Renewables and Ontario/Quebec Transmission System Interties

An Implications Assessment

Final Report

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STRATEGIC POLICY ECONOMICS

Executive Summary

Historically, Ontario has exported and imported significant amounts of electricity to and from Manitoba, Quebec, Michigan and New York. These arrangements help ensure Ontario has sufficient reliable energy and capacity to meet provincial demand. The province's 2013 Long-Term Energy Plan (LTEP) indicated that Ontario would continue to pursue cost-effective imports to help meet its future electricity needs. Most recently, Ontario and Quebec have been engaged in discussions regarding electricity exchanges that would benefit both provinces. As Ontario embarks on the next iteration of its LTEP, the costs and benefits of this option will be among the province's supply choices.

This report examines the implications associated with expanding electricity transmission (Tx) intertie capacity between Ontario and Quebec. Specifically, the following four posited benefits are assessed:

1. Provide a peak capacity reserve exchange to balance the seasonal needs of the two provinces;
2. Smooth the intermittency of Ontario's wind generation by leveraging the storage capacity of Hydro Quebec's large reservoirs;
3. Source lower carbon firm hydroelectric imports from Quebec and lessen Ontario's increasing dependence upon its higher carbon-emitting natural gas-fired generation;
4. Enhance the interprovincial ties to augment the provinces' export capability to the U.S.

Many of these aspirations are premised on the near term electricity supply mix of the two provinces. The predicted supply mix conditions ten years hence, when enhanced interties may possibly be operational, is explored along with the longer-term implications that may arise as a result of emerging government climate change policies and strategies in Ontario, other provinces and in the United States.

Key Findings

Expanding interties to seek the posited benefits is an imprudent and expensive option for addressing Ontario's energy challenges. Potential intertie investments are economically undermined by the lack of winter generation capacity in Quebec and the future generation shortage in both provinces.

- The interties are adequately sized to meet peak reserve needs and, even if they were not, upgrades would cost up to $150M/year, or 50%, more than the IESO recommended SCGT alternative.
- Surplus wind energy smoothed by Quebec's reservoirs today would cost $275/MWh. Quebec can't smooth wind in the winter and, with current surplus in both provinces, does not need Ontario's.
- Seeking firm imports of Quebec hydro to complement Ontario's wind would still require gas-fired generation. The blended cost would be $150/MWh, double the cost of refurbishing Darlington which, if replaced, would increase emissions by 40% and cost Ontario 52,000 jobs.

In the future, both provinces will need substantial new low carbon baseload generation. If new generation is to be created, then enhancing the interties may offer future benefits for locating such generation, enabling related firm energy transfer and also possibly enhancing combined exports to the U.S. if accompanied by electricity market reform.

Specific Findings

This assessment has identified specific findings from in-depth lines of enquiry into the four posited benefits of enhancing the interties.

1. Addressing Peak Reserve

   Existing interties are sufficient to meet current forecast peak reserve capacity needs for the next 10 years if the provinces wanted to extend their capacity agreement beyond the current 500 MW. The forecast peak reserve capacity shortfall in Ontario is forecast to not exceed 1000 MW for at least the next 15 years, and not exceed 2000 MW in Quebec by 2025. Forty to fifty percent of the peak reserve capacity shortfalls in both provinces have arisen due to the additional reserve capacity required to accommodate the intermittent nature of the wind capacity that has been added to the supply mixes in Ontario and Quebec.

   Both provinces plan on supporting their respective peak supply needs with fossil-fired generation. Ontario can only supply Quebec's emerging winter import needs with natural gas fired generation, which will result in higher greenhouse gas (GHG) emissions in Ontario. Upgrading the interties is 50% more expensive than meeting peak reserve capacity needs through Simple Cycle Gas Turbines (SCGT) as recommended by the Independent Electricity System Operator (IESO).

2. Smoothing Intermittent Supply

   Over 50% of Ontario's wind is surplus to Ontario demand and being wasted through curtailments of other supply and the "dumping" of electricity at low and or negative prices into export markets. In 2015, this effectively resulted in the cost of Ontario's utilized wind energy being ~$300/MWh. Upgrading the interties to a sufficient capacity to match the variability of Ontario's installed wind base so the surplus energy could be stored temporarily in Quebec's reservoirs would lead to costs of ~$275/MWh, representing only a marginal improvement to the current situation.

   Quebec currently provides energy supply smoothing, mostly in response to Ontario's night time surplus baseload energy. Wind makes up 34% of the provincial night time surplus. Greater energy transfers in future could occur if Ontario needed it, and if Quebec wanted it.

   Ontario's energy supply and demand mix, the Tx system and geographical zonal constraints currently combine to transfer less than 10% of Ontario's wind energy to the Quebec border. Ninety percent of Ontario's wind supplies are over 800km from the Quebec HVDC intertie east of Ottawa, which is the only intertie with Quebec that dynamically supports the load variations associated with tracking wind patterns. The characteristics of Ontario's overall electricity system and low demand for Ontario's surplus in export markets is currently effectively bottling approximately 40% of the generated wind energy within Tx network zones and limiting its delivery east of Toronto.

If this wind energy could be delivered, and assuming Quebec wanted it, the interties have the potential to handle up to 600% more intermittent wind energy than they accommodate today.

3. Supply/Demand and the Economics of Quebec/Ontario Trade

Forecasts indicate that there will be insufficient low carbon energy sources in both provinces to meet demand beginning in the mid-2020s; and data shows that Ontario is not Quebec's favoured export market. The feasibility of Ontario accessing low cost hydro power from Quebec is not supported by the findings of this study.

Quebec has a near term surplus created by the recent expansion of several hydro facilities and the addition of wind resources to the province's supply mix. However, Quebec is now forecasting higher industrial demand growth which can be expected to erode the current surplus within the next 10 years.

At present, Quebec trades five times more energy with the U.S. than it does with Ontario because electricity market prices there are more attractive. Quebec's largest market is New England, which has much higher electricity prices than in Ontario. Electricity prices in the region are influenced by the price of natural gas in the U.S. which is projected to double in the next 15 years[1]. Quebec's recent investments in generation are estimated to produce power at about $81/MWh as compared to a cost of $20-$27/MWh for its heritage assets.

Quebec's export practices with Ontario have recently been characterized by price arbitrage, where Quebec has realized a premium of $22/MWh. Net flow to Ontario has averaged less than 1 TWh over the last three years. Historically, Quebec has drawn net energy resources from Ontario.

Like Quebec, Ontario is experiencing a short-term baseload capacity surplus. However, the supply and demand forecast shows that a shortage of low carbon generation will arise after the Pickering Nuclear Generating Station (PNGS) is retired. With the PNGS retirement, natural gas-fired generation will increase 60% by 2030 to make up the shortfall. This change in the supply mix will reduce Ontario's current energy surplus from 15 TWh/year to less than 4 TWh by 2030, but GHG emissions will increase by 60%. Quebec will no longer be able to profit from surplus trade with Ontario and their available reservoirs will be negatively impacted as they concurrently approach their own shortage of supply. However, an ongoing surplus of 2 to 3 TWh of wind generation will continue in Ontario until the wind assets begin to reach the end of their contracted life.

Finally, even if Quebec were willing to sell its hydro generation to Ontario, for both the market based reasons cited and the forecast reduction of the supply gap in Quebec, future imports from Quebec can be expected to be at higher prices.

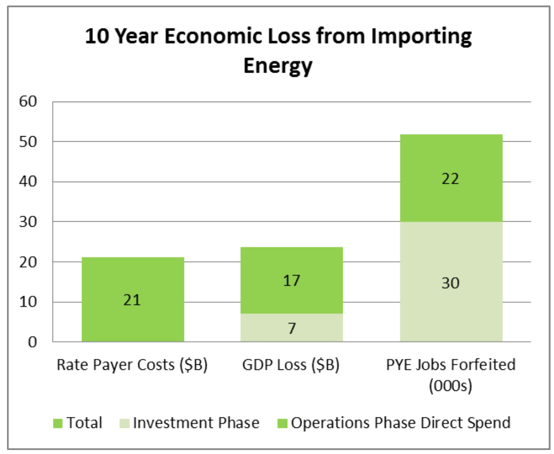
[1] AEO2016 early release, U.S. Energy Information Administration, 2016

4. Providing Firm Imports

This study assumes that firm imports from Quebec will be paired with wind generation in Ontario. A composite Ontario wind and Quebec hydro supply scenario was created and contrasted against a baseload nuclear scenario. Both scenarios used the capacity of the Darlington Nuclear Generating Station as the reference. Two important caveats are relevant to the scenarios compared: (1) Quebec does not have sufficient generation to support the scenario; and (2) While the capacity of Darlington has been used as a reference to bring out the relevant considerations regarding interties, the Ontario government has decided that refurbishing the Darlington units is in the best interest of Ontario.

The resulting scenario comparison shows that for a wind + hydro option:

- The net cost to rate payers of the wind + hydro option would be ~$150/MWh, approximately double the announced cost of the Darlington refurbishment project.
- Rate payers would pay $2.1B/year more, or $21B after the first 10 years of operation.
- The economy of Ontario would suffer a loss of over $2.4B/year for a total of $24B for the first 10 years of operation.
  - The investment difference accounts for $0.7B/year. The economic drain of using imported hydro and natural gas in lieu of the mostly domestic operating costs of Darlington represent another $1.7B/year.
- Ontario would forfeit 52,000 jobs.



Moreover, a wind + hydro scenario would increase Ontario's dependence on external sources for 65% of the forecast supply. GHG emissions would increase by 2.4 Million tonnes (Mt) of carbon dioxide (CO_2), or approximately 40% more than Ontario's entire electricity system produces today. Quebec would have to redirect 50% of its exports from the U.S. to Ontario to supply it.

The analysis demonstrates that pursuing firm imports from Quebec to supplement Ontario's wind energy in lieu of a nuclear baseload option is not attractive for Ontario's environment or economy.

Looking Forward

The future demands on Ontario's electricity system resulting from the province's emissions reduction targets, combined with incentives to direct the new demand towards lower cost off peak hours, will create a need for new low-carbon baseload capacity or equivalent capability. In this context, the interties could be a tool for facilitating the location of such new generation in a manner that could best serve the needs of the two provinces and also allow for greater exports to the U.S. from both provinces. This would require further assessment to determine its feasibility, potential electricity trading market reform, and to develop a business case.

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1.0 Introduction

Historically, Ontario has exported and imported significant amounts of electricity to and from Manitoba, Quebec, Michigan and New York. These arrangements help ensure Ontario has sufficient reliable energy and capacity to meet provincial demand. The province's 2013 Long-Term Energy Plan (LTEP) indicated that Ontario would continue to pursue cost-effective imports to help meet its future electricity needs. Most recently, Ontario and Quebec have been engaged in discussions regarding electricity exchanges that would benefit both provinces. As Ontario embarks on the next iteration of its LTEP, the costs and benefits of this option will be among the province's supply choices.

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Approach

This study conducted a literature search for materials describing or assessing the characteristics of the Ontario and Quebec electricity systems and accessed Ontario's Independent Electricity System Operator (IESO) data for historical records of supply, demand, and energy flows across the interties between Quebec and Ontario. Strapolec undertook two analyses to characterize the implications of the intermittent production from wind generation on the interties between the provinces:

(1) Examined how wind generation energy flows through Ontario's Tx zones; and,

(2) Compared two scenarios for Ontario's electricity supply mix to assess the annual implications of using nuclear baseload versus a composite supply scenario that included maximum leverage of hydro imports from Quebec, coupled with matched wind capacity and the requisite gas-fired complement to the two. The Darlington Nuclear Generating Station (DNGS) production profile was used as the nuclear reference case which established the generation profile required from the composite supply scenario.

Structure of this document

This report provides a comprehensive description of the drivers, assumptions and outcomes of the assessment conducted regarding the implications of enhancing the interties between Ontario and Quebec. Graphics and graphs, based on real data have been used to help illustrate the results achieved from the analyses presented in this document. The following sections explore and describe the fundamentals of the electricity systems in Ontario and Quebec, and an assessment of the related cost effects for each major subject area is provided.

Section 2 summarizes the structural and operating characteristics of the electricity system in Quebec, the nature of the interties with Ontario, and the economic studies conducted by the Independent Electricity System of Ontario (IESO) on potential upgrades to the interties.

Section 3 presents the findings of this study. Four areas were assessed: (1) peak reserve capacity; (2) smoothing of the intermittent output from renewables; (3) future supply and economic considerations; and (4) an evaluation of firm import scenarios. The relevance of each area to the capability/capacity of the Ontario/Quebec interties is explored, including costs.

Finally, Section 4 presents some forward looking considerations that may emerge as a result of the global push to combat climate change.

The sources consulted during the research for same are listed in Appendix A. A list of acronyms is contained in Appendix B.

