2008 Long Term Acquisition Plan

BC hydro

APPENDIX F3

Wind Integration Cost Assessment

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1.1 Introduction

Wind generation resources can have highly variable output over a time frame of minutes, hours and days. Due to this variability and the difficulty of accurately forecasting wind energy output, wind resources that are acquired by BC Hydro will result in new operating requirements and procedures. While BC Hydro has a flexible large hydro based generation system that can manage this variability, the total system flexibility is limited and its value is optimized in the markets. As a result, there are costs associated with managing this wind variability that need to be recognized.

To understand the impacts and costs of integrating wind resources, BC Hydro is undertaking a wind integration study, identified in two phases:

Phase 1 – Undertake an initial assessment of wind impacts based upon currently available wind data and perform a jurisdictional review for comparison purposes to determine preliminary wind integration impacts and cost estimates;

Phase 2 - To undertake a wind data study and wind model development, and provide a more detailed assessment of wind integration costs and impacts.

This appendix describes the analysis undertaken in Phase 1 and concludes that a wind integration cost estimate of $10/MWh is appropriate. This wind integration cost estimate for the BC Hydro system is used to model wind resources in the 2008 LTAP and will potentially be used to evaluate wind offers in the Clean Power Call.

1.2 Wind Integration Cost Analysis

Wind penetration on the BC Hydro system will be approximately 3 per cent of installed capacity when the wind projects included in F2006 Energy Purchase Agreements come online. This penetration level could increase to approximately 20 per cent or more if a significant portion of the 5,000 GWh/year for the Clean Power Call were awarded to wind projects. Adding wind resources will require the carrying of appropriate additional reserves to compensate for sudden fluctuations in wind power in three different planning horizons:

- Regulation (minute to minute);
- Load following (minutes to hours);
- Unit commitment/scheduling (hours to days).

For the regulation and load following planning horizons, the analysis focuses on the incremental reserve requirements driven by wind resource additions and has valued these regulating reserves at California ISO ancillary services market prices. Reserve costs associated with the unit commitment/scheduling planning horizon are valued at the electricity trade opportunity cost. This component is referred to as the energy shift cost in the remainder of this document.

The following sections describe the analysis of regulation and load following reserve costs, and energy shift costs in more detail.

1.2.1 Regulating and Load Following Reserve Costs

The analysis for regulation and load following reserve costs is based on 10-minute average load data obtained from BC Hydro's Plant Information (**PI**) system for the year 2007 and wind generation data based on 10-minute average wind speed data collected at several sites during BC Hydro's wind monitoring program in 2002.

Four wind sites were selected to represent the four main regions of B.C. under consideration for wind energy development: Bear Mountain (Peace Region), Merritt (Southern & Eastern (**S&E**) Interior), Mt. Hays (North Coast), and Rumble Mountain (Vancouver Island). The wind data was quality controlled and extrapolated to a hub height of 80 m, using a site specific vertical wind shear exponent. A generic 2.3 MW power curve adjusted for region specific air densities was used to calculate the power generation. The final power output was adjusted assuming production losses of 13.6 per cent.

The wind generation profiles of the four sites were scaled and aggregated to achieve wind penetration levels of 10, 20, 30 and 40 per cent. Three different aggregation scenarios were considered.

Case I - assumes an aggregation distribution of:

- Peace Region 46 per cent
- North Coast 32 per cent
- Vancouver Island 8 per cent
- S&E Interior 14 per cent.

This aggregation distribution is based on the F2011 existing transmission system with a generation sink in the Peace Region (Table 2 of the Wind Integration Project Transmission Planning Study: Stage 1 Study Preliminary Report[1]) and is consistent with BCTC's assessment of the maximum wind generation in each of the four regions.

Case II - assumes an aggregation distribution of

- Peace Region 63 per cent
- North Coast 10 per cent
- Vancouver Island 16 per cent
- S&E Interior 11 per cent

This aggregation distribution was derived from supply curves assuming a 40 per cent wind penetration.

