HQD - DEMANDE D’APPROBATION DES CARACTÉRISTIQUES DU SERVICE D'INTÉGRATION ÉOLIENNE ET DE LA GRILLE D'ANALYSE EN VUE DE L'ACQUISITION D'UN SERVICE D'INTÉGRATION ÉOLIENNE

Dossier : R-3848-2013

EVIDENCE OF

WILLIAM K MARSHALL

Review of HQD Application

PRÉSENTÉ À LA
RÉGIE DE L’ÉNERGIE DU QUÉBEC

LE 8 NOVEMBRE 2013

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1. <u>INTRODUCTION</u>

I was engaged by Énergie Brookfield Marketing s.e.c. ("EBM"), Association québécoise des consommateurs industriels d'électricité ("AQCIE") and Conseil de l'industrie forestière du Québec ("CIFQ") to review the Hydro-Québec Distribution ("HQD") application to the Régie de l'énergie ("Régie") dated June 25, 2013, *"DEMANDE D'APPROBATION DES CARACTÉRISTIQUES DU SERVICE D'INTÉGRATION ÉOLIENNE ET DE LA GRILLE D' ANALYSE EN VUE DE L'ACQUISITION D'UN SERVICE D'INTÉGRATION ÉOLIENNE"* docket number R-3848-2013. The review is to consider the Application relative to previous considerations of HQD regarding procurement of wind integration services[1] and verify its consistency with the current legislation/regulation, previous decisions of la Régie de l'énergie ("Régie") and the accepted industry requirements for wind integration. More specifically, the following questions are to be addressed:

- Do you believe that the service described in the Application is not a single service but rather a bundle of several distinct and separate services?
- Does the current proposed service in the Application exceed what is required for reliable integration of wind in Québec?
- Are certain requested services not required for reliable integration of wind generation?
- Could procurement of the unbundled services necessary for reliable integration of wind in Québec be achieved at a lesser cost than the bundled service in the Application?
- Will procurement of the proposed service likely require costs for supply of local load higher than is necessary?

My review has determined that the answer to each of these questions is "Yes" and this report provides explanation and rationale to support that response. It is my view that the supplemental capacity and modulation service are not required for reliable integration of wind and should be procured, if deemed necessary by the Régie, through separate Request For Proposals ("RFP") processes. Also, the real time ancillary services necessary for reliable integration of wind generation (Frequency Control and Load Following) should be procured through separate RFP processes.

[1] "*Entente d'intégration éolienne*" ("EIÉ ") with HQP in 2005 (Dossier R-3573-2005, HQD-1 Doc 1); "*Entente globale de modulation"* ("EGM") proposed in 2011 (Dossier R-3775-2011, HQD-1 Doc 2); and "*Appel de qualification* (QA/O 2012-01) " proposed in 2012 (Dossier R-3806-2012, EBM-6)

The report includes the background history of actions leading to this Application including a review of the regulatory framework for electricity in Québec. Examination of the past positions of HQD regarding wind integration is undertaken because knowledge of those earlier actions is required in order to analyse and understand the current Application. An analysis of the Application is undertaken including a review of the evidence of Mr. Philip Hanser that is then compared to the North American reliability standard requirements for wind integration. These include FERC Order 764 plus examples of actions and studies taken in other jurisdictions. Finally, conclusions and recommendations are provided.

2. **BACKGROUND**

HQD entered into an agreement, *Entente d'intégration éolienne* ("EIÉ")[2], in 2005 under which Hydro-Québec Production (HQP) provided supplemental capacity and energy storage such that 35% of installed wind capacity was continuously delivered to HQD. The EIÉ was approved[3] by the Régie for a five year period from 2006 into 2011.

Also in 2005 HQP and HQD entered into the *Entente de services complémentaires* [4] through which HQP provides to HQD the ancillary services needed to support the Heritage Pool[5] supply of electricity. Most of these services are in turn supplied to Hydro-Québec TransÉnergie ("HQT") who utilizes them to maintain secure and reliable operation of the power system in Québec. This fulfills HQD's obligation under Schedule 8 of the Hydro-Québec Open Access Transmission Tariff ("OATT").

In 2008 the Régie ruled in D-2008-133 that the EIÉ should not be renewed as is and that HQD needed to submit studies that quantified the amount of supplemental capacity and complementary ancillary services required.

HQD completed several wind related studies[6] ("HQD Wind Studies") and applied[7] to the Régie on July 22, 2011 for approval of the proposed *Entente globale de modulation* ("EGM"). The intent was to replace the EIÉ after having the characteristics of the services approved by the Régie in the Supply Plan 2011-2020.[8] The EGM included energy modulation, supplemental capacity, and complementary ancillary services desired by HQD to balance wind on an hourly basis.

EBM and others intervened in the subsequent hearing arguing that the services in the EGM are separate and distinct services that should be open for competition through separate requests for proposals as required under section 74.1 of the *Loi sur la Régie de l'énergie* ("the Act").

The Régie agreed in its decision D-2011-193 of December 19, 2011 that the process followed by HQD did not conform to the requirements of section 74.1 of the Act and rejected the request of HQD for approval of the EGM.

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2 Dossier R-3573-2005, HQD-1 Document 1

3 Decision D-2006-27

4 Dossier R-3689-2009, HQD-3 Document 2, Annexe 1 *Entente concernant les services nécessaires et généralement reconnus pour assurer la sécurité et la fiabilité de l'approvisionnement patrimonial* ("*Entente de services complémentaires*")

5 The Heritage Pool electricity is that electricity set out by the Government of Québec in regulation 1277-2001 dated October 24, 2001 *Concernant les caractéristiques de l'approvisionnement des marchés québecois en électricité patrimoniale*. It includes annual delivery to HQD customers of 165 TWh of electricity plus transmission and distribution losses fixed at 8.4% plus all the services necessary to assure the security and reliability of the power system in Québec.

6 The "HQD Wind Studies" are referenced in detail throughout this report in footnotes 36, 52, 60 and 61.

7 Dossier R-3775-2011, HQD-1 Document 1

8 Dossier 3748-2010, Decision D-2011-162

On April 24, 2012 HQD issued its Call for qualification QA/O 2012-01 ("CFQ")[9] regarding acquisition of a bundled wind integration service that not only included supplemental capacity, energy modulation and complementary ancillary services but also reduces the balancing interval from hourly to a five minute period.

On June 19, 2012 EBM filed a request[10] with the Régie to annul HQD's CFQ for a single wind integration service and to order HQD to proceed with separate RFPs for the separate component services needed for wind integration in conformance with decision D-2011-193.

On August 6, 2012 HQD submitted a motion to the Régie to dismiss the EBM request.

On October 26, 2012 the Régie issued Decision D-2012-142 ruling against HQD and requiring it to get approval for the altered characteristics of the wind integration services as well as the procedures for any requests for supply.

HQD withdrew the CFQ and on June 25, 2013 HQD filed the current Application "*DEMANDE D'APPROBATION DES CARACTÉRISTIQUES DU SERVICE D'INTÉGRATION ÉOLIENNE ET DE LA GRILLE D' ANALYSE EN VUE DE L'ACQUISITION D'UN SERVICE D'INTÉGRATION ÉOLIENNE*" and on July 12, 2013 the Régie issued Procedural Decision D-2013-104 setting out the schedule applicable to a public hearing for this docket R-3848-2013.

In this context, EBM and AQCIE-CIFQ retained WKM to provide evidence regarding the characteristics and quantities of the services necessary for reliable integration of wind generation.

I have reviewed the Application and the evidence of Mr. Phillip Hanser and found that they lack significant details regarding wind integration. In order to address the omissions I have also reviewed the HQD Wind Studies, the EIÉ, the EGM, the CFQ, and several other wind integration related documents applicable in other jurisdictions in North America in regard to this case and prepared this report.

9 Dossier R-3806-2012, Document EBM-06
10 Dossier R-3806-2012, EBM-01 Document 1

3. THE REGULATORY FRAMEWORK

The Hydro-Québec Act ("HQ Act") sets out the rights, obligations and governance of the Company (Hydro-Québec). The Company may *"generate, acquire, sell, transmit and distribute power."*[11] The primary objects of the Company *"are to supply power and to pursue endeavours in energy-related research and promotion, energy conversion and conservation, and any field connected with or related to power or energy."*[12] Regarding HQD as a distributor of power the HQ Act specifies that *"the rates and the conditions for the distribution of power shall be fixed by the Régie."*[13]

A major obligation of Hydro-Québec is that "*the Company must supply the heritage electricity pool as established by the Act respecting the Régie de l'énergie (chapter R-6.01)."*[14] Regarding this obligation "*The Government shall determine the characteristics of the supply to Québec markets of 165 terawatt-hours of heritage pool electricity. The supply must include all necessary and generally recognized services to ensure its security and reliability."*[15] As set out in footnote 5 the Government sets these characteristics in Regulation 1277-2001 dated October 24, 2001.

The Heritage Pool regulation and other regulations are issued subject to section 61.1 of the HQ Act which states that *"the Minister may issue directives on the direction and general objectives to be pursued by the Company. The directives must be approved by the Government, and come into force on the day of their approval. Once approved, they are binding on the Company and the Company must comply with them."*[16]

The Act defines "*electric power distributor*" (HQD) as "*Hydro-Québec when carrying on electric power distribution activities"*[17] and sets out its jurisdiction to regulate HQD. "*It is within the exclusive jurisdiction of the Régie to fix or modify the rates and conditions … for the distribution of electric power by the electric power distributor [and] monitor the operations … of the electric power distributor … to ensure that consumers are charged fair and reasonable rates."*[18] The specific considerations to be undertaken by the Régie regarding HQD rates are set out in Sections 52.1, 52.2 and 52.3 of the Act. Of specific interest for this case is determination of the costs of supply. "*The cost of electric power referred to in section 52.1 shall be established by the Régie by adding the cost of heritage pool electricity and the actual costs to the electric power distributor of the supply contracts entered into to meet the needs of Québec markets in excess of the heritage pool, or the needs to be supplied out of an energy block determined by the Government in a regulation under subparagraph 2.1 of the first paragraph of section 112."*[19]

[11] Hydro-Quebec Act, section 29
[12] Ibid, Section 22
[13] Ibid, Section 22.0.1
[14] Ibid, Section 22
[15] Ibid, Section 22
[16] Ibid, Section 61.1
[17] *Act respecting the Régie de l'énergie*, Section 2
[18] Ibid, Section 31
[19] Ibid, Section 52.2

Power supply contracts to meet loads in excess of the Heritage Pool and to meet energy blocks specified by regulation must be detailed in a supply plan for Régie approval. *"A holder of exclusive electric power distribution rights shall prepare and submit to the Régie for approval, according to the form, tenor and intervals fixed by regulation of the Régie, a supply plan describing the characteristics of the contracts the holder intends to enter into to meet the needs of Québec markets following the implementation of the energy efficiency measures the holder proposes. The supply plan shall be prepared having regard to the risks inherent in the sources of supply chosen by the holder and, as concerns any particular source of electric power, having regard to the energy block established by regulation of the Government under subparagraph 2.1 of the first paragraph of section 112."*[20]

Following approval of a supply plan by the Régie procurement of the supply contracts are governed by Section 74.1 of the Act. "*To ensure that suppliers responding to a tender solicitation are treated with fairness and impartiality, the electric power distributor shall establish and submit for approval to the Régie, which shall make its decision within 90 days, a tender solicitation and contract awarding procedure and a tender solicitation code of ethics applicable to the electric power supply contracts required to meet the needs of Québec markets in excess of the heritage pool, or the needs to be supplied out of an energy block determined by regulation of the Government under subparagraph 2.1 of the first paragraph of section 112"*[21]

The "*Regulation respecting the conditions under which and the cases in which a supply contract entered into by the electric power distributor must be approved by the Régie de l'énergie*"[22] (the "Regulation") specifies the information that must be contained in the application including the demonstration that the contract or combination of contracts is at the lowest cost and the demonstration that the characteristics of the contracts approved in the supply plan are met.

Within this regulatory context the Government has issued several regulations under Section 112 that require the inclusion of wind energy in the portfolio of HQD ("Regulatory Decrees").[23] The 2003 regulation specifies that the block of energy "*is subject to a guarantee of hydroelectric power installed in Québec, in the form of a balancing agreement between the electric power distributor and another Québec supplier or Hydro-Québec in its electricity production operations.*" The three other regulations refer to a "*balancing service and supplementary capacity in the form of a wind energy integration agreement*" to be provided by HQP or another Québec supplier. The expression "electric power supplier" in the Act is defined at s. 2 as any electric power producer or trader supplying electric power.

In 2010 HQD filed the Supply Plan 2011-2020[24] with the Régie for consideration and approval. It did not just include the wind generation required in the regulations but also the characteristics of the wind integration services of the EGM that needed to be procured to

[20] Ibid, Section 72
[21] Ibid, Section 74.1
[22] Chapter R-6.01, r.1
[23] *Regulation respecting wind energy and biomass energy,* Order-in-Council 352-2003, *Regulation respecting the second block of wind energy,* Order-in-Council 926-2005; *Regulation respecting a 250-MW block of wind energy from Aboriginal projects,* Order-in-Council 1043-2008 and *Regulation respecting a 250-MW block of wind energy from community projects,* Order-in-Council 1045-2008.
[24] Dossier R-3748-2010

reliably handle the wind. The characteristics and proposed cost analysis of the EGM were accepted by the Régie subject to a review of the final characteristics of the EGM in file R-3775-2011. However, the supplemental capacity was seen as a separate electricity supply service that needed to be procured via a tendering process as required under Section 74.1 of the Act.[25]

HQD applied for approval of the EGM with its services to integrate wind in 2011. The Régie heard evidence and arguments on the characteristics of the proposed service and came to the conclusion that it included several distinct services that all were separate electricity supply services that needed to be procured via tendering processes as per Section 74.1 of the Act. *"En regard des faits mis en preuve et des argumentations soumises et après examen des dispositions législatives et réglementaires pertinentes, la Régie est d'avis que les divers services prévus par l'EGM constituent chacun une « fourniture d'électricité » et donc un approvisionnement en électricité, en vertu de la Loi. Elle est d'avis que de tels services doivent faire l'objet d'appels d'offres conformément à l'article 74.1 de la Loi et de la Procédure d'appel d'offres, notamment en appliquant les principes de traitement équitable et impartial des fournisseurs et de recherche du prix le plus bas. Ces appels d'offres doivent être conçus de façon à permettre que les besoins puissent être satisfaits par plus d'un contrat d'approvisionnement."*[26]

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[25] Decision D-2011-162, paragraphs 254-256
[26] Decision D-2011-193 issued February 12, 2012

4. REVIEW OF EXISTING AND PROPOSED SERVICES

Before analysing the current Application it is important to review the existing and the previously proposed services in view of determining what the needs of HQD are, the type of services capable of meeting the needs, the regulatory requirements, and the costs associated with the various services.

4.1 THE "*ENTENTE D'INTÉGRATION ÉOLIENNE*"

The *Entente d'intégration éolienne* ("EIÉ") was executed by HQD and HQP June 9, 2005. In the agreement, HQP provides to HQD a wind energy modulation service ("*Service d'équilibrage éolien*") and a supplemental capacity service ("*Puissance complémentaire*").

Under the wind energy modulation service HQP absorbs all the wind energy produced under contracts held by HQD with various wind parks and delivers energy back to HQD each hour at a rate equal to 35% of the wind Contract Capacity. HQD must provide an hourly forecast of wind energy each day ahead by hour 1600 and can update it up to four hours before each delivery hour. The absolute value difference between this final scheduled wind energy and the actual wind energy for each day is summed over the year. It is essentially the daily accumulated wind energy forecast error and it has been paid by HQD to HQP at a fixed rate, without escalation, of 0.1 cents/kWh. HQD also has procured the necessary transmission services from Hydro-Québec TransÉnergie ("HQT") to accommodate the modulation service transaction.

HQD has required that the Guaranteed Capacity of the wind parks be equal to 35% of its Contract Capacity with the wind parks. The Contribution Capacity deemed to be supplied by the wind parks is defined as the minimum quantity delivered in MWh per hour during the 300 highest load hours of HQD each year with a minimum quantity equal to 15% of the Contract Capacity. The supplemental capacity provided by HQP is equal to the difference between 35% of the Contract Capacity and the Contribution Capacity. Initially the Guaranteed Capacity was capped at 346.5 MW but has been amended over time as additional wind parks have been constructed. For the supplemental capacity HQD has paid HQP a base price of $80/kW-yr in 2006 that has been escalated at 2% per year for subsequent years. There is no requirement for transmission as the transmission that accommodates delivery of the modulated energy also accommodates delivery of the supplemental capacity.

There is a need for an energy settlement at the end of each year because the actual amount of wind energy produced will likely be higher or lower than the targeted 35% capacity factor of the Contract Capacity. The settlement price was 7.5 cents/kWh in 2005 and has escalated at 2.5% per year since. If the actual wind energy is higher than the 35% capacity factor then HQP pays HQD for the surplus. If the actual wind energy is lower than the 35% capacity factor then HQD pays HQP for the shortfall.

The initial term of the EIÉ was five years to February 2011. It has been extended[27] and is still in force until a new wind integration arrangement is approved by the Régie.

[27] The EIÉ has been extended more than once, the latest extension having been granted in Dossier R-3799-2012, Decision D-2012-144, 2 novembre 2012

There are significant issues with the EIÉ with respect to fair and equitable treatment of suppliers and the importance of favouring supply contracts at the lowest based cost. The issues relate to:

- Bundling of the various services into one amalgamated service
- Mismatch of the modulated energy delivery versus HQD seasonal load
- Pricing of energy in the annual settlement
- Recognized wind capacity is not accounted for

It is important to review these issues since the Application is similar to the EIÉ and their review will provide some understanding of the costs and characteristics of the Application.

Bundling of the various services into one amalgamated service

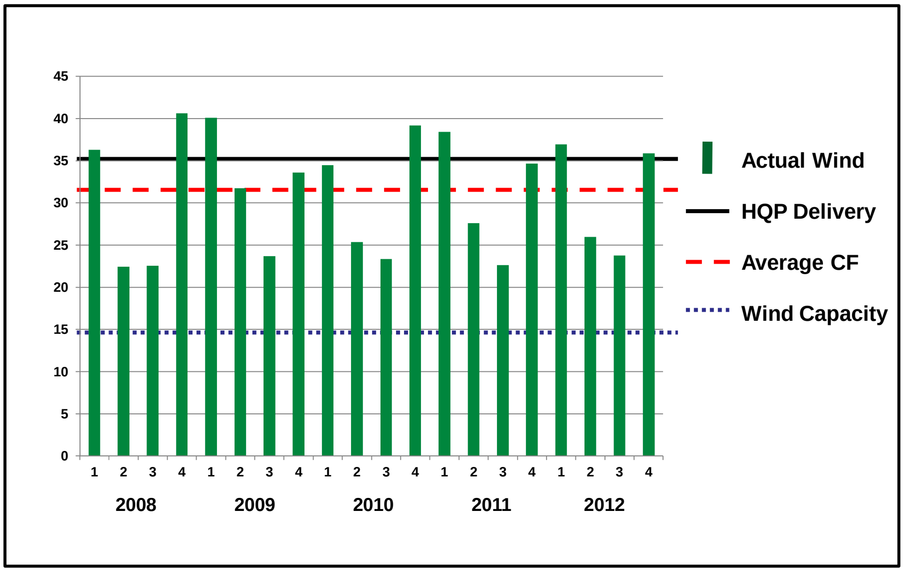
The EIÉ includes an hourly modulation service and a supplemental capacity service. Each of these, and especially the supplemental capacity, is a distinct and separate service that could be procured independently. As set out in the Supply Plan (D-2011-162) and in the EGM (D-2011-193), the additional supplemental capacity must be procured by way of an RFP. The amalgamation of the services into a single product does not enable HQD to proceed to separate RFPs for separate supply services as set out in the Regulation. As I shall discuss in later chapters these services could be supplied by different parties and possibly could be procured at lower prices if competitive RFP processes were applied.

To assist in explaining the remaining issues I have plotted the historical quarterly performance of the EIÉ for the years 2008 through 2012 in Figure 4-1. The bars represent the actual wind capacity factors by quarter, the solid line at 35% capacity factor is constant energy delivered by HQP to HQD and the red dashed line is the actual average wind capacity factor over the period equal to 30.96%. Because the red dashed line is lower than the solid HQP line the settlement payment has gone from HQD to HQP each year. The blue dotted line is the winter capacity contribution of the wind for the 300 peak load hours which has always been at the 15% minimum. The figure is done using capacity factor rather than actual energy so that the normalized operation can be seen each year.

Mismatch of the modulated energy delivery versus HQD seasonal load

The figure shows that the wind production is highest in the Winter (Quarter 1) and Fall (Quarter 4) and lowest in the Spring (Quarter 2) and Summer (Quarter 3). This is analogous to the HQD load which is highest in Fall/Winter and lowest in Spring/Summer. Modulating the wind to 35% capacity factor for the year takes energy away from HQD when it is most needed in high load periods and gives it to HQP to sell in high priced winter markets. This is not in the interests of HQD's customers but even worse it returns the energy in lower load periods when it is not needed. This is an inefficient use of modulation that does not account for the seasonal nature of HQD requirements and is not consistent with the mandate of HQD to supply customers at the least possible cost.

Figure 4-1
Historical EIÉ Capacity Factor Performance by Quarter[28]



André Robitaille of IREQ in a 2007 presentation[29], stated that one of the positive impacts of wind power for Hydro-Québec is its good seasonal correlation with load. This advantage has been ignored in the EIÉ. Modulation is a commercial product that is not required for reliability as we shall discuss in greater detail in Chapter 9. If modulation of wind energy is deemed necessary or economic by HQD it should not be at a uniform rate throughout the year. This uniform return for twelve months a year is not required according to the Régie[30] and correctly so in my opinion. Modulation should be on a seasonal storage basis that could enhance supply to HQD load or as a minimum on a monthly basis so that it at least matches the HQD seasonal load shape.

<u>Pricing of energy in the annual settlement</u>

The cost of the wind forecast error has been small at only $1/MWh. On average over the five years the forecast error for wind energy has been 4.7% of capacity factor. In 2015 at 3139 MW of wind the cost is estimated to be only about $1.25 million. The annual settlement for energy has been about 4.04% capacity factor on average at a price that appears to be based on HQD wind contracts - 7.5 cents/kWh in 2005 escalating at 2.5% per year. In 2015, with 3139 MW of wind in the system and with an escalated price of 9.6 cents/kWh, the capacity factor settlement using the 4.04% historical value[31] would be about $107 million. As was explained in the

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28 Data sourced from HQD settlement reports to the Régie at http://www.Régie-energie.qc.ca/audiences/Suivis/Suivi_HQD_D-2006-027.html

29 *"Hydro-Québec and Wind Power Integration Challenges"*, André Robitaille, Hydro-Québec – IREQ, presented to International Energy Agency, September, 2007, slide 20

30 Dossier R-3648-2007, Decision 2008-133, page 42

31 Actual wind performance in 2015 is not possible to predict accurately and will not be equal to historical data according to HQD's response to IR 6.4 of the Régie (HQD-02-01). I generally agree with this position because

previous paragraph this is for energy which is essentially delivered in the Spring and Summer. In this period the settlement energy does not displace other energy that is at a similar price. The HQD dispatch would take the wind modulation energy first then other contract take and pay energy (biomass, small hydro, etc) and lastly it would use the Heritage Pool energy. Because HQD load has not grown significantly there is not enough room to utilize all the Heritage Pool energy. Rather than use the Heritage Pool energy at a price of 2.79 cents/kWh, HQD is required by the EIÉ to pay the settlement price. The additional price above the Heritage Pool price for HQD in 2015 would be 9.6 – 2.79 = 6.81 cents /per kWh which would result in an additional cost of $ 75.6 million. This creates unnecessary costs for HQD customers and should be fixed in any future wind modulation agreement. The Régie has questioned the high costs of this agreement in the last HQD rate case.[32]

There are two ways the energy settlement issue can be fixed. Firstly, the modulation service could be dropped. It is not required to reliably integrate wind, it is not normally done in other jurisdictions and it is not legally mandated[33] that HQD must do it. HQD could procure only the incremental ancillary services needed to reliably integrate the wind. These incremental ancillary services would be the services needed in addition to those provided through the *Entente de services complémentaires*. This would require HQD to provide the additional ancillary services to HQT and to dispatch its contracted energy resources in a manner to accommodate the actual wind generation and eliminate the settlement issue. Secondly, if a modulation agreement is necessary or economic , it should be monthly at the average historical capacity factor for each month. In this case the settlement price should not be the wind contract price. Rather it should be the Heritage Pool price if the pool energy is not fully utilized or the ISO-NE or NYISO market price if the Heritage Pool energy is fully utilized. There is no need for transmission adjustment on either price as the transmission for the actual wind and modulated wind energy would already have been scheduled.

<u>Recognized wind capacity is not accounted for</u>

As shown in Figure 4-1 the wind capacity contribution under the EIÉ has been the 15% minimum for each year. This has made the supplemental capacity provided by HQP equal to 20% of the wind Contract Capacity for which HQD has paid $80/kW-yr in 2006 and escalated at 2% per year since. This is problematic for two reasons. Firstly, the minimum wind production for the 300 peak load hours is an extremely conservative criterion to measure Contribution Capacity and secondly, there is no consideration of Northeast Power Coordinating Council ("NPCC") recognition of HQD wind capacity.

Review of the five (5) minute wind production data provided by HQD[34] for the week of January 20-26, 2013 highlights the weakness of the Contribution Capacity criteria. During that week there were extreme cold temperatures across the Northeast region that created high demand for both natural gas and electricity. Natural gas prices at Boston reached $35/mmbtu and every utility in the Maritimes Area experienced annual peak loads. It did not occur for

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the future sites may have different wind regimes and the applied wind technology will likely be better than existing generators. However, HQD have failed to provide even indicative forecast data so I am using the historic data to provide indicative costs for 2015.

32 Decision D-2013-021, paragraph 63

33 HQD-02-03.2 EBM(WKM) IR response 2.4

34 HQD-02-03.3 DDR-1 Compléments EBM #4.14

only a few hours of single day but lasted over several days especially January 23 through January 25. During this period HQD likely experienced its winter peak as well, but if not, it certainly experienced many of its 300 peak hours for the winter period. During this three day period the average wind production was 970 MW. Expressed in percentage terms it was 67.5% of the 1437 MW of installed wind capacity at the time. This was a tremendous contribution of wind generation that significantly exceeded the obligation of HQP to guarantee 35% delivery. However, this great contribution went unrecognized, presumably because at least one hour out of the 300 peak load hours wind production was less than 15% of capacity. As a result HQP charged HQD $6.4 million for 20% capacity for 2013 Quarter 1 settlement of the EIÉ[35]. Not only did HQP gain this payment but they had access to the wind surplus energy during the system peak week when external market prices were $200/MWh and higher. The Contribution Capacity measure favours HQP and is not at the least cost for HQD's customers.

Beginning in 2009/10 HQD credited wind capacity at 30% of the contract value based on a capacity adequacy valuation of wind generation study[36] and had this approved by NPCC in March 2010[37]. However, settlement of supplemental capacity in the EIÉ was not reduced. For the winters of 2010/11, 2011/12 and 2012/13 (based on the settlement reports cited in footnotes 28 and 35) HQD has continued to pay HQP for supplemental capacity equal to 20% of the wind contract capacity and not at the incremental 5% (above the 30% recognized by NPCC) that is all that HQD needs to achieve its targeted 35% level. Effectively, HQD has paid for 15% of its wind capacity credit twice; once, implicitly to the wind producers through the wind contracts, and again to HQP through the EIÉ. The second payment should be returned to HQD and any future supplemental capacity agreement should reflect the 30% wind capacity credit recognized by NPCC. If this EIÉ capacity arrangement continues to 2015 the cost of the supplemental capacity at 20% of contract capacity would be just shy of $60 million. This would include an excess payment of $45 million above that needed to achieve the 35% capacity target.

If wind operation in 2015 is the same as that experienced between 2008 to 2012 (as shown in Figure 4-1) the total cost of the EIÉ in 2015, if still in effect, would be about $1.25 million (forecast modulation) plus $106.6 million (annual settlement) plus $60 million (supplemental capacity) for a total cost to HQD of just under $168 million. Inherent in this are additional unrequired costs for energy and capacity of about $120 million. If an adjustment to the supplemental capacity for the EIÉ is made to reduce it from 20% to 5% the total cost would reduce to about $123 million and the differential unrequired cost to HQD would reduce to the settlement differential versus the Heritage Pool of $75.6 million.

[35] "*Suivi de l'Entente d'intégration éolienne pour la période du 1^er^ janvier au 31 mars 2013*" available at http://www.Régie-energie.qc.ca/audiences/Suivis/Suivi_HQD_D-2006-027.html

[36] "*Évaluation de la contribution en puissance de la production éolienne sous contrat avec Hydro-Québec Distribution*", completed by HQD, October 2009 and available at htt p://www.Régie-energie.qc.ca/audiences/EtatApproHQD/Rapport_Contribution%20en%20puissance%20.pdf

[37] 2009 Interim Review of Resource Adequacy For Québec Balancing Authority Area available at https://www.npcc.org/Library/Resource%20Adequacy/2009_Quebec_Interim_Review_final_22_janvier10.pdf

Summation

There are lessons to be learned from review of the EIÉ that should apply to any new agreement for wind integration. In order to comply with the Act and the past decisions of the Régie:

- the 30% wind capacity recognition by NPCC must be considered;
- supplemental capacity is not required for reliable integration of wind generation but is a separate product that should be procured by a separate RFP if and when required;
- wind modulation should not be at an annual uniform return basis;
- as a minimum modulation should be monthly at historical monthly capacity factors; and
- as a separate service modulation should be procured via a separate RFP.

4.2 THE "*ENTENTE DE SERVICES COMPLÉMENTAIRES*"

HQP supplies to HQD the ancillary services necessary to support the reliable operation of the Heritage Pool electricity via the *Entente de services complémentaires* executed on February 15, 2005. The Heritage Pool electricity is that electricity set out by the Government of Québec in regulation 1277-2001 dated October 24, 2001 *Concernant les caractéristiques de l'approvisionnement des marchés québecois en électricité patrimoniale*. It includes annual delivery to HQD customers of 165 TWh of electricity plus transmission and distribution losses fixed at 8.4% plus all the services necessary to assure the security and reliability of the power system in Québec.

The necessary services set out in Appendix A of the agreement are as follows:

1) **Planning** – Plan the availability of capacity resources to meet the adequacy criteria for supply of the load associated with the Heritage Pool of no more than one day in ten years loss of load.

2) **Voltage Control** – Provide reactive capacity to maintain regulation of system voltage. The amount of reactive capacity is equal to that available from each of the HQP generators that were installed on January 1, 2001.

3) **Frequency Control** – Provide 500 MW to 1500 MW of generation capacity that can be placed on automatic generation control ("AGC") in order to maintain the frequency at 60 Hz. Such capacity is to be supplied within the 1500 MW of Operating Reserves and not increase the Operating Reserve requirements in #4.

4) **Operating Reserves** – Provide 1500 MW of 30 Minute Reserve which includes 1000 MW of 10 Minute Reserve and 250 MW of Spinning Reserve, all of which must be able to provide electricity for an hour if activated. Within the 1500 MW provide a stability reserve equal to 3% of the synchronized capacity up to a maximum of 1000 MW.

5) **Maintenance** – Maintain the Heritage Pool generators in a startup state to deliver to the load. Schedule maintenance after breakdowns without affecting delivery of the load. Follow HQT directions to assure functioning of automatic systems.

6) **<u>Generation Scheduling (Following the Load)</u>** – Make available each day dispatchable generation to meet hourly load variations up to11% of the peak hour load to be supplied by the Heritage Pool to a maximum of 3000 MW.

7) **<u>Stabilization of the System</u>** – Provide excitation systems and stabilization circuits for the Heritage Pool generators including provision for activation of automatic generation rejection as required.

8) **<u>Governor Control</u>** – Provide speed governors on the Heritage Pool generators to be set as required by HQT to limit frequency variations and maintain system integrity.

9) **<u>Adapt to System Events</u>** – Permit re-dispatch of generation to respect security limits during system conditions in order to maintain system reliability.

10) **<u>Minimum Generation</u>** – Permit re-dispatch of generation in the following situations:
    a. During low load in Québec
    b. To assure reliability of the regional system
    c. To assure maintenance of reserves
    d. To maintain voltage profiles and automatic protection systems

    Where such re-dispatch is proportional among the different suppliers of the local load.

A separate service that is not listed in the above ten services is an obligation for HQP to provide to HQT resources to limit risk because of errors in load forecast ("*provisions pour aléas*") as follows:

- 500 MW in real time for the next six (6) hours
- 1000 MW (700 MW from May 1 to October 31) for 6 hours and more ahead
- 1500 MW (1200 MW from May 1 to October 31) for the next day

This load forecast risk provision may include recallable transactions and may be less than all the resources available.

The services set out in the *Entente de services complémentaires* are those necessary to support the reliable delivery of the Heritage Pool supply to HQD. They are contractually provided by HQP to HQD who in turn provide them to HQT to fulfill their obligation under Schedule 8 in the HQT OATT. As additional supply resources are added to the HQD supply portfolio it is expected that additional ancillary services will be required. This is especially true for large increases in wind generation that add to overall system generation and load variability that must be reliably accounted for by HQT.