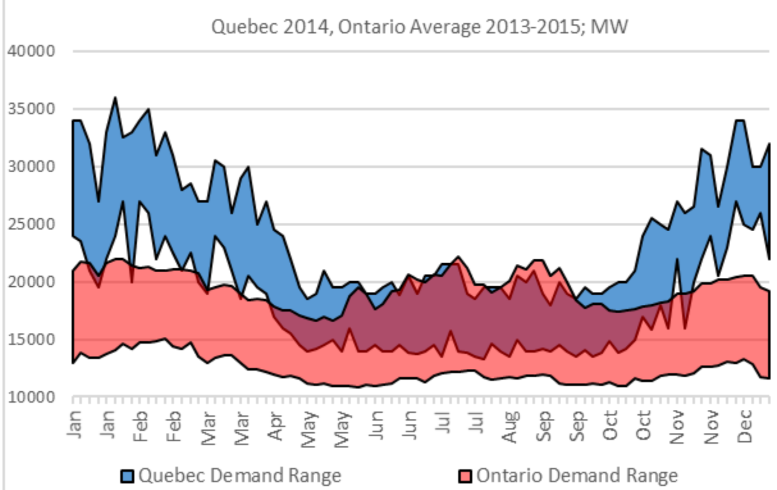
2.0. Context

The existing infrastructure and operating characteristics of the Quebec and Ontario electricity systems and the costs of upgrading the interties are important considerations before any further integration occurs. This section provides an overview of electricity demand in Quebec and Ontario, Quebec's Tx system, and the interties between the two provinces. The current operational use of the interties is also discussed. In addition, a summary of the IESO's assessment of the costs of upgrading the interties is provided.

2.1. The Quebec and Ontario Electricity Demand

Quebec and Ontario have very different energy needs and supply characteristics. As shown in Figure 1[2], the Quebec winter peak is much higher than its summer peak due to the extensive use of electrical heating. Demand in the summer is very similar in the two provinces.

Figure 1 – Quebec and Ontario Electricity Demand



Quebec's reservoirs provide a provincial/grid level seasonal storage capability essential to meeting Quebec's winter peak demand, which is over 65%, or 15 Gigawatt (GW), higher than its summer peak demand. Quebec's annual cycle of demand variation is visibly more amplified than Ontario's. Quebec has a globally unique and flexible hydro-electric capability that provides the benefits of seasonal storage in meeting the province's electricity needs. The reservoir capability, from installations such as James Bay, has 178.9 Terawatt Hours (TWh) of net storage capacity to manage across the annual cycle. Quebec also has access to 34 TWh of energy from the 5.4 GW Churchill Falls complex in Labrador[3]. Together these vast resources help Hydro-Quebec meet its 222 TWh of provincial demand.

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[2] Can Ontario and Quebec Benefit from more Electricity Market Integration?, Pierre-Olivier Pineau, Professor, HEC Montreal, Chair in Energy Sector Management, 2015; IESO Data; Strapolec Analysis

[3] 2015 Annual Report, Hydro Quebec, 2016; Strategic Plan, 2009-2013, Hydro Quebec 2009

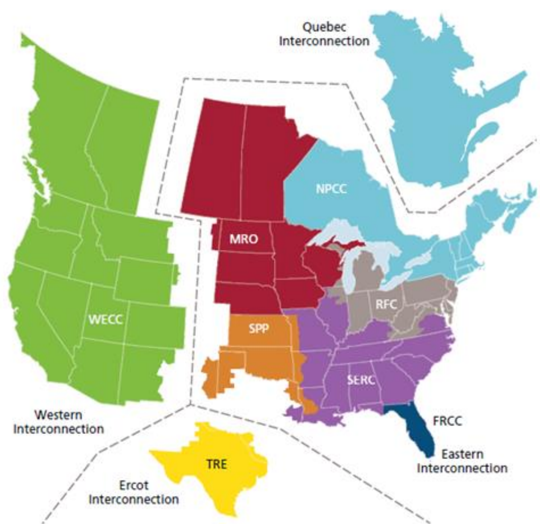
Ontario's total annual demand is in the range of 160 TWh and, in contrast to Quebec, has very limited and only short term daily storage. Ontario is known to be a jurisdiction that is summer peak limited. The forecast difference between Ontario's summer peak demand and its winter peak demand was projected by the 2013 LTEP to be only ~7% or 1.5 GW over the period of 2013 to 2020[4]. There is an operational variation year to year between the winter and summer peaks. For example, in Ontario for 2014, the combination of a cold winter and a mild summer led to a lower summer peak demand in the province that was 6% less than its winter peak – a notable if not rare circumstance.

Ontario and Quebec have offsetting peak demand needs, but the magnitude of Ontario's winter to summer difference of 1.5 GW is only ~10% of Quebec's summer to winter difference of 15 GW. While the two provinces have offsetting seasonal peaks, the need is not comparable.

2.2. Quebec's Transmission System and Interties with Ontario[5]

Quebec's Tx network is physically distinct from Ontario's and that in the U.S. as it is isolated from the North American Tx networks as shown in Figure 2[6]. There are four electricity networks in North America: (1) the Eastern Interconnection; (2) the Western Interconnection; (3) the Electric Reliability Council of Texas (ERCOT) Interconnection; and (4) the Quebec Interconnection.

Figure 2 – Networks and Regions within the NERC Interconnections



[4] IESO Data

[5] Description in this section highly leverages material from: Canada's Low Carbon Electricity Advantage: Unlocking the Potential of Inter-Regional Trade, Chapter 6 of CANADA: Becoming a Sustainable Energy Powerhouse, Canadian Academy of Engineering, 2014

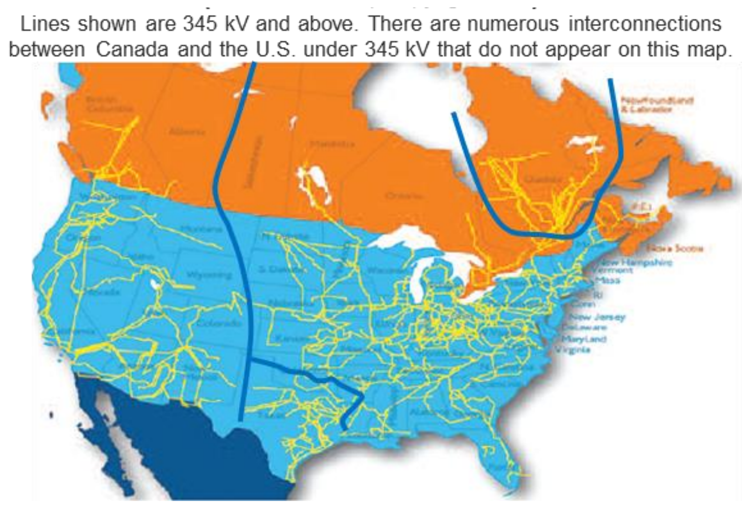
[6] Canada's Low Carbon Electricity Advantage: Unlocking the Potential of Inter-Regional Trade, Chapter 6 of CANADA: Becoming a Sustainable Energy Powerhouse, Canadian Academy of Engineering, 2014

The four interconnections are independent in that they are not synchronized with each other, but are linked through limited direct current (DC) interties. The Eastern and Western Networks include Tx connections with the electrical grids in Canada. The Eastern Interconnection is the largest synchronous electrical system in the world comprising more than 60% of the circuit length of the Tx lines in North America. Of all the provinces, Ontario is the most highly connected to neighbouring states and provinces. Ontario has a diversity of energy supply resources with seventeen interconnections (or circuits) at nine locations with neighbouring jurisdictions.

While segregated by asynchronous operations, Quebec does have many interfaces across its borders and operates within the Northeast Power Coordinating Council (NPCC). The Hydro Quebec (HQ) system is connected to Ontario, New York and New England by DC interconnections.

Figure 3[7] illustrates the distinctive boundaries between continental grids and how they reflect the underlying geographic distribution of population and energy consumption. This figure also shows the degree to which the grids within the four networks are relatively independent of each other and have limited locations where they interconnect.

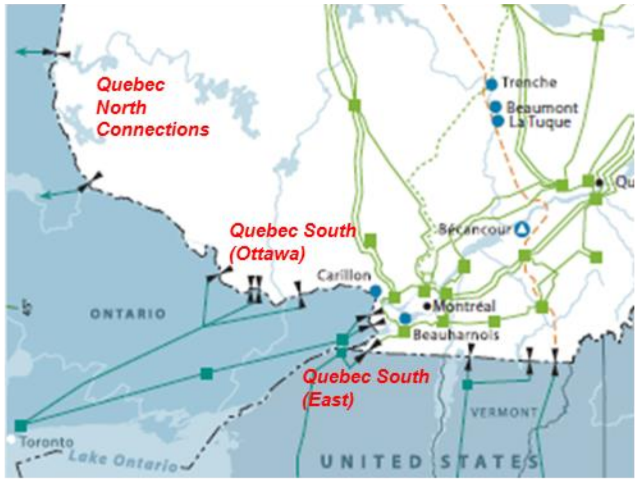
Figure 3 – Major U.S.-Canada Transmission Interconnections



The Quebec and Ontario Tx systems are connected by nine interties as shown in Figure 4.

[7] Canada's Low Carbon Electricity Advantage: Unlocking the Potential of Inter-Regional Trade, Chapter 6 of CANADA: Becoming a Sustainable Energy Powerhouse, Canadian Academy of Engineering, 2014

Figure 4 – Overview of Ontario/Quebec Interties



In the IESO's description of the Tx system, these interties are grouped into three regions[8]:

1. Quebec North connections (2 connections) have modest capability generally under 100 MW.
2. Quebec South (Ottawa) (4 connections):
   - 1250 MW HVDC line is a bi-directional tie in the Ottawa region.
   - The other interties in the Ottawa region have a total of 660 MW into Ontario and 220 to 240 MW out of Ontario.
3. Quebec South (East) connections (3 connections) which have a material capability to support up to 800 MW of imports into Ontario and 470 MW in exports out to Quebec.

The physical nature of the interties limits which Tx lines are relevant to the discussion regarding possible capacity enhancements. The current interties between Quebec and Ontario have a combined capacity of 2,775 Megawatts (MW). Just east of Ottawa, two 230 KV lines use a High Voltage Direct Current (HVDC) converter to transfer up to 1,250 MW of supply into or out of Ontario. This interconnection is relatively new and came into service in 2009. This recently constructed 1250 MW HVDC is the primary interface for the seamless flow of energy between the provinces.

At other points along the Ottawa River, east of Cornwall, and in the Abitibi region, generation resources from either province are connected, or segregated, onto one system or the other depending on system and market conditions. The total import transfer capability of these segregated interties is 1,525 MW. The total export capacity, while rated at 900 MW, is limited to ~700 MW due to the segregated and/or emergency use constraints (Table 1)[9].

[8] Ontario Transmission System, IESO, 2015
[9] Review of Ontario Interties, IESO, 2014

Table 1 - Ontario-Quebec Regional Intertie Peak Flow Characteristics, Max Flow 2013-2015								
		Import from Quebec			Export from Ontario			
Region	Intertie	Name	Flow Limit (MW)	Actuals (MW)	Name	Flow Limit (MW)	Actuals (MW)	Comments
Total Flows			**1525**	**1190**		**900**	**704**	
East	PQBE	Beauharnois	800	602	Saunders	470	422	Segregated
Ottawa	PQXY	Bryson	65	68				One way only to Ontario
	PQQC	Quyon			Chats Falls	130	136	Segregated; one way only to Quebec
	PQPC	Paugan	345	253				Circuit breaker issue at Chats Falls
	PQDA	MacLaren	250	190		200	44	Ontario side emergency only
	PQHA	Masson	0	0				Quebec side emergency only; if PQDA out of service
	Total		660	511		330	180	
Northeast	PQHZ	Kipawa			Near Otto Holden	100	102	Far north; one way only to Quebec
	PQDZ	Rapiddesisle	65	77				One way only to Ontario
	Total		65	77		100	102	
Flows Relevant to Study			**1525**	**1190**		**700**	**660**	Excluding PQDA emergency intertie

According to the IESO, transmission constraints in Ontario regularly limit available transfer capability between the two provinces. Real-time transactions with Quebec have reached maximums of about 1,800 MW either way under ideal conditions over the last few years. The nature of the interties themselves, as well as transmission constraints in the Ottawa zone, is responsible for most of the limits.

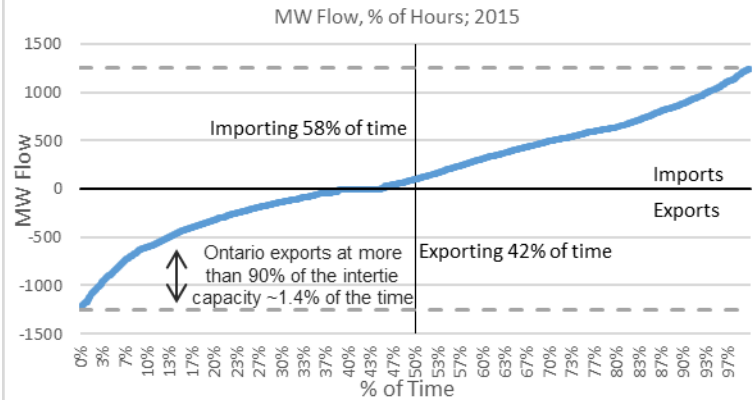
For the most part, regional interties are devoted to specific hydro dams whose output to either province is “segregated”. The dams physically require a switching mechanism to move the dams from being part of either the Ontario or Quebec supply grids at any given time. The result is unidirectional flow capabilities at the associated interties when the flows are reversed. To switch across this interface requires physical dispatching. Normal market Transmission Rights protocols only apply depending on how the switch is configured. Entire blocks of dam capacity are switched in and out. With these capacity and production blocks, if full flow of available of water is not being used, then the production is not being efficiently used, arguably curtailed. The dams on both sides of the border associated with the segregated interties are “run of river”. As a result, the associated intertie capacity varies with water levels and hence has a unique profile of constraints. It is unknown as to whether the currently observed production profiles of these dams can be modified for some future purpose. Finally, the energy flow from Quebec across the segregated interties is from these run of river dams themselves not from Quebec’s reservoirs. Hence the segregated Quebec intertie capability does not reflect the desired “battery” characteristic deemed useful for managing intermittency.