Case III - assumes an equal contribution from each region

- Peace Region 25 per cent
- North Coast 25 per cent
- Vancouver Island 25 per cent
- S&E Interior 25 per cent

Due to the limited amount of available wind data available and the methodology used to scale the wind power output, the smoothing effect on wind generation due to geographic diversity (both on a wind farm and a regional scale) is not fully reflected and may result in an overestimation of aggregated wind generation variability.

To determine the incremental amounts of regulation and load following reserves required with the introduction of wind, the following steps were followed

1) Subtract total wind from load (= load minus wind);

2) Create 1-hour moving averages for load and load minus wind;

3) Calculate the regulation reserve for both load and load minus wind by subtracting the moving average for each 10-minute interval from the actual;

4) Calculate the load following reserve for both load and load minus wind as the moving average value minus the moving average value 1-hour prior;

5) Calculate the incremental regulation reserve by subtracting the load regulation reserve from the load minus wind regulation reserve;

6) Calculate the incremental load following reserve by subtracting the load following reserve from the load minus wind following reserve.

The balancing reserve requirements are determined using the dispersion or spread of the frequency distribution of the incremental regulation and load following reserves. In North America, reserve requirements are typically based on 3 standard deviations, whereas in Europe, 4 standard deviations are used to calculate the reserve requirements. For this study, it was decided to use a lower range of standard deviations to compensate for the potential overestimation of the wind power variability. The balancing reserve requirements were determined using 2, 2.5, and 3 standard deviations, and were then priced using the California ISO (**CAISO**) annual ancillary services prices[2], averaged over the period 2003 to

[1] *Wind Integration Project Transmission Planning Study: Stage 1 Study Preliminary Report*, Transmission System Planning, BCTC, Report No. SPA 2008-05.

[2] Annual Report on Market Issues and Performance, CAISO, April 2007 (http://www.caiso.com/1bb7/1bb776216f9b0.pdf)

2006, and adjusted to 2008 Canadian dollars using the consumer price index by Statistics Canada.

Tables F3-2, F3-3, and F3-4 show the resulting regulation and load following cost estimates at various penetration and balancing reserve requirement levels for the three aggregation scenarios. As expected, the regulation and load following costs increase with increasing wind penetration level as well as increasing balancing reserve requirement levels. The regulation and load following costs are also somewhat sensitive to the aggregation scenario used to produce the power generation data. Generally speaking, Case III (25 per cent Peace Region, 25 per cent North Coast, 25 per cent S&E Interior, and 25 per cent Vancouver Island) produces the lowest regulation and load following reserve costs, whereas Case II (63 per cent Peace Region, 10 per cent North Coast, 11 per cent S&E Interior, and 16 per cent Vancouver Island) results in the highest regulation and load following reserve costs.

As discussed earlier, the balancing reserve requirement levels in this study were reduced to compensate for the likely overestimation of the wind power variability. For determining the total wind integration cost, a balancing reserve requirement of 2 standard deviations instead of the North American norm of 3 standard deviations was used. As can be seen in Tables F3-2, F3-3, and F3-4, this results in a reduction in regulation and load following reserve cost estimates between 62 and 68 per cent. It is assumed that this reduction in the balancing reserve requirement provides a reasonable compensation for the possible overestimation in wind power variability. Assuming a wind penetration level of 20 per cent, and balancing reserve requirement of 2 standard deviations, the regulation and load following reserve cost estimates vary between $3.8/MWh and $4.9/MWh for the three aggregation scenarios.

Table F3-1 Case I - regulating and load following incremental reserve costs as a function of penetration and balancing reserve requirement levels for aggregation scenario (45.8% Peace Region, 32% North Coast, 14.6% S&E Interior, and 7.6% Vancouver Island). Costs are in $/MWh.