Of all of the services set out in the *Entente de services complémentaires* the ones of most significance for wind integration are Frequency Control, Operating Reserves, Generation Scheduling (Following the Load), and provision for load (and wind) forecast errors. These will be dealt with in detail in the next chapters of the report.

4.3 SERVICES PROPOSED IN THE *"ENTENTE GLOBALE DE MODULATION"*

In the proposed EGM HQP was to supply for a 3 year term the three types of services listed below to HQD and HQD was to arrange for the necessary transmission service for the delivery of the services:

- A supplemental capacity service;
- A modulation service;
- Additional ancillary services required from variable generation to assure the security and the reliability of the power system including
    - Services to regulate frequency and maintain operating reserves
    - Load following service
    - Provision for forecast errors and risk.

While all of the services involve generation capacity in MW the electric utility industry acknowledges (as we shall discuss later in Chapter 9) that each has operational characteristics and implementation requirements that make them distinct and separate services. The Régie has also confirmed that the three types of services were distinct supplies which need to be procured by separate RFPs.[38] Within the EGM in fact there were eight (8) such services and their parameters, requirements, characteristics and general availability are described in the subsections that follow.

Supplemental Capacity Service

Capacity is the capability of a generator to deliver energy as needed when dispatched. It is a distinct product that is separate from energy. Wind generation is intermittent and generally not dispatchable but produces energy. Throughout the industry the installed capacity of wind generation is not accepted as accredited capacity for system adequacy purposes. Where wind generation exists system operators and/or utility planners have conducted studies to determine the effective reliability contribution of wind generation for their systems. In most cases this effective reliability contribution is converted to equivalent generator capacity that is valid for accreditation. As stated earlier HQD have completed such a study[39] and have determined that wind generation in Québec has an effective capacity equal to 30% of the installed name plate wind capacity. This is similar to the 29% determined by New Brunswick System Operator ("NBSO")[40] for the Maritimes Area. Both of these equivalent capacities have been accepted by NPCC as accredited capacity for resource adequacy.[41,42]

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38 Decision D-2011-193; Quote from the decision is provided on page 8 of this report in the Regulatory Framework Chapter.

39 See footnote 36

40 "*Maritimes Area Wind Integration Study*", New Brunswick System Operator, August 2005 is no longer available at the NBSO web site which has been shut down. A copy is available as Appendix A to this report.

41 "*2011 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy*", Approved by the NPCC Reliability Coordinating Committee November 29, 2011 and available at https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

42 "*2012 Maritimes Area Interim Review of Resource Adequacy*"**,** Approved by the NPCC Reliability Coordinating Committee November 27, 2012 and available at https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

In the EGM HQD had requested supplemental capacity equal to 15% of the wind nameplate capacity for the winter months. This would have combined with the accredited wind capacity to achieve a total of 45 MW accredited capacity for each 100 MW of installed wind capacity. Note that **this supplemental capacity was not required for the reliable integration of wind generation**. It was to increase the winter supply capability of HQD from a supply adequacy viewpoint. **The services needed for reliable integration of wind generation are capacity based ancillary balancing services** that will be discussed in detail a little later in this section and in Chapter 5.

The 15 MW of supplemental capacity in combination with the 30 MW of wind accreditation capacity combined with the modulated winter energy schedule would have been equivalent to a firm 45 MW of designated supply for each 100 MW of installed wind capacity. However, as was discussed earlier for the EIÉ and illustrated in Figure 4-1, the actual winter wind production is not equal to 45% capacity factor.. Using monthly data for December provided by HQD [43] and the EIÉ filed data[44] for Quarter 1, the actual winter performance over the last three years has been determined to be about 37.2% capacity factor This capacity mismatch could be a problem and lead to greater energy settlement issues and it is not required for wind integration.

The capacity reliability requirement for load serving entities is to have sufficient designated capacity under contract for them to meet their share of the regional adequacy requirement. The 15 % supplemental capacity desired by HQD through the EGM should have been obtained via an RFP and could have been provided by Third Parties in Québec, or by any market participant in an adjoining area. At issue for customers, however, is how much additional capacity over and above the recognized capacity contribution of wind is needed and what is its cost.

The EGM set out a price for the supplemental capacity equal to the higher of $US 2/kW-mo or the NYISO monthly auction UCAP price for New York – Rest of State. The cost of the 15% supplemental capacity for 3139 MW of wind installed in 2015 for the four winter months would have been a minimum of $3.8 million. Whether or not this price is competitive and in the best interests of HQD customers is not known. Given the opportunity to procure capacity from multiple parties, the only way to determine the real value of supplemental capacity in Québec may be through a competitive RFP process for such capacity.

Modulation Service

The modulation service proposed in the EGM is not required to support system reliability nor is it required to integrate wind generation. Rather, it is a commercial energy banking arrangement to accommodate wind energy contracts, small hydro contracts, and biomass contracts. I will focus on wind modulation.

In general, HQP would absorb and store all the wind generated energy forecast by HQD and would return an amount of energy each hour according to schedules provided by HQD. Forecasts of wind energy production and schedules of energy withdrawals would have to be provided monthly for the next three months, daily for the next five days and hourly for the next

[43] HQD-02-03.2 EBM(WKM) IR 4.1
[44] See footnotes 28 and 35

38 hours. HQP would provide a guarantee that energy withdrawals could be at a rate of 45% of installed wind capacity in the winter and 30% in other months. HQD would not need to accept energy at these rates but would have the option to schedule its withdrawals. It could schedule at rates higher than the guarantee if its total load is less than 32,000 MW and could request rates higher than the guarantee if its load is 32,000 MW or higher. HQP may or may not accept the higher request but must have delivered at least at the guarantee rate if requested.

The amount of energy modulated for any hour was the absolute value of the difference between the actual wind energy production and the scheduled withdrawal. The price for the modulation service was set at $7/MWh of modulated energy. Effectively, the $7/MWh charge would apply to wind energy going into storage that was surplus to an hourly schedule and to energy withdrawal from storage needed to supplement actual wind energy to achieve an hourly schedule.

There was also a commercial settlement arrangement for the accumulated annual net deviation between the hourly scheduled energy and the real wind production. This is similar to but different than the EIÉ in that HQD was not obligated to schedule energy each hour at the guaranteed rate. Under the EGM HQD would have paid HQP $91.54CAN/MWh[45] in 2012 escalated at 2.5% for any net annual wind energy shortfall. However, HQP would not have paid HQD this same wind based price for any annual net surplus of wind energy. Rather HQP would have paid a market based price, equal to the average annual day ahead price set by NYISO for the "HQ_GEN_IMPORT" point, less $5US/MWh with a floor value equal to the Heritage Pool price of $27.9CAN/MWh. This price was to apply for the first TWh while for additional TWhs the price would have been reduced cumulatively by $1/MWh for each TWh.

These changes provided for in the EGM gave greater flexibility for HQD to manage its energy consumption than what was provided for in the EIÉ. The price at $7/MWh seemed high in comparison to the forecast error price of $1/MWh in the EIÉ but the services were very different. The EGM provided a controllable banking service that had more value than the fixed delivery of the EIÉ.

Such banking services could have been partly supplied by a third party that has access to neighboring markets or generation facilities that are capable of supplying the service. For example, in Québec EBM, Alcan and Boralex ("Third Parties") have hydro facilities that are capable of supplying a portion of the modulation service that was set out in the EGM. In addition some industrial loads can vary their consumption and act like a negative hydro generator. Whether or not these Third Parties could supply the service at a price that is competitive with HQP ($7/MWh or less) could have only been determined through a competitive RFP process as required by the Régie.

Additional Ancillary Services for System Reliability

This third general category of EGM services is not a single service but rather contains six (6) separate and distinct services, of which, most are the capacity based ancillary services defined by the US Federal Energy Regulatory Commission ("FERC") in its pro forma Open Access

[45] Note that the $91.54/MWh in 2012 is slightly higher than the EIÉ price of $75/MWh in 2005 escalated at 2.5%. It still appears to be based on HQD wind contracts which would have increased in recent years.

Transmission Tariff (“OATT”)[46], by NERC in its Resource and Demand Balancing Reliability Standards[47], or by NPCC in its Directories 1 and 5.[48] Each is discussed below and those necessary for reliable integration of wind generation are identified. These services today are supplied by HQP to HQD under the *Entente de services complémentaires.* HQD in turn provides these services for the use of HQT who is responsible for the security and reliability of the Québec Balancing Area.

a) Frequency Regulation and Operating Reserves

This sub group of services is made up of four (4) separate defined services that must be provided continuously in real time as follows:

1. Frequency Control Service

This service is a real time ancillary service explained in Schedule 3 of the HQT OATT. Total generation and total load in a Balancing Area must be equal in order to maintain the frequency at 60 Hz. The deviation between load and generation is the Area Control Error (“ACE”) and, in a single balancing Interconnection like Québec, will cause frequency to increase or decrease. To maintain control of the frequency an amount of generation (or demand response) needs to be placed on automatic generation control (“AGC”) that will increase or decrease output as the ACE changes. This AGC controlled generation is usually set to control all ACE deviations that occur in real time up to 10 minutes To provide this service, generators must have ramp rates that will respond quickly dependent on the ACE and have AGC equipment installed. The AGC equipment must be under control of the Balancing Area operator which in Québec is the HQT *Centre de Contrôle du Réseau* (“CCR”). The generation selected to provide the service is also referred to as Regulating Reserve [49].

The minimum requirement for a load serving Balancing Area operator like CCR set out in NERC standard BAL-03-0.1b is 1% of peak load for 0.1 Hz change in frequency. The exact minimum requirement for AGC in Québec is not known by me but based on the *Entente de services complémentaires* it appears to be 500 MW. Hydro generation is a preferred source of this service because of its flexible operating ability. This service normally must be provided within the Balancing Area. As we shall discuss later in Chapters 6 and 7 utilities throughout North America do not require separate Regulating Reserves for load variations and for generator variations. That would be inefficient. Rather, Regulating Reserves are needed for the combined variation in load and generation. According to Information Request responses this practice is apparently also observed by HQT in Québec

[46] FERC pro forma Open Access Transmission Tariff is available at http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890-B/pro-forma-open-access.pdf

[47] Applicable NERC standards are available at http://www.nerc.com/page.php?cid=2|20

[48] NPCC Directory 5 available at https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

[49] AGC and Regulating Reserve are used interchangeably in this paper and consistent with the Evidence of Mr. Hanser (HQD-02-01 page 7, lines 26-27) are the “balancing *reserve capacity … to meet … moment to moment variations [up to 10 minutes]”*

whereby load and generation balancing is accounted for globally for the entire system.[50]

The amount of Regulating Reserve required for the additional wind generation was not specified in the proposed EGM contract.[51] It was not required initially as the *Entente de services complémentaires* provided a sufficient quantity but might have been required in the future as the amount of wind generation increases. One of the HQD Wind Studies completed by IREQ[52] has determined **that 6 MW of additional Regulating Reserve is required for 3000 MW of installed wind capacity on the Hydro-Québec system**. The price of the service for 2011 was set at $13,500/MW[53] and future prices would have been as approved for the HQT OATT. The Third Parties, in addition to HQP, have generation resources capable of providing it.

2. Operating Reserve Services (Three separate services)

(a) Spinning Reserve Service – This is a real time service provided through Schedule 6 of the HQT OATT to Transmission Customers who require it. From a supply viewpoint, it is a continuously synchronized stand-by capacity in MW that is able to respond to meet 25% (or more) of the largest system contingency[54] in 10 minutes. If activated it must be sustainable for at least one hour and it can be supplied by load that is interruptible or by generation that is on line. Dispatch control of the capacity either through AGC or direct communications must be available to the Balancing Area operator CCR. In some systems there are market price adjustments to compensate competing suppliers of such reserves[55] and in others they may be procured through an RFP process[56]. Currently in Québec the CCR gets most (if not all) of its Spinning Reserves either directly, or indirectly through HQD, from HQP via the *Entente de services complémentaires*. The EGM would have extended this arrangement as HQP would have continued to contract the service to HQD who would provide it to CCR. No additional requirement was specified in the EGM but if needed in future HQD would need to pay. The price set for 2011 was $49,700/MW with future adjustments consistent with the HQT transmission tariff. This was not necessarily the best arrangement for the customers of HQD as there may be lower cost resources available. Third Parties have generation resources capable of providing the service and there are many industrial loads in Québec that are also capable of varying their loads to supply the service.

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50 HQD-02-01 (DDR Régie 4.1) and HQD-02-03.1 (DDR EBM 4.7)

51 Dossier R-3775-2011, HQD-1 Document 2, page 10

52 "*Impact de la production éolienne sur le service de régulation de fréquence*" available at. http://www.Régie-energie.qc.ca/audiences/EtatApproHQD/Rapport_Régulation%20de%20la%20fréquence.pdf

53 Dossier R-3775-2011, HQD-1 Document 2, page 21

54 A contingency is a single loss of supply that could occur because of a sudden forced outage of a generator or a trip of a transmission line that is delivering power to the system. In Québec the first contingency is set at 1000 MW so the 25% minimum results in a base requirement of 250 MW spinning reserve.

55 In ISO-NE spinning and AGC reserves are selected to minimize cost to meet reliability requirements. Note information at http://www.iso-ne.com/markets/othrmkts_data/ncpc/index.html

56 NBSO used an RFP process to procure different ancillary services in 2005 and was prepared to run another auction in 2007 dependent on interest.

An RFP process could have possibly reduced the cost for end use customers of HQD.

(b) 10 Minute Supplemental Reserve – This is a real time service provided through Schedule 7 of the HQT OATT to Transmission Customers who require it. From a generator viewpoint it is off line quick start capacity (or surplus synchronized capacity) that is available continuously in real time and able to respond to meet the remaining amount of the largest system contingency that is not supplied by Spinning Reserve. It can be supplied by load that is interruptible or by generation that is off line or synchronized. Similar to Spinning Reserve, it must be sustainable for at least one hour if activated, dispatch control must be available to the Balancing Area operator and procurement is often via markets[57] or an RFP process. The base requirement is 75% of the 1000 MW first contingency. No additional amount was specified in the EGM but if required in the future HQD would need to pay for it. The price set for 2011 was $49,600/MW with future adjustments consistent with the HQT transmission tariff. If there was a requirement in future the Third Parties and industrial loads in Québec have the capability to provide at least a portion of the service requirement.

(c) 30 Minute Supplemental Reserve - This real time service, measured in MW, is off line quick start capacity (or surplus synchronized capacity) that is able to respond to meet 50% of the second largest contingency in 30 minutes. Similar to 10 Minute Supplemental Reserve it must be continuously available in real time and sustainable for at least one hour if activated, dispatch control must be available to the Balancing Area operator, and procurement is often via markets or an RFP process. The base requirement was 500 MW but no additional requirement was specified in the EGM. If so, it would be the same price as 10 minute supplemental reserve. In addition to HQP, the Third Parties and industrial loads in Québec have the capability to provide at least a portion of the service requirement.

b) Load Following Service

This is a balancing service that is an extension of Frequency Response Service and is itemized in some transmission tariffs as Schedule 3(b)[58]. In addition to AGC which operates quickly (up to 10 minutes) to correct the ACE other generation is required to provide for the change in load beyond 10 minutes inside the hour and from hour to hour.[59] In addition to load that varies hour to hour wind generation is intermittent and varies between hours. This hour to hour Load Following capacity for HQD is itemized as Generation Scheduling (Following the Load) capacity in the *Entente de services complémentaires*. It is equal to 11% of daily peak load with a maximum of 3000 MW.

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[57] ISO-NE operates a Forward Reserve Auction for 10 Minute and 30 Minute Supplemental Reserves. Information is available at http://www.iso-ne.com/markets/othrmkts_data/res_mkt/index.html

[58] NBSO (now NB Power) tariff at http://tso.nbpower.com/Public/en/op/transmission/tariff.aspx

[59] The definition of Load Following used in this paper is consistent with that in the Evidence of Mr. Hanser (HQD-01-02 page 7-8, lines 26- 1) being the *"reserve capacity … to meet … the longer timeframe variations over 10 minutes [up to an hour]"*.

In order to accommodate the variability of the wind from hour to hour the EGM requires an additional 82 MW of Load Following service for 3000 MW of installed wind generation. This 82 MW quantity was determined by HQD through a load variability study[60] The actual amount of service for each year forward was to be prorated based on the actual installed wind capacity. The price was to be 1.5 times the price of Frequency Control Service which for 2011 would have been $20,250/MW. Assuming the same price for 2015 the requirement would be 86 MW at a cost of $1.75 million which would be $0.55/kw-yr for installed wind capacity.

This service which must be available in real time each hour is not continuously activated. It should be able to be provided by synchronized generators that have ramping capability to change schedules within 10 minutes or to ramp gradually from one hour to the next as directed by CCR. As will be discussed later in more detail, it could also be partially supplied through 15 minute scheduling of exports or imports with NYISO. In addition to HQP, the Third Parties have such capabilities and could provide a share of the required service.

c) <u>Provision for Forecast Errors and Risk</u>

In order to be able to commit generation for the next day to meet the load and reserves required to reliably operate the system and accommodate potential forecast errors there is a need to have an amount of capacity in excess of the forecast load plus reserves. **This is not a capacity based ancillary service needed to reliably operate wind generation in real time but rather is a short term day ahead adequacy requirement**. The amount specified in the *Entente de services complémentaires* is 1500 MW in winter and 1200 MW in summer. With intermittent wind generation added to the system there is potential for greater combined forecast error of load and wind so there is a need to have more capacity available in the day ahead time frame. The amount of additional capacity that was specified in the EGM for this requirement would be prorated based on a 45 MW[61] requirement for 3000 MW of installed wind capacity. This requirement is simply making capacity available for potential commitment and can be partially met by any generation capacity in neighboring markets and generators in Québec including that of the Third Parties. The price of this service was set out in the EGM as equal to that of 10 and 30 minute supplemental operating reserve which for 2011 was $49,600/MW. For contract wind capacity of 3139 MW the amount of additional capacity needed would be 47 MW at a total cost of at least $2.33 million which would be $0.74/kW-yr for installed wind capacity.

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[60] *"Impact de la production éolienne sur le service de réglage de production (suivi de la charge)"* available at : <u>http://www.Régie-energie.qc.ca/audiences/EtatApproHQD/Rapport_Réglage%20de%20production%20-%203000MW%20éol.pdf</u> , page 9

[61] The rationale for the 45 MW requirement is not stated but appears to be the average of the day ahead requirements for winter (34 MW) and summer (57 MW) provided in the table on page 27 of *"Évaluation de la provision pour aléas en considérant les erreurs de prévision de la production éolienne"* available at <u>http://www.Régie-energie.qc.ca/audiences/EtatApproHQD/Rapport_Provisions%20pour%20aléas.pdf</u>

Summation

This section 4.3 has reviewed all the services included in the EGM and described their characteristics and the generation requirements to supply them. Essentially, the EGM was a more advanced version of the EIÉ that would have provided a more flexible wind energy modulation service. The optional wind energy banking provided an opportunity for HQD to more efficiently manage its total energy supply. It was still proposing a flawed approach as far as supplemental capacity was concerned since the 15% of winter additional supplemental capacity should have been procured independently of what is required for wind integration. It broke out and quantified the specific incremental capacity based ancillary services required to integrate wind generation reliably but failed to propose them as distinct services to be obtained through RFP processes.. This quantification of the incremental ancillary services required when wind variations and load variations are combined together (as we shall discuss in greater detail in Chapters 5) is the accepted industry standard approach to wind integration and is appropriate in Québec for HQD.

Finally, this section has demonstrated that all of the services requested in the EGM are separate and distinct services that could be supplied by parties other than HQP. The Régie in its decision D-2011-193 also came to this conclusion[62] and was of the view that the services should be procured by HQD through a competitive call for offers.[63] I agree with these findings.

4.4 CALL FOR QUALIFICATION ("CFQ")

HQD issued on April 24, 2012 the CFQ to identify potential providers of a wind integration service that included supplemental capacity in the winter months of December through March. The amount of wind to be integrated ranged from 845 MW in 2012 to 3127 MW by the end of 2017. The contract term was 5 years (but 3 years was an option) and the contract quantity was to be at least 20 MW and no more that the total amount of wind installed. The provider's generation capacity for provision of the service must be situated in Québec and synchronized to the balancing area of HQT's CCR. The Contract Quantity would not be tied to a specific wind farm but instead be prorated from the total of all wind farms under contract to HQD.

The wind integration service required the supplier to

- Absorb in real time with a firm load the variable energy production of a Contract Quantity.
- Return at all times an amount of electricity corresponding to 35% of the Contract Quantity
- Guarantee the delivery of capacity and energy in the winter months and be subject to penalties if the delivery is short.

[62] D-2011-193, page 38, paragraphs 127-129
[63] Ibid, page 41, paragraph 142

Information provided to the supplier would be:

- The name plate capacity of installed wind under contract and any changes in capacity as they occur,
- The losses required to be supplied,
- Every hour, an hourly forecast of wind production for the next 36 hours,
- Notification from CCR if the suppliers generator would be placed on AGC and if not, every five (5) minutes, a generation dispatch instruction from CCR that meets the suppliers load, HQD load equal to 35% of the contract quantity and system losses, such instruction to be executed within five (5) minutes.

Actions that must be undertaken by the supplier would be:

- Obtain a firm transmission reservation for delivery of surplus wind power to a load on HQT or at an interconnection point[64],
- Schedule the amount of firm load that is to be supplied using the reservation each hour and maintain that schedule for the hour subject to the HQT transmission tariff,
- If its generation is not on AGC control by CCR, follow the dispatch instructions issued every five (5) minutes by CCR for its full Contract Quantity
- Maintain communications with CCR subject to NERC standards

Conformance with the five minute dispatch was to be within +/- 5% or would be subject to penalties as follows:

- If short, the supplier must pay HQD 125% of the highest market price in the markets of ISO-NE, NYISO and Ontario IESO.
- If long, HQD will pay the supplier 75% of the lowest market price in the markets of ISO-NE, NYISO and Ontario IESO with a floor price of $25.74/MWh for 2012.

There are several issues with the Call for qualification (CFQ) including:

- The bundling of the required services
- Excessive imbalance penalties
- Excessive scheduling requirements

<u>The Bundling of Required Services</u>

The CFQ was for the provision of a supposed single wind integration service including supplemental capacity. It actually included a modulation service that abandoned the flexibility proposed in the EGM[65], a supplemental winter capacity reduced to 5% from the 15% in the EGM, and all the ancillary services in the EGM masked through a 5 minute scheduling requirement.

This bundling of CFQ services was discriminatory and limited competition. It was clearly against the decision of the Régie in the EGM. It did not permit fair and equitable treatment of the suppliers and did not permit favouring supply contracts at the lowest based cost. A supplier that could supply some of the services (possibly at very attractive prices) but not the

[64] The amount is up to the supplier, but to minimize risk of over usage HQT recommends a reservation equal to 60% of the Contract Quantity.

[65] The CFQ modulation is for 35% capacity factor year round similar to the EIÉ and does not provide for any optional energy banking that was in the EGM.

amalgamated service was not able to participate. This reduced competition for those services and potentially would have increased costs because the number of suppliers that could have provided the amalgamated service was limited.

Excessive Imbalance Penalties

The imbalance penalties in the CFQ were far more stringent that those approved by the Régie in its Decision D-2012-010 on February 10, 2012 regarding the HQT OATT. In the OATT imbalance for wind generation less than 1.5% is settled at 100% of market value[66] while imbalances greater than 1.5% are settled at 90% or 110% of market values for long or short delivery, respectively. Note that there is no settlement of wind generation imbalances in the Tariff at the band 3 rates of 75% and 125% of market value. But in the CFQ, HQD proposed to impose penalties that apply at the 75% and 125% of market value for deviations greater than 5% on a five minute measurement basis. This is extreme because there could be long and short five minute deviations in any hour that are penalized yet for the hour the delivery could be balanced to the hourly schedule and meet the conditions in the OATT.

Excessive Scheduling Requirements

In addition to a firm schedule in each hour for the 35% of the Contract Quantity for delivery to HQD, and an hourly firm load to account for excess wind generation, the provider must make available capacity equivalent to the Contract Quantity to CCR and follow its dispatch instructions every five (5) minutes. This five (5) minute dispatch requirement is excessive in that it is more than what is needed to meet the reliability requirements of NERC and NPCC. In the EGM the requirement was for 82 MW of hourly Load Following (available in real time and dispatchable between 10 minutes to an hour) and 45 MW of day ahead short term adequacy capacity to mitigate load and wind forecast risk for 3000 MW of wind generation. The equivalent amount of ancillary services capacity that would have been provided through the five (5) minute dispatch requirement is actually 100% of the Contract Quantity in real time which is excessively more than is required.

4.5 THE PRESENT APPLICATION

The present Application is for approval of the characteristics of a bundled wind power integration service and approval of the process to implement a call for offers on the service. It is not based on the decision of the Régie for the Supply Plan 2011-2020 nor is it consistent with the Decision of the Régie in the EGM case that the services are distinct and should be procured via separate RFPs. I agree with the Régie decisions and believe that a bidding process would be advantageous for HQD customers as it should enable procurement of integration services at the least cost. As to the specifics of the process I have no comments but rather focus on the characteristics of the wind integration service.

66 Market value for under production is set hourly at the highest price market adjusted for export transmission of ISO-NE, NYISO and Ontario IESO. Market value for over production is set hourly at the lowest price market adjusted for import transmission of ISO-NE, NYISO and Ontario IESO.

Overview of the Application

The characteristics of the wind power integration service are almost the same as those in the CFQ. It is for a term of five years and requires the supplier to

- Absorb in real time with a firm load the variable energy production of a Contract Quantity.
- Return at all times an amount of electricity corresponding to 35% of the Contract Quantity
- Guarantee the delivery of capacity and energy in the winter months and be subject to penalties if the delivery is short.
- Mobilize a load capable of absorbing the wind power generation that is in excess of the 35% required to return to the Distributor.

As in the CFQ, suppliers will not be allocated a specific wind farm but rather a share of the total wind under contract to HQD in proportion to the contract quantity. The only difference from the CFQ is that all contract capacity must be subject to CCR control within one minute rather than the five minutes in the CFQ. It must be controllable on AGC or via an electronic communication system to the supplier.

The supplemental capacity is equal to *"5% of the installed wind power capacity, which corresponds to the difference between the guaranteed energy returns in the winter (35% of the wind power generation in commercial operation) and the capacity contribution specific to wind power generation, which corresponds to 30% of the installed wind power capacity*"[67] as approved by NPCC.

The specific ancillary services required for wind integration are masked by requiring 100% of the Contract Quantity to be under the one minute control of CCR. As stated by HQD *"The wind power integration service, which allows deliveries that fluctuate from minute to minute and that are associated with major uncertainties to be balanced,* ***implicitly provides the ancillary services required*** *for the integration of wind power generation*" (Bold underline added).[68] The effect of requiring 100% of the Contract Quantity to be under one minute control to CCR makes 100% of the Contract Quantity equivalent to Regulating Reserve capacity which also provides for Load Following and Day ahead Forecast Risk. Given that 65% of the contract quantity would be needed to adequately supply the mobilized load and losses, the adequacy capacity for HQD is effectively equal to the remaining 35% of the Contract Quantity and not only the 5% of supplemental adequacy capacity requested.

The justification for this excessive amount of CCR control is based on HQD's interpretation of the regulatory framework in Québec. They take the position that the services described in the *Entente de services complémentaires "that are required and generally recognized to ensure the security and reliability of the heritage supply of electricity are strictly associated with the supply of heritage electricity and cannot be used for any other purposes."*[69] As a result of this position HQD assumes that variability of wind power must be managed separately from the load supplied by the Heritage Pool and that *"The proposed wind power integration service is*

[67] HQD-1 Document 1 Translation, page 11, lines 9-13
[68] Ibid, page 11, lines 20-21
[69] HQD-01 Document 1 Translation, page 12, lines 11-14

the only service that allows the Distributor to cover all the impacts of wind power generation, while ensuring the reliability and security of the transmission system."[70] They state that it is the service needed to enable HQD to meet its obligation under Schedule 8 of the OATT under which HQD "*shall provide, or have provided by its Delivering Parties, the Ancillary Services […] required to ensure at all times Transmission System security and reliability."*[71]

HQD maintains that "*wind power integration service is a whole which, although consisting of various aspects, cannot be separated into different services."*[72] The supplemental capacity guarantee is "*directly linked to the need to strengthen the deliveries of electricity from wind turbines."*[73] HQD requires that the ancillary services that continuously offset the unpredictable fluctuations of wind power generation need to do so not on an hourly basis but also intra-hour to handle variances within a given hour.

HQD concludes that *"Dividing the wind energy integration service into separate services has no practical basis, does not support the reliability of the Distributor's electricity supply, and is in breach of regulatory provisions.*"[74]

<u>Concerns About the Application</u>

There are serious flaws in HQD's arguments. Not separating the services is counter to the ruling of the Régie in its decision D-2011-193.[75] There is no reference in the *Entente de services complémentaires* that makes the ancillary services exclusive to reliability of the Heritage Pool supply. Moreover, even if these ancillary services were exclusive to the Heritage Pool supply in the sense that they could not be used for wind integration, this doesn't mean that ancillary services for wind power (and other non-Heritage pool resources) should be determined by considering wind power apart from the rest of the supply (and load). Indeed, in such a case, one should determine what is required **<u>over and above what is already taken care of by the *Entente de services complémentaires* for the grid as a whole</u>**. This is the approach taken by HQD in the EGM. Yet here there is no attempt to quantify the additional ancillary services necessary to reliably integrate wind generation. The security and reliability of the Transmission System referenced in the OATT is not just for HQD's resources but for all the resources in the Québec Balancing Area. The obligation for HQD under Schedule 8 of the OATT is to contribute its proper share of the ancillary services needed.

The Application is essentially the EIÉ with one-minute balancing. As such it bundles rigid energy modulation, additional supplemental capacity and excessive ancillary services that are more than is required for reliable integration of wind generation. Separate bidding processes would be advantageous for HQD customers as it should enable procurement of the various services at least cost. It would also separate the commercial services (modulation and additional supplemental capacity) from the ancillary services needed for reliable integration of wind generation. The next chapter considers in detail the operating characteristics of wind

70 Ibid, page 12, lines 24-26
71 Ibid, page 13, lines 3-5
72 Ibid, page 13, lines 1-2
73 Ibid, page 13, line 8
74 Ibid, page 13, lines 23-25
75 See Régie quote in Chapter 3 page 8

generation relative to the Application and the following chapter determines what the required services are for secure and reliable integration of wind generation into the HQT system.

5. RELIABILITY REQUIREMENTS

This chapter sets out the reliability standards that drive the need for the various services and compares the required services with those in the Application. In the EIÉ, the EGM, the CFQ and the Application **the Modulation Service is a commercial service with no reliability requirement.** In the EIÉ, the EGM, and the Application the additional supplemental capacity service for winter months is not required for reliability as per the Regulatory Decrees. The Application bundles the sought after services into one package and HQD argues that the bundle is required for reliability. The only way that reliability can be understood is to consider the separate Reliability Standards and then determine the specific services that are required by each standard.

Reliability has two major components – Adequacy and Security. Adequacy requires that sufficient capability exists in supply resources and transmission to supply the loads demanded by end use customers. This is actual constructed generation and transmission capacity in concrete and steel that is available prior to operation and measured in MW. It is what is needed day, week, month and years ahead. Security requires that the integrated transmission system operate continuously in real time even in times of contingency. Security services are also measured in MW but they are not separate MW of capacity from that required for adequacy. They are a subset of the adequate concrete and steel generators that are operated in a specific manner to provide the security capacity needed rather than to produce energy.

Resource Adequacy

The requirement for Resource Adequacy in all supply areas of North America is the responsibility of all load serving entities, who through the Reliability Coordinator for their area, must demonstrate to the North American Reliability Corporation ("NERC") or one of its regional councils that sufficient capacity exists presently and into the future to reliably supply the forecast load. In Québec it is the responsibility of HQD to demonstrate to NPCC that *"The probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than one day in ten years."*[76] The HQD report "***2011 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy***" which was referenced earlier (see footnote 41) demonstrates that sufficient resources will exist in Québec through 2016. Inherent in the analysis is an installed wind capacity under contract to HQD of 3139 MW which was reduced to an accredited capacity equal to 30% of nameplate (941 MW). Total planned resource adequacy capacity of 45,401 MW is forecast to supply a peak load of 39,313 MW with a resulting loss of load expectation ("LOLE") of only 0.021 days per year for 2015/16 which is well below the requirement of 0.1 days per year.

If the 5% supplemental capacity required in the Application is needed, it would be firstly for adequacy as it is not needed for integration of wind under the Regulatory Decrees. It combines with the 30% wind credit to achieve a 35% adequacy capacity for wind. This 5% supplemental capacity can come from any capacity source. It need not be located in Québec and it need not be a generation resource. Interruptible loads and generation contracted from adjacent areas

[76] "*NPCC Regional Reliability Reference Directory # 1 - Design and Operation of the Bulk Power System*", Section 5.2 Resource Adequacy – Design Criteria

through interconnections can both qualify. The 5% supplemental capacity may also provide for system security dependent on its operating characteristics and how it is employed but it is initially only for adequacy. Its potential security value will be considered later.