Due to all of the limitations and complexities associated with assessing the segregated interties, the Ottawa 1250 MW HVDC intertie is deemed to be the primary intertie relevant for consideration in this analysis. The IESO also focussed on this intertie in its 2014 assessment of capacity modifications to support firm imports to Ontario.

2.3. Operational Use of Intertie Capacity

Figure 5 illustrates the profile of energy flow across the HVDC intertie in 2015. It shows how often the intertie is used to export (45% of hours) and the percentage of capacity that is being used at any given hour in each direction. The exports to Quebec exceed 90% of the intertie capacity only 1.4% of the time with an average operating factor of 36%. This implies that greater energy transfers could occur if Ontario needed it and if Quebec wanted the electricity.

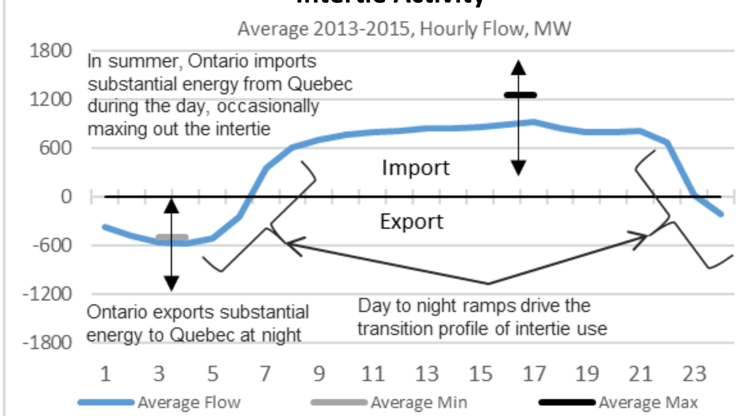
Figure 5 – Quebec South (Ottawa) HVDC Yearly Intertie Usage



The total amount of energy that could be delivered to the Quebec border could be more than doubled before an upgrade would be needed.

Since the intertie is bidirectional, there are natural transition times that moderate the rate at which the intertie shifts from an import to an export mode. Figure 6 shows how the daily profile of demand and energy transfer by hour relates to the import/export transitions on the intertie.

Figure 6 – Average Summer Weekday Quebec Intertie Activity



In the summer of 2015, Ontario exported energy to Quebec at night and imported energy during the day. The transition from the low demand in Ontario at night to higher demand in Ontario during the day drives the gradual change in intertie volumes as illustrated in Figure 6. The maximum and minimum lines indicate the range of nighttime and daytime peaks that occurred over the summer. The inherent demand variability and associated operational considerations all impact on the IESO's management of the interties.

2.4. Interties and the Cost of Upgrading

The IESO assessed the viability of using the interties to accommodate various scenarios for firm imports, based on needs and options suggested in the 2013 LTEP. The 2013 LTEP identified a need for 10-15 TWh of imported energy[10] after the retirement of the Pickering Nuclear Generating Station (PNGS). The IESO's report indicated that the interties were not designed to be used to replace significant amounts of baseload power and that any arrangements between Ontario and Quebec would likely involve both capacity and energy.

Table 2 summarizes the costs estimated by the IESO based on incremental investments in intertie capacity[11].

Table 2 - IESO Intertie Upgrade Cost Estimate

Region	Firm Import Scenario (MW)	Notes	Estimated Total Cost of Transmission Upgrades ($M)	Estimated Time to Complete Regulatory and Construction Phases	Capacity Addition
Quebec	500	Using current facilities - the capability declines to zero by 2020 due to constraints in the Ottawa Area	0	0	No added capacity
	1000	Adding facilities to improve Ottawa area flows	$325	3-5 years	No added capacity, allows for more efficient use of existing capability
	1800	1. New 230 kV double circuit line between Cornwall and Ottawa 2. A new 230 kV circuit, approx. 8km in length to connect existing circuts in the west of Ottawa 3. Additional voltage control equipment in the Ottawa area	$825 ($325 + $500)	5-7 years	Adds 800 MW capacity
	3300	1. New 500 kV double circuit line from Bowmanville to Cherrywood 2. New HV dc Interconnection	$2,200 ($825 + $1,400)	7-10 years	Adds additional 1500 MW capacity for a total of 2300 MW

It is assumed that the first $325M will be invested independent of the issues addressed by this report as they are required to address anticipated transmission constraints in the Ottawa area in the next 10 years. This first upgrade is mainly required to meet Ottawa demand by 2020. These initial investments

[10] Rethinking Ontario's Long-Term Energy Plan, Brouillette, M., 2014
[11] Review of Ontario Interties, IESO, 2014

do not involve intertie capacity upgrades, just eliminating the limitations within the Ottawa region or zone. However, it is also assumed that a 1000 MW capability of firm import flow from Quebec will be technically enabled by the Ottawa area improvements.

The possible upgrades identified by the IESO that directly affect enhancements of HVDC intertie capacity were costed at $1.9B to $3.3B. The scope of these upgrades would add 2300 MW of capacity, enabling imports to be delivered to the GTA, the heart of Ontario's electricity demand. The IESO report suggested that the related investments required in Quebec could be similar in magnitude.

To confirm this estimate, Strapolec obtained the cost information related to Quebec's investment on the intertie upgrade for the 1250 HVDC line. According to the HQ 2008 Annual Report, the intertie related investments for Quebec totalled $650M. By comparison, adding 2300 MW of intertie capacity involves double the number of MWs. Assuming an equivalent doubling of costs and adding some inflation supports the IESO's cost assumption of about $1.4B.

Strapolec's analysis therefore assumes that upgrading the interties to allow an additional 2300 MW will reflect the IESO cost estimate of $1.9B on Ontario's side, and another $1.4B on the Quebec sidem for a total of about $3.3B.

There are two ways to consider these costs: (1) as they relate to providing peak reserve capacity; and (2) those that would accrue under a firm import objective as a per Megawatt Hour (MWh) charge on energy delivered to consumers.

Investing in a 2300 MW intertie upgrade for peak reserve capacity purposes would represent a financed investment cost of ~$450M/year. The IESO has stated that Simple Cycle Gas Turbine (SCGT) capacity is more cost effective for peak reserve supply.[12] The IESO has stated that an SCGT capacity charge is approximately $130K/MW/year. For 2300 MW, this equates to a cost of about $300M/year. Upgrading the interties is approximately 50% more expensive than solving peak reserve capacity challenges with SCGT plants that are likely to be idle.

The incremental consumer cost is a direct function of the energy that the interties may transport under any chosen scenario: the higher the usage, the lower the per MWh costs and vice versa. For a fully utilized line, IESO estimated the Tx upgrades would add between $20 and $30/MWh to the cost of electricity. As an independent check, Strapolec used U.S. Energy Information Administration (EIA) financing assumptions[13] to estimate the per MWh cost of the $3.3B investment to enhance the interties by 2300 MW. Assuming a 90% capacity usage factor the cost would be $25/MWh as shown in Table 3. This is consistent with the IESO's estimate. At today's operating factor of a 36% utilization rate this added energy unit cost of the Tx asset approaches $63/MWh.

[12] NUG Framework Assessment, IESO, 2015

[13] EIA suggest pre-tax WACC of 14%, and 30-year life. $3.3B equates to $456M/year. 2300 MW could support up to 20TWh of energy transfer

Table 3 - Assumptions for Unit Tx Costs					
	Case 1	Case 2	Case 3	Case 4	Case 5
Capacity Usage	100%	90%	80%	36%	23%
TWh	20	18	16	7.2	4.7
Cost after Financing ($/MWh)	$23	$25	$28	$63	$97

The IESO concluded it would not be cost effective to upgrade the interties for the purpose of addressing the firm import needs of the 2013 LTEP.

2.5. Summary

The electricity systems of Quebec and Ontario balance very different energy needs and constraints. The Quebec winter peak is over 65% higher than its summer peak, due to the province's reliance on electrical heating. Ontario's summer peak needs are only 6-7% of its winter peak and this seasonal peak variation of 1.5 GW is only 10% the size of Quebec's.

The Quebec system is isolated within the North American network of Tx networks. The nature of the interties between the provinces has segregated dam "switching" constraints on how energy flows. These constraints leave Ontario/Quebec with only one dynamic two-way interface relevant to using Quebec's reservoirs for smoothing intermittent wind generation, the 1250 MW HVDC line near Ottawa.

The HVDC is rarely used to its maximum capacity. Flows exceed 90% of its capacity less than 4% of the time in each direction. The operational profile is highly correlated with Ontario's demand profile. The shift from higher demand in the province during the day to lower demand at night directly influences the direction of the flow of the intertie, leaving significant periods of time where the intertie capacity is only used marginally.

Costs for upgrading the HVDC Tx intertie capability have been assessed by the IESO. They estimated these costs to be in a range of $1.9B to $3.3B for 2300 MW of additional intertie capability. From a peak reserve capacity cost perspective, the intertie upgrade costs 50% more than the standard SCGT option recommended by the IESO. For moderate intertie operating factors similar to today, the added Tx investment could add $63/MWh to the cost of energy for rate payers.

3.0. Findings

Strapolec's analysis assessed ways to leverage Quebec's hydro reserves to accommodate challenges within Ontario's electricity system, specifically: (1) peak reserve capacity described in Section 3.1; (2) the intermittency of Ontario's wind generation explored in Section 3.2; and (3) the possibility of firm imports to reduce Ontario's emerging reliance on the greenhouse gas (GHG) emitting natural gas fired generation explored in Section 3.4 through a case study of alternative supplies to an equivalent capacity reference case based on the Darlington Nuclear Generating Station (DNGS).

Section 3.3 provides an examination of the forecast supply shortage in both provinces and the economic implications for Quebec of ongoing trade with Ontario to ensure a full exploration of the future implications of supply, demand, and pricing.

Observation on Concurrency of Benefits

The interties cannot be used to simultaneously address all possible uses. Peak reserve, intermittent wind generation, and firm imports cannot all be accommodated by the same capacity at the same time as summarized in Table 4.

Table 4 – Conflicts Among Intertie Application Commitments

Opportunity	Definition	Constraint
Peak capacity reserve exchange	Address shortages in Quebec (winter) and Ontario (Summer)	• Capacity allocated for reserve purposes cannot also be planned as generation for operational needs. Firm import assumptions do that
Smooth intermittent and variability	Enable use of Quebec hydro reservoirs as a grid level provincial storage capacity for both provinces to absorb excess energy from intermittent wind resources	• Energy must flow both ways: first to absorb and send back, doubling the cost per MWh • Accommodate the peak intermittency of renewables directly implies an unused capacity margin equivalent to the say ~30% capacity factor of wind turbines. • Keeping the dual flow capacity available inhibits ability to support peak reserve or firm import.
Source firm imports	Dedicate capacity of interties for firm year round imports as a baseload substitute	• Dedicated capacity disables flexibility for intermittent • Uni-directional flow at odds with the peak exchange
Enhancing US exports	Enable flows of low carbon electricity between provinces to help expand exports	• Commitments have similar constraints to firm imports

The viability, economic merits and future implications of the above scenarios are each explored in detail in the following sections of this report. The economic benefits are assessed both from an Ontario cost perspective as well as the possible economic impacts for Quebec.

3.1. Peak Reserve Capacity

To assess the value of using the interties to enable peak reserve capacity exchanges given the off-setting peaks in Ontario and Quebec's demand, this section examines:

- The nature and magnitude of the peak reserve requirements in each province,
- Implications of the recent deployment of wind capacity in both provinces,
- A detailed assessment of the current use of the interties and how the interties already contribute to meeting the electricity needs in both provinces,
- The plans of both provinces to leverage gas-fired generation to meet the peak needs.

3.1.1. Peak Reserve Requirements of Ontario and Quebec

As previously illustrated by Figure 1, leveraging interties can help support the respective peak capacity needs of both provinces given that their respective peak demands occur at different times of the year.

The North American Electricity Reliability Corporation (NERC) requires that peak reserve capacity limits reflect a capacity level at a reserve margin above the highest forecast of expected peak demand. NERC's Peak Reserve margin definition applies to all members of the NPCC. The peak reserve margin is stated as a percentage of expected peak demand for the purpose of ensuring that there is sufficient supply capacity in any jurisdiction such that no more than one 3-hour period every 10 years is likely to experience a shortage in available generation. The margin is determined probabilistically based on failure modes characterized by each jurisdiction's specific grid[14].

