-45 of their report recommends that Manitoba Hydro provide additional analysis supporting the premium applied to the forecasted export price when calculating opportunity export sales revenues.

The premium accounts for on-peak day-ahead energy sales as well as for additional revenue realized through sales activities which take place within a one year time frame. In response to LCA/MH I-471b, Manitoba Hydro states that opportunity revenues include those from:

a) Real-time and day-ahead energy sales to Manitoba Hydro's energy markets (AESO, IESO, MISO)
b) Ancillary services
c) Bilateral term sales at fixed forward prices for terms as long as a year. These sales may include capacity revenues
d) Premiums associated with capacity call options
e) Auction Revenue Rights, Financial Transmission Rights and Transmission Rights
f) Merchant trading profits
g) Revenues from the sale of unbundled Renewable Energy Credits.

Items c) to g) above provide Manitoba Hydro with additional revenue above real-time and day-ahead market energy sales. Manitoba Hydro noted in the preparation of this Rebuttal Evidence that the response to LCA/MH I-471(b) incorrectly included Ancillary Services in the additional revenue which has been corrected here.

5.0 SUPPLY OPTIONS

This section deals with the evidence of IECs LCA and KP and that of GAC witness Power Advisory regarding Manitoba Hydro's assumptions with respect to various resource options in its NFAT analysis.

5.1 Wind

5.1.1 Asset Life

Manitoba Hydro in its NFAT submission has assumed a typical asset life of an onshore wind turbine of 20 years. La Capra[46,47] and the Green Action Centre[48,49] in their evidence presented to the PUB both recommend that a 25-year typical asset life of wind be used instead. Manitoba Hydro does not agree and maintains use of 20 years is a reasonable estimate consistent with asset life used by others in the industry such as BC Hydro[50], NREL[51,52,53], Irena[54] and Vestas[55].

In addition to government funded agencies, Vestas, a wind turbine manufacturer, indicates a 20 year service life in a fact sheet for its V90-3.0 MW wind tower. The twenty year life is also a function of the deleterious effects of materials fatigue[56] which directly impact the overall service or project life estimates of wind turbine components. In addition, Manitoba Hydro is not aware of any wind turbines greater than 1 MW in nameplate capacity that have operated for more than 20 years.

5.1.2 Wind Capacity Factor Assumptions are Valid

Manitoba Hydro uses an assumed Capacity Factor for Wind resource options of 40% in its evaluations. GAC and La Capra have questioned the validity of the use of this value especially in future years. GAC states "*La Capra Associates has questioned this*

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[46] La Capra Technical Appendix 2 – Page 2-12, Section II - C. Wind Lifetime
[47] La Capra Technical Appendix 3A – Page 3A-28, Section VI – B. Wind cost assumption analysis
[48] Green Action Centre Evidence on Fuel Switching, DSM and Wind – Page 4-7, Section 4.2.2.4 – Project Life
[49] Green Action Centre Evidence on Fuel Switching, DSM and Wind – Page 4-14, Section 4.5 Conclusions
[50] BC Hydro (2013), Integrated Resource Plan, Appendix 3A-4, 2013 Resource Options Report Update, Resource Options Database (RODAT) Summary Sheets.
[51] Tegen, S., … [et al] (2013), 2011 Cost of Wind Energy Review, NREL Technical Report, NREL/TP-5000-56266.
[52] Martin-Tretton, M., … [et al] (2012), Data collection for current U.S. wind energy projects : component costs, financing, operations, and maintenance : January 2011-September 2011, NREL Technical Report, NREL/SR-5000-52707.
[53] Jimenez, Antio C., (2013), Wind Resource Assessment Report: Mille Lacs Indian Reservation, Minnesota, NREL Technical Report, NREL/TP-5000-60429.
[54] IRENA (2012), Wind Power, Renewable Energy Technologies: Cost Analysis Series.
[55] Vestas Wind Systems A/S (2009), V90-3.0 MW Exceptional performance and reliability at high-wind-speed sites
[56] Sari, J. ... [et al] (2009), Statistical Analysis of Static and fatigue Strength Characteristics of Wind Turbine Blade Materials.

assumption, noting recent projects in the region with an average capacity factor of 42%, and assuming a 43% capacity factor in its sensitivity analysis." [57,58]. Manitoba Hydro does not agree that capacity factors in excess of 40% are achievable for all future wind projects. Manitoba Hydro maintains that using a representative capacity factor of 40% is reasonable and appropriate.

A study[59] undertaken for Manitoba Hydro and completed in 2005 examined the wind performance characteristics of 7 sites throughout southern and central Manitoba. The following table summarizes the findings of this study demonstrating the variability of the wind resource at locations across Manitoba.

Table 1: Estimated Capacity Factors at 7 Manitoba Sites

Site Location	Average Wind Speed @80 m AGL (m/s)	Wind Class	Capacity Factor @80 m AGL (%)
Lizard Lake – (within St. Leon Wind Farm area)	8.3	5	38.2
Boissevain	7.9	4	35.3
Letellier - (approximately 8 km from St. Joseph Wind Farm)	7.6	4	33.0
Minnedosa	7.1	3	27.7
Grandview	6.9	3	27.3
Lake Manitoba Narrows	6.6	2	24.6
PTH 60 near Cedar Lake	6.5	2	22.8

57 La Capra Technical Appendix 3A – Page 3A-28, Section VI – B. Wind cost assumption analysis
58 Green Action Centre Evidence on Fuel Switching, DSM and Wind – Page 4-7, Section 4.2.3.1 Capacity Factor
59 Helimax Energy Inc. (2005), Wind Monitoring Program Final Report (2003-2004) Manitoba Hydro

A separate report prepared by Helimax[60] for Manitoba Hydro focused on the St. Leon/Darlingford area and explored the Manitoba Hydro system impacts of installing 1000 MW of nameplate wind capacity in this area. The capacity factors associated with a large expansion of wind generation in this specific area were also studied. The report provides estimated capacity factors based on utilization of two different technologies at seven sites in this area, the General Electric GE 1.5sle wind turbine and Mitsubishi MWT95/2.4 wind turbine. These capacity factors are provided in Table 2. Table 2 shows that within a specific area the capacity factor decreases as less productive sites are developed.

Table 2: Average Wind Speeds and Capacity Factors at Seven Sites in St. Leon/Darlingford Area

	Average Wind Speed at 80m	Capacity Factor At 80m (%)	
	(m/s)	GE1.5sle	MWT95/2.4
Site 1	8.0	37.4	36.1
Site 2	7.8	36.4	35.1
Site 3	7.7	35.7	34.3
Site 4	7.8	35.9	34.9
Site 5	7.5	34.5	33.1
Site 6	7.3	30.7	29.2
Site 7	7.8	37.1	35.7

With the exception of Site 6 that exhibits Wind Class 3 characteristics, all other sites in Table 2 can be classified as Wind Class 4. Given the potential for increased efficiency of wind turbines and related components, Black & Veatch[61] have forecast future improvements for onshore wind capacity factors between 2010 and 2050 based on the wind class of a site.

[60] Helimax Energy Inc. (2008), Generation of Power Production Time Series, Seven Virtual Wind Projects in Manitoba

[61] Black & Veatch (2012), Cost Report Cost and Performance Data for Power Generation Technologies, pg. 46.

Table 3: Black & Veatch Capacity Factor Projection for Onshore Wind Technology

	Capacity Factor (%)				
Year	**Class 3**	**Class 4**	**Class 5**	**Class 6**	**Class 7**
2010	32	36	41	44	46
2015	33	37	41	44	46
2020	33	37	42	44	46
2025	34	38	42	45	46
2030	35	38	43	45	46
2035	35	38	43	45	46
2040	35	38	43	45	46
2045	35	38	43	45	46
2050	35	38	43	45	46

On the basis of the Black & Veatch projections in Table 3, onshore wind facilities located in Wind Classes 5 or higher are the only Wind Classes that are projected to exceed the 40% capacity factor threshold. Wind Classes 3 and 4 are not forecast to achieve a 40% capacity factor. Therefore the only area from Table 1 with a potential of consistently achieving a capacity factor greater than 40% is Lizard Lake (St. Leon) site area. The six other sites in Table 1 do not appear to have the potential of achieving a 40% capacity factor based on the Black & Veatch assumptions. By comparing both Tables 1 and 2, the only site identified in the two studies that fall within the Wind Class 5 category is the Lizard Lake (St. Leon) area, which is the site of one of Manitoba's current wind farms. In addition information contained in the Canadian Wind Atlas[62], suggests that Manitoba does not have an abundance of Wind Class 5, or better, onshore wind resource areas in southern Manitoba. As a generalized characterization, North Dakota has a better, onshore, wind resource than southern Manitoba based on the relative abundance of Wind Class 5 or better, areas.

It is Manitoba Hydro's position that with the varied wind resource in Manitoba, there is potential for a range of achievable capacity factors for future wind resource options. Manitoba Hydro acknowledges that there is also potential for projected technological advancements to result in higher capacity factors given a particular location. Based on the current understanding of the wind resource in southern Manitoba, utilizing a capacity factor of 40% for all future wind farm developments, recognizes the potential for

[62] Environment Canada (2003), Canadian Wind Atlas at http://www.windatlas.ca/en/index.php.

technological advancements and represents a reasonable overall average achievable capacity factor for wind resource options in Manitoba over the long term.

5.1.3 Capital Costs for Wind

La Capra, Knight Piesold and Green Action Centre have indicated that Manitoba Hydro's estimated capital costs for on-shore wind projects are too high[63,64,65,66], out of date[67], and provide skewed results[68]. Manitoba Hydro does not agree with these positions.

Manitoba Hydro maintains that the capital costs used in the NFAT Business Case reflect current market costs for on-shore wind projects and the assumptions for the cost of wind generation in future are reasonable and do not skew results. The cost used by Manitoba Hydro is supported by a number of respected industry sources including U.S. Energy Information Administration (EIA), and Black & Veatch.

The costs for wind generation, excluding the cost for transmission, Manitoba Hydro provided in the NFAT Submission are shown in Table 1. Manitoba Hydro's response to LCA/MH I-308 provides the most up to date source of these costs.

Table 1: Manitoba Hydro's NFAT Wind Development (Without Transmission) Capital Cost Assumptions

ASSUMPTION	CAPITAL COST ($/kW in 2012$ USD)	ROUNDED CAPITAL COST ($/kW in 2012$ USD)
100 MW Wind Development Reference Capital Cost	$2,110	$2,100
65 MW Wind Development Reference Capital Cost	$2,096	$2,100

63 La Capra Technical Appendix 2 – Page 2-20, Section IV - A. Cost Assumption Issues
64 La Capra Initial Expert Analysis Report – Page LCA-14, Section 3 Wind Power Options
65 La Capra Technical Appendix 3A – Page 3A-32, Section VII – E. Wind cost assumptions provide skewed results
66 Green Action Centre Evidence on Fuel Switching, DSM and Wind – Page 4-14, Section 4.5 Conclusions
67 Knight Piesold Independent Expert Consultant Report – Page III of IV, Item 4
68 La Capra Technical Appendix 3A – Page 3A-32, Section VII – E. Wind cost assumptions provide skewed results

The capital cost for wind generation suggested for use by La Capra is $1,750/kW (2012$ USD)[69], by Knight Piesold is $1,800/kW (2012$ USD)[70] and by Green Action Centre is $1,710/kW (2012$ USD)[71]. Manitoba Hydro does not agree that these costs are representative of current industry costs as discussed below.

The April 2013 report "Updated Capital Cost Estimates for Utility Scale Plants" produced by the U.S. Energy Information Administration provided a capital cost estimate of $2,213/kW (2012$ USD) for onshore wind projects. Table 2 provides a summary of historical US EIA capital cost estimate assumptions for onshore wind made for their Annual Energy Outlook (AEO) reports for 2011, 2012 and 2013 which demonstrates that since 2000 the cost for on-shore wind projects has been generally increasing. The table also shows that on a 2012 USD basis, the costs have been in the order of $2100 USD or higher since 2009. The April 2013 report value is included for comparison.

[69] La Capra Technical Appendix 3A – Page 3A-26, Section VI – B. Wind cost assumption analysis
[70] Knight Piesold Independent Expert Consultant Report – Page 48 of 73, Section 5.3.2 Capital Costs
[71] Green Action Centre Evidence on Fuel Switching, DSM and Wind – Page 4-3, Section 4.2.2.1 Base 2012 Capital Costs

Table 2: Review of Onshore Wind Assumptions for the AEO

U.S. Energy Information Administration
Onshore Wind Assumptions to the Annual Energy Outlook
Various Years

AEO YEAR	In-Service Date	Quoted Total Overnight ($/kW)	USD $Year	Total Overnight (2012 USD$/kW)
1997		$929	1995	$1,313
1998		$1,235	1996	$1,714
1999		$1,109	1997	$1,512
2000	1999	$993	1998	$1,339
2001	2000	$983	1999	$1,306
2002	2001	$982	2000	$1,277
2003	2002	$1,003	2001	$1,276
2004	2003	$1,015	2002	$1,270
2005	2004	$1,134	2003	$1,390
2006	2005	$1,167	2004	$1,391
2007	2006	$1,206	2005	$1,391
2008	2007	$1,434	2006	$1,603
2009	2008	$1,923	2007	$2,089
2010	2009	$1,966	2008	$2,089
2011	2010	$2,409	2009	$2,538
2012	2010	$2,437	2010	$2,533
2013	2012	$2,175	2011	$2,214
EIA April 2013 Report		$2,213	2012	$2,213

Black & Veatch, a respected global engineering, consulting, construction and operations company specializing in infrastructure development in energy, water, telecommunications, management consulting, federal and environmental markets, published an analysis of wind costs for the National Renewable Energy Laboratory (NREL) in February 2012. Table 3 provides the estimated capital costs from this analysis in 2012$ USD for the years 2010 to 2050 for which the cost of onshore wind is forecast to be $2086 USD and there is no decline projected over the long-term.

Table 3: Black & Veatch Onshore Wind Cost Projections

Cost Report Cost and Performance Data for Power Generation Technologies Prepared for the National Renewable Energy Laboratory by Black & Veatch February 2012 From Table 28: Cost and Performance for Onshore Wind Technology		
Year	Capital Cost $/kW (2009$ USD)	Capital Cost $/kW (2012$ USD)
2008	$2,060	$2,170
2010	$1,980	$2,086
2015	$1,980	$2,086
2020	$1,980	$2,086
2025	$1,980	$2,086
2030	$1,980	$2,086
2035	$1,980	$2,086
2040	$1,980	$2,086
2045	$1,980	$2,086
2050	$1,980	$2,086

The Midcontinent Independent System Operator, Inc., (MISO) is an Independent System Operator (ISO) and the Regional Transmission Organization (RTO) that provides open-access transmission service and monitors the high voltage transmission system throughout the Midwest United States and Manitoba. As part of its annual Transmission Expansion Plan (MTEP) process, MISO includes an estimate of capital costs for new build resource options. Table 4 provides the capital cost estimate for wind reported in MISO's 2013 MTEP plan which was finalized on December 12, 2013. These MISO estimates represent an estimated cost for onshore wind in the energy market that Manitoba Hydro interacts with on a daily basis. Manitoba Hydro's capital cost estimate for onshore wind falls within the range of Low to High Level capital cost estimates for MISO's new generation onshore costs. The cost estimates of $1800/kW or less proposed by La Capra, Knight Piesold and Green Action Centre are lower than MISO's Low Level capital cost estimate of $1,973/kW in 2012$ USD.

Table 4: MISO 2013 MTEP New Generation Onshore Wind Capital Costs

MISO Transmission Expansion Plan 2013 Appendix E2 EGAS Assumptions Document by Midcontinent Independent System Operator (MISO) December 12, 2013				
New Generation Capital Costs				
	Unit/ USD Year	**Low Level (L) Cost Estimate**	**Mid Level (M) Cost Estimate**	**High Level (H) Cost Estimate**
Wind-Onshore	$/kW 2013$ USD	$1,993	$2,214	$2,768
Wind-Onshore	$/kW 2012$ USD	$1,973	$2,193	$2,741

La Capra[72] and KP[73] place a great deal of significance on the report "2012 Wind Technologies Market Report" prepared for the U.S. Department of Energy, dated August 2013 where data provided in Table 6 was presented.

Table 6: Wind Technologies Market Report Cost Assumptions

2012 Wind Technologies Market Report US Department of Energy August 2013			
Region	**Projects**	**Quantity**	**Capacity Weighted Average Project Costs (2012$ USD)**
ALL	118	9414 MW	$1,943
Interior	42	3827 MW	$1,763

[72] La Capra Technical Appendix 2 – Page 2-9, Section II - C. Wind Capital Costs
[73] Knight Piesold Independent Expert Consultant Report – Page 49 of 73, Section 5.3.2 WIND Capital Costs

Manitoba Hydro obtained information from a dataset maintained by SNL Energy to allow comparison to the values from "2012 Wind Technologies Market Report" for the Interior Region. Manitoba Hydro obtained capital cost information from the SNL Energy database conforming to the following criteria:

- Wind projects completed in 2012 and 2013
- Wind Projects from the U.S. states of Iowa (IA), Illinois (IL), Kansas (KS), Minnesota (MN), North Dakota (ND), Nebraska (NE), Oklahoma (OK), Texas (TX) and Wisconsin (WI)

Similarly, projections of project costs made by SNL over the same states was obtained for wind projects that are in the planning, early development and construction stages and are expected to come into service between 2014 and 2018. SNL Energy provides a subscription news service and access to a large energy industry database on a proprietary basis. Permission was obtained from SNL Energy to publically release the information provided in Table 7 under the condition that all capital cost values be rounded to the nearest hundreds of dollars.

Table 7: Review of SNL Energy Data for US "Interior" Equivalent Wind Projects

Review of SNL - US Interior States Wind Project Data				
	RECENTLY COMPLETED 2012 & 2013		PROJECTS IN DEVELOPMENT Online from 2014 to 2018	
State	Estimated Average Cost (2013$ USD)	Estimated Average Cost (2012$ USD)	Projected Average Cost (2013$ USD)	Estimated Average Cost (2012$ USD)
IA	$2,400	$2,377	$2,200	$2,179
IL	$2,100	$2,080	$2,200	$2,179
KS	$2,100	$2,080	$2,100	$2,080
MN	$2,100	$2,080	$2,100	$2,080
ND	$1,800	$1,783	$2,100	$2,080
NE	$1,900	$1,882	$2,000	$2,080
OK	$1,800	$1,783	$2,100	$2,080
TX	$2,200	$2,179	$2,100	$2,080
WI	$2,200	$2,179	--	--
TOTALS	$2,100	$2,080	$2,100	$2,080
Source: SNL Energy				1/16/2014

The dataset maintained by SNL Energy and the dataset used for the "2012 Wind Technologies Market Report" contain a similar number of projects, although the projects in the SNL dataset appear to be larger on average. At $1800/kW (2012 USD) or less, the cost estimates suggested by LCA, KP and GAC are lower than costs in all but two states for recently completed projects and are lower than the projected costs in all states.

It should be noted that in Table 7, while the average costs reported for recently complete projects in North Dakota and Oklahoma are similar to the estimates provided by LCA, KP and GAC, these states have the lowest average capital costs for this entire category. In the case of Recently Completed Projects for North Dakota, the low capital costs are reflective of two large expansion projects, specifically Bison Wind 2 and Bison Wind 3, which were both built after the completion of Bison Wind 1 in 2010 and were able to take advantage of some of the infrastructure developed for Bison Wind 1. In addition, capital costs for wind project derived from North Dakota projects completed in 2012 are not representative of development costs for Manitoba for the following reasons:

- The low relative construction costs in North Dakota in 2012 and 2013 are not projected to continue for projects expected to come online between 2014 and 2018,
- Costs to build are generally higher in Manitoba than in North Dakota[74], and
- Generous production and investment tax credits available to wind plants in North Dakota are not available to the same degree for projects in Manitoba

By contrast, Manitoba Hydro's onshore wind capital cost estimates for wind projects, without transmission, of $2,100/kW in 2012$ USD are current and compare very favourably with recent government and industry information. Use of the $2,100/kW capital cost is appropriate for the NFAT Business Case and should continue to be used as an input for any economic analysis including onshore wind projects in Manitoba.

5.2 Photovoltaic Solar

La Capra Associates states that "Manitoba Hydro deemed solar photovoltaic (PV) not suitable for further evaluation based upon its high costs" and that "assuming the cost declines projected by MH…..would likely not have been deemed unsuitable for further consideration in the screening process" [75].

Manitoba Hydro indicated in NFAT Business Case[76] that "This resource technology was screened out because: energy costs for solar photovoltaic were significantly higher than other resource options costs (although costs have recently been trending downwards) and solar photovoltaic is an intermittent resource that is highly variable and, as a result of its reliance on direct sunlight, there is potential for significant instantaneous drops in power output due to the unpredictable nature of localized cloud cover".

With respect to solar costs, Manitoba Hydro did not make specific projections of solar PV costs, however did reference industry trends illustrating potential cost declines[77,78]. Manitoba Hydro qualified these trends indicating that "the current competitive position of solar generation remains heavily dependent upon North American governments promoting

[74] RSMeans Heavy Construction Cost Data (2014), 28th Annual Edition.
[75] La Capra Associates, Technical Appendix 2 Generation Alternatives, January 2014 Page 2-14 to 2-15
[76] NFAT Business Case, Chapter 7 - Screening of Manitoba Resource Options, Section 7.1.2.2 page 18
[77] NFAT Submission, Appendix 7.1, Emerging Energy Technology Review, Page 20
[78] NFAT Submission, Appendix 7.2, Range of Resource Options, Page 20

solar generation through feed-in-tariffs, tax credits, renewable portfolio standards and climate change legislation"[79], none of which are currently in place in Manitoba.

Manitoba Hydro considers projected significant declines in solar PV costs very optimistic and not necessarily representative of the cost of future solar PV installations in Manitoba[80]. In response to CAC-GAC/MH I-020a Manitoba Hydro highlighted key assumptions required to achieve solar PV price declines including a reduction in PV module costs due to "the realization of technological advancements such as implementation of nano materials", which are currently not available on commercial or utility scale, and a reduction in balance of system costs such as "civil and electrical works and related labour" which are on an increasing trend in Manitoba. As demonstrated in the following figure, which provides a typical Solar PV project's capital cost breakdown[81], the balance of system costs, which exclude the PV module cost, represent in the order of 75% of the total cost of the installation.

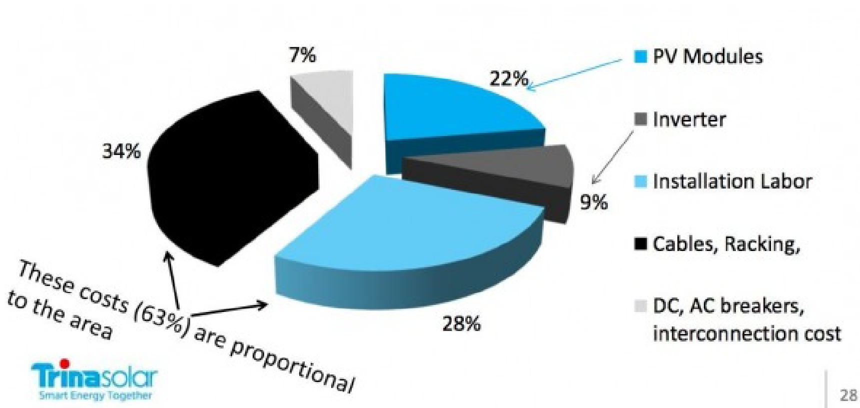


Figure: Solar PV Project Cost Breakdown

As also indicated, Manitoba Hydro's decision to screen solar PV from further economic analysis in NFAT Business Case was also based on the intermittent nature of the solar PV resource. Due to the intermittent nature of solar PV, significant instantaneous variability in generation must be either managed with backup generation or with a type of storage technology, increasing the capital cost significantly and/or incurring system integration costs. These types of additional costs for solar PV technologies, while not specifically included in the screening process, were recognized as additional challenges to implementation on a utility scale basis[82].

[79] NFAT Submission, Appendix 7.2, Range of Resource Options, Page 21
[80] Manitoba Hydro's response to LCA/MH I-288
[81] http://reneweconomy.com.au/2014/graph-of-the-day-solar-pvs-path-to-2ckwh-53452
[82] NFAT Submission, Appendix 7.2, Range of Resource Options, Page 20 and Table Appendix 7.2-11.

Another key factor particularly important to Manitoba, relative to other jurisdictions is that the peak load and the highest energy demand in Manitoba occur in the winter, when there are substantially reduced sunlight hours and a low angle of incidence. Furthermore, the system peak typically occurs in hours when it is dark.

5.3 Thermal

5.3.1 Contingency Ranges on Thermal Generation are Appropriate and Reasonable

La Capra, on Page LCA-14 of their Initial Expert Analysis Report, state with respect to CCGT, SCGT and aeroderivative simple cycle gas turbines, that "*MH's assumed uncertainty bandwidth for the cost of these turbines of -30% to +50% for the capital costs excessive given the experience with these turbines in the industry.*" Manitoba Hydro does not agree with this statement.

Manitoba Hydro did not assume an uncertainty bandwidth of -30% to +50% for the cost of natural gas-fired generation. MH's uncertainty analysis included a range of costs relative to reference capital costs that were based on an analysis performed by a third party risk consultant and are project appropriate. The ranges, as presented in Table 2.5 of Appendix 9.3 of the NFAT submission using a 2022 in-service date as an example, are provided in the following table:

Resource	Low	Reference	High
SCGT (2022)	-30.2%	-	+38.1%
CCGT (2022)	-31.7%	-	+40.1%

In addition, as explained in Manitoba Hydro's response to GAC/MH I-003a the capital cost ranges used by Manitoba Hydro are appropriate for analysis of natural gas-fired projects:

"The range of capital costs for wind and natural gas-fired projects included in the analysis is primarily related to the level of estimate as defined by the AACE Cost Classification System. Under AACE, the level of capital cost estimate for wind and natural gas-fired projects used in the NFAT Business Case is a Class 5 estimate which has a higher uncertainty due to the lesser amount of overall engineering completion at this time when compared to that of the Keeyask and Conawapa generating stations. Conawapa is a Class 3 estimate and Keeyask is between a Class 2 and Class 3 estimate, as stated in Appendix 2.4. The modular characteristics of gas-fired and wind generation technologies have been taken into consideration in establishing the range for the capital cost estimate. As shown in Appendix 9.3, Table 2.3 AACE Cost Estimate Classification Table the expected accuracy range for Class 5 estimates can vary from -20% to -50% for the low end of the range and from +30% to +100% for the high end of the range. The cost estimate ranges for wind and natural gas-fired resources fall within a narrower expected accuracy range than the outer bounds of the Class 5 estimate, primarily due to the modular characteristics of these technologies, the low level of complexity in completing the project, and the maturity of the technologies. These ranges were based on systemic risks as calculated by a third party risk and contingency consultant and are consistent with and developed using AACE Recommended Practice 18r-97."

The third party consultant reports were made available to LCA and are referenced in their Initial Expert Analysis Report[83].

5.3.2 Natural Gas Generation Efficiency Assumptions are Considered in the Analysis

La Capra has stated "*As previously noted, MH anticipates future improvements in combustion turbine efficiency—an assumption which was not incorporated into their analysis.*"[84] Manitoba Hydro did consider future improvements in combustion turbine efficiency along with other factors related to overall turbine efficiency/output in the analysis.

Manitoba Hydro acknowledges in Chapter 7 of the NFAT Submission, on page 28, that "innovation in the field of combustion turbine generation will lead to more efficient machines that operate at lower heat rates. These efficiency improvements will be achieved through higher cycle pressure ratios, improved turbo-machinery component efficiencies and higher turbine inlet temperatures." While continued improvements in turbine technology can be expected, due the maturity of the technology the timing and magnitude of efficiency improvements are difficult to predict. Manitoba Hydro made the decision to leave turbine efficiencies constant over time based on the consideration of the effect of technological improvements relative to the effect of other off-setting assumptions

[83] Page B-1 of Attachment B as Documents numbered SP-002, SP-003, SP-004, SP-005
[84] LCA Technical Appendix 2 – Generation Alternatives Page 2-6

including: degradation of turbine efficiency[85] and reduction in maximum plant output[86] over its operating life as well as inefficiencies during actual operation, some of which is recoverable after unit overhauls and some of which is not. Manitoba Hydro does not assume any performance degradation will occur over the life of the Simple or Combined Cycle Gas Turbines. Similarly Manitoba Hydro does not assume maximum plant output degrades over time.

In modeling the operation of natural gas-fired resources, Manitoba Hydro assumes that the generators are operating at their peak loading, which assumes their optimum performance characteristics for all of the energy produced. At lower loading, natural gas-fired and steam turbines will operate at lower efficiency than at full load, which includes operation during start up as well as partial loading. In the assumptions used in modeling the performance and resulting variable costs of generation from natural gas-fired units, Manitoba Hydro does not include these reductions in performance which would be expected to occur during actual operation.

Manitoba Hydro is aware of factors that could positively or negatively impact the variable cost assumptions for natural gas-fired resources. The potential impact of these factors has been considered in the assumptions made related to modeling of the generation options over the long term. As positive and negative effects of these assumptions are expected to be offsetting over the long term, refinement of these assumptions is not expected to impact the overall analysis.

5.3.3 Class of Estimate for Wind, and Natural Gas-Fired Generation Options

KP has suggested that the Class of estimates Manitoba Hydro has determined for all projects included in the analysis should be revised to higher levels. Manitoba Hydro maintains that the Class of estimates for technologies used in the NFAT Submission is based on sound practice, is appropriate and should not be revised.

KP states in Section 2.3.3 on Page 9 of its report: "*…it is KP's opinion that by default the maturity level of the definition deliverables of a generic wind farm, solar farm or gas plant will be higher than that of a generic building, manufacturing plant, or hydroelectric facility, since the large proportion of 'off the shelf' equipment automatically provides a*

[85] "Degradation in Gas Turbine Systems " from Journal of Engineering for Gas Turbines and Power Vol. 123, Issue 1.
[86] http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger3567h.pdf

more mature definition. As such a wind farm, solar farm or gas plant should have a higher classification than given by Hydro despite the identical end usage of the estimate; as a result KP does not entirely agree with the classifications made by Hydro."

The Class of estimates used in the NFAT submission are based on evaluations and information provided to Manitoba Hydro by two independent experts: Gryphon International Engineering Services Inc. (Gryphon) and Validation Estimating LLC (Validation Estimating).

Gryphon was contracted by Manitoba Hydro to provide a recommendation of and cost estimates for natural gas-fired generation for potential inclusion in Manitoba Hydro economic evaluations for long term development plans. KP was provided the Gryphon report and characterizes Gryphon as "an engineering consultant experienced in the design and implementation of natural gas fired power technologies" and notes that "Gryphon indicated that the level of detail provided is sufficient for an AACE Class 4 estimate" [87].

Validation Estimating was contracted by Manitoba Hydro to provide an independent, third party assessment of the risks and uncertainty in the estimates for wind and natural gas-fired generation options, including a review of the estimate provided by Gryphon. Validation Estimating has a wide range of experience in estimating, project controls, risk and cost management, and is an industry recognized expert in these fields, experienced with both owner and contractor organizations. The expert from Validation Estimating who completed the analysis, has been instrumental in the development and application of the AACE Recommended Practices.

In order to complete the analysis, Validation Estimating applied the AACE International Recommended Practice 18R-97[88] to determine the class of estimates for the wind and natural gas-fired generation. KP references Recommended Practice 17R-97on page 9 of their report, and provides a generic cost estimate classification matrix from that practice. Recommended Practice 17R-97 is a generic practice, from which the more detailed Recommended Practice No. 18R-97 was developed. The first page of Recommended Practice No 18R-97 provides the following description:

[87] KP report Section 5.4.1 Natural Gas-Fired Technology – Consultant's Report, Page 51

[88] AACE® International Recommended Practice No. 18R-97COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES TCM Framework: 7.3 – Cost Estimating and Budgeting

"This addendum to the generic recommended practice (17R-97) provides guidelines for applying the principles of estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) work for the process industries. This addendum supplements the generic recommended practice by providing:

- a section that further defines classification concepts as they apply to the process industries; and
- a chart that maps the extent and maturity of estimate input information (project definition deliverables) against the class of estimate."

Recommended Practice No 18R-97 provides a detailed list of the Maturity Level of Project Definition Deliverables which state the required level of a number of deliverables which must be obtained in order for an estimate to be classified as a particular Class. These are applied as threshold criteria, for which estimates need to meet all levels defined in order to obtain the classification. Validation Estimating applied this Recommended Practice and determined that the wind and natural gas-fired generation estimates used by Manitoba Hydro in the NFAT analysis are Class 5. The high and low cost estimates used in the NFAT analysis were based on the work completed by Validation Estimating, and are directly related to the determination of classification of the cost estimates for these projects.

6.0 TRANSMISSION

In this section of Manitoba Hydro's Rebuttal Evidence, Manitoba Hydro addresses the written evidence of IECs Power Engineers (PE) and La Capra (LCA) as well as Intervenor witness Whitfield Russell Associates (WRA). Through these sections of the Rebuttal Evidence, Manitoba Hydro will address the need for the transmission upgrades proposed in the PDP, as well as their technical and economic feasibility.

6.1 Justification of Need for Proposed Transmission Upgrades

In their reports, PE and LCA each provide an analysis of Manitoba Hydro's need for additional North-South AC transmission when Conawapa comes on line. PE's report on Page 28 indicates that both Option 2 and Manitoba Hydro's PDP, (Option 2a) meet reliability standards, but Option 2 is the most straightforward means of maintaining adequate sparing and provides a wider reliability margin when compared with Option 2a. Similarly, the LCA Report casts doubt on the justification for Manitoba Hydro's PDP over

Option 2[89] or Option 1. However, these analyses are based on two critical misunderstandings related to the following issues: (i) NERC requirements related to firm transmission service; and (ii) Manitoba Hydro's internal criteria for establishing a transmission reliability margin.

6.2 Determination of Transmission Capacity Required for Manitoba Load

Manitoba Hydro uses two criteria for the determination of the amount of transmission capacity required to meet Manitoba firm load: NERC transmission planning ("TPL') standards and Manitoba Hydro's internal criteria for establishing an additional reliability margin. While NERC standards provide an adequate minimum standard for what is required for firm transmission, Manitoba Hydro has adopted additional criteria in order to meet its own standards for firmness to ensure a reliable supply of electricity to Manitoba retail customers. Unfortunately, PE and LCA misapply these criteria to arrive at the incorrect conclusion that there is currently a shortfall of firm transmission capacity in the Manitoba transmission system which needs to be addressed.

6.3 All Existing Generation is Delivered Via Firm Transmission Service

On page 26 of the PE Report, PE states "Non-firm transmission totaling 200 MW exists today with Bipole I and Bipole II able to carry only 3354 MW of firm. This is a direct result of Bipole II having a deficit of 200 MW of spare valve group capacity over generation. An additional 200 MW of transmission would be required to meet the Manitoba Hydro definition of firm transmission. POWER has not been able to find documentation that attributes this amount of non-firm transmission to a specific generation resource."

PE is incorrect in its assessment of how much firm and non-firm transmission service exists today. All of the existing generating stations in Manitoba Hydro's northern collector system ("NCS") receive firm transmission service for delivery of their full capacity to Manitoba retail load (known as Network Load or Native Load Customers) under Manitoba Hydro's Open Access Transmission Tariff ("OATT"). Under the provisions of Manitoba Hydro's OATT, the owner of generating facilities can designate such facilities as Network Resources for the receipt of firm Network Integration Transmission Service to Network

[89] Option 2 adds additional north-south transmission to enable three Kettle units to be connected to the 230 kV northern ac system compared with one Kettle unit in Option 2a . The incremental cost of Option 2 over Option 2a is $212 million ($2011).

Load. Manitoba Hydro's Designated Network Resources at Kettle, Long Spruce and Limestone have been granted firm Network Integration Transmission Service in the following amounts:

Generator	Network Integration Transmission Service level
Kettle	1224 MW
Long Spruce	980 MW
Limestone	1350 MW
Total – Northern Collector System	3554 MW

While these transmission capacity values are slightly different from the assumed winter peak capacity values provided by Manitoba Hydro in Table 5.1 of Chapter 5 – The Manitoba Hydro System, Interconnections and Export Markets (NFAT –page 3) , the differences are negligible and can be attributed to the use of different methodologies for determining generating capability, such as the use of individual generator unit tests rather than name plate capacity.

