SUBJECT: Fuel Switching

REFERENCE: Sections 2.1-2.3

PREAMBLE: Sections 2.1-2.3 of the report are a summary of Manitoba Hydro's evidence on fuel switching.

QUESTION:

Does GAC accept Manitoba Hydro's findings as summarized in the report? If not, why not?

RESPONSE:

GAC accepts Manitoba Hydro's findings regarding

- The unfavorable economics of electric space and water heating, rather than gas, from the perspective of the customer, the utilities, and the province.
- The adverse global environmental effect of using electricity for space and water heating, rather than gas.
- Existing saturation of electric space and water heating.
- Recent penetration rates for electric space and water heating.

GAC has not been able to determine the basis for Manitoba Hydro's various forecasts of electric space and water heating penetration, and thus can rely on those forecasts only for illustrative purposes.

SUBJECT: Fuel Switching

REFERENCE: Page 2-13

PREAMBLE: The report states that "Some customers assume that their use of electricity for heating protects the global environment, even though Hydro understands that wasting electricity on domestic heat loads reduces the availability of that energy to back down higher-emission coal and gas-fired generation."

QUESTION:

Please confirm that this statement is predicated on displacement of fossil-fuelled load in the MISO market.

RESPONSE:

The statement that "wasting electricity on domestic heat loads reduces the availability of that energy to back down higher-emission coal and gas-fired generation" recognizes that Manitoba Hydro renewable energy not used in Manitoba will displace fossil-fuelled energy in MISO, Ontario, or Saskatchewan.

SUBJECT: Fuel Switching

REFERENCE: Page 2-13

PREAMBLE: The report states that "Some customers assume that their use of electricity for heating protects the global environment, even though Hydro understands that wasting electricity on domestic heat loads reduces the availability of that energy to back down higher-emission coal and gas-fired generation."

QUESTION:

Does GAC have any independent evidence as to the relative GHG efficiency of gas space heating vs. gas generation?

RESPONSE:

Yes. Gas generation is less than 50% efficient, even with the best combined-cycle units operating new and clean, and even lower for load-following combined-cycles, older units, and simple-cycle combustion turbines. Losses in the distribution system would reduce the delivered efficiency by several additional percent. New gas heating systems exceed 80% efficiency.

SUBJECT: Fuel Switching

REFERENCE: Page 2-13 (shown as 3-13 in the IR)

PREAMBLE: The report recommends "incentives to offset the self-interested preference of developers, builders and contractors for electric equipment over gas".

QUESTION:

Please elaborate on the incentives CAC is suggesting.

RESPONSE:

The incentives would increase the cost to the developers, builders and contractors of using electric heat and hot water and decrease the cost of using gas. For new construction, those incentives might include the measures described on page 2-16 of the GAC report.

> Since MH has identified market barriers due to the reluctance of developers to "coordinate additional work crews associated with natural gas" and to investing any more than necessary in the building cost, an effective extension policy would raise the initial cost of electric heat and hot water to parity with the initial cost of gas heat and hot water. That approach would probably result in most developers opting for the electric lower extension costs associated with gas usage. If the policy collects excess funds (above the total system cost of the extension and the unnecessary electric use) for extensions to developments that persist in pursuing resistance heating, the difference can be used to fund additional efficiency for the affected customers, to fund other efficiency and renewable projects to offset the extra energy usage, or refunded to the affected customers over time….
>
> As a mirror image of the high line-extension charges for electricity service, lower charges to developers for gas connections would also tend to encourage the selection of gas over electricity. Hydro is in a very favourable position, compared to most electric utilities, in that it owns the gas distributor. Payments from

Power Smart to Centra to provide gas connections and overcome the first-cost concern would be consistent with incentives to other trade allies.