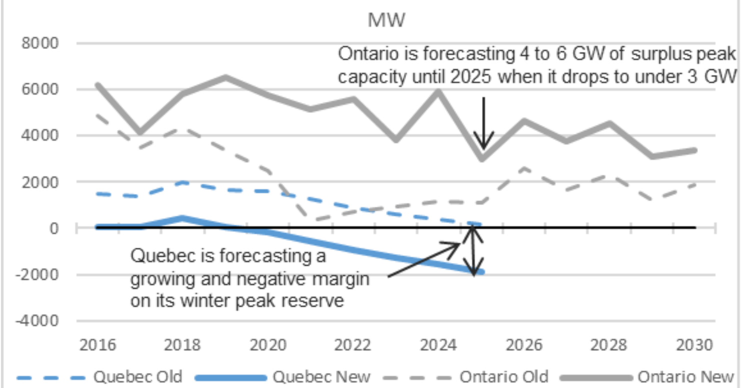
Peak reserve calculations do not include available capacity from other jurisdictions, unless the capacity has been identified through firm commitments. Absent firm commitments for supply outside of a jurisdiction, intertie capabilities do not enter into the reserve capacity calculations in meeting NERC requirements.

While intertie capacity itself cannot be "planned on" as a generation source in meeting peak demand and reserve requirements, Ontario, in its 2013 LTEP, included the possibility of imports in meeting the reserve capacity requirements through its "planned flexibility" provisions and an assumption of available firm imports. These provisions provided a basis for the IESO to assess the possibility of enhancing the interties to accommodate firm imports. Upgrading interties is a very high cost approach to addressing the peak reserve challenge, a need that the IESO has identified as being better met by peaking gas-fired generation which the IESO stated would only be expected to operate 2% of the time.[15]

[14] For details see: Regional Reliability Reference Directory # 5 Reserve, NPCC, 2012
[15] IESO NUG Framework Assessment, 2015

Ontario and Quebec have formed a Memorandum of Understanding (MOU) agreement to exchange peak reserve capacity options[16]. Ontario and Quebec have recently committed to making a 500 MW reserve available across the existing interties. Ontario will provide 500 MW of reserve capacity to Quebec in the winter and Quebec will provide 500 MW of firm capacity in the summer. Ontario originally agreed on the basis of a four-year horizon to 2020, anticipating PNGS retirement at that time. Peak capacity shortages are now expected to emerge over the next decade, in Quebec before Ontario, as shown in Figure 7[17]. Figure 7 shows forecasts of reserve capacity that were current when the original MOU was being negotiated, as well as the more recent forecasts for both provinces that have emerged since then. The Ontario forecast was made public in March of 2016.

Figure 7 – Evolution of Provincial Winter Peak Capacity



Quebec's winter peak capacity reserve shortage is forecast to grow as much as 2 GW by 2025, due to expected industrial and economic growth[18]. Ontario is forecast to have an ongoing peak reserve surplus in winter throughout that time frame, even after the retirement of the PNGS in 2024. The intertie reserve capacity agreement with Quebec has now been extended through 2024. This deal mostly benefits Quebec over this time frame as Ontario is not forecast to have a peak reserve capacity shortfall.

Quebec will require additional peak reserve capacity beyond the 500 MW defined in the MOU. The projected Quebec peak reserve capacity shortfall of 2000 MW is nearing the current intertie capability but does not exceed Ontario's forecast winter surplus, even after the PNGS retirement. It is not evident that the interties would require expansion to satisfy Quebec's peak reserve needs alone. It is also not imperative that only the Ontario/Quebec interties be looked to for this purpose.

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[16] Joint Memorandum: Seasonal Exchange of Electricity Capacity Between Ontario and Quebec, Office of the Premier of Ontario, 2014

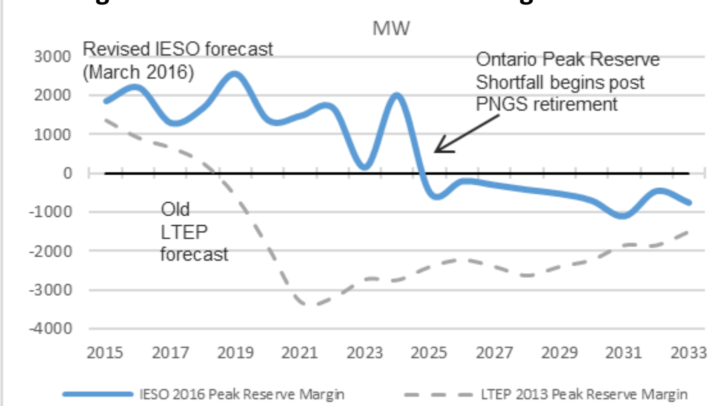
[17] LTEP data tables; État D'Avancement 2014 Du Plan D'Approvisionement 2014-2023, Hydro Quebec Distribution, 2014; 2015 Long-Term Reliability Assessment, NERC, 2015; Preliminary Outlook and Discussion, IESO, 2016; Ontario's Long-Term Energy Plan, Ontario Ministry of Energy, 2013; Review of Ontario Interties, IESO, 2014

[18] État D'Avancement 2014 Du Plan D'Approvisionement 2014-2023, Hydro Quebec Distribution, 2014; Strapolec analysis

The peak shortfall is also coincident with Quebec's emerging generation-limited constraints in winter. These constraints have led HQ to forecast a need for winter imports of over 3 TWh by 2023[19]. However, if expanding the interties is used to meet the peak reserve requirement, the same capacity cannot be relied upon as a source of firm imports for the 3 TWh shortage of energy in Quebec.

Ontario's near term summer peak reserve exceeds requirements by a wide margin, until the PNGS retires. The IESO revised its peak reserve forecast with the recent confirmation of the nuclear fleet capacity availability forecast. The new peak reserve capacity margin forecast is shown in Figure 8[20]. Ontario is expected to have a shortage of about 500 to 1000 GW after the PNGS retires. This shortage will persist to 2032 and beyond even after the nuclear fleet refurbishments are completed. The shortage is much smaller than previously projected in the 2013 LTEP. While now no longer severe, the reserve shortfall must still be addressed.

Figure 8 – Ontario Peak Reserve Margin Forecast



3.1.2. Peak Reserve Requirements and Renewables

Ontario and Quebec both have growing peak reserve requirements as shown in Figure 9[21]. Despite the significantly different magnitude of the provinces' respective peak demands, the reserve margins of the two provinces are very similar due to their different reserve margin requirements (and definitions).

In both Quebec and Ontario, the magnitude of the growing reserve margin is due to increasing reserve margins required by NERC. Quebec is forecast to require 12.8% more generation capacity than it expects to need in 2025 as compared to the 11.6% in 2016. Ontario's forecast peak reserve need has grown to 20% from 2010 level of 17%.

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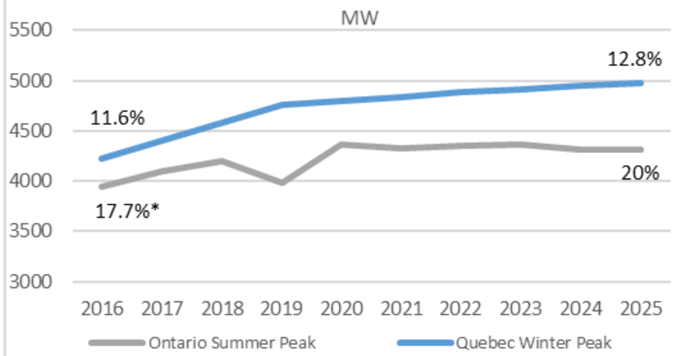
[19] État D'Avancement 2014 Du Plan D'Approvisionement 2014-2023, Hydro Quebec Distribution, 2014
[20] IESO Preliminary Outlook and Discussion 2016; Ontario's Long-Term Energy Plan, Ontario Ministry of Energy, 2013
[21] 2015 Long-Term Reliability Assessment, NERC, 2015

Figure 9 – Peak Reserve Requirements at Peak Season

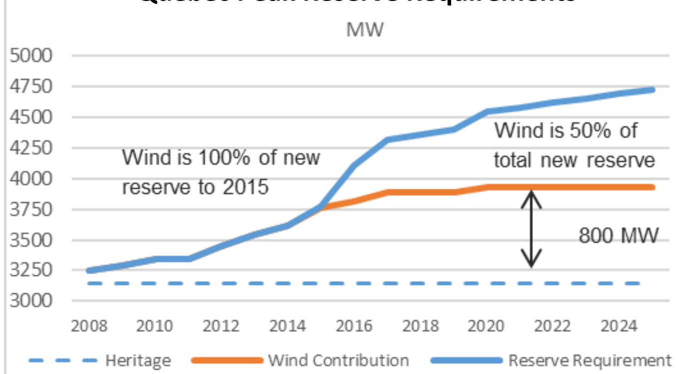


* In 2010, LTEP had Ontario Reserve Requirement at 17%

The shortfalls are due in part to the increased reserve margins that must be provided to compensate for the lack of dependability resulting from intermittent wind resources. In Quebec, all of the reserve increase between 2008 and 2015 was due to its addition of wind capacity as shown in Figure 10[22]. The 800 MW of new reserve capacity is required due to the variability in wind production, and represents 100% of the total reserve requirement increase in 2015. Wind generation's contribution is projected to continue to represent at least 50% of the total forecast increase in reserve capacity out to 2025. Specifically, the additional reserve requirement in Quebec is approximately 57% of the expected contribution that wind will make at peak.

The 800 MW is 40% of Quebec's expected reserve capacity shortfall in 2025.

Figure 10 – Contribution of Renewables to Quebec Peak Reserve Requirements



In Ontario, the growth in reserve capacity requirements of 324 MW is due to the added wind capacity. This increase in reserve peak capacity is calculated using the 57% observed for Quebec. This 324 MW is

[22] État D'Avancement 2014 Du Plan D'Approvisionement 2014-2023, Hydro Quebec Distribution, 2014; 2015 Long-Term Reliability Assessment, NERC, 2015

~44% of the future forecast increase in the peak reserve requirement for Ontario post 2024 as shown in Figure 11.

When it reviewed the peak reserve supply options, Ontario's IESO stated that SCGT generation was the most cost effective. The cost of an SCGT, as a reference, is $130,000/MW/year[23]. Table 5 shows that the cost of the additional 324 MW of new reserve capacity is $42M. It affects the cost of wind energy by $2.5/MWh to $10/MWh, depending on how much wind is put to productive use.

Figure 11 – Change in Ontario Reserve Requirement Attributed to Wind

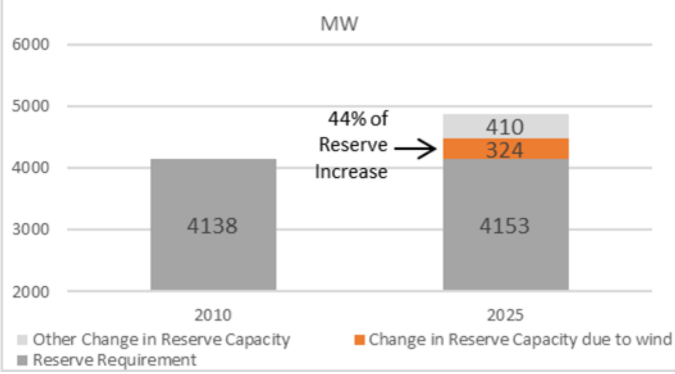


Table 5 - Cost of Increase to Reserve Capacity in 2025 from Wind	
Capacity Cost	2025
Change in Reserve Capacity (MW)	324
Cost of SCGT Peaking Capacity ($M/MW/Year)	$ 0.13
Total Cost of Added Reserve ($M)	$ 42
Equivalent Energy Charge - LTEP Assumptions	
LTEP Wind Output (TWh)	17
Cost of LTEP Wind ($/MWh)	$ 2.47
Equivalent Energy Charge - 2015 Usable Energy	
Estimated Domestic Wind Used 2015 (TWh)	4.3
Equivalent Unit Cost of Reserve ($/MWh)	$ 9.78

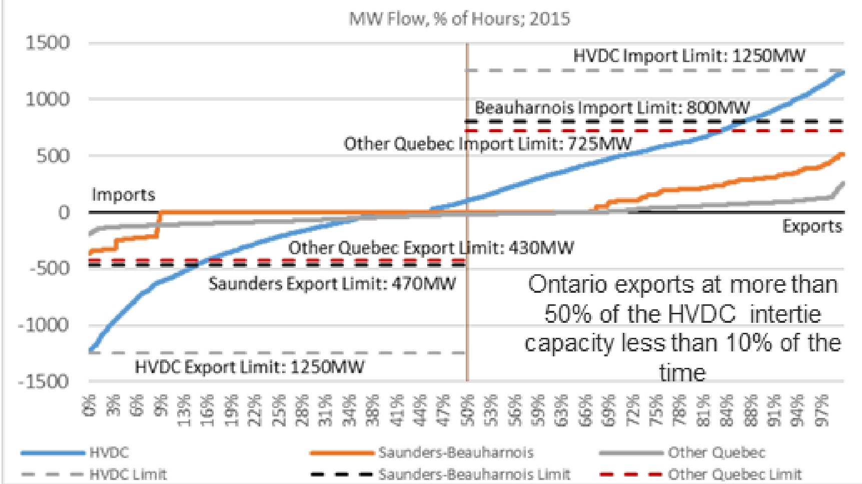
3.1.3. Peak Reserve Requirements and Interties

Existing intertie capacities are sufficient to meet current forecast peak needs which allows for the current Ontario-Quebec MOU. The interties with Quebec consist of three operational groups, which regionally represent significant blocks of capacity with different operational constraints as explained earlier. Figure 12 shows the flows across the three operational groups of interties.