6.4 Existing Transmission System Meets NERC Requirements

The granting of 3554 MW of firm transmission service for the delivery of the output of Kettle, Longspruce and Limestone is consistent with NERC requirements. The rating of Bipole I and II is 3854 MW, which exceeds the total amount of firm generation (i.e. 3554 MW) in the NCS. At this maximum level of generation, and assuming the HVdc network is intact, the Manitoba Hydro network meets the performance criteria specified in the NERC Transmission Planning standards (TPL-001, TPL-002 and TPL-003). Although concerns have been raised by PE (pg.26 of PE Report) and LCA (Pg. 8-56 of Appendix 8 of LCA report) regarding the remaining transmission capacity relative to the amount of generation connected to the NCS following loss of a single pole (DC) line, these concerns are unwarranted. NERC standard TPL-002-0a requires that transmission facilities be planned such that following a single contingency (such as the loss of a single DC line) the system is stable, thermal and voltage limits are within applicable ratings, there are no cascading outages and there is no loss of demand or curtailment of Firm Transfers (including firm transmission service), except as provided in note b of the standard. Note b from Table 1 of NERC TPL-002-0a permits system adjustments to be made, including curtailment of contracted Firm Transfers, to prepare for the next contingency.

Both PE and LCA appear to have either glossed over or misunderstood note b of this standard and reached the conclusion that there are reliability concerns related to loss of a single pole (LCA Report at p. 8-55 and 8-56, PE Report at p. 26). This is not the case.

Following a DC pole outage in Bipole II, 1000 MW of transmission capacity is removed from service through the automatic operation of protective devices in order to protect equipment and prepare for the next contingency. This entails the temporary curtailment of Firm transfers. In such a case, the maximum amount of generation that could be transmitted is 3854 MW minus 1000 MW or 2854 MW. If the generation connected in the NCS is 3554 MW, then 700 MW of generation could not be delivered over the remaining HVdc system. However, to ensure that there is no loss of demand, Manitoba Hydro calls on generator contingency reserves from MISO. Manitoba Hydro and MISO have formed a contingency reserve sharing group in accordance with NERC standards. Details of this arrangement are documented in Appendix B of the Coordination Agreement between MISO and Manitoba Hydro. The contingency reserve obligation of MISO is 1850 MW. Pursuant to the provisions of the Coordination Agreement, MISO is obligated to provide the contingency reserves on a firm basis when called upon by Manitoba Hydro.

There are two relevant scenarios to consider. The first scenario is a summer peak load scenario where Manitoba Hydro is exporting Firm Transfers to MISO. Following a dc pole loss, Manitoba Hydro would request MISO to supply contingency reserves equivalent to the net loss of generation (e.g. which could be up to 700 MW for a DC pole loss). Manitoba Hydro would curtail Firm Transfers to MISO for the duration of the DC pole outage. As required by NERC standards, no loss of demand would result. The second scenario is a winter peak load case where Manitoba Hydro is not making any export sales to MISO. In this case, following the DC pole outage, Manitoba Hydro would again call on MISO for contingency reserves. The difference in this case is that no Firm Transfers would be curtailed. Manitoba Hydro requires up to 700 MW (depending on the amount of available generation contingency reserves still available in the Manitoba network) of firm transmission import capability to ensure Manitoba demand can be supplied from the contingency reserve sharing group's generation reserves. Manitoba Hydro has demonstrated that it has sufficient firm import capability in table 5.8 of the NFAT submission (Chapter 5 – page 16). In either case, there would be no loss of demand and therefore the NERC TPL standard requirements have been met.

6.5 The Reliability Margin of the Current DC System meets MH Criteria

PE's conclusion[90] that there is currently 200 MW of non-firm generation in the NCS (Page 26 of PE Report), as well as La Capra's conclusion that there is currently 700 MW of non-firm generation in the NCS (Page 8-57 of LCA Report) and MMF's conclusion that the existing system does not meet the reserve criteria of "a spare pole over load" (Page 24 of the WRA Report) are based on the faulty assumption that there is insufficient spare HVdc capability at the present time to meet Manitoba Hydro's internal criteria for a reliability margin, which PE assumes is the requirement to withstand a 500 MW valve group outage and which LCA and MMF assume is the requirement to withstand a 1000 MW DC pole outage. However, Manitoba Hydro has presented evidence (Page 4 of Integrated Transmission Plan for Keeyask and Conawapa Generation) that it is not until the addition of Bipole III that Manitoba Hydro will start planning the HVdc system to have a reliability margin equal to the largest valve group (i.e. 575 MW) spare above generation connected in the NCS. Today, the approved criterion in place is to maintain a spare dc pole above load. It is to be noted that PE acknowledges this misunderstanding as to the application of this criterion in their response to MH to PE IR 11.

The criterion 'spare pole over load" was developed in 1986 as an integrated generation and transmission planning criterion that covers both ac and dc development. It defines the "System capacity" to meet Manitoba firm load as the sum of the southern system generation plus the HVdc capacity less the largest DC pole. The existing system has 3854 MW DC transmission capacity and the "System Capacity" meets the "pole over load" criterion until approximately 2019 (as shown in Fig. 1 below) when considering Manitoba Hydro peak loads (Appendix D of the NFAT submission) and the existing ac generation capacity of about 2200 MW.

[90] In PE's response "MH to PE IR 11", they note 'This (200 MW of non-firm transmission) assumes that the Valve Group spare over Generation criteria is applied to the existing single northern collector system. However, as MH subsequently explained, the existing 'Pole over Load' planning criteria will be in place until after Bipole III goes in service.

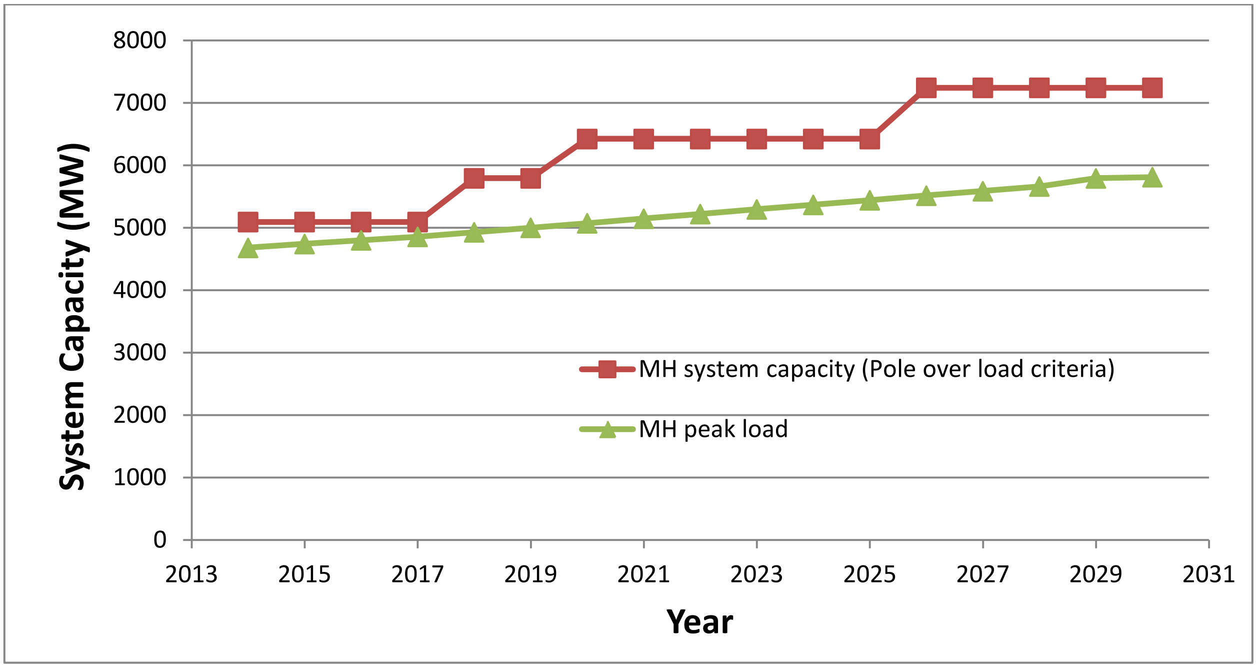


Figure 1: System Capacity vs. Manitoba Hydro load (dc pole over load criteria)

The required DC transmission under a "spare pole over load" criterion may not be adequate for the future northern generation development considering the frequent valve group outages that are currently being experienced with Bipole I and II. A review of past operating experience and increasing economic benefits received from power exports has led to the consideration of the criterion of maintaining a minimum of "on-line valve group spare over NCS generation" to cover frequent value group outages. This spare valve criterion is considered to provide optimum reliability and economic benefits.

For the single NCS, Manitoba Hydro plans to adopt the "on-line valve group spare over NCS generation" criterion after Bipole III goes into service in 2017. Further evaluation of the HVdc spare criterion is currently underway for the split NCS proposed following the addition of Conawapa after Keeyask.

The required dc transmission under a "Spare pole over load" criterion would in general be less than (and increase gradually to match) the required dc transmission under an "on-line valve group spare over NCS gen" criterion. Figure 2, for example, shows that the existing HVdc capacity would have been increased by a minimum of 200 MW to meet a valve group over NCS generation criterion, if it were in effect today. In fact, it would have been added coincident with the last generation plant, Limestone in the early 1990s. The pole over load criterion does not limit the amount of firm generation currently in the NCS.

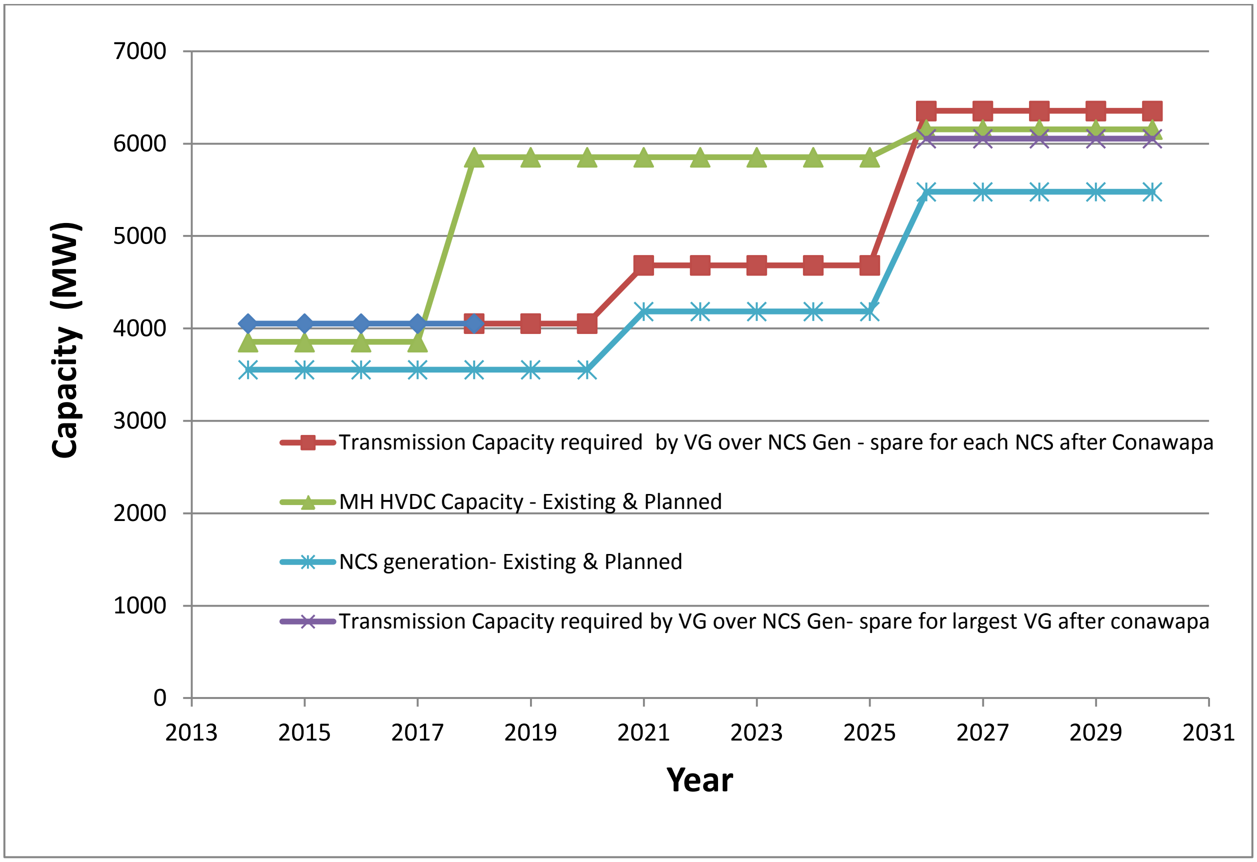


Figure 2: DC Transmission Capacity Considering Valve Group over NCS Generation

Since Manitoba Hydro meets the NERC reliability standards, as well as the current Manitoba Hydro criterion of a spare pole over load, all of the generation currently connected to the NCS is considered firm.

6.6 The Reliability Margin of the Future DC System with Keeyask and Conawapa meets MH Criteria and NERC Standards

At page 8-84 of the LCA Report, LCA states “Furthermore, the addition of Conawapa will result in the split of the NCS which may require additional transmission upgrades to satisfy the NERC reliability standards and HVdc loading issues. The study provided by MH included an option that may assist in meeting the reliability standards but will result in additional cost.” This conclusion seems to be drawn from the assumption identified on page 8-60 of the LCA Report that Manitoba Hydro should plan the future Manitoba network to accommodate loss of a single pole. WRA makes a similar assertion in MMF to PE IR 14a, accusing Manitoba Hydro of essentially ignoring NERC criteria. In order to meet such a criterion, LCA suggests that Manitoba Hydro must consider building Option 1 at a cost premium of $551 million (according to Fig. 8-30 on page 8-61 of LCA’s report).

LCA goes further to state on page 8-62 that this transmission risk is a significant uncertainty related to the Conawapa development.

Manitoba Hydro strongly disagrees with LCA's and WRA's positions and interpretation of the NERC standard requirements. As has been previously mentioned in Section X.X, following a DC pole outage, transmission capacity is removed from service through the automatic operation of protective devices in order to protect equipment and prepare for the next contingency. This may entail the temporary curtailment of Firm transfers (if Manitoba Hydro is exporting at the time), which is permitted by note b of TPL-002-0a. In such a situation, Manitoba Hydro ensures that there is no loss of demand as required by NERC standards. Manitoba Hydro has determined the transfer limits of the three bipoles in both the single collector system and the split collector system in the Integrated Transmission Plan for Keeyask and Conawapa. For the single collector system, Manitoba Hydro determined the total transfer limit to be 5200 MW and applied a 450 MW reliability margin to define the firm transfer level of 4750 MW (Page 39). In the split collector system, it was determined that the combined three Bipole system could transfer 5579 MW. This corresponds to the expected simultaneous maximum level of all generators(Keeyask – 630 MW, Conawapa – 1395 MW, Kettle – 1224 MW, Long Spruce – 980 MW and Limestone – 1350 MW). No additional reliability margin is required to meet the NERC standards. Loss of a DC pole will be covered by generation contingency reserves and curtailment of Firm Transfers as permitted by NERC.

The allocation of the amount of spare DC planned for the split NCS as a reliability margin is an economic choice for Manitoba Hydro, as it impacts the amount of non-firm generation, and is not defined by the NERC standards. PE on page 29 of their Report agrees that the amount of on-line spare capability is an economic choice "Additional studies may be needed to determine the economic value of providing complete on-line sparing capability and the maximum safe operating limit for the combined three-Bipole HVDC system." The initial position taken in the "Integrated Transmission Plan for Keeyask and Conawapa" was to have on-line valve group spare in each NCS. This would result in a margin of 309 MW in NCS1 and 575 MW in NCS2. However, in Manitoba Hydro's NFAT submission, the proposed on-line spare provided in Option 2a is 677 MW with one Kettle unit connected to the northern AC system. As a result, the difference between the desired on-line spare of 884 MW and actual spare of 677 MW defined the amount of non-firm Conawapa generation of 207 MW. The study performed for the Integrated Transmission Plan for Keeyask and Conawapa assumed the additional north-south transmission firmed up 85 MW of existing non-firm generation at Wuskwatim and

Kelsey. For NFAT, it was assumed that Kelsey and Wuskwatim did not require adjustment to their current output levels. This translates to 779 MW of actual on line spare and 105 MW of non-firm generation. Applying the non-firm generation to Conawapa results in 1290 MW being possible to be designated as a Network Resource. This was rounded to 1300 MW in NFAT.

Provisions have been made to make up to three Kettle units switchable between NCS1 and NCS2. This effectively adds 306 MW of off-line spare transfer capability that can be accessed very quickly by operator action. Manitoba Hydro is evaluating whether this off-line spare capability will be sufficient to declare Conawapa output as being firm. These Kettle units must be capable of being switched on to the northern collector system that experienced the valve group outage in 30 minutes or less under all credible weather conditions. The NFAT submission assumed a conservative position that the off-line spare capability would not make the last 100 MW of Conawapa firm.

Manitoba Hydro has conducted studies as documented in the "Integrated Transmission Plan for Keeyask and Conawapa" that demonstrate the system meets the NERC planning standards. One issue raised in that study was performance for normally cleared AC faults in the southern system. The system was able to not violate the 59.3 Hz minimum transient frequency criteria even at the maximum simultaneous generation level of 5579 MW. The PDP Option 2A with one Kettle unit on ac only has 5477 MW connected to the three DC bipoles, which provides an additional 102 MW reliability margin. Manitoba Hydro plans to work with the successful HVdc vendor for Bipole III and develop models for Bipole III that reflect the expected performance of the actual equipment. PE in their report on page 28 confirms the above. They state "With the split NCS bus configuration, the maximum loading limit studied for the combined three-Bipole HVDC system is 5579 MW. This loading produced stable results. However, the safe HVDC loading limit needs further review." Manitoba Hydro agrees that it would be prudent utility practice to review the safe HVDC loading limit once updated HVDC models are developed by the successful vendor of Bipole III. Manitoba Hydro has made conservative assumptions in representing Bipole III in their planning study models and feel the performance of the vendor models will be as good or better. Manitoba Hydro submits that there is minimal transmission risk and uncertainty with the proposed plan for Conawapa.

6.7 Analysis of Transmission Service Requests

LCA questions whether Manitoba Hydro has appropriately evaluated the existing 1850 MW of firm Transmission Service Requests (“TSRs”) under Manitoba Hydro’s OATT in the event that roll-over rights are not exercised (LCA Report at p.8-83). While not clear, the implication is that Manitoba Hydro should have analyzed the possibility that one or more of the TSRs would not be rolled over. Such a position is inconsistent with Manitoba Hydro’s obligations under its OATT.

Section 2.2 of Manitoba Hydro’s OATT grants transmission customers with firm TSRs extending five years or longer the right to continue taking such firm capacity, in priority to new transmission customers, by rolling over their TSR. In order to accommodate this rollover right, Section 2.2 b.(v) requires the Transmission Provider to model its system as if all the existing Firm TSRs that are eligible for rollover rights continue their service when evaluating new requests. In accordance with Manitoba Hydro’s Standards of Conduct, Manitoba Hydro must strictly apply its OATT provisions unless the OATT allows for the exercise of discretion. Since Section 2.2 of the OATT does not allow for exceptions or the use of discretion on this issue, Manitoba Hydro must perform the Group Study assuming that rollover rights will be exercised.

Contrary to another of LCA’s suggestions (LCA Report at p. 8-83), Manitoba Hydro is also not at liberty to discontinue or fail to grant a Firm Point-to Point TSR (or fail to evaluate a TSR) if a power purchase agreement is not in place. There is no condition in Manitoba Hydro’s OATT which makes the granting of transmission service conditional on power purchase agreements.

6.8 Justification of Costs

Keeyask Interconnection Facilities: At page 8-83 of the LCA Report, LCA states that the Interconnection Facilities Study (“IFS”) for the Keeyask interconnection requires additional analyses and may provide that additional transmission upgrades are required. LCA also questions whether these potential costs have been included in the NFAT economic analysis.

In response, Manitoba Hydro can advise that the analyses related to the Keeyask IFS are now complete. These results indicate that no additional upgrades are required. As per the provisions of the Manitoba Hydro Open Access Interconnection Tariff, these results will be incorporated into a Preliminary IFS Report that will be issued to the Generator for review and comment, and then finalized. The costs included in the preliminary Facilities study for Keeyask are consistent with the $157 million ($2012) submitted in NFAT. The assumed accuracy error in the original estimates submitted in NFAT were +/-50%. At the time of submittal to NFAT, any potential costs were considered to be within the included contingency ($19 million) and the accuracy of the estimate.

Manitoba-U.S. Interconnection: At page 8-83 of their Report, LCA states that Manitoba Hydro’s submission does not provide adequate information on whether the Network Upgrades needed in the United States to accommodate the new international line are included in the costs. Similarly, PE in their response to PUB/IR-12A questions the reasonableness or logic of Manitoba Hydro’s failure to include such upgrades in the Group Facility Study.

However, it is not Manitoba Hydro’s role under its OATT to determine the necessary network upgrades on adjacent systems, such as MISO’s, or determine their costs. As provided in Section 19.8 of the OATT, the scope of a Facilities Study is to determine Network Upgrades and Direct Assignment Facilities, which are defined as upgrades done by Manitoba Hydro to its own transmission system. Although a Facilities Study conducted by Manitoba Hydro in coordination with another Transmission Provider may alert the customer to the possibility of required upgrades on another system, the determination of the need for those Network Upgrades and their cost is the responsibility of the adjacent Transmission Provider. In this case, MISO must determine the need for additional upgrades in the MISO region and their associated costs in accordance with the MISO Tariff. Accordingly, it would be inappropriate for Manitoba Hydro to include the costs of potential U.S. Network Upgrades in its Group Facilities Study Report. Based on Manitoba Hydro’s communications with MISO arising from the coordination of their respective studies, it is unlikely that MISO will identify any Network Upgrades other than the U.S. portion of the international power line. However, MISO’s study has not been completed and no report has been issued identifying the upgrades.

Conawapa Interconnection Facilities; At Page 8-84 of their Report, LCA states that *“The option chosen in the study resulted in up to 120 MW of non-firm transmission which is unclear if it was included in the economic evaluations in its entirety.”* While Manitoba Hydro’s economic analysis related to the value of capacity sold from Conawapa took into account non-firm transmission, it did not take into account that a certain amount of Conawapa’s energy would be delivered on a non-firm basis. However, taking this factor into account does not impact the choice of Option 2A as the preferred development plan. Energy sold on a non-firm basis only has a value that is not significantly less than firm energy and does not impact the ranking of alternatives.

Table 7.6 on page 39 of Chapter 7 of the NFAT submission, summarizes the characteristics of the selected resources. The capacity of the Keeyask plant is noted as nominal 695 MW with 630 MW net winter capacity. For Conawapa, Table 7.6 indicates that the nominal rating is 1485 MW and the net winter capacity is 1300 MW. The lower values of 630 MW for Keeyask and 1300 MW for Conawapa correspond to the capability of assumed firm transmission plan (Option 2a) submitted for NFAT. Option 2a assumed a designated Network Resource level of 1188 MW for Conawapa as well as increased north to south ac transmission capability to firm up 85 MW at Wuskwatim and Kelsey. In addition, Option 2a assumed Jenpeg had an output of 168 MW rather than 135 MW. The NFAT submission kept Jenpeg, Wuskwatim and Kelsey at lower values and increased the assumed DNR level at Conawapa to 1300 MW. The value of 1300 MW for Conawapa was used in the economic evaluations for capacity additions, which corresponds to 95 MW of non-firm transmission when compared to 1395 MW (expected simultaneous maximum output level of Conawapa) or 185 MW of non-firm transmission when compared against the 1485 MW nameplate rating.

6.9 Firmness of Transmission Service

On page 26 of the WRA Report, WRA reaches the following conclusion: *"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 …"*. However, WRA has misunderstood Manitoba Hydro's response. The question posed to Manitoba Hydro in CAC/MH II-075a was: *"Do Manitoba Hydro's firm export contracts require that the transmission delivering the load be able to do so in the event of single contingency equipment failure?"* Manitoba Hydro's response was: *"Yes. 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.*

However, Manitoba Hydro is not required to provide a similar level of firmness of transmission service on its HVDC system. The firm export contracts expose the buyer to the risks of the generating system which is defined to include all of Manitoba Hydro's

HVDC facilities. As a result single contingency equipment failures on the HVDC system are a reason to curtail contract deliveries to avoid curtailment of higher priority loads."

The context of the response was in relation to Manitoba Hydro's delivery obligations under a firm export contract (rather than the requirements of firm transmission service over HVDC facilities). If there were an HVdc outage, Manitoba Hydro would not be responsible for delivering the export. However, the purchaser, who is also a transmission owner with retail load obligations, is still bound to the NERC standards when planning its system and is responsible for ensuring their load is supplied. All U.S. utilities are bound by the NERC standards and according to the transmission planning standard (e.g. NERC TPL-002-0a) must ensure no loss of demand in the event of a single contingency equipment failure. The reliability of the dc and ac systems are treated equally for the purchaser.

7.0 DEVELOPMENT PLANS

7.1 Optimization of Development Plans in Manitoba Hydro's Analyses

On Page 3A-20 of their Appendix 3, LCA states "*MH's process for creating and testing the alternative development plans lacks a process of optimization…. Internal or third party model software (such as Ventyx Strategist) offer resource planning tools that optimize resource build out given a set of inputs*."

Manitoba Hydro recognizes that testing development plans to identify the best outcome is dependent on the inputs which are subject to forecast error and imperfect information. As a result, Manitoba Hydro chose to address uncertainty through probabilistic analysis. As stated by Dr. Borison on the Navigant report in Section 2.2.2, "This is a form of optimization." Dr. Borison goes on to say "There is few, if any, third party resource planning tools (including Strategist) that are capable of true automated optimization under uncertainty."

7.2 Manitoba Hydro's CCGT/SCGT Optimization Is Appropriate

La Capra states that "*Use of the average water flow year in the process does not appropriately consider the drought hedge value of a thermal resource in the plan development process"*[91] and that "*Even if the use of the average of the 99 years was appropriate, this method gives weight to operational characteristics over economic*

[91] LCA Technical Appendix 3A Page 3A-23

benefits. Additionally, the averaging method does not allow for placing more importance on a SCGT's ability to help mitigate the risk of drought conditions, a key feature of gas generation resources."[92]

Manitoba Hydro's maintains that the optimization process for selecting CCGT or SCGT is reasonable and appropriate. SCGTs are installed as peaking resources until average annual demand for energy from thermal generation resources is sufficient to justify a more efficient but higher capital cost combined-cycle gas turbine. This optimization process is strictly based on economics to meet Manitoba load, and uses the operational characteristics of the SCGT and the CCGT to determine which resource, under required amounts of demand on thermal resources, is the next economic resource to meet demand out in time.

The 99 year flow record, which includes high flow and drought periods, is considered in each year of the planning horizon. The development plans are created using the need determined under dependable flows, so thermal generation is included based on the need in low flow years. CCGTs and SCGTs are equally capable of responding to drought and acting as a drought hedge. Planning for the maximum available energy from CCGTs and SCGTs to be available in the dependable flow year as the starting point to including a new thermal resource (SCGT or CCGT) already recognizes the value of the asset in the lowest flow year.

7.3 250 MW Export Line versus a 750 MW Export Line

In their report including at page 41, MPA compares the proposed 750 MW export line with the 250 MW export line and concludes that the 250 line ranks better than the 750 MW line but notes that they are never more than 1% apart from a financial perspective. However, Manitoba Hydro believes that achieving US regulatory approval for the 750 MW line has a higher probability of success than a 250 MW export line. The reasons for this are as follows:

1. In Minnesota Power's Certificate of Need filing, Minnesota Power stated that a 250 MW project would not meet the long-term needs of the region and would not prove to be cost-effective for customers or environmentally preferable over the long-term;

2. Minnesota Power's Certificate of Need filing with the Minnesota Public Utilities Commission is for a 750 MW line premised on Manitoba Hydro's Preferred

[92] LCA Technical Appendix 3A Page 3A-24

Development Plan. Minnesota Power, other utilities in Minnesota and others in the MISO region receive significant wind storage synergies as a result of the development of Conawapa. These regional benefits would not exist with a 250 MW line as Manitoba Hydro is only proposing to build Keeyask with a line this size. The development of Keeyask does not significantly enhance the storage capabilities of the Manitoba Hydro system which means there are minimal wind synergies associated with that development plan compared to development plans which include the 750 MW export line;

3. A stated goal for transmission planning in the State of Minnesota is to maximize the use of transmission corridors. With this policy it is risky to assume that multiple small transmission lines to Minnesota could be built over time when a single large line could be in the first instance;

4. The cost of providing transmission service for the Minnesota Power 250 MW Power Sale Agreement is significantly more than a pro-rata share of the costs of a 750 MW line. This is because a larger line can take advantage of economies of scale. These additional costs may jeopardize the overall economics of the 250 MW Sale Agreement.

5. Minnesota Power is well into a development and permitting process assuming that the line will have a minimum capacity of 750 MW with an in-service date by June 2020. A switch to a 250 MW line would require Minnesota Power to start the entire state and federal regulatory process over from scratch which would make achieving the 2020 in-service date very difficult if not impossible.

7.4 An Import Only Transmission Line

LCA directed Manitoba Hydro to complete a development plan case that postulates the construction of the 500 Kv line for imports, along with assumptions for DSM and fuel switching in Manitoba. LCA indicated in its Report that it will be evaluating that plan and addressing the results in its supplemental analysis.

To date, this supplemental analysis has not been filed. As such, Manitoba Hydro reserves the right to file Rebuttal Evidence with respect to the Import Only Transmission Line.

Manitoba Hydro has in the meantime requested a report from Winthrop and Weinstine, a Minnesota firm providing legal representation, lobbying and regulatory consulting services. The Winthrop and Weinstine report, authored by Eric Swanson, addresses the feasibility of an Import Only Transmission Line given U.S. and Minnesota law (including Minnesota Public Utilities Commission Certificate of Need considerations), including commentary regarding whether surplus resources exist in Minnesota or the region that might be relied upon for the purpose of meeting the long term firm supply needs of Manitoba Hydro. Manitoba Hydro is attaching the Winthrop and Weinstine Report as Schedule 1 to its Rebuttal evidence.

The Report confirms that an Import Only Transmission line is not a feasible development plan for Manitoba Hydro.

8.0 EXPORT MARKET

8.1 Export Price Forecasts

8.1.1 Manitoba Hydro's electricity export price forecasting methodology and results are appropriate for use in long term resource planning

Manitoba Hydro's Electricity Export Price Forecast report provides a 35-year forecast of electricity prices in the upper Midwest region of the United States, a long forecast period relative to industry standards, however one that is necessary due to the long life of hydraulic generating facilities.

Manitoba Hydro believes its Electricity Export Price Forecast is appropriate for use in long-term resource planning. Manitoba Hydro will provide evidence to show that Potomac's forecast is in the general range of other, independent expert consultant views and therefore is not justification alone to dismiss other outlooks. This rebuttal will also present evidence indicating that Potomac's critical assessment of the price forecast consultant inputs is based on a number of incorrect assumptions and their resulting conclusions about the "reasonableness" of the figures is inconsistent with Potomac's own recent work for MISO. Manitoba Hydro will also highlight assumptions within Potomac's forecast that do not appear to be within industry's expectations. These aspects are provided to highlight that there is variability in "reasonable" assumptions that can be plausibly considered, and this uncertainty can manifest itself and drive divergent results. This section of the rebuttal also reconciles the analysis on congestion and losses performed by Potomac and Gotham with how Manitoba Hydro accounts for this in the electricity export price forecast.

8.1.2 Consensus forecasting methodology is appropriate

Manitoba Hydro employs a consensus forecasting methodology whereby a number of independent expert perspectives are obtained to ensure that the Corporation is adequately capturing a broad range of perspectives on the future of electricity prices in the upper Midwest. Consensus forecasting has been validated by a number of different economists, statisticians and other academics as a robust approach to reducing forecasting error over use of a single forecast[93].

Allan Timmermann, in the introduction to his 2004 paper, "Forecast Combinations" provides a concise summary of the academic research on this issue:

> Summarizing the simulation and empirical evidence in the literature on forecast combination, Clemen (1989, page 559) writes, *"The results have been virtually unanimous: combining multiple forecast leads to increased forecast accuracy….in many cases one can make dramatic performance improvements by simply averaging the forecasts."* ...Similarly, Stock and Watson (2001, 2003) undertook an extensive study across numerous economic and financial variables using linear and nonlinear forecasting models and found the pooled forecasts generally outperform predictions for the single best model, thus confirming Clemens' conclusion. Their analysis has been extended to a large European data set by Marcllino (2004) with broadly the same results."[94]

Manitoba Hydro specifically engages external price forecasting firms that are well-established, reputable and have a defined expertise in electricity market forecasting. The external price forecasting firms are experts in their field who utilize sophisticated methodologies and tools including formal production costing models which simulate actual market dispatch characteristics and capacity expansion models/ methodology that calculates the value of capacity price using a Net Cost of New Entry (Net Cone) analysis. All six external consultants used in the 2013 price forecasting process as reviewed by Potomac, are highly regarded and reputable, and are active throughout North America in

[93] Academic papers on this issue include Bates & Ganger (1969) - Link / Clemen (1989) – Link / Timmerman (2004) - Link / Genrea, Kenny , Meyler & Timmermann (2013) - Link

[94] "Forecast Combinations", Allan Timmermann (2004)

providing expert advice to the electricity industry on regulatory, financial and technical issues for long-term resource planning.

8.1.3 Potomac Economics' forecast is in the general range of other consultant views of future prices

Notwithstanding any issues with the Potomac forecast to be noted in subsequent sections, Manitoba Hydro would contend that Potomac's price forecast is within the range, albeit at the low end, of the independent electricity export price forecast consultant forecasts used by Manitoba Hydro. Given that the Potomac forecast is within the range of the independent electricity export price forecast consultants, Potomac has no basis on which to assert that the independent electricity export price consultants' forecasts are not reasonable for use.

The table below provides a summary of a comparison of the Potomac forecast (including carbon) relative to Manitoba Hydro's 2013 Electricity Export Price Forecast and its inputs for On-Peak Energy, Off-Peak Energy, Capacity and a bundled On-Peak Energy & Capacity product for the Reference Case at the MHEB pricing location.

- The first column for each Product (i.e. On Peak Energy) compares the Potomac forecast to the Reference Case of the 2013 consensus Manitoba Hydro forecast (Electricity Export Price Forecast – EEPF).
- The second column for each Product compares the Potomac forecast to the lowest individual forecast of each of the six consultants used.

[redacted]

General observations:

- In regards to [redacted] than Manitoba Hydro's Reference Case forecast over the 20 year forecast horizon. More importantly, for the years after 2020 which are relevant to the evaluation of differences between development plans, Potomac's forecast is, on average, [redacted] than Manitoba Hydro's consensus forecast for On-Peak Energy.
- In only [redacted] would it be [redacted], and by the end of the forecast period, is [redacted].
- Relative to Off-Peak Energy and Capacity forecasts, Potomac forecast is [redacted]. However in both cases other consultants do have [redacted] for at least a portion of the forecast period.
- As other consultants do have [redacted] the Potomac forecast for at least part of the forecast period, it follows that the following initial Potomac conclusion is incorrect: *"The figure shows that the consultants' forecasts are* [redacted] *the Potomac Economics forecast after 2020 when most of Manitoba Hydro's new capacity enters the MISO market"*[95]. The Brattle Group's capacity prices remains below Potomac's until the mid 2020s where it trends only slightly above that reference point for the final few years of the forecast. Over the entire forecast period it would appear Brattle projects a lower average capacity price than Potomac.
- Subsequently, in the IR process, Potomac did acknowledge the misstatement in the initial report as follows: "The statement should read: "The figure shows that the

[95] Potomac IEC Report – Page 41 – 1st paragraph

consultants' forecasts are [redacted] than Potomac Economics forecast after 2020 when most of Manitoba Hydro's new capacity enters the MISO market.[96]""

- When considering the All–In On-Peak product (a bundled On-Peak Energy and Capacity product), the Potomac forecast is [redacted] than the consensus and would only be the [redacted] of the six consultant forecasts [redacted] select years in the 20 year horizon. By comparison, for the years after 2020 which are relevant to the evaluation of differences between development plans, Potomac's forecast is, on average, [redacted] than Manitoba Hydro's consensus forecast for the All-In On-Peak Product.

The above data shows that, in general, although Potomac's forecast is somewhat more pessimistic than the average view considered, it is within the range of independent outlooks provided by Manitoba Hydro's consultants.