An adequate firm supply of energy to meet the total load need not be tied to the firm capacity contracted for adequacy. The energy could come from a recallable energy source as long as it is backed up by firm capacity. For example, a combustion turbine could provide the capacity while more economical less costly energy could be purchased as non-firm. This separation of energy from capacity is standard throughout North America because it enables the system load to be supplied at the least cost. It allows for avoidance of high priced energy from firm capacity if it can be sourced elsewhere. It is not just practical, it is valuable for end use customers and is counter to the position of HQD who argues that *"Dividing the wind energy integration service into separate services has no practical basis"*[77]

The requirement in the Application to mobilize a load to absorb the excess wind energy above 35% capacity also influences adequacy. The supplier will need to have capacity equal to 100% of the wind Contract Quantity. Within this 100%, 65% is required as adequacy capacity to supply the mobilized load and losses. The remaining 35% has to back up the wind in all hours. As such it cannot be used by the supplier as adequate capacity for another market because it has to be given to the CCR. The effect of the modulation service is to provide HQD with 35% of the Contract Quantity as adequate capacity rather than just the official 5% supplemental capacity. The Régie raised this issue in an information request[78] and HQD responded that 30% of the capacity would come from the adequacy capacity of the wind as recognized by NPCC. If that is the case the 30% capacity credit of the wind has to be transferred to the supplier in order to keep him whole and limit his supplemental capacity contribution to 5%. Otherwise the supplier would be providing 35% capacity while only being paid for 5%.

An additional requirement in the EGM that was examined was Provision for Forecast Errors and Risk on a day ahead basis. Having sufficient capacity day ahead to meet the peak load the next day is a short term adequacy issue. Hydro-Québec studies referenced earlier (see footnote 61) have determined that for 3000 MW of wind an additional 45 MW of capacity must be available day ahead in order to attain the same risk level as would exist without the wind. This would be prorated to 47 MW for 3139 MW in 2015. It is required for potential forecast error and would not necessarily be committed. Note that if 5% supplemental capacity is provided for next winter as requested in the Application it should also be available day ahead so this is not necessarily an additional capacity requirement.

Security

Understanding the security of a power system requires a basic understanding of the physics of electricity. Electricity travels at the speed of light and because of this rapid speed, any change in the system is essentially instantaneous. As a result electricity is the only product in the world that has to be generated at the exact time that it is consumed. Any imbalance between generation and consumption will cause the power system to speed up or slow down and cause frequency to increase or decrease. In order to keep the system secure and reliable it is

77 HQD-1 Document 1 Translation, page 13, lines 23-24
78 HQD-02-01 Régie IR 8.1

necessary that controllable resources, usually generators but potentially variable loads, must continuously vary in order to balance the total generation with the total load. This requires that balancing security services be provided to the system operator in order to provide for secure continuous operation of the system. As was said earlier, security services, usually referred to as capacity based ancillary services, are measured in MW of generation but are not separate capacity from the physical concrete and steel adequacy capacity. They are subsets of the physical adequacy capacity that are operated in a specific manner for security rather than to generate energy.

All of the ancillary services necessary to integrate wind relate to security and the requirements for them are set out in NPCC Directories 1 and 5[79] or the previously referenced NERC Standards (see footnote 47). Meeting these standards is the responsibility of HQT through CCR who is the Reliability Coordinator for Québec Interconnection. It is CCR who should set out the ancillary services requirements to meet the reliability standards and not HQT nor HQD. HQD being the supplier of local load in Québec has the responsibility (under Schedule 8 of the OATT) to provide services necessary to CCR so that the standards will be met. While there are requirements for communications, procedures and reporting the primary issues for security relating to wind integration are balancing generation and load to maintain a stable operation at 60 Hz and recovery to that stable operation after a disturbance contingency.

a) Balancing and Control Performance

The NERC Control Performance Standards CPS-1 and CPS-2 measure the actual performance of CCR in controlling frequency. They are two complicated mathematical measures that consider the number and magnitude of actual frequency deviations on a rolling 12 month basis. If the performance of a Balancing Area does not meet the standards sanctions may be taken and there may be a requirement for increased generation on AGC.

The record shows that CCR has done a good job and continually exceeds the standards with CPS1 values of 100% and CPS2 values of 160%.[80] This has not just been in years when there was little wind on the system but also this past year when there has been about 1600 MW of wind. The ancillary service required to meet the Control Performance Standard is Frequency Control Service which is specified in Schedule 3 of the HQT OATT. It requires generation Regulating Reserve capacity that can increase or decrease its output via AGC. The amount of increased Regulating Reserve to integrate 3000 MW of wind was determined by the previously referenced study (see footnote 52) undertaken by IREQ to be 6 MW. The study was done to achieve the NERC control standards. An additional Hydro-Québec study referenced under International Energy Agency Wind Task 24[81] determined that the incremental

[79] NPCC Directory 1 - Design and Operation of the Bulk Power System and Directory 5 – Reserves available at https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

[80] "*Indicateurs de Performance*", HQT-2 Document 11 http://www.Régie-energie.qc.ca/audiences/RappHQT2012/mainRappHQT2012.htm

[81] Wind Engineering Volume 36, No. 1, 2012, *"Integration of Wind and Hydropower Systems: Results of IEA Wind Task 24"*, Hydro-Québec study #1, p. 8. This study was requested by WKM and not supplied by HQD. It apparently is a combination of the studies referenced as "HQD Wind Studies" under footnotes 36, 52, 60 and 61.

AGC required for 3000 MW of wind would be 1% of wind capacity or 30 MW. This places the Regulating Reserve (AGC) requirement for 3139 MW of wind at a low of 6 MW and a high of 31 MW.

In addition to Regulating Reserve which handles load/generation imbalances in the 10 minute time frame there is the need to balance deviations hourly and within the hour. The previously referenced study (see footnote 60) undertaken by HQD to determine the amount of hourly Load Following (82 MW) required to integrate 3000 MW of installed wind generation has been done in a manner consistent with North American standards. It evaluated the system in 2016 with and without 3000 MW of wind resources and determined that an additional 82 MW is needed for the wind case. In doing so it did not balance load separately and wind separately (as is required in the Application) but balanced the combination of load and wind and other generation which is the reliability requirement under the NERC standards that CCR and HQT must meet. The IEA Wind Task 24 study referenced above for AGC requirements also determined that Load Following requirements for 3000 MW of wind would be about 5% of wind capacity. For 3139 MW of wind the Load Following requirement would be a low of 86 MW and a high of 157 MW.

It should be noted that the requirement for Regulating Reserve (AGC) and Load Following are not additive. The Regulating Reserve(AGC) is a minimum quantity that must be put on AGC to respond quickly to short term changes (up to 10 minutes) but it will also respond to load imbalances throughout the hour so it double counts as both Regulating Reserve(AGC) and Load Following and reduces the incremental Load Following requirement. Some of the incremental remaining Load Following requirement may also be placed on AGC but it is not necessary. The minimum requirement is to have ramping capability that can respond automatically via its governor droop settings or on a scheduled dispatch according to CCR instructions.

The requirement in the Application is to have the total Contract Quantity (3139 MW) under either AGC or one minute control. Dependent on wind production this obligation adds significant AGC and spinning reserve to the system. At 100% wind production the Contract Quantity is to be regulated down to zero output while at zero wind production the Contract Quantity is to be regulated up to 100%. This adds 3139 MW of Regulating/spinning reserve which is clearly excessive of the reliability requirement.

b) Disturbance Recovery

The NERC Disturbance Control Standard (DCS) requires that a Balancing Area report its performance for any contingency equal to or greater than 80% of its largest contingency. The required performance is that the Balancing Area must recover to its pre disturbance schedule within 15 minutes and restore its operating reserves within 105 minutes. NPCC requires reporting and performance for all disturbances of 500 MW or more (300 MW for Maritimes Area). To be able to meet the DCS requirements HQT carries 1000 MW of 10 Minute Reserve of which 250 MW is Spinning Reserve consistent with the *Entente de services complémentaires*. If there is a failure to meet the DCS standard NPCC increases the Spinning Reserve requirement by 20% of the first contingency. The Area must carry this additional Spinning Reserve until it successfully recovers two times from a reportable contingency. At that point it can reduce the requirement by 10% of the first contingency. Repeated DCS failures could result in Spinning Reserve equal to 100% or more of the first contingency. DCS performance by CCR has been good and the NPCC Spinning Reserve requirement remains at 25% and the 10 and 30 Minute Reserve Requirements remain at 1000 and 500 MW, respectively.

Hydro-Québec studies do not specify the amount of additional Spinning, 10 or 30 Minute Reserves required for 3000 MW of installed wind capacity but it should be little, if any. The 3000 MW of wind will be made up of individual turbines that are most likely in the 1 to 4 MW size range. A contingency greater than 1000 MW as a result of wind failure is highly improbable as it would require about 500 turbines to trip simultaneously. The only way this could happen is if the transmission connecting a wind farm of this size failed. Considering that the current base system reserve of 1000 MW already covers transmission failures, it is unlikely that more reserves are needed to meet the DCS standard.

I submit that there is no additional MW operating reserve capacity requirement for wind generation other than what contribution may be made by the additional Load Following capacity. There would however, likely be an increase in the activation of operating reserves.

c) Reserve Activation and Load Following

When there is a disturbance caused by a large loss of generation (whether or not it is a reportable DCS event) there is also a frequency deviation and an increase in the ACE. The capacity set aside for Spinning Reserves and 10 Minute Reserves will be activated to increase generation to correct the frequency and bring the ACE back to zero within 15 minutes. But during this 15 minutes it will not be the only capacity that responds. The fast acting Regulating Reserve and a portion of the Load Following capacity will also respond. For this reason the Regulating Reserve and the synchronized Load Following capacity capable of responding in 10 minutes may be counted towards the Spinning Reserve requirement and non-synchronized Load Following capable of responding in 10 minutes can contribute to the 10 Minute Reserve requirement. This contribution is accepted by NPCC and is done in New Brunswick[82] and has been approved by the NB regulator.[83] It is also consistent with the *Entente de services complémentaire* where the 500 MW to 1500 MW needed for Frequency Control (Regulating Reserve) are included within the 1500 MW of Operating Reserves.

[82] NBSO (now NB Power) cumulatively applies credits for Regulation and Load Following toward Spinning and 10 Minute Reserves. The rate design methodology for these Capacity Based Ancillary Services (CBAS) is provided as APPENDIX B as it is no longer available at the NBSO web site which has been shut down.

[83] NB Energy and Utilities approved the CBAS rates referenced in footnote 91 in its Nov 28, 2008 decision available under Electricity Decisions at http://www.nbeub.ca/index.php/en

"NERC indicates that large wind ramping events are similar to conventional generator contingency events in that they are large and relatively infrequent, yet they differ in that wind ramps are much slower than instantaneous contingency events"[84] Because the wind ramp can last longer than the 15 minute DCS recovery period and even longer than the 105 minute reserve restoration period it is difficult to include wind ramps as actual contingencies. *"Still, NERC indicates that it may be appropriate to use contingency reserves in response to a portion of a wind ramp. NERC states that shared contingency reserves could be used to initiate the response, allowing time for alternate supply (or load reduction) to be implemented."*[85]

This activation of intra-hourly ancillary services to support wind variations and less than DCS forced outages appears to be supported by an additional study conducted by Hydro-Québec under IEA Wind Task 24.[86] It looked at short term adequacy to determine the amount of "*Balancing Reserves*" needed to address *"uncertainties on load forecasts and forced outages.*" It is not stated exactly what these "*Balancing Reserves*" include but the study results *"showed that with current Hydro-Québec balancing reserves being relatively high and risk levels relatively low, little additional balancing reserves are required to integrate 3,000 MW of wind power capacity*". It appears from information request responses[87] that this study may be the same as that referenced earlier in footnotes 60 or 61. If we assume that the maximum Load Following of 157 MW is an additional requirement then the total intra-hourly ancillary service capacity needed to reliably integrate 3139 MW of wind in 2015 would be a maximum of 157 MW.

Summation

This Chapter 5 has reviewed the separate services required in the Application and compared them with what is required to meet NERC standards and NPCC criteria for reliability. It has shown that while the ancillary services for reliability are distinct it is possible to have some MW capacity of a generator contribute to the provision of two or more of the services at the same time. Figure 5-1 breaks out the allocation of the capacity requirements by service for reliability and compares them with the implicit allocation of services in the Application. Note that in the figure, Regulating Reserve contributes to Load Following so the incremental Load Following is the total Load Following less the Regulating Reserve. Also the Forecast Risk capacity requirement is not a separate additional requirement. The CCR needs to know day ahead that it will have the additional Regulating Reserve and Incremental Load Following for each hour the next day. As such the Forecast Risk requirement is met by the Regulating Reserve and Incremental Load Following capacity. For these reasons the Total Required Capacity in the table is not equal to the sum of the separate allocations but rather the minimum capacity needed to meet the various requirements.

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84 FERC Order 764, paragraph 337
85 Ibid, paragraph 338
86 Wind Engineering Volume 36, No. 1, 2012, "Integration of Wind and Hydropower Systems: Results of IEA Wind Task 24 - *Hydro-Québec study #2"*, p. 9
87 HQD-02-03.2 EBM(WKM), IR 23

Figure 5-1
Required Reliability Services For Wind Integration Compared to the Application
(For 3139 MW of Wind Capacity)

		Minimum Requirement For Reliability		Implicitly Required in the Application	
		Winter	Summer	Winter	Summer
Adequacy					
(Year,Month,Day ahead)					
Supplemental Capacity(%CF)		0%	0%	35%	35%
	(MW)	0	0	1099	1099
Forecast Risk Capacity	(MW)	45	45	1099	1099
Security					
(Real Time)					
Ancillary Service Capacity					
Regulating Reserve (0-10 min)	(MW)	6-31	6-31	3139	3139
Load Following (<60 min)	(MW)	86-157	86-157	3139	3139
Incremental LF (10-60 min)	(MW)	80-126	80-126	0	0
Required Reliability Services Capacity	(MW)	86-157	86-157	3139	3139

Note – Supplemental capacity is not required for integration of wind but solely for supply adequacy dependent on a Supply Plan. However, if it is to be procured via an RFP it could not just meet an adequacy need but also be operated in such a way as to provide the required ancillary service needs for wind integration.

The differential reliability capacity required in the Application versus the individual services required is 3139-157 = 2982 MW. Using a cost of $13,500/MW-yr, which is the lowest capacity cost specified in the EGM, the lowest cost to HQD customers of this excess capacity is about $40 million per year.

One of the key reasons that the Application creates a surplus in the capacity actually needed for reliability is that it is aimed at balancing wind alone with separate ancillary services rather than balancing the total system with its combination of wind, other generation and load. The approach in the Application is inefficient as well as excessive. The excess required capacity in the Application will likely increase costs to the detriment of HQD customers. The 5% supplemental capacity is not a service needed for reliable integration of wind generation. The Load Following capacity, the Regulating Reserve capacity, and the Forecast Risk Capacity are distinct services that should be procured via separate RFPs. However, it must be understood that real physical accredited capacity could supply overlapping services. For example, any additional capacity for adequacy, be it for long term adequacy or for short term day ahead Forecast Risk adequacy, could be employed under AGC to provide Regulating Reserve or on a ramping basis to provide Load Following if it is not fully dispatched to provide energy.

The actual reliability requirements are to meet CPS-1, CPS-2 and DCS for the system as a whole and not the wind component separately. NERC does not have separate standards for wind balancing as confirmed by HQT in response to an information request by EBM.[88] FERC in its recent order[89] on integration of wind and other variable energy resources support efficient integration that deals with the reliability of the system as a whole. FERC's view will be reviewed in greater detail in Chapter 7 but first isolated operation of wind generation is examined relative to HQD's Application.

[88] HQD-02-03.1 EBM, IR 4.7
[89] FERC Order 764 "*Integration of Variable Energy Resources*", Final Rule, Issued June 22, 2012

6. ISOLATED OPERATION OF WIND GENERATION

The last chapter reviewed the reliability requirements for integration of wind generation. The previous chapter reviewed the different agreements and proposals considered by HQD that are related to system operations and wind integration. This chapter details the requirements of those proposals relative to the isolated operation of wind generation, which is what HQD proposes in the Application, but not what I would recommend nor what was considered in the 2009 studies. As per the agreements, the EIÉ and the EGM both balanced wind generation on an hourly interval. The CFQ and the Application require that 100% of the Contract Quantity be under operational control of CCR within a time frame of five minutes or less. Wind forecasts are generally provided for hourly production. What is the real hourly and five minute variation in wind generation and how large are the forecast errors? Is 100% CCR control really needed for isolated balancing of wind generation? The answer to these questions resides in a comparison of CFQ and Application requirements with real wind production.

Dispatch Requirements in the Application

To understand the amount of ancillary services capacity provided through a five (5) minute or one (1) minute dispatch requirement it is worthwhile examining the range of potential dispatch change in five minutes and over an hour. Figure 6-1 presents examples of CCR Five Minute dispatch requirements for two different scenarios for a 100 MW contract quantity. The first scenario has an original forecast of 100% wind for the hour but has actual wind production of 80%, 50% and 10%, respectively. The second scenario has an original forecast of 0% wind for the hour but has actual wind production of 20%, 50% and 90%, respectively. By using wind forecasts of 100 % and 0% it is possible to see the full range of potential CCR dispatch instructions.

Figure 6-1

Examples of CCR Five (5) Minute Dispatch Requirements

Contract Quantity (MW)	100							
	Scenario 1 High Wind Forecast Low Actual Production				Scenario 2 Low Wind Forecast High Actual Production			
HQD Wind forecast	100%				0%			
Actual HQD Wind Production		80%	50%	10%		20%	50%	90%
	Planned Hourly Schedule	CCR Five (5) Minute Schedules			Planned Hourly Schedule	CCR Five (5) Minute Schedules		
Firm Supplier Commitment (MW)								
HQD load (35%)	35				35			
System losses (5.4%)	5				5			
Load at HQT or Interconnection	60				60			
Total Supply Required	100				100			
Generation Dispatch (MW)								
HQD Wind Generation	100	80	50	10	0	20	50	90
Initial Supplier Dispatch	0				100			
CCR Instruction to Supplier		20	50	90		80	50	10
Dispatch Change Required	0	20	50	90	0	-20	-50	-90

In the first scenario with a wind forecast of 100% the wind integration supplier plans to utilize all of the wind to meet its 35% obligation to HQD, a 60 MW load that it is supplying on the HQT system (or at an interconnection point) plus system losses of 5 MW. This load obligation is for an hour but within the hour wind production drops. For the 80% wind production situation there is a requirement for 20 MW of generation to make up the wind production shortfall and CCR issues a dispatch instruction to the supplier to increase its generation to 20 MW. Similarly, if the wind production drops to 50% or 10%, then the shortfall is 50 MW or 90 MW and the CCR dispatch instruction will be to increase supplier generation to 50 or 90 MW, respectively.

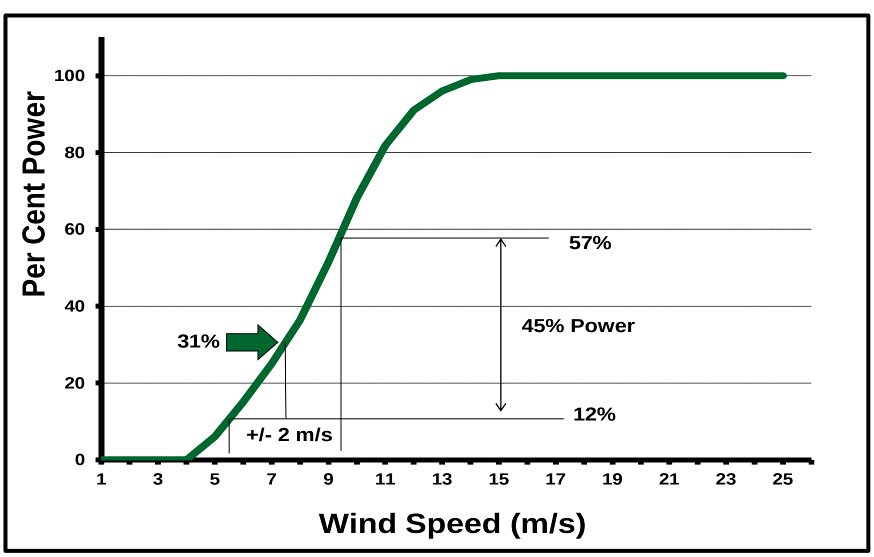
In the second scenario with a wind forecast of 0% the wind integration supplier needs to utilize its own generation to meet its load obligations and commits to do so for the hour. Within the hour wind production increases and the CCR issues dispatch instructions for the wind integration supplier to reduce generation. For wind increases to, 20%, 50% or 90% the CCR dispatch instruction is to reduce generation by 20, 50 or 90 MW, respectively.

While Figure 6-1 provides the extreme range of possible CCR dispatch instructions it is improbable that 90 MW changes, while contractually required in the CFQ and the Application, would be actually dispatched in five minutes or in one minute. The amount of hourly, five minute and one minute dispatch changes should be significantly less. To determine how much less it is necessary to analyse the power production characteristics of wind generation and real wind production data.

Hourly Wind Operation

Dispatch changes for wind operation will occur when the amount of wind blowing changes and the wind production changes with it. Generation from a wind turbine is primarily a function of wind speed as shown in Figure 6-2.

Figure 6-2
Typical Wind Generator Power Curve



The wind power curve in Figure 6-2 shows that there is no production (0% power) for wind speeds less than 5 meters per second (m/s) and maximum production (100% power) at speeds between 15 m/s and 25 m/s. Above 25 m/s typical turbines turn out of the wind and shut down for protection so the output is zero. Forecasting wind production at low wind speeds and high wind speeds is fairly easy and quite accurate. Much greater forecast errors and hourly output changes occur when wind speeds are in the 6 to 12 m/s range. Average wind power output of 31% capacity occurs at a speed near 7.5 m/s. A variation of +/- 2 m/s at this average point will create an output range as low as 12% and as high as 57%.

Figure 6-2 helps explain and understand the reasons for the variability of wind generation but to determine the magnitude of the variability it is necessary to analyse the real wind production data provided by HQD[90] for 2012. Results of the analysis are shown in Figure 6-3.

Figure 6-3
Analysis of Actual Hourly HQD Wind Production for 2012

Range of Hourly Wind Production - Maximum to Minimum For Single Hours

Installation Period	Installed Cap MW	Maximum Hour MWh/hr	Maximum Hour % Capacity	Minimum Hour MWh/hr	Minimum Hour % Capacity
Jan 1 - Mar 27	706.5	679.6	96.2%	0.01	0.00%
Mar 28 - Oct 10	845.1	781.6	92.5%	0.02	0.00%
Oct 11 - Nov 05	925.1	911.4	98.5%	0.40	0.04%
Nov 06 - Dec 11	1036.1	952.0	91.9%	0.11	0.01%
Dec 12 - Dec 31	1137.3	964.6	84.8%	2.05	0.18%
Weighted Average Installed Capacity (IC) =	852.1				

Production Variations

	Annual Average	Maximum	Minimum
Hour to Hour Variation (% of Capacity)	3.2%	26.9%	0.0%
Applied to 3139 MW in 2015 (MW)	100.3	844.1	0.0

Analysis of Wind Production for All Hours in 2012

Number of hours in year 2012 (HRS) = 8784 Hours

	Actual Production	Potential Production	35% CF Production	Annual Differential	Hourly +ve Deviations	Hourly -ve Deviations	Absolute Value Modulation
	a	b=IC*HRS	c=b*0.35	d=a-c	e=Sum(a-c)+	f=Sum(a-c)-	g=e-f
Energy (MWh)	2,317,270	7,485,041	2,619,764	-302494	632,036	-934530	1,566,566
Average Energy (MWh/h)	263.8	852.1	298.2	-34.4	187.0	-172.9	178.3
Average Cap Fac (%)	31.0%	100.0%	35.0%	-4.0%	21.9%	-20.3%	20.9%
Expected Dispatch (%Cap)					56.9%	14.7%	

Figure 6-3 illustrates several points regarding HQD wind production. Single hourly production ranges from a minimum operation near 0% of installed capacity to a maximum operation that is slightly less than 100% of capacity. This full operating range is not seasonally dependent and applies regardless of the amount of installed capacity which varied from 706.5 MW in January

90 HQD-02-03.3 DDR-1 Compléments EBM #4.16

to 1137.3 MW by the end of December. The weighted average installed capacity for the 8784 hours of the leap year was 852.1 MW. While the wide range of single hour operation is very high there is a low probability that operation will be at either extreme.

Further analysis of all hours of production for 2012 indicates that the average operation for the year was at 31% of capacity and that the expected lower and higher operating levels were at 14.7% and 56.9% of capacity, respectively. This actual expected range of operation compares very well with that illustrated in Figure 6-2. The annual amount of energy settlement was at 4.0% capacity factor similar to the EIÉ settlement for the five year period from 2008 to 2012 as discussed earlier in Section 4.1.

The most significant information in Figure 6-3 is the hourly wind production variation analysis. The average hourly variation was only 3.2% of installed capacity which for 3139 MW of wind capacity in 2015 would be only 100 MW. The maximum single hour variation was 26.9% which for the 3139 MW in 2015 would be 844 MW. Only 340 hours (3.9% of the year) had hourly variations greater than 10% of wind capacity. These variation values are well below the 3139 MW of wind capacity and they clearly demonstrate that hourly control of 100% of wind capacity as required in the Application is excessive.

Wind Forecast Errors

The analysis in Figure 6-4 provides the expected operating range of wind generation but does not provide an indication of forecast errors and thus the need to alter the dispatch within an hour and, as such, provide Load Following. The HQD CFQ document[91] in Table 5 of Appendix 5 provides some summary data for wind forecast error for the 447 MW of contracted wind that operated on average at 143 MW for the production period from September 2010 through August 2011. It indicates that the average forecast error provided one hour prior[92] to the operating hour was 33 MW which is 23.1% of the average production and 7.2% of installed capacity. Assuming accurate forecasts for low and high wind conditions it is reasonable to think that the forecast errors for operation at 31% output were higher but likely less than the ranges exhibited in Figure 6-2.

It is possible to use the 2012 hourly data to estimate a forecast error assuming a "persistence" forecast. A persistence forecast assumes that the known value of wind production for the past hour will persist into the next hour. Considering that HQD are to provide a wind forecast each hour forward and communicate to suppliers prior to the next operating hour there is a slight time lag. As such, for a forecast to be provided in the current hour for the next hour it is necessary to use the known wind production from the previous hour. This makes the forecast equal to the production two hours before the operating hour. Figure 6-4 presents the results of such a persistence forecast analysis for HQD 2012 wind operation. The primary measure is the average forecast error expressed as a percentage of installed capacity.[93] It is provided for wind

[91] See footnote 9

[92] One hour before the operating hour is the proper time frame as this will be the best information available to the supplier in order to submit its firm schedules to HQT under the Transmission Tariff for the operating hour.

[93] Because there were five different levels of installed wind capacity for different periods of the year as shown in Figure 6-4 the average of actual MW errors would be skewed and have little meaning, so each hourly MW error was divided by the installed capacity in that hour to get a % error.

production at different operating ranges along with the percent time in that range and the maximum single hour error for that range.

Figure 6-4
Persistence Wind Forecast Results For HQD Wind Operations in 2012

	Production level considered (% of Capacity)					
	<100%	<15%	>15%	<60%	>60%	15% to 60%
Average Error (% of Capacity)	5.6%	3.4%	6.7%	5.5%	5.9%	6.9%
Applicable Hours (% Time)	100%	33.3%	66.7%	84.7%	15.3%	51.4%
Hours Excluded (% Time)	0%	66.7%	33.3%	15.3%	84.7%	48.6%
Maximum Single Error (% Cap)	44.9%	33.6%	44.9%	38.9%	44.9%	38.9%
2015 Wind Capacity (MW)	3139					
Average 2015 Error (MW)	175	107	210	174	185	217

The average forecast error for the entire year was 5.6% of installed capacity. As expected, forecast errors were lowest at low production levels below 15% capacity and highest in the expected operating range between 15% and 60% of capacity. The maximum forecast error for a single hour in each operating range is very high but this is partly due to the nature of a persistence forecast. It would occur in periods of rapid wind ramps because it forecasts that the next hour will be equal to the second previous hour. A forecaster armed with good weather data should be able to reduce the size of these particular errors.

Applying the average forecast error to the 3139 MW of wind in 2015 translates to average errors ranging from 107 MW to 217 MW. These plus the single hour maximum error of 1410 MW (3139 x 44.9%) are all well below the 100% capacity control requirement in the Application and again illustrate the excessiveness of HQD's position.

Analysis of Five Minute Wind Data

The CFQ requires CCR control of 100% of Contract Quantity within five (5) minute intervals and the Application has reduced the control period to one (1) minute. EBM requested that HQD provide one (1) minute wind data but it apparently is not available as the response provided[94] was for five (5) minute data for the week of January 20-26, 2013. An analysis of this data for both five (5) minute and hourly intervals is provided in Figure 6.5.

Results indicate that the range of wind operation varied from a low of about 20% of capacity to a high of 78% of capacity over the week. As expected the five minute results have slightly higher and lower values than the hourly results but also as expected the five minute deviations from interval to interval are much lower than the hourly deviations. The hourly deviations translated to 2015 are an average of 80 MW and a maximum of 686 MW which compare very well with the slightly higher values based on the full year 2012 data. Given that Figure 6-5 data

[94] HQD-02-03.3 DDR-1 Compléments EBM #4.14

is only a single week, albeit a peak weak with high wind production, it is reasonable and expected that the magnitude of the deviations would be slightly lower than full year data.

Figure 6-5
Analysis of HQD Five (5) Minute Data

Operation of 1437 MW of Wind Capacity for Jan 20-26, 2013					
	Hourly Intervals				
	Hourly Wind Production	% Installed Capacity	Hourly Deviations	% Installed Capacity	Amount for 3139 MW in 2015
Average MW	868.7	60.4%	36.5	2.5%	80
Maximum MW	1,116.9	77.7%	314.0	21.8%	686
Minimum MW	314.0	21.8%	-174.9	12.2%	382
	Five (5) Minute Intervals				
	5 Minute Wind Production	% Installed Capacity	5 Minute Deviations	% Installed Capacity	Amount for 3139 MW in 2015
Average MW	868.7	60.4%	6.1	0.4%	13
Maximum MW	1,133.1	78.8%	52.1	3.6%	114
Minimum MW	279.4	19.4%	-174.9	-12.2%	-382

The main opportunity with the five minute data is to determine the magnitude and range of the isolated variation of the wind production for short intervals. The average of the five (5) minute intervals over the week was only 6.1 MW or 0.4% of the installed wind capacity. Applying this same deviation level to the projected 3139 MW of wind capacity by 2015 would be an average five (5) minute deviation of only 13 MW. Deviations were greater than 1.5% of wind capacity for only 46 intervals or 2.3% of the time. Even taking the largest single deviation of 12% in the negative direction the equivalent deviation for the 3139 MW in 2015 would be -382 MW. Even this extreme is much less than the 100% of the 3139 MW required under five (5) minute CCR balancing control in the CFQ and under one (1) minute CCR balancing control in the Application. These results again demonstrate that the requirements in the Application are excessive.

<u>Summation</u>

Review of the HQD Application in Section 4-5 determined that a key position of HQD is that wind generation must be balanced separately from load supplied by the Heritage Pool generation because the ancillary services of the *Entente de services complémentaires* are strictly for the Heritage Pool and cannot be used for wind generation. This chapter has examined the operational characteristics of wind generation in isolation from the rest of the system. It has determined that the amount of hourly balancing required for 3139 MW of wind on average is in the range of 80 MW to 217 MW with an extreme one hour per year maximum requirement of 844 MW to about 1000 MW.[95] Based on this analysis of one year of hourly wind production data, **<u>about 300MW of intra-hour Load Following capacity[96] should be sufficient to separately balance 3139 MW of wind generation projected for 2015</u>**. Once again, I do not recommend that wind be balanced separately, as it is more efficient to balance the system as a whole.

The review has also determined that the amount of five (5) minute balancing required for 3139 MW of wind in isolation is on average about 13 MW and the extreme one hour maximum requirement is about 382 MW. This is based on a single week of data and could vary somewhat if more data was available. No one (1) minute wind data was available to be analysed but it is expected that one (1) minute wind variations would be less than five (5) minute variations just as five (5) minute variations are less than hourly variations. But this is irrelevant as the amount of Regulating Reserve required on AGC is usually determined by the variations within a ten (10) minute interval. On that basis **<u>about 50MW of Regulating Reserve[97] should be sufficient to separately balance the 3139 MW of wind generation projected for 2015.</u>**

The sum of the isolated Load Following estimate and the isolated Regulating Reserve estimate is about 350 MW which is considerably less than the requirement in the Application to have 3139 MW (100%) as Regulating Reserve under one (1) minute CCR control. The Application requirement is excessive even for isolated balancing of wind generation.