1. South Ottawa bidirectional HVDC link built in 2009 with a capacity of 1250 MW.
2. South East Saunders/Beauharnois segregated interties: These two hydro facilities on either side of the border switch the operations to either supply Ontario or Quebec. Blocks of up to 470 MW in Saunders capacity can be switched in as demand from Quebec rises in the winter. Otherwise this intertie is typically supplying Ontario with a capacity of up to 800 MW from Beauharnois.
3. Segregated facilities north and west of Ottawa offer up to 500 MW to Quebec and 725 MW to Ontario. The Ottawa supplies are dominated by the Chats Falls segregated capability that switches blocks of capacity onto the Quebec grid from the Ottawa area.

[23] NUG Framework Assessment, IESO, 2015

Figure 12 – Ontario-Quebec Yearly Intertie Usage



The Saunders/Beauharnois intertie by itself can practically address the 500 MW of capacity exchange recently agreed to by the two provinces. The actual flow of supply across this segregated intertie correlates with the Quebec winter and Ontario summer peaks respectively. This explains why the recent agreement between Ontario and Quebec could be made at no cost and with no identified need for construction of new generation capacity or consideration of upgrades to the HVDC line.

Once the IESO completes its upgrades to the Tx system in the Ottawa area to provide the needed relief to congestion internal to that zone, the interties will be able to support their full rated capacity.

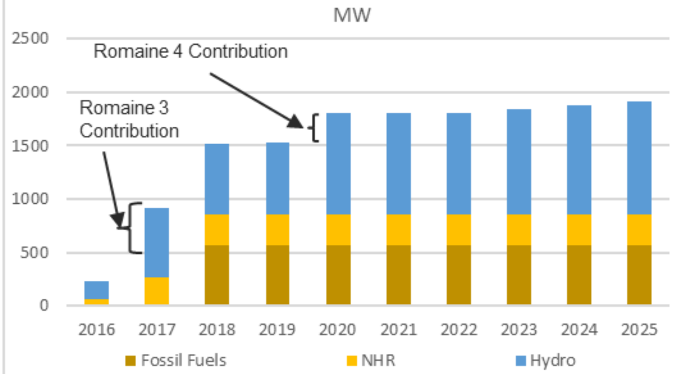
3.1.4. Planned Gas-Fired Generation & Peak Reserves

Ontario and Quebec are both planning on fossil-fired generation resources to comply with NERC's peaking capacity reserve requirements.

To meet the emerging peak reserve requirements, 30% of Quebec's planned peak capacity additions will be from fossil. Quebec is planning on 600 MW of new fossil-fired generation capacity as shown in Figure 13[24]. The 600 MW of fossil is 75% of the 800 MW new reserve capacity needs that have been driven by intermittent wind generation. This forecast requirement for an addition of 600 MW of fossil fired reserve capacity may have been a consideration for Quebec in reaching the agreement with Ontario.

[24] 2015 Long-Term Reliability Assessment, NERC, 2015

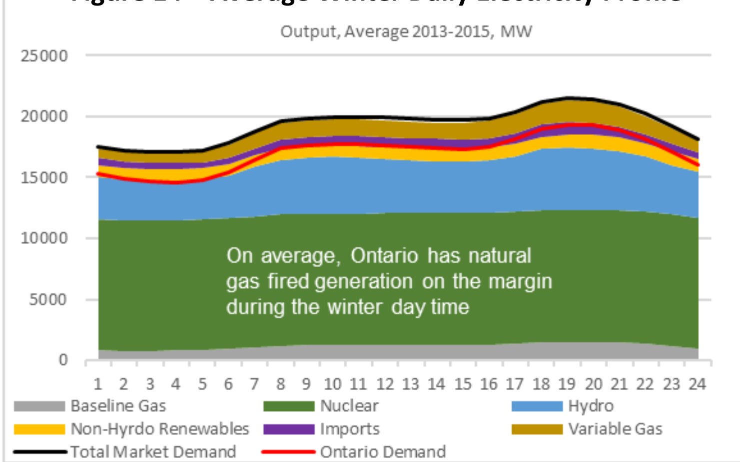
Figure 13 – Quebec Forecast Peak Generation Capacity



Expanding the interties and allocating firm peak reserve capacity commitments could potentially help Quebec avoid building some the fossil-fired assets it is planning.

Yet, even today, Ontario can only support Quebec's winter peak needs with natural gas-fired generation. Figure 14 shows the daily profile of generation during the peak winter months in Ontario for the past three years. All of the supply that exceeds the domestic demand line is gas-fired. The energy above the demand line is exported. Today, on-peak exports to Quebec could be argued to be generated by Ontario's gas-fired facilities. In the future, as the nuclear refurbishments proceed and subsequently the available low carbon baseload supply decreases, drawing on capacity reserves to supply greater exports to Quebec during winter peaks, will inevitably be from Ontario's natural gas-fired generation.

Figure 14 – Average Winter Daily Electricity Profile



3.1.5. Summary

The capacity of the existing interties should be adequate for the next 10 to 15 years to accommodate the forecast peak reserve capacity shortfalls of 500 to 1000 MW for Ontario to 2030 and 2000 MW for Quebec by 2025. Enhancing the interties by 2300 MW for the purpose of providing access to peak reserve capacity on either side of the border is not needed. Strapolec's analysis suggests this option is estimated to be 50% more expensive than the peaking gas-fired generation option recommended by the IESO.

Both provinces have fossil-fired generation supplying their respective peak reserve capacity needs. If Ontario were to be called upon to supply energy to Quebec during its winter peak, that energy would come from Ontario's gas-fired generation even today.

Forty to fifty percent of the peak reserve capacity shortfalls in both provinces have resulted from reliability impacts caused by the intermittent production from the added wind capacity. The added capacity requirements effectively increase the true cost of the useable wind energy by between $2.5/MWh to $10/MWh.

As these wind assets come to the end of their economic life, it may be more cost effective to replace them with more dependable low-carbon sources thereby reducing the need for gas-fired reserve capacity.

3.2. Smoothing the Intermittency of Renewables

Smoothing the intermittent production from renewables is interpreted in this report to mean shifting surplus non-hydro renewable energy to when it can be used. The need to "smooth" the intermittency of non-hydro renewables varies with each type of renewable generation:

Biomass: There is no urgent need to "smooth" the output from biomass renewable generation as the production from biomass generation is controllable, much like a gas-fired generation plant

Solar: The intermittency of solar generation stems primarily from cloud cover and seasonal factors. Since solar energy largely arises during the higher demand day-time hours in Ontario, the hydro and natural gas-fired generation assets currently address much of the intermittent production. There is an emerging surplus solar generation challenge where surplus solar exceeds the daily storage capability of Ontario's hydro capacity. Direct analysis of solar implications is difficult as most of it is installed as embedded generation within the local distribution networks with production not reported by the IESO.

Wind: Intermittent wind generation varies significantly at all hours of the day. There is poor correlation between wind energy generation and energy demand from the electricity system. As with solar, managing the intermittency challenge is less severe during daytime hours when the inherent flexibility of natural gas-fired generation can be leveraged.

Wind intermittency represents the greatest challenge to the management of the electrical system, given the distributed and significant installed capacity of wind generation that has been developed in Ontario and the aforementioned correlated production variability at any hour of the day. This study focusses on an analysis of the wind conditions in the province as this wind generation data is readily available.

Topics in this section of the report include:

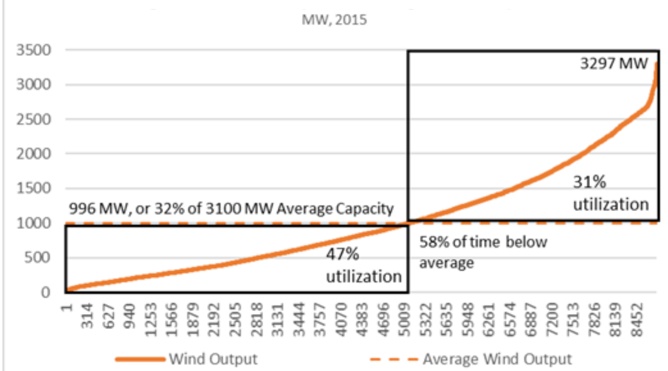
- An examination of the nature of wind intermittency and the characteristics of a storage system that would be required to accommodate Ontario's currently installed and planned wind capacity;
- The different forms of intermittency, from hourly to seasonal, are described and related to the current use of the interties;
- A description of the degree to which Quebec is already providing a "smoothing" function, including an assessment of the contribution of wind to the current surplus baseload generation (SBG) situation in Ontario;
- An examination of the nature of Ontario's zonal Tx system with respect to the location and flow of Ontario's wind capacity output; and,
- Finally, a discussion of the implications on the capacity of the intertie with Quebec.

3.2.1. Wind Variable Output Challenge Implications for Storage

The assessment of wind intermittency in this report focusses on how the Tx interties with Quebec may best be leveraged to accommodate it. For expanded Tx interties to be helpful in smoothing wind generation, HQ would need to absorb wind when it is in surplus and, through some accommodation via its hydro resources, effectively store it for delivery back to Ontario when needed. If this function is also to contribute to the reduction of Ontario's GHG emissions, the stored energy would ideally be supplied back on-peak to displace gas-fired generation.

It is important to note that there is variability in the magnitude of output from wind farms. Figure 15 illustrates the output of Ontario's wind farms in 2015 for each hour in the year, ordered by the power output. This figure illustrates how often wind generation is producing power.

Figure 15 – How Often Wind Produces Power



In Ontario, there was ~3100 MW of grid-connected wind in 2015. At the beginning of 2015 Ontario had ~3000 MW of installed wind capacity, and by the end of the year that had reached ~3300MW. Ontario's 2013 LTEP estimates the province's installed wind capacity to reach~6500 MW by 2025. The average hourly wind production in 2015 was 996 MW as shown in Figure 15[25]. This represents an average operating factor of 32%. As an illustration, it is assumed that the role of a combined wind/storage system is to act like a smoothed energy supply that can track the demanded energy from it. Using this simplified baseload model, the objective of the storage system is notionally to absorb any wind energy that arises above the average output and then provide the energy back to the system to sustain an average output flow. To fully accommodate the wind in that manner, the input capacity of a storage system, or in this case the intertie to Quebec's hydro reserves, would have to be 68% of the wind capacity, or approximately 2250 MW today. By 2025, the capacity needed could grow to 4400 MW. This future need is higher than the current export capacity of the interties and also higher than the 3300 MW scenario evaluated by the IESO at the estimated cost of $3.3B.

[25] Installed wind capacity at beginning of 2015 was 3000 MW, at end of year it was 3300 MW, for an average of ~3100 MW. Wind generation operating factor was 32%.

To return the power to Ontario, the import capacity would have to be 32% of the installed wind capacity. This equates to an import capacity of 1000 MW today and 2100 MW by 2025. These levels are largely within the capacity limits of the interties today.

To facilitate cost estimating, the analysis assumed that all of the wind capacity is located near the Ontario border and Quebec's storage capability is similarly located in close proximity on its side. While this is clearly an unreasonable and oversimplified assumption, it is useful for the purpose of conceptualizing the cost of a best case scenario for an integrated renewable storage capability. How much of Ontario's wind actually gets delivered to the Quebec border is discussed later.

Assuming average production as the reference case for Ontario, 58% of the time Ontario would be importing from Quebec to top up production, and 42% of the time Ontario would be exporting.

In the context of Tx build out to accommodate this scenario, and based on Ontario's wind generation characteristics, only 27% of the capacity of the intertie would be used: 53% for 58% of the time to import at up to 44% of the capacity, and 31% of the intertie capacity for the 42% of the time Ontario would be exporting.

Under this hypothetical scenario, several assumptions are made to illustrate the added cost per MWh of the Tx investments: (1) all the energy could be delivered to the Quebec border; (2) the full suite of hourly, daily, weekly and seasonal storage functions could be supported; and (3) enhancing the interties would cost the same as the $3.3B investment estimated by the IESO, which would be recovered over 30 years. With these conditions, the Tx costs equate to a $63/MWh adder[26]. The premium on the supplied power that Quebec would charge for the storage service is discussed later.

Cost Implications

There is an implied bi-directional flow of intermittent energy, firstly into Quebec for storage and then accessing the "smoothed" hydro energy back out to Ontario. This implies that the energy will have to recover the Tx investment cost twice for a total of $125/MWh. The energy will also incur the line losses of the combined Ontario and Quebec grids twice. This is assumed to be 10% line losses for energy to get from southern Ontario to Montreal and an additional 10% in losses to get from Quebec's reservoirs to Toronto. Since the average cost of wind stated in the LTEP was $125/MWh, the combined 20% line losses add ~$25/MWh to the $125/MWh cost of wind for a total of $150/MWh. Then including the $125/MWh for the bidirectional Tx investment recovery yields a cost estimate that approaches $275/MWh for the "recycled" wind energy. If full costs were reflected, then the $7/MWh identified in section 3.2.4.1 as well as the $2.5/MWh additional reserve requirements discussed in Table 5 would show the total cost to rate payers of deploying wind as $285/MWh.

The next sections examine more closely the different forms that intermittency may take and how that may impact the interties with Quebec.