For contractors and plumbers replacing failing water heaters, Manitoba Hydro suggests that “contractors may encourage customers to install an electric water heater rather than assessing the need for adjusting the venting or installing a more costly sideventing natural gas water heater.” (GAC/MH I-071) This behaviour can be discouraged by imposing a fee for replacing an electric water heater with a a gas water heater, or by paying an incentive to the contractor to install efficient gas water heaters, based on the savings of gas over electricity. Depending on the exact nature of the contractors’ motivation, the problem may also be addressed by providing technical assistance to the contractor to assess the venting.

SUBJECT: Fuel Switching

REFERENCE: Page 2-14

PREAMBLE: The report recommends including-block rates to create incentives to switch to gas heating, but recognizes the need for alternatives for customers without gas service.

QUESTION:

Is GAC suggesting rate relief only in areas in which gas service is not available, or also in buildings where retrofits are not feasible, e.g., apartment blocks or buildings that are too small to allow side venting.

RESPONSE:

It is not clear why a small house would preclude side venting as a general rule. In any case, the heating load of apartments and very small houses would be much lower than the heating load of averge to large houses, so the inclining block rate might not increase the annual electric bill of those small customers.

If an equity problem is identified for existing heating customers, the PUB could create a grandfathered rate for those customers, as suggested in the GAC evidence at page 2-14.

SUBJECT: Fuel Switching

REFERENCE: Page 2-14

PREAMBLE: The report recommends including-block rates to create incentives to switch to gas heating, but recognizes the need for alternatives for customers without gas service.

QUESTION:

In GAC's view, is the issue rate design (after all, all parties acknowledge that gas heat is cheaper than electric heat) or the fact that most people have no input into the source of heating in their homes, either because the home is built by a builder or it is purchased resale?

RESPONSE:

Both rate design and the adverse incentives of builders are important.

Rate design has a role in providing price signals to customers. To the extent that there is a "tendency for customers to make choices that increase emissions, as well as costs to the Province as a whole, [that] can be reduced by implementation of inclining-block residential rates, especially in the winter heating season." (GAC Report at page 2-14) That approach might encourage customers to decline the proposal of contractors to replace gas water heaters with electric, and encourage customers with gas access to convert to gas, among other responses. The prospect of trying to sell a house with higher energy bills would also tend to encourage builders to make the additional investment to employ gas.

In addition, Manitoba Hydro should directly address builders' incentives.

SUBJECT: Fuel Switching

REFERENCE: Page 2-15

PREAMBLE: The report discusses the use of incentive program to encourage gas heat.

QUESTION:

Does this deal with the primary problem that builders are not responsible for operating cost and have no incentive to install the more efficient technology?

RESPONSE:

Yes. If builders only care about their investment in the housing, their decisions can be guided by increasing the investment required for electric heat.

SUBJECT: Fuel Switching

REFERENCE: Page 2-15

PREAMBLE: The report discusses the use of incentive program to encourage gas heat.

QUESTION:

Does GAC envision programs being tailored to builders, i.e., providing builders with an immediate discount for gas furnaces, or does it envision these programs to be tailored to retrofits?

RESPONSE:

Different programs would be appropriate for the new-construction and retrofit markets.

SUBJECT: Fuel Switching

REFERENCE: Page 2-15

PREAMBLE: The report discusses the use of incentive program to encourage gas heat.

QUESTION:

Has GAC considered how high incentives would have to be to obtain meaningful results if gas is already the better choice?

RESPONSE:

Most energy-efficiency programs provide incentives for measures that are "already the better choice" for the customer over the long term. The level of the incentives will vary among programs and measures. Technical assistance, integrated analysis and PAYS financing, and other low-cost measures may be adequate in some cases. For new construction, the incentives could be a combination of carrots and sticks, with no net cost to Manitoba Hydro. For some situations, the incentive (combined with financing) might need to bring the customer's initial cost down to the first year's savings.

SUBJECT: Fuel Switching

REFERENCE: Page 2-15

PREAMBLE: The report discusses the use of incentive program to encourage gas heat.

QUESTION:

Has GAC considered how high incentives could be without negatively affecting Manitoba Hydro's revenue?