There is no need to have 100 % of contract capacity under CCR one (1) minute control in order to provide for system security even for isolated balancing of the wind. But, systems throughout North America, as was discussed in Chapter 5 and will be expanded upon in Chapter 7, do not balance wind in isolation from other generators and loads on the system. The standard is to balance the total load and total generation for secure and reliable operation of the entire balancing area. **<u>This requires balancing the net variations of the load, wind production and other generation which minimizes the total balancing requirements and the associated costs.</u>** As expected, it is the approach currently undertaken by HQT[98] but apparently not recognized by HQD.

[95] The 1410 MW wind forecast error extreme was not considered here because of the limitations of a persistence forecast during wind ramps when these large errors occur. It was reduced to "about 1000 MW."

[96] The rationale for 300 MW of Load Following is that hourly deviations are less than 10% of capacity for 96.1% of the time

[97] The rationale for 50 MW of Regulating Reserve is that five (5) minute deviations are less than 1.5% of capacity for 97.7% of the time

[98] HQD-02-01 Régie IR 4.1

7. **FERC ORDER 764**

FERC Order 764, as summarized by Mr. Hanser, "*was passed in 2012 to define the integration of variable energy resources. It sets the basic requirements to improve the operational procedures to facilitate variable energy resource integration. Under Order 764 each transmission provider must offer intra-hourly transmission scheduling, and interconnection customers with Variable Energy Resources ("VER"), such as wind plants, must provide meteorological and forced outage data to the transmission provider for the purpose of power production forecasting*"[99].

The motivation for the changes as articulated by FERC is that "*VERs are making up an increasing percentage of new generating capacity being brought on-line. This evolution in the Nation's generation fleet has caused the industry to re-evaluate practices developed at a time when virtually all generation on the system could be scheduled with relative precision and when only load exhibited significant degrees of within-hour variation. As part of this evaluation, the Commission initiated this rulemaking proceeding to consider its own rules and, based on the comments received, concludes that reforms are needed in order to ensure that transmission customers are not exposed to excessive or unduly discriminatory charges and that public utility transmission providers have the information needed to efficiently manage reserve-related costs.*"[100]

Originally, FERC proposed introduction of a new Schedule 10 in its *proforma* OATT for Generator Regulation and Frequency Response Service that would be similar to Schedule 3-Regulation and Frequency Response Service. "*Where Schedule 3 allows public utility transmission providers to recover the costs of regulation reserves associated with variability of load within its balancing authority area, proposed Schedule 10 would provide a mechanism through which public utility transmission providers can recover the costs of providing regulation reserves associated with the variability of generation resources both when they are serving load within the public utility transmission provider's balancing authority area and when they are exporting to load in other balancing authority areas.*"[101] However, after receiving comments from various interveners FERC decided not to proceed with a generic Schedule 10. "*Instead, the Commission takes this opportunity to respond to the individual commenter concerns regarding the proper design of a generator regulation service charge in order to provide guidance in the development of proposals for such services.*"[102]

"*Taken together, the reforms adopted and guidance provided in this Final Rule are intended to address issues confronting public utility transmission providers and VERs and* ***to allow for the more efficient utilization of transmission and generation resources to the benefit of all customers****. This, in turn, fulfills our statutory obligation to ensure that Commission-jurisdictional services are provided at rates, terms, and conditions of service that are just and reasonable and not unduly discriminatory or preferential.*"[103] *(Bold Underlines added)*

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[99] HQD-02 Document 1, page 8, lines 5-11
[100] FERC Order 764, Paragraph 1
[101] Ibid, Paragraph 241
[102] Ibid, Paragraph 315
[103] Ibid, Paragraph 5

There are two results of Order 764 that are of particular relevance to this Application made by HQD. Firstly, NYISO has implemented intra-hourly transmission scheduling and secondly, the guidelines regarding management of ancillary service related costs are informative for wind integration in Québec.

Implementation of intra-hourly transmission scheduling does not just apply inside NYISO. It extends to some of their interconnections with neighbouring systems and has been confirmed through information request responses by HQT[104] that it is available for transactions both into and out of Québec. This intra-hourly transmission scheduling with NYISO at the Massena interconnection is for intervals of 15 minutes which is very significant for wind integration.

In the previous chapter we found that the Load Following requirement to reliably integrate 3139 MW of wind in 2015 would be in the range of 86 MW to 157 MW. It was not stated but a reader may have assumed that this 86 MW to 157 MW needed to be physically controllable generating capacity located inside Québec. That is not correct. Given that Load Following is the need to balance generation and load in the 10 minute to one hour time frame there is an opportunity to utilize 15 minute scheduling with NYISO to meet a portion of the Load Following requirement. For example, consider a 15 minute imbalance of 100 MW where wind has increased above its forecast. There are two ways to address this imbalance, reduce generation or increase load. For the former, CCR could reduce controllable generation by 100 MW to get total generation and total load in Québec in balance. Alternatively, a transmission customer exporting to NYISO could increase its export schedule by 100 MW so that the total load would increase by the 100 MW and be in balance with total generation.

The significance of intra-hourly transmission scheduling with NYISO is that it is a tool for wind integration that can contribute Load Following and hence reduce the amount of controllable generation inside Québec that is required for Load Following. Given that the NYISO interconnection at Massena is 1100 MW there is ample opportunity to modulate 150 MW of transaction schedules to provide Load Following. In future, if 15 minute scheduling is implemented with Ontario, New England and New Brunswick there would be about 7000 MW of interconnection capacity available. With their liquid markets connecting dispersed loads and different generation patterns in addition to increased interconnection capacity the opportunity to achieve 150 MW of scheduling modulation would increase immensely.

The second area of FERC Order 764 value for the HQD Application concerns management of ancillary service related costs. FERC *"agrees that calculating the relative impact of individual customers or customer classes on a public utility transmission provider's* ***overall generation regulating reserve needs and allocating those costs accordingly*** *can be a difficult and complex determination. However, the Commission believes that the complexity of these proceedings can be mitigated where entities take note of, and incorporate, the following principles."*[105] (Bold underline added)

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[104] HQD-02-01 Régie, IR 5.1 and HQD-02-03.2 EBM(WKM), IR 12.4

[105] FERC Order 764, Paragraph 317

> *"… the Commission encourages transmission providers, generators, and transmission customers to work together to explore options to find **<u>the least cost methods of balancing the system as a whole."</u>**[106]* (Bold underline added)

> *"The Commission has required that overall generator regulation requirements be established by taking diversity benefits into account. Diversity benefits result from **<u>aggregating the variations of all resources</u>** so that one resource's negative deviation can offset some or all of another resource's positive deviation … this **<u>portfolio-wide approach</u>** to assessing generator regulation charges appropriately shares diversity benefits among generators and load."*[107] (Bold underlines added)

> *"the overall quantity of regulating reserve it requires of its transmission customers accounts for diversity benefits **<u>among all resources and loads,</u>** and the allocations to individual customers (or customer classes) of their **<u>proportionate share is based on the operational characteristics of such customers</u>** (or customer classes)."*[108] (Bold underlines added)

> *"power production forecasting would be utilized to identify and acquire the **<u>appropriate amount of reserves needed to integrate VERs reliably</u>**. Nothing in this Final Rule alleviates the public utility transmission provider's obligations under NERC Reliability Standards."*[109] (Bold underlines added)

> *"The public utility transmission provider could continue to rely on existing rate mechanisms to recover reserve costs or may propose to require a uniform quantity of generation regulating reserves from all transmission customers that is commensurate with transmission customers' **<u>proportionate effect on net system variability and taking diversity benefits into account</u>**."*[110] (Bold underlines added)

It is clear from the above extracts from Order 764 that load variations and wind variations should not be balanced separately as would be achieved under the Application of HQD. The accepted industry wide approach is to balance the net variations of all loads and all generation on the system. Indeed this approach is recognized by the HQD expert Mr. Hanser where he states *"However, additional ancillary service needs are always considered for the entire pool of resources, rather than just for VERs."*[111]

We have also seen that implementation of 15 minute transmission scheduling by NYISO according to FERC 764 direction provides significant opportunity to reduce the Load Following capacity needed in Québec to reliably integrate wind generation. This opportunity appears to have been ignored by HQD in the Application.

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106 Ibid, Paragraph 274
107 Ibid, Paragraph 319
108 Ibid, Paragraph 320
109 Ibid, Paragraph 329
110 Ibid, Paragraph 334
111 HQD-1 Document 2, page 11, Lines 5-6

8. EVIDENCE OF MR. HANSER

Mr. Hanser covers five topics in his evidence report as follows:

- Background on power system operations and wind integration practices
- US Federal Regulatory Requirements
- Wind in Organized markets
- Wind integration outside organized markets
- Wind integration in HQD

There are no issues with the information provided in the first three areas. They provide good overview information on the state of wind integration. There were some omissions regarding FERC Order 764 but they have been addressed in the previous Chapter so the focus here is on the last two topics.

Wind integration outside organized markets

The information provided regarding wind integration in several utilities in the US that have specific wind integration charges is worth reviewing. It is difficult from the report to compare the utilities in detail because information on them is spotty.[112] Based on the report and information gleaned from the utility web sites a summary of the characteristics of those utilities has been prepared and compared with the HQD system. It is provided in Figure 8-1.

Figure 8-1[113]
Wind Penetration and Integration Cost Comparisons of Hanser Evidence

Utility	Peak MW	Energy GWh	Avg Load aMW	Wind MW	Wind GWh	Wind %CF	Penetration %Peak MW	Penetration %GWh	Rate @35% $/MWh
BPA	11,300	70,080	8,000	4,711	13,206	32%	**42%**	**19%**	$4.81
PSE	4,900	23,000	2,626	773	2,340	30%	**16%**	**10%**	$6.07
Idaho	3,245	15,409	1,759	678	1,496	27%	**21%**	**10%**	$5.01
Westar	5,000	27,000	3,082	614	2,151	40%	**12%**	**8%**	$0.58
NWE	1,784	10,836	1,237	141	494	40%	**8%**	**5%**	$6.18
HQD (2015)	38,972	189,214	21,600	3,139	8,513	30.96%	**8%**	**4%**	

It is acknowledged that the data in the above table may not be perfectly consistent as it comes from various sources and points in time. It is not intended to provide a basis for definitive analysis but rather to provide a relative comparison of the challenge of wind integration by HQD in 2015 to the current state of the US utilities referenced by Mr. Hanser.

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112 An attempt was made through HQD-02-03.2 EBM(WKM) IR-141 and IR 14.2 to obtain additional information but it was refused so I have obtained missing data from utility web sites.

113 Data taken from combination of HQD-1 Document 2 and corporate web sites.

Review of Figure 8-1 indicates that the US utilities range from small to relatively large utilities but none are near the size of HQD in 2015. To compare it is necessary to determine wind penetration on a relative basis and two measures are provided. Wind penetration is provided on a capacity basis equal to the installed wind capacity as a percentage of the system peak load. It is also provided on an energy basis which is the amount of annual wind energy as a percentage of total annual system energy. Note that the penetration rates for HQD in 2015 will be equal to North West Energy ("NWE") but significantly less than all the others which are 50% to 400% higher than HQD.

The resource make up of these US systems is a mix of nuclear, coal, natural gas and hydro while the resource make up of HQD is predominantly hydro. The challenge faced by these US utilities to acquire and provide regulation, load following and imbalance resources is much greater than that of HQD. Mr. Hanser has provided background information on how these US utilities have developed wind integration costs. Comment by me on those methods and costs is provided in Chapter 8 along with costs determined by other utilities.

Wind integration in HQD

Mr. Hanser states that *"None of the formally defined wind integration services in all of the jurisdictions reviewed is directly comparable with the service needed by HQD."*[114] He goes on to explain why the service needed by HQD is "unique". *"HQD requires similarly unique wind integration services as compared to other regions. These unique characteristics include contract duration, the type of services sought, and the location of the service providers."*[115] He later adds HQD's lack of generation ownership as an additional unique characteristic. Each of these characteristics must be separately reviewed.

> Contract Duration - Regarding service duration Mr. Hanser states "*The VER integration services in US jurisdictions only include intra-hour services. Longer term services are covered either by the wind power off-takers, which have access to other resources (e.g., NaturEner contract with SDG&E), or by the wind power producers if it controls more than only wind plants (e.g., Iberdrola). Because HQD is the wind power off-taker and does not control generation resources that can be used to provide integration services, HQD needs both the intra-hourly* services *and the longer-term services".*[116] The logic used by Mr. Hanser to come to these conclusions is based on a flawed "apples to oranges" comparison. Because the VER integration services ("apples") are intra-hourly and the desired combined service of HQD ("an orange") must also be long term it makes the HQD need unique. It is not unique. All distribution utilities have long term obligations.
>
> To undo this flawed argument it is necessary to go back to the reliability needs of both HQD and other distribution companies. Mr. Hanser clearly states the needs of HQD. *"As a distribution company, HQD needs to meet both energy and capacity demands. Thus, HQD needs to procure both energy and capacity to meet the demand beyond the heritage pool requirements. Moreover, HQD does not control balancing resources.*

[114] HQD-1 Document 2, page 2, lines 6-7
[115] Ibid page 28, lines 10-12
[116] Ibid page 29, lines 8-13

Therefore, intra-hour, hourly and longer-term integration services, including capacity firming, are required to enable HQD to use the output of its wind contracts to meet its energy and capacity demand obligation."[117] It is implied that this differentiates HQD from other distribution companies. It does not. All distribution companies have to meet energy and capacity demands and if they have wind resources they need to integrate them in the short and long term.

We saw earlier under section (a) of Chapter 5 on adequacy that HQD demonstrates its capacity and energy adequacy to NPCC. HQD does it directly because it is the only supplier of load within the HQT Balancing Area. Most other distribution companies do not constitute an entire balancing area so their demonstration of adequacy is through the Reliability Coordinator for the area. As an example, Summerside Electric is a distribution company in PEI that supplies the load of the Town of Summerside. It owns some diesel and wind generation, contracts for some additional wind from Suez Energy and contracts supplementary capacity, energy and some ancillary services from NB Power. It has an obligation to demonstrate to the Reliability Coordinator that it meets its share of the Maritimes Area obligations. This forms a portion of the adequacy filing of the Maritimes Area Reliability Coordinator to NPCC. While smaller in magnitude, Summerside has intra-hour, hourly and longer-term integration obligations that are no different than those of HQD.

Ownership – Through the smallest utility referenced by Mr. Hanser, NWE, he raises generation ownership as an issue. *"In NWE we find an example of a load serving entity which procured wind integration resources to meet both intra-hour and longer-term balancing needs. However the tool that NWE selected to provide for their longer-term balancing needs, building a power plant that will always be available for providing ancillary services, does not apply to the HQD situation."*[118] Why not? NWE did not need to build and own the power plant. They could have contracted with a third party to do it. At issue is not who owns the power plant but rather who owns the contractual rights to the intra-hour and longer-term balancing services that it provides. The obligations and needs of HQD, although larger in magnitude, are no different than those of NWE and vice versa.

Location of Services – Generally I agree with Mr. Hanser that the intra-hour regulation and load following services are best procured from within a balancing area. There are challenges to getting them from outside the balancing area but the challenges do not eliminate the possibility. Mr. Hanser suggests that transmission reservations from NYISO are an issue in this regard. "***Q. Can some wind integration service be provided through the DC ties connecting Québec to New York?*** *A. No. Because the import capacity on the interconnections with New York is fully reserved by HQD to meet its capacity obligation, potential service providers located in New York would not be able to use the interconnections between New York and Québec to provide the wind integration services, but would have to secure interconnection capacity through Ontario, New Brunswick, or New England*." [119] This is incorrect. As Mr. Hanser notes,

[117] Ibid page 29, lines 1-6
[118] Ibid Page 27, lines 7-11
[119] HQD-1 Document 2, page 31, lines 1-7

HQD holds the transmission reservation from NYISO to secure access "to capacity imports from neighboring markets."[120] There is no reason that specific capacity in NYISO that can provide intra-hourly services or energy exports on 15 minute schedules cannot utilize this same reservation. As was explained in Chapter 5 security services are measured in MW but are not separate capacity from the physical concrete and steel adequacy capacity. They are subsets of the physical adequacy capacity that are operated in a specific manner. The transmission reservation can deliver both.

Mr. Hanser also notes that delivery from NYISO could be an issue during outages. *"At times DC ties are unavailable. For example, the Châteauguay (Québec – New York) and Outaouais DC ties (Québec – Ontario) were respectively unavailable for 1666 and 346 hours in 2012, out of the 8784 hour in the year. The DC ties may be out of service due to either planned (maintenance) or unplanned (forced outage) reasons. Should wind integration services be provided through a DC tie, there would have to be provisions on how the services would be delivered to HQD when the DC tie is unavailable."*[121] This implies that any one resource contracted to supply intra-hourly services must be available 100% of the time. This is not the case. Generators that supply integration services are also subject to planned maintenance outages and occasional forced outages. All system operators procure surplus integration services so that they will have access to the additional resources should any source of intra-hourly services be not available.

Type of Services – As was quoted earlier the types of services required are "*intra-hour, hourly and longer-term integration services, including capacity firming*".[122] But as we saw earlier for Summerside Electric and NWE these are not unique to HQD. These services are required by all distribution utilities. If a distribution utility owns or contracts for wind resource supplies it needs an incremental amount of regulation, load following and imbalance. What is unique about HQD is not that it needs these resources but that it demands that they be bundled together and that 100 % of the contract quantity be under one minute control.

[120] Ibid, page 24, lines 21-22
[121] Ibid page 30, lines 13-18
[122] Ibid page 29, lines 1-6

9. WIND INTEGRATION STUDIES

As the penetration of wind into North American power systems has increased over the past 10 years there have been several studies undertaken to analyse the requirements to integrate wind into hydro thermal systems more efficiently. Most have been undertaken by specific utilities for balancing areas while some[123,124] have had a much wider view. Of most relevance for HQD in serving load in Québec are those studies for specific balancing areas. This chapter looks at a number of those studies and compares them with the studies undertaken by Hydro-Québec and the requirements in the Application.

The most significant point for the vast majority of these utility/balancing area studies is the methodology employed. They do not balance system load variations separately and wind variations separately. Rather **they consider the net load variations of wind and load**. This approach is clearly articulated in a study done by General Electric for the Electric Reliability Council of Texas ("ERCOT Study"). "*The impacts of wind generation on ancillary service requirements cannot be evaluated by examining wind generation output characteristics independently from the simultaneous behavior of the load. Factors causing inaccuracy in wind forecasting may also affect load forecasting (e.g., arrival time of a cold front). Operationally, the dispatchable generation output must conform to the characteristics of the net load, defined as the aggregate customer load demand minus the aggregate wind generation output. The fundamental approach of this study is to analyze the **net load** variability and the resulting impacts on ancillary services requirements brought on by increasing penetrations of wind generation.*"[125] *(bold and underlines in the original)*

I have reviewed several studies that deal with the amount of and/or cost of the incremental ancillary services required to reliably integrate wind generation. They include:

- ERCOT Study (March, 2008)
- General Electric Study for NS Power (June, 2013)[126]
- NBSO Maritimes Area Wind Integration Study (August 2005) referenced at page 17 in footnote 40
- NBSO Maritimes Area Final Wind Integration Report (May 2007)[127]
- NYISO Wind Integration Study (September, 2010)[128]
- HQD Wind Studies referenced in footnotes 52 and 60

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123 "*Western Wind and Solar Integration Study*", NREL, 2010, available at http://www.nrel.gov/electricity/transmission/western_wind.html

124 "*Eastern Wind Integration and Transmission Study*", NREL, 2010, available at http://www.nrel.gov/electricity/transmission/eastern_renewable.html

125 "*Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements*" available at www.ercot.com/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip

126 "Nova Scotia Renewable Integration Study", GE Energy Consulting, June 28 2013, NSUARB Matter 05419,), Exhibit M-110, Undertaking U-4(C) pages 5-329 available at http://uarb.novascotia.ca/fmi/iwp/cgi?-db=UARBv12&-loadframes

127 NBSO 2007 study is provided as Appendix C as it is no longer available on the NBSO web site which is shut down.

128 *"Growing Wind - Final Report of the NYISO 2010 Wind Generation Study", NYISO, September 2010 at http://variablegen.org/wp-content/uploads/2013/01/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf*

- IEA Wind Task 24 HQ Study #1 referenced on page 31in footnote 81
- Idaho Power Wind Integration Study (February 2013)[129]
- Excel Energy Wind Integration Study For Public Service of Colorado (December, 2008) [130]
- Utility Variable-Generation Integration Group (UVIG) Wind Integration Summary[131]

Results of these various studies are presented separately for Regulating Reserve (AGC) requirements, Load Following requirements and cost of wind integration. This separation enables the results to be more easily seen and compared with the HQD Application.

Regulating Reserve Requirements

Regulation results are provided by GE for ERCOT, NYISO, and UVIG for two different systems in addition to the two different Hydro-Québec studies in Figure 9.1.

Figure 9-1
Regulating Reserve (AGC) Requirements of Wind Integration Studies

Study	Peak Load MW	Wind MW	Penetration %Peak	Regulation MW	Regulation %Wind
GE-ERCOT 2008	65,000	15,000	23.1%	102	0.7%
NYISO 2010	37,130	8,000	21.5%	116	1.5%
UVIG #1	10,000	1,500	15.0%	8	0.5%
UVIG #2	33,000	3,300	10.0%	36	1.1%
HQ Regulation	39,000	3,000	7.7%	6	0.2%
IEA HQ Regulation	39,000	3,000	7.7%	30	1.0%
HQ Application	39,000	3,139	8.0%	3139	100.0%

The Regulating Reserve results in Figure 9-1 provide the system peak load in MW, the MW amount of installed wind capacity, and the required Regulation capacity in MW which ranges from a low of 6 MW to a high of 116 MW. The system sizes and wind penetration also vary significantly so in the last column Regulation is expressed as a percentage of wind capacity to get relative results. It shows that Regulation ranges from 0.2% to 1.5% of wind capacity. It is a very small amount relative to the total wind installed and clearly demonstrates that the 100% requirement in the HQD Application is excessive.

Load Following Requirements

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129 "*Wind Integration Study Report*", Idaho Power Company, February 2013, available at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/windIntegrationStudy.pdf

130 "*Wind Integration Study For Public Service of Colorado*", Excel Energy, December 2008, available at http://variablegen.org/wp-content/uploads/2013/01/CRPWindIntegrationStudy.pdf

131 "*Utility Wind Integration State of the Art*", Utility Variable=Generation Integration Group (previously Utility Wind Integration Group), May 2006, available at http://www.uwig.org/UWIGIntSummary.pdf

Other studies by NBSO, GE for NS Power, Idaho Power and Hydro-Québec focused on hourly and intra-hourly variations which are presented as Load Following requirements in Figure 9-2. Note that most studies consider different penetration levels of wind. As would be expected the magnitude of Load Following requirement increases with wind penetration. Another interesting point is illustrated in the NBSO[132] study. It included analysis of the Maritimes Area as a combined balancing area as well as two separate balancing areas for NB[133] and NS. As one might expect the combined Maritimes Area requires less Load Following that the sum of the two separate areas.

Figure 9-2
Load Following Requirements of Wind Integration Studies

NBSO 2005 #1	NB Area	3,300	400	12.1%	3.7	11.1	2.8%
#2	NB Area	3,300	600	18.2%	8.1	24.3	4.1%
#3	NS Area	2,100	400	19.0%	7.7	23.1	5.8%
#4	Maritimes	5,400	1000	18.5%	10.3	30.9	3.1%
GE-NS Power 2013 #1		2,100	335	16.0%		21	6.3%
	#2	2,100	488	23.2%		29	5.9%
	#3	2,100	551	26.2%		32	5.8%
	#4	2,100	916	43.6%		45	4.9%
Idaho 2013 #1		3,400	800	23.5%		50	6.3%
#2		3,400	1,000	29.4%		130	13.0%
#3		3,400	1,200	35.3%		195	16.3%
HQ Following #1		39,000	3,000	7.7%		82	2.7%
IEA HQ Following		39,000	3,000	7.7%		150	5.0%
HQ Application		38,972	3,139	8.1%		3139	100.0%

The most important finding in Figure 9-2 relates to the relative amount of Load Following requirement. Other than the very high penetrations in Idaho, the range of Load Following requirement is from a low of 2.7% of wind capacity to a high of 6.3 %. Note specifically that the results of studies undertaken by Hydro-Québec fall in this range. Again the amount of Load Following in each of the studies is relatively small especially compared to the excessive 100% requirement in the HQD Application.

Wind Integration Costs

The last area of interest from wind integration studies is the cost of integration. Costing information is provided by NBSO, Excel Energy, Idaho and the UVIG in Figure 9-3. Costing was also conducted by GE in the NS Power study but is blacked out in the public version of the study report. Before we comment on the costing results it is important to understand what separate services are included in the total cost. Generally these all include the cost of capacity

[132] The NBSO study presented results as the standard deviation of hourly variations. In order to get a comparable confidence level as the GE and Idaho studies three standard deviations are assumed to be required.

[133] The NB balancing area includes PEI and Northern Maine.

for Regulating Reserves (AGC), intra-hour and hourly load Following, the cost of unit commitment of this capacity and Energy Imbalance for the hourly deviations of actual energy from schedule.[134] Note that, unlike the Application, there are no scheduling penalty costs other than those included in Energy Imbalance to incent accurate scheduling. Results show that costs are not linear. They increase gradually as penetration increases but beyond about 20% penetration there is a knee in the cost curve and costs increase much more rapidly.

Figure 9-3
Integration Costs per MWh of Wind Production

Study	Peak Load MW	Wind MW	Penetration %Peak	Cost $/MWh
NBSO 2007 #1	3,300	400	12.1%	4.39
#2	3,300	600	18.2%	4.71
#3	3,300	800	24.2%	7.36
EXCEL Energy #1	7,148	720	10.1%	3.51
#2	7,148	1,075	15.0%	4.77
#3	6,922	1,400	20.2%	5.13
Idaho 2013 #1	3,400	800	23.5%	6.51
#2	3,400	1,000	29.4%	11.03
#3	3,400	1,200	35.3%	16.38
UVIG			20.0%	5.00

The knee in the costing likely occurs because the host utility has limited variable resources and runs into major unit commitment costs because normally base loaded units with slower ramping capabilities are needed. This is borne out by UVIG in their report where they state *"The greatest part of this [integration] cost is associated with the uncertainty introduced into day-ahead unit commitment due to the uncertainty in day-ahead forecasts of real-time wind energy production."*[135] It is also evident in the NBSO report which breaks out the unit commitment and energy balancing costs separately from the Load Following capacity.

It is worth noting that the integration costs shown in Figure 9-3 are generally consistent with the costs cited by Mr. Hanser in his evidence. For the benefit of the reader they are presented here in Figure 9-4 along with the peak load based penetration rates.

[134] This does not mean that the individual services are bundled. As stated by Mr. Hanser Transmission customers at BPA have the option of self supplying portions of any one service and purchasing the others or purchasing the bundle. (HQD-01- Document 2 page 13, lines 20-23).

[135] "*Utility Wind Integration State of the Art*", Utility Variable Generation Integration Group, May 2006, page 3, available at http://variablegen.org/wp-content/uploads/2013/01/UWIGIntSummary.pdf

Figure 9-4
Integration Costs per MWh of Wind Production From Hanser Report

Utility	Wind Penetration vs Peak Load % MW	Rate @ Published CF $/MWh	Rate @35%LF $/MWh
BPA	42%	5.27	4.81
PSE	16%	7.08	6.07
NWE	8%	5.41	6.18
Idaho	21%	6.50	5.01

In response to an information request from the Régie[136] HQD noted that the integration costs provided by Mr. Hanser could be considered as an indication of the costs that may be provided through an RFP. It is agreed that the costs cited by Mr. Hanser are generally consistent with integration costs determined through other studies as given in Figure 9.3 but whether or not they are reasonable for HQD is a separate issue.

There are different factors that indicate that the costs of wind integration in HQ should be less. Firstly, the wind penetration rate for HQD after the installation of 3139 MW of wind is only about 8% which is much less than all the utilities considered except NWE. Secondly, all of the utilities considered are mixed hydro thermal systems with limited hydro resources so start to encounter significant unit commitment costs at their penetration levels. HQP's resource profile and HQD's supply profile are both 90% or more hydro generation. Another difference for HQ is 7000 MW of intertie capacity to large neighbouring liquid markets with a potential for 15 minute scheduling. The quick start capability and the very small no load running costs of hydro means that there would be much less unit commitment cost for HQ. Of the US utilities in the table, only BPA would have a reasonable amount of hydro to accommodate wind integration. This is evident from its near $5/MWh cost at an exceptionally high penetration rate of 42%. What would BPA costs be if its penetration rate was only 8%? Based on the integration costs in Figure 9.3 at varying penetration rates[137] the BPA costs at 8% could be reduced by 40% to 60% to be in the range of $2/MWh to $3/MWh. I submit that wind integration costs in that range may also be appropriate for Québec but without an RFP or detailed cost analysis these can only be considered indicative costs.

136 HQD-02-01 Régie IR 4.4

137 From highest penetration rate modeled to the lowest penetration modeled the wind integration costs reduced by 40% for NBSO, 37% for Excel and 60% for Idaho.

10. CONCLUSIONS

This report reviews the EIÉ, the EGM, the CFQ, the Application, the evidence of Mr. Hanser, FERC Order 764, the HQD Wind Studies and several other wind integration related documents applicable in other jurisdictions in North America, and it has resulted in the findings detailed here.

- The EIÉ which was entered in 2005 has been renewed several times and is still in force including its several shortcomings.
  - It bundles commercial services as well as various distinct reliability services into one amalgamated service.
  - The supplemental capacity methodology over charges HQD for 15% of its wind capacity because it does not recognize the 30% capacity credit for wind generation accepted by NPCC
  - Uniform annual energy modulation at 35% capacity factor does not match HQD's seasonal load shape and creates significant energy settlement costs that are detrimental to HQD and its customers

- The EGM was a more advanced version of the EIÉ that corrected many of its flaws but had procurement shortcomings.
  - Annual uniform energy modulation was adjusted to provide optional wind energy banking that provides an opportunity for HQD to more efficiently manage its total energy supply.
  - It properly applied NPCC's recognition of 30% capacity credit for wind generation in its determination of supplemental capacity but ignored the Régie's direction to procure it via separate RFPs.
  - It properly applied the accepted wind integration principles accepted throughout North America to break out and quantify the specific incremental ancillary services required to integrate wind generation reliably.
  - It continued to bundle all the services within one agreement and did not recognize the opportunity for their procurement as separate services via separate RFPs. This bundling mixed the additional supplemental capacity not required for reliability under the Regulatory Decrees with the capacity based ancillary services needed to provide the balancing and integration required by the Decrees
  - It was rejected by the Régie not because of the characteristics of the individual requested services but rather because of the bundled procurement requirement

- The CFQ defined a bundled integration service that effectively was a more rigid form of the EIÉ but with proper recognition of wind capacity at 30% of nameplate.
  - It did not take into account the Régie's ruling in the EGM to offer distinct RFPs
  - Its energy modulation was an annual uniform 35% return balanced not hourly but every five minutes
  - It requested 5% supplemental capacity even though this should have been obtained through a distinct RFP assuming that it was necessary for HQD resource adequacy

    - By requiring that the entire Contract Quantity be provided to CCR under five minute control, it effectively made 100% of the Contract Quantity into Regulating Reserve and it effectively increased the supplemental capacity from 5% to 35%
    - In addition to the excessive scheduling requirement it included excessive imbalance penalties for each 5 minute interval
    - After the EBM challenge to dismiss it and the Régie decision to proceed with EBM's motion for cancellation it was withdrawn by HQD

- The Application is for approval of the characteristics of a wind integration service that is the same as that in the CFQ except that the CCR control is reduced from a five minute interval to one minute. There are several issues with the Application.
    - It includes several independent services that are bundled together into one combined request for a "wind integration service" contrary to the Régie's ruling in the EGM
        - The Modulation component is not required for reliability purposes but rather is a commercial banking and scheduling service that, if deemed necessary or economic, should be procured separately via a separate RFP
        - The supplemental capacity is not required to integrate wind generation but rather is simply capacity desired for adequacy purposes which also, if deemed necessary or economic, should be procured via a separate RFP.
        - The only services needed to reliably integrate wind generation are the intra hourly services of Regulating Reserve (AGC) and Load Following where hourly Energy Imbalance can be handled through the HQT OATT
    - The bundling of the services into one request essentially limits participation to HQP with little competition possible from other suppliers. This limited competition favours HQP and is not in the best interests of HQD customers because it may not result in the least cost of supply

- The effect of the Application is not to procure the required services for reliable integration of wind generation at minimum cost but rather to require that a supplier provide 100% of its Contract Quantity to CCR as Regulating Reserve capacity.
    - This requirement for Regulating Reserve capacity is excessive
    - It exceeds the reliability requirements of NERC and the ancillary services determined to be required in the EGM
    - It even exceeds the isolated balancing requirements of HQD wind as determined through analysis of 2012 wind data

- The intention of HQD to balance wind separately from other system variations is inconsistent with the utility industry throughout North America.
    - It is opposed to the principles and intent of FERC expressed through Order 764
    - It adds additional balancing burden that exceeds the reliability standards of NERC

- It is inefficient and costly and not consistent with a mandate to supply customers at least cost

- The required services to balance 3139 MW of wind in the Hydro-Québec system in 2015 based on existing studies is
  - 6 to 31 MW of Regulating Reserve (AGC)
  - plus 80 to 126 MW of Load Following
  - which taken together is a total balancing capacity of 86 to 157 MW

- Regulating Reserve and Load Following are separate capacity services which should be procured via separate RFPs in order to achieve a minimum cost of supply.