	10%	20%	30%	40%
2 ST-DEV Incremental Regulation Cost	2.4	3.5	4.0	4.4
2 ST-DEV Incremental Following Cost	0.4	0.9	1.4	1.8
2.5 ST-DEV Incremental Regulation Cost	3.7	6.0	6.9	7.4
2.5 ST-DEV Incremental Following Cost	1.0	1.7	2.4	3.2
3 ST-DEV Incremental Regulation Cost	6.7	10.0	11.3	12.0
3 ST-DEV Incremental Following Cost	2.3	3.4	4.6	5.6

Table F3-2 Case II - regulating and load following incremental reserve costs as a function of penetration and balancing reserve requirement levels for aggregation scenario (63% Peace Region, 10% North Coast, 11% S&E Interior, and 16% Vancouver Island). Cost are in $/MWh.

	10%	20%	30%	40%
2 ST-DEV Incremental Regulation Cost	2.7	3.7	4.3	4.6
2 ST-DEV Incremental Following Cost	0.6	1.2	1.7	2.2
2.5 ST-DEV Incremental Regulation Cost	4.3	6.6	7.6	8.1
2.5 ST-DEV Incremental Following Cost	1.2	2.1	3.1	3.9
3 ST-DEV Incremental Regulation Cost	8.0	11.2	12.5	13.2
3 ST-DEV Incremental Following Cost	2.2	4.0	5.6	6.8

Table F3-3 Case III - regulating and load following incremental reserve costs as a function of penetration and balancing reserve requirement levels for aggregation scenario (25% Peace Region, 25% North Coast, 25% S&E Interior, and 25% Vancouver Island). Cost are in $/MWh.

	10%	20%	30%	40%
2 ST-DEV Incremental Regulation Cost	1.9	3.1	3.7	4.0
2 ST-DEV Incremental Following Cost	0.4	0.7	1.1	1.4
2.5 ST-DEV Incremental Regulation Cost	2.9	4.9	5.9	6.5
2.5 ST-DEV Incremental Following Cost	0.7	1.3	1.9	2.5
3 ST-DEV Incremental Regulation Cost	5.1	8.1	9.5	10.1
3 ST-DEV Incremental Following Cost	1.7	2.6	3.4	4.1

1.2.2 Energy Shift Cost

Due to uncertainties in hour-to-hour and day-ahead wind forecasts, reserve commitments are required to cover a portion of the expected next day wind generation. Energy shift costs represent lost opportunity costs of having to forgo low price imports/high price exports due to these reserve commitments.

For the analysis of the energy shift cost, historical records of market prices and import/export access for the period 2002 to 2006 (adjusted to 2008 Canadian dollars) were used to represent the BC Hydro system going forward. The import/export opportunity costs were calculated from times when the BC Hydro system was viewed as constrained from the market perspective. Reserve requirements were based on monthly wind capacity factors determined from wind generation profiles described in the previous section, and a day-ahead wind forecast uncertainty interval of ± 85 per cent. Where these reserves were called on and could have been used to serve an export opportunity, wind was charged with an export lost opportunity cost. Where reserves were not used and could have scheduled into the day-ahead market in the previous day, wind was charged with the export lost opportunity of the difference in prescheduled and real-time prices. And where wind generation caused a reduction in a low cost import opportunity due to constraints, wind was charged with a lost opportunity cost.

Energy shift cost estimates due to lost export and import opportunities as well as the total energy shift cost estimate for the three different aggregation cases are shown in Table F3-5. The total energy shift cost varies between $6.04/MWh and $6.14/MWh for the three aggregation scenarios. The energy shift costs due to lost import opportunities are considerably higher than the energy shift costs due to export opportunities. This is partly due to the fact that BC Hydro is net short and is more frequently importing than exporting.

Table F3-4 Breakdown of the energy shift cost for the three aggregation scenarios. Costs are in $/MWh.