RESPONSE:

Manitoba Hydro’s retail electric revenues would decline as a result of smarter fuel choice and fuel switching, while Centra’s would rise. Manitoba Hydro’s wholesale revenues would rise, and its construction requirements (for generation, transmission and distribution) would tend to fall. Thus, Manitoba Hydro’s financial situation may be improved and its retail revenue requirements would be reduced by effective fuel-choice programs.

As noted in response to PUB/GAC-5c, high incentives to builders and on-bill financing might have no net cost to Manitoba Hydro.

SUBJECT: Fuel Switching

REFERENCE: Page 2-15

PREAMBLE: The report discusses the use of incentive program to encourage gas heat.

QUESTION:

Is GAC suggesting that a negative revenue impact on Manitoba Hydro is acceptable in light of other social benefits? If so, please explain your reasoning.

RESPONSE:

It is not clear what "negative revenue impact on Manitoba Hydro" is assumed in the question. Since Manitoba Hydro has found that electric heat costs Manitoba Hydro more than it collects in revenue, smarter fuel choice and fuel switching, Manitoba Hydro's financial situation may be improved by effective fuel-choice programs.

As noted in response to PUB/GAC-5c, high incentives to builders and on-bill financing might have no net cost to Manitoba Hydro.

SUBJECT: Fuel Switching

REFERENCE: Page 2-15

PREAMBLE: The report discusses the use of incentive program to encourage gas heat.

QUESTION:

Does GAC have any opinion on how high connection charges for electricity would have to be to dissuade the installation of electric heat?

RESPONSE:

No. Manitoba Hydro has indicated that builders' fuel choices are driven by the cost of extending gas and electric services, and perhaps by the nuisance of overseeing the work of gas contractors. While reducing or eliminating the difference in the utility charges for service extension for heating would eliminate much of the builder's adverse incentive, Manitoba Hydro has not provided data on the level of those costs. In addition, some level of incentive and design assistance might be needed to overcome the builders' reluctance to design gas-heated homes and supervise gas contractors.

SUBJECT: DSM

REFERENCE: Page 3-1

PREAMBLE: The report states that "None of these jurisdictions has Manitoba's combination of significant saturation of electric space and water heating with high availability of natural gas as an alternative."

QUESTION:

Please provide the data for this statement.

RESPONSE:

This statement is based on Mr. Chernick's knowledge of these jurisdictions. The availability of natural gas varies within most juridictions, and data on the percentage of customers with gas access is not readily available.

Hawai'i has very little heating load and natural gas is available only as LNG.

Much of California and Nevada also have little heating load and the mountainous portions that do have large heating load probably have limited gas availability.

Vermont had no natural gas service until 1966, and only a small portion of the state has gas service. Vermont has included fuel-switching from electricity to other fuels as a DSM measure, but most of that switching has been to oil or propane.

Nova Scotia has a saturation of electric space heat of about 30% and of electric water heat about 60%, but gas is available in only a small portion of Nova Scotia, which has only had gas service since 2003.

Connecticut and Massachusetts have programs (not included in the electric DSM programs) to extend gas service and connect more customers, but almost all the effort and potential appears to be from oil-heat customers.

Some suburban areas in New England that were developed in the 1970s (when the US gas pricing system was dysfunctional, gas was scarce and new gas hookups were essentially prohibited) have electric heat, but no access to gas.

Other than Vermont, none of the other jurisdictions appear to have included fuel-switching as a DSM measure.

The following table summarizes electric space heating saturation for the states listed in the text, from US census data. Manitoba Hydro has a 36.3% saturation of electric heat and a 63.4% penetration of electric heat in gas-served areas.

	Electric Space Heating Saturation
California	24.9
Connecticut	15.1
Hawaii	33.3
Massachusetts	13.7
Nevada	31.0
Rhode Island	8.6
Vermont	4.5

Source: U.S. Census Bureau, 2009 American Community Survey B25024.

SUBJECT: DSM

REFERENCE: Page 3-1

PREAMBLE: The report makes no reference to Manitoba Hydro's DSM potential study.