- HQD wind integration compared to results of wind integration studies for other jurisdictions indicates
  - The capacity penetration of wind for HQD at 8% of peak load in 2015 is small compared to other areas
  - The amount of Regulating Reserve and Load Following provided in the EGM is consistent with industry studies
  - Indicative integration costs for HQD should be less than thermal based systems and in the range of $2/MWh to $3/MWh of wind energy production

APPENDIX – A

APPENDIX A - NBSO Maritimes Area Wind Integration Study (August 2005)

Maritimes Area Wind Integration Study

August 2005

This study has been conducted by New Brunswick System Operator (NBSO) for the Atlantic Electricity Work Group (AEWG). Supporting data has been provided by Nova Scotia Power, New Brunswick Power, Prince Edward Island Energy Corporation and Vision Quest. The study has been jointly funded by Nova Scotia Power, New Brunswick Power, Maritime Electric Company and NBSO.

1.0 EXECUTIVE SUMMARY

The purpose of this study is to examine issues related to the integration of large amounts of wind-powered generation into the power systems of the Maritimes. These issues are not well known today, as the June 2005 total of all installed wind project capacity in the Maritimes is only 46 MW. The motivation for this study is that the provincial governments of the Maritimes intend to implement Renewable Portfolio Standards (RPS) requiring a certain percentage of the electricity sold in a province to be produced from renewable resources. Due to the current economic advantage that wind energy has versus other renewable generation alternatives, it is likely that these new policies will cause significant increases to the installed wind project capacity of the Maritimes.

There are four main areas where wind-powered generation can impact power system planning, operations, and associated costs. These are:

- Assigning a capacity value to wind projects that recognizes their contribution to system reliability,
- Managing hourly wind project output variation that increases the system load following requirement,
- Managing the minute-to-minute wind project output variation that increases the system regulating capacity requirement, and
- The need to accurately forecast wind project output on the day prior to operation so that unit commitment costs can be minimized

Due to data limitations, the latter two areas are not addressed in this report. Analysis of these issues in future studies may become possible as more data is gathered from new wind projects. The wind capacity integration issues that are analysed in this study in some detail are:

- Quantifying the reliability contribution (i.e. effective capacity) that new wind projects can make to the Maritimes,
- The impact of new wind projects on the variability of the load served by conventional generation, and
- The risk of increased costs associated with increased load variability during the spring run-off because the hydroelectric generation cannot be flexibly dispatched to respond to either load changes or wind generation changes.

This study measures the reliability contribution of eight simulated wind projects to the Maritimes power system (New Brunswick, Nova Scotia, PEI, and Northern Maine) using a standard Loss of Load Expectation (LOLE) analysis performed with a Monte Carlo simulation technique. The wind projects are simulated with wind speed and temperature data recorded at different sites. The result of this reliability measurement is the determination of an effective capacity for this intermittent wind resource.

The average effective capacity of simulated wind projects in the NB Area power system (NB, PEI, and Northern Maine) were calculated for different scenarios. The average effective capacities were:

- 66% - 2004 Maritimes with intra-area transfer limits

- 73% - 2004 Maritimes without intra-area transfer limits
- 60% - 2004 NB Area only
- 49% - 2003 Maritimes with intra-area transfer limits

It was seen in the study that the effective capacity results could vary year-to-year, and that the winter capacity factor was a good approximation of the effective capacity. Until additional years can be analysed, it is a recommendation of this study that wind projects connected to the NB Area power system be credited by capability period with a capacity equal to their expected capacity factor for that capability period.

The average effective capacity of simulated wind projects on the Nova Scotia power system was calculated for different scenarios. The average effective capacities were:

- 1% - 2004 Maritimes with intra-area transfer limits
- 62% - 2004 Maritimes without intra-area transfer limits
- 50% - 2004 Nova Scotia only

Similar to the NB Area, it is a recommendation of this study that wind projects connected to the Nova Scotia power system be credited with a capacity equal to their capacity factor by capability period.

The load variability of the NB Area, Nova Scotia Area, and Maritimes Area power systems was quantified by taking the standard deviation of the hourly load swing. The impact of wind generation on the load variability was calculated by subtracting simulated wind generation from the actual loads, and then recalculating the standard deviation of the hourly load swing of the remaining load. Using regulatory evidence filed by NB Power in 2002 regarding the cost of providing load following, it is estimated that a 1 MW increase in the standard deviation of the hourly load swing for the Maritime region results in an annual cost increase of $67,870.

The following table provides a summary of the load variability analysis.

Region	2004 Average System Load	2004 Load Swing Std. dev.	400 MW Wind Single Site Variability Increase		400 MW Wind Dispersed Sites Variability Increase		400 MW – NS, 600 MW – NB Composite Wind Impact	
	(MW)	(MW)	(MW)	$Millions	(MW)	$Millions	(MW)	$Millions
NS	1418	59	18.3	1.24	7.7	0.52	7.7	0.52
NB Area	2015	82	14.7	1.00	3.7	0.25	8.1	0.55
Maritimes	3433	123	10.2	0.69	1.8	0.12	10.3	0.70

The load variability analysis showed that the impact of wind generation on load variability is significantly reduced if the wind capacity is geographically dispersed amongst several sites as opposed to being all located at a single location. Thus, to integrate significant wind project capacity in the Maritimes, it is a recommendation of this study that the developed capacity be split up amongst several sites, and that these sites have a good geographic separation in order to minimize costs associated with increased load variability.

Another result of the load variability analysis was that the impact of wind generation on load variability is significantly reduced if load variability is managed on a Maritime basis versus a sub-area basis. This is demonstrated in the previous table where the additional load variability produced by 1000 MW of wind (600 MW NB Area, 400 MW Nova Scotia) is only 8.4%, or 10.3 MW more to the standard deviation of the hourly load swing at an estimated annual cost of $0.70 million. This compares to a 15.8 MW increase if the additional load variability is managed separately by the individual sub-areas at an estimated annual cost of $1.07 million. Note that these costs could be greater if the NS cost of load following is higher than the NBSO cost.

In the Nova Scotia and NB Area regions, the cost of load variability is distributed amongst the load in that region. Therefore, any load variability cost increase due to wind generation falls to the local customers, even if they are not the ones purchasing the wind energy. This may be seen as unfair in cases where a new wind project exports its power to a neighbouring system while producing higher load variability costs to customers in the local region. Should such scenarios develop, it is recommended that the Maritime regions may have to look at charging wind projects for increasing the local load variability.

At this time, it is difficult to say how much wind capacity is too much. The Maritimes only has 46 MW of wind generation as of June 2005, and that is not enough to properly judge the impacts of installing levels of wind capacity that are higher by an order of magnitude. Flexible hydroelectric generation is an important factor in terms of managing the variability of wind generation. Compared to other areas in Canada, this study shows that the Maritimes has relatively less flexible hydroelectric generation than any other area except Alberta. This may make it difficult to integrate as much wind capacity as some of those other areas, and policies such as the RPS for each Maritimes province may have to be more conservative because of this. It is a recommendation of this study that a conservative approach be taken with regard to the RPS design for the Maritimes to recognize that the Maritimes does not have the same quantity of flexible hydroelectric generation as do most other areas of Canada, with the exception of Alberta.

Spring run-off describes the April to May period where the snow melt and accompanying rainfall floods the rivers of the Maritimes and causes water to spill over at the hydroelectric stations. This study showed an example of how the 2004 spring run-off compromised the ability of the hydroelectric system to respond to load variability, and that the variability of the load served by thermal generation was increased by the simulated wind generation. It is recommendation of this study that the Maritimes take a gradual approach to integrating wind generation so that the costs associated with increased load variability during the spring run-off are better known. It is also a recommendation of this study that the Maritimes may be able to integrate more wind capacity if it finds opportunities to have the neighbouring power systems of Québec and New England assist with its load variability during the spring run-off.

2.0 TABLE OF CONTENTS

2.1 List of Tables

2.2 List of Figures

3.0 SYSTEM OVERVIEW

The objective of this study is to analyse the reliability issues regarding the integration of large amounts of wind generation capacity into the Maritimes Area. The Maritimes Area is consists of power systems in New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine. Within the Maritimes, Nova Scotia operates as a sub-area with a 350 MW transfer capacity limit to the New Brunswick. The NB Area (New Brunswick, PEI, and Northern Maine) operates as a single sub-area of the Maritimes with a 300 MW transfer limit to Nova Scotia.

Today, there is about 46 MW of wind generation in the Maritimes. Commercial wind projects have been developed in North Cape, PEI and Shelburne, Nova Scotia, plus there are a couple of individual test turbines. Monitoring of wind resources for the potential development of future wind projects has been conducted at several Maritimes Area sites. This study is based upon simulated wind project outputs from eight monitored wind resource sites in the Maritimes. Analysis in this study is mainly for 2004, with some supplemental analysis for 2003.

Wind energy simulations for 2004 were provided to the NBSO for three Maritime sites, and five additional wind energy sites were simulated by the NBSO using wind speed and temperature data recorded at 10-minute intervals. Wind data was converted to simulated wind power output levels using the power output characteristic curve for a Vestas V80 - 2.0 MW turbine at a 78-metre hub height. This particular output characteristic was chosen because it is typical of turbines being installed in current North American wind projects, and it was also chosen for its convenience, as this output characteristic can be found in the online database of NRCan's RETScreen® International wind energy project analysis software, available for free at NRCan's website.

The simulated wind projects for this study were for the following areas:

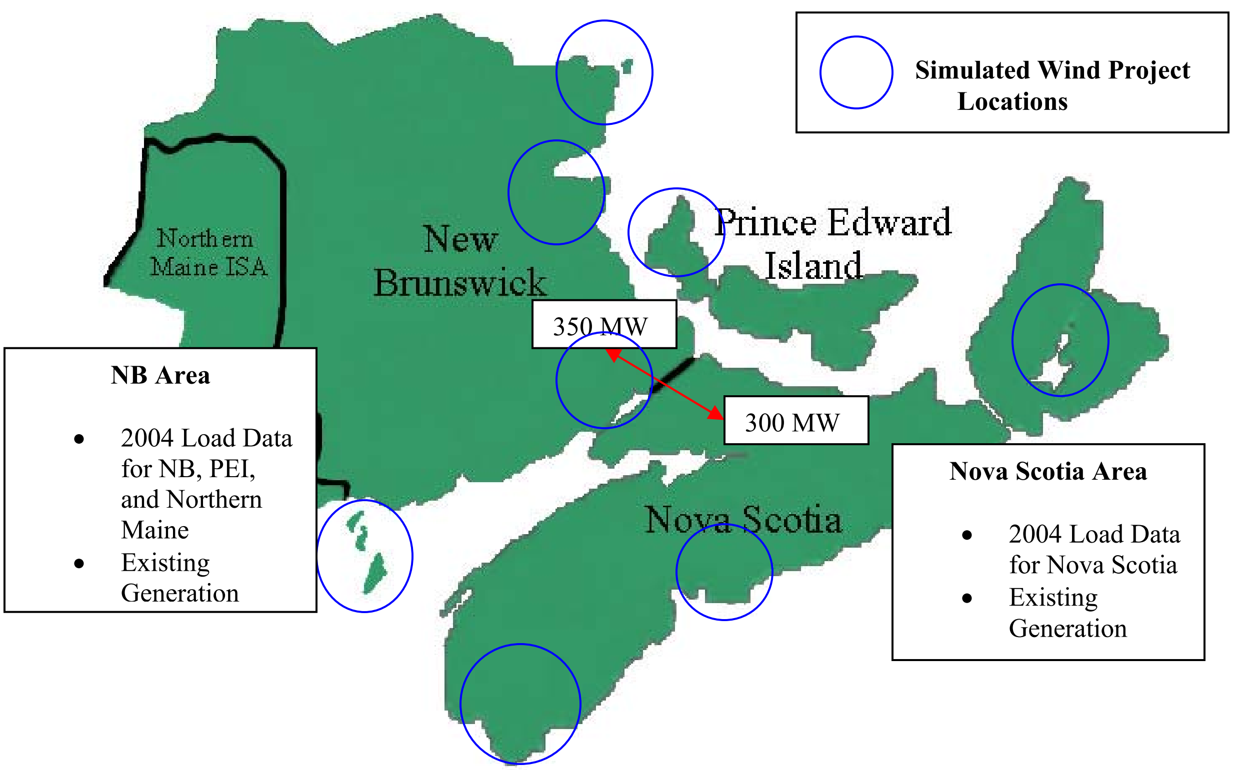
- North Cape / Tignish, PEI
- Cape Breton, NS
- Halifax / Dartmouth, NS
- Shelburne / Yarmouth, NS
- Dorchester / Tantramar, NB
- Miramichi, NB
- Grand Manan / Campabello, NB
- Lamèque / Miscou, NB

NBSO is cognizant that wind energy projections for individual sites have commercial value, and it was agreed to by the NBSO and all parties providing data for this study that wind energy calculations for individual sites would be kept confidential. As a result, no specific wind production performance of any one site is reported in this study. Where it was necessary in some areas of this study to report a result for a single site, the number reported is actually an average of the results at multiple sites.

No consideration of transmission limits other than those between New Brunswick and Nova Scotia is considered in any analysis. Also included are the actual hourly loads from 2004, plus the generation data utilized in the NPCC Maritimes Area Triennial Review of Resource Adequacy (December 2004). This review is available at https://www.npcc.org/publicFiles/documents/resourceAdequacyReviews/currentYear/Maritimes_Area_Triennial_Review_2004.pdf

A model of the system used for analysis is provided in Figure 1 below.

Figure 1
System Model



3.1 Limitations of this Wind Integration Study

This is the first wind integration study done by NBSO for the Maritimes Area and, because of its limited data, should be considered as preliminary.

There are four main areas where wind-powered generation can impact power system planning, operations, and associated costs. These are:

- Assigning a capacity value to wind projects that recognizes their contribution to system reliability,
- Managing hourly wind project output variation that increases the system load following requirement,
- Managing the minute-to-minute wind project output variation that increases the system regulating capacity requirement, and
- The need to accurately forecast wind project output on the day prior to operation so that unit commitment costs can be minimized

This study attempts to address only the first two areas. The impacts on regulation and unit commitment should be considered in future studies.

The regulation impact can be addressed with proper time synchronized data that should become more readily available as actual turbines are installed or greater effort is placed on data collection.

The unit commitment problem requires performing a day-ahead hourly load forecast and scheduling adequate conventional generation resources to meet that forecast. It is part of the normal practice for any power system. If the installed wind generation capacity in the Maritimes becomes significant, it will be necessary for the Maritime power systems to have day-ahead hourly wind energy forecasts incorporated into their scheduling. Failure to do so will likely cause an inefficient scheduling of resources, and may result in extra costs to ratepayers or degradation to system reliability. Neither is acceptable.

At this time, an analysis of the impact of day-ahead hourly wind energy forecasts on the costs associated with the scheduling of convention generation is unable to be performed by the NBSO. In order to perform such a study, the NBSO would need to acquire the following:

- A history of day-ahead hourly wind energy forecasts for the simulated wind projects used in this study,
- Software to perform a day-ahead security constrained unit commitment and energy dispatch for each sub-area of the Maritimes, and
- Conventional generation dispatch data for each sub-area of the Maritimes.

4.0 EFFECTIVE CAPACITY OF WIND GENERATION

4.1 Description

Electric utilities must own or contract for sufficient generation capacity in order to provide a reliable supply of electricity to their customers. Sufficient generation capacity ensures that adequate resources can be committed and scheduled for each hour, and that the electrical supply can always maintain a balance with the electrical load.

Unlike conventional power plants, wind projects cannot supply their capacity to the system on demand. This has caused some areas to discount wind projects from being a capacity resource. However, wind projects can contribute towards meeting area requirements for Loss of Load Expectation (LOLE). By comparing the contribution of a new wind project towards LOLE with the contribution of additional conventional capacity towards LOLE, an effective capacity for the new wind project can be determined.

The following analysis attempts to quantify the effective capacity for simulated wind projects by measuring their contribution towards meeting area LOLE requirements in terms of real capacity.

4.2 Loss of Load Expectation (LOLE) and Loss of Load Hours (LOLH)

Loss of Load Expectation (LOLE) is the probability of disconnecting firm load due to a deficiency of generation resources. The Northeast Power Coordinating Council (NPCC) criterion for LOLE is 0.1 days/year after accounting for emergency operating actions and interconnection support. This criterion can also be expressed as Loss of Load Hours (LOLH) of 2.4 hours/year.

In this study, LOLH was determined through a Monte Carlo random number probabilistic simulation of each generator's availability for each hour of the year. This process considered that the probability of a generator being unavailable for any hour is described by its Forced Outage Rate (FOR). FOR's are provided for each generator based upon operating experience, and are typically in the range of 1-10%. Random numbers between 0 and 1 produced each hour for each generator simulated that a generator was unavailable if the random number for that generator was less than its FOR, otherwise it was available. Planned maintenance was also factored into each generator's simulated availability by forcing generators to be unavailable during planned maintenance hours.

The Monte Carlo simulation also determined the reserve requirements for each hour, which are based upon the first and second generation contingency. As per Maritime system reserve requirements, the 10-minute reserve requirement was made equal to the size of the largest available generator, and the 30-minute reserve requirement was made equal to 50% of the size of the second largest available generator.

A loss of load hour occurred if the total simulated available capacity for an hour was insufficient to meet that hour's requirements for firm load and reserve. Firm load was calculated by subtracting the forecast monthly interruptible customer load from the actual hourly load. Surplus capacity in one sub-area of the Maritimes could assist another sub-area, but this assistance was limited by the intra-area transfer capabilities. No reliance on external interconnections, reduced 30-minute reserve, voltage reductions, other emergency actions, or better than average generator performance was considered in this LOLH determination. It is important to note that this level of load interruption did not actually occur in 2003 and 2004, but rather it is a simulation under the assumed conditions.

The results of this study, for each scenario, were produced from 1000 Monte Carlo simulations for each hour of the simulated year. The set of random numbers was kept constant for each scenario.

4.3 LOLH Simulation Model

The following inputs were incorporated into the LOLH simulation model:

- 2004 actual hourly load data for the Maritime Area (New Brunswick, Nova Scotia, PEI, and Northern Maine.)
- 2004 simulated hourly wind energy outputs for up to 8 sites.
- Intra-Area transfer capabilities
- 2004 Generator Capacities with corresponding Forced Outage Rates
- Planned Maintenance Schedule (typical, monthly)
- Interruptible Customer Load (monthly)

4.4 LOLH Simulation Scenarios

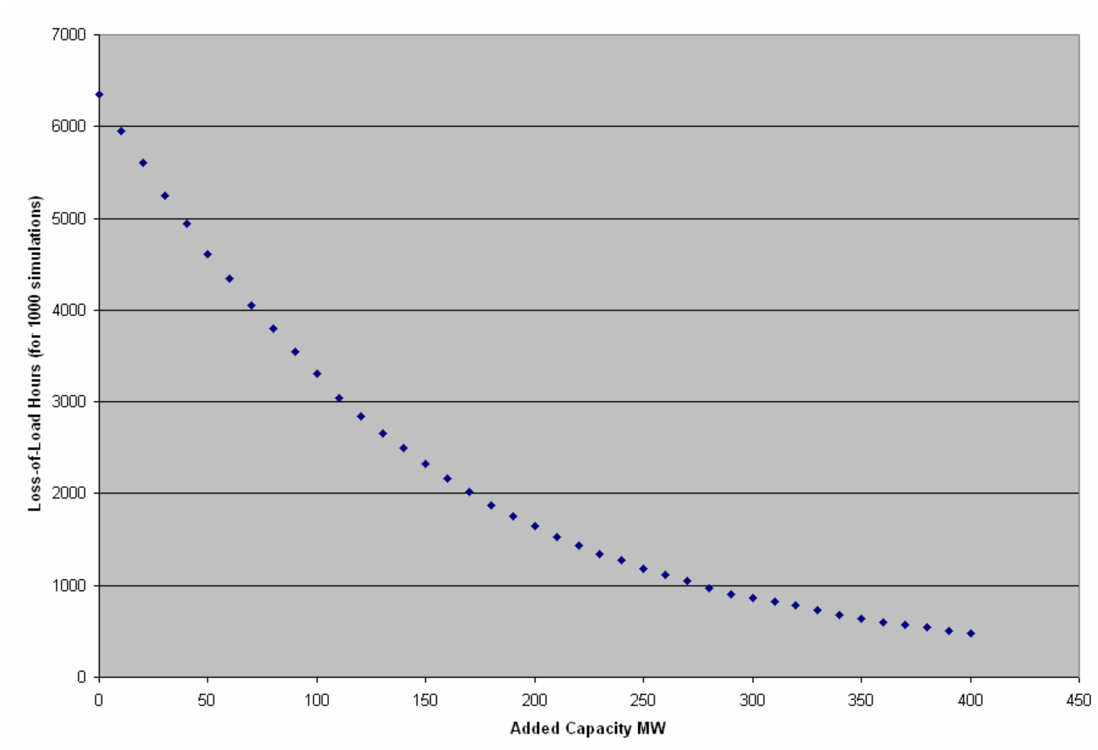
The following is a listing of the scenarios for which the LOLH was calculated:

- Scenario 1 - 2004 Maritime System with Intra-Area Transfer Limits
- Scenario 2 - 2004 Maritime System without Intra-Area Transfer Limits
- Scenario 3 - 2004 NB, PEI, and Northern Maine Areas Only
- Scenario 4 - 2004 NS System Only
- Scenario 5 - 2003 Maritime System with Intra-Area Transfer Limits

4.5 Scenario 1 - 2004 Maritime System with Intra-Area Transfer Limits

Figure 2 shows how the simulated 2004 Maritime System LOLH decreases with the addition of conventional capacity. In this scenario, the additional capacity was located in the New Brunswick sub-area, and intra-area transfer limits were enforced.

Figure 2
LOLH vs. Added Capacity – Scenario 1



This characteristic curve defines the relationship between LOLH and added capacity for this scenario. To determine the effective capacity of the simulated wind sites, the analysis was repeated with wind energy added to the system instead of conventional capacity. The impact of the wind energy on the LOLH determined a corresponding effective capacity value according to Figure 2.

4.6 Scenario 1 - Results

Table 1 shows how the initial LOLH (i.e. added capacity is zero) of 6346 hours from 1000 simulations (i.e. 6.346 hours/year) was distributed on a monthly basis.

Table 1
LOLH Distribution – Scenario 1

Month	LOLH	Percentage
Jan-04	5635	89%
Feb-04	385	6%
Mar-04	22	0%
Apr-04	109	2%
May-04	2	0%
Jun-04	0	0%
Jul-04	3	0%
Aug-04	1	0%
Sep-04	1	0%
Oct-04	1	0%
Nov-04	28	0%
Dec-04	159	3%
Totals	6346	100%

January 2004 was an exceptionally cold month with extreme wind chill as well, and these sustained cold temperatures caused the Maritime electric heating load to soar, resulting in all-time highs for hourly demand. The record demand levels for January 2004 give that month a huge 89% weighting on the LOLH simulation totals in Table 1.

The slight increase in LOLH seen in April 2004 is the result of some scheduled generator maintenance during the spring run-off. Overall, scheduled generator maintenance in the months of April through October does not have a significant impact on these LOLH numbers.

Based on Table 1, it is obvious that the calculation of effective Maritime capacity for the simulated wind projects is very dependent on the simulated January performance of these projects during the extreme load hours.

Table 2 represents the aggregated effective Maritime capacity calculations for the simulated wind projects.

Table 2
Effective Capacity – Scenario 1

Project Location	Simulated Wind Capacity (MW)	Effective Maritime Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	100	66	56	46	40
NS	100	1	48	40	33

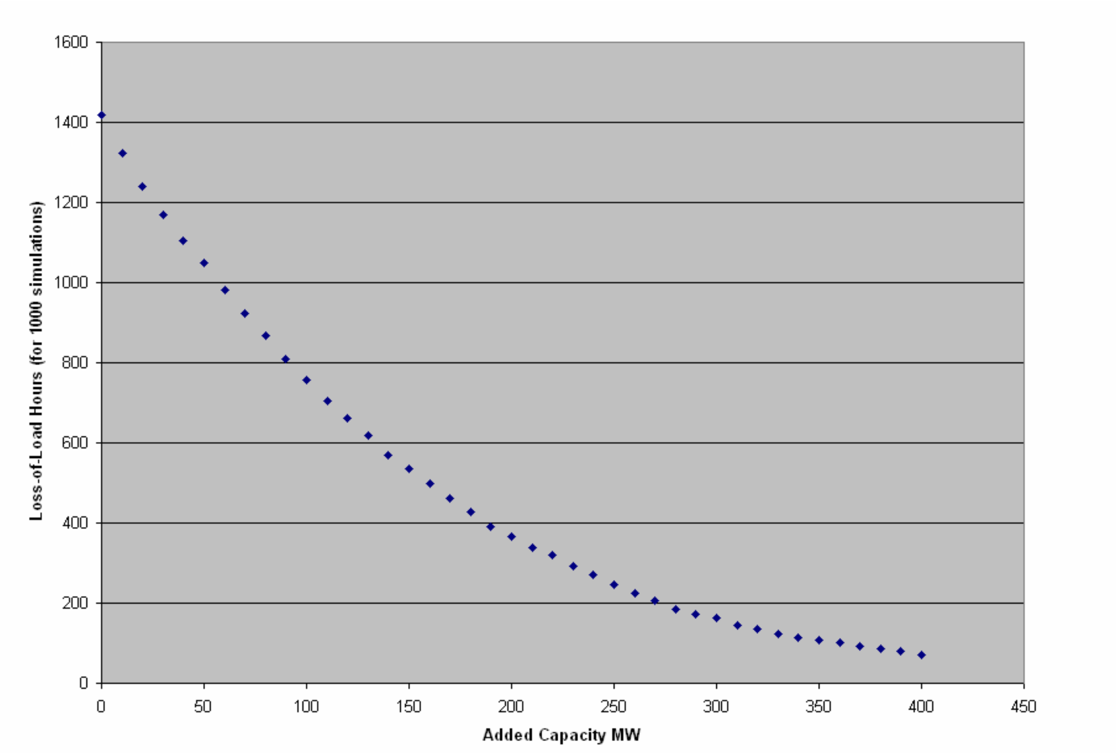
For the NB Area, a 100 MW wind project provided about 66 MW of effective Maritime capacity. This value is higher than the January, winter, or annual capacity factors, and thus demonstrates strong positive correlation between the simulated outputs of these wind projects and the highest loads experienced by the Maritimes in 2004. This is understandable because of the high correlation between high winds and low temperatures in January 2004, a correlation that was much higher than normal years according to meteorologists.

For Nova Scotia, the simulated wind projects provided negligible effective Maritime capacity, and this was entirely due to the 350 MW intra-area transfer limit between Nova Scotia and New Brunswick. Analysis of the LOLH showed that for the vast majority of simulated Maritime generation deficiencies, surplus available capacity in Nova Scotia was already assisting the rest of the sub-areas up to this 350 MW limit. Therefore, it was impossible for even additional conventional generation capacity in Nova Scotia to provide effective Maritime capacity in this scenario.

4.7 Scenario 2 - 2004 Maritime System without Intra-Area Transfer Limits

Figure 3 shows how the simulated 2004 Maritime System LOLH decreases with the addition of conventional capacity. In this scenario, the additional capacity was located in the New Brunswick sub-area, and intra-area transfer limits were not enforced.

Figure 3
LOLH vs. Added Capacity – Scenario 2



4.8 Scenario 2 - Results

Table 3 shows how the initial LOLH of 1417 hours over 1000 simulations was distributed on a monthly basis.

Table 3
LOLH Distribution – Scenario 2

Month	LOLH	Percentage
Jan-04	1362	96%
Feb-04	48	3%
Mar-04	0	0%
Apr-04	0	0%
May-04	0	0%
Jun-04	0	0%
Jul-04	0	0%
Aug-04	0	0%
Sep-04	0	0%
Oct-04	0	0%
Nov-04	0	0%
Dec-04	7	0%
Totals	1417	100%

As was seen in the previous scenario, the record demand levels for January 2004 give that month a huge 96% weighting on the LOLH simulation totals here.

As was the case in Scenario 1, the calculation of effective Maritime capacity for Scenario 2 is very dependent on the simulated January performance of these projects during the extreme load hours.

Table 4 represents the aggregated effective Maritime capacity calculations for the simulated wind projects.

Table 4
Effective Capacity – Scenario 2

Project Location	Simulated Wind Capacity (MW)	Effective Maritime Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	100	73	56	46	40
NS	100	62	48	40	33

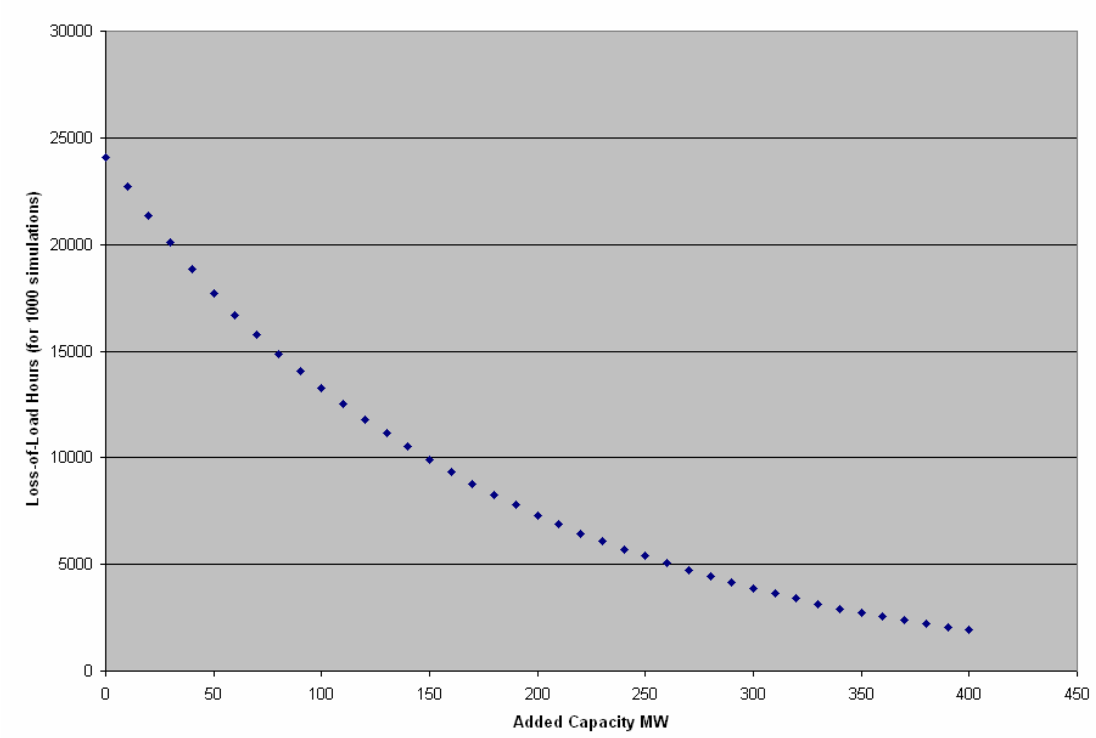
For the NB Area, a 100 MW wind project provided an average of 73 MW of effective Maritime capacity. As was the case in Scenario 1, the effective capacity value is higher than the January, winter, and annual capacity factor calculations, and thus demonstrates strong positive correlation between the simulated outputs of these wind projects and the highest loads experienced by the Maritimes in 2004.

For Nova Scotia, a 100 MW wind project provided an average of 62 MW of effective Maritime capacity. This too demonstrates strong positive correlation between the simulated outputs of these wind projects and the record high loads experienced by the Maritimes in 2004. It also proves that the intra-area transfer limit between Nova Scotia and New Brunswick was the cause of the negligible effective Maritime capacity values for the simulated Nova Scotia wind projects in Scenario 1.

4.9 Scenario 3 - 2004 NB Area Only

Figure 4 shows how the simulated 2004 NB Area LOLH decreases with the addition of conventional capacity. The Nova Scotia sub-area was excluded.

Figure 4
LOLH vs. Added Capacity – Scenario 3



4.10 Scenario 3 - Results

Table 5 shows how the initial LOLH of 24086 hours over 1000 simulations was distributed on a monthly basis.

Table 5
LOLH Distribution – Scenario 3

Month	LOLH	Percentage
Jan-04	19552	81%
Feb-04	1771	7%
Mar-04	185	1%
Apr-04	1236	5%
May-04	63	0%
Jun-04	12	0%
Jul-04	5	0%
Aug-04	1	0%
Sep-04	64	0%
Oct-04	69	0%
Nov-04	234	1%
Dec-04	894	4%
Totals	24086	100%

As was seen in the previous scenarios, the record demand levels for January 2004 give that month a huge 81% weighting on the LOLH simulation totals here.