8.1.4 Clarification of Assumptions and Inferences of Price Consultant Information

Both the Potomac and Gotham reports contain several mischaracterizations. Firstly, the critical assessment of the consultant forecasts was inappropriate given the limited amount of propriety model information Potomac had at their disposal. This limited information led to incorrect conclusions that drove their assessment of the reasonableness of these inputs. These issues will be clarified below.

Evidence will also be provided that demonstrates that Potomac (through their work with MISO) endorsed a capacity valuation very similar to that of Manitoba Hydro during the same period Manitoba Hydro's consultants were developing their 2013 forecasts.

Finally, there are specific assumptions within Potomac's own price forecast that could be considered outside of the conventional industry perspective that would serve to reduce their long-term price forecasts. These items are also noted and expanded upon in the sections below.

These points of evidence are being provided to support Manitoba Hydro's contention that the inputs used by the Corporation (i.e. external consultant forecasts) are entirely appropriate for the purposes of creating a corporate long-term price forecast. Despite the fact that one can question the judgment applied with respect to aspects of Potomac's own

[96] IR MH-POT 024.

forecast, Manitoba Hydro is of the opinion that the Potomac forecast is not fundamentally different than the forecasts Manitoba Hydro aggregated for its 2013 forecast.

8.1.5 Potomac improperly dismissed individual consultant forecasts

Potomac notes that their access to consultant models', assumptions and inputs was limited. *"At the outset, we note that detailed info regarding each of the consultants' models, assumption and output was limited. We generally only received high-level representations of the models and inputs. This limited our ability to critically review the consultants' results and ultimately compelled us to produce our own forecast"*[97].

Price forecast consultant models and the underlying methodology are extremely proprietary and closely guarded as commercially sensitive information and corporate trade secrets. In fact even the output and content of the forecast reports are confidential and were only get released in the PUB CSI process after written assurances that they would be subject to confidentiality agreements.

8.1.6 Potomac's Conclusions on the Consultants' Adherence to Net Cone Methodology was Incorrect

Potomac stated that "*Additionally, some of the consultants appear to not account for the net revenues that a new resource would earn in MISO's energy and ancillary services markets, without which the forecasted capacity price will be inflated"*[98]. This statement implies that an improper or inconsistent methodology was used and would result in capacity price forecasts being "overstated". This assertion is not correct.

A description of how capacity prices are determined by the price forecast consultants was provided in the 2013 price forecast follows:

> A pure capacity product can be thought of as a peaking combustion turbine (the lowest capital cost generator available) which is available to operate at any time during the year – but is never actually called on to operate. The annual carrying costs of this peaking combustion turbine (interest, depreciation, and annually fixed operation and maintenance costs) determine the annual value of a pure capacity product. In practice, a new peaking

[97] Potomac IEC report, Page 10 – 2nd paragraph
[98] Potomac IEC report, Page 41 – 2nd paragraph

combustion turbine will operate a small number of hours per year during high load conditions. When it is operating, it is likely to make some operating profit (the market price minus the variable operating cost of the unit). The annual value of capacity as determined by the consultants is approximated as annual carrying costs of a peaking combustion turbine, minus any annual operating profit the unit may have made in the energy market.[99]

The methodology described above is often referred to as the Net CONE methodology. The term CONE refers to the Cost of a New Entrant, the fixed annual carrying costs of a peaking combustion turbine, sometimes referred to as the Gross Cone. The term Net refers to the annual operating profit from net energy market revenues being deducted from the annual Gross CONE to leave an annual fixed cost of carrying peaking type generation capacity or the Net CONE. As noted by Potomac, "This net revenue approach is a reasonable way to forecast the capacity price[100]".

The following are excerpts from the consultants' 2013 price forecasting report which directly contradict the Potomac assessment that energy market revenues were not considered (i.e. Net vs. Gross CONE). It should be noted that all consultant reports where the following excerpts were sourced from were made available through NFAT's CSI process:

[redacted]

[99] Manitoba Hydro's 2013 Electricity Export Price Forecast – Page 12-13
[100] Potomac IEC report, Page 9 – 4th paragraph

[redacted]

These statements confirm that all price forecast consultants did utilize a Net CONE methodology, did account for net energy market revenues in their capacity price forecasts, and that the Potomac assertion that "some of the consultants appear to not account for the net revenues that a new resource would earn in MISO's energy and ancillary services markets" is incorrect.

8.1.7 Range of Price Forecast Consultant Capacity Values are Reasonable

Potomac notes that *"Given they [forecast capacity prices] are substantially higher than the fundamental approach we used, we do not find them to be credible and recommend that PUB evaluate the business case for the Manitoba Hydro development plans on the basis of Potomac Economics' forecast."*[101] Potomac's conclusions would suggest the capacity prices in the Manitoba Hydro consensus electricity export price forecast should be rejected simply because they differ from Potomac's results. While Manitoba Hydro's consensus capacity price forecast may differ from that provided by Potomac, it is reasonable, supported by sound analysis and a consensus forecasting approach, and in addition is consistent with estimates of capacity prices provided in other proceedings by Potomac Economics.

On September 4, 2012, MISO made a submission to the US Federal Energy Regulatory Commission (FERC) titled: *Filing of MISO Regarding LRZ CONE Calculation.*[102] In this submission, undersigned by David Patton from Potomac Economics, MISO recommended a Gross CONE value $99/kW-year for the 2013/14 planning year. Accounting for net energy market revenue would result in a net CONE value very close to the $85-90/kW-year capacity forecast that was presented in the 2013 Electricity Export Price forecast report. It should be noted that the consultant forecasts for the 2013 forecasts were

[101] Potomac IEC report, Page 41 – 2nd paragraph
[102] https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2012-09-04%20Docket%20No.%20ER12-2580-000.pdf

developed in the late fall of 2012, during the same period that MISO/ Potomac Economics recommended it 2013/14 gross CONE value. The MISO letter specifically notes this capacity valuation is based on Potomac's IMM analysis reports.

Therefore based on this MISO submission, it would appear that Potomac believed that a Gross CONE value $99/KW-year for the 2013/14 planning was completely appropriate in the fall of 2012, in the same time period the Manitoba Hydro price forecast consultants were developing their 2013 capacity valuation estimates. This MISO submission is further evidence that the forecast capacity prices provided by Manitoba Hydro's price forecast consultants are reasonable estimates.

8.1.8 Potomac Misunderstood Brattle's Capacity Analysis Inputs

Beginning on page 9 of their IEC report, Potomac provided a review of individual price forecast consultant reports, including The Brattle Group work as provided in Appendix 3.1 Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO. Potomac stated "*In particular, the consultant (The Brattle Group) assumes a cost of $1200/KW for a CT, whereas the EIA has identified an advanced CT as having a capital cost of approximately $700/KW. This would have a significant effect on the consultant's capacity prices. EIA's estimate of the advanced combined cycle plant ($1000) and the conventional combined cycle plant ($900/KW) are also somewhat lower than the estimated cost used by the consultants*."[103]

The Brattle Group has noted that Potomac has misinterpreted the capital cost inputs used in Brattle's model, assuming they were using $1,200/kW for a Combustion Turbine (CT). Although a conventional turbine was available at this price in their model, Brattle noted that their simulation actually utilized the lower-cost advanced CT ($846/kW), and this was the resource (along with $1,200/kW Combined Cycle (CC)) that set the capacity price. As a result of this misunderstanding, Potomac improperly concluded that "*The consultants' assumed capital costs for the combustion turbine are generally higher than those used by other consultants*[104]."

[103] Potomac IEC report, Page 11 - 4th paragraph
[104] Potomac IEC report, Page 11 - 4th paragraph

8.1.9 Potomac Mischaracterized Manitoba Hydro's extrapolated capacity value

In reference to the price of capacity over time, Potomac states, "*With regard to capacity prices, we find no basis for assuming the real price will increase after 2034. For reasons stated above, such prices might even decline.*"[105] As noted in Appendix A of Manitoba Hydro's 2013 Electricity Export Price Forecast, the post-2034 real growth rate applied on the reference Capacity price was -0.1%/year resulting in a declining capacity price (in real terms) as Potomac suggests could be a plausible outcome.

8.1.10 Each Consultant Developed their Own Load Growth Assumptions

The Gotham report states, "*Supplemental evidence provided by Manitoba Hydro was in the range of reasonable expectations, but on the high end of the range. The reasons for this include using load forecasts that were not representative of the export region and that did not include the impact of higher prices that would be consistent with the CO2 costs assumed by Manitoba Hydro.*[106]" The load forecast that the Gotham report references is outlined on page 6 of their report "*Load Growth in the Export Region*". The Gotham report appears to assume that the indicative macro-level US electric load growth statistics outlined in Chapter 3 of the NFAT filing were provided by Manitoba Hydro to each price forecast consultant as a required input. This is not the case as each price forecast consultant has their own assumption for regional load growth for the specific areas they are modeling. A summary of the consultant level assumptions are available in Appendix C of the 2013 Electricity Export Price forecast that was filed under the NFAT's CSI process.

8.1.11 Carbon Price Embedded within the Export Price Forecast is Reasonable

In preparing their independent forecasts, the export price forecast consultants make their own assessments of a number of pricing factors including but not limited to: fuel price forecasts (coal and natural gas), future load growth forecasts, capital costs and required rates of return, generation retirements and additions, power market rules, future legislative regulations including greenhouse gases and renewable portfolio standard requirements, and characteristics of the existing generation fleet. Therefore, environmental factors including carbon pricing policies are among many factors considered in developing the consensus electricity export price forecast.

[105] Potomac IEC Report – Page 45 – 3rd paragraph
[106] Gotham report – page 9 – 3rd paragragh

Both Gotham and Potomac have raised concerns about the inclusion of a carbon price in Manitoba Hydro's price forecast. Potomac produced two reference case export price forecasts to consider possible inclusion of carbon pricing. Potomac utilized the reference carbon price forecast of MNP for one forecast and used zero CO2 costs for the second. Potomac considers each scenario equally likely. Manitoba Hydro notes the following regarding the value of carbon embedded in the electricity price forecast:

- First, Manitoba Hydro does not explicitly mandate that a value for carbon must be included within the consultant forecasts. Rather, the value for carbon, if any, is based on the consultants' perspective of the future. In fact [redacted] of the six consultants in the 2013 electricity price forecast have a [redacted] for carbon in their reference case. Therefore the consensus forecast for the reference case is a measured view of the future containing [redacted].
- Second, the annual carbon price embedded in Manitoba Hydro's 2013 electricity price forecast was [redacted] than Myers Norris Penny's (MNP) carbon price forecast.
- Third, the Low Case in the 2013 electricity price forecast and in the 2012 adjusted forecast, [redacted] for carbon throughout the forecast horizon. Therefore it can be noted that Manitoba Hydro does consider a [redacted] through application of its [redacted].
- Fourth, embedding a price for carbon has become a common approach in the Canadian energy industry to capture expected regulation of GHG emissions.[107] Within Manitoba Hydro's export region, Minnesota utilities are explicitly required to develop resources plans that consider a carbon price to ensure the social cost of carbon is being considered in generation project evaluation[108].

MNP attempted to calculate the present value of carbon within the preferred development plan, arriving at $582 million ($2014 dollars), and concluding this was 9% of the total present value revenues of the preferred plan[109]. However, the MNP calculations overestimated the proportion of the revenue due to carbon. MNP improperly extrapolated carbon values beyond 2047 in their analysis, whereas Manitoba Hydro assumed no real

[107] Shadow Carbon Pricing in the Canadian Energy Sector, Sustainable Prosperity, University of Ottawa, March 2013

[108] Minnesota Stat. §216H.06 requires the Commission to establish, by January 1, 2008 and updated annually thereafter, an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation to be used in all electric generation resource acquisition proceedings.

[109] MNP Report A Review of Manitoba Hydro's Macro Environmental Consideration, page 35, and IR PUB –MNP-041 b) which restates the present value to $1,055 at a 5.05% discount rate.

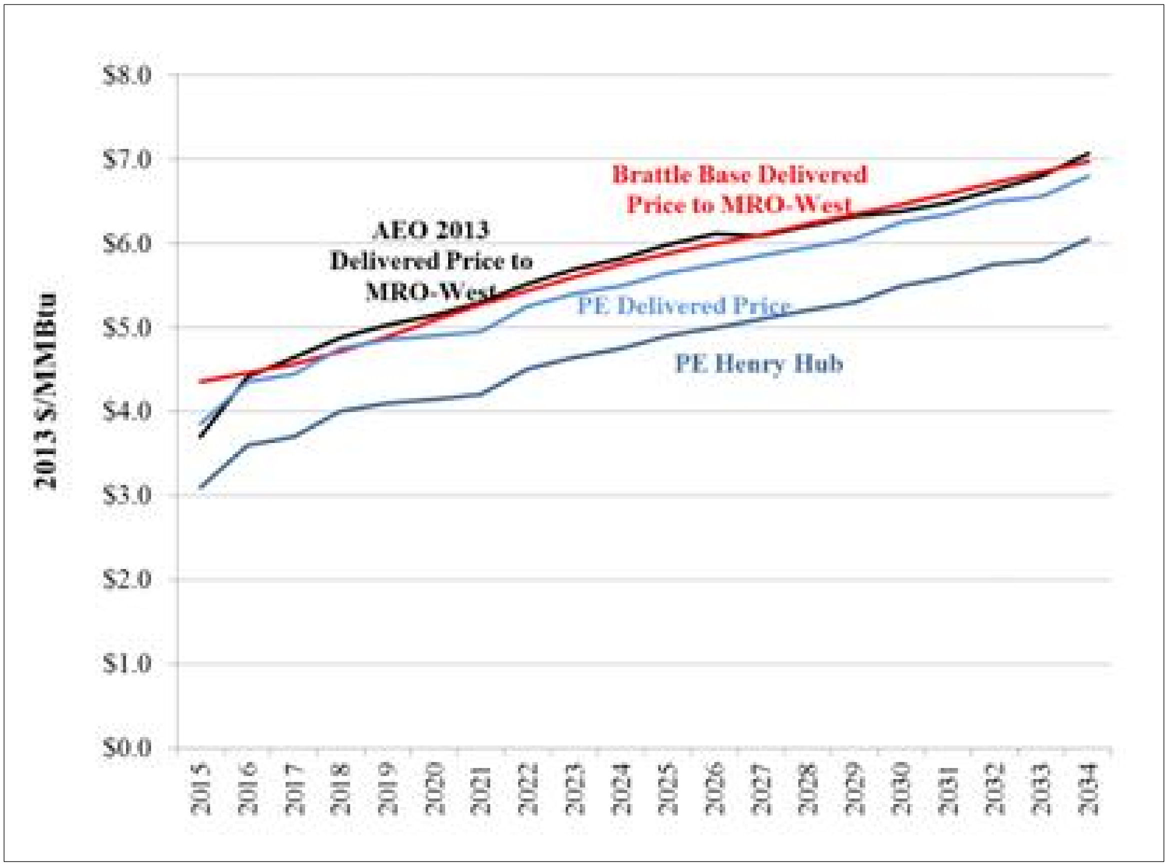
increase in carbon values past 2047. MNP used the carbon value from the 2013 price forecast and compared it to revenues from detailed revenue analysis from SPLASH based on the 2012 adjusted forecast. Further, the MNP methodology assumed a single annual marginal emission value, rather than more detailed modeling which is performed by each of the electricity price forecast consultants. A better estimate of the carbon value was "Carbon prices make up about [redacted] of off-peak electricity prices, about [redacted] of peak opportunity electricity prices, and about [redacted] of long-term dependable electricity prices[110]."

8.1.12 Potomac has Mischaracterized Brattle's Energy Prices

Potomac states that *"[Brattle's] emissions [CO2] and fuel cost assumption along with the high level of coal plant retirements are likely to overstate energy prices."*[111] However, Brattle's carbon price ($15.70 in 2020 to $24 in 2035) is quite similar to Potomac's assumption ($13 in 2021 to $26 in 2035). Brattle's natural gas price ends up being quite similar too, as near as Brattle could determine (there appear to be some differences in the Henry Hub price versus transportation adders, but it appears that these largely offset so that Potomac arrives at a delivered gas price that is similar to Brattle's). Potomac's assumed coal price, based on PRB coal price plus $1.70/MMBtu transportation cost, appears to be significantly above Brattle's coal price, which was based on EIA's delivered regional coal price. The following comparison chart was produced by The Brattle Group to compare the natural gas inputs[112].

[110] LaCapra, Technical Appendix 4 Environmental Issues and Policy, page 4-19.
[111] Potomac IEC report, Page 12
[112] The Brattle Group interpreted Potomac's pricing levels from the charts provided in their report as no data tables were provided.

Chart 1: Natural Gas Price Assumptions: Potomac Economics & The Brattle Group



8.1.13 Several Potomac's Forecast Assumptions are Outside of Current Expectations or Standard Practice

Several of the assumptions used by Potomac in the preparation of their forecast are problematic.

8.1.14 Potomac's Coal Retirement Assumptions are well below industry's and MISO expectations

Potomac notes, *"As explained below, we assume 6 GW of MISO-wide coal plant retirements."*[113] Potomac's assumption of only 6 GW of coal retirements in MISO seems to be quite low, relative to MISO's own projections. In the 2013 MISO Transmission Expansion Plan (MTEP13), as approved by MISO's Directors in December 2013, MISO projected coal retirements of 12.6 GW relative to coal capacity online as of January 2013 in its "Business as Usual" future, which has no carbon price. This is to account for

[113] Potomac IEC Report – Page 11 – 1st paragraph

retirements due to pending federal EPA regulation and the current natural gas price environment. This same 12.6 GW of coal retirements was projected in all the other futures MISO considered, except for the "Environmental" future. This scenario includes a high carbon price of $50/ton and leads to 23 GW of projected retirements[114]. Further, Potomac does not appear to have increased the level of coal retirements when it analyzed the case that included a carbon price.

Potomac's low assessment of coal retirements could be further questioned when looking at the upward trend of expected coal retirement as the implementation date for mercury emissions controls driven by the US EPA's Mercury and Air Toxin Standard (MATS) draws nearer. The EIA's 2014 Annual Energy Outlook (AEO) had coal retirements across the US about 6% higher than its 2013 AEO estimate, up to 60 GW. Specifically Midwest retirements in the 2014 AEO are also about 6% higher (relative to 2013 estimate) indicating that there is increasing expectations for coal retirements, not decreasing. [115]

It appears Potomac's coal retirement forecast is substantially understated relative to other consultant forecasts and MISO's own projections. Underestimating coal retirements would be expected to have the effect of suppressing forecast energy prices, particularly in the off peak period, and delaying the forecasted need for new capacity resources.

8.1.15 Potomac's Carbon Emission Rate Assumptions are Simplistic

Potomac uses the same carbon emission rate[116] and thus the same cost (per MWh) for all coal generators; it assumes all coal plants emit 1.02 tons CO_2/MWh, without allowing for differences in efficiency. In fact, carbon emissions and thus carbon costs are lower for more efficient generators; coal plant emission rates differ by as much as 20%. Similarly for natural gas generators; Potomac does not differentiate carbon emissions for different types of natural gas technology (i.e. combined cycle vs combustion turbine); it applies the same emissions rate of 0.516 tons CO_2/MWh for all natural gas units. This modeling simplification will have some undetermined impact on the energy prices in cases with a carbon value.

[114] Page 65, 2013 MISO Transmission Expansion Plan
[115] EIA's Annual Energy Outlook - http://www.eia.gov/forecasts/aeo/er/index.cfm
[116] Potomac IEC Report - Page 23 -3rd paragraph,

8.1.16 Capacity Expansion Analysis too Simplistic

Potomac assumes that new generation capacity additions are simply split equally between natural gas CCs and gas CTs, rather than determining which technology type is most economic and thus most likely to be added. This could be considered a limitation of the Potomac's forecasting approach as it is inconsistent with market behavior or more sophisticated capacity expansion models employed by Manitoba Hydro's electricity export price forecast consultants who would determine the optimum type of new generation capacity to be added. This modeling simplification will have some undetermined effect on the value of capacity forecast by Potomac.

8.1.17 Manitoba Hydro Adequately Considers Congestion & Losses in its Long Term Price Forecasts

The Potomac and Gotham reports focus on characterizing the issue of congestion in MISO region. Unchallenged, this might lead an outside stakeholder to conclude that Manitoba Hydro has not adequately considered this issue in its long-term forecasts.

8.1.17.1 Mischaracterization of Manitoba Hydro's Perspective of Congestion in Northwest MISO

There appears to be a misconception in the Gotham report that "*Manitoba Hydro indicates there is no significant transmission congestion issues between Minnesota/Wisconsin region and the rest of the MISO.*"[117] This assessment is likely a result of Manitoba Hydro being unwilling, in its responses to Information Requests, to broadly characterize a complex and multifaceted issue such as congestion, in such simple and subjective terms as "significant". Rather, Manitoba Hydro presented actual historical data in responses to Information Requests CAC-MH I-031 and CAC-MH I-075b to allow stakeholders to understand and assess the magnitude of congestion themselves and assess whether it has been appropriately captured in Manitoba Hydro's export price forecasts. Contrasting the Gotham quote at the beginning of this section, Manitoba Hydro notes "Historically, as shown in Figure A22, prices at eastern hubs such as the Indiana and Michigan hubs have been somewhat higher than Minnesota."[118]

[117] Gotham report – Page 1 – 5th paragraph
[118] See IR CAC/MH I -031

8.1.17.2 Manitoba Hydro Accounts for Congestion and Losses in its Price Forecast

The external price forecasts provided to Manitoba Hydro by the price forecast consultants are locational forecasts for the Minnesota Hub. Therefore, no further adjustments need to be made for any congestion and losses between the Minnesota Hub and locations further east in the MISO market such as the Indiana or the Michigan hubs.

As noted in Appendix 9.3, section 1.5.1 of Manitoba Hydro's NFAT filing and Information Request CAC-MH I-075a, Manitoba Hydro applies a congestion and losses factor based on historical MISO data to estimate the basis differential between MHEB and the Minnesota Hub.

8.1.17.3 Independent experts congestion analysis and conclusions do not contradict Manitoba Hydro's methodology

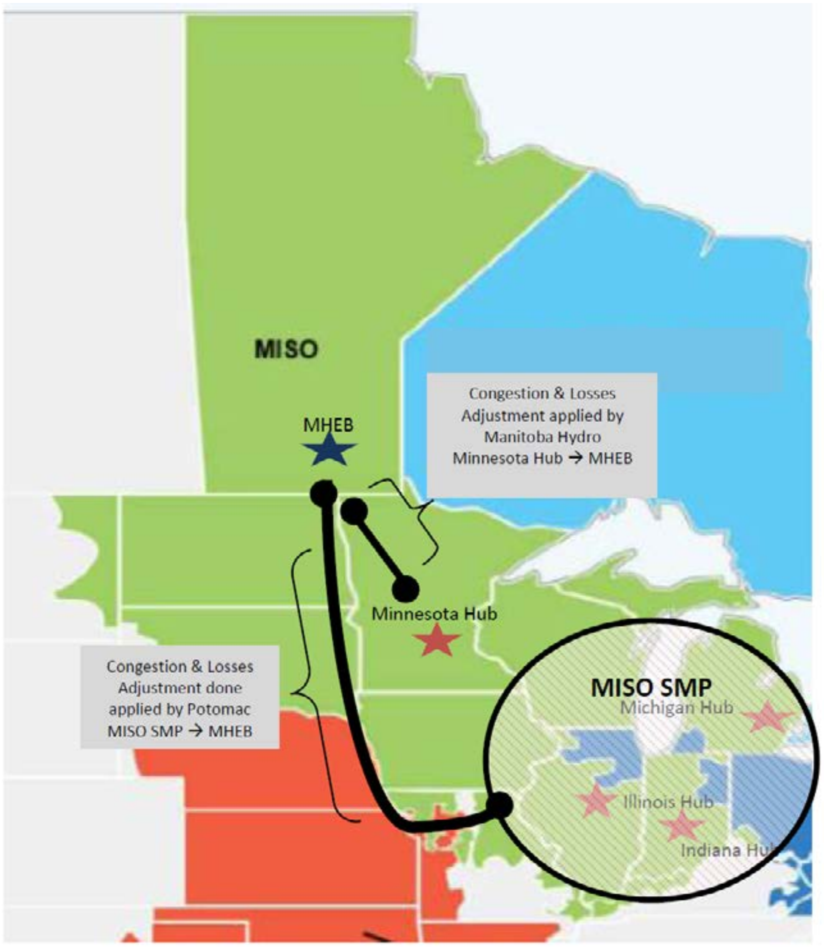
As confirmed by Potomac, "*the System Marginal Price (SMP) calculated by Potomac is equivalent to the energy component of the locational marginal price over the entire MISO footprint, and that this SMP must be separately adjusted for congestion and losses to each studied pricing node such as Minn Hub or MHEB*[119]." In other words, Potomac's methodology forecasts the MISO system marginal price (SMP), which is not the locational price for the Minnesota Hub or for MHEB.

Both Manitoba Hydro and Potomac adjusted the forecasts from their base location to its point of use – the MHEB pricing node. Manitoba Hydro applies an adjustment to account for congestion and losses between the Minnesota Hub (the location for its price forecasts) and MHEB. Potomac also applies a congestion and losses factor, but one that accounts for congestion and losses between the reference bus used in the System Marginal Price calculations, and MHEB. It is Manitoba Hydro's understanding that the reference bus used for the System Marginal Price calculations is a load-weighted distributed reference bus which effectively means it would be similar to locations further east in the MISO market such as the Indiana or the Michigan Hubs.

The congestion and losses adjustment applied by Potomac can be expected to be different and potentially larger due to the greater distance between the reference bus used in the System Marginal Price calculations and the MHEB pricing node used in the Potomac

[119] See Information Request MH-POT 017.

analysis in comparison with the distance between the Minnesota Hub and the MHEB pricing node used in the Manitoba Hydro analysis, as shown in the following Figure:



Potomac did not specifically comment on the congestion and losses adjustment that Manitoba Hydro applies to the consultants' Minnesota Hub energy price forecasts. While the Potomac congestion and losses adjustment is from a different location (as the Potomac forecast is for the MISO SMP rather than the Minnesota Hub) it is similar to the Manitoba Hydro adjustment in that both rely on an analysis of historical congestion and losses.

8.2 Greenhouse Gas (GHG) Emissions

8.2.1 The Preferred Development Plan Offers the Greatest GHG Emission Reduction Potential

Manitoba Hydro expects that greenhouse gas (GHG) emissions will be significantly constrained, either through federal or state/provincial legislation and/or regulation.

Although there is uncertainty in the future of GHG policies, by choosing low- and non-emitting resources, generators are sheltered from the risk of financial impacts associated with potential GHG policy and regulation. Emission constraints are a significant driver for increasing electricity market prices and would favour hydropower as a virtually GHG-free form of generation.

The Preferred Development Plan offers substantial GHG emission reductions relative to other development options, both within Manitoba and from a broader global perspective as a result of the displacement of fossil fueled generation outside of Manitoba[120].

The GHG emission characteristics of the Preferred Development Plan are supported by the following evidence:

- Life Cycle Assessment - The life cycle assessments indicate that of the options compared, Keeyask and Conawapa result in the lowest greenhouse gas (GHG) emissions.
- Manitoba Hydro's GHG Emission Displacement Factor is Reasonable - The Preferred Development Plan also offers the greatest benefit in terms of contributing to the global reduction of GHG emissions because of its impact on thermal power production in the U.S.

8.2.2 Life Cycle Assessment

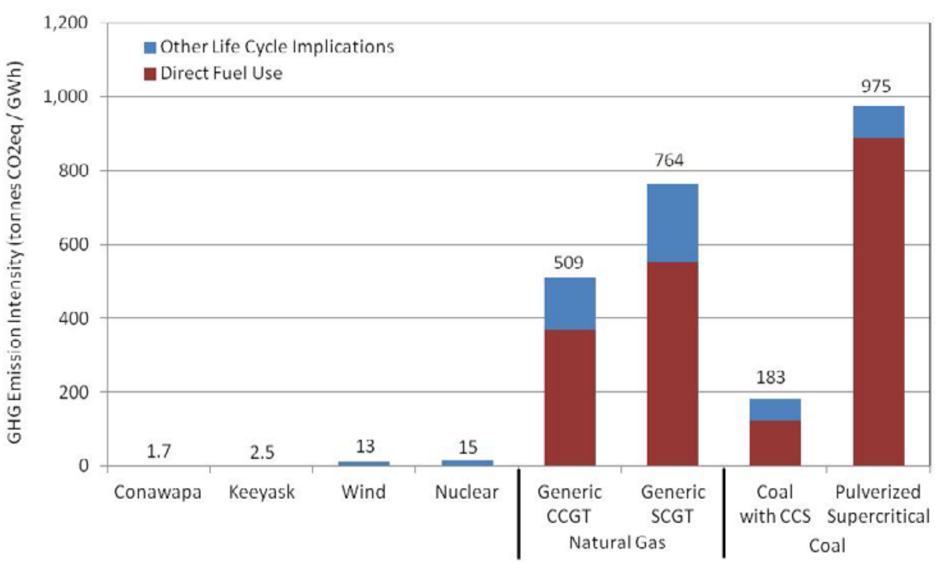
The life cycle assessments (LCA) completed by The Pembina Institute for Keeyask and Conawapa considered three key air emission indicators of local and regional environmental significance: Greenhouse gases (carbon dioxide, methane and nitrous oxide), Nitrogen Oxides, and Sulphur Dioxide. The life cycle assessments indicate that the Keeyask and Conawapa options result in the lowest greenhouse gas (GHG) emissions. The study was carried out in accordance with the appropriate ISO guidelines. It considered emissions from all relevant Project components and inputs during construction and operation, including the reservoir. A comprehensive set of assumptions and input data were used, including emission factors that are publicly available from multiple robust data sources such as the Intergovernmental Panel on Climate Change. An independent review of the Keeyask Life Cycle Analysis found no significant errors or omissions in the analysis. At the time of submission, only preliminary results of the Conawapa GHG Life Cycle

[120] Figure 13.7 and Figure 13.8 in Needs For and Alternatives To: Chapter 13 – *Integrated Comparisons of Development Plans – Multiple Account Analysis*

Analysis were available. Since that time, the Pembina Institute has finalized the Conawapa Life Cycle Analysis. Although the final results are nearly identical to those submitted, an updated summary of the life cycle GHG emissions for the proposed Conawapa Generation Project is shown below.[121] Similarly, a revised comparison of the lifecycle GHG emissions for electricity generation is also provided in Figure 1. As previously concluded, the net positive effect of the Keeyask and Conawapa Generation Projects on climate change is reflected in the small life cycle GHG emissions of the proposed projects versus the vast emission reductions that will result from the displacement of high GHG intensity sources of generation.

Construction			**Land Use Change**	**Operation**	**Decommissioning**	**Total**
Building Material Manufacture	Transportation	On-Site Construction Activities	Reservoir and Carbon Stock Changes	Maintenance and Refurbishment	Decommissioning and Recycling Activities	
Conawapa Generation Project *(Revised)*						
0.94 t CO_2e/GWh	0.21 t CO_2e/GWh	0.32 t CO_2e/GWh	0.14 t CO_2e/GWh	0.01 t CO_2e/GWh	0.06 t CO_2e/GWh	**1.69 t CO_2e/GWh**

Figure 1: Comparison of Lifecycle GHG Emissions For Electricity Generation (Revised)



[121] Original data presented in Appendix 7.3: *Life Cycle Greenhouse Gas Assessment Overview*

8.2.2.1 Life Cycle Assessment Results are Highly Credible

MNP questioned the objectivity of the Pembina Institute with respect to delivering results which would tend to favor low emitting forms of generation such as hydropower versus other alternatives such as gas. MNP itself seems to contradict this point when it noted of the life cycle assessments prepared by the Pembina Institute that "*Given the expertise of the organization and a strong reputation for high quality research and analysis, Pembina is well suited to analyse the long-term climate-related impacts of energy infrastructure projects*".[122]

The detailed GHG Life Cycle Analyses completed for Keeyask and Conawapa are quantitative analyses which rely on material estimates provided by Manitoba Hydro and emission factor information from public life cycle data sets. Similarly, the methodology for determining the comparison technology intensities were not based on opinion but on the results of a literature survey of published life cycle values. MNP completed a materiality assessment of Keeyask Life Cycle Analysis component calculations, performed sensitivity testing and separately assessed the results of the literature review of the comparative technologies.

8.2.2.2 Scope of Life Cycle Assessments is Appropriate

Elenchus, in their report titled "*NFAT Review: A Review of Manitoba Hydro's Demand Side Management Plan*" recommends that ecological footprint analysis is required to assess all alternatives including demand side management (DSM) options. This recommendation would yield little or no value to the evaluation of Keeyask, Conawapa, the comparative technologies or any DSM options.

The notion that the inclusion of additional environmental indicators such as an ecological footprint would make the assessment of Keeyask or Conawapa complete is misguided. For Keeyask, other Project environmental effects have been assessed in accordance with EIS guidelines and reported in the EIS, supplemental information, responses to interrogatories, and throughout the Keeyask CEC Hearings. The GHG life cycle assessments considered emissions from all relevant project components and inputs during construction (including material sourcing, manufacture and transport), operation and land-use changes including reservoir implications.

[122] MNP IEC Report – Page 18 – 2nd paragraph

Besides providing results in the form of an alternate metric, evaluating Keeyask and Conawapa on an ecological footprint basis would require the utilization of the same construction, operation and land-use change impacts and would not yield fundamentally different conclusions. For example, instead of presenting the results in terms of GHG emissions directly from fossil fuelled generators Elenchus proposes that, "…*the associated emissions of carbon dioxide may be converted into an equivalent area by using assumptions about the area of forest needed to absorb those emissions*."[123] In response to a Manitoba Hydro interrogatory, Elenchus indicates that the key benefit of an environmental footprint analysis is that all alternatives would be expressible in terms of a common unit – area of the Earth's surface.[124] Manitoba Hydro finds that the use of an ecological footprint would add little value and would present results in a way that obfuscates rather than clarifies the GHG implications.

Manitoba Hydro did not include DSM in the technology comparison within the Keeyask and Conawapa life cycle assessment studies for a number of reasons. In general, Manitoba Hydro assumes that demand side management measures are amongst the lowest GHG emitting intensity options available, and therefore assumes no negative implications when evaluating the GHG emission impacts of DSM projects and programs. However, as demand side management programs are typically combinations of numerous technologies, activities and behaviour changes, their life cycle assessment would be complex and program specific. Manitoba Hydro has judged the cost and level of effort required to develop life cycle assessments for DSM programs to be unjustified.

8.2.2.3 Keeyask and Conawapa are the Lowest GHG Emission Intensity Option

In the report prepared by Gunn & Olagunju, Table 4.6 and the associated narrative suggests that the CO2e emissions associated with wind are lower than that of hydropower renewable energy technologies.[125] This conclusion for hydropower is misleading since it is not consistent with the specific detailed GHG life cycle assessment of Keeyask and Conawapa. Although not specifically identified in this report, the referenced paper which is relied upon clearly qualifies this conclusion:

[123] NFAT Review: A Review of Manitoba Hydro's Demand Side Management Plan – Elenchus – Page 30
[124] MH-ERA-6d
[125] Gunn and Olagunju – Page 36

- "*It should be highlighted here that the ranking was provided for the global international conditions, while each technology can be significantly geographically affected.*"[126]

In other words, the conclusions presented by Gunn & Olagunju with respect to life cycle GHG emissions of hydropower do not address the specific site conditions, design, construction materials and activities that correspond to Keeyask and Conawapa as considered in the life cycle assessments completed by the Pembina Institute.

As demonstrated by the Pembina Institute's life cycle analysis (Figure 1), the Keeyask and Conawapa projects have the lowest GHG implications of any of the resources options compared including wind. A comparably sized high efficiency combined cycle natural gas turbine would have more direct GHG emissions in its first half year of operation than full lifecycle GHG emissions of the Keeyask G.S. over its 100 year life.

8.3 <u>Climate Change Impacts Reasonably Addressed</u>

Manitoba Hydro recognizes the importance of drought to dependable energy in its system and that climate change has the potential to impact its severity into the future. Furthermore, Manitoba Hydro recognizes that spatial granularity and seasonality also play important roles in the consideration of climate change impacts on dependable energy.

8.3.1 Climate Change Impacts on Drought

LCA and MNP have commented on Manitoba Hydro's analysis of the potential impact on future drought projections as it relates to climate change. The main criticism from these IECs is the absence of analysis on the probability and severity of future droughts as a result of climate change and its related impact[127,128].