QUESTION:

What is GAC's position with respect to the achievable potential and market potential established by ENERNOC in the DSM potential study, and how does this influence your "reasonable DSM targets" as set out in Table 3.1?

RESPONSE:

See the testimony of Philippe Dunsky on behalf of CAC and GAC for a critique of the ENERNOC DSM potential study. Detailed review of the DSM potential study is beyond the scope of GAC in this proceeding.

Mr. Chernick's experience with DSM potential studies is that they depend on many subjective judgements and speculation about the effectiveness of well-designed programs. As a result, the results are unreliable. For example, in its 2009 IRP, Entergy Arkansas filed a DSM potential study by ICF that found maximum achievable energy saving in its "reference case" of 0.25% annually over the next 10 years. The Arkansas PSC set targets of 0.25% in 2011, 0.50% in 2012 and 0.75% in 2013, which Entergy has been achieving: ICF now projects Entergy Arkansas savings potential of 1% annually by 2019, rising slightly through 2031. ("Meet Future Energy Needs Through Cost Effective Demand Side Management," Entergy Arkansas, Integrated Resource Plan Stakeholder Committee Meeting, July 31, 2012)

Detailed DSM potential studies are very difficult to review, and should not be relied on without benchmarking to actual results.

SUBJECT: DSM

REFERENCE: Page 3-3

PREAMBLE: Table 3-2 shows a capacity surplus with GAC's aggressive DSM scenario.

QUESTION:

What capacity factor was assumed for DSM in the preparation of Table 3-2? Please explain your reasons, including which DSM measures GAC considers to result in "dependable" DSM and why.

RESPONSE:

The effective load factor assumed was 54.3%, estimated from Manitoba Hydro’s assumed ratio of energy to demand savings from its projected programs.

Once installed, almost all energy-efficiency measures are dependable. If anything, energy savings should increase under the conditions (extreme cold winter, hot dry summers) in which Manitoba Hydro would most need the savings.

Failure of efficient equipment generally results in a reduction of load, not an increase. The savings from some measures (e.g., programmable thermostats) depend on user behaviour, but the diversity of thousands of individual installations should result in very little variation in aggregate savings.

SUBJECT: Wind Integration

REFERENCE: Page 4-2

PREAMBLE: The report states that "In this section of our analysis, we will focus on the calculations and assumptions for a generic 65-MW wind project with Stage I capital costs and Reference Case project costs, as this is what Manitoba Hydro used in its screening process."

QUESTION:

To what extent are there economies of scale in wind power development such that a larger windfarm would have a lower cost per MW or GWh?

RESPONSE:

There are significant economies of scale with respect to development and mobilization costs, substation and interconnection infrastructure, transmission tie lines, and O&M facilities. In addition, larger project sizes enhance the negotiating leverage of project developers and owners with equipment vendors and lenders, which can result in lowerequipment costs.

With a staged, sequential development of wind projects such economies of scale could be realized in Manitoba.

SUBJECT: Wind Integration

REFERENCE: Page 4-2

PREAMBLE: The report states that "In this section of our analysis, we will focus on the calculations and assumptions for a generic 65-MW wind project with Stage I capital costs and Reference Case project costs, as this is what Manitoba Hydro used in its screening process."

QUESTION:

If there are any significant economies of scale, please comment on Manitoba Hydro's choice of a 65-MW wind farm.

RESPONSE:

Manitoba Hydro assumed virtually the same $/kW unit cost for 65 MW and 100 MW, so their choice to base costs on a 65-MW project had virtually no impact on their results. However, if larger wind projects were to be developed through a staged, sequential development and procurement process the economies of scale discussed in PUB/GAC-009a could be realized.

SUBJECT: Wind Integration

REFERENCE: Page 4-5

PREAMBLE: The report states that "NREL's graph shows projections of LCOE, not capital costs per se, with the declines due to a combination of decreasing capital costs and increasing capacity factors. NREL's report does not provide enough information to distinguish between the two factors. However, they can be treated as more-or-less equivalent: a decline in capital costs has much the same effect on LCOE as an increase in capacity factor, and is much easier to model using Manitoba Hydro's LCOE spreadsheet."