	Case I	Case II	Case III
Export Energy Shift Cost	0.69	0.69	0.69
Import Energy Shift Cost	5.35	5.40	5.45
Total Energy Shift Cost	6.04	6.09	6.14

1.2.3 Total Wind Integration Cost

The total wind integration cost estimate, determined as the sums of the regulation and load following reserve costs, and the energy shift cost, are presented for different penetration and balancing reserve requirement levels in Figures F3-2, F3-3, and F3-4 for the three aggregation scenarios. The response of the total wind integration cost with respect to wind penetration levels, balancing reserve requirement levels, and aggregation scenario is identical to that of the regulation and load following reserve cost, due to the relative invariability of the energy shift cost.

Assuming a wind penetration level of 20 per cent and a balancing reserve requirement level of 2 standard deviations, the total wind integration cost estimate varies between $9.9/MWh and $11.0/MWh for the three aggregation scenarios. Regulation and load following reserve costs account between 38 and 45 per cent of the total wind integration cost, while the remainder is due to energy shift costs.

Figure F3-1 Variation of total wind integration cost with penetration and balancing reserve requirement levels for Case I aggregation scenario (45.8% Peace Region, 32% North Coast, 14.6% S&E Interior, and 7.6% Vancouver Island).

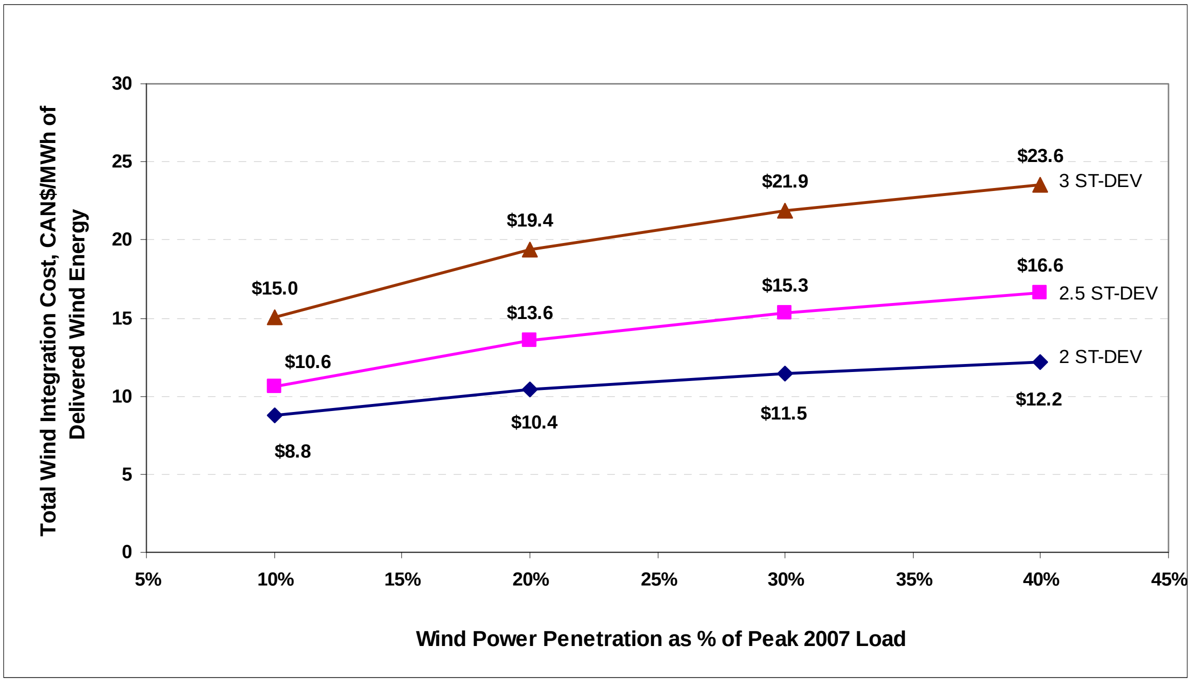


Figure F3-2 Variation of total wind integration cost with penetration and balancing reserve requirement levels for Case II aggregation scenario (63% Peace Region, 10% North Coast, 11% S&E Interior, and 16% Vancouver Island).