In light of these criticisms, Manitoba Hydro sought the opinion of the Ouranos Consortium on Regional Climatology and Adaption To Climate Change ("Ouranos") regarding Manitoba Hydro's use of scientific climate change data, including future climate change projections of extreme events such as prolonged hydrologic droughts. Attached as

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[126] Evans, A., Strezov, V., and Evans, T. (2009) Assessment of sustainability indicators for renewable energy technologies. *Renewable and Sustainable Energy Reviews*, 13:1082–1088. Referenced in Gunn and Olagunju – Page 36.
127 See LCA, 2013. Technical Appendix 4, p. 4-11
128 See MNP, 2013. NFAT Review: A Review of Manitoba Hydro's Macro Environmental Considerations, pgs.9-11.

Schedule 2 to Manitoba Hydro's Rebuttal is a copy of the Ouranos Report dated February 21, 2014.

Ouranos was created in 2001 as a joint initiative of the Quebec government, Hydro-Quebec and Environment Canada. Ouranos conducts integrated research projects that combine the development of regional climate projections, the assessment of physical and human impacts related to climate change and adequate measures to prepare them and different stakeholders in adaptation.[129] Ouranos presently has 14 members including Hydro Quebec, Environment Canada, numerous Government of Quebec departments, and several Universities. Manitoba Hydro is an affiliated member and relies on the work of Ouranos in developing its approach to modeling Climate Change.

Manitoba Hydro recognizes that drought is a complex issue, one in which climate change impacts are not fully understood by the scientific community. Though there is general consensus in the scientific community that climate change could impact the frequency and severity of extreme events, there is "low confidence" that the intensity and duration of drought will increase into the future in the Nelson-Churchill watershed. This is due to inconsistent projections, inconsistent signal, and lack of agreement by the global climate models on drought and the inability of the global climate models to include all factors that influence droughts[130]. In contrast to projections of future extremes in the Nelson-Churchill watershed, areas of the southern part of central North America show a "medium" level of confidence in future impacts to extreme drought, due to better agreement amongst models and stronger evidence of future changes, while no regions currently show a "high" level of confidence. Research is still ongoing and there is currently no power utility accepted standard methodology to quantify climate change impacts on extreme events (i.e. droughts and floods).[131,132]. Manitoba Hydro is not aware of any hydro-power utilities that have applied extreme event projections of drought for the purposes of resource planning decision making. This is supported by Ouranos which states the following in their report[133]:

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[129] See http://www.ouranos.ca/en/our-organisation/background.php

[130] Intergovernmental Panel on Climate Change. 2012: Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation. A Special Report of Working Groups I and II of the Intergovernmental Panel on Climate Change [Field, C.B., V. Barros, T.F. Stocker, D. Qin, D.J. Dokken, K.L. Ebi, M.D. Mastrandrea, K.J. Mach, G.-K. Plattner, S.K. Allen, M. Tignor, and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, UK, and New York, NY, USA, 582 pp. (http://ipcc-wg2.gov/SREX/images/uploads/SREX-All_FINAL.pdf)

[131] Canadian Dam Association, 2007. Technical Bulletin. Hydrotechnical Considerations for Dam Safety. 49 pp. (http://www.imis100ca1.ca/cda/CDA/Publications_Pages/Dam_Safety_Guidelines.aspx)

[132] Federal Emergency Management Agency, 2013. Selecting and Accommodating Inflow Design Floods for Dams. FEMA P-94/August 2013. (http://www.fema.gov/media-library-data/1386108128706-02191a433d6a703f8dbdd68cde574a0a/Selecting+and+Accommodating+Inflow+Design+Floods+for+Dams.PDF)

133 Braun, M. (2014). Ouranos Testimony for Manitoba Hydro Needs for and Alternatives To (NFAT) Business Case. The Climate Change Assessment Approach. 4pgs.

> Current scientific knowledge and assessment of changes to drought from global climate models is limited (Trenberth et al., 2014). Due to the smaller record of such annual extreme events in climate simulations, it currently remains questionable to make sound statements on these issues.

As a result of the state of the science, there is low confidence in projections of drought as it relates to climate change in the Nelson-Churchill River basin and as such the information is not available to undertake a quantitative assessment based on scientific consensus as suggested by LCA and MNP. Therefore, Manitoba Hydro has quantitatively addressed drought based on the historical record of water flows in NFAT Chapter 10 Section 10.2.1 and has qualitatively assessed the impacts of a drought worse than the drought of record in NFAT Chapter 10, Section 10.3.3.

This approach is supported in the Ouranos Report which states that "maintaining historical droughts from the meaningful LTFD [long-term flow record] record represents a good way to compensate the limitations of the delta approach with respect to representing drought in future climate scenarios" [8].

Based on the cited literature contained in MNP's report, it appears that they are defining drought with respect to meteorological events, which is substantially different than hydrologic drought. MNP's report contains no quantification of the magnitude of climate change impacts to drought events relevant to future hydroelectric energy, and furthermore, does not attempt to describe the level of uncertainty associated with climate change projections of future extreme events.

8.3.2 Climate Change Impacts on Spatial Granularity

In order to capture the spatial distribution of future changes to runoff within the Nelson-Churchill River Basin, an ensemble of 109 spatially distributed, Global Climate Change Model (GCM) derived climate scenarios were analyzed and ranked to assess future streamflow availability (see NFAT Confidential Filing – Nov. 1, 2013 Presentation – Climate Change Sensitivity Analysis in NFAT Business Case).

LCA alleges in its report that the coarseness of GCMs is a limitation of the representativeness of future climate scenarios for the basins analyzed. For this study Manitoba Hydro elected to use GCM-derived climate scenarios as they provide a large ensemble of 109 simulations, three emission scenarios and capture a large source of uncertainty in assessing climate change impacts on future water availability. The horizontal resolutions of the GCMs typically range from 250 km to 600 km which is reasonable to represent watersheds of the scale of the Nelson-Churchill River Basin at 1.4 million square kilometers and is supported in the Ouranos Report:

> *"This is well justified due to (1) the size of the area of study [is] large enough to be well captured by GCMs (Knutti et al, 2010) (2) the small added value that high spatial resolution could administer in the rather homogeneous area of the plains (Di Luca, Elia & Laprise, 2012)."*[134]

LCA's statement that *"the method depends on the allocation of outputs in very large-resolution GCMs to smaller-resolution river basins"* (LCA, Page 4-12) is incorrect given the spatial context of Manitoba Hydro's study.

8.3.3 Climate Change Impacts on Seasonality

LCA and MNP have alleged certain shortcomings in Manitoba Hydro's consideration of changes to seasonally altered precipitation in the climate change sensitivity analysis. The main criticism stems from the absence of an explicit analysis of changes to precipitation timing. *(LCA, Technical Appendix 4 and MNP Macro Environmental Report)*

LCA suggests that Manitoba Hydro's approach was limited in its consideration of a single variable (i.e. GCM runoff) (LCA Appendix 4, Page 4-13), however, it should be noted that this variable was specifically selected as it implicitly incorporates model simulated impacts to temperature, precipitation, and evapotranspiration. Though hydrologic routing was not employed in this analysis, the delta method employed by Manitoba Hydro incorporates the routing and seasonal distribution present within the historic flow record and provides representative inter-annual temporal sequencing of future flow events within each basin.

LCA's and MNP's criticisms on the consideration of changes in river flow seasonality (LCA Appendix 4, Page 11 and MNP page 9) are founded on projected changes of precipitation timing. The relationship between precipitation timing and river flow timing is complex due to river routing, lake storage, regulation by upstream agencies and spatial variability of upstream contributions. Therefore, changes to average precipitation timing

[134] Braun, M. (2014). Ouranos Testimony for Manitoba Hydro Needs for and Alternatives To (NFAT) Business Case. The Climate Change Assessment Approach. 4pgs.

are different than changes to river flow timing, and seasonal impacts to river flow do not directly correspond to changes in precipitation patterns. Manitoba Hydro's detailed hydrological modeling of climate change has demonstrated that the projected impacts to average future streamflow seasonality are relatively small in comparison to the annual cycle (NFAT Filing Appendix K, Page 15). Manitoba Hydro has successfully operated its system, despite large year to year variations in the past. Given the storage present in Manitoba Hydro's system and its proven record of effectively managing the interannual variability of streamflow in its system, it is the opinion of Manitoba Hydro that this simplification is acceptable for the purposes of assessing economic sensitivity of the development plan to projected long-term water supply availability.

9.0 ECONOMIC ANALYSIS

Manitoba Hydro prepared the Economic Analysis for the NFAT business case utilizing the guidance of Navigant Consulting, Inc. Dr. Adam Borison of Navigant assisted Manitoba Hydro in developing its economic probabilistic analysis approach and assumptions used to evaluate uncertainty associated with the development plans included in the NFAT filing. Manitoba Hydro's economic analysis has been the subject of commentary from IEC LCA as well as Bill Harper and Wayne Simpson on behalf of CAC, Whitfield Russell on behalf of the MMF and Patrick Bowman on behalf of MIPUG. Manitoba Hydro provided Navigant Consulting with copies of the IEC and Intervenor evidence and requested it prepare a report regarding the merits of the analysis and conclusions contained in the identified IEC and Intervenor Reports as they relate to Manitoba Hydro's economic and uncertainty analysis. Manitoba Hydro is attaching as Schedule 3 a copy of Navigant's Report: Uncertainly Analysis: Overview and Concerns.

9.1 NFAT Analysis is Robust

LCA in their Economic Analysis Appendix on pages 9A-21 and 9A-22 state that Manitoba Hydro has a "*singular focus on the 78-year metric*" and that "*MH does not feature the annual differences in cash flow between the plans … which is important foundational information for assessing relative rate payer cost and risk implications* …". Manitoba Hydro disagrees with these statements. In the NFAT Business Case, Manitoba Hydro provided three major sets of analyses: economic, financial and multiple account. The economic analysis determines the investment value over the life of the longest lived assets. The financial evaluation focuses on the comparative impact on future customer rates and Manitoba Hydro's comparative exposure to financial risk. Affordability and the temporal distribution of costs and benefits are addressed in the financial analysis. The multiple account benefit cost analysis takes into consideration consequences for Manitobans that are not reflected in the revenues and expenditures of Manitoba Hydro and provides a comprehensive assessment of all the benefits and costs to Manitobans to address the question of overall socio-economic benefit. Manitoba Hydro provided these analyses in separate chapters to distinguish the purpose and value of each type of analysis in the NFAT process.

LCA in their Economic Analysis Appendix on pages 9A-22 and 9A-49 are examples where the purpose of the economic analysis has been confused with that of the financial analysis. The following table provides a comparison of the major attributes related to economic and financial evaluations.

	Economic Evaluations (standard benefit/cost methodology)	**Financial Evaluations**
Type of Costing	Incremental, only those costs/revenues that would be incurred if the project proceeded	All relevant costs/revenues including reallocated and overhead costs
Operations	Project only or project with considerations of how other operations may be affected	Total financial operations of the corporation
Measurement	Net Present Value benefit to Manitoba Hydro (domestic customers and project partners)	Rate increases & consumers revenue for domestic customers, effect on financial targets
Price Levels	Constant currencies with real escalation, ignoring general inflation (real $)	Nominal currency with real escalation & inflation (current $)
Financing	Specific funding requirements not relevant; reflected in the discounting of cash flows	Project funding, interest payments, debt repayments explicitly included in costs and revenue requirements
Depreciation	Depreciation not directly applicable. Residual Value calculated for project life longer than 35 year study period	Depreciation used. Residual value not needed as project cost calculated annually

9.2 Use of NPV Rather than IRR, Break-Even Analysis or Annual Cash Flow

On Page LCA-ii of the Executive Summary, LCA also states: "*MH's economic modelling did not test the plan with standard metrics other than 78-year NPV, such as IRR, break-even, or interim period NPV.*"

From the perspective of economic analysis, NPV has both a better logical rationale and is more widely accepted than other metrics. NPV is unique amongst decision criteria in that it recognizes the time value of money, it is not impacted by accounting policies, and incremental NPVs for individual components of the plan can be directly added together.

"IRR, in particular, has serious limitations in resource planning and similar contexts. It is generally used to screen financial investments with simple cash flows for a portfolio subject to a budget constraint. It is not well-suited to detailed evaluation of "real" (non-financial) investments with complex cash flows."[135] Development plans that require periodic investments can produce anomalies in the calculation of IRR. Anytime the cashflows change from positive to negative, or vice-versa, multiple IRR solutions will result – as many as there are changes in the sign of the cashflows. It is also very poorly suited to evaluation of mutually-exclusive investments such as a choice between generating station options. Dr. Borison in the Navigant Report Section 2.2.6 states:

> "The leading textbook in corporate finance makes a telling statement in referring to the difficulties with applying IRR in such situations: "A number of adaptations of the IRR rule have been devised for such cases. Not only are they inadequate, they are unnecessary, for the simple solution is to use net present value."[136] A classic corporate finance text by Ross, Westerfield and Jaffe makes the following more general statement: "While we found that the alternatives [payback period, discounted payback period, accounting rate of return, internal rate of return, and profitability index] have some redeeming qualities, when all is said and done, they are not the NPV rule; for those of us in finance, that makes them decidedly second-rate." [137]

[135] Navigant Report – Uncertainty Analysis: Overview and Concerns, February 25, 2014 Section 2.2.6
[136]Stewart Myers and Richard Brealey, Principles of Corporate Finance, 6th Edition, International, McGraw-Hill, 2000, p. 104.
[137] Stephen Ross, Randolph Westerfield and Jeffrey Jaffe, Corporate Finance, 8th Edition, McGraw-Hill, 2008, p. 186.

9.3 Use of an "Unleveraged Cash Flow"

On Pages 9a-16 and 17 of LCA's Appendix 9A Economic Analysis the authors state that the unleveraged cash flow approach in economic analysis is commonly used for single investments with short construction periods and generally anything more involved, for utilities, would be better served with a revenue requirements analysis. Manitoba Hydro disagrees with this perspective.

As stated on page 3 of Chapter 9 of the NFAT Business Case, Manitoba Hydro uses standard economic analysis for project evaluation, known as NPV. The economic analysis compares investments on an equivalent basis. In general, the analysis determines the equivalent amount of money required today, if invested in core business activities (reflected by the company real weighted average capital cost - RWACC) for each project, over a defined period of time, and then selects the project that has the greatest value. As the weighted average cost of capital generally includes the interest rate as a component of the RWACC, the economic analysis does reflect interest. The economic analysis is meant to represent the value to an investor today, who remains invested in the project for the life of the project. The economic analysis evaluates the life benefit of the project. The financial analysis is used to determine the affordability of the project, and the temporal distribution of costs and benefits.

Further to this, Dr. Borison, in Section 2.2.7 the Navigant report, opines that

> For the purpose of economic evaluation, we believe that the approach taken by MH (discounting unleveraged cash flow with the weighted average cost of capital) is appropriate. This approach is widely viewed as a standard and reliable measure of economic value created, distinct from the form of financing or the impact on specific stakeholders in specific time periods.

9.4 The Use of Residual Value is Appropriate for Economic NPV Evaluations

On page 9A-68 of LCA's report on Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations – Technical Appendix 9A the authors introduce the issue of viewing the economic results through shorter life spans rather than through the 78-year study period. LCA has chosen to view three additional time periods – 20 years, 35 years and 50 years. Also in LCA's Initial Report, Page 25 they conclude "*Based on a 35-year NPV metric, Plan 4, Plan 5 (Keeyask,* *Gas 25 750 MW transmission) and All Gas are the most economic plans using MH Reference scenario assumptions.”*

Upon review of LCA’s analysis of shorter life spans, Manitoba Hydro has found that LCA’s approach does not consider the residual value of the remaining life of the assets in the truncated time periods which has a pronounced effect on their results. Manitoba Hydro does not believe that such an approach should be used for decision making. It is standard benefit/cost evaluation methodology to include residual values of the remaining asset life in the analysis.

Manitoba Hydro chose the 78-year time frame because of the long-lived nature of the hydro assets and because of the considerable uncertainty over that life. As explained by Dr. Borison in Section 2.2.8 of the Navigant report, “Shortening the time horizon is akin to applying a 100% discount rate or equivalently, assigning a zero value to long-run impacts…even very large ones…with certainty. This is clearly in conflict with the idea that there is severe uncertainty in the long run. Instead, it is best to recognize and incorporate uncertainty over this time period in the evaluation.”

The use of NPV analysis requires that the benefits and costs over the entire life of an asset be included as part of the analysis. Shorter study periods are often analyzed in NPV analysis, but in so doing, the benefit of the asset that remains at the end of the study period is estimated, and included as part of the benefit. Many times in NPV analysis, the cost of the asset is simply represented by amortizing the asset cost over the life of the asset, and only including the amortized costs that are included in the study period together with the residual value of the assets. The residual value is included either by identifying the remaining value of the assets, which has the effect of reducing costs, or by extending the study period such that it includes the entire life of the assets, or both.

In Manitoba Hydro’s analysis the study period was extended to 78 years to capture the residual value of the assets in the development plans. Manitoba Hydro has determined the effect of the residual value by calculating the salvage value of the assets at the end of the 35-year detailed study period. The table below provides a comparison of the ranking of the twelve development plans evaluated in the probabilistic analysis using LCA’s calculations with and without salvage value (salvage value calculated by Manitoba Hydro) as well as Manitoba Hydro’s calculations showing a 35-year and 78-year study period with salvage value. As shown in the development plan rankings, shortening the time horizon without consideration of residual value (column 1) places the highest capital cost plans to the lowest position in the ranking. Column 1 then shows the effect of assigning a zero residual value to long-run impacts on the ranking of the development plans.

Development Plan Ranking With and Without Salvage Value (Ref-Ref-Ref NPV)						
LCA 35-year, no salvage value	LCA 35-year, with salvage value	MH 35-year, with salvage value	MH 78-year, with salvage value		Plan Number	Plan Name
4	14	14	14		Plan 1	All Gas
5	4	4	15		Plan 2	K22/Gas
1	5	5	12		Plan 3	Wind/Gas
6	12	12	4		Plan 4	K19/Gas24/250MW
2	15	15	13		Plan 5	K19/Gas25/750MW (WPS Sale & Inv)
7	6	6	11		Plan 6	K19/Gas31/750MW
8	11	11	5		Plan 7	SCGT/C26
14	13	13	6		Plan 8	CCGT/C26
3	2	2	2		Plan 9	Wind/C26
13	7	7	10		Plan 10	K22/C29
9	8	8	8		Plan 11	K19/C31/250MW
15	10	10	7		Plan 12	K19/C31/750MW
11	9	9	9		Plan 13	K19/C25/250MW
12	1	1	1		Plan 14	K19/C25/750MW (WPS Sale & Inv)
10	3	3	3		Plan 15	K19/C25/750MW

9.5 78-Year Total Study Life Appropriate for Economic Evaluation

As stated in Appendix 9.3 of the NFAT submission, the total study life used in the economic analysis is 78 years. For the total study life, Manitoba Hydro combined two approaches - a 35 year detailed evaluation and 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.

La Capra is of the opinion that the economic analysis results related to the development plans should be undertaken over multiple time frames (LCA Economic Analysis Appendix on page 9A-21). Manitoba Hydro's approach extended the economic outlook out to about 2090 which is approximately 67 years after the in-service dates of the Keeyask and Conawapa generating stations. Assets with shorter lives that are included in the development plans were replaced with similar assets at the end of their life, and a salvage value was applied in 2090 to recognize any remaining life the last replacement asset might have.

Manitoba Hydro maintains that the economic analysis is meant to determine the investment value over the asset life. The issues of affordability and temporal distribution of costs and benefits are addressed in the financial analysis.

La Capra's concern appears to be based on the viewpoint of the ratepayer, rather than the economics of the decision from Manitoba Hydro's perspective.[138] The determination of rate increases is included as part of the financial analysis, rather than the economic analysis.

Whitfield Russell on behalf of MMF states that, "*The 78 year study period is too long*"[139] and that export price forecasts for the outermost years makes net production costs "*even more suspect*"[140]. LCA voices similar concerns [141]. When considering resource options that have significantly different asset lives, it is necessary to study the benefits over the life of the longest lived assets in order to establish a fair comparison between the development plans. Although uncertainty increases farther into the future, the analysis cannot be considered complete, and would otherwise be misleading, if the enduring costs and benefits are not captured over the long term.

9.6 Length of Study Life Does Not Significantly Change Conclusions

On page 7 of Whitfield Russell Associate's report, Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan (PDP), prepared for the Manitoba Metis Federation the authors, regarding LCA/MH 1-397, raise the question as to "*Exactly how an amount that is $226 million higher is "essentially the same" as another amount remains unexplained*."

In LCA/MH I-397, a comparison is made on two separate metrics for two different study lives on the results of the economic analysis. In this response, Manitoba Hydro is not saying that Plan 4 and Plan 14 have "essentially the same" expected value. One is the "incremental NPV under the reference scenario" and the other is the incremental "expected value". Manitoba Hydro's conclusion in LCA/MH I-397 that Plan 4 and Plan 14 have "essentially the same incremental NPV" relates to the incremental NPV under the reference scenario. This is a valid conclusion. The statement that "Plan 4 has a higher expected value by $226 million" relates to the incremental expected value metric and not

[138] La Capra Appendix 9A Page 9A-17
[139] MMF - Whitfield Russell Associates Page 3
[140] MMF - Whitfield Russell Associates Page 13
[141] La Capra – Appendix 9A Page 9A-24

the incremental NPV under the reference scenario. This also is a valid conclusion. Manitoba Hydro's key conclusion related to the comparison between Plan 4 and Plan 14 in the NFAT Business Case, Chapter 10 page 39 is that careful consideration must be given to the tradeoffs between the plans given the different characteristics of these plans. Further analysis of other perspectives (financial, multiple account and optionality) are important to the overall conclusions provided in Chapter 14.

9.7 Discount Rate Used in Economic Analysis is Appropriate

The selection of the appropriate discount rate is essential for the determination of meaningful present value calculations. Concern has been expressed that Manitoba Hydro has utilized discount rates that do not fully reflect its cost of capital or are not representative of the various constituent groups in Manitoba.

Manitoba Hydro is not regulated on a rate-of-return basis – rates are set to recover costs and to make contributions to retained earnings. Despite this, Manitoba Hydro still utilizes a weighted average cost of capital (WACC) approach to determining the appropriate discount rate for project evaluations. The purpose of this is to recognize the need to have an equity cushion that can accommodate normal business risks and provide a return that can be used to make contributions to retained earnings and/or be used to reduce electricity rates. Allowed rates of return on equity (ROE) for other utilities are used to determine the 3% equity adder that Manitoba Hydro utilizes as a proxy for an allowed rate of return.

Even though this equity adder is used as a proxy for an allowed return on equity, both intervener and independent expert witnesses have challenged the details of the calculation. Manitoba Hydro's reference discount rate is based upon its long term cost of debt, calculated as: forecast long term Canadian bond rate, plus an adjustment for the credit spread between Manitoba and Canada, plus the provincial guarantee fee. With a 0.65% provincial spread and the 1.0% guarantee fee, the 3% equity adder results in an ROE that is 4.65% above the long term *projected* Canadian bond interest rate. Morrison Park cited a single 2009 Ontario Energy Board decision (p. 63 of their evidence) of a 5% spread above Canadian long bonds (although they thereafter recommend 6% or 10% nominal returns) while Econalysis also included an Alberta decision from 2011 and a British Columbia 2013 decision that indicated an acceptable range of 4.68 – 5.50% over the long term bank of Canada rate. Ignoring the specifics of annual adjustment mechanisms and of different provincial spreads, there are issues with using one to three decisions (albeit important and prominent ones) to establish the industry norm. Manitoba Hydro periodically reviews a wide range of sources, including those cited above, to determine the reasonableness of its equity return proxy. One of the most recently reviewed was an October 2013 report from Concentric Energy Advisors: (http://www.ceadvisors.com/news/pdfs/ROENewsletterVolumeI.pdf) which includes 35 Canadian and US electricity and gas distribution utilities. Their subsequent paper (http://www.ceadvisors.com/publications/reportsandpublications/Recent%20Developments%20in%20the%20Cost%20of%20Capital%20for%20Canadian%20Utilities.pdf) supports the appropriateness of using US ROE awards in the data used in a determination of suitable Canadian returns.

Rather than getting mired in the details of calculating the equity premium over the projected cost of debt, Manitoba Hydro recognizes that the underlying interest rate forecast is also subject to uncertainty and that looking at a range of discount rates would be a more appropriate exercise. The 5.05% real discount rate is based upon a projected long term Canadian bond rate of 4.65% nominal or 2.70% real after removing a 1.9% escalation forecast. In order to capture the uncertainty in discount rates, via the underlying interest rates, low and high cases were prepared that reflected the historical range of real interest rates (provided in response to PUB/MH I-165a). Morrison Park erroneously cites historical movements in nominal interest rates (page 62 of their evidence) when criticising the *real* interest range that Manitoba Hydro utilized in its risk analysis. The high interest rate period from 1975 to 1995 that they refer to was accompanied by similarly high rates of inflation: interest rates peaked in 1981 with an average long term Canadian bond rate of 15.22%, but the 12.50% CPI at the time meant that the real interest rate was only 2.42%. The response provided to PUB/MH I-165a also shows that very low real interest rates have also been experienced periodically. Sudden upturns in inflation such as after World War II or in the early 1970's can even produce negative real interest rates until the markets adjust their outlooks of the future. More recently, during 12 of the last 69 months since the April 2008 financial crisis, interest rates have remained below 2.31% (the underlying long Canada rate in the low case), in contrast to Morrison Park's view that there is "little if any support for the low scenario" (page 63 their evidence). La Capra interprets this statement by Morrison Park to mean that "low discount rate scenario postulated by MH is not feasible" and then assign a zero probability to Hydro's low discount rate case. Since real long term Canadian rates have been at or below 1% at various points throughout history, including very recently, there would seem to be little or no support for the assignment of a zero probability – a declaration of absolute impossibility – for Manitoba Hydro's low discount rate case.

10.0 UNCERTAINTY ANALYSIS

In this section of Manitoba Hydro's Rebuttal Evidence, Manitoba Hydro addresses the written evidence of the Independent Expert Consultants LCA as well as the Intervenor witnesses Harper and Simpson on behalf of CAC and Bowman on behalf of MIPUG regarding the NFAT economic uncertainty analysis.

10.1 Use of 27 Scenarios is Considered Appropriate and Reasonable to Test Uncertainty

After an assessment of the uncertainty in ten individual factors, the three key variables were selected and the probabilistic economic evaluations in the NFAT submission considered the uncertainty of the three key variables that represent 1) electricity markets, 2) economic indicators and 3) capital costs each with three possible outcomes – high, reference and low. The combinations of three variables, each with three outcomes, resulted in 27 possible scenarios.

Although Mr. Harper acknowledges that Manitoba Hydro selected the three most significant factors, on page 40 of Econalysis Consulting Services' (ECS) report on "Needs for and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan" he suggests that Manitoba Hydro's analysis is "*fairly simplistic*" since only three factors were used with only three possible outcomes assigned to each factor. Mr. Harper also suggests that the resulting probability distributions for each plan are not as robust as they could have been. Similarly, Dr. Wayne Simpson suggests on pages 2 and 3 of his report on "Risk Analysis in the NFAT" that Manitoba Hydro ignored some potentially important risk factors in its risk analysis and that "*much more could be accomplished with modern computational methods and capabilities to analyze more factors with more conventional distributions*".

As stated in Chapter 10, page 2 of the NFAT submission, "*Probabilistic analysis will grow exponentially with each added factor* ….". The compilation of massive amounts of input data required to complete a meaningful analysis, such as that used in a Monte Carlo simulation, was not feasible to adequately and meaningfully represent Manitoba Hydro's system. Monte Carlo analysis, for example, would require an understanding of the relationships between variables and the data that are currently modelled in the SPLASH model to reasonably estimate the probability distribution of the variables that represent Manitoba Hydro's complex interconnected system. Manitoba Hydro is not aware of any commercially available model which could do this. An alternate approach would be to develop an overarching model which embeds the SLASH model in it; however, the modelling that would be required would involve unacceptably long computational time duration. It can also be more opaque and less flexible. More importantly, Manitoba Hydro's approach to probabilistic analysis provides greater ability to review and understand the impact of each of the key factors on the various development plans. It is more important to fully understand the impacts of the more critical factors than to have an analysis which provides a large mass of information for many factors which masks the more important trends.

For the probabilistic analysis, Manitoba Hydro chose to include those factors that are 1) most significant and 2) most subject to rapid dramatic change. As well, in most economic or financial applications, and as described in PUB/MH I-161, three-point distributions are considered a reasonable approximation since they can be used to benchmark the underlying continuous distribution.

Manitoba Hydro considers its probabilistic evaluation approach to be a robust analysis as the range of key factors that impact the overall economic and financial outcomes have been considered.

Please also see Navigant's report Section 2.2.3 The Choice of Variables in Uncertainty Analysis and Section 3.2.1 Use of Three Point Probability Distributions.

10.2 Manitoba Hydro's Use of a Mix of Historical Data, Model Forecasts and Expert Judgments from Internal and External Sources to Assign Probabilities is Reasonable

On page 11 of LCA's report on "Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations – Initial Expert Analysis Report", the authors state that they are concerned that the perspective of the experts that was captured in the probabilistic analysis as it relates to the assessment of probabilities has likely changed in the two years since the analysis was conducted.

The probabilities used by Manitoba Hydro were intentionally made consistent with the vintage of the forecasts used in the analysis. Therefore, if the inputs were updated or changed, there would be valid reason to reassess the assigned probabilities to reflect the likelihood of the updated set of data. For this reason, the probabilities would not be updated in isolation.

On page 9A-54 of LCA's report on "Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations – Technical Appendix 9A" the authors also state that the probability distributions were "*estimated by experts and Manitoba Hydro personnel, not data derived from forecasts or statistical analysis*". This statement is not correct. Manitoba Hydro used a mix of historical data, model forecasts and expert judgments from internal and external sources to assign probabilities to the high, reference and low cases. For example, the economic indicator probabilities involve historical data on past interest rates, model forecasts on inflation rates and expert judgments about relationships among variables. Where appropriate, expert judgments reflect a consensus rather than a single view. This perspective is supported in Navigant's report Section 3.1.

10.3 Inclusion of Range of Discount Rates in Probabilistic Analysis Related to Required Market Return

On page 41 of ECS's report on "Needs for and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan", Mr. Harper states "*The scenarios should all be evaluated using the same discount rate (i.e. time preference)*". Mr. Bowman describes a similar concern on page B-10 of his pre-filed testimony.

Manitoba Hydro maintains that it is appropriate to consider discount rates as a key factor in its economic probabilistic analysis. The concern raised by Mr. Harper and Mr. Bowman relates to the use of discount rates when considering the time preference for money. The analysis provided by Manitoba Hydro was intended to reflect a specific kind of monetary time preference; the cost of capital to Manitoba Hydro and uncertainty in the cost of debt (i.e. interest rate) in terms of the return that financial markets would require of Manitoba Hydro's investments. In support of this, Dr. Borison, in Navigant's report in Section 2.2.5, says,

> "When the source of this [discount rate] uncertainty is a fundamental market parameter such as interest rates, it is not only reasonable to consider discount rate uncertainty but it is reasonable to do so by 1) assigning probabilities to different discount rate outcomes, 2) calculating NPV's given specific outcomes, and 3) calculating the expected NPV (ENPV) across these outcomes. In comparing analytical approaches, a team of thirteen leading economists including Nobel Laureate Dr. Ken Arrow, referred to this approach favorably. "An alternate approach to modeling discount rate uncertainty that is more empirically tractable is the expected net present value (ENPV) approach." This is essentially the approach taken by Manitoba Hydro."

In the financial and multiple account analyses, Manitoba Hydro used other discount rates to capture issues such as stakeholder time preference.

10.4 Discount Rate Linked to Interest Rate

On Page B-4, MIPUG states: "*Hydro has modelled the economics in a manner that can only reflect interest rates on debt through the discounting rate for present values. This means that there is no ability to independently test variations in discount rate within a desirable range*."

As described in Section 10.3 of this Rebuttal Evidence, the meaning of discount rate is specifically intended to reflect the returns that financial markets require of Manitoba Hydro's investments. Given this economic evaluation perspective, discount rates and interest rates are intricately linked. Discount rate uncertainty and interest rate uncertainty, therefore, are tied.

Outside the economic evaluation, different discount rates can be used to gain insights into how stakeholders with different time preferences would judge the alternatives and to capture other perspective. The financial analysis directly models interest rates, and not the discount rate. In the financial and multiple account analyses, Manitoba Hydro uses other discount rates to capture issues such as stakeholder time preference.

10.5 The Utilitarian Approach Should be Used Over the Regret Approach to Make Complex Decisions

On page 9A-61 of LCA's report on "Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations – Technical Appendix 9A" the authors state that they *"believe that MH's methodology of comparing all 27 scenarios of a development plan's potential outcomes to a single (reference) point in the base case does not indicate the most important element, which plan is economic for a given scenario."*

Manitoba Hydro's probabilistic analysis is based on the "utilitarian" approach to measure the impact of uncertainty for each development plan rather than the "regret" approach. The utilitarian approach evaluates each alternative without any reference to the impact of the other alternatives in that scenario and therefore does not presume that we know which future scenario will occur. Alternatively, the regret approach evaluates each alternative based on the relative impact that it has in a specific scenario compared to the impact if some other alternative had been chosen instead.

In its response to MIPUG/MH-I-9(a), Manitoba Hydro explains why the utilitarian approach is the correct method to use for the purpose of evaluating alternatives based on the impact that each alternative has in each scenario. Manitoba Hydro provides an example that illustrates why the utilitarian approach should be used over the regret approach to make complex decisions and states the following in MIPUG/MH-I-9(a).

> The regret approach has intuitive appeal and provides interested parties with some useful information at the high level. Consequently, it is used in Table 2 of the Executive Summary. However, it is usually viewed as being more descriptive than prescriptive. There is little support, analytical or empirical, for using the regret approach to make complex, future altering decisions.

Please also see Navigant's report in Section 4.2.1 Use of Utilitarian Rather Than Regret Approach.

11.0 FINANCE

This section addresses the evidence of IECs MPA and LCA and Intervenor witnesses Patrick Bowman on behalf of MIPUG and Bill Harper and Wayne Simpson on behalf of CAC.

11.1 A Crossover Period of 3 – 7 Years is Neither Realistic Nor a Common Objective Amongst Utilities

MIPUG suggests that, *"A common standard for new bulk power projects such as hydraulic generation is that adverse impacts on financials or rates from new developments should not exceed somewhere in the order of 3-7 years until the "cross-over" point of costs into benefits is reached, and should not be excessively costly during the time frame up to the cross-over."* [Pre-Filed Testimony of P. Bowman, Page 3-9]

It is Manitoba Hydro's view that achieving rate savings within a period of three to seven years is not a "common standard" for the hydro-electric industry nor is it realistic as an objective.

The response to MH/MIPUG I-3 cites a number of examples of projects in other jurisdictions but fails to provide any research or analysis conducted regarding the projects. The examples provided are not directly comparable to the rate impact analysis conducted in Manitoba Hydro's NFAT financial evaluation. Comments specific to each of the examples are as follows:

BC Hydro – Site C

- BC Hydro "*compares the rate impacts between the different incremental resource options considered in the IRP to meet the identified need.*" Clearly, how any option compares to the others is a function of which others were being compared against. If BC Hydro had included an All Gas case in their incremental analysis as the baseline option, it is unlikely they would have shown incremental rate reductions as early as is portrayed in BC Hydro's Figure 6-21 (a link to which is provided in MH/MIPUG I-3). As the base case for BC Hydro's incremental rate impact analysis is simply Site C with a specific DSM option ("Base Case: DSM Option 2 and Site C ISD F24 (Load without expected LNG)”), and all the selected cases for comparison are either a different DSM option or a different In-Service date, their analysis is no basis for comparison with the analysis of Manitoba Hydro development plans and any such “cross-over” period.

Yukon Energy Corporation – Mayo B

- Yukon Energy received either free or low-cost funding that guarantees a maximum levelized cost of electricity at levels ½ to ⅓ of the LCOE that would need to be passed on to ratepayers without such funding. Without such funding the costs would be too high for the project to proceed, so to claim that comparative benefits begin to accrue in year 1 is not a reasonable comparison. The claim that the cross-over between Mayo B and a diesel generation baseline is 14 years, without government funding, is more consistent with Manitoba Hydro’s hydro pathways relative to All Gas, but 14 years is well outside MIPUG’s claim that 3-7 years is the ‘common standard’.

