Technical Presentation of John Dalton on Behalf of Canadian Wind Energy Association and the Clean Energy Association of British Columbia

Introduction

Good Morning. My name is John Dalton. I am President of Power Advisory LLC, an electricity sector-focused management consulting firm with offices in Boston, Toronto and Calgary. We were engaged by the Canadian Wind Energy Association (CanWEA) and Clean Energy Association of BC (CEABC) to provide an independent assessment of the cost of commercially feasible clean energy generating projects in BC and the relative benefits of these projects compared to Site C.

I would like to thank the Panel for this opportunity to respond to the questions that posed in its Preliminary Report. Specifically, I respond to two primary issues identified by the Panel: (1) the downside risks of lower electricity demand, drawing upon my experience in other electricity markets; and (2) the costs of alternative resources relative to Site C.

Downside Risks of Lower Electricity Demand

BC Hydro's May 2016 load forecast reflects a 2.6% compound annual growth rate from 2018 to 2024 before DSM impacts and 1.8% compound annual growth rate after DSM impacts are considered. It is relevant that BC Hydro has consistently over-forecasted actual load growth. The Panel noted that downside risks of lower electricity demand have not been considered by BC Hydro and requested comments on these risks.

These are very real risks that are being realized in many other North American electricity markets. In New England, where I am from, the most recent long-term electricity demand forecast by the Independent System Operator is for a .6% compound annual decline in energy consumption over the next ten years, with no meaningful increase in peak load. New York ISO is also forecasting a decline in energy consumption (-.2% per year). Interestingly, my assessment regarding these risks is consistent with that provided by Powerex which last month noted that "demand is not growing in most places in North America."

These are not markets in which one makes large investments in baseload resources that require a 70-year payback (like Site C).

So what's driving this decline in energy consumption? Two things:

First, investments in energy efficiency and conservation, which are commonly understood to be the lowest cost energy resource. According to the American Council for an Energy-Efficient Economy (ACEEE, a preeminent demand side management think tank) leading utilities and jurisdictions have been able to reduce electricity demand by about 1.8 to 2.0% of retail sales, at a cost of about US$35/MWh. Interestingly, ACEEE analysis indicates that the cost of achieving these energy savings has remained at about this level since 2007, driven in large part by improvements in technology.

The second factor that is contributing to this decline in electricity demand is the growth of behind-the-meter solar PV such as rooftop solar projects. While solar insolation levels in the US Northeast are marginally better than those in much of BC, continued reductions in the cost of solar are likely to support the penetration of rooftop solar in BC, which will lead to lower electricity demand.

Cost of Alternative Resources Relative to Site C

As to my second major area of focus: the costs of alternative resources relative to Site C I offer the following.

BC Hydro has employed a series of assumptions which have biased the analysis results against alternatives to Site C. Collectively the effect of these biases is to ensure that alternative portfolios offer a cost that is significantly higher than Site C. These sources of bias include:

First, adding to the alternative portfolio a generating resource (pumped storage hydro) that has a cost that is almost 60% higher than the most obvious alternative;

Second, failing to consider the full range of cost-effective resources. BC Hydro assumes that all the energy in the Alternative Portfolio will be provided by wind when in fact there are other resources available that offer comparably low costs, and in some instances lower costs, than the lowest cost wind resources. In addition, relying on these alternative resources is likely to reduce the cost of incremental firm transmission and transmission losses by spreading energy development across BC; and

Third, wind integration costs are overstated and as discussed in my report, (Exhibit F104-01) are considerably higher than many other estimates for jurisdictions with equivalent wind penetration levels and fail to consider the flexibility of BC Hydro's existing hydroelectric portfolio to integrate these resources.

Reliance on High Cost Pumped Storage in Alternative Portfolio

BC Hydro uses a pumped storage project to provide the capacity for the Alternative Portfolios. Pumped storage projects are a very high cost way to provide capacity. Reflecting these high costs, pumped storage hydro projects are not being built by other utilities or in other electricity markets that have much higher penetrations of variable output renewable energy resources and don't have the benefit of the operating flexibility offered by BC Hydro's existing hydroelectric resources. There are other lower cost alternatives to provide capacity and integrate renewable energy. BC Hydro analysis indicates that the Unit Capacity Cost for a pumped storage project is 60% higher than that for a Simple Cycle Gas Turbine, which is typically the lowest capital cost generating capacity. I understand that the BC *Clean Energy Act* imposes constraints on the operation of natural gas-fired generation in BC, but natural gas-fired operations have been well below these constraints and as a peaking unit the operating hours and resulting GHG emissions of such a resource would be very limited.