[26] Based on value calculated in Table 3

3.2.2. The Challenge of Intermittent Wind Generation

The variable and intermittent nature of wind generation output presents four different challenges

- **Seasonally:** Smoothing the anti-cyclical nature of wind across seasons
- **Weekly:** Harnessing the weekend production for when it is needed during the weekday peak periods
- **Hourly:** Absorbing hourly peaks and filling in hourly valleys
- **Daily:** Taking excess production at night and feeding it back during the day

3.2.2.1 Seasonal Variability

Annual wind patterns in Ontario affect the seasonal production from wind generation. Consequently, the pattern of wind production is counter-cyclical to the demand for electricity in Ontario as shown in Figure 16. Wind blows strongest in the spring and fall, when Ontario's demand is lowest, blows the least in the summer when Ontario's daytime demand is higher, and doesn't rise as average weekly demand grows in the winter. While it is generally recognized that Ontario's peak energy needs occur in the summer, it is notable that its average energy consumption is higher in winter. This is largely due to the seasonal difference between nighttime demand and daytime demand.

Figure 16 – Average Wind Output vs. Demand

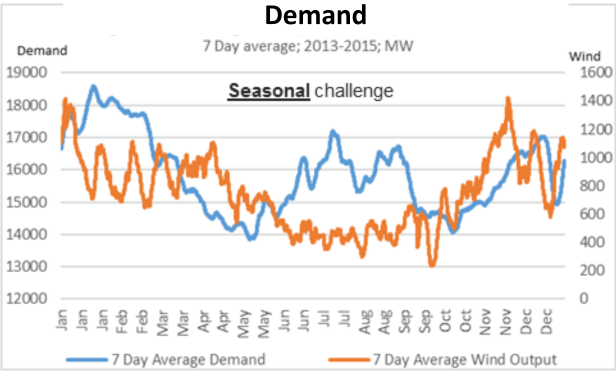
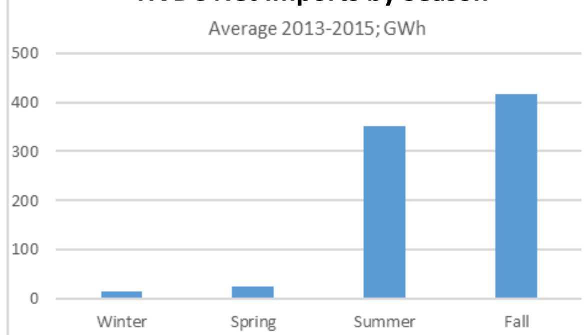


Figure 17 – Quebec South (Ottawa) HVDC Net Imports by Season



If Quebec were to provide a seasonal storage capability for Ontario's wind generation, Quebec would have to absorb generation from Ontario in the spring and fall and pass it back during the summer and winter.

A high level intertie analysis shows that net flows across the interface vary by season. In winter and spring the net flow is approximately zero, while Quebec is a net exporter to Ontario in the summer and fall. The annual net flow of energy between the provinces across the HVDC averaged 0.8 TWh from 2013 to 2015. The average imports were 2.3 TWh and average exports were 1.5 TWh. The seasonal behavior of the HVDC intertie in 2015 is illustrated in Figure 18. This figure shows what percentage of time the intertie is used to import energy to Ontario (upper right side of chart) or export energy (lower left side of chart) to Quebec.

Figure 18 – Quebec South (Ottawa) HVDC Intertie Usage by Season

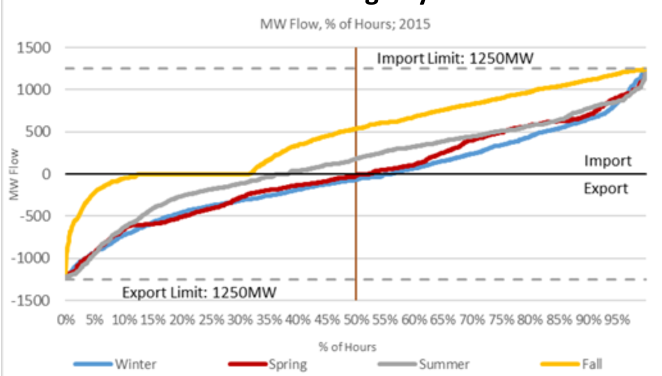


Table 6 - Annual Net Flows Through Quebec South (Ottawa) HVDC Intertie Average 2013-2015	
	TWh
Exports	1.55
Imports	(2.36)
Net Exports	(0.81)

In spring and winter, the imports and exports not only net out in total energy, but appear to be balanced in terms of the amount of time the intertie is used for the two functions. Quebec does not appear to want net energy from Ontario as the energy transfers appear to be balanced. In the Fall, a particularly windy season, there is a net flow to Ontario across the intertie for over 65% of the time, with a few peak export circumstances occurring only 5-10% of the time. In the summer, the intertie supplies energy to Ontario over 60% of the time, primarily to support Ontario's on-peak needs. As will be discussed later in this document, this practice is more related to daily smoothing than seasonal smoothing.

The notion of seasonal storage to help Ontario smooth its surplus from non-hydro renewables or even surplus energy from other sources is not apparent in the current practise. Given the overall low utilization of this intertie, the lack of a seasonal accommodation of wind is not because of any limitation of the physical intertie itself.

3.2.2.2 Hourly Variability

Figure 19 illustrates an analysis of wind patterns to quantify how much variability arises over different time spans. The figure shows that the variability, or change in magnitude of the wind, is more moderate on an hour to hour basis than it is on a daily or multiple-day basis. Table 7 summarises the variability characteristics for different periods of time.

Figure 19 – Change in Wind Magnitude

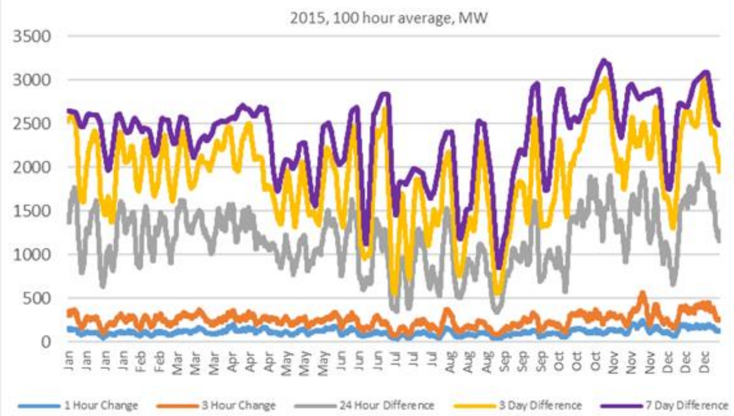


Table 7 - Average Change in Wind by Magnitude				
	MW	Average	Max	Min
Change	1 Hour	113	1412	0
	3 Hour	249	2014	0
Max less Min	1 Day	1170	3075	74
	3 Day	1905	3188	222
	Weekly	2353	3225	642

The average change in wind from hour to hour, or even over a three-hour period, was less than 250 MW in 2015. Peak variability did approach 1400 MW and 2000 MW respectively. However, when looked at over daily periods of up to a week, the average peak swings are on the order of 2000 MW and can be up to 3200 MW, almost 90% of the installed capacity.

The presence of hourly variability is why the segregated interties would not be optimal for this application as they are physically switched and transfer blocks of power and hence would be less efficient. Given the complexity of the operational and technical issues associated with an hourly variability analysis, Strapolec has focused this study more on the daily and weekly challenges of managing intermittent production from wind generation.

3.2.2.3 Weekly Variability

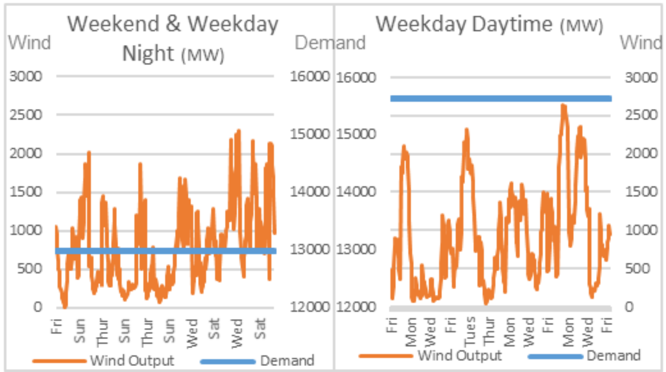
The weekly variability and intermittency challenges presented from wind generation arise when the resulting production is matched against the demand of electricity during two time periods:

1) Low demand periods (weekends and night time defined as 11pm to 6am);
2) High demand periods (weekday days defined as 7am to 10pm).

The left side of Figure 20 illustrates the wind generation that occurred in May 2015 on the weekends and weeknights contrasted with average demand of 13 GW at the time. The right side of the Figure illustrates the weekdays against the average demand of 15.7 GW. Given that the demand is higher in the day and that Ontario has a significant baseload capability, the objective of daily and weekly smoothing would be to transfer the wind energy from the low demand times to the higher times during the day on weekdays.

Figure 20 – Wind Intermittency Patterns

Wind Output vs. Demand (MW), May 2015



The Quebec interties are serving a modest weekly smoothing function to help balance Ontario's supply and demand between weekdays and weekends. Table 8 shows the total Gigawatt Hours (GWh) exchanged across the intertie by each season and as separated by weekends and weekdays. Note that there are 5 weekdays contributing to the weekday total and only 2 days to the weekend total.

During the week, Ontario has a net import of 867 GWh or 170 GWh/annualized-day. On the weekends, over the year Ontario exports 58 GWh or 27 GWh/annualized-day. Quebec typically absorbs energy from Ontario on the weekend and transfers it back during the week. Table 8 also shows that this effect varies by season. It is most pronounced in the spring, effectively negligible in winter, and is moderated in the fall.

Table 8 - Net Electricity Flows From Quebec South (Ottawa) HVDC Intertie by Season, Average 2013-2015

	GWh	Winter	Spring	Summer	Fall	Total
Weekday	Exports	456	180	209	193	1,037
	Imports	(445)	(295)	(582)	(582)	(1,904)
	Net Exports	11	(116)	(373)	(389)	(867)
Weekend	Exports	137	117	142	121	517
	Imports	(162)	(27)	(121)	(149)	(459)
	Net Exports	(26)	90	22	(28)	58

Figure 21 – Daily Electricity Flows Through Quebec South (Ottawa) HVDC Intertie

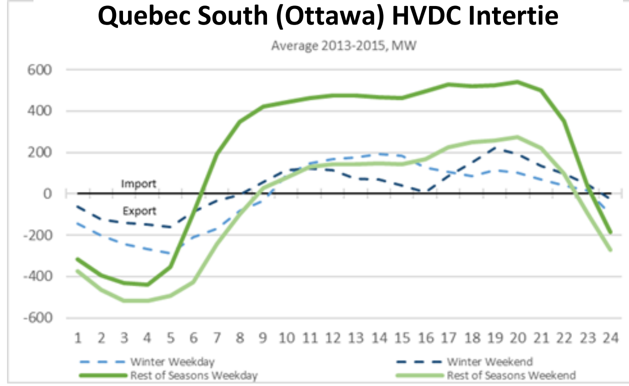


Figure 21 shows how the import and export patterns between weekends and weekdays vary with the seasons. It is clear that the winter season (blue lines) are negligibly different. When weekdays are contrasted against weekends, the rest of the seasons show a marked difference in both exports at night and imports in the day. While the drivers behind the observed patterns were not investigated for this study, a pattern is evident whereby Quebec absorbs energy on the weekend and returns it back during the week. The degree to which this is related to wind generation is explored later in the report. The distinct pattern common to all the data in Figure 21 is that exports occur at night and imports during the day. This is examined in the next section.

3.2.2.4 Daily Variability

The operational challenge is smoothing the intermittent production from wind generation to match the daily profile variation of demand. Demand variations across the daily cycle are a primary contributor to Ontario's SBG. Figure 22 illustrates the SBG challenge that arises in the spring and the fall. The yellow line represents wind generation and it is clear that most of the wind generation is above the domestic Ontario demand line (red)[27].

Figure 22 – Daily Intermittency Manifests as SBG

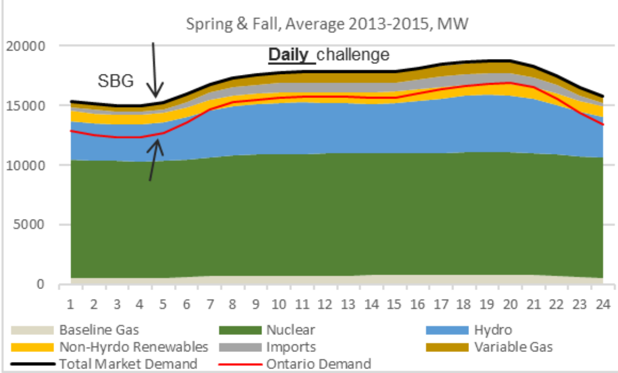
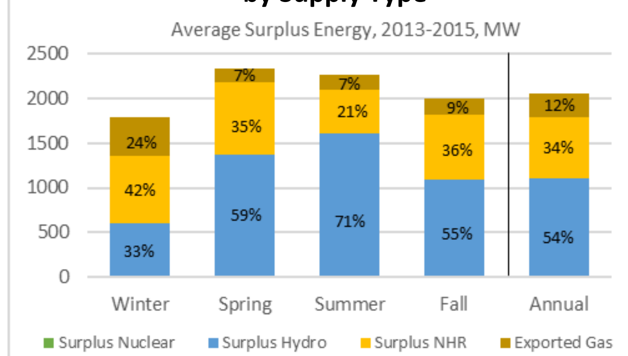


Figure 23 – Nighttime Surplus Energy by Supply Type



During the day, supply above the demand line is exported, usually in response to demand in the export markets. That is why imports are required along with gas-fired generation during the daytime hours (7am to 10pm). Outside of this range, supply above the demand line is generally surplus which also typically correlates with significantly lower average Hourly Ontario Energy Price (HOEP), the indicator that the energy supply is higher than demand.