Mayo Dawson Transmission

- The recovery of the transmission line costs is simply a function of the cost differential between the LCOE of low cost hydro generation and that of diesel, and any such comparison should be attractive if the spread is large enough. Consideration of a ‘cross-over’ point in this context is not a credible metric.

Northwest Territories Power Corporation – Snare Cascades

- The reference to "5 years" in the response refers only to the period in which NTPC chose to protect the ratepayer from excessive rate increases, and is not at all related to any 'cross-over period'. In fact, by the details of NTPC's rate policy provided in Table 1, NTPC doesn't even begin to recover from this rate protection strategy until 15 years from the ISD of the plant.

Nalcor Energy – Muskrat Falls

- The price of $76/MWh (2010$) quoted by MIPUG was not intended to be a cost to the ratepayer – it was a cost that was back-calculated to achieve a target return on investment that would be potentially able to attract private-sector debt from the bond market. This cost was strictly an estimate of the cost that would be charged to Newfoundland Hydro, which is the distribution company for power on the island of Newfoundland, and who issues bills to ratepayers. There was no intergenerational equity consideration in the structuring of that cost, nor for its subsequent escalation. (see http://www.pub.nf.ca/applications/MuskratFalls2011/files/mhi/MHI-Report-VolumeII-Cumulative.pdf, Section 12.4 Muskrat Falls PPA)

- Second, the comparison of Muskrat Falls costs was against the base case of continuance with the Holyrood 490 MW an inefficient oil-fired generating plant, life-extension costs to keep it operational past its current projected retirement point, and its required additional investment to meet Provincial environmental guidelines. This sets a high cost threshold against which to compare most other options, and as indicated above this leads to comparative cost/benefits that do not match the options provided by MH.

Manitoba Hydro – Wuskwatim

- The analysis provided by Manitoba Hydro was simply to consider an investment in Wuskwatim at one point in time, versus a later point in time. This is a common consideration in determining an optimal investment profile given current economic and cost/revenue assumptions for an already selected development program, but is entirely different than considering two mutually exclusive development plans like All Gas and the PDP. The cross-over point between development plans in the case of Wuskwatim was not a factor in the decision.

Based on the range of examples provided by MIPUG, it is evident that one cannot reasonably compare decisions made by different utilities, under different sets of development plan alternatives and decision contexts, and claim there is a 'common standard cross-over point'. Notably, none of examples reference 'cross-over' points based on the net present value of consumers revenue. In Manitoba Hydro's view, the information provided in MH/MIPUG I-3 does not form the basis for a standard and is not a reasonable benchmark for comparison.

In the 20 year time period, the All Gas Development Plan (1) ranks lowest, K19/Gas 250 (4) ranks closely to the All Gas Development Plan (1), and not surprisingly, the Preferred Development Plan (14) ranks highest with the highest capital cost in terms of both cumulative rates and present value of consumers revenues. By year 20 (2032), Keeyask has only been fully in-service for 11 years and Conawapa for four years under the Preferred Development Plan with little time for export benefits to accrue to Manitoba Hydro or its ratepayers. Despite this, the Preferred Development Plan (14) cumulative rates cross-over and are lower than the All Gas Development Plan (1) by 2035 under the reference scenario. The Keeyask/Gas/250 Development Plan (4) cumulative rates are lower than the All Gas Development Plan (1) by 2033. Achieving rate savings relative to other development plans in a much shorter period of time implies an extremely high rate of return to customers which is incongruent with the regular, reasonable contributions to retained earnings and very low rates of return Manitoba Hydro experiences given Manitoba Hydro's business mandate is to provide basic electrical needs and services to Manitobans at a reasonable cost.

11.2 Indicative Rate Increases Recover the Cost of the Entire Manitoba Hydro System

MIPUG states that, "None of the Plans start to become beneficial to ratepayers up to year 20 as compared to Plan 1(All Gas)…" [Pre-Filed Testimony of P. Bowman, Page 4-6].

All development plans result in rate increases in the range of 3.4% to 4.0% per year (reference scenario) in the 20 year time period. Contrary to LCA's presumption that, "[these rate increases] are those related solely to each development plan" [LCA Technical Appendix 10A – Financial Analysis, Page 10A-17], these rate increases reflect the revenues required to recover costs for the operations of the entire hydro-electric system.

Costs directly related to development plans are deferred until in-service (except for sunk costs discussed below) resulting in minimal impacts on rate increases in the 20 year time period. Even with the addition of development plans, the Manitoba Hydro electric system will be comprised predominantly of existing infrastructure for a significant period of time and the rate increases in this time period are due largely to investments in existing aging infrastructure and reliability.

If circumstances such as favourable water flows and sufficient cash flows are present in the latter part of the 20-year time period, Manitoba Hydro may have some flexibility to taper-off the projected even-annual rate increases but this would have the effect of extending the timeframe of achieving the 75:25 debt/equity ratio target. LCA provided sensitivity analysis in this regard [LCA Initial NFAT Report January 24, 2014, Page LCA-53]; however, LCA's rate impacts of advancing the target year are overstated, and understated by delaying the target year, due to the limitations of LCA's financial model which does not incorporate the compounding effects of changes to cash inflows/outflows or changes to debt. Manitoba Hydro calculates that delaying the target year to 2039-40 reduces the even-annual rate increase required to achieve the 75:25 target debt/equity ratio from 3.95% to 3.01% under the Preferred Development Plan (14) reference scenario (LCA evidence 2.54%). In such a situation, Manitoba Hydro must balance a prudent financial position with sensitivity to customers.

LCA further provides analysis that removes the impacts of sunk costs from the development plans in which Keeyask and/or Conawapa are discontinued. [LCA Initial NFAT Report January 24, 2014, Page LCA-30] Again, LCA overstates the reduction in rate increases related to the sunk cost impact due to the LCA financial model not incorporating the compounding effects of the lower cash inflows. Manitoba Hydro projects that the even-annual rate increases for the All Gas Development Plan (1) would be 3.25% (LCA evidence 3.05%) compared to 3.43% with sunk costs included. LCA suggests, "*This type of analysis provides an approximation to an analysis that assumes no cost recovery for costs incurred related to the hydro facilities and is not intended to make any determination regarding the actual outcomes of future general rate applications.*" [LCA Initial NFAT Report January 24, 2014, Page LCA-31] However, it is important to note that, in the event that sunk costs are deemed to provide no future benefit and must be written-off by the corporation, no cost recovery from ratepayers only serves to weaken Manitoba Hydro's financial position, the impacts of which are ultimately borne by ratepayers. MPA provides support for this view, "*For ratepayers, this amounts to an incremental debt burden which must be retired, without any compensating benefits (in the other plans, since the facilities are actually built the sunk costs are an investment with associated benefits, as opposed to a loss to be written off). This fact is inescapable, because real dollars have been spent and must be recovered from ratepayers*." [MPA

Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case, Page 40]

Finally, Manitobans benefit from the lowest total average cost of electricity and among the lowest applied and proposed rate increases compared to other jurisdictions in Canada as shown below. The current low rates are the results of benefits derived from Manitoba Hydro's generation infrastructure investments made in the 60s, 70s and 80s.

Utility Rate Changes

	2006	2007	2008	2009	2010	2011	2012	2013	2014	Cumulative	Current Rate Index*
Manitoba Hydro	0.00%	2.30%	5.00%	2.90%	2.80%	2.00%	4.40%	3.50%	3.95% (proposed)	30.10%	100
BC Hydro	1.50%	2.10%	0.80%	9.30%	7.30%	7.80%	7.10%	1.40%	9.00%	56.30%	118
Hydro Quebec	5.30%	1.90%	2.90%	1.20%	0.40%	-0.40%	-0.50%	2.40%	5.8% (proposed)	20.40%	101
NB Power	6.90%	5.90%	3.00%	3.00%	3.00%	0.00%	0.00%	2.00%	0.00%	26.20%	187
Nova Scotia Power	8.70%	3.80%	0.00%	9.30%	0.00%	6.10%	8.70%	3.00%	3.00%	50.80%	207
SaskPower	4.90%	4.20%	0.00%	8.50%	4.50%	0.00%	0.00%	4.90%	5.5% (interim)	37.20%	158

* This index compares the average price per kWh for the various utilities, and it is based on the Edison Electric Institute Survey. Manitoba Hydro's average price is $0.623/kWh. The Survey is based on data ending June 2013.

Manitoba Hydro is not the only utility that will be facing costs pressures associated with investments in new generation, transmission and distribution infrastructure to meet growing demand, as well as investments in aging infrastructure. Other electric utilities across Canada are facing similar cost pressures driving their rate increases, as evidenced by the higher than inflation rate increases being proposed in 2014 and beyond.

For example, the British Columbia government has announced that electricity rates for BC Hydro will increase by 9.0% in 2014 and 6.0% in 2015. The rate increases for 2016, 2017 and 2018 have been capped by the BC government at 4%, 3.5% and 3.0% respectively.

The Saskatchewan Rates Review Panel is currently reviewing proposed increases for SaskPower of 5.5% for 2014, and 5.0% in each of 2015 and 2016.

Nova Scotia Power's rates increased by 3% in each of 2013 and 2014 as part of a rate stabilization plan to defer the recovery costs associated with load reductions to future years. In absence of a rate stabilization plan, the rate increases would have been 7.2% in 2013 and 2.8% in 2014. The cost increases of 2.8% in 2014 are mainly attributable to increased fuel costs, and increased capital investments in the distribution and transmission system to improve reliability and prepare the system to receive intermittent renewable energy. In addition, the Nova Scotia Utility and Review Board has approved an increase to the 2014 Demand Side Management Cost Recovery Rider which will result in overall rate increases ranging from 3.5% to 4.6% when combined with the 3% general rate increase depending on the rate class.

Hydro Quebec is proposing a rate increase of 3.4% for 2014, which, when incorporated with a proposed increase to their rate of return, will result in an overall average increase of approximately 5.8% in 2014.

Manitoba Hydro's current ratepayers will continue to benefit into the future from the low cost past long-term investments in addition to the future long-term investments proposed by the Corporation.

11.3 Manitoba Hydro's Findings on Rate Impacts Provides a Balanced View for All Ratepayers

MPA states that, "*Minimizing risk-adjusted cost over time is the primary interest of ratepayers, after the maintenance of a safe and reliable electricity system.*" [MPA Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case, Page 38] Based on their present value analysis of ratepayer costs, MPA and LCA conclude that there is no clear distinction between the development plans from a ratepayer perspective. [MPA Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case, Page 40 and LCA Initial NFAT Report January 24, 2014, Page LCA-62] MPA further concludes that, "*…there is an apparent difference in intergenerational treatment between the Resource Plans,*" and "*…a strong opinion on the time value of money can have an almost deterministic effect on the choice of Plans from a Ratepayer perspective.*" [MPA Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case, Page 71] MPA, LCA and MIPUG each conduct their own present value analysis utilizing similar discount rates which exceed that used by Manitoba Hydro in its present value analysis of consumers' revenue and consider the present value analysis at different points in time.

It is Manitoba Hydro's view that the analysis and findings presented in Chapter 11 and PUB/MH I-149a provide a balanced view of the impacts to rates for all ratepayers, whether they are customers today, in the future, residential or general service customers.

LCA, MPA and MIPUG rely heavily on the present value of consumers' revenue to support their conclusions. This analysis provides information about the relative value of future rate changes to customers today. While this is an important consideration, it is one of a number of important factors to consider. First and foremost, Manitoba Hydro's mandate is to provide for a safe and reliable source of energy to Manitobans. Manitoba is a province rich in water resources and Manitoba Hydro has leveraged that advantage very successfully in its past investments in resource developments. This business model of investing in hydro resources is anticipated to continue to be successful for future decisions. In Manitoba Hydro's view, the decision regarding how best to meet the energy needs of the province is a long-term infrastructure decision affecting multiple future generations.

Manitoba Hydro carefully considered the appropriate discount rate to apply in its present value analysis of consumers' revenue based the principle of equity across generations. The economic literature supporting the application of an inter-generational discount rate is well-established. For example, The US Environmental Protection Agency's Guidelines for Preparing Economic Analysis[142] document discusses the current state of research in establishing the appropriate discount rate, and specifically addresses the topic of equal treatment across generations. In the final section of Chapter 6, Recommendations and Guidelines, the EPA recommends for projects with a long time horizon – 50 years or greater – that "the analysis should use the consumption rate of interest as well as … calculating the expected present value of net benefits using an estimated time-declining schedule of discount factors." They clarify further "that the after-tax returns on savings instruments generally available to the public will provide a reasonable estimate of the consumption rate of interest."

As MPA indicates, the choice in development plan is an investment in infrastructure with permanence at a relatively low cost of borrowing which is not dissimilar to governments. [MPA Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case, Page 64] This is consistent with the rationale for applying intergenerational discount rates for projects with benefits extending 50 to 100 years. Zerbe and Allen provide further supportive recommendations regarding the appropriate range of discount factors as follows[143]:

[142] Chapter 6, Discounting Future Benefits and Costs, in http://yosemite.epa.gov/ee/epa/eed.nsf/pages/guidelines.html

[143] A Primer for Benefit-Cost Analysis, Zerbe, Richard O. Jr. and Allen S. Bellas, Edward Elgar Publishing Ltd, Northampton, Mass. USA, 2006, page 251.

- The Social Rate of Time Preference should be used to calculate the discount rate, and is reasonably approximated to be the after-tax yield on government bonds for the project in question.
- For project time periods from 50 to 100 years, the suggested real discount rate should be 1%-2.5%

In reference to both these sources, Hydro's calculated real discount rate of 1.86% on additional revenue requirements conforms closely to the economic literature on estimating the appropriate rate. The 1.86% rate, which is the estimated real return on treasury bills, is arguably conservative as a discount rate, as it is not adjusted for income taxes. Instead of applying a declining discount rate, which by current economic research is appropriate for long-life projects, Hydro chose to use a single discount rate that is calculated in the recommended manner. And, the calculated value is approximately in the middle of the recommended range for a development plans having benefits extending over 100 years.

The concept of an inter-generational discount rate is implicitly accepted by MPA and MIPUG, however they suggest that it is not appropriately applied to all customer classes. In applying a higher discount rate as LCA, MPA and MIPUG have done in their analysis, they have given greater weighting to development plans with lower rates early in the study period on the basis that industrial and commercial customers, who are generally shorter-term in focus, have higher required rates of return. While these customers view this as an opportunity cost, they are not making an investment decision among various alternatives. The economic literature including the material referenced above does not suggest it would be appropriate to segment society at large into distinct segments having different opportunity costs. The same treatment is applied by economists to any long-lived public infrastructure project which serves all members of society broadly, such as wastewater treatment systems, a flood protection scheme, or a publicly owned 100-year power plant. Manitoba Hydro is recovering a portion of fixed costs for a basic need and service that is reliably available to all customers over the long term. It is recognized and understood in making the investment in the Preferred Development Plan that the returns will accrue over a long period of time and that they will be lower than what is required by a private entity. Given that customers today benefit from rates that are lower than many other jurisdictions, it is Manitoba Hydro's view that heavier weightings to lower early rates in the present value analysis of consumers revenue is a disservice to the future benefits that ratepayers as a whole may receive and violates the principle of inter-generational equity that the corporation strives to achieve.

A second factor considered in the selection of an appropriate discount rate for the purposes of the present value analysis of consumers' revenue is that the revenue being discounted already includes the cost of debt and equity, as well as risk adjustments to the underlying assumptions. Manitoba Hydro's financial projections model the impacts of capital expenditures including the incremental interest costs associated with incremental debt required to finance the capital expenditures, the depreciation over the full life of the project's assets, and any additional revenue required to make moderate annual contributions to retained earnings and meet corporate targets for debt/equity ratio and interest coverage. The WACC, which in the economic resource planning analysis is used to incorporate the cost of capital is not appropriate to use as a discount rate in the present value analysis of consumers revenue, because the incremental revenue requirement already includes a cost of debt component (interest on incremental debt) and an equity component (incremental equity required to achieve the target equity balance on the Balance Sheet). Since these costs have already been factored into the values to be discounted, it is not appropriate that the same costs be again reflected in the discount rate. Similarly, the analysis includes the rate impacts and additional revenue requirements under 27 different uncertainty scenarios. Since uncertainty has been considered in the underlying assumptions of the 27 scenarios, it is not appropriate to reflect the same uncertainty in a risk-adjusted discount rate.

Manitoba Hydro's present value analysis presented in the response to PUB/MH I-149(a), shows that the Preferred Development Plan has a lower cumulative present value of consumer revenue compared to the All Gas Development Plan at all cumulative probability values and the lowest cumulative present value compared to all other development plans up to about the 90% probability value. Additionally, Manitoba Hydro provided a sensitivity analysis on the rank order of the development plans across a range of discount rates in Figure 11.13 in the same response. This analysis showed that the Preferred Development Plan results in lower cumulative consumers' revenue on a present value basis at real discount rates up to approximately 4.15% (6.16% nominal) under the reference scenario. Further, as MPA points out, the present value analysis is somewhat prematurely truncated at the end of the 50-year study period. If the analysis is extended beyond 50 years, development plans which include Conawapa will tend to show even lower cumulative present values at lower discount rates. Based on the justification of the discount rate, the sensitivity analysis, and the conservative nature of the 50-year present value analysis, it is Manitoba Hydro's view that the findings on the present value of consumers revenue presented in Chapter 11 of Manitoba Hydro's NFAT submission and the response to PUB/MH I-149(a) are a fair representation of rate impacts on all ratepayers, current and future.

Finally, the cumulative rate analysis presented in Chapter 11 of Manitoba Hydro's NFAT submission provides information about the rates charged to customers relative to other development plans at different future points in time; in other words, the relative cost to customers of the day. MPA acknowledges that the Preferred Development Plan (14) results in lower cumulative rates compared to the All Gas Development Plan (1) [MPA Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case, Page 44]; however, LCA and MIPUG essentially ignore the cumulative rate comparisons. LCA does provide monthly bill comparisons in nominal dollars but focuses on the increases in bills relative to today rather than between development plans at different points in the future. The cumulative rate comparison findings presented in Chapter 11 of Manitoba Hydro's NFAT submission clearly demonstrate that the Preferred Development Plan (14) results in lower customer rates in the long-term and fairly represent the rate impacts to ratepayers of the day.

12.0 SUSTAINABILITY

This section of Rebuttal Evidence was prepared in collaboration with Mr. Norman Brandson, N2B Consultancy, Winnipeg, MB.

Gaudreau and Gibson, in their Sustainability Assessment Framework Paper (hereinafter referred to as the SAFP) dated February 3, 2014, assert that their framework for a sustainability assessment "integrates and specifies the requirements of the Manitoba *Sustainable Development Act* (1998)"[144] (p. 1). This rebuttal provides information about the development and intent of this Act.

Language is very carefully chosen in the drafting of legislation. Concerning the substantive subject areas of sustainable development the provincial *Sustainable Development Act* (the Act) – passed by one government and endorsed by its successor – the language of the Act is uniformly permissive, not prescriptive, and uses adjectives that are intended to allow for flexibility in interpreting if and how the principles and guidelines are applied to individual projects. Examples from the *Principles* and *Guidelines* contained in the Act include:

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[144] Gaudreau, K. and Gibson, R. (2014). *Framework for Sustainability-based Assessment for the Public Utilities Board's Need For and Alternatives To (NFAT).* Prepared for the Consumers Association of Canada (Manitoba Branch).

- Economic decisions should adequately reflect environmental, human health and social effects. [*Principles 1(1)*]
- Environmental and health initiatives should adequately take into account economic, human health and social consequences. [*Principles 1(2)*]
- Manitobans should (a) maintain ecological processes … (b) harvest renewable resources on a sustainable yield basis (c) make wise and efficient use of renewable and non-renewable resources [*principles 5*]
- **Efficient use of Resources** – which means (a) encouraging and facilitating development and application of systems for proper resource pricing … [*Guidelines 1(a)*]
- **Public Participation –** which means (a) establishing forums which encourage and provide opportunity … [*Guidelines 2(a)*]
- **Access to Information** – which means (a) encouraging and facilitating the improvement and refinement of economic, environmental, human health and social information [*Guidelines 3(a)*]
- **Integrated Decision Making and Planning** – which means encouraging and facilitating decision making and planning processes that are efficient, timely, accountable and cross-sectoral … [*Guidelines 4*]

The substance of what the government of Manitoba considers to be at the heart of sustainable development is clearly intended to be flexibly applied, and directional, not prescriptive. Nowhere do the words *must* or *shall* appear in the *Principles* or *Guidelines.* Whenever these words are used in the Act they apply to administrative rather than substantive measures. The words *Principles* and *Guidelines* themselves connote an approach that is far more discretionary than command and control. This distinction between prescriptive and permissive is a critical issue in the drafting of legislation. To suggest that the Legislature of Manitoba intended to imply that sustainable development be implemented through the application of prescriptive criteria, but inadvertently neglected to mention it in the legislation, while never sanctioning a process to develop such criteria, completely ignores how legislation in general is, and *The Sustainable Development Act* in particular, was developed.

The New Democratic government of Premier Pawley embraced the concept of sustainable development when it accepted the 1987 report of the Canadian Council of Resource and

Environment Ministers (CCREM) Task Force on Environment and Economy[145] and proceeded to implement its recommendations. This included the passage of the *Manitoba Environment Act*. In May of 1988 this government was succeeded by the Conservative administration of Premier Filmon. The Filmon government not only confirmed the province's commitment to sustainable development but identified it as a flagship initiative. A Sustainable Development Coordination Unit was established as a central agency of government. The Manitoba Round Table on Environment and Economy[146] was directed to manage a highly public process to develop sectoral sustainable development strategies for Manitoba.[147] The Sustainable Development Unit also developed a White Paper on the possible content of sustainable development legislation. The Legislature ultimately adopted a *Sustainable Development Act* in 1997, the substance of which remains in today's Act. The fact that government, while enthusiastically embracing the concepts of sustainable development, has had considerable difficulty in articulating how to implement its concepts, is evidenced by the flexible approach taken in the legislation, and by the launch of the Consultation on Sustainable Development Implementation (COSDI) to further examine the question in 1997[148]. The Filmon Government was replaced by the New Democratic Government of Premier Doer in October 1999. The Doer administration acknowledged the COSDI report and accepted in concept the nested planning scheme recommended by COSDI, which resulted in the East Side Planning Initiative as Manitoba's first Wide Area Plan. But the government did not pursue any of the recommendations relating to the development of more specific sustainable development evaluation criteria. A further review of *The Environment Act* in 2002-2003 offered yet another opportunity for discussion of more concrete criteria for sustainability to be built into that legislation. Again government declined to pursue such a course and retained the discretionary language contained in *The Sustainable Development Act*.

The Manitoba Law Reform Commission recently initiated a public review of Manitoba's Environmental Assessment and Licensing Regime[149]. In the Commission's consultation

[145] *Report of the National Task Force on Environment and Economy* submitted to the Canadian Council of Resource and Environment Ministers – September 24, 1987

[146] The National Task Force had recommended that "Round Tables on environment and economy" (the phrase "environment & economy" was eventually replaced by "sustainable development") of opinion leaders be established in every province and territory and by the federal government. All jurisdictions established these but today almost all have either been eliminated or fallen into disuse.

[147] The Task Force Report recommended all jurisdictions prepare a "Conservation Strategy"; Manitoba's component strategies included Land & Water (Water, Soil, Forests), Capital Region, Waste Minimization and Minerals.

[148] Report on the Consultation on Sustainable Development Implementation (June, 1999)

[149] Discussion Paper: Manitoba's Environmental Assessment and Licensing Regime – Manitoba Law Reform Commission (January 2014)

prior to preparation of a discussion paper the topic of sustainability assessments was considered. The Commission stated its considered conclusion on this topic in its discussion paper:

In the Commission's view it is not yet possible to identify a best practice of sustainability assessment. Moreover, the adoption of a sustainability assessment framework would represent a significant policy choice, involving new forms of knowledge, different participants and a change in focus.

Finally, it should be noted that where government has determined that there is sufficient consensus to better define some of the broad concepts of sustainability, such as social equity and open, accessible and transparent decision-making, it has developed regulatory and policy instruments governing their application. Examples include the Province's Aboriginal training, employment and business development policies, and various regulatory requirements for access to information, and intervener funding. Manitoba's Clean Energy Strategy, which is explicitly included in the NFAT TOR, is another example of government defining its approach to sustainability in the energy sector.

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

NEEDS FOR AND ALTERNATIVES TO

REVIEW OF MANITOBA HYDRO'S

PREFERRED DEVELOPMENT PLAN

Regis Gosselin - Chairperson

Marilyn Kapitany - Board Member

Larry Soldier - Board Member

Richard Bel - Board Member

Hugh Grant - Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

April 1, 2014

Pages 4601 to 4747

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Jessica Saunders	(np)	)MMF
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Christian Monnin		)IEC
Michael Weinstein	(np)	)

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LIST OF UNDERTAKINGS (Con't)

--- Upon commencing at 9:03 a.m.

THE CHAIRPERSON: Good morning. I hope everybody had a good evening last night. I believe we're ready to commence today's proceedings. And unless there are matters to attend to I will turn the microphone over to Ms. Ramage. Thank you, Ms. Ramage.

IEC POTOMAC ECONOMICS PANEL RESUMED:

ROBERT SINCLAIR, Previously Affirmed (Qual.)

CONTINUED CROSS-EXAMINATION BY MS. PATTI RAMAGE:

MS. PATTI RAMAGE: Thank you. And I just have a -- just three (3) topics that hopefully we can burn through fairly quickly. One (1) -- the first deals with expanding market access, and I think there was a discussion, I believe with the chairman, about whether building a line would expand Manitoba Hydro's market.

And to follow up on there -- on that topic, are you aware that it's part of the Preferred Development Plan which includes the 750 megawatt line, that Maniti -- Manitoba Hydro also has 700 megawatts of firm MISO point-to-point transmission service request sinking into Wisconsin?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: And, so we're all working from the same page, can you clarify for the panel exactly what transmission service request is?

DR. ROBERT SINCLAIR: Transmission service request is sort of self-explanatory. It's a request for transmission on -- on the MISO network.

MS. PATTI RAMAGE: And would I be correct that a transmission service request is -- is something Manitoba Hydro would have this -- at this stage in the Development Plan, but that would be converted to a transmission service reservation once we actually have a line built?

DR. ROBERT SINCLAIR: Yes. Provided that line provides the adequate capacity associated with the request, yes.

MS. PATTI RAMAGE: And with the transmission service reservation, it's essentially yours to your -- yours to use, and at that point you would have the associated financial transmission rights and option revenue rights?

DR. ROBERT SINCLAIR: Correct.

MS. PATTI RAMAGE: Would you agree then that these firm MISO TSRs, they're referred to --

the firm MISO TSRs serve to increase Manitoba Hydro's market access for bilateral transactions for capacity and dependable energy?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: Effectively it increases the number of customers we have access to, and thus a larger market.

DR. ROBERT SINCLAIR: Yeah, it can get more megawatts into the market.

MS. PATTI RAMAGE: Yeah. And that should tend to provide Manitoba Hydro with higher prices because at that point we're now getting the Wisconsin price, not the Manitoba node?

(BRIEF PAUSE)

DR. ROBERT SINCLAIR: So if you go straight to -- yes, if you go straight to Wisconsin then you bypass the congestion between Manitoba and the Minnesota Hub.

MS. PATTI RAMAGE: Yeah, I think we're in agreement there?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: Put that one aside.

THE CHAIRPERSON: I do have some

questions of clarification, though. In terms of the passage from a transmission service request to a transmission service reservation, is it automatic? In other words, if you -- assuming a line is built, is it necessary automatic that the -- one (1) follows the other?

DR. ROBERT SINCLAIR: Pretty much. As long as -- as long as the line provides the capacity that's in the request, MISO would do a study. But I think in this case it's rather straightforward; the line is -- has lots of capacity on it, so I think pretty much it goes from the request to the reservation.

THE CHAIRPERSON: So here's no queueing mechanism where some other transmission provider wants to build a line, a similar line? There's no -- there's no competition? There's no...

DR. ROBERT SINCLAIR: Correct. Just -- if you're building a line you get the -- you get the access rights to it.

CONTINUED BY MS. PATTI RAMAGE:

MS. PATTI RAMAGE: Next, if I could have you turn to slide 31 of your presentation. And I just want to clean up a little bit on the -- on the discussion we had regarding the advanced CT. You noted in that -- in your first sub-bullet that you used the capital cost of an advanced CT from the EIA to determine the value of capacity, and I want to follow-up on -- on what an advanced CT is.

And would you agree it reflects improvement in fuel efficiency?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: In technical terms, it uses the lower heat rate?

DR. ROBERT SINCLAIR: Yes. And a lower capital cost I think was the most -- the most impressive factor.

MS. PATTI RAMAGE: Perfect. That was my next question. And does the number -- in terms of capital cost, the EIA suggests -- I think the overnight capital cost is nine hundred and seventy-three ($973) per kilowatt for a conventional CT versus six hundred and seventy-six (676) per kilowatt for an advanced CT.

Does that sound correct?

DR. ROBERT SINCLAIR: Correct. Yes.

MS. PATTI RAMAGE: So it's a 30 percent difference. Similarly, it's a 30 percent difference on the operating costs of the advanced --

the advanced does 30 percent better than the conventional.

Would that be correct?

DR. ROBERT SINCLAIR: I -- I can't recall. Subject to check, though, I'll agree.

MS. PATTI RAMAGE: Now, when the EIE -- EIA publishes these results, you're familiar that they classify the various technologies as revolutionary, evolutionary, and mature?

DR. ROBERT SINCLAIR: I think I remember seeing something like that.

MS. PATTI RAMAGE: And then would you accept, subject to check, that the advanced CT is classified as an evolutionary technology?

DR. ROBERT SINCLAIR: Subject to check.

MS. PATTI RAMAGE: Whereas the conventional CT is classified as a mature technology?

DR. ROBERT SINCLAIR: I think that's right.

MS. PATTI RAMAGE: So your slide at page 31, it -- it seeks to capture three (3) market risks you identified on realizing the expected capacity value in your forecast.

Oh, I'm sorry, I'm on just slide 33.

If we could turn to slide 33. And there it capture -- you identify the -- the market risks on realizing expected capacity value.

And num -- point number 2 in particular addresses technology improvement that could reduce the cost of new generation, correct?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: So as your model is already using an advanced CT that uses 30 percent lower capital and 30 percent variable O& -- O&M costs, the -- that 30 percent less than a conventional CT and it's classified as still evolutionary, would you say your approach inherently captures some of that technology development risk?

DR. ROBERT SINCLAIR: I think some of it, yes.

MS. PATTI RAMAGE: And -- and lastly, just for clarification, in your evidence you suggested the panel reject the forecast of Manitoba Hydro's six (6) independent forecasters, and instead adopt your forecast for the purposes of evaluating the Preferred Development Plan. And I want to make sure I understand your basis for saying this.

So if I understand correctly, what I interpreted you as saying is that, based on your re --

your review of the price consultant information that had been provided to Manitoba Hydro and thereafter provided to do -- to you, you don't feel you're in a position to say there is something -- you're not in a position to say there's something fundamentally wrong with that -- with those forecasts. Rather, you're of the view you're not in a position to endorse them.

Would that be a fair summary of the problem?

DR. ROBERT SINCLAIR: I think it's a combination. On -- on the one (1) hand we see -- we see some of the outputs of the model that do not -- are not consistent with what we see in the marketplace. We weren't able to get into the data in the models enough to understand why those results come about.

So on the one (1) hand we -- we suspect there's -- there's some distortion, or inaccuracies, but we can't get into the models to verify.

(BRIEF PAUSE)

MS. PATTI RAMAGE: I think, Mr. Chair -- thank you, Dr. Sinclair. I think that is all of Manitoba Hydro's questions.

THE CHAIRPERSON: Dr. Sinclair, I guess a question I have is in relation to the methodology used in determining future prices. And it's -- it's somewhat related to the question that has just been asked by Manitoba Hydro. Specifically, I'm wondering about whether you have done any retro -- retrospective testing of the method -- your methodology relative to its predictability based on the data that is already available?

In other words, have you gone back and checked your methodology against what actually occurred during the -- the following period?

DR. ROBERT SINCLAIR: So, for example, whether we had taken our model and tried to predict what we've seen in -- for instance, 2013 -- actually, we did -- we have not. Although, we would expect that because 2013 is very close to 2012 that predictions wouldn't be very good. But we -- we didn't -- we didn't take the data.

THE CHAIRPERSON: No, I meant so much -- not so much that, but using the meth -- the same methodology, for example, to look at, for example, 2011 prices; it's ability to -- you know, after the fact go back and check the -- the methodology against the actual data from the marketplace --

DR. ROBERT SINCLAIR: M-hm.

THE CHAIRPERSON: -- to verify if it was pre -- it would have pre -- you know, a high predictive value?

DR. ROBERT SINCLAIR: That's a definitely interesting proposition, but we did not do it. It is possible to go back to say 2008, or a year earlier, or some years earlier to set up the -- the various actual market characteristics and then try to make the prediction. It's possible.

THE CHAIRPERSON: It -- it is possible, but I -- I guess you haven't had the opportunity to do that. Is that -- I mean, it would, sort of, in my mind, it would confirm to some extent the adequacy of the model when examining prices going forward, wouldn't it, to some extent?

DR. ROBERT SINCLAIR: I do agree with you, but we didn't do it. Yeah.

We could consider doing it. It may be something that may not require lots of resources.

THE CHAIRPERSON: Now, I guess I'm looking at your report, page 37, and the conversation we had around the -- the fact that the CT -- I'm looking at -- at the paragraph just before the cost of new entry. And specifically there that you -- you indicated that your analysis indicates that for -- forward prices all result in the CT being the most economical addition for capacity having the lowest -- and I'm wondering, given that statement, why would anybody ever build the CCCT turbine if -- if it is more expensive than a -- than a -- you know, at some point I'm trying to understand the tactical thinking of a company that would build a CCCT given what you've just said in this statement.

DR. ROBERT SINCLAIR: Okay. I'm glad you asked that, because I was thinking about that last night and I thought there may have been a misunderstanding about some of the -- some of the statements we make.

And so when we say that the most economical way to add capacity is a CT, we don't mean that, Oh, additional capacity should be a CT. What we mean is the price for the capacity portion of any new project that is going to satisfy capacity need should be based on the cost of a CT. So it's -- I think it's perfectly fine that companies buy hydro capacity for long-term capacity needs.

What we're saying is that if Manitoba, for instance -- Manitoba Hydro, for instance, goes into the market to sell capacity that they may be able to -- that the capacity component of that sale would be set by the cost of a CT.

And there may be other reasons why a utility may be buying new capacity. They may want a different mix of capacity. They may want to lower their overall energy costs. So they may contract with a hydro supplier to add capacity to their system.

But what we mean by CT is that the capacity payment that that resource should receive should be based on the cost of a CT. It very well may be that the -- the capacity itself is much more expensive than a CT, but there may be reasons a utility may want to buy the more capital-intensive resource, for instance, to lower their overall energy costs. But just to serve capacity, if a utility was just interested in serving capacity they would buy a CT, and that's the capacity compo -- price component that the market would be willing to pay.

THE CHAIRPERSON: One (1) of -- one (1) of the -- the base plan for Manitoba Hydro involves the construction of a successive series of CT generators, and the question that the panel has been asking itself is: Why wouldn't you -- instead of building a succession of CTs, why wouldn't you build a -- a lower cost over time CCCT generator?

DR. ROBERT SINCLAIR: M-hm.

THE CHAIRPERSON: And your -- your analysis suggests that that the -- the behaviour or the decision to build successful -- a successive series of CTs is the right decision, but -- but there were some context where building the more -- the more capital-intensive turbine would make sense, wouldn't it?

DR. ROBERT SINCLAIR: For sure. And the -- they hydro -- Manitoba Hydro plan involves meeting incremental capacity needs and some -- also some energy needs. And so -- and there's also -- part of the plan, as I explained yesterday, was to support some export sales. So Manitoba Hydro is not just focussed on adding, you know, 10 megawatts or a thousand megawatts of capacity; they're also interested in meeting some long-term energy needs, and also they have some plans to make export sales.

So it mak -- could -- could make sense and it's -- that's the evaluation we're doing here, to invest in highly capital-intensive investments that will not just meet your capacity needs, which could be met by a CT, but also longer-term needs for energy and also plans to make export sales.

So when we said -- when we talk about

the CT, we're really meaning what's the least cost way of meeting 10 megawatts of extra capacity on a system, if that's all your consideration was. And really, if a -- if a utility just wants to buy capacity, they're short on capacity, and they're -- they're happy with the rest of the mix, they're happy with their marketing situation, then they would just buy a CT.