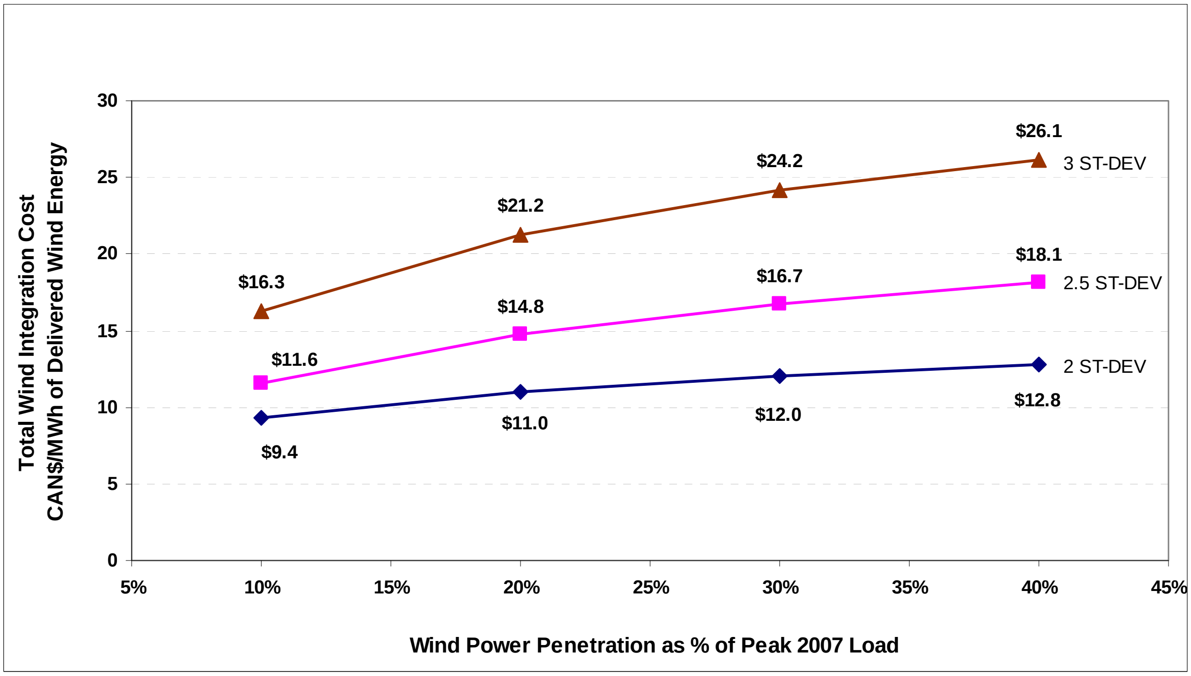
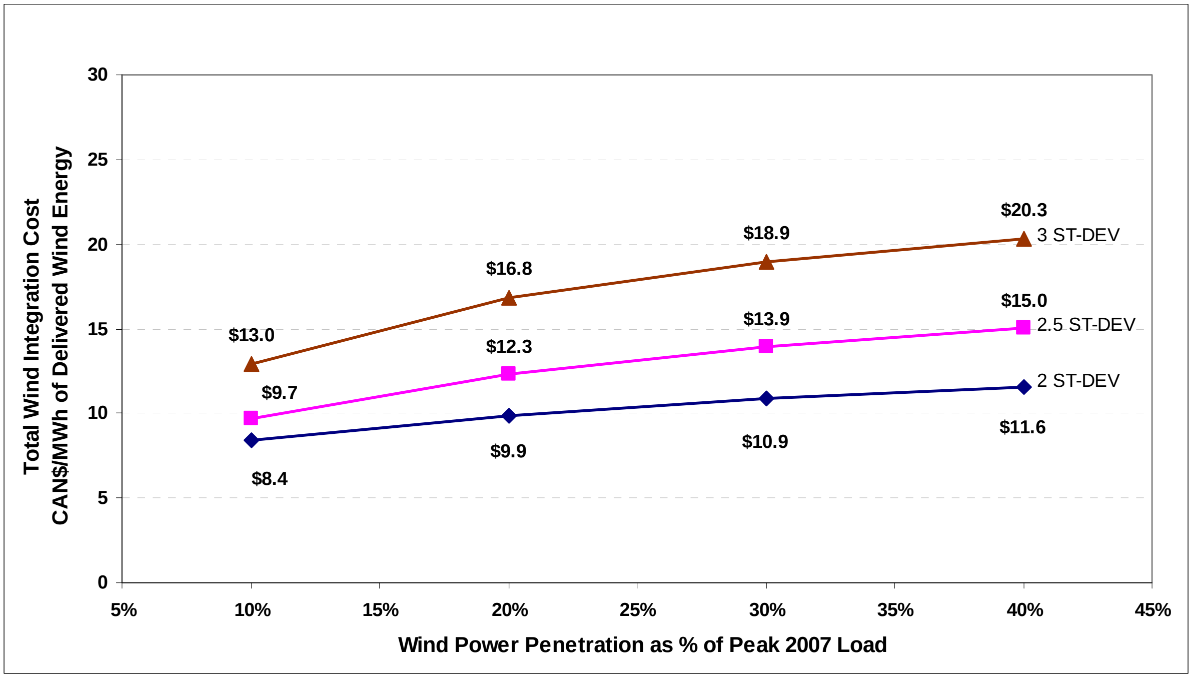