According to BC Hydro, pumped storage has a total Unit Energy Cost impact for the Alternative Portfolio of $48/MWh resulting in a 56% increase in the Interconnection Point UEC.

Experience elsewhere indicates that demand response is also likely to be significantly less expensive and can be configured to provide much of the flexibility that BC Hydro would require to integrate increasing amounts of variable output renewable resources.

One cost-effective and well-proven demand response resource that could be used by BC Hydro is control of electric hot water heaters. The PowerShift Atlantic Project, implemented by four Atlantic Canada electric utilities, demonstrated that electric hot water heaters could be deployed to assist with the integration of renewable energy resources. With over 600,000 electric hot water heaters, BC Hydro customers could provide about 500 MW of peak load reduction just from an electric hot water heater control program, representing almost half the capacity offered by Site C. And with Smart Meters already deployed in BC the most significant costs of such a program have already been incurred, further enhancing the cost-effectiveness of this program.

Cost Analysis Omitted Cost-Effective Alternative Resources

As to BC Hydro's failure to consider the full range of cost effective alternatives, the Panel noted in its Preliminary Report that geothermal, solar, biomass and battery storage should be included in the Alternative Portfolio. An indication of the degree to which BC Hydro has constrained alternatives, the incremental resources in the Alternative Portfolio is composed of just wind and pumped storage to provide capacity and assist with wind integration.

I would add to the list of omitted or understated resources identified by the Panel: (1) additional amounts of energy efficiency, conservation and demand response; (2) hydroelectric project upgrades, which were focused on by Deloitte and are often represent a low-cost source of capacity and energy; and (3) capacity and energy from existing IPPs whose contracts expire given that BC Hydro assumes that only 50% of the biomass and 75% of the hydroelectric IPP capacity is recontracted. While I understand that these IPP contracts don't represent a large volume of capacity or energy and that Deloitte may have overstated the opportunities offered by hydroelectric project upgrades, the capacity and energy that these resources offer can have a meaningful impact because it is likely to be among the lower cost resources and it would displace the need for highest cost resources.

I have already discussed how BC Hydro appears to have understated the potential offered by energy efficiency and demand response programs and by so doing overstated the need for Site C. BC Hydro's portfolio of DSM resources is overly focused on energy rather than capacity even though it is capacity constrained and has an energy surplus. The design of BC Hydro's DSM programs should reflect this.

Interestingly, BC Hydro noted in its initial filing with the Panel that with respect to demand response, "We are testing technologies that then can be used on a larger or aggregated scale to meet the system peak needs or to contribute to a non-wires alternative on the distribution system. This work is still ongoing so data for consideration as an alternative is not available at this time." This is surprising.

Demand response is used across North America to provide large volumes of "capacity." There are large, experienced companies that offer demand response solutions, with whom BC Hydro could contract to realize these peak load reductions quickly. In New England demand response resources provide over 8% of the capacity resources that are relied upon to meet peak demand. Demand response resources provide equivalent amounts of peak load reductions in the PJM (Pennsylvania-New Jersey-Maryland) capacity market. Experience in these markets as evidenced by the results of capacity auctions indicates that these are among the least costly capacity resources since they invariably bid lower prices than generation resources.

Installed costs of wind projects have been declining and their capacity factors increasing as a result of technological improvements. Data from across Canada and the US shows a steady decline in unit energy cost of wind projects down to about CAD$65 to $73/MWh for 2016, depending on the region. Reflecting future reductions in project costs yields a real levelized price of about CAD$68/MWh for BC for 2024. Onshore wind costs are forecast to continue to decline through 2050 and a recent study indicates that the median estimate of the reduction from 2014 to 2020 is 10%. Bloomberg New Energy Finance forecasts a 47% decline in the cost of onshore wind.

BC Hydro asserts that it has already considered in its wind UEC about half of the cost reductions that are forecast in the near term. However, there is no ability to independently assess this. Clearly the $85/MWh UEC that it presents is significantly higher than the $68/MWh that I calculated as a reasonable UEC for wind. A small portion of this difference can be explained by the fact that BC Hydro assumes that wind generation representing over 6 TWh is developed, which would require that higher cost projects be developed.