But certainly you see CCCTs and coal plants being everywhere, so it's not just the only decision that a utility would make.

MS. MARILYN KAPITANY: So, Dr. Sinclair, this is on a -- a completely different subject and something that puzzled me yesterday. In the transcript Ms. Ramage asked you:

"Does it surprise you that parties might see you as a competitor in the business would not provide you unfettered access to their proprietary models and underlying methodologies?"

And you said:

"It's right they should protect themselves. I think there could have been ways to provide the necessary data and underlying processes to help

us better understand and perhaps
develop sensitivities that we
needed."

Could you give some concrete examples of that. And could you maybe elaborate a bit on how you've seen CSI handled in other processes in which you've been involved.

DR. ROBERT SINCLAIR: Okay. I -- I've actually thought about that question too overnight.

So I think what would have been an approach that could have been taken in this case could have been that there could have been some discussions with each of the individual companies' consultants. Perhaps, set up some kind of technical conference, and perhaps make those consultants available for not just explaining how everything in their model works but also providing us maybe some sensitivities if we were to ask them to run some alternative cases. And -- so actually just more information. Perhaps, talking directly to the consultants themselves.

In past -- in past cases, the -- the discovery would -- would have enabled us to do just that; get enough information from the consultants. And also this information would have been available to the panel staff as -- and that would have been protected sort of CSI agreements; that we would not be able to use the information; we would not be able to use the underlying intellectual property. And we protect it like we do the CSI in this case.

Now, I can remember a case we had with another client where some of the -- actually one (1) of the experts that's used by Manitoba, we actually ran into another case where they were providing some services to a utility, and we were monitoring. And we worked very closely with them. They provided -- they were very forthcoming as far as what their model does, how their model works. They -- the would provide us with various calculations, various sensitivities.

So we do have experience working with these companies and opening up their intellectual property for us to understand what's going on.

(BRIEF PAUSE)

DR. ROBERT SINCLAIR: Now, probably in -- in defence of Manitoba Hydro, we did have a short time frame, so it may have -- if we hadn't gone down the road of setting up technical conferences to -- to really dig into these, we -- we may have run out of time. So in part we sort of cut -- we sort of cut that path short and said, you know, We -- if we go down that path we may not get what we want, and it may take too long. So we just went ahead and -- and said, Okay, let's -- let's do our own forecast at this point.

THE CHAIRPERSON: In your experience, Dr. Sinclair, is the approach used by Manitoba Hydro to forecast prices, namely securing price estimates from various forecasters and generating a value, is that consistent with what the -- approaches that are being used by other generators in North America?

DR. ROBERT SINCLAIR: We -- yes, we have seen other generators using forecasters like this to support their expansion plans.

THE CHAIRPERSON: Can you give us an idea of what others are using if they're not using the approach that's used by Manitoba Hydro?

DR. ROBERT SINCLAIR: What I said was that, yeah, we do see the other -- the other clients we've worked with, we do see them using consultants to provide price forecasts.

THE CHAIRPERSON: But -- I'm sorry, I'm wondering in some cases where clients are not using this approach, what are they using? What are they --

DR. ROBERT SINCLAIR: Oh, okay. Let's see. So I'm trying to think of some examples. You can -- sometimes there are some -- yeah, I -- I can't really think of -- I'm thinking of the client we had when they were doing power supply procurement which is the closest to what Manitoba Hydro is doing right now, and they used a price forecaster.

But I can't think of any -- I'd have to think some more about what some other people have done. I -- I can't answer that right now.

THE CHAIRPERSON: Coming back to the methodology you used to project prices into the future, are you actually using that technology right now in your market monitoring, in terms of the operation of MISO?

DR. ROBERT SINCLAIR: Yeah, we -- we sort of use components of it to do our market monitoring. For instance, the -- we oftentimes will take the supply curves, and adjust them for fuel prices, because we sometimes use those offer curves as -- for reference prices. If you remember yesterday, I discussed sometimes we have these processes where we have to compare the offers made by a participant to their marginal costs, and that changes with the fuel prices. So sometimes we'll have to make some projections on the supply curves in future periods when fuel prices change.

So that's one (1) component that we use.

THE CHAIRPERSON: And how far -- how far ahead do you go with those projections?

DR. ROBERT SINCLAIR: Typically for those we'll just go a year ahead or so. But we will do all -- we also have components of the capacity price estimates that we use on an ongoing basis, and those are typically a year ahead. But they -- but a long-run equilibrium in the capacity market doesn't have to go that far ahead. As you saw with -- our discussion yesterday, what -- what you need to know is the cost of entry and the net revenues, and you can project that into the future fairly consistently.

CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Good morning, Dr. Sinclair.

DR. ROBERT SINCLAIR: Good morning.

MR. BOB PETERS: I guess asking questions at the end of the list allows me to try to clean up some areas, so I'm not intending to duplicate what parties have done before me. And I'm also -- my questions are not designed to elicit commercially sensitive information to be put onto the public record.

You understand that, sir?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And if -- if, to give the panel a complete answer to your question, you believe you have to use CSI information, then I would just ask you to undertake to provide it through your counsel. And that could be provided in a way that still protects the CSI of the company.

DR. ROBERT SINCLAIR: Okay.

MR. BOB PETERS: In discussions you've even had this morning with the Chairman and others, and you also mention on slide 4 of your slide deck, that Potomac is the market monitor for the mid-continent ISO, amongst other ones, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: How long have -- has Potomac been the -- the independent market monitor for MISO?

DR. ROBERT SINCLAIR: Since 2003.

MR. BOB PETERS: And for the other wholesale electricity markets in New York, New England, and Texas?

DR. ROBERT SINCLAIR: New York and ISO New England, in about 2001. For Texas, I believe around 2006.

MR. BOB PETERS: You did touch on some of the areas in which the independent market monitor functions, but I -- I didn't get a good handle on the thrust of the independent market monitor's work.

Can you explain that further to the panel, please?

DR. ROBERT SINCLAIR: Okay. The -- when the RTOs form and like MISO, when MISO formed, the Federal Energy Regulatory Commission required them to have a market monitor; partly just because some of the market failures that occurred in California, if you recall, in 2000, 2001. And the idea was that if you -- if the RTO wants to operate a market then there should be some way to make sure that the market is working, mitigating market power.

And so all the RTOs were required to have some kind of market monitoring unit. And some of them decided to get a market monitor independently contracted like MISO. MISO did that.

So our -- our job is really we are hired by the MISO, and also the other RTOs we work for, but we're independent, and there are certain guidelines that the Commission sets up for our independence. And we're not allowed to be removed by the MISO. So there's not allowed to be pressure by the MISO or any RTO to have us removed without the Commission approving. So that establishes some degree of independence.

And so, really, the main responsibility of the market monitor is to make sure the markets work. And to do that we monitor participants, making sure that -- that their behaviour in the market is not causing inefficiencies or exercising market power. We also monitor the RTO itself, so to make sure that the operations of the RTO are not interfering with the market, such as -- by committing too much resources or putting lines out of service at the wrong time. And we also assist the RTO in developing market rules to make the market more efficient.

Now, in all these responsibilities we're required to, of course, look closely at the underlying data in the market to see what participants are doing, to see what the impact of the market is, and to work closely with the RTO in implementing changes to the market. And we also then report on a periodic basis about the state of the market.

MR. BOB PETERS: That report is an annual report on the state of the market?

DR. ROBERT SINCLAIR: We do annual reports on -- in each of the markets, but in some markets we do quarterly and also monthly reports. And also it could be special reports as issues -- special issues arise that may be inte -- to the interest of market participants.

MR. BOB PETERS: And when you talked to the Commission in your second last answer, Dr. Sinclair, you were referring to the FERC, or the Federal Energy Regulating Commission?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And how often do you detect market manipulation in your independent monitoring?

DR. ROBERT SINCLAIR: Well, we have some automated mitigation measures that can detect market manipulation and correct it right away. We oftentimes have referrals to FERC, the Commission, when we see a certain behaviour taking place. I don't have on -- at -- in my mind right now exactly how often that happens, but Dr. Patton later on may be able to give you more information on it. He tracks that more closely.

MR. BOB PETERS: Can you tell the panel what is Potomac's understanding as to why Potomac was chosen to be the independent market monitor for MISO?

DR. ROBERT SINCLAIR: I understood that the panel was interested in an expert that would understand the workings of the MISO market and what the potential -- the expectations of -- for prices and quantities in that market, and the potential for Manitoba Hydro to sell into that market.

MR. BOB PETERS: But I meant in terms of why Potomac was chosen by MISO to be the independent market monitor.

DR. ROBERT SINCLAIR: Oh, I thought you meant why the panel chose us. That's why the panel chose us, I think.

It -- we -- we had orig -- initially had some experience as monitors in New York and New England, so we alre -- already had some expertise in that area. And we had expertise in engineering and economics, and also some expertise in electricity markets.

MR. BOB PETERS: Was it a competitive process?

DR. ROBERT SINCLAIR: I believe they

interviewed more than just us, yes.

MR. BOB PETERS: In your assignment for this panel, did you review Hydro's forecasts of export revenues?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And -- and that was in addition to the forecast unit export prices?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And to -- to look at those forecasts of export revenues, I -- I wasn't clear in your answer to Mr. Williams yesterday whether you went back to 2009 in the integrated financial forecast and followed through on -- on that particular forecast as well as other ones?

DR. ROBERT SINCLAIR: We did review the forecast from 2009, but we did not evaluate it quantitatively. We don't have any results to say whether the forecast was in line with actual results or not.

MR. BOB PETERS: And I want to also clarify for the benefit of the panel, there's been evidence in this proceeding that Manitoba Hydro had a 2012 export price forecast.

And you're aware of that, are you?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And in the course of preparing for this NFAT application Hydro realized that the 2012 forecast may not be accurate, and they adjusted the 2012 export market price forecast.

You're aware of that?

DR. ROBERT SINCLAIR: That's correct. Yeah.

MR. BOB PETERS: And -- and subsequently, Hydro obtained a 2013 market price forecast, which was then different from the 2012 forecast and also different from the adjusted 2012 forecast that they had used.

You're aware of that as well?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And I -- I do think Mr. Rainkie put on the record the -- the percentages, but I don't know that that's germane at this point.

But in terms of the forecast, would the panel be correct in understanding that Potomac's review was primarily of the 2013 price forecast and that's the basis for your report?

DR. ROBERT SINCLAIR: That's correct.

MR. BOB PETERS: Now, you had talked to the Chairman this morning about retrospectively testing your methodology. And in terms of testing it in the near term going forward you'd expect that your methodology would track relatively closely, because of the -- the proximity in time in which it was done, correct?

DR. ROBERT SINCLAIR: That's correct.

MR. BOB PETERS: I didn't understand how you could use your methodology and test it in -- in years past, maybe the '08 or '09 or '10 years. Can you explain what -- what your understanding is as to how that would have to happen?

DR. ROBERT SINCLAIR: Yes. Well, we simply do backwards what I explained we did forward in the market; that is we'd have to remove capacity from the market. We'd have to use the -- probably lower gas prices. We'd have to use lower demand. So we simply would be adjusting the supply curve backwards instead of forward.

MR. BOB PETERS: Would it be adjusted based on knowns, or based on -- on what would be forecasts?

DR. ROBERT SINCLAIR: You know, we would put what -- what actually happened.

MR. BOB PETERS: So if you did what exactly happened, wouldn't it follow that it would be -- because it was based on -- on '12 and '13 materials, if you did go backwards it -- with what you know it would -- it would line up again? I'm not understanding the --

DR. ROBERT SINCLAIR: Yeah, I think it would line up pretty well, because we would just be using -- we would still be using 2011/2012 base supply curves, because that's the idea, we're using those base supply curves, but we would be adjusting it to see how it performed against the -- like a back cast, seeing how it performed.

MR. BOB PETERS: All right. So you'd be -- you'd be testing the 2011/'12 supply curves for what actually happened to see if it -- it would line up with the numbers that would be generated.

DR. ROBERT SINCLAIR: That's right, yeah.

MR. BOB PETERS: Okay. And you said that that may not take an inordinate amount of resources, is what under -- interpreted your answer?

DR. ROBERT SINCLAIR: Yeah, I think so. I'd have to check, but it's possible that we could run that without spilling a lot of blood, so to speak.

MR. BOB PETERS: Well, I wonder if -- I'll just ask you to -- to check into that, and undertake through your counsel to advise Mr. Monnin what resources and time frame would -- would be required to perform that back testing, and then we'll leave it to the panel to decide whether that's something that they want to pursue further. Would that be acceptable, sir?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: All right. Thank you.

--- UNDERTAKING NO. 81: Potomac to indicate the resources and the time frame that would be required to perform that back testing

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: We heard in your answers to, I believe almost all counsel, Mr. Williams, Mr. Hacault, and Ms. Ramage included, that your base forecasts had assumptions made by the Energy Information Agency, correct?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: Can you explain to this panel specifically what is the Energy Information

Agency?

DR. ROBERT SINCLAIR: Yes. The Energy Information Agency is an agency of the Department of Energy, and they -- I believe the were created sometime in the 1990s when energy was a high prof -- high profile subject in the US; around the world really.

And what the Energy Information Agency does is track all forms of energy used in the US: electricity, oil, natural gas markets. And they also produce a model that is intended to replicate the energy consumption in the United States. And they also make forecasts of energy consumption supply in the United States. And this includes electricity, natural gas, oil, transportation fuels, production of fuels; all -- all manner of energy market and supply issues.

And, so we were focussed, of course, just on the electricity sector, and just in the region of the MISO. So they do it all across the US, and in all sectors. And they -- they work to produce these long-term forecasts which are also integrated with each -- with one another. For instance, the gas markets are integrated with the electricity markets, the transportation fuels are integrated with the industrial sector, and the industrial sector is integrated with the gas and electricity sector. So they have an integrated model. So they're able to produce these forecasts of natural gas prices, retirements, changes in demand, and also to conduct sensitivities of those forecasts.

MR. BOB PETERS: How often do they do those forecasts, Dr. Sinclair?

DR. ROBERT SINCLAIR: They do major -- they do their annual energy outlook every year, and I do believe they update that outlook once a year.

MR. BOB PETERS: So in addition to the annual report there's a mid -- a mid-term update?

DR. ROBERT SINCLAIR: Yes. And, you know, I think the update varies other components of it from time to time --

MR. BOB PETERS: All right. And --

DR. ROBERT SINCLAIR: -- through other studies.

MR. BOB PETERS: -- can you explain to the Panel what you meant by integrating the forecasts. And I wasn't sure if you were trying to cover that in your answer.

But what is integrated into the electricity forecast?

DR. ROBERT SINCLAIR: So there -- there will be -- be some interest in forecasting electricity demand which will depend in part on the price of natural gas, because that determines not just how much electricity is -- costs to produce but also whether there is some shifting of demand between electricity, natural gas, as a result of prices. Also, transportation fuels will -- will affect overall cost of industrial production which then will impact demand for electricity. So it's integrated in that sense.

MR. BOB PETERS: From Potomac's experience, does the EIA have a forecast for the commencement date for CO2 prices?

DR. ROBERT SINCLAIR: EIA in the reference case assumes that CO2 prices will not be -- will not occur, but they do have some sensitivities where CO2 prices do come into play. And, in fact, when they do -- when they do a sensitivity on the CO2 price it comes into play I think in 2015.

MR. BOB PETERS: You say the reference case of EIA doesn't contain a CO2 component; and is that because there is currently no existing US legislation requiring CO2 tax or costs?

DR. ROBERT SINCLAIR: That's correct.

MR. BOB PETERS: But in terms of the sensitivities, those are the what-ifs if there was a -- a carbon cost. They've done it -- they have a -- GHG-10 sensitivity that -- that you're familiar with?

DR. ROBERT SINCLAIR: Yes, they have a greenhouse gas cost of ten dollars ($10) per tonne. And I believe that sensitivity starts in 2015. They also have one at twenty-five dollars ($25) and -- and higher, I think -- at twenty dollars ($20), I can't remember. But they have a couple of --

MR. BOB PETERS: A number of sensitivities? DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And can you explain to this panel what triggers the -- the commencement date of 2015 in the sensitivities?

DR. ROBERT SINCLAIR: I think -- you know, we didn't look into that why they start in 2015, but I think they did not want to speculate on when it would actually happen.

MR. BOB PETERS: On a -- a different topic, Dr. Sinclair, would the panel correctly understand Potomac's assumption that the historical net impacts into MISO continue at a relatively static level into the future for at least the twenty (20) year forecast period that you used?

DR. ROBERT SINCLAIR: Yeah. The net imports are -- are based on the 2011/2012 volumes, except that the -- we incorporate the Manitoba Hydro new imports from their Development Plan.

MR. BOB PETERS: So with the exception -- the -- sorry, let me rephrase that. The net imports into MISO are -- are continuing at a relatively static level with the exception of increases for Hydro's planned increased exports resulting from its Preferred Development Plan?

DR. ROBERT SINCLAIR: That's correct.

MR. BOB PETERS: And why is it reasonable for Potomac to assume that net exports, excluding the Manitoba Hydro exports, do not change?

DR. ROBERT SINCLAIR: We thought that was reasonable, because we had no basis for -- we did not see developments in neighbouring markets which would suggest that imports would increase one -- in one direction or the other, except that we knew that there may be some new hydro coming in from -- from Canada.

MR. BOB PETERS: I realized when I was asking that question that what we on this side of the border consider exports you refer to them as imports, so I -- I --

DR. ROBERT SINCLAIR: Yeah, I understood. Yeah.

MR. BOB PETERS: I'd like to turn, if I could, to page 49 of Potomac's public report which is marked as Exhibit Potomac 2.1.

And on page 49, that's on the screen in front of you, Dr. Sinclair, this is Potomac showing the panel what the capacity changes are over the -- forecast over the next twenty (20) years, correct?

DR. ROBERT SINCLAIR: That's correct.

MR. BOB PETERS: And if we look at the left-hand side of the chart, this represents the reference case that Potomac has developed, correct?

DR. ROBERT SINCLAIR: That's correct.

MR. BOB PETERS: Is that with or without carbon?

DR. ROBERT SINCLAIR: The reference case is -- it's the same with and without carbon.

MR. BOB PETERS: And the retirements are shown here as a cumulative retirement total?

DR. ROBERT SINCLAIR: Those are cumulative.

MR. BOB PETERS: And so if I look at this chart -- before I ask that, explain to the panel what the steam reference is.

Is that natural gas file -- fired boilers?

DR. ROBERT SINCLAIR: Yes, it'll be boilers. Natural gas fired boilers.

MR. BOB PETERS: Not coal fired?

DR. ROBERT SINCLAIR: Not coal. Coal would be separate.

MR. BOB PETERS: All right. And in discussions that we've heard about in terms of coal retirements, this view of the capacity changes in MISO from Potomac shows coal retirements somewhere between 4 and 5 gigawatts?

DR. ROBERT SINCLAIR: Yeah, I think it turns out to be closer to six (6). You see there's some additions there.

MR. BOB PETERS: I see. So when we take the lowest point we're -- when -- when we add in the -- the steam as well as the coal and -- and it looks like the CTs that are going to be retired, it -- it gets closest to -- closer to six (6), correct?

DR. ROBERT SINCLAIR: Yeah, that's correct.

MR. BOB PETERS: And -- and then if we look in the middle of the chart we see the low gas price case that Potomac has developed, correct?

DR. ROBERT SINCLAIR: That's correct.

MR. BOB PETERS: And in this particular case, can you explain to the panel why the retirements of coal cumulatively are -- are greater?

DR. ROBERT SINCLAIR: Yes, because it -- when you have lower gas prices the -- the least -- the -- the less efficient coal plants become less profitable and they would go into retirement, because the gas is cheaper to run for base load.

MR. BOB PETERS: And so what you're showing here is, there's more coal retirements, but then there's also likewise more combustion turbines added on?

DR. ROBERT SINCLAIR: That's correct, yeah. And by the way that -- the black line that goes through all of this it would be the net of all capacity. So you'll see it first in the -- in the reference case, the black line; it shows lots of retirements in the first couple of years on -- on a cumulative basis, and then they'll start adding over time again. And, actually, the capacity in the end increases by about 2,000 megawatts, at the end of the period, that black line.

MR. BOB PETERS: Right. And you're referring in that answer to the reference case?

DR. ROBERT SINCLAIR: The reference case, yeah.

MR. BOB PETERS: And is the -- in that -- while we're still on the reference case then, Dr. Sinclair, that -- that black wavy line that runs through the -- through the bar chart, you show the accelerated cumulative retirements of coal in the early years, correct?

DR. ROBERT SINCLAIR: That's correct. They retire early.

MR. BOB PETERS: And does that help establish the capacity price going forward in terms of tightening up the capacity that would be available in MISO?

DR. ROBERT SINCLAIR: Exactly. That's why in our capacity price we see it increase over the first couple of years and it reaches equilibrium about 2018 when the -- when the coal is finally bal -- the coal retirements cause the system to be balanced.

MR. BOB PETERS: And, lastly, let's just turn over to the high growth portion of the chart.

And that high growth scenario includes a carbon cost, does it not?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And would it be correct for this panel to understand that that -- that high growth would be higher without carbon costs?

DR. ROBERT SINCLAIR: The -- the growth rate and demand would be higher without carbon cost.

Is that what you mean?

MR. BOB PETERS: That -- yes, that was my question.

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: But in terms of the -- we'll -- I'll come to that later on a -- on another slide, I think.

DR. HUGH GRANT: Before you leave this slide, I was just wondering what the overall capacity in the market is? And this is in percentage terms. Is it -- is it a lot, or...?

DR. ROBERT SINCLAIR: Yeah, the MISO capacity is about 105,000 megawatts. May -- maybe a hundred and ten thousand (110,000).

DR. HUGH GRANT: So in the -- if you change the axis it would be sort of plus or minus 10 percent, sort of.

Is that about right?

DR. ROBERT SINCLAIR: Let's see. Each

-- each line would be 5 percent -- 5 percentage points. So minus -- is that what you mean?

DR. HUGH GRANT: No, I thought at the top it would be -- is it -- it's ten thousand (10,000) --

DR. ROBERT SINCLAIR: Ten (10) percent would be the top, yeah. Yeah, that's right. Yes.

DR. HUGH GRANT: Okay.

DR. ROBERT SINCLAIR: So, yeah, you can convert the ten thousand (10,000) to 10 percent, that's right.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Maybe I'll ask Ms. Villegas to turn to slide 40 from Potomac Exhibit 4, and -- and just deal with that point that we were talking about, Dr. Sinclair. Or at least one (1) of the points is that, as I read Manitoba Hydro's rebuttal, that the more efficient coal plants will have lower carbon emissions and thus pay lower carbon prices.

Is that how you understood their point to be?

DR. ROBERT SINCLAIR: The point was that the -- the less efficient ones will have higher -

- will have higher carbon output.

MR. BOB PETERS: And with that answer, when I turn to slide 40 I don't see that demonstrated, Dr. Sinclair, particularly in the middle row where I think Ms. Ramage has it that the -- the CT-New is the single cycle combustion turbine new, correct?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And if we follow that line item across, the general understanding is that because it's a single cycle combustion turbine it will require more fuel than the combined cycle gas turbine, correct?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And, so under the fuel cost column we see that the fuel cost for the -- for the CT-new is -- is higher than that for the CCGT-New, correct?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And then if we follow that further, assuming the carbon cost is -- you have it as approximately twenty dollars ($20) a ton, right?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And that ton --

DR. ROBERT SINCLAIR: That's a long --

MR. BOB PETERS: -- on your side of

the border is the 2,000 pounds?

DR. ROBERT SINCLAIR: Yeah, this is a long ton. It's twenty (20) --

MR. BOB PETERS: Twenty-two hundred (2,200) pounds --

DR. ROBERT SINCLAIR: -- kilograms, yeah.

MR. BOB PETERS: Sorry, it's 2,000 kilo --

DR. ROBERT SINCLAIR: One thousand (1,000) kilograms. Twenty (20) -- 200 pounds.

MR. BOB PETERS: Okay.

DR. ROBERT SINCLAIR: Yeah.

MR. BOB PETERS: Or call that the US long ton. Would that be --

DR. ROBERT SINCLAIR: Long ton. Yeah, we call it the long ton.

MR. BOB PETERS: And I thought metric was confusing, but let's continue on.

Well, just the significance of that. If it's the long ton, it's approximately 10 percent more than -- than what I guess is considered the US short ton, correct?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And the US short ton

is equivalent to approximately 2,000 pounds?

DR. ROBERT SINCLAIR: That's correct. This is all done in metrics here. Okay.

MR. BOB PETERS: And your last answer meaning it was done --

DR. ROBERT SINCLAIR: In the long -- in long --

MR. BOB PETERS: -- in met -- the long ton --

DR. ROBERT SINCLAIR: Yeah.

MR. BOB PETERS: -- or the -- the metric tonne?

DR. ROBERT SINCLAIR: Yeah, the metric tonne.

MR. BOB PETERS: All right. Sorry to digress on that, but let's stay with that CT-New row. And we see under the fuel cost of fifty-eight dollars and thirty-three cents ($58.33) per megawatt hour, correct?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And we use a common carbon cost, but it appears the carbon cost is identical for the CT-New as it is for the CCGT-New.

Do you see that on the chart?

DR. ROBERT SINCLAIR: That's correct,

yes.

MR. BOB PETERS: Is that an error on the chart?

DR. ROBERT SINCLAIR: No, this -- this is the way we did it in our -- in our analysis. And this is where Manitoba Hydro came back and said, Well, if you have a less efficient plant like the CT, which is less efficient, the higher heat rates means it requires more fuel to produce a kilowatt hour, that you really should be producing more carbon, and that the carbon cost should vary with the heat rate.

And we agree with that logic. But what we want to show here is that, and this table will illustrate it, what would happen here if we were to make that adjustment, to make the -- a heat rate -- to make the carbon cost a function of the heat rate. You would have a lower carbon cost for the CCGT. And actually, that fifty dollars ($50) would be reduced. We didn't do the calculation.

The CT-New would have a higher carbon cost, because this is an average sale. We need to -- to bite out the two (2) types to get a lower for one and a higher for the other. CT-New would have a higher carbon cost. And also the coal plant, because it's one of the less efficient ones, if we were to take Manitoba Hydro's suggestion and break out the carbon costs by heat rate, we would -- that coal plant would have -- also have a higher carbon cost.

So you would end up -- if we were to take the suggestion the CCGT-New would have a higher marg -- a lower marginal cost than fifty dollars ($50), and the old coal plant would have a higher marginal cost. So you would actually have CCGTs overtaking coal plants in the production cost stack, which means that they will be running in base load, at least with respect to the older coal plants. So you'd be -- coal plants would be -- the carb -- the -- sorry, the CCGTs would be setting a price in the offbeat periods as a result of that. So if we were to adust the way Manitoba Hydro is suggesting we'd likely have a lower off-peak price.

MR. BOB PETERS: Are you able to do that calculation as an undertaking and provide it to this panel?

DR. ROBERT SINCLAIR: We did do a sensitivity. We haven't quality controlled it. We haven't made sure everything's in order. But we did find that the off-peak price declines several percentage points; 4 percent, perhaps.

MR. BOB PETERS: And CCGT-New prices

are overstated here by 4 percent then?

DR. ROBERT SINCLAIR: No, the -- if we were to allow the CCGT to have a lower carbon cost, and when you go through the whole year of off-peak prices, the total effect on the off-peak price is about 4 percent.

MR. BOB PETERS: Oh, I see --

DR. ROBERT SINCLAIR: At some hours the coal pri -- coal is still setting the price.

Of course, on the peak times you have the opposite effect. You'll have -- you'll have CTs with higher marginal cost, setting the price in more hours, and you'll have a higher peak price. We calculate that to be about 2 percent higher.

MR. BOB PETERS: Can you provide through your counsel a calculation that will demonstrate both the off-peak and the peak price impacts?

DR. ROBERT SINCLAIR: Okay.

MR. BOB PETERS: All right. Thank you.

--- UNDERTAKING NO. 82: Potomac to provide a calculation that will demonstrate both the off-

peak and the peak price
impacts

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: What carbon price would be required to make Hydro more economic than coal?

DR. ROBERT SINCLAIR: So -- interesting.

MR. BOB PETERS: That may be another one to take away unless you're able to do some quick math on the microphone.

DR. ROBERT SINCLAIR: I can't do quick math, but I can tell you what the influences would be. So the Hydro is typically bid in at -- we -- we -- in our model we bid the man -- the Hydro in at the CCGT rates, because they have an opportunity cost of -- they just don't want to dump their water all the time. They want to sort of optimize the water and we assume that they optimize that with respect to the -- sort of the mid-range part of the curve with just the CCGT.

(BRIEF PAUSE)

DR. ROBERT SINCLAIR: But I could --

I'll take that back, too.

MR. BOB PETERS: All right. Mr. Monnin, we would then appreciate an undertaking for Dr. Sinclair and Potomac to provide their view to this panel as to what carbon price would be required to make hydro more economic than -- than coal, taking into account the information that Dr. Sinclair has already indicated in terms of directionally dealing with the CCGTs.

DR. ROBERT SINCLAIR: I mean, in short-term hydro is already less expensive to provide than coal. The question is how they would bid it into the market.

MR. CHRISTIAN MONNIN: We undertake to do that and --

DR. ROBERT SINCLAIR: Which I could get a better explanation than that for you.

MR. BOB PETERS: All right. Thank you for that, sir.

--- UNDERTAKING NO. 83:   Potomac to provide their view as to what carbon price would be required to make hydro more economic than coal

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: While we're on slide 40, the marginal cost with carbon price, that was set out for 2030.

Have I got that right?

DR. ROBERT SINCLAIR: Yeah, those values, like the -- the gas price for instance, is from 2030.

MR. BOB PETERS: And -- and the purpose of this chart, though, if we -- if we just rewind that -- that movie, was to demonstrate to this panel that the assumptions used by Potomac, when considered through our -- make it relatively the same for the CCGT and the -- and the coal plant.

That was your -- your point of demonstrating this to the panel?

DR. ROBERT SINCLAIR: Yeah, there was some discussion made about the coal -- coal plant retirements and that we were -- we were -- it was suggested that our -- we didn't retire enough coal plants. And this table was to demonstrate that the effect of retiring coal plants is not going to be that significant, because the CCGTs will come -- come in to replace them and the marginal costs are comparable. And so --

MR. BOB PETERS: Would -- yeah, sorry.

DR. ROBERT SINCLAIR: So all the hours when the coal plants were setting the price, you now have a -- a -- you would now have that replaced by CCGT and the price is comparable. So you don't have a big price effect from more retirements.

MR. BOB PETERS: Did Potomac in its work consider what the first year in-service cost would be for the energy coming out of Keeyask generating station?

DR. ROBERT SINCLAIR: The fully allocated cost, or --

MR. BOB PETERS: Yes, sir.

DR. ROBERT SINCLAIR: With -- including capital cost?

MR. BOB PETERS: Yes, sir.

DR. ROBERT SINCLAIR: No, we didn't do that.

(BRIEF PAUSE)

MR. BOB PETERS: When we talk of carbon emission rates, there was prior evidence before this panel that at least some of the MISO state regulators require utilities to make assumptions as to carbon in their resource planning.

Are you aware of that?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: Can you explain to this panel why that occurs; why that's -- why that procedure is done?

DR. ROBERT SINCLAIR: Yes. Across the US in some of the MISO states there -- the regulators are requiring that utilities have a mix of renewables in their -- in their generate -- generator fleet, and part of that is to reduce the amount of carbon emissions from the generators in their states. And so there's -- that provides an incentive for them to procure wind and -- and hydro units.

So that may be one (1) of the other factors I think I discussed earlier; why a utility adding capacity may not be restricted just to the CT, because the CT, although it's the cheapest, may not advance other types of goals that the regulators may set for the utility.

MR. BOB PETERS: Can we turn please, Ms. Villegas, back to figure 1 on page 6. I guess it's in the executive summary.

And, Dr. Sinclair, if you would prefer to use any of the slides from Potomac Exhibit 4 in lieu of this, certainly -- certainly let us know.

DR. ROBERT SINCLAIR: Okay.

MR. BOB PETERS: But Figure 1 shows your two (2) forecasts of the potential opportunity export energy prices, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: The peak prices are on the left, and the off-peak are shown on the right?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: and the lower line in each of the figures reflects the reference case without CO2 or carbon tax, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And these price forecasts are in real 2013 dollars?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: US dollars?

DR. ROBERT SINCLAIR: US dollars, yes.

MR. BOB PETERS: And these are prices at the -- what we -- the -- the delivery point into MISO market which we've called the Manitoba Hydro Electric Board pricing node, or MHEB node?

DR. ROBERT SINCLAIR: Yes, that's the locational marginal price at the Manitoba border.

MR. BOB PETERS: Is it -- is --

MS. PATTI RAMAGE: Mr. Peters, could we just have a quick break for a second while we confirm something here?

MR. BOB PETERS: Certainly.

MS. PATTI RAMAGE: Just if we could pause for a moment.

(BRIEF PAUSE)

MS. PATTI RAMAGE: Okay, Mr. Peters. Sorry, false alarm. We just had to look.

(BRIEF PAUSE)

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Dr. Sinclair, while you didn't do a fully -- I think you told me you didn't do the fully allocated cost on in-service of Keeyask, have you a perception of -- of what that might be?

DR. ROBERT SINCLAIR: I guess it would depend how long you amortize it. So we -- we really haven't thought it through.

MR. BOB PETERS: And when you say "amortize it," you're talking about the depreciation on the --

DR. ROBERT SINCLAIR: Yeah, how long you -- you would want to have the underlying capital cost reflected in the production costs. For instance, do you want to do it for thirty (30) years or eighty (80) years. Then you would have a different allocated cost.

MR. BOB PETERS: And the life of these hydro assets, though, is long term?

DR. ROBERT SINCLAIR: Long term, yes.

MR. BOB PETERS: So wouldn't eighty (80) years be a more appropriate time frame?

DR. ROBERT SINCLAIR: I -- I think a longer term would be appropriate.

MR. BOB PETERS: And even in light of that longer term are you then able to assist the panel in understanding the Potomac perception of the annual in-service costs of -- of the energy?

DR. ROBERT SINCLAIR: No, we -- we didn't do a -- we didn't do a -- even a -- we didn't even do a rough one.

MR. BOB PETERS: All right. And when we talked to, before we just broke, briefly, the prices in delivery on Figure 1 were at the -- the LMP, the locational marginal price for Manitoba Hydro?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: That -- that LMP, is that the physical location or shall we take that as a -- as a notional or virtual location?

DR. ROBERT SINCLAIR: I believe actually it's a physical bus, yeah. That's where the transactions are settled.

MR. BOB PETERS: And is that likewise -- is there a physical bus for the -- for the MISO SMP?

DR. ROBERT SINCLAIR: Not -- not really. It's -- it's more of a calculation.

MR. BOB PETERS: So it's a notational location?

DR. ROBERT SINCLAIR: Yes. It's more of a -- it's kind of a -- an artifact of their optimization model where they -- they start to -- they've taken all the information on the -- the load and the resources that are available, and they tried to minimize the production costs across the whole footprint. And the model will provide them with sort of the marginal cost of -- of meeting load before considering all the congestion and losses on the system. So it's sort of an uber-marginal cost.

MR. BOB PETERS: All right. Back to

Figure 1 still. And would it be correct that the prices that are shown here do not include a capacity component?

DR. ROBERT SINCLAIR: That's correct; just the energy price.

MR. BOB PETERS: And these prices are the day-ahead market prices?

DR. ROBERT SINCLAIR: The day-ahead market prices.

MR. BOB PETERS: They're not the firm contract prices, or expected?

DR. ROBERT SINCLAIR: They're -- they're day-ahead energy prices, right.

MR. BOB PETERS: And in terms of a -- an overall view, Potomac is forecasting that absent the imposition of CO2 pricing, the export prices that Hydro can achieve both on-peak and off-peak will increase by about 50 percent from 2015 through to 2033?

DR. ROBERT SINCLAIR: I think with carbon they will increase about 50 percent. The green -- the green line.

MR. BOB PETERS: Well, with carbon -- sorry, I may have -- I may have been looking at the wrong chart here. I'm looking at it on the -- on the peak side increasing from thirty dollars ($30) to about sixty dollars ($60) with carbon, correct?

DR. ROBERT SINCLAIR: That's correct, yes.

MR. BOB PETERS: So it would go up a hundred percent?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And then looking at the -- the line without carbon, the one without the hockey stick that Ms. Ramage likes, the energy price goes from about thirty dollars ($30) to forty-five dollars ($45).