Figure F3-3 Variation of total wind integration cost with penetration and balancing reserve requirement levels for Case III aggregation scenario (25% Peace Region, 25% North Coast, 25% S&E Interior, and 25% Vancouver Island).

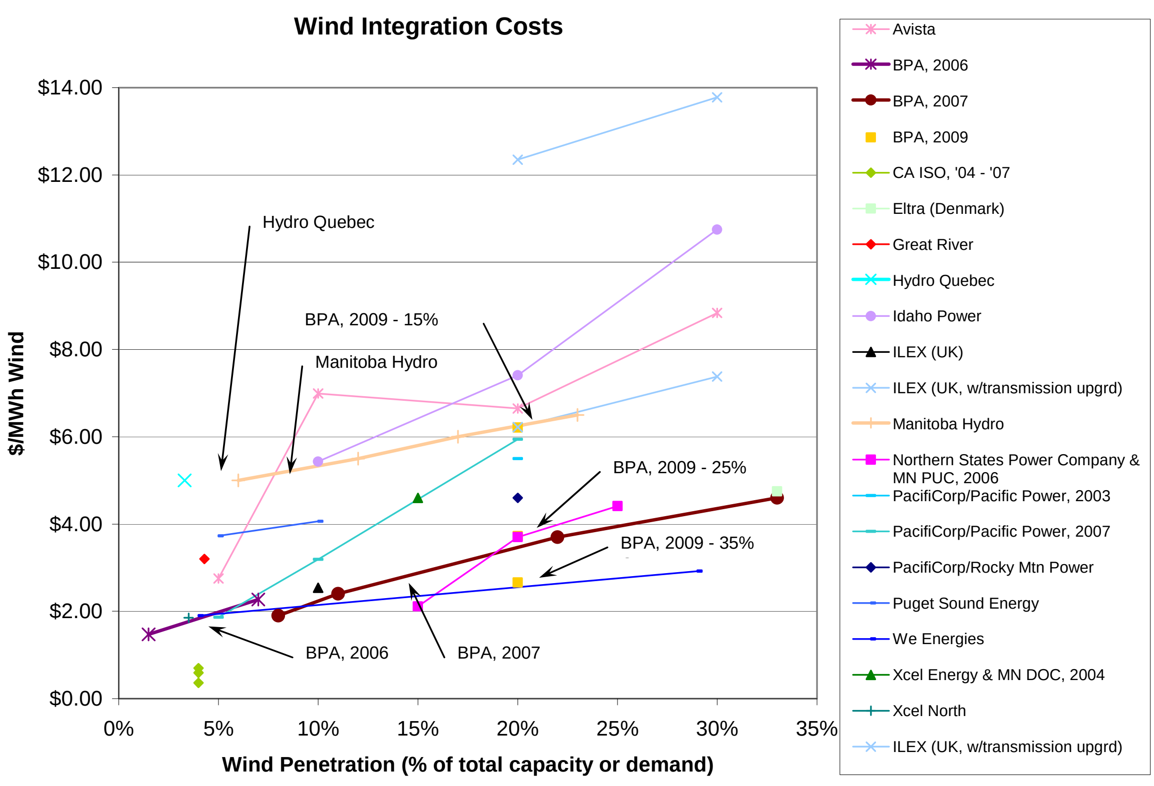


1.3 Comparison to Wind Integration Costs in Other Jurisdictions

In this section, wind integration cost estimates for other jurisdictions are presented to provide context for the results of this assessment. As will be shown below, wind integration cost estimates can vary considerably from utility to utility. This is due to the fact that wind integration costs and cost estimates are strongly influenced by a number of factors, such as social policy, value of energy (cost-based or market-based), structure of the market that each utility participates in; consideration of forecasting, scheduling, and unit commitment; types of generation resource mix within each utility; and modelling techniques used for each study (statistical, system, or mixed modelling approach). Although these factors can lead to significant differences in the wind integration cost estimates between utilities, they are not always clearly identified in the studies. In addition, no guidelines exist to standardize assumptions and methodologies used in wind integration cost assessments.

Figure F3-4 shows the total wind integration cost estimates for other jurisdictions as a function of wind penetration. With the exception of Manitoba Hydro, these wind integration costs generally include regulation, load following and unit commitment reserve costs, but not lost opportunity costs. The BPA values only include within the hour balancing costs. As a result, BC Hydro's total wind integration cost estimate (using a balancing reserve requirement level of 2 standard deviations and assuming a wind penetration