QUESTION:

What assumptions are involved in the increasing capacity factor? Specifically, is it based on different technology, such as taller turbines or turbines with a larger blade diameter?

RESPONSE:

The increasing capacity factor is attributable to taller tower heights which offer a more favourable wind resource (stronger winds and less turbulence), larger rotor diameters that increase energy capture, advances in rotor designs that capture more wind, and reduced turbine down time.

SUBJECT: Wind Integration

REFERENCE: Page 4-6

PREAMBLE: The report states that "The assumption of 3% of capital costs three years before the in-service date is not unreasonable, but we would recommend splitting the remaining capital costs evenly between the next two years, resulting in a three-year capital expenditure schedule of 3%/48.5%/48.5%."

QUESTION:

Please explain the basis for your proposed split. Specifically, please advise whether this assumes that turbine supply costs and construction costs are incurred in different years.

RESPONSE:

In our experience working with developers, the bulk of costs are typically incurred within the 12 months prior to the in-service date. Our suggestion to split costs evenly between 1 and 2 years prior to ISD was conservative.

Since submitting our report, we have completed more detailed and specific discussions with wind developers. On the basis of these discussions, we would recommend the following split of capital costs:

- 3 years (36 to 25 months) prior to ISD: 5%
- 2 years (24 to 13 months) prior to ISD: 35%
- 1 year (12 to 1 months) prior to ISD: 60%

Turbine costs are typically split over two years, with a down payment more than a year prior to ISD, and the final payment in the last 12 months prior to ISD. The bulk of construction costs are incurred during the final 12 months.

SUBJECT: Wind Integration

REFERENCE: Page 4-7

PREAMBLE: The report states that "Power Advisory recommends assuming a life of 25 years for the turbines and related equipment, after which they will be replaced. This is consistent with the terms of the St. Joseph and St. Leon project PPAs."

QUESTION:

Aside from relying on the current PPAs in Manitoba, do you have any other evidence to support a 25-year operating life as opposed to a 20-year operating life?

RESPONSE:

Our recommendation is based on discussions with wind developers, who use 25 years or more in their internal financial analysis. We have been told by wind developers that equity research firms consistenly use 25 years.

SUBJECT: Wind Integration

REFERENCE: Page 4-7

PREAMBLE: The report further recommends assuming that turbines can be replaced at 80% of the then-current term of a new wind project.

QUESTION:

Please state the basis for this assumption.

RESPONSE:

Wind power generation does not have abandonment and reclamation costs since recent experience in mature wind power generation regions have shown that the value of the end of life turbines including associated metallurgy is in excess of the reclamation costs. As well, if the site is to be re-used for wind generation, significant components of the capital cost of a greenfield site, including site preparation, permitting, studies, and resource analysis, will not need to be incurred when the project is replaced.

Since submitting our report, we have completed more detailed and specific discussions with wind developers. They have indicated that end-of-life replacement typically costs 85-90% of original costs – i.e., savings are significant, but somewhat lower than what Nova Scotia Power assumed.

However, Power Advisory's calculations indicate that replacement cost assumptions in this range (80% to 90% of original cost) would not have a significant impact on the cost of wind generation.

SUBJECT: Wind Integration

REFERENCE: Page 4-7

PREAMBLE: The report further recommends assuming that turbines can be replaced at 80% of the then-current term of a new wind project.

QUESTION:

Please confirm that this factors out any transmission interconnection costs.

RESPONSE:

Confirmed. In our analysis, we assumed that transmission interconnection costs have a life of 35 years, and that the replacement cost is the same as the full original cost.

SUBJECT: Wind Integration

REFERENCE: Page 4-7

PREAMBLE: The report further recommends assuming that turbines can be replaced at 80% of the then-current term of a new wind project.

QUESTION:

Please further advise whether this factors out the cost of installing a distribution network within the rebuilt windfarm.