Based on Table 5, it is obvious that the calculation of effective NB Area capacity for the simulated wind projects is very dependent on the January performance of these projects during the extreme load hours.

The slight increase in LOLH seen in April 2004 is the result of scheduled generator maintenance during the spring run-off. Overall, scheduled generator maintenance in the months of April through October does not have a significant impact on these LOLH numbers.

Table 6 represents the aggregated effective NB Area capacity calculations for the simulated wind projects.

Table 6
Effective Capacity – Scenario 3

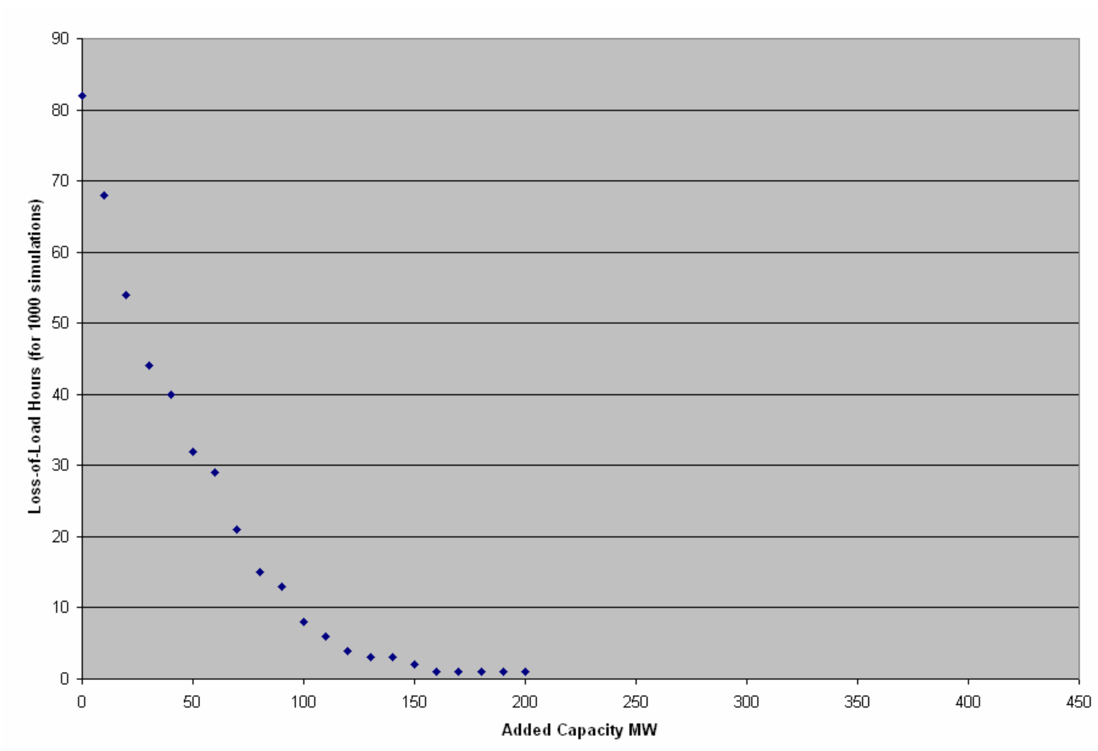
Project Location	Simulated Wind Capacity (MW)	Effective NB Area Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	100	60	56	46	40
NS	Not app.	Not app.	48	40	33

For the NB Area, a 100 MW wind project provided an average of 60 MW of effective NB Area capacity. This result is slightly higher than the January capacity factor, which indicates that there was some positive correlation between the simulated January wind energy and the highest January loads. As was the case in the previous scenarios, the effective capacity is much higher than the winter or annual capacity factors.

4.11 Scenario 4 - 2004 Nova Scotia Area Only

Figure 5 shows how the simulated 2004 Nova Scotia Area LOLH decreases with the addition of conventional capacity. The NB Area was excluded.

Figure 5
LOLH vs. Added Capacity – Scenario 4



4.12 Scenario 4 - Results

Table 7 shows how the initial LOLH of 82 hours over 1000 simulations was distributed on a monthly basis.

Table 7
LOLH Distribution – Scenario 4

Month	LOLH	Percentage
Jan-04	76	93%
Feb-04	4	5%
Mar-04	0	0%
Apr-04	0	0%
May-04	0	0%
Jun-04	0	0%
Jul-04	0	0%
Aug-04	0	0%
Sep-04	0	0%
Oct-04	0	0%
Nov-04	0	0%
Dec-04	2	2%
Totals	82	100%

As was seen in the previous scenarios, the record demand levels for January 2004 give that month a huge 93% weighting on the LOLH simulation totals here.

Based on Table 7, it is obvious that the calculation of effective Nova Scotia capacity for the simulated wind projects is very dependent on the January performance of these projects during the extreme load hours.

Table 8 represents the aggregated effective Nova Scotia capacity calculations for the simulated wind projects.

Table 8
Effective Capacity – Scenario 4

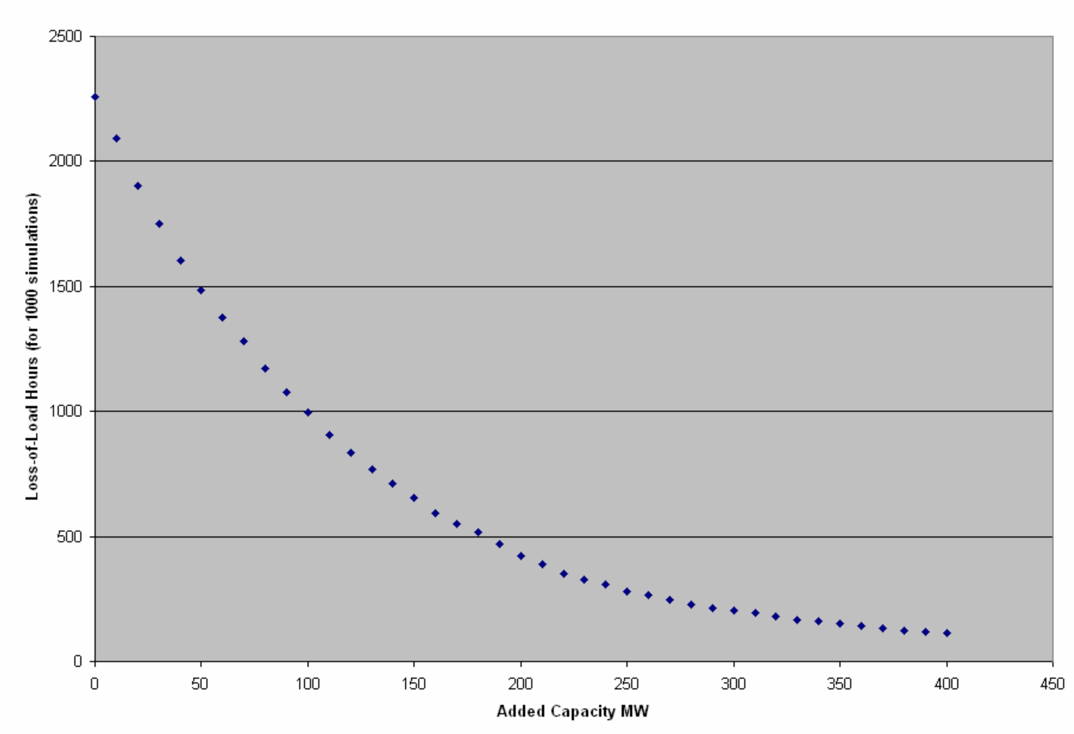
Project Location	Simulated Wind Capacity (MW)	Effective Nova Scotia Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	Not app.	Not app.	56	46	40
NS	100	50	48	40	33

For Nova Scotia, a 100 MW wind project provided an average of 50 MW of effective Nova Scotia capacity. This result is slightly higher than the January capacity factor, which indicates that there was some positive correlation between the simulated January wind energy and the highest January loads. As was the case in Scenario 2, the effective capacity is much higher than the winter or annual capacity factors.

4.13 Scenario 5 - 2003 Maritime System with Intra-Area Transfer Limits

Figure 6 shows how the simulated 2003 Maritime System LOLH decreases with the addition of conventional capacity. In this scenario, the additional capacity was located in the New Brunswick sub-area, and intra-area transfer limits were enforced.

Figure 6
LOLH vs. Added Capacity – Scenario 5



4.14 Scenario 5 - Results

Table 9 shows how the initial LOLH of 2258 hours over 1000 simulations was distributed on a monthly basis.

Table 9
LOLH Distribution – Scenario 5

Month	LOLH	Percentage
Jan-04	727	32%
Feb-04	852	38%
Mar-04	85	4%
Apr-04	448	20%
May-04	27	1%
Jun-04	1	0%
Jul-04	0	0%
Aug-04	4	0%
Sep-04	0	0%
Oct-04	4	0%
Nov-04	14	1%
Dec-04	96	4%
Totals	2258	100%

Unlike 2004, the 2003 year did not see record high demand occurring in the month of January. In this simulation, the months of January, February, and April comprise 90% of the LOLH. The high LOLH numbers for January and February can be explained by the typically colder temperatures causing the electric heating load to be at its highest during the year. The noticeable increase in LOLH seen in April 2003 is the result of scheduled generator maintenance during the spring run-off, combined with higher April loads than those seen in 2004.

Based on Table 9, it is obvious that the calculation of effective Maritime capacity for the simulated wind projects will be very dependent on the January, February, and April performance of these projects during the high load hours.

Table 10 represents the aggregated effective Maritime capacity calculations for the simulated wind projects. Unlike 2004, the 2003 simulation only had wind data for 2 out of the 8 wind sites, and both of these sites were located in the NB Area.

Table 10
Effective Capacity – Scenario 5

Project Location	Simulated Wind Capacity (MW)	Effective Maritime Capacity (MW)	January Capacity Factor (%)	Winter Capacity Factor (%)	Annual Capacity Factor (%)
NB Area	100	49*	48*	47*	44*
NS	Not app.	Not app.	Not app.	Not app.	Not app.

* - This value represents a projection for all five NB Area wind sites, but it is only based upon two sites since there was no data available for the other three sites in 2003.

For the NB Area, a 100 MW wind project provided an average of 49 MW of effective Maritime capacity. This value is not much different than the winter or annual capacity factor values, and thus demonstrates that there was not a strong correlation between the simulated outputs of these wind projects and the highest loads experienced by the Maritimes in 2003.

4.15 Effective Capacity Results and Recommendations

The average effective capacity of simulated wind projects in the NB Area was calculated for different scenarios. The average effective capacities were:

- 66% - 2004 Maritimes with intra-area transfer limits
- 73% - 2004 Maritimes without intra-area transfer limits
- 60% - 2004 NB Area only
- 49% - 2003 Maritimes with intra-area transfer limits

These results show that the 2004 effective capacity of the simulated wind generation in the NB Area was much higher than its 46% winter capacity factor. A major contributing factor to this was that the extreme cold temperatures experienced in January 2004 were accompanied by high wind speeds at the simulated wind project locations. This weather event is considered unusual as wind speeds usually drop at extremely low temperatures. Supplementary analysis for 2003 produced an effective capacity that was very close to the 47% winter capacity factor.

The NBSO Market Rules require that the procedure to determine capacity credits from energy limited resources take into account the amount of energy production. The current Market Rules procedure for wind generation is to credit a wind project based upon the average capacity factor of its past three years of operation. This study provides evidence to support that position and suggests that projected generation using wind speeds could bridge the gap until three years of actual performance is achieved.

It is recommended at this time that wind projects in the NB Area be credited with a capacity equal to their winter capacity factor. Although the 2004 results produced effective capacity values that were much higher than the winter capacity factor for the wind generation, it was not established by this study as to whether extremely cold winter temperatures will always be accompanied by high wind speeds. Such a determination requires a broader study involving the simulation of many other winter periods.

The average effective capacity of simulated wind projects in Nova Scotia was calculated for different scenarios. The average effective capacities were:

- 1% - 2004 Maritimes with intra-area transfer limits
- 62% - 2004 Maritimes without intra-area transfer limits
- 50% - 2004 Nova Scotia only

This study showed that the transmission limit from Nova Scotia to New Brunswick prevented any additional Nova Scotia generation, including wind, from contributing effective capacity to the Maritimes. Once the transmission limit was removed, the 2004 effective capacities outperformed the 2004 Nova Scotia average winter capacity factor of 40%. As in the NB Area, a major contributing factor to this was that the extreme cold temperatures experienced in January 2004 were accompanied by high wind speeds at the simulated Nova Scotia wind project locations.

Similar to the NB Area, it is recommended at this time that wind projects in Nova Scotia be credited with a capacity equal to their winter capacity factor. Although the transmission limit from Nova Scotia to New Brunswick produced a negligible effective capacity value on a Maritimes basis, future wind projects in Nova Scotia can contribute effective capacity by replacing existing facilities, or by providing for additional load growth. As was the case in the NB Area, the 2004 results produced some effective capacity values for Nova Scotia wind generation that were much higher than the winter capacity factor, but it cannot be established that this will always be the case, and the study of additional years is required to make that determination.

5.0 IMPACT OF WIND GENERATION ON LOAD VARIABILITY

5.1 Description

Load variability is the fluctuation of electrical demand on the system for which dispatchable generation resources must balance with equivalent fluctuations of electrical supply. Adequate response to load variability is essential for maintaining both system frequency and scheduled interconnection flows. Since wind generation projects are non-dispatchable with fluctuating outputs, they can add to the load variability that the dispatchable generation resources must accommodate.

Higher load variability requires additional load following capability from generation resources, and a system operator's procurement of this additional capability ultimately results in additional costs to customers. Failure of a system to respond to load variability is likely to result in penalties from neighbouring areas due to variances between actual and scheduled interconnection flows. In a worst case scenario, the failure of systems to follow load may result in line trips or frequency deviations that could blackout customers.

The following analysis measures the load variability of the NB Area, NS Area and Maritimes Area systems as the standard deviation of the hourly load swing. The impact of wind capacity at single sites and wind capacity at multiple sites on this hourly load swing is also analysed.

5.2 Variability Measurement of the Hourly Load Swing

The ability to integrate significant wind generation capacity into the Maritimes depends very much upon the impact of these wind projects on the hourly load swing. Having some diversity amongst the wind project locations will generally produce a lesser increase to the hourly load swing than if the wind projects were close together, and thus will allow for more wind generation to be integrated into a system at a lower cost.

Diversity amongst the modeled wind sites for this study is quantified by calculating the correlation coefficients of the simulated wind project output levels between two projects. Perfect negative correlation between two wind projects results in a coefficient calculation of -1.0, perfect positive correlation results in a coefficient calculation of +1.0, and uncorrelated or zero correlation between projects results in a correlation coefficient of 0.

Table 11 provides a summary of the correlation coefficients between the hourly energy output levels of the modeled wind project sites in this study.

Table 11
Hourly Wind Energy Correlation Coefficients

	North Cape / Tignish, PEI	Cape Breton, NS	Halifax / Dartmouth, NS	Shelburne / Yarmouth, NS	Dorchester / Tantramar, NB	Miramichi, NB	Grand Manan / Campabello, NB	Lamèque / Miscou, NB
North Cape / Tignish, PEI	1.00							
Cape Breton, NS	0.50	1.00						
Halifax / Dartmouth, NS	0.37	0.45	1.00					
Shelburne / Yarmouth, NS	0.27	0.30	0.61	1.00				
Dorchester / Tantramar, NB	0.53	0.34	0.52	0.44	1.00			
Miramichi, NB	0.52	0.36	0.38	0.30	0.46	1.00		
Grand Manan / Campabello, NB	0.39	0.28	0.41	0.45	0.52	0.42	1.00	
Lamèque / Miscou, NB	0.63	0.42	0.29	0.29	0.42	0.54	0.38	1.00

In Table 11, the correlation coefficient between two sites is located at the intersection of the row and column corresponding to those sites. For example, the correlation coefficient between Lamèque / Miscou, NB and North Cape / Tignish, PEI is 0.63. This high coefficient reflects that these two sites are not very diverse, relative to one another, and that there is a strong connection between their hourly wind output levels. This is not surprising given that these two sites are relatively close to each other. This pattern is consistent throughout Table 11, where sites that are far apart from one another tend to have lower correlation coefficients (i.e. more relative diversity) than sites that are close together.

Table 12 is similar to Table 11 except that the correlation coefficients are calculated on a daily energy basis instead of hourly. As a whole, the correlation coefficients in Table 12 are higher than Table 11, indicating that the relative correlation of wind project output levels increases when longer timeframes such as days are considered, and decreases as shorter timeframes such as hours or minutes are considered.

Table 12
Daily Wind Energy Correlation Coefficients

	North Cape / Tignish, PEI	Cape Breton, NS	Halifax / Dartmouth, NS	Shelburne / Yarmouth, NS	Dorchester / Tantramar, NB	Miramichi, NB	Grand Manan / Campabello, NB	Lamèque / Miscou, NB
North Cape / Tignish, PEI	1.00							
Cape Breton, NS	0.67	1.00						
Halifax / Dartmouth, NS	0.52	0.61	1.00					
Shelburne / Yarmouth, NS	0.41	0.43	0.73	1.00				
Dorchester / Tantramar, NB	0.69	0.47	0.63	0.54	1.00			
Miramichi, NB	0.67	0.52	0.50	0.40	0.57	1.00		
Grand Manan / Campabello, NB	0.53	0.42	0.55	0.57	0.67	0.53	1.00	
Lamèque / Miscou, NB	0.75	0.56	0.37	0.39	0.55	0.63	0.53	1.00

While Table 11 and Table 12 show how the wind sites correlate with each other, it is necessary to simulate how each site, or group of sites, will impact the load variability of the system. For this study, an hourly time frame is used for measuring the impact of the simulated wind generation on load variability. Although wind data is available at smaller 10-minute intervals for each site, the clocks at these wind data collection towers were not synchronized together when the data was recorded. This compromises any attempts to study wind correlation at 10-minute intervals because such a study requires confidence that the 10-minute intervals being compared actually coincide amongst the sites, at least to a high degree. It is assumed that the hourly time frame chosen for this analysis allows the hourly intervals being compared to coincide to a high degree, even if the unsynchronized clocks differed from one another by a few minutes at the time that the wind data was recorded.

The hourly load swing is the change of a system's average load from one hour to the next. The variability of this hourly load swing can be calculated as the standard deviation of this change. Standard deviation is the most commonly used measure of statistical dispersion, and for this analysis represents how spread out the hourly load swing becomes as increased amounts of simulated wind energy are added to the system.

The cost of additional load variability in this study is approximated by using load following cost data submitted by NB Power in its 2002 evidence filing for its Open Access Transmission Tariff. This regulatory evidence filing is available at http://www.nbpower.com/en/transmission/regulatory/tar_july25_2002.html In Appendix B, p.46, Table 4-1 the charge rate for acquiring load following from generation for 2003/04 is $67.87 / kW-yr. While this charge rate applies to generation capacity, it can be shown for the New Brunswick system that the amount of generation capacity required for load following is approximately equal to the standard deviation of the hourly load swing. Therefore, additional load variability cost in this study is calculated as the $67.87 / kW-yr charge rate multiplied by the standard deviation MW increase of the hourly load swing.

5.3 Scenario 1 - Impact of Wind Energy on the NB Area Load Variability

For 2004, the NB Area's standard deviation of its combined hourly load swing was 82 MW. Table 11 shows the average impact of simulated wind generation in the NB Area on the load variability for 2004. The results show the impact of the wind capacity being located at a single site, and the impact of the wind capacity if it is evenly distributed amongst the five sites in the NB Area. Cost increases in this table were calculated as per the method described in Section 5.2.

Table 13
2004 Impact of Wind Projects on NB Area Load Variability

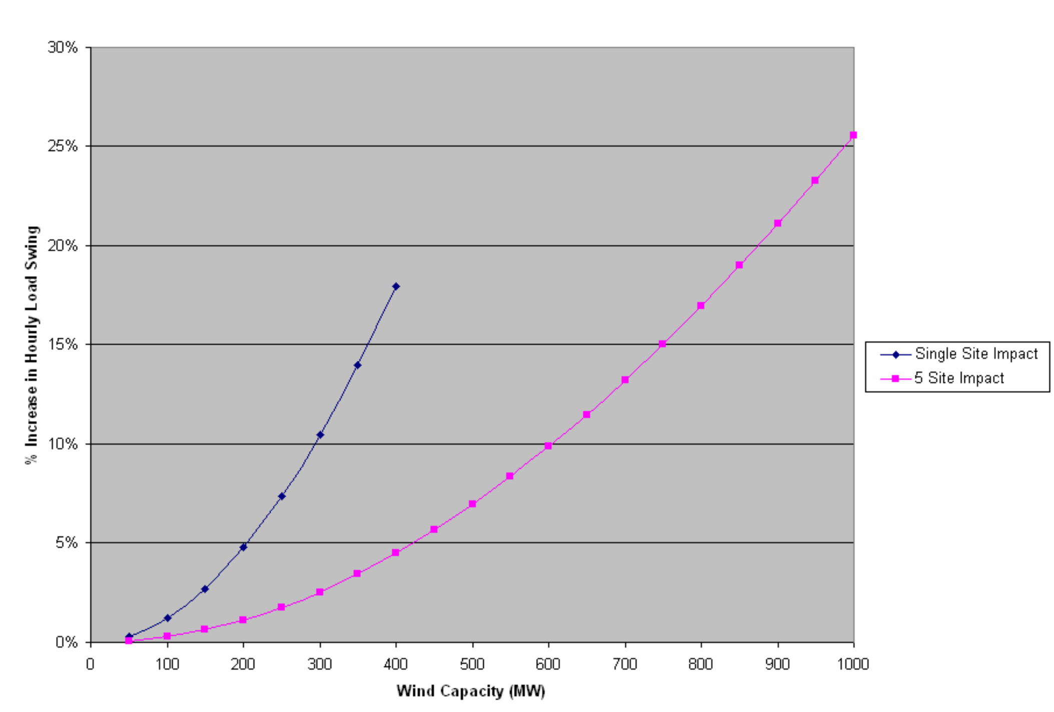
NB Area Wind Capacity MW	Increase on NB Area Load Variability (Single Site)	Single Site Annual Cost Increase ($Millions)	Increase on NB Area Load Variability (5 Sites)	5 Site Annual Cost Increase ($Millions)
100	1.2%	0.07	0.3%	0.02
200	4.8%	0.27	1.1%	0.06
300	10.5%	0.58	2.5%	0.14
400	17.9%	1.00	4.5%	0.25
500	-	-	6.9%	0.38
600	-	-	9.9%	0.55
700	-	-	13.2%	0.73
800	-	-	17.0%	0.95
900	-	-	21.1%	1.17
1000	-	-	25.5%	1.42

Adding 100 MW of wind at one site adds 1 MW (1.2% of 82) of load variability. From the data in Table 11, it can be seen that the impact on load variability by adding wind generation is not linear. The impact for 400 MW at one site is 14.7 MW (17.9% of 82). As wind capacity is added the impact on load variability appears to increase in proportion to the square of the capacity added. The load variability at one site is about four times that attained by the same amount of capacity added at diverse sites (note 17.9 % vs. 4.5% for 400 MW). Also if diverse sites are employed the amount of wind capacity that can be accommodated with the same degree of load variability is double (note17.9% and 17.0% at capacities of 400MW and 800MW respectively). From these results, we can state the following:

- Installing wind capacity amongst several sites versus a single site results in lower load variability, and thus any costs associated with increased load variability should also be lowered.
- Systems can accommodate more wind generation with less load variability problems if the wind projects are geographically dispersed.

Figure 7 displays the results of Table 11.

Figure 7
2004 Impact of Wind Projects on NB Area Load Variability



5.4 Scenario 2 - Impact of Wind Energy on Nova Scotia Load Variability

For 2004, Nova Scotia's standard deviation of its hourly load swing was 59 MW. Table 12 shows the average impact of simulated wind generation in Nova Scotia on the load variability for 2004. The results show the impact of the wind capacity being located at a single site, and the impact of the wind capacity if it is evenly distributed amongst the three sites in Nova Scotia. Cost increases in this table were calculated as per the method described in Section 5.2.

Table 14
2004 Impact of Wind Projects on Nova Scotia Load Variability

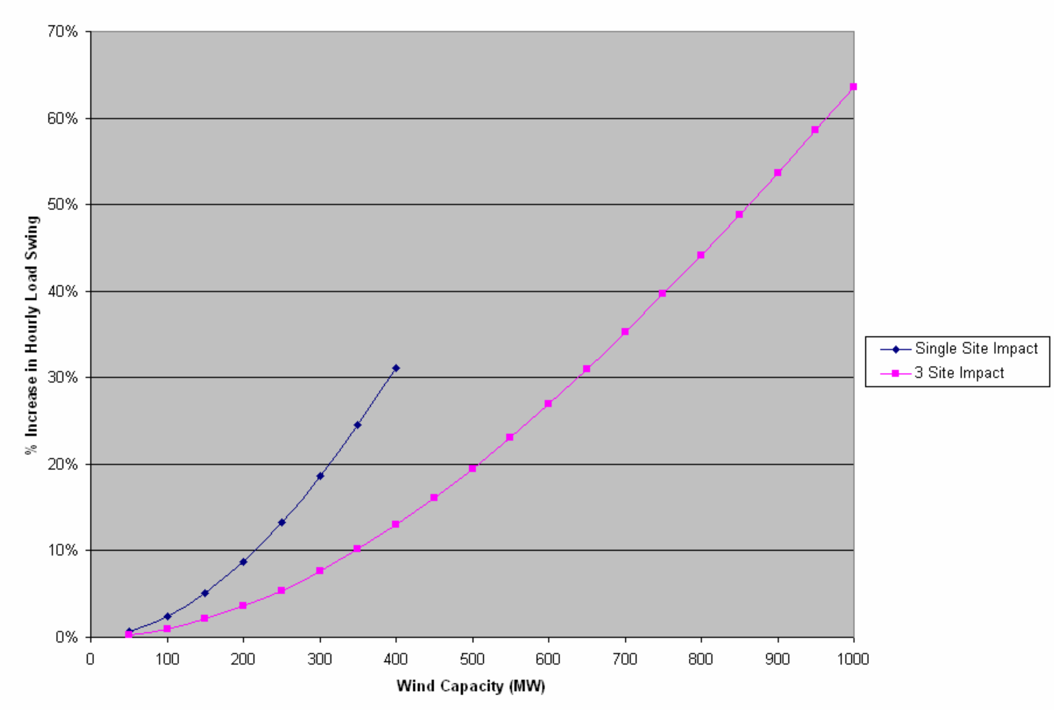
Nova Scotia Wind Capacity MW	Increase on Nova Scotia Load Variability (Single Site)	Single Site Annual Cost Increase ($Millions)	Increase on Nova Scotia Load Variability (3 Sites)	3 Site Annual Cost Increase ($Millions)
100	2.4%	0.10	1.0%	0.04
200	8.8%	0.35	3.6%	0.14
300	18.6%	0.75	7.6%	0.30
400	31.1%	1.25	13.0%	0.52
500	-	-	19.5%	0.78
600	-	-	27.0%	1.08
700	-	-	35.2%	1.41
800	-	-	44.2%	1.77
900	-	-	53.7%	2.15
1000	-	-	63.6%	2.55

From Table 12, it can be seen that the results are very similar in shape and proportion to the NB Area results but differ slightly in size. Let us compare. Adding 100 MW of wind at one site adds 1.4 MW (2.4% of 59) of load variability. The difference from the NB Area impact of 1 MW per 100 MW of wind can be attributed to system size. The load in Nova Scotia is about 67% of the load in the NB Area. This means that 100 MW of wind in Nova Scotia is a larger proportion of system load. If the impacts are normalized by system load, then it appears that there would be a 1 MW increase in load variability for about 70 MW of wind project.

To consider system size in the comparison of the NB Area results with the Nova Scotia results it may be more appropriate to compare the 300 MW Nova Scotia result of 18.6% against the 400 MW NB Area result of 17.9%. Another major consideration in viewing the Nova Scotia results is that there are only three diverse sites compared to five in the NB Area. The impact of this is that distribution of wind capacity resulted in a load variability impact of 41% of the average single site impact for Nova Scotia compared to 25% for the NB Area.

Figure 8 displays the results of Table 12.

Figure 8
2004 Impact of Wind Projects on Nova Scotia Load Variability



5.5 Scenario 3 - Impact of Wind Energy on Maritimes Load Variability

For 2004, the Maritimes Area's standard deviation of its combined hourly load swing was 123 MW. Table 13 shows the average impact of simulated wind generation in the Maritimes Area on the load variability for 2004. The results show the impact of the wind capacity being located at a single site, and the impact of the wind capacity if it is evenly distributed amongst the eight sites in the Maritimes. Cost increases in this table were calculated as per the method described in Section 5.2.

Table 15
2004 Impact of Wind Projects on Maritime Load Variability

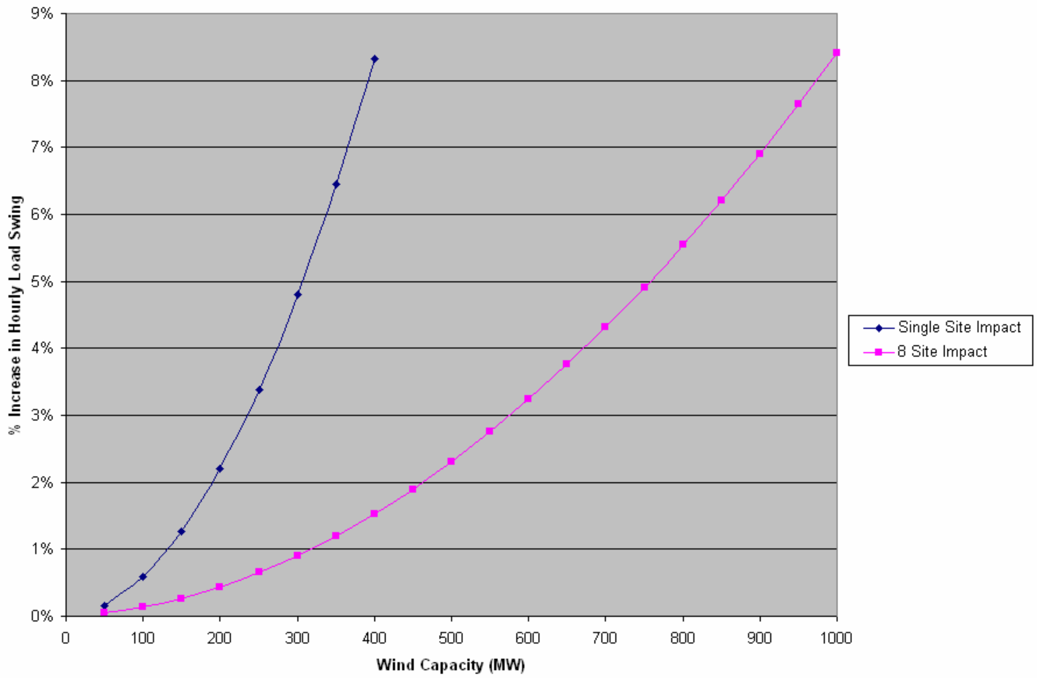
Maritime Wind Capacity MW	Increase on Maritime Load Variability (Single Site)	Single Site Annual Cost Increase ($Millions)	Increase on Maritime Load Variability (8 Sites)	8 Site Annual Cost Increase ($Millions)
100	0.6%	0.05	0.1%	0.01
200	2.2%	0.18	0.4%	0.03
300	4.8%	0.40	0.9%	0.08
400	8.3%	0.69	1.5%	0.13
500	-	-	2.3%	0.19
600	-	-	3.2%	0.27
700	-	-	4.3%	0.36
800	-	-	5.5%	0.46
900	-	-	6.9%	0.58
1000	-	-	8.4%	0.70

As expected following the comparison of Nova Scotia and NB Area results, the impact of 100 MW of wind is only 0.7 MW (0.6% of 123 MW). This result was expected to be lower because the impact of 100 MW is proportionately smaller. The impact of 400 MW at one site is also smaller and dispersion between eight sites also provides more moderation of the load variation impacts.

From Table 13, it can be seen that distributing the wind capacity amongst eight sites resulted in a load variability impact of only 18% of the average single site impact.

Figure 9 displays the results of Table 13.

Figure 9
2004 Impact of Wind Projects on Maritimes Area Load Variability



5.6 Wind Variability Results and Recommendations

The 2004 load variability of the Maritimes, as well as the sub-areas, was measured as the standard deviation of the hourly load swing. The standard deviation results were:

- NB Area - 82 MW
- Nova Scotia - 59 MW
- Maritimes - 123 MW

For 2004, it was shown that 400 MW of wind capacity at a single site increased the load variability significantly more than if it was distributed amongst several sites. These load variability increases for the Maritimes, as well as the sub-areas, were:

• NB Area	Single Site:	17.9%,	\$1.00 million per year
	Five Sites:	4.5%,	\$0.25 million per year
• Nova Scotia	Single Site:	31.1%	\$1.25 million per year
	Three Sites:	13.0%	\$0.52 million per year
• Maritimes	Single Site:	8.3%	\$0.69 million per year
	Eight Sites:	1.5%	\$0.13 million per year

In the Nova Scotia and NB Area regions, the cost of load variability is distributed amongst the load in that region. Therefore, any load variability cost increases due to wind generation falls to the local customers, even if they are not the ones purchasing the wind energy. This may be seen as unfair in cases where a new wind project exports its power to a neighbouring system while producing higher load variability costs to customers in the local region. Should such scenarios develop, the Maritime regions may have to look at charging wind projects for increasing the local load variability.