level of 20 per cent) is higher than those presented in Figure F3-4 for other jurisdictions. However, if only regulation, load following, and unit commitment reserve costs are considered, then BC Hydro's wind integration cost estimate between $3.8/MWh and $4.9/MWh compares well to wind integration cost estimates in other jurisdictions.

Figure F3-4 Total wind integration cost estimates for other jurisdictions as a function of wind penetration. Note that costs are in varying currencies and are valid for the year that the study was conducted.



Of the utilities shown in Figure F3-4, it is of interest to further examine the wind integration cost estimates of three utilities which have similar generation profiles to that of BC Hydro. These include Manitoba Hydro (**MH**), Bonneville Power Administration (**BPA**), and Hydro Quebec (**HQ**). Table F3-5 shows the peak load/capacity and generation mixes of these three utilities, and whether they are market-based or cost-based utilities.

Table F3-5 Generation characteristics for Manitoba Hydro, Bonneville Power Administration, and Hydro Quebec.

Utility	Peak Load/Capacity and Generation Mix	Type	Year of Wind Integration Study
Manitoba Hydro	5,000 MW total capacity 95% hydro 5% natural gas 2% coal	Market-based	Mar 2007
Bonneville Power Administration	14,000 MW peak load 90% hydro 8% nuclear 2% other	Cost-based	Feb 2006 Mar 2007 Feb 2008
Hydro Quebec	40,000 MW total capacity 96% hydro 2.2% natural gas 1.7% nuclear 1.5% oil 0.5% wind	Cost-based	July 2005

The wind integration cost estimate for MH, which include regulation, load following and unit commitment reserves, as well as lost opportunity costs, varies from \$5/MWh (\$5.2/MWh in 2008 dollars) at a wind penetration level of 6-8 per cent to \$6.5/MWh (\$6.7/MWh in 2008 dollars) at a wind penetration level of 22-23 per cent.