RESPONSE:

We would expect that this would be a factor in some cases, as the life of a wind farm's distribution infrastructure woud significantly exceed that of its wind turbines. Whether the distribution infrastructure could be re-used would depend on the design of the replacement project, including the number, size and placement of the new turbines, and therefore would vary from project to project.

SUBJECT: Wind Integration

REFERENCE: Page 4-7

PREAMBLE: With respect to capacity factors, the report discusses the availability of longer rotor blades for existing generators.

QUESTION:

Please comment on the impact longer blades may have on achieving environmental permitting. Does the mere fact that the technology exist mean that it can surmount regulatory constraints (e.g., wind noise or unsightliness complaints, bird & bat kills)?

RESPONSE:

Environmental permitting constraints need to be recognized and addressed in the siting process. However, longer blades and higher tower heights are not likely to be an unsurmountable barrier to the development of wind turbines in Manitoba given existing land use and available areas for wind project development.

SUBJECT: Wind Integration

REFERENCE: Page 4-9

PREAMBLE: The report states that "However, since MISO wholesale market prices are currently significantly lower than they were in 2005, it would be unreasonable to increase this estimate of wind integration costs, and it would not be unreasonable to decrease it."

QUESTION:

Please explain this statement. How do market prices (i.e., revenues) impact integration costs?

RESPONSE:

Manitoba Hydro stated: "The unit wind integration costs are … scaled to the current long-term export price forecast using the ratio of the current long-term price forecast divided by the 2005 price forecast" (Appendix 9.3 – Economic Evaluation, p. 26). Manitoba Hydro did not explain this statement, and any explanation offered by Power Advisory would be speculation.

SUBJECT: Wind Integration

REFERENCE: Page 4-9

PREAMBLE: The report states that "However, since MISO wholesale market prices are currently significantly lower than they were in 2005, it would be unreasonable to increase this estimate of wind integration costs, and it would not be unreasonable to decrease it."

QUESTION:

Do you accept the relatively significant marginal increase of wind integration costs going from 500 MW to 100 MW? Please explain your reasoning.

RESPONSE:

We presume the question should read “from 500 MW to 1000 MW”.

Numerous studies in various countries have found that wind integration costs tend to increase on a per-unit basis as wind’s share of total generating capacity increases. An increase in wind capacity from 500 MW to 1000 MW represents a significant increase in wind’s share of total capacity from 8% to 15% (assuming non-wind capacity of 5,500 MW). Some increase in unit wind integration costs is therefore reasonable.

However, Power Advisory is unable to comment on the reasonableness of the specific assumptions shown in Manitoba Hydro’s application, because we were not given access either to the 2005 Synexus Global study which is given as the source of these assumptions, nor to data on Manitoba Hydro’s experience with the existing wind farms. Section 4.2.3.3 of our report addressed the difficulty in reconciling Manitoba Hydro’s assumptions as stated in their application ($4.22/MWh at 500 MW, $4.99/MWh at 1000 MW, scaled to the export price forecast) with the assumption actually used in their calculations ($8.45/MWh in 2012 dollars) but did not attempt to evaluate the reasonableness of either set of assumptions.

SUBJECT: Wind Integration

REFERENCE: Page 4-11

PREAMBLE: The report states that "While modelling was beyond Power Advisory's mandate, it is possible that, if both of these factors were taken into consideration, one or both of the development plans with wind could be more cost-effective than the Preferred Plan, even over the period out to 2090."

QUESTION:

What you believe the appropriate timeframe is for analyzing the NPV of the alternative plans?

Do you agree with Manitoba Hydro's approach?

RESPONSE:

Power Advisory tends to use a relatively long analysis period for NPV purposes, in lieu of using a terminal value. Manitoba Hydro's 77-year analysis period is long but not necessarily wrong. However, if values beyond a 20- or 30-year period significantly affect the choice between options, we use multiple financial indicators in addition to NPV, and to make sure that the uncertainties associated with the longer time-frames are fully recognized. We do not believe that Manitoba Hydro's analysis adequately addressed these long-term risks.