So it goes up 50 percent?

DR. ROBERT SINCLAIR: Yes, that's right.

MR. BOB PETERS: All right.

(BRIEF PAUSE)

DR. ROBERT SINCLAIR: With that system marginal price, I just thought again that one way to think about it is that MISO is sort of a -- produces all their electricities. You can think of it as a commodity, and it's produced all in one spot, but then it has to be delivered to different places. And imagine if instead of electricity it was some kind of commodity like apples or something, and when you go to different locations you may run into different delivery constraints, and it costs more to get to different locations.

So that's sort of what you can think of the system marginal price in relation to congestion and losses to be. Sort of the dif -- how difficult is it to get it from the system out to the different buses.

MR. BOB PETERS: Thank you for that -- for that analogy, as well. When we look at these export prices on Figure 1, Dr. Sinclair, does Potomac believe that Manitoba Hydro's importing into the United States impacts the off-peak price?

DR. ROBERT SINCLAIR: We've found that the only impact that would really have is with respect to some losses, and it was rather -- it was rather small.

MR. BOB PETERS: When you say, "losses", you're meaning transmission losses?

DR. ROBERT SINCLAIR: Transmission losses. So when we estimate the transmission losses, we consider that additional imports into Manitou -- from Manitoba Hydro to the US will increase losses, but it was by a very small amount. And there's no -- there's no conceivable way that the -- the amount of power that Manitoba Hydro plans to sell would have an impact on the MISO price.

MR. BOB PETERS: And that's probably why it said that Manitoba Hydro is the -- is a price taker as opposed to a price setter.

DR. ROBERT SINCLAIR: Price taker, right.

MR. BOB PETERS: And -- and I suppose as the market monitor you want to make sure that there's -- you're telling the panel three's really no ability of Manitoba Hydro to manipulate the market based on its imports into the MISO?

DR. ROBERT SINCLAIR: Yeah, not just from withholding -- not -- not by pricing alone. There could be ways to manipulate congestion, but we monitor for that; we wouldn't expect that to happen either.

MR. BOB PETERS: Does the PJM importing into MISO impact the off-peak price of energy?

DR. ROBERT SINCLAIR: There -- there are some -- there -- there tends to be a flow of power from MISO to PJM, 'cause there's a -- currently a surplus in MISO. So the supply coming from PJM will -- tends to be minimal, so that will not have a big impact on the price. But in theory it's possible.

MR. BOB PETERS: If we turn to slide 26 from the Potomac Exhibit 4, we see maybe a little bit better graphically shown what we've been just talking about, Dr. Sinclair. But you've demonstrated before that when you start with the MISO system marginal price you subtract the congestion, and you subtract the losses, and you get the locational marginal price at the Manitoba border, correct?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And why is this congestion entirely allocated to Manitoba Hydro as shown here? Aren't there other parties partly responsible for that congestion, as well?

DR. ROBERT SINCLAIR: Well, the congestion we measured at each location. So there are other locations in MISO that will also have congestion components associated with it.

So this isn't the total MISO congestion. It's just the congestion associated with getting power from the MISO system to the Manitoba -- to the Manitoba system -- to the Manitoba node at the border. So it's not that all the congestion is allocated to the Manitoba location, it's just the -- the congestion associated with that location is allocated to that node.

MR. BOB PETERS: All right. I -- I -- maybe it's the lack of engineering understanding, but if Manitoba Hydro is taking this energy to the US border, and that's where their node is located -- and that's basically your understanding, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: What's the opportunity for congestion to occur at that location when there's nobody else putting energy there?

DR. ROBERT SINCLAIR: Okay. So the loc -- the -- the congestion isn't so much getting it to the node, the congestion is how much would it cost MISO to back down generators in that vicinity to allow that power to come into the node. So at any given time the system's in balance. So whenever you try to move -- increase an injection, for instance, at the -- the Manitoba border, you'd have to make room for it.

And if it's exp -- if it's an area like we have in the west of MISO, where there's lots of low cost power, you have to back down some of the low cost generators there to allow the Manitoba power to come in. So when -- when you're backing down low cost power, you're reducing -- you're re -- you're increasing the cost to the system, because you still have to keep it balanced.

MR. BOB PETERS: Okay. I -- I think I have your point. And so the -- the congestion you're measuring, you've called it 'marginal congestion' here on slide 26.

That's Manitoba Hydro's responsibility is what you're trying to demonstrate on your chart?

DR. ROBERT SINCLAIR: Yes. In order to allow imports you -- there is congestion that has to be managed.

MR. BOB PETERS: And that's at Manitoba Hydro's expense?

DR. ROBERT SINCLAIR: It's the price that would be earned -- this is the price that would be earned by Manitoba Hydro and it's a -- it's a -- it depends on the total cost in -- in MISO, but also what MISO would have to do to allow additional power to be produced there.

MR. BOB PETERS: But Manitoba Hydro's prices decreased from the system marginal price based on this congestion --

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: -- so it -- it is at

Manitoba Hydro's expense.

DR. ROBERT SINCLAIR: So it's at their expense because they got a lower price.

MR. BOB PETERS: And -- and on these tra -- on the marginal losses that you show we're talking -- I think you told Board member Kapitany that that was mostly related to transmission losses?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: What else is it other than transmission?

DR. ROBERT SINCLAIR: There could be some -- there could be some distribution level issues affecting the transfers, but mostly it's going to be line losses. There could be some capacitor banks that have to be managed. But, again, those typically -- they typically don't absorb a lot of the power. It's going to be line losses from transformers step -- you have to step down the power sometimes. You have some losses there.

MR. BOB PETERS: I recall you had given the Board a number of -- a percentage number, in any event, for average losses in MISO being about 9 percent?

DR. ROBERT SINCLAIR: At -- at that location it's about 9 percent.

MR. BOB PETERS: What is the system average MISO transmission loss? Do you know?

DR. ROBERT SINCLAIR: Typically it's about 4 percent, I believe. So it's higher in the west because of all the -- because of the tendency of the power to -- to be produced in the west and serving load in -- in the east. So that tends to -- in other words, the transmission lines are kind of hot because there's lots of activity on them. Think of -- the losses are associated with heat being absorbed by the lines, basically. When you're using them a lot to transfer over long distances, you're going to have higher losses.

MR. BOB PETERS: Before I leave that marginal congestion concept, is it the same day or night?

DR. ROBERT SINCLAIR: No, our marginal congestion changes on an hourly basis in accordance with certain markets -- various market factors such as the load. It will -- it will be different day and night. That would be the average for the peak and off peak, depending which -- which chart you're looking at.

MR. BOB PETERS: All right. I want to turn to -- to capacity prices. And maybe -- maybe we can go back to figure 2 on page 7 of your Potomac Exhibit-2.1. It's on the screen in front of you, sir.

This suggests to the panel, does it, that capacity prices will increase from twenty-two dollars ($22) a kilowatt-year to about sixty-eight dollars ($68) a kilowatt- year?

DR. ROBERT SINCLAIR: Correct.

(BRIEF PAUSE)

MR. BOB PETERS: And when -- when you use the concept kilowatt-year, can you explain that, please?

DR. ROBERT SINCLAIR: Kilowatt-year is the amount of money -- a kilowatt-year is -- is a capacity measure. So it tells you how much capacity you're providing for that year. So a -- a hundred megawatt plant would be providing a thousand megawatts -- I'm sorry, 10,000 kilowatt years -- 10,000 kilowatts a year if it's a capacity resource.

MR. BOB PETERS: You did the math in your head. Are you able to convert the --

DR. ROBERT SINCLAIR: I could be wrong. Let's see. So 1 -- 1 megawatt is 1,000 kilowatts, so if you had a 1 megawatt plant you're providing 1,000 kilowatts a year.

MR. BOB PETERS: Can you convert the capacity prices into an equivalent 5x16 energy price per megawatt hour?

DR. ROBERT SINCLAIR: Say that again?

MR. BOB PETERS: You show here capacity prices, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And is it possible to convert those capacity prices into an equivalent 5x16 energy price for megawatt hour?

DR. ROBERT SINCLAIR: Let's see. The kilowatt -- the capacity price is typically a -- not converted to an energy price. Capacity -- something has to be available at all hours, so you would not typically convert it to a 5x16.

MR. BOB PETERS: If you assumed it was just on 5x16 energy though, you would do the -- do the math to allocate the 5x16 hours in the year to that cost?

DR. ROBERT SINCLAIR: See, I'd -- I'd have to...

(BRIEF PAUSE)

DR. ROBERT SINCLAIR: So I'd have to think that through.

MR. BOB PETERS: All right. The -- what I was just getting at, Dr. Sinclair, is that the -- the purpose of the capacity cost is to -- to recover fixed costs?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And --

DR. ROBERT SINCLAIR: Cost of -- the purpose of the capacity cost is to provide enough revenue so that the new entrant can -- would not make losses.

MR. BOB PETERS: All right. And that was your cost of new entrant calculation that you went through yesterday?

DR. ROBERT SINCLAIR: Yes

MR. BOB PETERS: And --

DR. ROBERT SINCLAIR: It's meant to recover some of your capital costs, right.

MR. BOB PETERS: Right. All right. And, so if -- if that capacity price was only being recovered through a 5x16 contract, I'd ask you to undertake to see if you can convert that then into dollars per megawatt for -- for -- let's pick your twenty-two dollars ($22) a year shown in your -- your chart on Figure 2, and then also do the same calculation for the, say, sixty-eight dollars ($68) a year, and --

DR. ROBERT SINCLAIR: Okay.

MR. BOB PETERS: -- calculate that in terms of dollars per megawatt hour?

DR. ROBERT SINCLAIR: Okay. So what you want to know is how much more energy revenue you would need to cover your capacity costs?

MR. BOB PETERS: Well, if -- if you were to recover -- no, I don't think that's what I'm asking for. I'm asking that if you were to recover your capacity costs through energy --

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: -- how would you -- how would you equate those costs into --

DR. ROBERT SINCLAIR: Okay.

MR. BOB PETERS: -- dollars per megawatt hour.

DR. ROBERT SINCLAIR: I can certainly do that, yes.

(BRIEF PAUSE)

MR. BOB PETERS: I've asked Dr.

Sinclair to undertake to convert the capacity prices of twenty-two dollars ($22) per kilowatt year to -- as well as sixty-eight dollars ($68) per kilowatt year into dollars per megawatt hour.

DR. ROBERT SINCLAIR: 5x16x52, right?

MR. BOB PETERS: Correct.

DR. ROBERT SINCLAIR: Right.

MR. BOB PETERS: Okay. Thank you.

DR. ROBERT SINCLAIR: So that would be five (5) days a week, sixteen (16) hours a day, every week of the year?

MR. BOB PETERS: Yes, sir.

--- UNDERTAKING NO. 84: Potomac to convert the capacity prices of twenty-two dollars ($22) per kilowatt year as well as sixty-eight dollars ($68) per kilowatt year into dollars per megawatt hour, 5x16x52

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: And is it likely, Dr. Sinclair, that firm energy export contracts of 5x16 energy for any new Hydro contracts after 2035 will achieve the full capacity price that you're forecasting?

DR. ROBERT SINCLAIR: So you're saying that could you design a contract that would be a 5x16 that could give you the same revenues after 2035?

MR. BOB PETERS: No, let me rephrase the question. You're aware that Manitoba Hydro has some 5x16 contracts now?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And those contracts expire, and I'm assuming they've expired by 2034 --

DR. ROBERT SINCLAIR: Okay.

MR. BOB PETERS: -- or '35. And let's assume that Manitoba Hydro then wants to enter into new contracts after 2035, and they would be 5x16 contracts that would also not only have an energy price but they'd also seek to recover a capacity cost.

DR. ROBERT SINCLAIR: Mmm, sure.

MR. BOB PETERS: Are you with me?

DR. ROBERT SINCLAIR: Sure.

MR. BOB PETERS: And I guess what I'm wondering is from Potomac's perspective is it likely that firm export contract sales of 5x16 energy for any new contracts after 2035 will achieve the full capacity price that Potomac is forecasting as seen here on Figure 2?

DR. ROBERT SINCLAIR: Yes, that's -- that's what we are forecasting.

MR. BOB PETERS: And so it is likely then that the market will -- you're saying the market will provide that recovery to Manitoba Hydro's exports?

DR. ROBERT SINCLAIR: Yes. Yeah, we're projecting that's what they could earn on their capacity component of their contracts.

MR. BOB PETERS: And you've confirmed that Manitoba Hydro's long-term export contracts typically include an energy price as well as a capacity price?

DR. ROBERT SINCLAIR: That's correct.

MR. BOB PETERS: And in terms of you're also aware that Manitoba Hydro also has what they call diversity exchange contracts?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And those diversity exchange agreements do not recover capacity revenues, do they?

DR. ROBERT SINCLAIR: That's what I understand.

MR. BOB PETERS: You understand they do not recover capacity --

DR. ROBERT SINCLAIR: Yeah, I'd have to check but that's what I understand.

MR. BOB PETERS: And -- but you do understand that its firm price contracts recover capacity revenues?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And without disclosing any amounts, did you review or were you able to establish the annual capacity revenue Hydro achieved from the current 500 megawatt NSP long-term contracts?

DR. ROBERT SINCLAIR: I believe I looked at that one, yes.

MR. BOB PETERS: Did you look also at Manitoba Hydro's other current firm fixed price contracts?

DR. ROBERT SINCLAIR: I did.

MR. BOB PETERS: And would it be correct that whatever numbers came out of your review are not included in -- in your report?

DR. ROBERT SINCLAIR: Yeah. We did not include those in our report; we used them sort of as a point of reference.

MR. BOB PETERS: I wonder if you could undertake through your counsel if you can locate that information to -- to provide the panel as CSI, recognizing the sensitivity of that information, the annual capacity revenue that you see Manitoba Hydro achieving under its current contracts?

DR. ROBERT SINCLAIR: The ones we looked at we can do that for.

MR. BOB PETERS: Thank you, sir.

DR. ROBERT SINCLAIR: We didn't check every one in the same way, but if the other ones are similar then we can do it.

--- UNDERTAKING NO. 85: Potomac to locate the annual capacity revenue that it sees Manitoba Hydro achieving under its current contracts, and to provide as CSI

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: While -- and -- and in terms of the other contracts I was talking about existing contracts not -- not future contracts, Dr. Sinclair.

DR. ROBERT SINCLAIR: Yes, I understood existing.

MR. BOB PETERS: All right. And if we can go to I think page 44 of Potomac's Report, Exhibit 2.1. I think everybody has taken you here, Dr. Sinclair, so.

In your review of Hydro's historical export sales, you tried to determine the percentage of dependable energy sales that were through diversity exchanges?

DR. ROBERT SINCLAIR: No, we asked to verify the assumption that the -- that the future dependable capacity that would be created by the new projects would be sold on a long-term dependable basis.

MR. BOB PETERS: All right. I heard that answer and I provided through to your counsel a copy of PUB Exhibit 63, which is taken from Manitoba Hydro's -- it was actually some of the information in a previous book of documents that we've had on the public record. Ms. Villegas is -- is just handing it out at this time and it's on the screen. And what -- what I -- what we're attempting to show here, Dr. Sinclair, is our understanding, and see if your confirm -- if you can confirm or correct it otherwise.

Would it sound reasonable to Potomac that Hydro's dependable energy sales through diversity exchanges increased from 2005 through to 2012/'13?

DR. ROBERT SINCLAIR: I didn't look at that particular type of sale. We did look at the dependable sales. Now, I -- I did see a chart here before and I did not know that the dependable firm sales also include the diversity sales. I did not know that, yes.

MR. BOB PETERS: All -- all right. And -- and if we're correct in that, and -- and that'll be an 'if' that we'll leave on the record and Manitoba Hydro may address that, those diversity exchanges don't have a minimum quantity or a -- a price guarantee.

Is that your understanding?

DR. ROBERT SINCLAIR: That's my understanding.

MR. BOB PETERS: And so does that mean that Hydro's diversity exchange counterparties are not required to purchase any energy from Hydro?

DR. ROBERT SINCLAIR: That's what I understand.

MR. BOB PETERS: And so these -- these diversity exchange arrangements are not what would be considered a take or pay agreement?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And that would apply to both winter and to summer diversities?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And if a counterparty purchases energy under the diversity exchange, it's not at a firm fixed price then. Is that your understanding?

DR. ROBERT SINCLAIR: That's my understanding.

MR. BOB PETERS: It's -- it's at the market price?

DR. ROBERT SINCLAIR: That's what I understand, yes.

MR. BOB PETERS: Would it be the market price at Manitoba Hydro's locational marginal pricing node?

DR. ROBERT SINCLAIR: It would probably depend on that. It may be -- there may be some agreement to use that locational price as part of the settlement. But actually, I'm not sure sitting here.

MR. BOB PETERS: Okay. So even if the diversity sales are made out of dependable resources, they wouldn't be attracting a -- a fixed price agreement, correct?

DR. ROBERT SINCLAIR: Right. As I -- what I understand is that -- that the firm dependable sales -- when I -- when I think of firm -- firm sales, I think of them having a -- a capacity price associated with them.

MR. BOB PETERS: Now, back on page 44 you express concern in your report that Hydro assumes it can sell all of its dependable capacity under long-term firm contracts, correct?

DR. ROBERT SINCLAIR: That -- that's correct. That's part -- one of the assumptions made.

MR. BOB PETERS: And diversity sales do not provide capacity revenue, correct?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And if the diversity sales are provided under -- and -- and from dependable resources, you weren't aware that there was no capacity cost being attributed through to that type of a dependable sale?

DR. ROBERT SINCLAIR: That's correct. I was under the impression that dependable sales, as reported in that chart you had up previously, that that was given that first column.

MR. BOB PETERS: And we'll just put up PUB Exhibit 63.

DR. ROBERT SINCLAIR: Dependable sales. Right. Right. And I was working under the assumption that those dependable sales were firm sales that had a capacity price associated with them.

MR. BOB PETERS: All right. And even under that assumption you were suggesting that Manitoba Hydro was being a bit aggressive in assuming it was going to sell 100 percent of its dependable product under a firm sale?

DR. ROBERT SINCLAIR: Correct. Although, I think 90 -- 90 percent is still a pretty good percentage.

MR. BOB PETERS: And -- and to be more accurate, you suggested 91 percent would be more realistic than the 100?

DR. ROBERT SINCLAIR: That was based on some data that I saw provided by Manitoba Hydro that showed that in recent years, at least, the percent of dependable sales that were sold -- I'm sorry, the percentage of dependable capacity which was sold forward on a firm basis was about 91 percent; which again, I think is a pretty good rate, but it's not 100 percent.

MR. BOB PETERS: All right. So it was based on -- on the data that you saw. And that data's not on the public record, is it?

DR. ROBERT SINCLAIR: I believe it was a CSI.

MR. BOB PETERS: It was CSI on the share point arrangement that was existing, or information that they provided directly to you?

DR. ROBERT SINCLAIR: It was posted on that share point. It was an -- part of an IR.

MR. BOB PETERS: And so based on your -- what you saw, you then suggested it would be a more reasonable assumption for Hydro to assume that 9 percent of its dependable sales would not be sold under the firm sales, but rather could be sold on the peak opportunity market?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And if we're correct in terms of how we interpret the US diversity sales information, and that 91 percent included diversity sales, does that cause you to change your opinion as to what assumption should be made in terms of what percentage of Manitoba Hydro's dependable energy will be sold under a firm contract?

DR. ROBERT SINCLAIR: If the US

diversity sales do not have the characteristics of a long-term firm contract, then they should not be assumed to be earning that level of revenue. So I think the answer would be yes.

MR. BOB PETERS: And is -- is the data that's available on the screen from the snapshot that it's -- provided, does that give you any opportunity to provide this panel with a -- with a recommendation as to what would be a reasonable percentage to assume going forward would -- would be not sold under the US dependable firm sales?

DR. ROBERT SINCLAIR: Yeah, I think you would -- again, subject to check, if the US diversity sales do not earn the types of prices that the long-term firm sales earned then they should be assumed to be sold under a different type of product. And you could -- you could determine that by reducing the dependable sales by the US diversity sales. For instance, in 2012, you could reduce it by 1,280 megawatts -- gigawatt hours. And then use that resulting figure as the basis for calculating the percent of dependable capacity that is sold forward on a firm basis.

MR. BOB PETERS: All right. And then --

DR. ROBERT SINCLAIR: We could do that, yeah.

MR. BOB PETERS: Pardon me?

DR. ROBERT SINCLAIR: And we could do that.

MR. BOB PETERS: If you could undertake to --

DR. ROBERT SINCLAIR: Calculate that.

MR. BOB PETERS: -- provide that calculation that would be appreciated.

Dr. Sinclair, do you want to repeat on the record your undertaking just so that you're able to comply with it?

DR. ROBERT SINCLAIR: Under the assumption that US diversity sales do not earn the long-term firm price, we can recalculate the percentage of dependable capacity that is sold forward on a firm basis.

MR. BOB PETERS: All right. Thank you.

--- UNDERTAKING NO. 86: Potomac to recalculate the percentage of dependable capacity that is sold forward on a firm basis

under the assumption that
US diversity sales do not
earn the long-term firm
price

THE CHAIRPERSON: Mr. Peters, I'm looking at the -- at the clock and wondering, have you got many more minutes to go? Or should we use this as an opportunity for a break?

MR. BOB PETERS: This would be an opportune time. I've -- I -- I see that I've, I believe, covered off some of these questions that I have here, and I'll just use the break to make sure that I've addressed them. And I'll -- I'll finish after the break.

MS. PATTI RAMAGE: Mr. Chairman, before we break, typically at a GRA, and I forgot to mention on the record, although I did speak to Mr. Peters, when -- in a GRA when Manitoba Hydro is applicant we still -- if anything is raised in Board counsel's cross, we're provided an opportunity to -- to ask some questions.

And I don't want to belabour this portion of it, but we do have a couple of questions which, frankly, I could ask in the CSI session, too.

However, I've developed the questions to get on the public record 'cause I think it's the Board's preference to do more on the public record than the CSI. So I just thought I'd bring that to your attention. If I could have a few minutes after Mr. Peters.

THE CHAIRPERSON: In the interest of making sure we have as full -- fulsome a -- a public record as possible I would -- I would support that request, so.

So let's take ten (10) minutes. Thank you.

--- Upon recessing at 10:41 a.m.
--- Upon resuming at 10:54 a.m.

THE CHAIRPERSON: I believe, Mr. Peters, we're ready to resume the proceedings.

MR. BOB PETERS: Yes. Thank you, Mr. Chairman, panel members. M. Monnin has told me that over the break his witness has thought further in respect of a matter, Mr. Chairman, that you raised. And I thought we would just give him the opportunity to address that at this point in time if that's appropriate. Dr. Sinclair...?

DR. ROBERT SINCLAIR: Yes, Mr. Chairman, you asked a question about -- related to what other -- other utilities do when they're faced with the same kind of problems as far as forecasting prices. And I thought about it a little bit more and wanted to draw on some of our experience.

So what -- what you have is utilities oftentimes are deciding about adding capacity to their system, so they can do it by self-building their own units, in which case they may not have to go out and determine what the future prices are.

In this case, Manitoba Hydro is -- is very interested in making sales. And so the sale in their case are very important to their underlying economics of the project, so they need to go out and get the price forecast.

In some of our past cases we've also had utilities wanting to buy capacity and also needing to get price forecast, not because they want to make sales with it, but because they all -- they make purchases. And they need to know what their total production costs are for their system, so they need to use the price forecasts to determine one (1) component of their own costs.

So some utilities may not need price forecasts at all if they determine the need capacity. They don't have a -- any interest in making sales out of that capacity, it's just for earning, it's just for satisfying a regulatory requirement. And they also don't have a large amount of purchases that they need to make in the market, they may not need to know what the future prices are.

So in some cases a utility try -- trying to develop a project may not need consultants at all, or they may have enough in-house knowledge to have some idea of what -- what the prices may be in the near term.

So I just wanted to fill out that question a little bit more because I think that's what you were asking.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Thank you, Dr. Sinclair. If we could turn to Figure 14 on page 36 of Potomac's evidence, please. Thank you.

This is the high growth rate scenario that Potomac forecast, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And I wasn't sure if

I covered this very well earlier on this morning, Dr. Sinclair, but when we look at this high growth case this is considered under circumstances where the -- where the economy is -- there -- there's high economic activity?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And in terms of the high growth case, what you've plotted here, each one of them contains a carbon cost, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And would be Potomac's view that the high growth case would be even higher without the carbon cost?

DR. ROBERT SINCLAIR: Well, the carbon cost affects prices in two (2) ways. The main way it affects it is that jump up in 2020 where the price of energy is directly affected by the need for the offers in the market to reflect the additional cost.

So you have -- so really the -- you have the energy price which really reflect the marginal cost of the unit providing on the margin. And so it directly affects the energy prices through that bump up there in 2020. But the -- the carbon cost will also affect the demand in the market, because with the carbon cost economic activity is slightly reduced.

So in this case here the -- both the affect on demand is already taken into account from the carbon costs. So it's sort of a -- an integrated -- so the growth rate in demand is -- is slower than it would be if there was no carbon cost, but it's taken into account in -- in our assumptions here.

MR. BOB PETERS: If Potomac was re-plot the high growth scenario without carbon, where would that line be?

DR. ROBERT SINCLAIR: If we were to change this case to have no carbon, we would pro -- we would have to go in and change the growth rate in load for -- for the years after 2020. And I would exp -- you would have -- two (2) things would happen. One (1) you would -- that -- that bump up in 2020 you see there would be smoother. But the slope of the line after 2021, how -- how steeply it climbs would -- it would climb more slee -- steeply.

So you'd have to shift it down to where it was in 2020 and get rid of that -- get rid of that sharp increase, and then you'd have to increase the slope of the -- the price line, because you would have more econom -- slightly more economic growth.

MR. BOB PETERS: If we could take that

same and turn to slide -- on page 27 of -- of your presentation, Dr. Sinclair.

The chart that I've just put in front of you has the compilation of all four (4) of the forecasts provided, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And, so if we look at the high growth with carbon, it's the -- it's the green line?

DR. ROBERT SINCLAIR: High growth with carbon is the -- the top line: light blue.

MR. BOB PETERS: Light blue. I'm sorry, I was looking at -- reference case with carbon is the green line?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And the reference case without carbon is the -- the dark blue line?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And when we go back to the high growth that we were just talking about, this -- this high growth plot is -- is, in essence, the same one we saw in your evidence, correct?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And, so -- just so the panel has a better understanding, are you able to take this chart and undertake to replot where the high growth would go with no carbon?

DR. ROBERT SINCLAIR: We would have to run the model again. The model is already set up so running the model itself isn't a problem, but we would also have to sort of vet the results to make sure -- to quality control the results. We -- we wouldn't want to just change one (1) of the assumptions and it just spit out the numbers. We would want to analyze them first.

MR. BOB PETERS: Is that a day, or a two (2) day --

DR. ROBERT SINCLAIR: This wouldn't be a day.

MR. BOB PETERS: All right. If --

DR. ROBERT SINCLAIR: We can make an attempt to do it, yes.

MR. BOB PETERS: All right. I'll ask you to undertake to do that, and if I get different instructions I'll be back to your counsel in -- in short order on that.

DR. ROBERT SINCLAIR: Okay.

MR. BOB PETERS: Thank you, sir. Yes, the undertaking is to re-plot slide 26 -- oh, I'm sorry, slide 27 -- it's not numbered, but I think we all know what -- we're talking slide 27 from Potomac's Exhibit 4 to include a high growth scenario without carbon.

And that's your understanding, that you can accomplish that?

DR. ROBERT SINCLAIR: I believe so, yes.

MR. BOB PETERS: All right. Thank you for that.

--- UNDERTAKING NO. 87: Potomac to re-plot slide 27 from Potomac's Exhibit 4 to include a high growth scenario without carbon

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Just dealing with one of the points you answered still in this area, if we had a situation of higher economic growth without a carbon cost there would be -- would the electricity price be higher or lower than it is with the carbon? Are you able to indicate that at this time?

DR. ROBERT SINCLAIR: I don't know for sure, but looking at the chart I would say that high growth without carbon would -- would be lower than high growth with carbon. So the answer would be that the price would be still lower than the high growth with carbon.

MR. BOB PETERS: All right. And we'll see when you do the undertaking as to what -- what that comes back with.

All right. Thank you, sir. I'd like to move to --

THE CHAIRPERSON: Mr. Peters, so -- just -- I just want to ask a question here in relation to -- say for example that the -- the carbon market was not a tax but a cap and trade system. Would that influence the line to slope at all? I mean, it -- it would probably -- depending on what the -- what the -- where the cap was set, that probably would just mean that the -- the distance between the reference/CO2 and no CO2 would probably be influenced by the level of the -- of the cap, right? Is that --

DR. ROBERT SINCLAIR: That's correct, yeah. I think the -- the dollar -- the dollar cap that we're putting in, or -- or the tax we're putting in is supposed to -- could be interpreted to reflect the cap and trade, or some estimate of where the cap and trade might turn up to -- to trade. And certainly the -- the level would then tell you how much -- how much you shift up.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Dr. Sinclair, on page 48, Figure A-4 of -- of your evidence, we see the load growth. And I just wanted to come back to a comment that you made in your -- your answers to me, sir.

When the panel looks at this information, we see -- we see the purple line being the CO2 reference case -- that's in -- in between the other two (2) lines, correct?

DR. ROBERT SINCLAIR: Yes, this is the one that has to bend. The -- there's two (2) lines with a bend in -- in them: a kink. The lower one is the CO2 reference case, right.

MR. BOB PETERS: And the -- the lower one with the CO2 reference case has a -- a dotted line that is to reflect no carbon in the reference case, correct?

DR. ROBERT SINCLAIR: That's correct.

MR. BOB PETERS: And if there was high growth without carbon -- and we're looking at that red line or that -- sorry, the red or purple line at the top -- would the high growth without carbon line likewise continue on with a less pronounced kink in it, as you described it?

DR. ROBERT SINCLAIR: That's correct, yeah. It'd be -- it's be steeper. It'd be of a higher growth rate.

MR. BOB PETERS: All right. And when we talked about the various scenarios that Potomac had done, you assigned probabilities to them, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And you'd indicated that the reference with CO2 and the reference without CO2 were equally weighted?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And then a lower weighting was given to the high growth, and also a -- the high growth was also weighted the same as the low energy prices?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And so back on slide 27, we see in that -- in the box that you have, the reference/CO2, the weighting was 30 percent?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And then the reference/no CO2 was also 30 percent?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And then high growth

was twenty (20) and low energy was also twenty (20)?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: That made up your hundred percent?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And in light of the questions, if we had the high growth but without carbon, would that impact the probabilities that you would assign to these different forecasts?

DR. ROBERT SINCLAIR: Yeah, I think we would have to rethink our probabilities.

MR. BOB PETERS: Maybe I'll ask you then to undertake that in conjunction with the last undertaking is to -- to also then advise this panel as to what, if any, changes would be made in the probability weightings that Potomac would assign to -- to the various cases, including the high growth without carbon case?

DR. ROBERT SINCLAIR: Yes.

--- UNDERTAKING NO. 88: Potomac to advise as to what, if any, changes would be made in the probability weightings assigned to the various cases, including

the high growth without
carbon case

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: And on Figures 13 and 14 in your evidence that we've looked at before, back on pages, I think, 35 and 36, we have in Figure 13 the high resource case and then on the next page we have the figure for the high growth, correct?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: I want to panel to be clear in understanding your evidence, Dr. Sinclair. Is Potomac indicating that these forecasts are not indicative of future price boundaries for the opportunity export sales, but they should be considered likely boundaries of the range in which future prices will come in?

DR. ROBERT SINCLAIR: This -- number -- Figure 14?

MR. BOB PETERS: I was thinking Figure 13 and 14; one setting the high, one setting the low.

DR. ROBERT SINCLAIR: Okay. So probably the --

MR. BOB PETERS: Maybe we should go back to slide 27 if you --

DR. ROBERT SINCLAIR: Yeah, I wonder if there's a better chart to look at that.

MR. BOB PETERS: Slide 27 of your presentation.

DR. ROBERT SINCLAIR: Yeah.

MR. BOB PETERS: And we'll go back. It's on the screen.

DR. ROBERT SINCLAIR: Yeah, I think that's a better one, yeah.

MR. BOB PETERS: All right. If you see it in the screen in front of you and you have it in your slide deck?

DR. ROBERT SINCLAIR: Yes. So these are our -- the alternative forecasts we made. And we wouldn't look at these as the -- as the limits of potential high prices or low prices. We would look at these as the boundaries of what we think to be the great -- the preponderance of the outcomes that we expect. So the high case isn't necessarily what we -- what's the most high -- high case possible, but what we call plausible.

So we think that between the high case and the low case we would observe almost -- a -- a very high percentage of the likely outcomes, as opposed to an absolute lower or -- or upper bound. It could be higher or lower cases that could possibly arise, but we think that sort of in -- sort of a -- maybe normal kind of expectation you would expect almost all of your observations -- future observations to fall within these boundaries.

MR. BOB PETERS: Okay. I think I have your -- your position on that then, sir.

Does Potomac have access to energy price forecasts that extend beyond 2033?

DR. ROBERT SINCLAIR: When you say "access", do you mean have them -- like we've procured them and we have them in our office?

MR. BOB PETERS: I'm just wondering if -- if that is the case, do -- do you know if they -- you know, do they exist as shelf products, or they have to be developed?

DR. ROBERT SINCLAIR: Not that I'm particularly aware of, no.

MR. BOB PETERS: Okay. Well, what's the usual industry practice with respect to forecasts that go out beyond twenty (20) years?

DR. ROBERT SINCLAIR: I think consultants are very hesitant to go beyond twenty (20) years.

MR. BOB PETERS: Again, for all the

uncertainty reasons you've mentioned?

DR. ROBERT SINCLAIR: Yes, I think EIA goes out thirty-five (35) years. Or, I'm sorry, twenty-five (25) years. But I have not -- I have not seen that many that go beyond twenty (20) years, just because of the uncertainty.

MR. BOB PETERS: Are you aware as to whether there are long-term contracts in MISO that extend out after 2035?

DR. ROBERT SINCLAIR: I'm not aware of any particular, but I wouldn't be surprised if there are some.

MR. BOB PETERS: And why -- why do you say you wouldn't be surprised if there were some?

DR. ROBERT SINCLAIR: There are some -- there are some contracts that might be associated with a particular plant, and you may have rights to purchase capacity from that plant for the life of the plant which could extend beyond thirty (30) years.

MR. BOB PETERS: Are those likely coal or nuclear plants?

DR. ROBERT SINCLAIR: Probably some of the bigger plants, yeah. More capital intensive ones.

MR. BOB PETERS: Meaning nuclear?

DR. ROBERT SINCLAIR: Could be nuclear

and coal. CCGTs tend to be a little shorter in their contract durations. But they probably would be nuclear or coal plants.

MR. BOB PETERS: Is it safe to say that, you know, since 2002 to 2012, just to pick ten (10) years, there's been a progression of plant efficiencies related to these combustion turbines?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And is -- is there a law of diminishing returns at some point where you -- you can't squeeze any more efficiency out of them?

DR. ROBERT SINCLAIR: Probably. I haven't looked into, you know, the rate at which these are improving. But technology always surprises us, so I would hate to say what's going to happen next.

MR. BOB PETERS: But I think I heard you tell one (1) of my colleagues that technology change is inevitable in Potomac's view?

DR. ROBERT SINCLAIR: Yeah, we think the technology would keep advancing.

MR. BOB PETERS: Do you have any -- any feel or any opinion as to how efficient CTs or CCGTs are going to be in the next, you know, by 2035?

DR. ROBERT SINCLAIR: No, we don't really -- we don't have a view on that.

MR. BOB PETERS: Likewise, further out you have no view?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And I just want to talk about those future -- the future value of contracts for Manitoba Hydro beyond 2034, and -- and how Potomac recommends those contracts be calculated in terms of their value. Let's start with my understanding of what Manitoba Hydro does and see if it's the same as yours.

And going out past 2034, Manitoba Hydro takes the -- the last four (4) years of that time period and calculates what's the compounded annual growth rate?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And that's for the last four (4) years out to 2034, so it would be 2030 to 2034, approximately?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And then they take that compounded annual growth rate and they extend the forecast that they've been provided from 2034 out to 2049, based on that compound annual growth rate declining to zero?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: All right. And then after 2049, Hydro assumes zero growth?

DR. ROBERT SINCLAIR: Correct.