Specifically, SBG is defined as the total generation, including imports, less Ontario domestic demand. Figure 23 shows the average composition for the last three years of the average daily MWh of surplus energy in the night time hours of 11pm to 6am[28]. The total yearly exported surplus during these hours is 4.2 TWh. Wind represents 34% of the SBG during these time periods over the year.

The mix of surplus that is exported changes by season. The cost of this surplus energy is summarized in Table 9. The net costs of this surplus is estimated at $550M/year, after netting out the HOEP received on

[27] Nuclear has been placed at the bottom of these illustrations as its capacity was committed to and came on line prior to the wind capacity.

[28] Note: Surplus variable gas is any gas >513MW, which is the average nighttime gas in summer, spring & fall. Surplus nuclear is negligible (<5MW)

the exports and using the 2013 LTEP average cost per unit type. Surplus wind, at a cost of $372M/year, represents over 70% of the total cost of SBG. Finding alternatives that take advantage of this energy would appear to be warranted.

Table 9 - Total Cost of Nighttime Surplus Energy, 2015

Cost ($M)	Winter	Spring	Summer	Fall	Total Cost	Cost Net of HOEP Received on Exports
Exported Gas	$ 14	$ 0	$ 1	$ 1	$ 17	$ -
Surplus NHR	$ 163	$ 76	$ 75	$ 81	$ 396	$ 372
Surplus Hydro	$ 54	$ 48	$ 76	$ 26	$ 204	$ 177
Surplus Nuclear	$ -	$ 0	$ 0	$ -	$ 1	$ 1
Total Cost of Surplus	$ 231	$ 124	$ 153	$ 109	$ 618	$ 550

Yet, this simplified assessment is net of spilled hydro and vented nuclear and only considers the specified nighttime hours. The full challenge of surplus energy related to intermittent wind generation may be higher and is explored further in upcoming sections of this study.

3.2.3. Role of Interties in Daily Smoothing of Ontario Demand

Ontario has several interties, that all play a role in managing night time SBG. Figures 24 and 25 show the average energy flows by hours of the day across the interties in 2011 and 2015, respectively. These two years are selected because 2011 predates when most of Ontario's wind capacity came on line and 2015 is the most recent full year.

Figure 24 – Average Daily Intertie Flow 2011

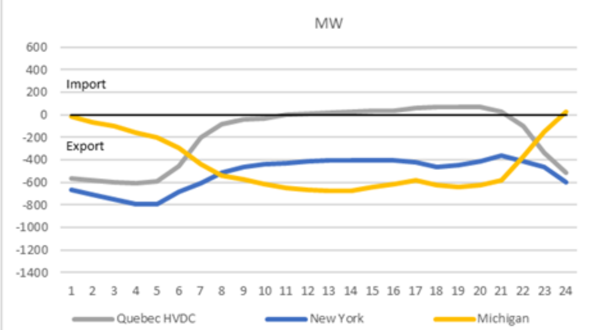
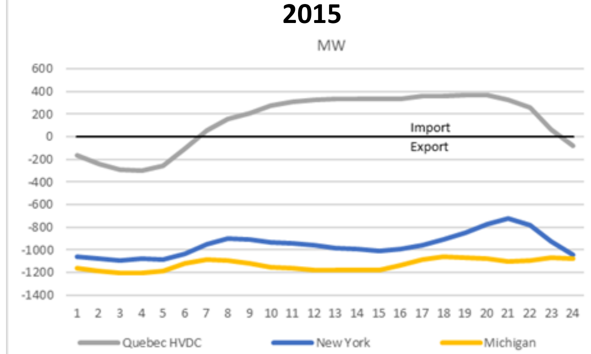


Figure 25 – Average Daily Intertie Flow 2015



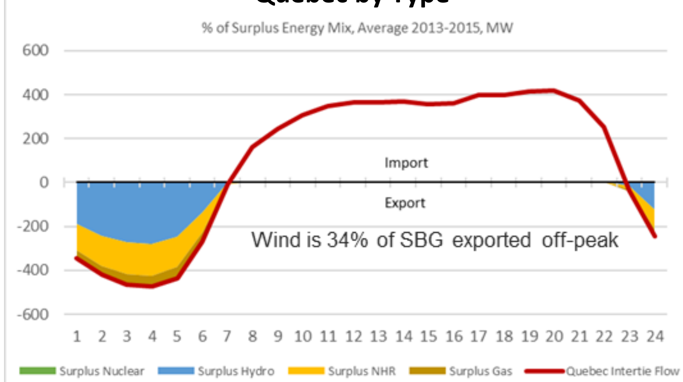
The role that the Quebec interties play in smoothing Ontario's SBG is clearly apparent in both years. In 2015, both Michigan and New York have similar import patterns throughout the entire day suggesting these two jurisdictions are not playing a role with respect to Ontario's SBG. However, Michigan in 2011 had no imports from Ontario at night and now their night time imports are greater than some of their daytime imports. This suggests that some of Ontario's SBG is now headed to Michigan. New York's profile of energy flow across the intertie has modestly changed its shape but, like Michigan, it is seeing much higher imports today.

Quebec has the only intertie with a consistent pattern of flows out of Ontario at night and with offsetting flows into the province during the day. As such, the concept of smoothing in practice can today only be attributed to Quebec. The shift in flows from Quebec being a net importer of energy from Ontario in 2011 to a net exporter of energy to Ontario in 2015 is explored further in Section 3.3.

3.2.3.1 Quebec's Daily Smoothing of Wind Supply

In general, Quebec's current smoothing activities can be mostly attributed as a response to Ontario's night time surplus baseload energy. As shown in Figure 26, however, wind does make up 34% of the surplus.

Figure 26 – Nighttime Energy Flows to Quebec by Type



As wind generation is independent of demand, its presence impacts many aspects of Ontario's energy system. The impact of wind energy on intertie activity overall is illustrated in Figures 27. Figure 28 shows the average daily profile of intertie flow by hour. It is clear that during the day Ontario imports less energy when the wind is on and similarly exports more when the wind is on at night. When wind is blowing in Ontario, it either reduces the amount of energy imported from Quebec or increases the flow of exports to Quebec, depending on the demand situation.

Figure 27 – Quebec South (Ottawa) HVDC Average Flow Wind On vs. Off

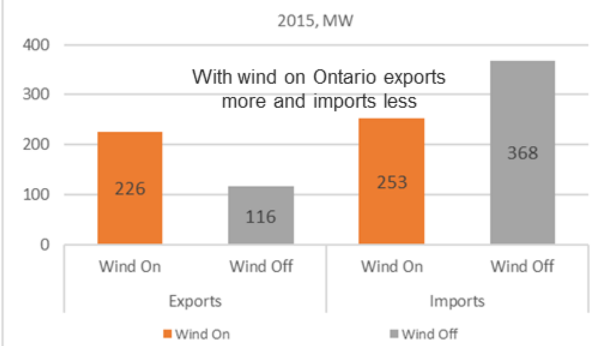
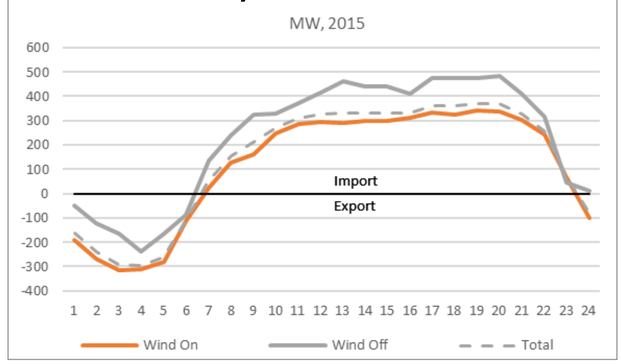


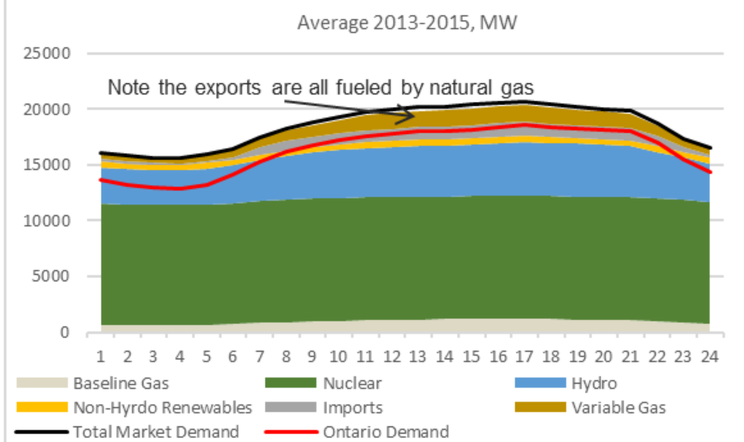
Figure 28 – Quebec South (Ottawa) HVDC Daily Flow Wind On vs. Off



3.2.3.2 Benefits of Imports from Quebec

Imports from Quebec contribute to meeting Ontario's domestic demand. Figure 29 shows the average daily profile by hour in the summer for the last three years.

Figure 29 – Weekday Summer Electricity Generation Profile



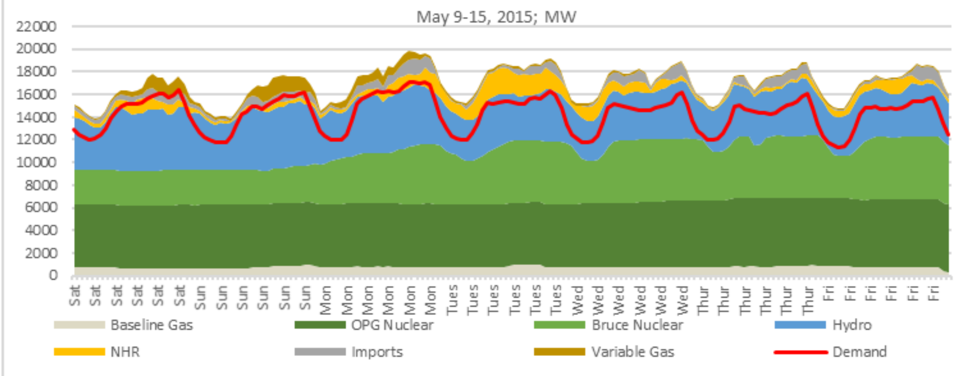
Excluding impacts of embedded generation

The smoothing function of Ontario's total SBG is already provided by Quebec and is helping to reduce emissions in Ontario. In fact, if Ontario did not export gas-fired generation to the U.S. in the summer, this high level assessment suggests there would be little need for gas-fired generation and the associated emissions. Summer is currently when much of Ontario's emissions occur, the rest arise in winter when Ontario cannot import electricity from Quebec due to Quebec's generation capacity limitations.

3.2.4. Wind Within Ontario's Electricity and Transmission Network

The IESO has been focused on managing the intermittent production from Ontario's wind generation and the province's SBG for some time. To manage the intermittency of non-hydro renewables, the IESO dispatches many supply resources. Figure 30 illustrates the demand and associated supply mix response for a typical week in May. Generation above the red demand line represents exported energy. The term "surplus" tends to relate to energy generated during low demand periods, usually at night. In Figure 30, the exports at night could be viewed as surplus, but these are already net of curtailed energy.

Figure 30 – Weekly Surplus Energy Patterns



Wind production is highlighted in yellow. As noted earlier, the data used to calculate the contribution from wind generation is based on actuals and does not include the impacts of the IESO's dispatching decisions that result in the curtailment of nuclear and hydro resources. Figure 30 illustrates these dispatching decisions.

The first significant observation is the nighttime curtailment of Bruce Power's nuclear generation when demand is low. This curtailment is much more pronounced when the wind generation is high (differences between Tues/Wed and Thurs). As well, closer inspection reveals that hydro is visibly curtailed during the high wind periods (Tuesday vs Monday). A similar impact on imports is also evident between Tuesday and Thursday. Mid-day demand dips on the Wednesday and Thursday indicate embedded solar production may also be influencing demand on the grid.

Additionally, Figure 30 shows the progression of the dispatch of Ontario's supply resources on the Monday and how the nuclear capacity at Bruce is ramping up from the weekend with support of gas-fired generation.