SUBJECT: Wind Integration

REFERENCE: Page 4-12

PREAMBLE: The report states that "US federal tax subsidies are not available for any wind projects completed after 2015."

QUESTION:

Please state the source of this information.

RESPONSE:

The Federal Production Tax Credit (PTC) expired on December 31, 2013, except for projects which had committed significant funds to project construction (for details, see http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F). While there are efforts to extend the PTC the success of these efforts is at best uncertain.

SUBJECT: Wind Integration

REFERENCE: Page 4-12

PREAMBLE: The report states that "Wind developers are assumed to assume all price risk, whereas in the NFAT, Manitoba Hydro, and through it, the ratepayers of Manitoba, take on the price risk associated with hydro exports."

QUESTION:

Do you believe that this assumption is incorrect? If so, please elaborate.

RESPONSE:

We believe that supply options should be compared on an equal footing. When comparing wind generation to hydro generation in the NFAT, we believe that the approach taken in NPV's calculations – to treat all supply (hydro, wind, thermal, imports) equally, and all demand (domestic or exports) equally – is appropriate. Specific contractual arrangments – such as, for example, having a wind, hydro or thermal plant developed by a third party, either with a Power Purchase Agreement or on a merchant basis – can be considered at a later date, but to assume different contractual arrangement for different types of generation at this stage could obscure the underlying economics.

SUBJECT: Wind Integration

REFERENCE: Page 4-12

PREAMBLE: The report states that "Manitoba Hydro's reasons for rejecting this possibility are based on (incorrect) market considerations, not on technical considerations."

QUESTION:

Please indicate which market information you believe to be incorrect, and why.

RESPONSE:

We consider the following statements to be incorrect:

- "Information provided from potential Manitoba wind developers indicates that the cost of new wind power projects far exceeds the current market energy price in the US market."

As discussed in our report, Manitoba Hydro has greatly over-estimaed the cost of new wind power projects. While the cost of new wind exceeds current market prices, "far exceeds" is incorrect. As well, it is incorrect to compare the future cost of wind generation to current market prices, just as it would be inappropriate to compare the future cost of hydro generation to current market prices.

- "US customers have access to relatively inexpensive wind energy because of US federal subsidies."

This has been true in the past. However, the Product Tax Credit, which is the main US federal subsidy, is about to expire, with no assurance that it will be renewed.

- "Wind energy from Manitoba may technically qualify for meeting US Renewable Portfolio Standards (RPS) in some jurisdictions but Manitoba Hydro's US customers are not interested in purchasing wind energy from Manitoba to meet state RPS requirements."

While this may have been true for RECs under long-term contracts, it is incorrect to carry that assumption forward. Short-term REC markets have developed in the northeastern U.S., and may well develop over time in the Mid-West.

SUBJECT: Wind Integration

REFERENCE: Page 4-13

PREAMBLE: The report states that "A possible objection to any development plan that postpones Keeyask while retaining an intertie is that the interties under consideration are contingent on export contracts which in turn are contingent on development of new hydro capacity in Manitoba.39 However, it is not clear why the recipients (Minnesota Power, Northern States Power, or Wisconsin Power) would require the development of new hydro facilities. The recipients have an obvious interest in a guarantee that the power would delivered as contracted. Manitoba Hydro has not explained why the purchasers would care whether the power would come specifically from Keeyask, or specifically from new hydro."

QUESTION:

Are you recommending a renegotiation of any existing export contracts to the extent they are contingent on Keeyask or new hydro development more generally? If so, please comment on how price differentials between existing and new contracts would affect your NPV analysis.

RESPONSE:

We would recommend first analyzing whether there would be a significant benefit to Manitoba from a development plan that included postponement of Keeyask, while retaining some or all of the export contracts, with or without postponement. If there is a significant benefit, then we would recommend attempting to renegotiate the contracts in a way that increases their benefit to the people of Manitoba.