MR. BOB PETERS: And from Potomac's perspective, is that an appropriate way to calculate the opportunity sales beyond 2034?

DR. ROBERT SINCLAIR: If you look at those, those growth rates are pretty small once you get past 2035 and you're progressively making them smaller. So in our testimony we thought there should be some analysis of what happens to the revenues at -- at growth rate zero.

But we don't have a -- we don't -- we don't see that growth rate as being a particular problem as far as the impact on the overall analysis. We didn't -- we didn't really take a shot at our own estimate of that, because we thought it very difficult to do. But given that it does go to zero, we just thought a sensitivity on what would happen if it was zero after 2035 would be sufficient to inform the panel.

MR. BOB PETERS: And you didn't see that sensitivity?

DR. ROBERT SINCLAIR: Not yet.

MR. BOB PETERS: Is it feasible for

Manitoba Hydro to count on imports from MISO going forward?

DR. ROBERT SINCLAIR: When you say "imports" you mean bringing power from MISO into Manitoba?

MR. BOB PETERS: Correct --

DR. ROBERT SINCLAIR: Okay.

MR. BOB PETERS: -- which would be an export from your side of the border --

DR. ROBERT SINCLAIR: Yeah.

MR. BOB PETERS: -- but to import it from the United States into Canada?

DR. ROBERT SINCLAIR: Yeah, I think they have a model that indicates that it's profitable sometimes to do that. It's reasonable.

MR. BOB PETERS: And going forward, is it likely that Hydro could enter into bilateral contracts for the supply of energy?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And what prices would Manitoba have to pay relative to the Potomac reference case prices for such energy?

DR. ROBERT SINCLAIR: So the purchases that Manitoba Hydro would make are typically going to be off-peak, because I think they want to fill their reservoirs overnight and on weekends. So they would typically pay MISO market the off-peak price.

MR. BOB PETERS: And what if those purchases were on-peak?

DR. ROBERT SINCLAIR: Then they would pay the on-peak price.

MR. BOB PETERS: All right. So simply the -- the MISO market price?

DR. ROBERT SINCLAIR: Yeah, energy price, right.

MR. BOB PETERS: And if Manitoba Hydro was able to enter into a bilateral contract for the supply of firm energy, have you any handle on what -- or any opinion on what the -- the price would be?

DR. ROBERT SINCLAIR: Yeah, firm contract would include a capacity component. So you would want to have the energy price and then you would add to that an annual capacity price. If you want you could, as you suggested before, spread that annual capacity price over the -- the sixteen (16) hours of the -- the day. But basically a firm contract would be sold or purchased at the energy price plus the capacity price.

MR. BOB PETERS: All right.

THE CHAIRPERSON: Would you expect

that to be the same for a diversity agreement?

DR. ROBERT SINCLAIR: Diversity agreement, as I understand it, would not include the capacity price. It would include an exchange of energy.

THE CHAIRPERSON: So while you didn't examine the diversity agreements, looking at it from simple arbitraging standpoint, so I think what Manitoba Hydro is doing is attempting to arbitrage the difference in prices between peak versus non-peak, both on a day-to-day basis but also on a -- a seasonal basis.

Now, can -- can you comment on -- on that -- that spread that exists between day -- I realize it probably varies all the time, but is there an average spread between peak versus non-peak and -- and season to season?

DR. ROBERT SINCLAIR: I don't know what it is off the top of my head, but there are certainly ways to calculate that spread. And it makes sense for Manitoba Hydro to, you know, buy power during the off-peak when it's, I don't know, twenty dollars ($20), so that their reservoirs can fill up and have more available on -- on the on-peak where it may be fifty dollars ($50). So that does make sense.

We could probably get you some statistics on what that is in recent times. Manitoba would have statistics that would explain that probably better.

THE CHAIRPERSON: So -- so there -- there is no published data that allows one to calculate that difference with some certainty? You would have to go Manitoba Hydro to be able to establish that, is that...

DR. ROBERT SINCLAIR: Oh no, you can look at the MISO market to see what the historical prices are in -- in any hour. And so you could -- you could calculate the spread between the off-peak hours and the on-peak hours.

But as far as how it makes sense for their own system to save that water that would be something they -- they would have dev -- developed over time and optimized for their own marketing.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: Sorry, Mr. Chair, I'm not sure if you wanted Dr. Sinclair to undertake to provide that information?

DR. ROBERT SINCLAIR: If you look at

the chart that's actually on the screen now, if you looked at the 2015 prices those are pretty close to current prices. And so you see that the off-peak is roughly eighteen dollars ($18), maybe little higher today than -- than that, and the on-peak is around thirty (30). These are average.

So the average difference just looking at that data would be about twelve dollars ($12). So they could buy twelve dollars ($12) -- or they can buy at eighteen dollars ($18) at nighttime, and then sell at thirty dollars ($30) during -- during the day. And again it changes during the year, so the would have to decide themselves what the best -- best time to make those purchases are and -- to save their water.

THE CHAIRPERSON: But having a diversity agreement would let you lock in -- lock in the ability to deliver peak versus non-peak, right? I mean, if -- if you have a counterparty in the US that is willing to sign a diversity agreement that allows you to get the transmission to lock in the difference in day-to-day prices and -- and so on, am I correct?

DR. ROBERT SINCLAIR: Sitting here, I don't know exactly the terms of diversity agreement, so I can't say exactly how those operate.

DAVID PATTON, Previously Sworn

DR. DAVID PATTON: Yeah, I think -- I think it depends a lot on the nature of the -- the limitation. If -- if you're already going to be fully utilizing the -- the transmission capability to import power in the peak, then exporting power in the off-peak doesn't help you very much. The -- but -- so you'd have to look at -- at how much excess you have, what the nature of the -- the limitation is, and how to optimize it, and whether there's any -- whether there's enough transmission capability to effectively shift off-peak power to -- to on-peak.

DR. ROBERT SINCLAIR: Sorry. A lot of hours of the year they'll -- they'll be constrained in how much they can export on the peak hours, so there would be no sense saving it overnight.

CONTINUED CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Welcome back, Dr. Patton. My last question actually for -- for this panel and the public record, Dr. Sinclair, is: Did the panel -- would they be correct in understanding your evidence to be that no domestic load growth after 2047 is a conservative assumption?

DR. ROBERT SINCLAIR: I think that -- again, it's hard to say that far out, because we don't -- we would expect the population to continue to grow, of course, but we don't know whether population growth will also result in a growth in demand, as we don't know how the population will be using electricity at that point in time. Whether it's conservative, I would say that -- that it's conservative.

MR. BOB PETERS: All right. And then out to -- let's go out past 2047 in terms of the increase in the average export price beyond 2047.

How should that be considered on a conservative basis?

DR. ROBERT SINCLAIR: I think zero percent growth would probably be conservative. Zero percent real growth.

MR. BOB PETERS: Did you have an opportunity to review Manitoba Hydro's Appendix 11.3 in terms of their forecasts for exports and export prices?

DR. ROBERT SINCLAIR: Yes.

MR. BOB PETERS: And my understanding of that information is that Manitoba Hydro continued to forecast an increase in the average export price beyond 2047.

Is that your understanding?

DR. ROBERT SINCLAIR: My understanding was that export prices would go to zero after 2047.

MR. BOB PETERS: All right. I'll -- I'll double check that. And if they didn't, your suggestion is that as a conservative estimate they should?

DR. ROBERT SINCLAIR: Yeah. My understanding was zero, and we thought that was conservative and -- and be useful for evaluating the -- the economics.

MR. BOB PETERS: All right. If you could also just undertake to double check that -- I think it was Appendix 11.3 -- and opine from Potomac's view as to whether the Preferred Development Plan assumptions are conservative or otherwise.

DR. ROBERT SINCLAIR: With -- with respect to prices?

MR. BOB PETERS: Yes, sir.

DR. ROBERT SINCLAIR: Yeah. All right.

--- UNDERTAKING NO. 89: Potomac to indicate view as to whether the Preferred Development Plan

assumptions are
conservative or otherwise

MR. BOB PETERS: Thank you. Mr. Chairman, with that I do want to thank Dr. Sinclair as well as Dr. Patton, although -- those -- those will be my questions from this morning. Thank you.

THE CHAIRPERSON: I have a few additional questions and I'm assuming that the -- the other panel members may have some as well. But any case let's -- I want to address the -- your report on page 44 and page 45. And it's specifically addressing the fact that Manitoba is -- Manitoba Hydro is able to obtain a premium in relation to on-peak opportunity sales relative to what normally -- the price is -- normally be available in the marketplace.

And so I just wanted to ensure that the -- the data that allowed you to determine that was that data that published data, or is that data that was provided to you by Manitoba Hydro?

DR. ROBERT SINCLAIR: That -- that was data provided by Manitoba Hydro.

THE CHAIRPERSON: And so you only examined 2011 and 2012? You didn't examine any other years than that?

DR. ROBERT SINCLAIR: That's correct. They were the recent years that was available from Manitoba.

THE CHAIRPERSON: Now, you referred to the val -- the -- the -- you referred to a hedge obtained by the buyers of on-peak. You're not talking about a hedge available in a futures market, you're talking about a physical hedge here, are you?

DR. DAVID PATTON: Yes, that you've -- you've locked in your -- your energy price in the form of the -- the procurement so that you're not subject to the volatility in the day-ahead market.

THE CHAIRPERSON: So what I'd like to know is are you in a position to -- to -- you make a recommendation to the effect that Manitoba Hydro should be attending to model these values, in other words to -- well, I'm -- I'm assuming to allow it to make sure it captures the most -- the most premium possible. How would you do that? I mean, how would you -- you would have to make some -- some assumptions about the causes for the premium and then try to mod -- model that from the data.

Is that how you do it -- you would do that?

DR. DAVID PATTON: Yeah, so basically

it would be -- if -- if you assume the buyers are risk-neutral the premium would be zero, so you -- so you have to model some -- some preference for reducing risk. Now, we didn't -- we didn't undertake that but -- but if you were -- if you were banking on earning a premium over and above the day-ahead market then -- then I think what we're suggesting is it would be useful to develop a model of what that -- what the value of that hedge is to a buyer whose -- whose risk adverse and -- and wants to protect itself against that -- that sort of volatility, so that you come up a -- a fundamental estimate of how large you could expect that premium to be over time. Because I -- I don't know that over time Manitoba really has the ability to increase that premium. That premium is going to be driven by the -- the preferences of the buyers.

THE CHAIRPERSON: Can you comment on the explanation why in 2011 it was only two (2) -- it was 2 percent and -- and the following year was 10 percent?

What -- what would account for that sizeable difference between the two (2) years based on your intuition, or your knowledge of the market?

MS. PATTI RAMAGE: I think that's a

question we ought to be dealing with this afternoon.

(BRIEF PAUSE)

DR. HUGH GRANT: Can I come back to this page 49, this table, again, about capacity change, because I'm just -- I'm new at this. So if the -- if the axis was percentage changes, I think the thing I find quite striking is just how slow capacity comes offline, right. Because this is really -- almost twenty (20) years on the bottom, and it would be over this twenty (20) year period even in the low -- with low gas prices it's maybe at most 10 percent of total existing capacity comes offline?

DR. DAVID PATTON: That's correct, yes.

DR. HUGH GRANT: Is there something specific about the nature of these coal-fired stations that -- like what's -- what is their typical shelf life?

DR. DAVID PATTON: A coal plant?

DR. HUGH GRANT: Yeah.

DR. DAVID PATTON: Well -- yeah, a lot of these coal plants, I think people would normally assume something like forty (40) years, but a lot of the coal plants that we're talking about here actually are -- are about fifty (50) years. So they're -- they're beyond their assumed useful life.

DR. HUGH GRANT: But they simply get retrofitted and keep chugging on?

DR. DAVID PATTON: Yeah, it turns out that the -- you -- you know, the cost of patching it together and keeping them in operation tends to be lower than -- than building replacement capacity, so.

DR. HUGH GRANT: And this is not true, I take it -- if you look at the reference case, this is not true of CT plants, where you notice in some of the early years you actually get CT capacity coming off line where the coal plant just persist and...

DR. DAVID PATTON: Well, now the -- the -- just make sure you're interpreting this correctly. When -- when you say how slowly the coal plants come offline, to me this chart looks like the coal plants are dropping off extremely quickly. In other words, the retirements of coal plants -- you know, we're assuming in the next two (2) years that we're going to lose most of our coal plant capacity.

DR. HUGH GRANT: I thought this was a cumulative chart, so that...

DR. DAVID PATTON: Oh, no, no. This

is a -- this is absolute.

DR. HUGH GRANT: Annual...

DR. DAVID PATTON: Well, in other -- in other words, the -- the fact that in the coal plant bar that you see is the same amount in 2020 as in 2021, means -- doesn't mean that those are two (2) different slugs of capacity that are retiring, one (1) in 2020 and one (1) in 2021. It -- it means a plant retired in 2016 and it stayed retired for the whole duration.

DR. HUGH GRANT: So that -- that's what strikes me as rather a slow rate of removal, isn't it? Because even -- like, again, take the low gas price scenario. You're saying between 2016 and 2034, there's only 10,000 megawatts coming offline, which is roughly 10 percent of capacity.

DR. DAVID PATTON: Oh, I see what you're saying.

DR. HUGH GRANT: It seems -- it just strikes me as an extremely slow...

DR. DAVID PATTON: So it's -- so we didn't -- so it's fast initially that you lose a lot, and then it's slow thereafter.

DR. HUGH GRANT: Yeah, it's just that --

DR. DAVID PATTON: Okay.

DR. HUGH GRANT: I -- I mean, I guess it's unique to this industry, but you're used to sort of more rapid rates of retirement of capital stock, I think, in most cases, but...

DR. DAVID PATTON: Yeah, I think what happens is we're getting an accelerated retirement of units that are at the end of their useful life. And so you're left with -- with units that are more cost effective, particularly once you've spent the money to upgrade them to meet the -- the more stringent environmental standards. It's more economic to -- to keep them in operation.

DR. HUGH GRANT: And -- and most coal plants would be of a particular vintage, or they're spaced out over, I guess, expansion of the '60s, perhaps, or...?

DR. DAVID PATTON: I think it varies, but there -- yeah, there was a -- there was a slug that -- that came in in the -- in the '60s, early '70s when -- when demand growth for electricity slowed in the, let's say late '70s the -- the building really slowed down.

DR. HUGH GRANT: And -- and so the variable cost of running a coal plant would still be lower than a natural gas plant? So the --

DR. DAVID PATTON: Yes. Most of -- yeah, most of the time and in -- in most locations we do have -- we do have, sort of, coal plants that are operating on two (2) different types of coal, one (1) of which is quite a bit more expensive. But the coal that's on the western side of the footprint is -- is -- tends to burn the -- the Powder River Basin coal, and that coal is lower quality and very, very cheap --

DR. HUGH GRANT: And so that -- that's what encourages you to try to keep your capital stock going, and -- because of this low margin?

DR. DAVID PATTON: Yeah, you earn a pretty high net revenue on -- when you run for energy.

DR. HUGH GRANT: Right. Okay. Thanks.

THE CHAIRPERSON: Thank you. I -- the panel has no further questions, at least in the -- Ms. Ramage, please?

RE-CROSS-EXAMINATION BY MS. PATTI RAMAGE:

MS. PATTI RAMAGE: Thank you. And if I could have -- I think it's PUB Exhibit 63, the table that Mr. Peters was referring to -- that's the one, thank you -- up on the screen.

I have a few questions for you on -- on this. And to be fair, I want to begin by letting you know this is not a Manitoba Hydro exhibit.

You -- you're aware of that?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: It was created by the Public Utilities Board advisors. and -- and to be fair in terms of my line of questioning, Mr. Cormie disagreed with the presentation of this material on the record --

DR. ROBERT SINCLAIR: Okay.

MS. PATTI RAMAGE: -- previously. so I'm trying to get at what parts of this presentation that you can speak to in terms of your knowledge.

DR. ROBERT SINCLAIR: Okay.

MS. PATTI RAMAGE: So -- and I understood you to say that you're not familiar with the specific terms associated with energy deliveries under Manitoba Hydro's diversity sales.

Is that right? Is that what you said?

DR. ROBERT SINCLAIR: Yeah, it's not something that we focussed on for purposes of our report.

MS. PATTI RAMAGE: Okay. And --

DR. ROBERT SINCLAIR: But we're used

to these types of arrangements.

MS. PATTI RAMAGE: Right. Manitoba Hydro has three (3) diversity sales? That's your understanding?

DR. ROBERT SINCLAIR: I think I heard that at some point, yes.

MS. PATTI RAMAGE: Okay. And is it -- would you -- is it your understanding that capacity is treated the same in all of the diversity sales? We don't pay for capacity that we get in the winter, and our counterparties don't pay for the capacity they receive in the summer?

Do you recall that from the agreements?

DR. ROBERT SINCLAIR: Okay. Subject to check, that's -- I think that's what I understand.

MS. PATTI RAMAGE: Okay. So would you agree that when there's an equal exchange of capacity it doesn't mean you're getting zero value for the capacity?

DR. DAVID PATTON: Do you mean capacity or energy?

MS. PATTI RAMAGE: I mean capacity right now.

DR. DAVID PATTON: Okay.

MS. PATTI RAMAGE: When neither charge

a demand charge. If you're exchanging equal amounts of capacity --

DR. ROBERT SINCLAIR: Okay. Assuming capac -- you -- it's inter-temporal, right, so you -- you're getting capacity at some times --

MS. PATTI RAMAGE: In the --

DR. ROBERT SINCLAIR: -- other times --

MS. PATTI RAMAGE: -- Manitoba Hydro gets capacity in the winter.

DR. ROBERT SINCLAIR: Okay.

MS. PATTI RAMAGE: It gives capacity in the summer. It doesn't get charged for what it gets in the winter. It doesn't charge for what it gives in the summer.

DR. ROBERT SINCLAIR: Okay. So you're receiving some value for it, for sure.

MS. PATTI RAMAGE: Right. Now with regard to the energy price, would it be your understanding that two (2) of the diversity sales are for fixed prices for fixed volumes of energy sold in the summer?

DR. ROBERT SINCLAIR: Subject to check.

MS. PATTI RAMAGE: And then are you aware that one (1) of the diversity sales is for market priced energy in the summer?

DR. ROBERT SINCLAIR: I think I saw that, yes.

MS. PATTI RAMAGE: Okay. And then would you be aware that the same contact allows Manitoba Hydro to use the transmission secured year round into the MISO market for market sales in the winter when Manitoba Hydro doesn't need to purchase energy and has surplus to sell?

DR. ROBERT SINCLAIR: Okay.

MS. PATTI RAMAGE: Accept that subject to check?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: Okay. Are you aware that the increased volumes of diversity energy sales shown over the last few years in this chart were under the market price contracts, and priced at the LMP node at the Minnesota Hub rather than the Manitoba Hydro node?

DR. ROBERT SINCLAIR: I don't remember seeing that, but subject to check.

MS. PATTI RAMAGE: Subject -- would you accept, subject to check, then that that contract ends in 2014?

DR. ROBERT SINCLAIR: Sure.

MS. PATTI RAMAGE: And based on the -- the three (3) contracts in place, is it reasonable to assume that Manitoba Hydro and its customers have flexibility to negotiated diversity agreements involving either firm energy or market priced energy, and that the current mix is not necessarily determinative of the future?

DR. ROBERT SINCLAIR: Sure.

MS. PATTI RAMAGE: All right. However, would you see any -- any reason to expect a change with respect to the tre -- treatment of demand charges, assuming volumes -- volumes exchanged are -- or not volumes -- assuming the capacity exchanged is equal summer and winter?

DR. ROBERT SINCLAIR: I would not.

MS. PATTI RAMAGE: Thank you.

DR. DAVID PATTON: I'm interested in -- in what that question meant, because we did -- we did -- we have transformed the capacity market from a monthly market into an annual product. So were -- were you asking whether -- whether future -- future value is likely to be similar to historic value from--

MS. PATTI RAMAGE: No --

DR. DAVID PATTON: -- trading capacity between seasons?

MS. PATTI RAMAGE: No, I think it was far more simplistic in terms of if the -- if a contract says, I'll give you 150 megawatts of capacity in the summer if you give me 150 megawatts of capacity in the winter, and we'll just -- we're not going to exchange -- I'm not going to give you a hundred and fifty dollars ($150) for that, so that you can write me a cheque for a hundred and fifty dollars ($150). That's what I'm getting at.

DR. DAVID PATTON: Okay.

MS. PATTI RAMAGE: So you would see no reason for that to exchange if that is the arrangement?

DR. ROBERT SINCLAIR: No reason.

THE CHAIRPERSON: Ms. Ramage, could you explain the -- the significance of the different notes?

MS. PATTI RAMAGE: You know, I could, but I'm not actually a witness. Mr. Cormie perhaps should. But I'm very proud to say I could.

MR. DAVE CORMIE: As I explained, Mr. Chairman, several weeks ago, this one (1) diversity agreement has grandfathered transmission associated with it, which means it's not subject to the MISO tariff yet. And Manitoba Hydro is able to sell its energy at the Minn Hub price rather at the Manitoba nodal price. And that avoids the cost of congestion and losses that -- that the two (2) doctors had talked about.

And so we will use that transmission in order to deliver energy into MISO in order to receive the Minn Hub price rather than the Manitoba nodal price. And -- and the two (2) companies who are part of the diverse could share that benefit. And that's one (1) of the values -- that's one (1) of the additional values that in the opportunity market that we gain revenue that's not associated with the MISO day ahead sales and real time sales at the Manitoba node. So it generates revenue for the company.

So it's -- it's kind of one of those extra ways that Manitoba Hydro produces value that's not reflected in the MISO forecast market price at the -- at the Manitoba Hydro node. And -- but unfortunately, that grandfather transmission expires next -- this year and we will go into a new arrangement. And -- and that arrangement will -- will cease to be able to capture that value. But we're -- we're always trying to capture that value out of our portfolio.

And it -- I'm -- all our -- all we're

suggesting is that the diversity arrangements that we had in the past still have some of the grandfather transmission benefits associated with them. And as those grandfathered arrangements expire we'll enter into new arrangements, generally under the tariff, and -- and then we'll proceed into the future. But what's happened in the past is not indicative of what you can expect in the future.

And the companies that are -- are making these arrangements are fully free to do whatever makes business sense for them. Right now it makes sense for us to trade under, you know, move spot market energy under the diversities.

But as we go forward and we build Conawapa and Keeyask, we will be wanting to put fixed price take or pay energy under the diversity sales. And just because we have those market priced non-fixed quantities today doesn't imply that that will be the situation in the future.

THE CHAIRPERSON: Thanks. I believe that's all the questions, unless you have something else to add?

MS. PATTI RAMAGE: I have one (1) other question. And I have to compliment Mr. Cormie, that's almost as good as I would have said it.

CONTINUED BY MS. PATTI RAMAGE:

MS. PATTI RAMAGE: Dr. Sinclair, you indicated this morning that you had dealt with one (1) of Manitoba Hydro's price consultants and they had been very forthcoming with information in other situations.

Is that correct?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: Would you accept that different price forecasters have different business models and they produce different products?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: And you're aware that a number of the consultant's market products that, for example, include selling a licence to use a model, that the purchaser could then use itself? They create their own forecast and input their data, or purchase data, and they can manipulate that data.

That is one (1) of the -- the products that can be purchased?

DR. ROBERT SINCLAIR: That sounds reasonable.

MS. PATTI RAMAGE: That's not what Manitoba Hydro purchased though? Of the -- the price forecasts you saw, they were not models that Manitoba

Hydro purchased the model and then manipulated data itself?

DR. ROBERT SINCLAIR: Are you asking me what the nature of the agreement was with your consultants?

MS. PATTI RAMAGE: No, not the nature of the agreement, the -- just the general product that was bought.

Did we purchase a forecast or did we purchase a model to produce a forecast?

DR. ROBERT SINCLAIR: Oh, I understand. You purchased a forecast.

MS. PATTI RAMAGE: Right. And then in terms of purchased forecasts, you're aware a number of forecasters market a -- their own generic forecasts where they use their own models and their own data to come up with a long-term forecast.

Is that correct?

DR. ROBERT SINCLAIR: Your consultants did that. Are -- are you asking me that?

MS. PATTI RAMAGE: I'm asking in -- first in general terms that there are -- that's one (1) of the business models that -- or products that price forecast consultants will sell: the generic model?

DR. ROBERT SINCLAIR: Oh yeah, the model itsel --

MS. PATTI RAMAGE: Or gen -- I'm sorry, the generic price forecast. It's an off-the-shelf product.

DR. ROBERT SINCLAIR: Yeah, we -- we've seen those. Yeah.

MS. PATTI RAMAGE: And you -- you can confirm that at least some of Manitoba Hydro's price forecasts that you saw were off-the-shelf products?

DR. ROBERT SINCLAIR: The ones that your consultants produced were off-the-shelf products? I -- I don't know if I've seen products from those consultants like that before, so I don't know if that's their off-the-shelf product or not.

MS. PATTI RAMAGE: Okay.

DR. ROBERT SINCLAIR: I know that what they gave you is a forecast, not -- not the model.

MS. PATTI RAMAGE: Okay. Another product that price forecasters can provide then is a -- a forecast that is customized to the purchase interests?

DR. ROBERT SINCLAIR: Correct.

MS. PATTI RAMAGE: Do you agree with that?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: And at least some of the forecasts, one (1) or more of the forecasts you saw of Manitoba Hydro's, would have been a customized product.

Is that correct?

DR. ROBERT SINCLAIR: Seems like it, yes.

MS. PATTI RAMAGE: And if a company's business model, for example, includes both the sale of a generic forecast off-the-shelf, and customized forecasts, can you see why they might carefully guard their models?

DR. ROBERT SINCLAIR: Sure.

MS. PATTI RAMAGE: And based on your review of the consultants' information that was provided to Manitoba Hydro and provided to you, would you agree that it was apparent that they did not rely on publicly available EIA data to the same degree as Potomac did?

DR. ROBERT SINCLAIR: I think there was at some point a request that they produce forecasts with the EIA data. I believe most of the reference -- so-called reference case forecasts they would have used a mixture of some -- I've seen EIA data in some of those forecasts. I've seen some of their own internal forecasts used for some of the inputs.

MS. PATTI RAMAGE: Would you agree then that the value provided by the independent price forecasters is that they study the same type of information as EIA, but they provide their independent perspectives and insights?

DR. ROBERT SINCLAIR: So if you're saying that because they don't use EIA data from top to bottom that somehow they might find their own analysis superior to the EIA? Is that what you're...

MS. PATTI RAMAGE: Yes.

DR. ROBERT SINCLAIR: It must be what they -- they think, yes.

DR. DAVID PATTON: Well, I mean, let me answer that. The -- I think it's important to differentiate between the value they're providing through their model, you know, how they translate inputs into forecasts and outputs, and -- versus the value that they're providing in coming up with better forecasts of the inputs themselves.

I'm not sure all of the consultants would say that -- well, I think generally the consultants I've interacted with are really selling their model, and not so much -- and this may not be true for all of them, but not so much testing the majority of their value and -- in being able to come up with a better input assumption.

MS. PATTI RAMAGE: But if -- you'd agree if we all just used EIA and we can buy off-the-shelf products, we would come up with the same amount? There has to be some value in those insights into that input data?

DR. ROBERT SINCLAIR: I don't know about off-the-shelf, but -- I don't know exactly how they pitch it when they -- when they sell it to you, but they could -- they -- I wouldn't be surprised that they represented to you that they have value-added in their inputs as well.

MS. PATTI RAMAGE: They certainly have independent perspectives.

DR. ROBERT SINCLAIR: Different than the EIA --

MS. PATTI RAMAGE: Different --

DR. ROBERT SINCLAIR: -- in some cases, yeah.

MS. PATTI RAMAGE: Yes. And they have to invest in developing those independent perspectives? Is -- I -- sorry --

DR. ROBERT SINCLAIR: Yeah, they would have to spend money to do that.

MS. PATTI RAMAGE: So a company that invests its resources in developing its own data, and who markets that information in the context of both generic forecasts, specialized price forecasts, and perhaps even off the -- providing off-the-shelf models, is likely to be more protective of the models they use to develop the forecasts they sell with their data than a company that just uses off-the-shelf data -- or, I mean, publicly available data, and -- and an off-the-shelf model, or a publicly available model?

DR. ROBERT SINCLAIR: Well -- yeah, it's logical, so I can't disagree. And that wasn't -- the fact that they protected it it wasn't really our issue as much as -- I mean, it's natural for a company to protect it. We -- we were -- our complaint really is that we wanted to understand better what they were doing, because it's being used in a proceeding where it's important to have some transparency of the underlying calculations and how they get to the results.

So even though they -- I understand they protect it, I think in a proceeding like this they should have been a little more transparent in helping us understand how they got to where they were. And because of that we -- we needed to do our own forecast.

MS. PATTI RAMAGE: Now, going back to -- you referenced one (1) of Hydro's price consultants sharing data in a different forum.

Do you know what product that customer purchased in that case?

DR. ROBERT SINCLAIR: Yes.

MS. PATTI RAMAGE: Are you able to share that with us on the public record, or...?

DR. ROBERT SINCLAIR: Would -- I -- you mean you want me to tell you who your consultant was?

MS. PATTI RAMAGE: No. No, I don't want you to tell me who the -- I want to know which classification of product was it? Was it a -- an off-the-shelf product? Was it a specialized product? Was it --

DR. ROBERT SINCLAIR: In the case I had in mind it was a specialized product.

MS. PATTI RAMAGE: And without revealing the identity of the -- the actual -- the -- the customer in this case, was it a merchant generator, or a regulated utility?

DR. ROBERT SINCLAIR: It was a regulated utility.

MS. PATTI RAMAGE: Okay.

(BRIEF PAUSE)

MS. PATTI RAMAGE: And was the information shared in the context of a regulatory process like this?

DR. ROBERT SINCLAIR: I'm sorry, I missed the first part. What --

MS. PATTI RAMAGE: Was the information shared with you in the context of a regulatory process like this?

DR. ROBERT SINCLAIR: Some of it was made public. It wasn't in a regulatory process.

MS. PATTI RAMAGE: And would it be one (1) of -- more akin to one of Potomac's short-term -- short-term -- well, I shouldn't say "Potomac's".

Was it a -- a short-term forecast?

DR. ROBERT SINCLAIR: The -- the model that was being used was a short-term fore -- forecast.

MS. PATTI RAMAGE: So it was not something that was used for negotiating long-term sales?

DR. ROBERT SINCLAIR: No, they were short-term sales.

MS. PATTI RAMAGE: Okay. Thank you. That concludes my questions.

THE CHAIRPERSON: Mr. Williams, please? Me. Hacault...?

MR. ANTOINE HACAULT: Just some comments, members of the panel. I note that there's been approximately an additional twenty (20) minutes of cross-examination not -- which was not part of the agreed to sequence. The information, I guess, was useful. I also note that there was out of sequence testimony by Manitoba Hydro during the cross-examination.

And I just want to note for the record that we're not consenting to that unless all parties are going to be given the same latitude going forward. It's occurred, but there are questions and may be questions that Intervenors may like to ask after the cross-examination by Board counsel also, which would be very relevant to their positions.

So I just wanted to note for the record that we aren't consenting by the fact that this occurred during this occasion to it reoccurring again, unless all parties are given the same kind of treatment.

MS. PATTI RAMAGE: If I could speak to that. Mr. Hacault is forgetting, or perhaps is not aware that the -- the practice before the Public Utilities Board has always been that Manitoba -- or the -- Manitoba Hydro has been given the opportunity after Board counsel to re-examine, because as an Applicant it gets -- it should get the last word and be able to cross-examine. It's as an agreement amongst the parties, because Board counsel prefers to do a clean-up at the end and, so that is the practice that has developed over many years. This is not new.

MR. BYRON WILLIAMS: Mr. Chair, if I might?

THE CHAIRPERSON: Mr. Williams, please, yeah.

MR. BYRON WILLIAMS: I guess I have three (3) general comm -- comments. First of all, we always love to hear from Mr. Cormie, but we -- certainly I -- I think some of the process this morning was unusual, and we certainly want the Board to have all the information it requires, so we -- we did not raise an objection at that time.

But it does put us in a difficult position. There may be -- in this case the questions of Mr. Cormie I don't think I would have wanted to cross-examine him, but there -- it -- it does put us in a difficult position, and so I offer that comment in terms of his.

In terms of the -- the cross-examination of My Friend Ms. Ramage, the -- the post Board counsel, I would divide it into two (2) pieces, because I would concede that there was some material new in terms of the comments from Potomac in terms of information shared by one of Hydro's forecasters, but it is arguable that My Friend also took some liberties to revisit some of her cross-examination earlier. And so I would distinguish -- so I would just say that to the extent that we follow that process it -- it really should be focussed on new issues arising through Board -- Board counsels, and not kind of another kick at the -- at the cat.

A third caution in terms of process from my client is the -- their -- from our client's perspective there are material differences in terms of interpretation of CSI. We have heard again this morning some commentary about matters that might be better referred to CSI, and our client would urge extreme caution in restricting the -- the CSI discussions to those matters that are -- that are truly CSI.

And so just as you move into this afternoon, again, our client, for a variety of reasons, feels shut-out of the CSI process, and we would urge caution in restricting that to -- to truly CSI matters.

THE CHAIRPERSON: I wonder if we can stand down for a minute or two (2) so I can consult with Mr. Peters, please?

(BRIEF PAUSE)

THE CHAIRPERSON: Ms. Ramage, have you --

MS. PATTI RAMAGE: Yes. I don't think we're still quite there in figuring out what the question was that -- we were going to find out what the answer was to find out if the answer is CSI, but we're seeing a series of questions and we're not sure which one it was. I think Dr. Pan -- Patton, for example, thinks he may have already answered it. So I think we're going to have to take a little more time with that.

And I would suggest, in order that the parties can go back to their offices, that that might be something that we deal with by way of undertaking.

THE CHAIRPERSON: That sounds like a good solution. So in respect of the issue that was raised by Mr. Williams, I want to indicate that in the future the Chair will be restricting questions from Manitoba Hydro on new issues that are raised as part of the cross-examination. So that provides some guidance with respect to that particular matter.

Now, our -- our witnesses are having to catch a flight sometime later this afternoon, so we have a restricted amount of time with -- with them today. And so what I propose we do, we have an abbreviated lunch, half an hour, if possible, and that will maximize the amount of time that we have with -- with them. And so after lunch it's our intention to go into the CSI session, so it'll be restricted to those individuals who are eligible to consider CSI.

So with that I think some people will be leaving for the day, so I would invite them to be back here at nine o'clock tomorrow morning for the continuation of the public hearing. Thank you very much.

(BRIEF PAUSE)

MS. PATTI RAMAGE: The undertaking is to determine and identify the question posed by Mr. Hacault, which Manitoba Hydro indicated may be CSI. And once we identify that question, to determine whether the res -- the response by Potomac is in fact CSI; and if it is not CSI, Potomac to provide the answer by way of undertaking.

--- UNDERTAKING NO. 90: Manitoba Hydro to determine and identify the question posed by Mr. Hacault, which Manitoba Hydro indicated may be CSI; and then to determine whether the response by Potomac is CSI; and if it is not CSI, Potomac to provide the answer by way of undertaking

THE CHAIRPERSON: We're -- we're hoping it's a really good question.

(PANEL RETIRES)

--- Upon adjourning at 12:07 p.m.

Certified correct,

____

Cheryl Lavigne, Ms.

- MFR 80 – Review this!
- Overarching question – this is most important – can the Board rely on Hydro's reporting on:
  - Export revenues
  - Fuel & power purchases
  - Water rentals
-

MFR 79

- Redacted on web site
- Confidential version not yet with us GET THIS

Possible scope addition:

- Compare what they got in the NFAT (or in between) and what they get now – how do the "custom" versus "off the shelf" products differ?

Possible next step:

- Speak to vendors (Extra scope)

Follow up:

- Write up of what we've done to date
- What we see as possible conclusions
- What we could do as follow up to possibly advance these items?

Issues:

- Process (and available data) as MH used them

Boston Consulting Group Report

- MFR 72
- Attachment – 630 pages or so
- Issues
  - Change in process for premiums
  - Slide 572 – MISO seasonal capacity offer
- Board has been talking about economic evaluation of transmission projects
  - Manitoba Saskatchewan Line
  - $60M project
  - Underpinned by 1 contract
  - May want evidence, which would mean IEC work
  - BCG determines transmission is still beneficial to proceed, slide 480+
  - Would like a review of the underlying economic analysis

- Possible areas of overlap with Dr. Yatchew
    - Natural gas prices
    - Exchange rate – Any 2017 update?