The wind integration cost estimate for regulation and load following reserves in BPA's 2009 Tariff Study is \$0.81/kW per month which translates to \$7.4/MWh at a capacity factor of 15 per cent, \$4.4/MWh at a capacity factor of 25 per cent, and \$3.2/MWh at a capacity factor of 35 per cent. Prior to 2006, BPA offered a storage/shaping service at \$6.00/MWh to manage the hour-to-hour variability associated with wind output[3].

[3] Bonneville Power Administration, *BPA Wind Integration Services*, March 2004. Available from the company's website: http://www.bpa.gov/Power/PGC/wind/BPA_Wind_integration_Services.pdf.

For HQ, a wind integration study conducted in March 2004 suggested a wind integration cost estimate (based on transmission integration and wind balancing integration fee) of \$9/MWh (\$9.8/MWh in 2008 dollars)[4]. This fee was reduced by HQ to \$5.00/MWh after it received considerable negative feedback from the wind industry concerning the high cost of wind integration.

Based on these findings, it appears that the preliminary assessment of regulation and load following reserve cost estimates for BC Hydro compares well to those proposed in other jurisdictions. The total wind integration cost estimate is slightly higher than that used by Manitoba Hydro (which also includes lost opportunity costs), but are comparable to the total wind integration cost estimates previously proposed by Bonneville Power Administration and Hydro Quebec.

1.4 Summary

In this assessment, a statistical modelling approach was used to determine the regulation and load following reserve cost, and the energy shift cost estimates for three different aggregation scenarios. Based on wind penetration level of 20 per cent and a balancing reserve requirement of 2 standard deviations, the regulation and load following reserve cost estimates vary between \$3.8/MWh and \$4.9/MWh. Comparison of these reserve costs to wind integration cost estimates (not including lost opportunity costs) in other jurisdiction shows good agreement. Energy shift costs are estimated to range between \$6.04/MWh and \$6.14/MWh which suggests that there are significant market opportunity costs associated with wind generation on the BC Hydro electric system. BC Hydro uses opportunity cost to evaluate the value of system surpluses in all of its resource modelling and the practice is consistent with the BCUC Resource Planning Guidelines[5]. The total wind integration cost estimate for the BC Hydro system varies between \$9.9/MWh and \$11.0/MWh for the three aggregation scenarios. These estimates are slightly higher than that used by Manitoba Hydro (which includes lost opportunity costs), but are comparable to the total wind

[4] Gil, H., Deslauriers, J.C>, Dignard-Bailey, L., and Joos, G., *Integration of Wind Generation with Power Systems in Canada: Overview of Technical and Economic Impacts*, CETC 2006-016 (TR), CANMET Energy Technology Centre – Varennes, Natural Resources Canada, February 2006, 44 pp.

[5] *BCUC Resource Planning Guidelines*, December 2003, Page 4

integration cost estimates previously proposed by Bonneville Power Administration and Hydro Quebec.

For the purpose of evaluating offers to the Clean Power Call as well as modelling wind resources in the 2008 LTAP, it is recommended that a total wind integration cost of $10/MWh be used.

The more detailed wind integration cost analysis to be completed later this year will follow a similar statistical approach and will include a detailed wind data study based on numerical mesoscale modelling and dynamic modelling based on the BC Hydro Generalized Optimization Model (**GOM**), the Short Term Optimization Model (**STOM**) and other models. Until that analysis is complete, BC Hydro plans on using the $10/MWh wind integration cost estimate as required.