I reviewed in our report the dramatic cost reductions that are being realized by solar PV and battery technologies. I have reviewed the cost estimates that BC Hydro has provided for these technologies and believe that they overstate the cost of these technologies. BC Hydro excluded solar resources because they were viewed as "uneconomic". BC Hydro cites Adjusted UECs of from $133 to $182/MWh. The Panel appropriately finds that "there have been significant declines in the cost of utility scale solar over recent years, and that further declines are expected." (p. 27 of Appendix A)

The Panel requested that BC Hydro estimate the costs of a 5 MW solar PV farm in 2025 and 2035. Similar to other technologies solar PV costs are characterized by economies of scale. The US National Renewable Energy Laboratory estimates that a 5 MW utility scale project is 34% (23% for a 50 MW project) more costly than a 100 MW project and these are at costs that are well below those assumed by BC Hydro. BC Hydro estimated the UEC for solar in 2025 assuming 100% BC Hydro financed debt to be $48.04/MWh (2018$) and $59.04 ($2018) delivered to the Lower Mainland. And this was for a 5 MW project; a 100 MW project would have a cost that is about 30% less.

Wind Integration Costs

The third issue that causes BC Hydro to overstate the costs of the Alternative Portfolio are its wind integration costs. When determining the wind integration requirements, it doesn't appear that BC Hydro has done any analysis of the operating flexibility of its existing hydroelectric portfolio to integrate additional wind generation. BC Hydro adds a $5/MWh wind integration cost, while also including $48/MWh for pumped storage which can assist with integration. Considering both costs is double counting.

BC Hydro adds costs to the UEC for the Alternative Portfolio to reflect the cost of incremental firm transmission, cost of required network upgrades, and line losses. The cumulative impact of these costs is $17/MWh, which represents a 25% increase in the UEC I calculated for wind. BC Hydro's analysis fails to consider that it is able to influence where such projects are built, by considering these costs when it procures such energy, which will in turn reduce them.

In addition, BC Hydro generally evaluates alternatives in terms of their cost delivered to the Lower Mainland. This is contrary to the change that BC Hydro made with respect to its Standing Offer Program where BC Hydro announced in 2016 that it would move to a postage-stamp price (i.e., eliminate regional pricing) for projects with CODs after 2019.[1] BC Hydro notes that changing system requirements and the development of multiple load centres undercuts the appropriateness of regional pricing. This calls into question the appropriateness of the loss and network upgrade costs which are based on delivering energy to the Lower Mainland.

One final point: BC Hydro has argued that the increasing penetration of variable output renewable energy resources (specifically solar and wind) in export markets create opportunities for a flexible hydroelectric resource with significant storage capability such as Site C. What these export markets need is increased ramping capability. We see this in California which has created a new ramping product. To provide such ramping capability from resources located in adjacent electricity markets you need to reserve transmission capacity. Specifically, this requires not using the transmission capacity in hours when a ramp up service is likely to be required. This increases the costs of providing this service and tends to make it more costly for out-of-market resources to provide this service.

Summary

BC Hydro has overstated future electricity requirements and understated the potential offered by energy efficiency, conservation and demand response. In addition, there appear to be a number of low-cost energy and capacity resources available to BC Hydro that have not been adequately considered including recontracting the full capacity of IPPs, and pursuing upgrades of existing hydroelectric facilities through runner replacements etc. This is critical because BC Hydro's analysis with no adjustments for its optimistic demand forecast or pessimistic assumptions regarding DSM, hydro upgrades, and recontracting IPPs indicates that it has a need for dependable capacity in 2023 and an energy shortfall in 2028. To address this need BC Hydro is proposing a risky multi-billion dollar baseload resource with a 2024 in-service date. This need could be deferred and possibly eliminated with the availability of these other resources that BC Hydro has failed to consider. From a capital commitment perspective it is relatively inexpensive to satisfy capacity requirements; billions of dollars need not be risked. Bringing Site C into service in 2024 before there is a need for the project's energy exposes BC Hydro customers to the risks associated with energy prices in the export markets, which are highly variable, and increases the costs of Site C.

Large scale hydroelectric projects historically have been attractive given their ability to generate large volumes of clean energy, their operational flexibility, low operating costs and long useful lives. However, these investments need to be evaluated with careful attention to the risks that they pose to customers. This is evident from the experience in Newfoundland and Labrador where cost overruns at Muskrat Falls and associated transmission facilities are forecast to cause electricity rates to customer to increase by about 80% over a five-year period. For investor-owned projects there is the potential for risk-sharing with investors. For Crown-owned utilities lower returns can be mandated if the project performs poorly. With 100% debt financing there are no such opportunities for risk sharing for Site C, cost overruns or bad investment decisions are directly borne by customers.

[1] The Micro-Standing Offer Program and Standing Offer Program Information Session, February 29, 2016, p. 15