To integrate significant wind project capacity in the Maritimes, it is recommended that the developed capacity be split up amongst several sites, and that these sites have a good geographic separation in order to minimize costs associated with load variability.

The Maritime load was shown to be less variable than the sum of its sub-areas, and thus it is less impacted by the additional load variability from wind projects. It is recommended that efforts to develop significant wind project capacity in the Maritimes should include a plan to manage load variability on a Maritime basis versus having each sub-area manage its own. Such a strategy will result in less additional load following requirement for a given wind quantity or enable increased wind development for a given load following requirement.

6.0 HYDROELECTRIC CAPACITY AND SPRING RUN-OFF ISSUES

6.1 Hydroelectric Capacity in the Maritimes

In the Maritimes, much of the load variability is managed by the hydroelectric generators. They are the fastest responding generators on the system whenever there is a requirement to ramp up or down, and they can be brought on-line much quicker than a thermal or nuclear unit. This makes the amount of flexible hydroelectric generation on a power system an important factor in determining how much load variability that a system can handle. Since it was shown in Chapter 5 of this study that wind projects contribute increased load variability to the system, the amount of flexible hydroelectric generation on a power system is also an important factor in determining how much percent wind capacity that a system can handle.

The installed hydroelectric generation capacity in the Maritimes is around 20%. About a quarter of this is run-of-the-river with little flexibility in the way it is dispatched. The remainder or about 15% of Maritimes hydroelectric capacity has storage and dispatch flexibility for 10 to 11 months per year. For comparison, the provinces of Newfoundland and Labrador, Québec, Manitoba, and British Columbia all have installed hydroelectric generation capacity totals that exceed 90%, much of which has large storage with flexible dispatch capability. Other areas are Ontario with 25%, Saskatchewan with 24%, and Alberta with 7%. One can safely say that the areas where the installed hydroelectric generation capacity exceeds 90% can handle a lot more load variability, and thus a lot more percent wind capacity, than can areas that are 25% hydroelectric or less. Other factors, none of which are studied in this report, affecting the amount of load variability and wind generation that a system can accommodate, are:

- Thermal unit ramp rates
- Interconnection support
- Low voltage ride-through capability from wind projects, and
- Curtailment control systems for wind projects.

6.2 Spring Run-Off Issues Affecting Wind Project Development

Spring run-off describes the April to May period where the snow melt and accompanying rainfall floods the rivers of the Maritimes and causes water to spill over at the hydroelectric stations. During this period, hydroelectric plants must be operated at their full output levels to produce as much cheap energy as possible. Failure to do so would cause extra spilling at the stations, and the opportunity to use the extra spilled water for power generation would be forever lost.

It is during the spring run-off period that the ability of the hydroelectric generators to flexibly respond to load variability is compromised. Response to load variability requires a generator to ramp up or ramp down, yet the hydroelectric stations are unable to do this during the spring run-off without incurring the cost of allowing extra water to spill. Therefore, the spring run-off may create a cost barrier that inhibits the integration of a large amount of wind capacity if there is insufficient capability from the non-hydroelectric generation to respond to the increased load variability from the wind projects.

The length of the spring run-off can vary. In New Brunswick, the spring period of base loaded hydro typically lasts 2-4 weeks. In 2004, it lasted only 1.5 weeks, but more recently in 2005 it lasted for about five weeks.

Figure 10 illustrates how 400 MW of simulated wind capacity at five sites in New Brunswick and PEI would have impacted the sub-area of New Brunswick and PEI during the 2004 spring run-off:

Figure 10
NB + PEI Load, Hydro, and Wind
2004 Spring

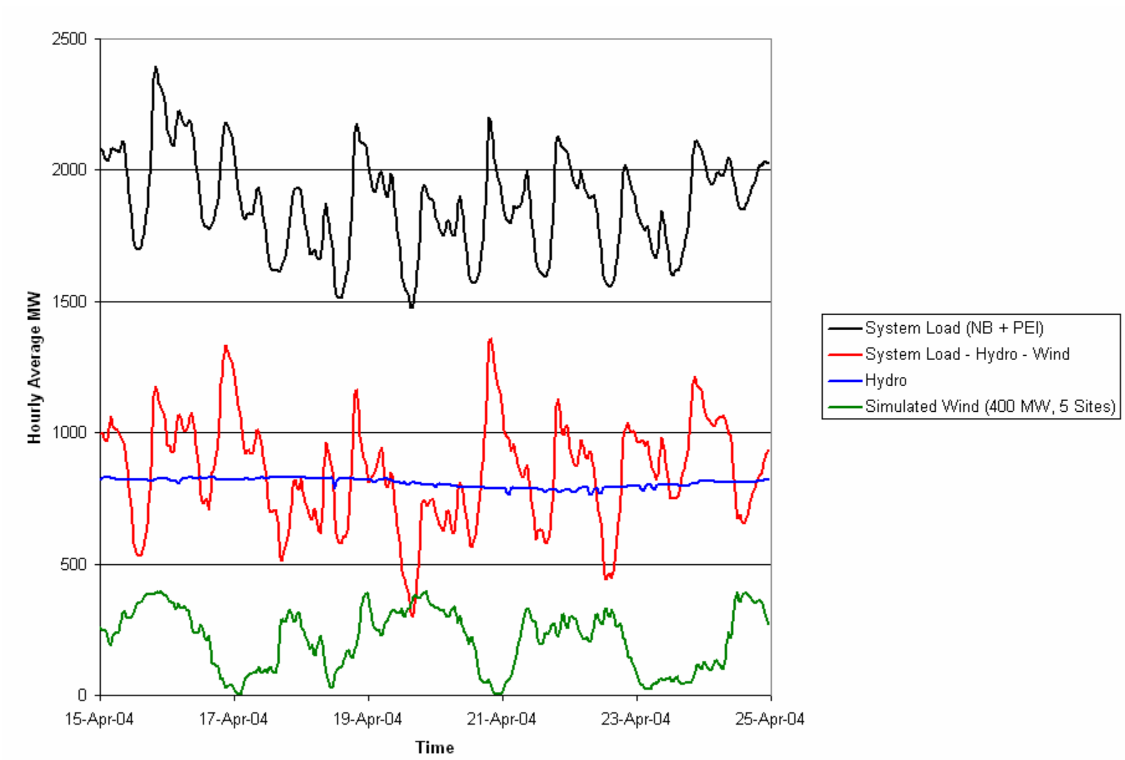


Figure 10 shows how the hydroelectric generation was base loaded over this 10-day period. The red waveform is the result of the hydroelectric and the 400 MW of simulated wind generation being subtracted from the initial load. The following comments can be made about the impact of the simulated wind generation during this period:

- Load variability has been increased by 8.1%. This increase must be responded to by the thermal generation on the system. As shown in the previous chapter, this

variability increase would have been much higher if the wind generation had all been located at a single site rather than five sites.
- Average thermal load has been decreased by 809 MW by the base load hydro operation and an additional 215 MW from wind generation. The simulated wind generation was running at a 54% capacity factor during this period. This decrease in the load results in the commitment of less thermal generation.

With both a decrease in load to be served by thermal generation and an increase in the load variability, the variability impact of the wind generation puts increased strain on the capabilities of the thermal generators to follow the load. Less thermal units are necessary to serve the average load, but more will most likely be necessary to handle the ramping up and ramping down requirements.

To put this spring run-off challenge into perspective it should be compared to operation in the non run-off period. Load variability attributable to wind has roughly doubled (8.1% vs. 4.5% impact) while thermal load is about half (851 MW vs. typically 1500 MW). The combined impact is that the variability of the load supplied by thermal generation for this run-off period is about four times the average of the non run-off periods. This assumes that all load following would be supplied by thermal units even in the non run-off period. However, outside the run-off period there is also flexible hydro capacity in the order of 200 to 600 MW to assist the thermal units with load variability. Therefore, the simulated wind generation's impact on the variability of the load supplied by thermal generation during this run-off period is actually much greater than four times.

It is important to understand that the issue of wind hydro integration is primarily an issue of economics. NBSO and Nova Scotia Power Inc, as balancing authorities for their respective sub areas will ensure that there is sufficient load following capability to meet reliability standards. However the cost of acquiring that capability likely will be significantly increased in the run-off period. Not only will it impact the commitment of thermal units it may force the deliberate spilling of hydro energy in order to free up hydro capacity for load following. This is an area that requires more study and should be considered as a detailed portion of a unit commitment analysis with varying levels of wind penetration.

While outside the mandate of NBSO it is also a factor that should be considered by load serving entities in the economic evaluation of wind generation in comparison to conventional generation sources.

6.3 Hydroelectric Capacity and Spring Run-Off Results and Recommendations

At this time, it is difficult to say how much wind capacity is too much. The Maritimes only has 46 MW of wind generation today, and that is not enough to properly judge the impacts of installing levels of wind capacity that are higher by an order of magnitude. Compared to other areas in Canada, the Maritimes has relatively less hydroelectric generation than any other area except Alberta. This may make it difficult to integrate as much wind capacity as some of those other areas, and policies such as Renewable Portfolio Standards (RPS) for the Maritimes sub-areas may have to be more conservative because of this. Current indications are that RPS programs could target 1000 MW within the next ten years for the Maritimes Area. This would constitute about 20 to 25% of the area 12-month coincident peak load.

While the load variability analysis in Chapter 5 of this study indicates that this may be achievable for the non run-off period it is highly unlikely that it could be accommodated without difficulty in the run-off period. On this basis it is recommended that a conservative approach be taken with regard to the RPS design for the Maritimes and limit the total capacity in the long term to no more than 1000 MW.

The spring run-off compromises the ability of the hydroelectric system to respond to load variability increases caused by wind generation. It is recommended that in the short term the Maritimes take a conservative and gradual approach to integrating wind generation. It is recommended that RPS targets be much lower (likely half or 500 MW) until additional studies can be undertaken to quantify the cost and operational magnitude of wind variability during the spring run-off period.

Finally, it is also recommended that the Maritimes may be able to integrate more wind capacity if the Maritimes Area becomes one balancing area (as opposed the current two sub areas) and if the New Brunswick System Operator (NBSO) finds opportunities to have the neighbouring power systems of Québec and New England assist the Maritimes with its load variability. While such assistance would have value throughout the year it is especially important during the spring run-off period.

7.0 SUMMARY OF RESULTS

Effective Capacity

- The average effective capacity of simulated wind projects in the NB Area (NB, PEI, and Northern Maine) was calculated for different scenarios. The average effective capacities were:
  - 66% - 2004 Maritimes with intra-area transfer limits
  - 73% - 2004 Maritimes without intra-area transfer limits
  - 60% - 2004 NB Area only
  - 49% - 2003 Maritimes with intra-area transfer limits

- The average effective capacity of simulated wind projects in Nova Scotia was calculated for different scenarios. The average effective capacities were:
  - 1% - 2004 Maritimes with intra-area transfer limits
  - 62% - 2004 Maritimes without intra-area transfer limits
  - 50% - 2004 Nova Scotia only

Impact of Wind Projects on Load Variability

- The 2004 load variability of the Maritimes, as well as the sub-areas, was measured as the standard deviation of the hourly load swing. The standard deviation results were:
  - NB Area - 82 MW
  - Nova Scotia - 59 MW
  - Maritimes - 123 MW

- The annual cost for a 1 MW increase in load variability as measured in this study is estimated to be $67,870.

- For 2004, it was shown that 400 MW of wind capacity at a single site increased the load variability significantly more than if it was distributed amongst several sites. These load variability increases for the Maritimes, as well as the sub-areas, were:

o NB Area	Single Site:	17.9%,	$1.00 million per year
	Five Sites:	4.5%,	$0.25 million per year
o Nova Scotia	Single Site:	31.1%	$1.25 million per year
	Three Sites:	13.0%	$0.52 million per year
o Maritimes	Single Site:	8.3%	$0.69 million per year
	Eight Sites:	1.5%	$0.13 million per year

- Using the 2004 data it appears that 1000 MW of wind capacity could be accommodated in the Maritimes Area if it is geographically dispersed and spring run-off conditions are ignored. In this analysis, the increase to load variability was 8.4% or 10.3 MW to the standard deviation of the hourly load swing at an annual estimated cost of $0.70 million.

Hydroelectric Capacity and Spring Run-Off Issues

- The installed hydroelectric generation capacity in the Maritimes is about 20%. The provinces of Newfoundland and Labrador, Québec, Manitoba, and British Columbia all have installed hydroelectric generation capacity totals that exceed 90%. Other areas are Ontario with 25%, Saskatchewan with 24%, and Alberta with 7%. Since the amount of hydroelectric capacity is an important factor with respect to the handling of the increased load variability due to wind generation, the Maritimes may not be able to integrate as much wind capacity as the areas with more hydroelectric generation.

- The spring run-off compromises the ability of the hydroelectric system to respond to load variability increases caused by wind generation. During this period wind load variability doubles, no hydro resources are available for load following, and the amount of thermally supplied load is halved. This significantly increases the impact of wind generation on load following requirements.

- This is predominantly a cost issue. Not only will it impact the commitment of thermal units it may force the deliberate spilling of hydro energy in order to free up hydro capacity for load following. This is an area that requires more study and should be considered as a detailed portion of a unit commitment analysis with varying levels of wind penetration.

- At this time, it is difficult to say how much wind capacity is too much. The Maritimes only has 46 MW of wind generation today, and that is not enough to properly judge the impacts of installing levels of wind capacity that are higher by an order of magnitude. The spring run-off compromises the ability of the hydroelectric system to respond to load variability increases caused by wind generation. It is recommended that in the short term the Maritimes take a conservative and gradual approach to integrating wind generation. It is recommended that RPS targets be much lower (likely half of current projections or 500MW) until additional studies can be undertaken to quantify the cost and operational magnitude of wind variability during the spring run-off period.

8.0 SUMMARY OF RECOMMENDATIONS

Effective Capacity

- It is recommended that wind projects in the NB Area be credited with a capacity equal to their winter capacity factor.
- It is recommended that wind projects in Nova Scotia be credited with a capacity equal to their winter capacity factor.

Impact of Wind Projects on Load Variability

- To integrate significant wind project capacity in the Maritimes, it is recommended that the developed capacity be split up amongst several sites, and that these sites have a good geographic separation in order to minimize costs associated with increased load variability.
- It is recommended that the Maritimes may have to charge wind projects for increasing the local load variability should scenarios develop where the project's wind energy is being sold outside of the local area, but local area load customers are absorbing increased load variability cost due to the wind project.
- It is recommended that efforts to develop significant wind project capacity in the Maritimes should include a plan to manage load variability on a Maritime basis versus having each sub-area manage its own.

Hydroelectric Capacity and Spring Run-Off Issues

- It is recommended that a conservative approach be taken with regard to the RPS design for the Maritimes to recognize that the Maritimes does not have the same quantity of flexible hydroelectric generation as do most other areas of Canada, with the exception of Alberta.
- It is recommended that the Maritimes take a gradual approach to integrating wind generation so that the costs associated with load variability increases experienced during the spring run-off are better understood.
- It is recommended that the Maritimes may be able to integrate more wind capacity if the New Brunswick System Operator (NBSO) finds opportunities to have the neighbouring power systems of Québec and New England assist the Maritimes with its load variability during the spring run-off.

APPENDIX B -

NBSO Rate Design for Schedules 3, 5 and 6 (CBAS) May 1, 2008

					effects are additive						
				1	2	3	4	5	6	7	8
				Rate Design (NB 2003/2004)	Balancing Area	Reg & LF as Reserves	Revised NS Share	NPCC Reserve Share	Contract Price Escalation	New Incr Reserve Threshold	2008/2009 Rates
1	CBAS Related Data	1st Contingency (MW)		660	660	660	660	660	660	660	660
2		2nd Contingency (MW)		458.1	458.1	458.1	458.1	458.1	458.1	458.1	458.1
3		Incremental Reserve Threshold (MW)		500	500	500	500	500	500	550	550
4		Net MCA Load Obligation (MW)	10S	125	125	125	125	125	125	138	138
5			10NS	375	375	375	375	375	375	413	413
6			30	229	229	229	229	229	229	229	229
7		NS Reserve Sharing (MW)	10S	25	25	25	32	32	32	32	32
8			10NS	100	100	100	142	142	142	142	142
9			30	50	50	50	50	50	50	50	50
10		NPCC Reserve Sharing (MW)	10S	0	0	0	0	100	100	100	100
11		OATT Requirements (MW)	Reg	16.76	19	19	19	19	19	19	19
12			LF	46.74	53	53	53	53	53	53	53
13			10S	88.19	100	82	75	50	50	63	63
14			10NS	242.52	275	221	179	104	104	142	142
15			30	157.90	179	179	179	179	179	179	179
16			CBAS Total	552.10	626	554	505	405	405	455	455
17		Purchase Price ($/kW-yr)	Reg	81.99	81.99	81.99	81.99	81.99	88.31	88.31	88.31
18			LF	67.87	67.87	67.87	67.87	67.87	73.20	73.20	73.20
19			10S	60.95	60.95	60.95	60.95	60.95	65.63	65.63	65.63
20			10NS	57.81	57.81	57.81	57.81	57.81	62.28	62.28	62.28
21			30	56.61	56.61	56.61	56.61	56.61	60.98	60.98	60.98
22		Billing Determinant (MW)	All CBAS	2571	2915	2915	2915	2915	2915	2915	2693
23											
24	Rate Calc'n	Rate Calculation ($/MW-m)	Reg	44.53	44.53	44.53	44.53	44.53	47.96	47.96	51.92
25			LF	102.83	102.83	102.83	102.83	102.83	110.89	110.89	120.06
26		*{OATT requirements*	10S	174.22	174.22	142.86	130.67	87.11	93.80	117.25	126.94
27		*x Purchase Price}*	10NS	454.45	454.45	365.21	295.81	171.86	185.14	251.90	272.72
28		*Billing Determinant*	30	289.75	289.75	289.75	289.75	289.75	312.09	312.09	337.88
29			Total	1065.78	1065.78	945.18	863.58	696.08	749.89	840.09	909.51

APPENDIX C -
NBSO Maritimes Area Final Wind Integration Report (May 2007)

Maritimes Area
Wind Power Integration Study
Summary Report

April 2007

NBSO
ERNB

Sponsored by:

Atlantic Canada Opportunities Agency (ACOA)
Aroostook Wind Energy, LLC (AWE)
Canadian Wind Energy Association (CANWEA)
Evergreen Wind Power, LLC (EWP)
Maritime Electric Company Limited (MECL)
NB Power Distribution and Customer Services (NBP)
New Brunswick System Operator (NBSO)
Northern Maine Independent System Administrator (NMISA)

Table of Contents

1. Introduction

The Maritimes Area is a common "Area" designated as such by the Northeast Power Coordinating Council for the purposes of reliability. The Maritimes Area includes New Brunswick, Northern Maine, Nova Scotia, and Prince Edward Island as shown in Figure 1. NBSO is the Reliability Coordinator for this Area.

Figure 1

Maritimes Area

The potential for wind power development in the Maritimes Area is significant. The wind regime is favourable, renewable portfolio standards exist in each jurisdiction within the area, and there is substantial demand for renewable energy in New England. Table 1 shows projections of wind power development in the Maritimes Area in the range of 16-24% of system peak load. Wind production in the order of 20% requires careful consideration in any power system, and even more so in systems such as the Maritimes Area that has significant differences between peak loads and light loads. Some jurisdictions have imposed limits of 10% on development pending further study and experience. It is also important to note that Table 1 shows significant differences in projected wind power versus peak load from one jurisdiction to another within the Maritimes Area.

Table 1

Maritimes Projected Wind Power Development (MW)

	NB	PE	NS	NM	Area
2004 Peak Load	3333	210	2238	153	5716
2016 Peak Load	-	-	-	-	6288
Wind Capacity	0	43	60	42	145
Projected by 2016	400	200	380	42-542	1022-1522
Penetration in 2016[1]					16-24 %

While Table 1 shows the projected wind power development, it does not identify the extent to which the wind powered generation is used to serve local load, other loads in the Maritimes Area, or loads outside of the Area. The potential for various combinations of these three types of transactions increases the importance of understanding the impact of wind power on system operations, the associated system costs, and the recovery of such costs.

Given the nature of the industry structure and the regional system operations, the potential exists for new costs to be incurred due to the integration of wind power, but these new costs would not necessarily be borne by the parties that receive the benefits of that wind power. Policies to address these issues need to be established on a timely basis. The uncertainty of a continuation of the policy void that currently exists could stifle investment and prevent realization of the full benefits of the regional wind resources. The choice of treatment of these costs impacts ratepayers, utility shareholders, and generation shareholders throughout the region and thus warrants a regional approach and broad stakeholder consultation.

The current industry structure in the Maritimes Area is presented in Table 2.

Table 2

Industry Structure in Maritimes

	NB	NM	NS	PEI
Open Access Transmission Tariff	Yes	Yes	Yes	Yes[2]
Wholesale Access	Yes	Yes	Yes	Yes
Retail Access - Transmission	Yes	Yes	No	No
Retail Access - Distribution	No	Yes	No	No
Independent System Operator	Yes	Yes[3]	No	No
Functional Unbundling	Yes	Yes	Yes	No
Utility Ownership	Public	Private	Private	Private
Renewable Portfolio Standard	Yes	Yes	Yes	Yes

[1] Projected wind power capacity divided by projected 2016 peak load.
[2] PEI has filed its proposed transmission tariff with the Island Regulatory Appeals Commission.
[3] The Northern Maine Independent System Administrator (NMISA) has a stakeholder board.

The Maritimes Area is highly interconnected with both the Quebec and New England transmission systems. Both of these systems have much larger amounts of generation and electrical loads than does the Maritimes Area. Traditionally Quebec, with its pre-dominance of large-scale hydro generation, has been a net exporter of electric power to New England and the Maritimes Area. New England has been a net importer of power from Quebec and the Maritimes Area. New England is projecting substantial load growth, experiencing challenges with building generation within New England, and has had renewable portfolio standards introduced state-by-state. Quebec is pursuing new large-scale hydro projects, and is undertaking substantial development of wind power.

This study is not intended to examine the overall net benefits of wind power generation, but such information provides a useful background to the discussion about wind power integration. Investment decisions regarding specific wind farms will be based on economic evaluations of project developers and load-serving entity procurement processes, both of which can be heavily influenced by government policies (e.g. renewable portfolio standards). Table 3 shows some dated, but indicative, new generation cost information for comparison purposes. The costs in that table include capital costs and the energy costs as of a point in time.

Table 3
Comparison of Levelized Costs[4]

Generation Type	$0/t	$15/t	$30/t
Wind Power[5]	$80.00	$80.00	$80.00
Natural Gas	$75.35	$81.24	$87.13
Coal	$59.33	$72.81	$86.29
Nuclear (CANDU 6)	$88.64	$88.64	$88.64
Nuclear (ACR-700)	$73.33	$73.33	$73.33

With marginal costs in the northeast set by natural gas and oil-fired generation, the market value of energy alone is volatile and is expected by some to be subject to substantial upward pressure. Although an estimate of the future value of energy would be more relevant to the discussion, it is interesting to note that the unweighted average ISO New England real-time energy price at the boundary of the Maritimes Area and the New England Area for 2006 was $60/MWh in Canadian dollars.

Clearly, different assumptions can lead to different cost comparison results, but the basic observation can be made that the cost of wind power generation projects are competing against other forms of generation. Characteristics that may also be considered, but which are more difficult to quantify include various types of emissions, visual impacts, effect on tourism, local content, employment, etc. Other key factors to be considered include fuel price risk, price volatility, availability and also reliability of generation.

[4] Non-wind costs adapted from a Canadian Energy Research Institute report of August 2004.
[5] CANWEA website Frequently Asked Questions.

Potential for high capacity factors, a dependency on carbon-emitting technologies, and provincial and state renewable portfolio standards are resulting in substantial investments in wind power generation in the Maritimes.

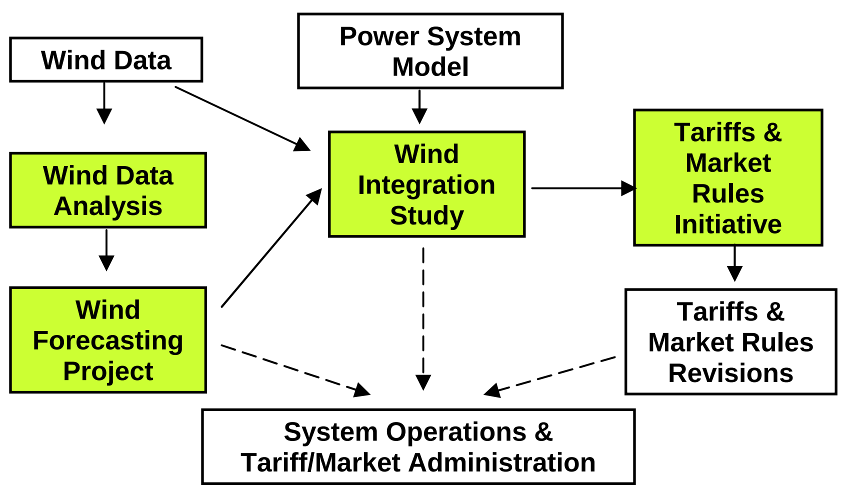
The primary focus of this report is wind integration, although there is some focus on the interconnection of wind generation facilities. Wind "interconnection" addresses the physical and electrical requirements of the wind generation equipment and the equipment that connects that equipment to the electric grid in a safe and reliable fashion. Wind "integration" addresses the means by which the characteristics of wind power production are accommodated within the overall portfolio of generation and the load characteristics.

The study explores the characteristics of wind power and the ability of parties to forecast its production, taking into account the wind regimes in some of the sites in the Maritimes that are either already developed, are in development, or are proposed for future development. The costs of integration are explored given the expected characteristics of the wind power and forecasting combined with the characteristics of the existing generation operation and also the region's consumption and export patterns. Options for reducing the cost of integration are also explored within this study with emphasis on how operational practices could be revised. Lastly, the above-noted observations are to be used to propose modifications to tariffs and market rules within the Maritimes Area so as to provide appropriate treatment of the recently emerged demand for wind power production in the Area.

The structure of the project work is captured in Figure 2.

Figure 2

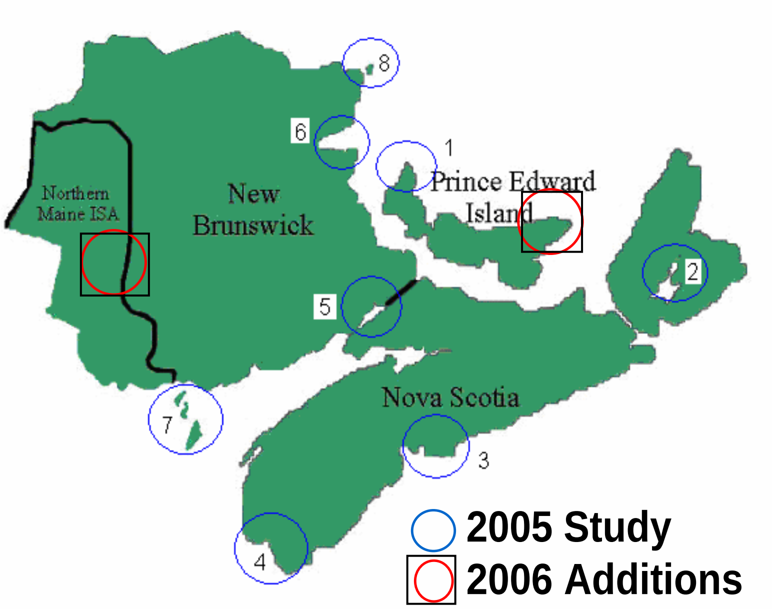
Project Structure



While this report provides a high level overview, four project reports explain how the analysis was performed, assumptions that were made, and provide more detailed results.

This project was undertaken as a Maritimes Area study, but has initially focused on the New Brunswick, Northern Maine, and Prince Edward Island Balancing Area. The approximate location of the sites for which wind data was obtained is shown on Figure 3. Note that the data for the sites marked as 2006 have not been incorporated in all of the analysis as much of the work was completed before that data was made available to NBSO.

Figure 3
Simulated Wind Power Production Data Locations



2. Policies Outside of the Maritimes Area

Various jurisdictions are examining the issue of wind interconnection and wind integration. Some standards are emerging with respect to the interconnection of wind power. The impact of wind integration varies significantly from area to area based on local characteristics such as wind penetration levels, wind power variability, wind power forecasting, as well as the availability of flexible generation, responsive load, and hydro storage. Detailed technical studies specific to local systems have been or are being carried out in many of these jurisdictions.

Published reports are available summarizing the results of such studies. Some of these studies have focussed on identifying the ability of the system to accommodate certain amounts of wind generation. Other studies have focussed on estimating the specific costs of integrating various amounts of wind power. The reports associated with at least some of these latter studies note material costs of integrating wind power. Summaries of costs identified in those studies are readily available from the websites of Natural Resources

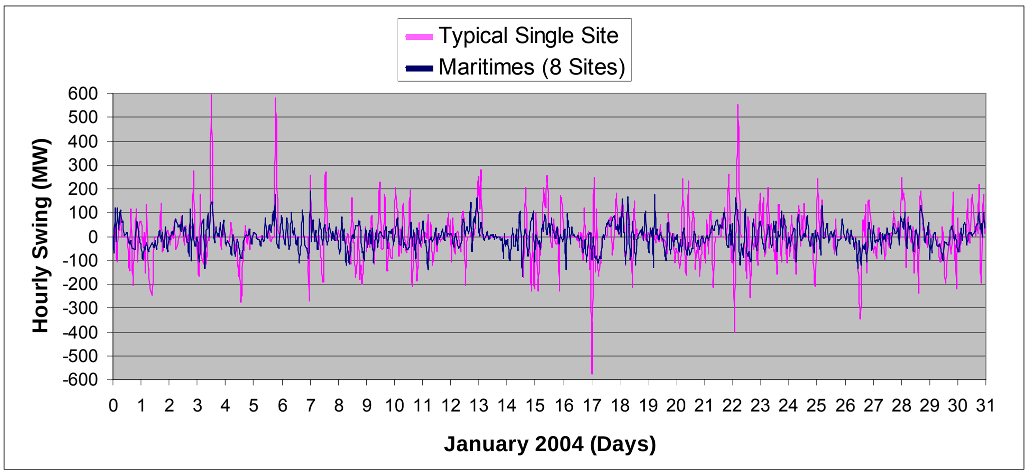
Canada[6] and the Utility Wind Integration Group[7]. The Natural Resources Canada report indicates that at least a couple of jurisdictions have proposed or implemented specific charges to wind power projects in order to address these costs (e.g. Bonneville Power Authority, and Hydro-Quebec).

3. Highlights of Study Results

Wind Data Analysis

In-depth analysis of the wind data from eight sites around the Maritimes in 2004 confirmed the observation made in the original NBSO Wind Integration Study[8] that variability of the aggregate hourly wind power production is reduced significantly if production is dispersed throughout the region. Figure 4 illustrates the diversity benefits with respect to the hour to hour swing in production for January 2004.

Figure 4
Diversity Benefits Illustrated



The analysis shows that even with diversity, the variability of wind power production combined with its limited dispatchability is significant relative to that of most other forms of generation in the Maritimes Area. A comparison of the production of a sample wind power plant and that of other facilities in Figure 5 illustrates the greater variability of wind power generation. Also, forecasting the output of a wind power plant is known to be more difficult than forecasting the output of most other forms of generation. These observations provide motivation for further exploration of the characteristics of wind power generation and their consequences.

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[6] Natural Resources Canada's February 2006, *Integration of Wind Generation with Power Systems in Canada*, Table 1.
(http://cetc-varennes.nrcan.gc.ca/en/er_re/inter_red/p_p.html?2006-016)
[7] Utility Wind Integration Group's *Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*, Table 2. (www.uwig.com)
[8] The original Maritimes Wind Integration Study of August 2005 is available at www.nbso.ca.