If the revised plan included postponement, or any other change in the delivery, of exports, then that might change the price that the recipients would be willing to pay. In that case, price, timing and delivery terms would be part of the negotiation. If the revised plan including honoring export commitments as envisaged in the current contract (with only one change: that the power would not be coming from Keeyask at least for the first few years), we would not anticipate any change in prices.

SUBJECT: Wind Integration

REFERENCE: Page 4-13

PREAMBLE: The report states that "Given the significant export volumes sold by Manitoba Hydro to these markets there are likely to be many periods when wind is being generated in Manitoba at the same time that Manitoba Hydro is exporting to the US, thus satisfying these renewable energy tracking programs."

QUESTION:

Please advise whether you have reviewed and analysed the REC programs for any specific MISO states in coming to this conclusion.

RESPONSE:

Yes, this is based on review of RPS programs and the requirements for RECs in Minnesota and Wisconsin. Both states participate in the Midwest Renewable Energy Tracking System (M-RETS) as does Manitoba.

SUBJECT: Wind Integration

REFERENCE: Page 4-12

PREAMBLE: The report states that "Given the significant export volumes sold by Manitoba Hydro to these markets there are likely to be many periods when wind is being generated in Manitoba at the same time that Manitoba Hydro is exporting to the US, thus satisfying these renewable energy tracking programs."

QUESTION:

If so, please file a copy of the relevant excerpts.

RESPONSE:

As discussed in response to PUB/GAC-021a, a number of MISO states participate in the M-RETS.

"M-RETS® tracks renewable generation located within the state and provincial boundaries of Illinois, Iowa, Manitoba, Minnesota, Montana, North Dakota, Ohio, South Dakota, and Wisconsin. Any generator located within the geographic footprint of M-RETS® may participate."

"Renewable generation is defined as energy generated by a facility that is considered renewable as defined by any of the states or provinces listed above. The M-RETS® Administrator will issue one electronic M-RETS® Certificate for each MWh of energy that is generated by registered generators. To prevent double-counting, generators participating in M-RETS® track their generation output by M-RETS®."

"Each individual state will be responsible for determining whether or not a particular generating unit qualifies for a state program or not."

(Source: http://www.mrets.net/about/AboutMRETS.asp)

DSIRE, a database regarding renewable energy programs, indicates that for Minnesota, "The 2007 legislation required the Minnesota Public Utilities Commission (PUC) to establish a program for tradable RECs by January 1, 2008. The PUC approved the Midwest Renewable

Energy Tracking System (M-RETS) for this purpose and required all utilities to register renewable generation assets by March 1, 2008. The program treats all eligible renewables equally and may not ascribe more or less credit to energy based on the state in which the energy was generated or the technology used to generate the energy. Only RECs recorded and tracked through the M-RETS can be used for compliance."

(Source: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN14R0)

DSIRE indicates that for Wisconsin, "The commission shall promulgate rules that allow an electric provider or customer or member of an electric provider to create a renewable resource credit based on use in a year by the electric provider, customer, or member of solar energy, including solar water heating and direct solar applications such as solar light pipe technology; wind energy; hydroelectric energy; geothermal energy; biomass; biogas; synthetic gas created by the plasma gasification of waste; densified fuel pellets described in sub. (1) (h) 1. i.; or fuel described in sub. (1) (h) 1. j.; but only if the use displaces the electric provider's, customer's, or member's use of electricity that is derived from conventional resources, and only if the displacement is verifiable and measurable, as determined by the commission. The rules shall allow an electric provider, customer, or member to create a renewable resource credit based on 100 percent of the amount of the displacement. The rules may not allow an electric provider to create renewable resource credits under this subdivision based on renewable energy upon which renewable resource credits are created under subd. 1. The rules may also not allow an electric provider to create renewable resource credits under this subdivision based on hydroelectric energy that is not eligible for creating renewable resource credits under subd. 1."

(Source: http://docs.legis.wisconsin.gov/statutes/statutes/196/378)