Figure 5
Power Plant Production

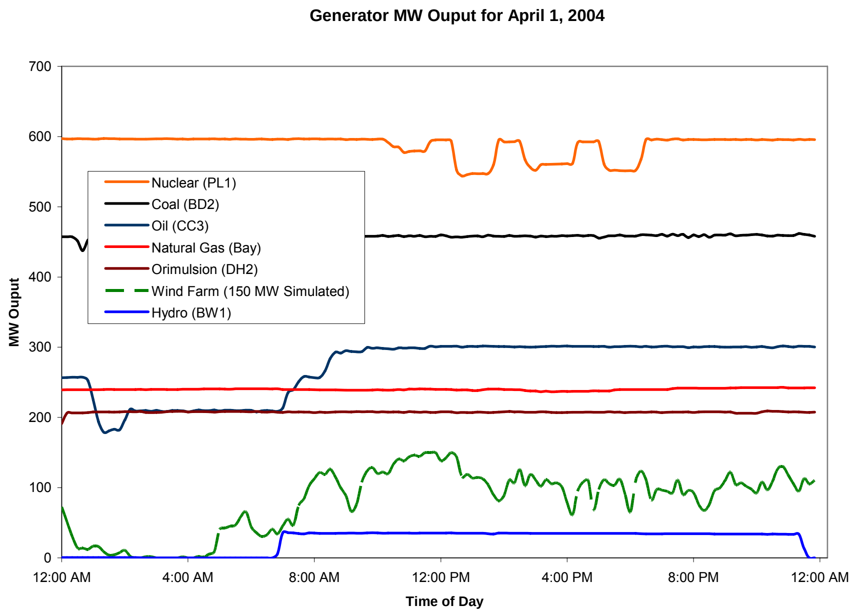
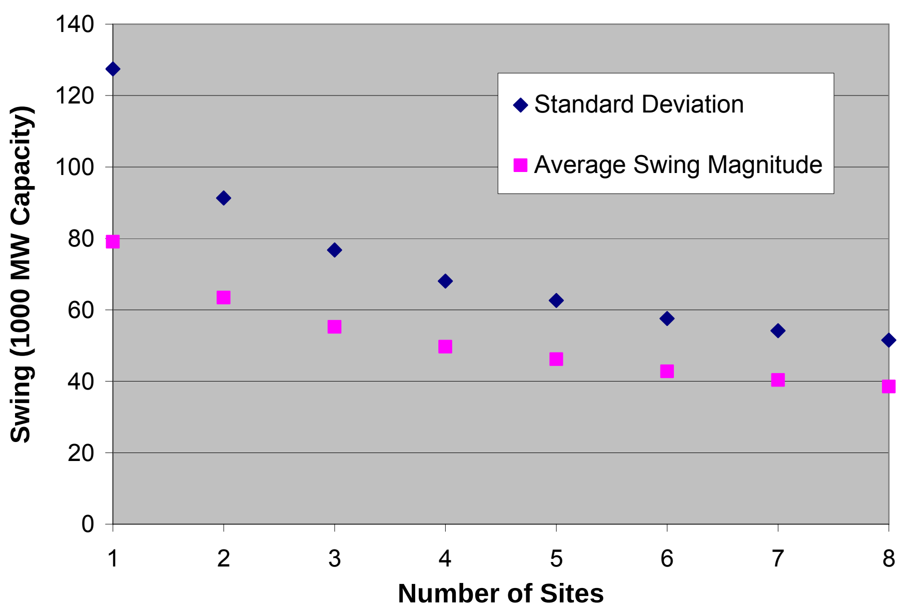


Figure 6 shows the relationship between hourly variability and the number of sites. That graph clearly shows these same diversity benefits for the full 2004 year, but with diminishing returns of spreading the same amount of production across more and more sites.

Figure 6

Diversity Benefits at Various Levels of Diversity



The study also looked at wind production variability in comparison to the load variability to provide some perspective on how significant this variability is to system operations. The hour-to-hour variability for 1000 MW of dispersed wind power was found to be less than half of the variability of the Maritimes Area load. Analysis of the data in Table 4 also showed that the standard deviation of the net load is approximately equal to the square root of the sum of the squares of wind power and load standard deviations. This observation supports the hypothesis that there is low correlation between the wind power production and the load.

Table 4
Wind and Load Variability

		Maritimes (1000 MW of Wind)			NB/PEI/NM (600 MW of Wind)			NS (400 MW of Wind)		
		Load	Wind	Net Load	Load	Wind	Net Load	Load	Wind	Net Load
	Standard Deviation (MW)	*127*	*51.5*	*137*	*83.7*	*38.5*	*92.2*	*60.1*	*31.1*	*67.8*
% of Hours in Given Range	> 100 MW	19%	3.3%	20%	10%	1.1%	12%	6.9%	0.54%	7.9%
	< -100 MW	20%	3.0%	22%	10%	1.1%	12%	3.9%	0.41%	6.0%
	> 200 MW	6.8%	0.08%	7.9%	3.4%	0.03%	3.6%	0.10%	0.02%	0.44%
	< -200 MW	4.2%	0.07%	5.7%	0.05%	0.00%	0.65%	0.01%	0.00%	0.11%

Wind Power Production Forecasting

Much work was done in the wind forecasting aspect of the project to compile and review work which has been published by other researchers. The knowledge gained from that work was leveraged to simulate wind power forecasting errors for the production sites covered by the study. Actual forecasting error data was made available to the integration study team for one of the eight sites. The characteristics of that data were extrapolated to produce forecasts for the other seven sites. Covariance and correlation between sites were studied and taken into account in the production of those simulated forecasts.

Some of the main points of exploration included answering the following questions:

- What is the best way to measure wind power production forecast performance?
- What is an acceptable threshold for wind power production forecasting?
- What are the diversity benefits of aggregating the forecast errors for a number of sites located throughout the Maritimes Area?

The standard deviation (or root mean squared error) measured over a full month is proposed as an appropriate measure of forecast error. A generic threshold based on the standard deviation as a percentage of the nameplate capacity is proposed to define the safe harbour provision for individual site forecasting. Wind farms providing Day-Ahead forecasts that meet or exceed that threshold will be considered to have performed adequate forecasting. Those not meeting that threshold will be investigated in order to determine whether there are site-specific conditions that make such accuracy in forecasting infeasible, or whether the forecasting efforts are inadequate.

With respect to Hour-Ahead forecasting it is acknowledged that the persistency method is the "target to beat" in the wind power production forecasting industry. That is, the forecast error for a forecasting tool should meet or exceed the error that would have occurred if the forecast for any given hour had been the actual production that occurred in the previous full clock hour.

The analysis of the covariance and correlation of Day Ahead forecast errors showed that although the forecast errors are not entirely correlated, the correlation is too significant to be ignored. The forecast error correlation coefficients for the simulated data for eight sites are as shown in Table 5.

Table 5

Forecast Error Correlations

Hourly Wind Energy Forecast Error Correlation Coefficients

	Site #1	Site #2	Site #3	Site #4	Site #5	Site #6	Site #7	Site #8
Site #1	1.00							
Site #2	0.07	1.00						
Site #3	0.18	0.20	1.00					
Site #4	0.11	0.17	0.33	1.00				
Site #5	0.16	0.16	0.23	0.20	1.00			
Site #6	0.06	0.25	0.13	0.17	0.30	1.00		
Site #7	0.15	0.18	0.23	0.27	0.25	0.36	1.00	
Site #8	0.22	0.06	0.16	0.12	0.20	0.32	0.20	1.00

Given the aforementioned observations, the proposed thresholds for wind power production forecasting in the NB/NM/PEI Balancing Area are as shown in Table 6. These thresholds are with respect to the standard deviation of the hourly forecast errors measured over a full month expressed as a percentage of the nameplate capacity. In addition to covering Day Ahead and Hour Ahead requirements from individual wind farms, the standard also establishes aggregate Balancing Area forecast error benchmarks in both timeframes. The Balancing Area benchmark is critical for system operations. Balancing is done for the aggregate, not for individual sites, and actual experience over the next few years will provide a better indication as to the appropriate benchmark for aggregate error. Increased forecast diversity benefits experienced in the future may lead to a loosening of the threshold for individual wind farms. Conversely, diversity benefits that are lower than anticipated may result in a tightening of the thresholds for individual wind farms.

Table 6

Initial Wind Power Production Forecasting Standard Deviation Expectations

	Individual Farms	Aggregate
Day Ahead	25%	20%
Hour Ahead	15%	10%

Accurate wind power forecasting is an important component of wind power integration. NBSO expects advances in the forecasting capabilities which may eventually lead to changes in both the forecasting standard and the metric upon which the performance standard is designed. Changes may also be required as a consequence of further experience in this region and others. For example, the mean absolute error will be reviewed as a metric that may be more appropriate.

CanWEA believes that if a wind energy forecasting system is adopted to facilitate wind integration, it should be a centralized forecasting system that is paid for by the system operator and makes use of wind data provided to the centralized forecasting system by individual wind energy projects.

Wind Power Production Integration Costs

The analysis indicates that wind power production will lead to material increases in the need for both regulation and load following services. Depending on how the associated costs are treated, cost shifting may occur. Neither actual nor perceived cost shifting between market participants or between jurisdictions is desirable because such a situation is unsustainable in the long run. Uncertainty as to how and when the cost shifting will be addressed can stifle investment.

NBSO has analyzed the potential impacts on costs for the NB/NS/PEI Balancing Area. The unit commitment and dispatch costs are a result of complex modelling of the Balancing Area loads and generation. This analysis is designed to capture the costs that arise from the integration of the wind power into the Balancing Area system, without regard for generation ownership or specific load-serving obligations. This analysis captures costs that arise from both hour-to-hour wind power production variability and day-ahead wind power production forecast error, but does not capture the costs associated with hour-ahead forecast error. Although additional cases were analyzed using the 2004 data, the key results are summarized in Table 7.

Table 7
Estimated Integration Costs
($/MWh of Wind Power Production)

Provider	Service	400MW	600MW	800MW
Market	Hour-to-Hour Schedule Balancing	3.41	3.45	5.95
System	Regulation Capacity	0.02	0.02	0.02
Operator	Load Following Capacity	0.03	0.03	0.03
	Regulation Unit Commitment & Dispatch	?	?	?
	Load Following Unit Commitment & Dispatch	0.93	1.21	1.36
	Subtotal	0.98	1.26	1.41
Total		4.39	4.71	7.36

This summary information illustrates that these costs are material, as can be seen in contrast to the current rates for the mandatory standard services for Point-to-Point Transmission services in the Maritimes Area Open Access Transmission Tariffs (OATTs) as shown in Table 8, and relative to the cost of wind power production of roughly $80.00/MWh (8 cents/kWh).

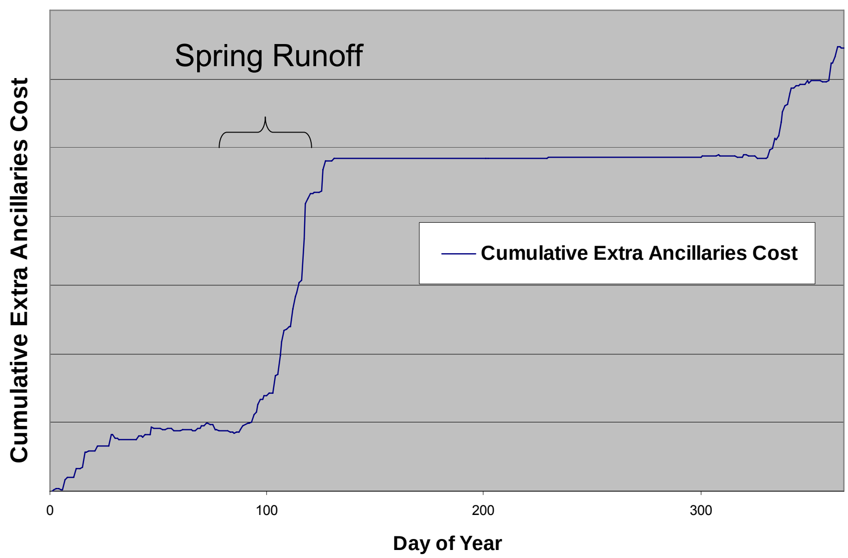
Table 8
OATT Services
($/MWh at 100% Load Factor)

OATT Service	NM[9]	NB	NS	PEI[10]
Transmission	$4.26	$2.88	$4.91	$3.61
Scheduling, System Control & Dispatch	$0.21	$0.24	$0.32	$0.16
Reactive Supply & Voltage Control	$0.09	$0.21	$0.40	$0.25
Total	$4.56	$3.33	$5.63	$4.02

The connection between system conditions and the costs for unit commitment and redispatch can be seen in an analysis of the timing of the costs incurred over the course of a year. Figure 7 shows the accumulation of simulated ancillary services costs over the course of the calendar year 2004 for the scenario with 400 MW of wind power at six equally sized sites in the New Brunswick Balancing Area.

Figure 7

Seasonality of Costs
Ancillaries Cost for 400 MW Wind (Six Sites)



The rate of accumulation of costs is rapid during the winter when loads are higher and even more rapid in the spring when the hydro system is fully loaded and thus not available to provide capacity-based ancillary services.

It is important to note that these costs are estimates for the 2004 year and that the estimates required a number of assumptions. Some of the parameters that change from year to year which would have some impact on costs include the duration of the spring runoff, load conditions, availability of generation capacity, level and nature of exports,

[9] Maine Public Service Rates converted to Canadian funds at $1US=$1.18Cdn.
[10] MECL proposed OATT as filed with IRAC on November 30, 2006.

and wind conditions. The two that are thought to have material impact are the duration of the spring runoff and the availability of generation capacity. The year 2004 had a relatively short spring runoff period and so from that perspective the above-noted costs may be conservative. The availability of generation capacity does not normally vary significantly from year to year, but activities such as the Lepreau refurbishment have material impact. Assumed parameters that have some impact on the costs include the location of the wind generation, the amount of generation at each location, unit start-up costs, no-load running costs, and thermal production costs. The assumptions made are based on best estimates and are thought to be reasonable for the purposes of this study.

Treatment of Integration Costs

The materiality of the estimated costs, combined with the potential for cost shifting, leads NBSO to propose that a regulated rate be established so that the costs of providing the incremental regulation and load following services can be recovered from the group of market participants responsible for the generation that is causing those incremental costs. It would then be up to those market participants to recover those costs from their customers along with the other project costs and profit margins. Market Participants would be permitted to schedule the supply of those services from qualifying facilities as an alternative to buying the services from NBSO. This option is already available for load-serving Market Participants in the current tariff.

The alternative supported by at least some wind power proponents is to not charge the market participants that are responsible for the wind power projects, but to socialize that obligation and those costs. The difficulty with socializing the costs is that whatever mechanism is used carries the risk that one portion of society carries a disproportionate share of the costs. Charging the costs directly to the wind power project increases the likelihood that the costs flow to the parties that purchase the output (or at least the attributes) and that get credit for producing the benefits. The point that there are global benefits to renewable energy production is valid, but that does not require having customers in one area pay most or all of the costs of integration.

Another approach has been proposed by a wind power proponent which is a hybrid of the two aforementioned approaches. The socialization approach would be used with respect to wind power development that is to supply New Brunswick load, and the regulated rates approach would apply for other wind power generation. This approach was raised late in the process and requires further analysis. The hybrid approach was proposed to address that fact the services are supplied by New Brunswick resources.

CanWEA’s position is that specific costs associated with the integration of wind energy into the system (e.g., ancillary services) should not be charged to wind energy producers. Rather, these charges should be borne by load (the customer base) because wind energy development in the Maritimes is being driven by government mandates and is therefore responding to the public interest. CanWEA notes that the addition of wind energy to the system provides both benefits and costs and therefore market rules and tariffs should not discriminate against wind energy relative to other sources of power.

The actual costs will change over time because they are influenced by the configuration and operation of the system, system costs, the amount of wind power production, and the nature of that production. The actual costs must be tracked and changes to any associated rates would be made as necessary through the appropriate approval processes. Another important observation was the fact that with approximately 400 MW of wind power in the Balancing Area imports were required in some hours and dump energy exports were required in other hours. These occurrences provide a noteworthy threshold with respect to what is required to integrate higher levels of wind power generation.

Capacity Credits
NBSO's initial wind power integration study supported the use of historical capacity factor as the level of capacity credit for wind power production. NBSO uses this approach in its capability period assessments. More specifically, the three year historical winter and summer capacity factors are used respectively for the winter and summer capability period assessments. With respect to the day-ahead and within-the-day resource assessments, the capacity available from intermittent resources such as wind will be based on the most recent production forecast for the respective hour. The ability to operate down to a yet-to-be-defined temperature is under consideration as a requirement to qualify for winter capability period capacity credit.

4. New Brunswick

One of the key observations in the review of the New Brunswick situation was the cost shifting concerns of NB Power Generation Corporation, the current supplier of balancing energy and most of the capacity-based ancillary services required in the NB/NM/PEI Balancing Area. The concern was that as the level of wind power production in the Balancing Area increases, the burden on NB Power Generation may increase their costs without an offsetting increase in revenues. The concern was heightened by the fact that much of the development is anticipated to be for the needs of loads in other jurisdictions such as PEI or New England. A similar concern exists with respect to increases in wind power production in Nova Scotia, because even though Nova Scotia is a separate balancing area, New Brunswick is responsible to manage actual flows between the Maritimes Area and New England, which requires balancing the generation and load of the NB/NM/PEI Balancing Area combined with the net Nova Scotia imbalances which flow through to New Brunswick across the NB/NS interface.

The above-noted cost-shifting issue arose from anticipation of increased capacity costs, increased unit commitment and dispatch costs, lost opportunity costs, and also balancing energy costs. A significant benefit of this review was a better understanding of the various services involved, the approximate costs involved, and the flow of costs for each of these services. At a high level, it is important to make a distinction between the costs that would be between Market Participants as opposed to those that would flow through the system operator. Given the physical bilateral nature of the Maritimes Area marketplace with hourly scheduling obligations, a significant component of the management of wind production volatility rests with the Market Participants. The buyers and sellers are to schedule their hourly transactions to cover the full quantity of forecasted production and consumption. As a consequence, the cost of following the expected variations in hour-to-hour production is born by the market participants and recovery of such costs is an issue to be dealt with, either explicitly or implicitly, by the contractual arrangements between the buyers and sellers. This study does estimate the costs in the context of wind power generation integrated into the local portfolio of resources. It does not, however, attempt to estimate those costs in the context of exports outside of the Balancing Area and/or the Maritimes Area (e.g. to New England).

The analysis estimates the costs of the intra-hour system balancing that is associated with regulation and load following. These are system operator functions, and thus require the appropriate approvals, and apply to all wind power production (i.e. for deliveries to loads within the Balancing Area and to exports). As shown in Figure 8 and Figure 9 the intra-hour requirements are system operator functions whereas the hour-to-hour requirements are addressed by market transactions. Although the intra-hour requirements are to be dealt with by the system operator, the services required to do so are provided by market participants under contract with the system operator. These services are currently provided by NB Power Generation under contract with NBSO at capacity prices which were established without contemplation of significant amounts of wind power generation connected to the Maritimes Area electric system. NB Power Generation has raised doubts about its obligation and ability to provide these services at the level of the anticipated requirements.

NBSO cannot produce these services itself and has no authority to force generators to provide them in unlimited quantities. Therefore, it may be necessary to set an upper limit on the incremental requirement for Capacity-Based Ancillary Services (e.g. regulation and load following) used to integrate intermittent generation including wind. Even with the exploration of various means to mitigate the impact, such an approach would most likely result in an upper limit on the amount of intermittent generation. Such limits would require that the jurisdictions involved either establish a policy for the allocation of the permitted development, or allow development to continue on a first-come-first-served basis until those limits are reached. Clearly the latter approach could lead to development that is disproportionate to system size, population, and renewable portfolio standard.

Alternatively, increasing the requirement above such limits might be made feasible by the stipulation that such incremental requirements be met by the market participants that are causing the incremental requirement. Such a policy would be similar to the current policy that requires the Point Lepreau nuclear generating station to supply the incremental operating reserves that are attributable to the large size of its contingency relative to the size of the Maritimes Area load. Such an approach provides a compromise that avoids a rigid limit on development, but does not put a limitless responsibility to procure capacity-based ancillary services on the system operator.

Figure 8
Separation of Responsibilities

This distinction between market and system operator responsibilities varies somewhat from market to market, but is generally true for physical bilateral markets such as the organized New Brunswick Market and the regional inter-jurisdictional market.

Figure 9
Balancing Services Provided

Schedule Balancing	Marketers schedule hour-to-hour changes in forecast	Market
Regulation (AGC)	Capacity Required + Unit Commitment and Dispatch	System Operator
Load Following	Capacity Required + Unit Commitment and Dispatch	
Operating Reserves	No increase in Capacity Required? Increased activation (balancing energy)	
Balancing Energy	Substantial hourly, but averages zero (unbiased forecast)	

As noted elsewhere in this report, energy imbalances associated with wind power production, combined with the lack of liquidity in the balancing energy market, is a concern for NB Power Generation which is essentially the default supplier of balancing energy to NBSO. Currently the balancing energy market is settled at the marginal bid prices with no penalties. NBSO is addressing various means to increase the liquidity of the balancing energy market and is requesting active participation in the balancing energy market by other market participants. If additional liquidity is not achieved, pressure to return to punitive imbalance charges will increase, especially with the anticipated variability of wind power production

Interconnection standards for wind power projects have been developed by the Federal Energy Regulatory Commission (FERC) and NBSO proposes to adopt similar standards for New Brunswick. Those standards pertain to low-voltage ride-through capability, voltage support, and SCADA requirements.

Wind Power Pooling is another avenue that was explored, with the main conclusion being that there are potential advantages, but that without a commitment by either wind power producers or load serving entities to participate, there is no justification for building such a model either within New Brunswick or on a regional basis. The potential advantages include reducing the hour-to-hour volatility that must be addressed in bilateral market schedules by individual market participants, increasing the ability to capture renewable energy credits on transactions between Balancing Areas, and reducing exposure of market participants to energy imbalance charges. NBSO has already committed to implementing such a model with respect to hourly imbalances for generation that is scheduled with NBSO, and NBSO seeks input from all parties as to their level of interest in participating in such an arrangement with respect to scheduled and actual production.

The project work has identified a number of areas in which the cost of integration might be reduced. The following are suggested to somewhat mitigate these issues:

- improved production forecasting methods to be developed by both the market participants for wind facilities, and system operators,
- development within each balancing area to be spread around geographically so as to take advantage of the diverse wind speeds,

In addition there are a number of things that should be explored to try and ease the accommodation of the variability and uncertainty such as the following:

(1) Pursue less onerous deadlines for schedule changes by Market Participants with ISO-New England,

(2) NBSO pursue use of 15 minute schedules with ISO-New England and Quebec,

(3) Explore the possibility of dynamic scheduling with ISO-New England and Quebec,

(4) Demand response capability be developed including bid-based demand response,

(5) Market rules and connection agreements must provide the right for production from generation facilities, including wind, to be curtailed as necessary to maintain system reliability,

(6) Market participants in the NB/PEI/NMe Balancing Area selling or buying output from wind facilities should structure contracts so that they can balance schedules hourly (or perhaps even every 15 minutes in the case of transactions with other Areas) to accommodate fluctuations in forecasted production,

(7) A regional joint RFP for capacity based ancillary services be implemented to encourage use of more resources for the provision of these services,
(8) Nova Scotia and the NB/PEI/NMe Balancing Area could form a Maritimes Balancing Area so as to take greater advantage of diversity of wind speeds, system peaks, and generation capabilities (one approach that should be considered is to implement a joint dispatch of regulation and load following as a precursor to forming some form of regional market).
(9) Policies should accommodate storage facilities (pumped hydro, compressed air, etc.).

NBSO has observed that its ability to perform its Balancing Area responsibility can be enhanced by having a better understanding of individual generation production. This is true in day-ahead, hour-ahead, real-time, and also after-the-fact. Such information with respect to intermittent generation is even more important. Such information also makes it easier to manage to the aggregate wind power generation in the area, rather than subsets thereof. NBSO proposes to work with NMISA and MECL to have wind power generation carved out with respect to scheduling, metering, and settlement. Real-time metering of those generators will also be pursued.

The transmission expansion policy was also revisited with respect to the treatment of the situation in which a generator has paid for direct assignment facilities and another generator is developed later and is able to make use of the excess capacity on the line that the first party had paid for. NBSO is considering revising its policy to allow subsequent projects to contribute to the costs as well, and for the parties that connected earlier to receive credit.

5. Northern Maine

As of early 2007, Northern Maine (NMISA-north) has 42 MW of wind generation, with a peak load of approximately 150 MW. This scenario is a prime example of why there is a need to carefully consider the impact of wind integration on the local and regional operations of the power system.

Northern Maine is a part of the NB/PEI/NMe. Balancing Area, and therefore has its intra-hour imbalances addressed by generation which is dispatched by NBSO. Generation in northern Maine is not dispatchable by NBSO for regulation and load following. NMISA is responsible for the administration of the Northern Maine Electricity Market. NMISA acknowledges that a cost-based charge for the increased regulation and load following burden arising from the integration of wind power may be required and understands that the NBSO expects to be applying to the regulator in New Brunswick for approval of such a charge.

The NMISA currently buys regulation and load following services from NBSO under the NB OATT with respect to Northern Maine load’s pro rata share of the Balancing Area requirements. NMISA is of the opinion that to the extent that ancillary service obligation and charges are approved by the regulator in New Brunswick as a consequence of costs arising from the introduction of wind power, that such costs should not be passed on automatically to the load in northern Maine, but rather should be born by the wind generators. Given the potential for extreme differences in the proportion of wind to load in the various jurisdictions within the Balancing Area, and the potential of wind power exports from the Balancing Area, it is fair and reasonable that such obligation and the associated costs be born by the respective generator. The impact of these costs on the sale of the power and/or the renewable energy credits is a matter for the generator and its power contract counterpart to resolve.

6. Nova Scotia

Nova Scotia Power Incorporated (NSPI) and the Nova Scotia Department of Energy elected not to participate in this study. As a consequence, some of the work has been focussed on the Balancing Area comprised of New Brunswick, Nova Scotia, and Northern Maine as opposed to the entire Maritimes Area.

Nova Scotia Power has committed to meet its obligations with respect to balancing supply and demand in Nova Scotia. Doing so will become more difficult and more expensive as the level of wind power penetration increases. To the extent that NSPI is not able to balance supply and demand within its territory, the potential exists for the burden to do so being passed onto the other Balancing Area in the Maritimes and costs being incurred within that area. NBSO intends to continue monitoring the interface between Nova Scotia and New Brunswick accordingly. In addition, NSPI and the Nova Scotia Department of Energy have been made aware of the potential for more efficient balancing of the intermittency of wind power generation by making the Maritimes a single Balancing Area. The tools and methods used in this study could be employed in future analysis of the potential savings of having a single Balancing Area for various levels and locations of wind power.

7. Prince Edward Island

The situation in Prince Edward Island is very similar to that of Northern Maine. As of early 2007, there are 43 MW of wind operating and an additional 30 MW in development on a system with a peak load of just over 200 MW. With the good wind regime, relatively small load, and government encouragement for use of this native resource, it is possible that Prince Edward Island will have a much greater penetration of wind power (i.e. generation relative to the size of its load) than New Brunswick, Northern Maine, or Nova Scotia.

Generally speaking, Prince Edward Island load is served by energy that is delivered to the island from or via New Brunswick. Other than wind power, on-Island generation is used mainly for reserve requirements and supplies energy only during peak load conditions. Therefore, both the inter-hour (hour-to-hour) and the intra-hour (i.e. within the hour) variations in the load, net of on-island wind power generation, are addressed by physical deliveries from off of the Island.

To the extent that they are forecasted, the inter-hour variations are to be taken into account in the hourly scheduled bilateral transactions and therefore are a matter to be addressed contractually by the load serving entities in Prince Edward Island and their wholesale market energy suppliers as opposed to through Open Access Transmission Tariff services.

On the other hand, since Prince Edward Island is in a common Balancing Area with New Brunswick and Northern Maine, the impact of the intra-hour variations on operations of a generator located in Prince Edward Island is the same as if it were in New Brunswick or Northern Maine. Specifically, the intra-hour variations impact the Balancing Area (New Brunswick, Northern Maine, and Prince Edward Island) requirement for regulation and load following. The regulation and load following services are used by NBSO to balance the system in real-time. These services are supplied by NBSO with services that it purchases from others such as NB Power Generation Company. Given that the impact of intra-hour variations is the same, it is reasonable that the regulation and load following requirements associated with wind generation be treated consistently throughout the Balancing Area.

MECL has filed an Open Access Transmission Tariff with the Island Regulatory and Appeals Commission (IRAC) in Prince Edward Island. MECL has commenced a stakeholder review process and will seek IRAC approval only after completion of that process. The wording in Schedule 3 of the proposed MECL OATT filed on November 30, 2006 already contemplates that the service may be provided by the Control Area[11] operator and that to the extent that this occurs, such costs will be passed on to the Transmission Customer.

> *The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.*[12]

As part of the stakeholder review process, MECL is now proposing to add more specific wording to the OATT relative to this issue. This wording would indicate that to the extent that there are Control Area Operator charges for capacity-based ancillary services such as regulation and load following associated with wind power, these charges will be passed on to the wind farms. MECL also commits to working with NBSO and the other parties involved in this study to find ways to ease the integration of wind power into the Balancing Area.

[11] The term Control Area exists in many OATTs, but this term is being phased out by NERC and NPCC and replaced by the term Balancing Area.
[12] MECL Proposed OATT (as filed with IRAC on November 30, 2006), Schedule 3.

8. Comparisons

Table 9 and Table 10 contain comparisons of observations and proposals for the various jurisdictions. Table 11 illustrates a similar comparison for interconnection requirements. Note that the discussion with Prince Edward Island and Northern Maine system operators is in its infancy and these proposals can be expected to evolve.

Table 9

Defined Ancillary Service Charges for Loads

	NB	NMe	NS	PEI[13]
Regulation	√	√	√	√
Load Following	√	√	√	√
10 Minute Spinning Reserves	√	√	√	√
10 Minute Supplemental Reserves	√	√	√	√
30 Minute Supplemental Reserves	√	√	√	√
Energy Imbalance	√	√	√	√

To date, the proposal is that a mechanism be implemented to recover the incremental costs associated with regulation and load following arising from wind power production. System operators in Northern Maine and Prince Edward Island are in agreement that to the extent NBSO assesses such charges that they should be passed on to the wind power producers.

While increased regulation and load following capacity requirements are expected, increased reserve capacities may not be required. However the frequency of activation of reserves will increase. For example, the 2004 data indicated that for 250MW at each of 4 sites in New Brunswick, the maximum drop in hour to hour production would have been only slightly less than 400 MW. While significant, this drop in production is less than the first and second contingencies and thus would not trigger an increase in required reserves.[14] [15] Nonetheless, as an example, hour-to-hour drops of at least 200 MW would have occurred in almost 82 hours, and such drops in production may require activation of reserves. Swings that are in excess of 200 MW (and even less) may require activation of reserves, but that depends largely on whether or not they were forecasted one-half hour before the hour and scheduled accordingly. Another area of concern is the requirement for NBSO to report any contingency events in excess of 300 MW and such events have cost implications.

Whether or not reserve requirements are increased by the integration of wind power depends on the amount of wind generation, diversity of the wind production, and the quality of the hour ahead forecasting. Therefore, this issue will need to be revisited on occasion as conditions change and as more experience is gained.

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[13] Pending IRAC approval.

[14] The 1st (i.e. largest) and 2nd contingencies today are Lepreau at 600 MW (approximately 700 MW after refurbishment) and Belledune at 466 MW.

[15] The 10 minute reserve requirement is 100% of the largest contingency and the 30 minute reserve requirement is 50% of the second largest contingency.

Table 10

Proposed Charges for Wind Generation

	NB	NMe	NS	PEI[16]
Regulation	√	√	?	√
Load Following	√	√	?	√
10 Minute Spinning Reserves	x	x	?	x
10 Minute Supplemental Reserves	x	x	?	x
30 Minute Supplemental Reserves	x	x	?	x

Since the focus of the project is wind integration the coordination of interconnection standards is in its infancy. Nonetheless, Table 11 shows the current status and identifies where more work is required. The voltage support, low-voltage ride-through and SCADA items are addressed by the Federal Energy Regulatory Commission (FERC) standards. NBSO proposes to add the requirement for telemetry of the turbine status, current temperature, wind speed, and wind direction at the wind farm to the SCADA system used by NBSO.

Table 11

Interconnection Standards

	NB	NMe	NS	PEI[17]
Voltage Support	√	?	?	?
Low-Voltage Ride-Through	√	?	?	?
SCADA	√	?	?	?
Curtailment	√	?	?	?

With respect to curtailments, it is proposed that generation connection agreements clearly specify the right of the system operator to curtail wind power generation in accordance with the relevant tariff or market rule provisions. NBSO has the same rights with respect to other forms of generation and with respect to loads. The NB Market Rules allow for curtailments for reliability reasons and to the extent feasible such curtailments are to be done based on the most economical approach, given the dispatch data provided by the Market Participants for the respective generators. The generator must be able to respond in accordance with such dispatch instructions for partial or full production curtailments.

CanWEA has noted that wind integration would be more easily facilitated through a regional market and network (as opposed to province by province) run by a regional system operator with common market rules and tariffs throughout the region.

[16] Pending IRAC approval.
[17] Pending IRAC approval.

9. Summary

Analysis of work done in other jurisdictions, simulated production and simulated forecasts, and examination of system costs have allowed NBSO to increase its knowledge of issues associated with wind power production and propose enhanced treatment of wind power production. The work has also led to identification of areas in which the cost of integration may be reduced through new practices by system operators and market participants. Regional cooperation has made these efforts easier and ongoing cooperation of various stakeholders can help the realization of the potential benefits of wind power production in the region, while minimizing costs.

10. Detailed Reports

The detailed work performed during the course of the project has been captured in individual reports on the topics listed below.

1. Wind Power Production Analysis
2. Wind Power Production Forecasting
3. Wind Power Integration
4. Tariff and Market Rules