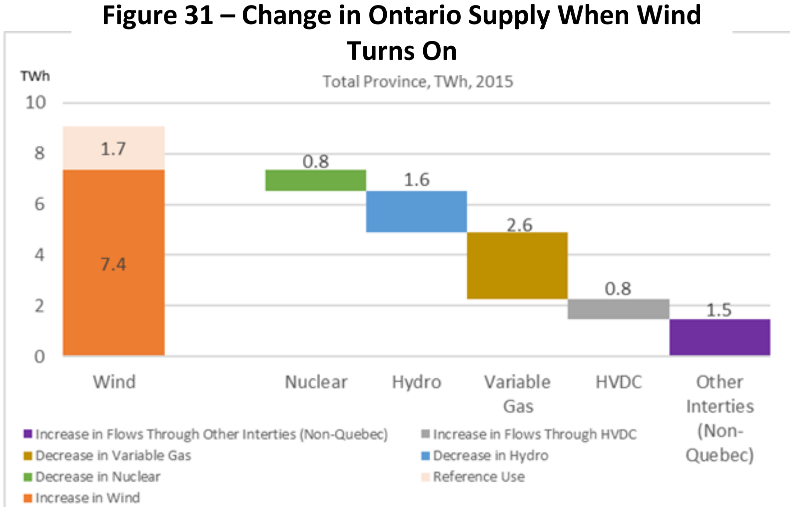
Wind production appears highly correlated with hydro and nuclear curtailments as well as decreased imports and increased exports. The question addressed by the next section is how much supply is curtailed or "wasted" overall in the province as a result of accommodating wind generation. In this report "wasted energy" is supply that has no matching demand and hence must be dispatched by some method that is generally not economical. Without a storage capability, electricity must be used when produced or "wasted". The pricing implications of wind production are explored later in this report.

3.2.4.1 Provincial Level Assessment of Wind on the Dynamics of Ontario's Supply Mix

Strapolec conducted a detailed analysis of wind patterns and the patterns of production from other generation sources. The analysis examined how the supply mix changes when wind production is or is not present[29]. The analysis was conducted under all demand conditions individually for the four seasons, whether it is weekend or weekday, and whether day-time or night-time.

The results for all of Ontario are provided in Figure 31. When wind generation is present it causes three distinct reactions of similar magnitude in the dispatch of Ontario's supply resources: (1) the curtailment of both nuclear and hydro; (2) the export of wind generated electricity; and (3) the reduction of natural gas-fired generation. A conservative estimate of the useful wind energy that results has two components: (1) the 1.7 TWh set aside for the reference case that represents the wind generation produced when operating at less than 10% of capacity; and (2) the 2.6 TWh that has been computed to directly offset natural gas-fired generation. The total useful wind energy therefore represents 4.3 TWh, or 47%, of the wind generation in Ontario. Over 50% of wind generation in Ontario is not productively used by Ontarians. It could be viewed as being wasted through curtailments or uneconomic exports. Further export pricing implications are discussed at the end of this section.

Figure 31 – Change in Ontario Supply When Wind Turns On



It is notable that the amount of wind energy exported to Quebec is 0.8 TWh, or less than 10% of the production from Ontario's wind generation. This suggests that Quebec is accommodating almost 10% of Ontario's wind energy variability and, as shown earlier, does so throughout the day.

Looking at the dynamics of wind generation under different demand conditions shows that the Ontario electricity system sometimes responds differently. For most of the time, wind generation results in

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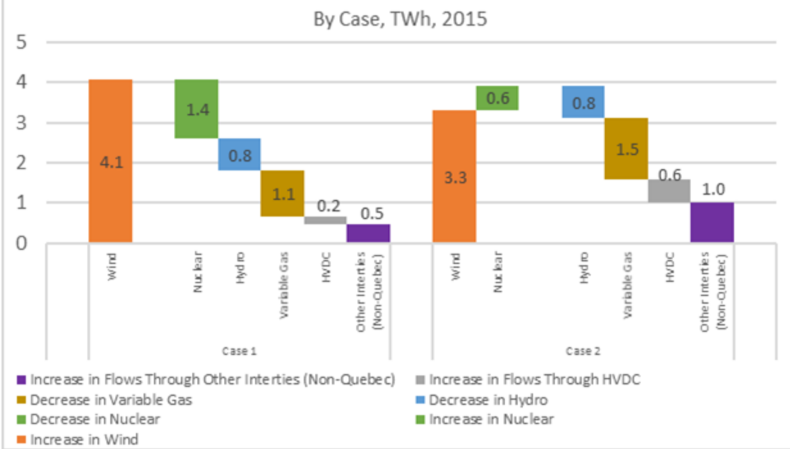
[29] The analysis used a threshold of 10% of installed wind capacity to define when wind was "On" or "Off". The "Reference Use" of wind thus represents the energy produced by wind generation when it is operating at less than 10% of the capacity. The impact of the use of this threshold on the analysis is that impacts on the other supply types are likely understated in the charts.

significant curtailments and exports, with a modest offsetting of gas-fired generation. Given Ontario's very clean and low carbon supply mix, the offsetting of gas-fired generation by the wind generation is currently the only mechanism by which wind production can contribute to reduce GHG emissions from the province's electricity sector.

Two Cases have been identified in the analysis, and they are summarized in Figure 32:

1) Case 1 which curtails all other supplies when wind generation increases;
2) Case 2 which is coincident with increased nuclear generation.

Figure 32 – Provincial Level Wind Patterns



Case 1: winter weekday, spring weekend day, summer

Case 2: winter weekend, spring weekday, spring weekend night, fall

Case 1 shows that substantially more nuclear generation is curtailed than indicated by the aggregated provincial results in Figure 31. Case 2 demonstrates an increase in nuclear when wind increases, a counter intuitive situation. This occurs during the spring and fall and on winter weekends. Additional nuclear generation appears at the expense of additional curtailed hydro and greater exports. Increases in nuclear that appear to correlate with changes in output from wind generation are more a consequence of the constraints on maneuvering nuclear units than a direct response to the variability of wind output. The maneuvering of nuclear in this way is a symptom of weekly smoothing, where the capacity is adjusted in response to/anticipation of production from wind generation that will last several days. Wind patterns typically last more than a day. When a nuclear unit at Pickering or Darlington Nuclear Generating Stations is maneuvered off, it takes several days before the unit can be brought back on due to normal shutdown and start-up procedures.

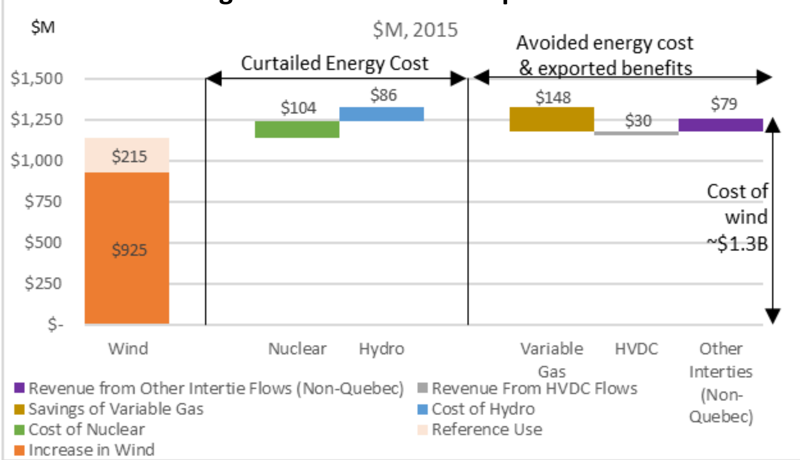
For this same reason, some of the identified decreases in natural gas-fired generation are actually wind induced and so the data in this report may be overstating the benefit that wind is providing in offsetting gas-fired generation. The details of this observation were not explored.

There are two conditions where this situation can occur, both are outcomes of the wind being at its strongest seasonal cycle. First, in the spring, the IESO has significant maneuverability potential from its hydro capacity with the spring freshet. The IESO can integrate the hydro with a nuclear fleet maneuvering strategy. Secondly, in the fall, the IESO attempts to manage its nuclear fleet maneuvering as a whole by off-cycling the Bruce and Ontario Power Generation (OPG) units.

Cost Implications

Figure 33 summarizes the cost implications of wind energy, including the additional nuclear curtailment. The production of the 9.1 TWh of wind costs ~$1.1B based on LTEP 2013 calculations. The various adjustments include the displaced 2.4 TWh of nuclear and hydro (adds $190M to the cost) and the displaced 2.6 TWh of natural gas-fired generation (cost savings of $148M). The total revenues from exports, however, are negatively impacted by wind production despite the increase in export volume. While some revenue is received for the exports, as shown by the exports to Quebec which positively contribute $30M, exports to the U.S. have a negative impact on HOEP, which impacts the price received for all exports. This causes a net loss of revenue on the order of $80M. The implications across all exports are explored further in Section 3.2.4.4. After considering the cost of production, avoided energy costs, and impacts on income from exports, the net cost of wind generation approaches $1.3B. The discussion of Figure 31 showed that 4.3 TWh of wind energy is useable within Ontario. Dividing the $1.3B into 4.3 TWh yields a value of ~$290/MWh that represents Ontario's true cost of wind generation based on IESO actuals.

Figure 33 – Wind Cost Implications



The results in Figure 33 represent the costs of the commodities involved, and include the additional savings on gas-fired production due to wind induced lower HOEP, as well as the equivalent losses on exports. These costs do not reflect Tx costs and the previously identified $10/MWh cost of peak reserve capacity that is incurred by the system due to the presence of the wind capacity.

There are no known, readily accessible data sources that identify Ontario's costs for the investments made in Tx to connect the wind farms. Two other sources, one from the U.S. and the other from Quebec, provide estimates of the costs of connecting wind. The EIA estimates a $5/MWh cost for this Tx. At a 30% exchange rate, this equates to approximately $6.50/MWh. In Ontario's case, since only half the wind is useable, this would represent a cost of $13/MWh. Quebec invested $900M in its Tx system to accommodate 2000 MW of wind capacity. Assuming a 34% operating factor over 20 years, this would equate to ~$7.50/MWh, slightly higher than the currency converted EIA estimate of $6.50/MWh. At the less than 50% utilization rate, an additional $15/MWh would be added to Ontario's effective cost. An average of the results of the two sources would suggest a cost of $14/MWh.

Combining the peak reserve capacity cost of $10 from Table 5 and Tx connection cost with the cost of the commodity results in a total unit cost of Ontario's wind energy amounting to ~$300/MWh ($314/MWh calculated).

3.2.4.2 Ontario's Transmission System and Zone Behaviors

Strapolec investigated the factors that have led to less than 10% of Ontario's wind energy currently being delivered to Quebec. Key factors appear to be more related to demand, the structure of Ontario's Tx system, and the associated geographic zone characteristics within the province, than they do to the physical nature of interties with Quebec.

The objective of Strapolec's zonal analysis is to identify how zonal specific demand and dispatching decisions may be impacting the transfer of wind energy through the zones and influencing the choices to curtail hydro and/or nuclear. Ontario has 10 geographic zones as defined by the IESO. The Tx system enables energy to pass between the zones as illustrated by the Tx system structure shown in Figures 34 and 35[30].

Figure 34 – Ontario's Major Internal Transmission Interfaces

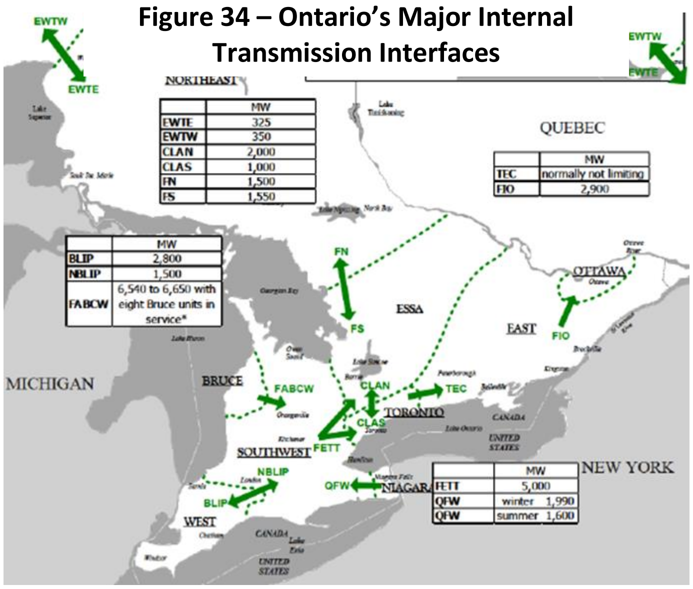
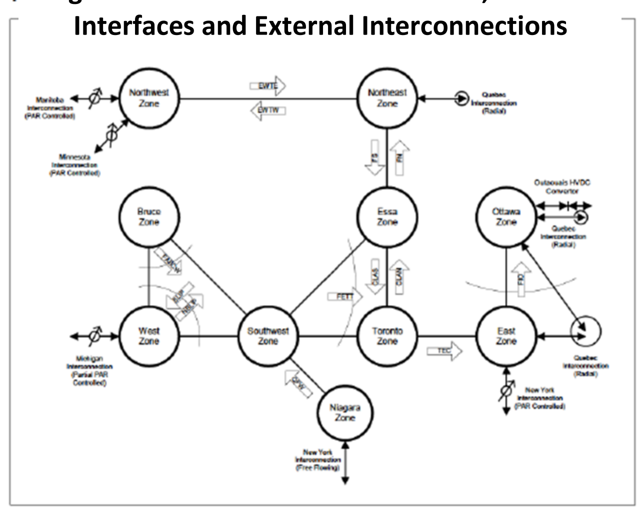


Figure 35 – Ontario's Internal Zones, Internal Interfaces and External Interconnections



Notes to Figure 4.3.2:

1. FABCW = FABC + MW Output of Wind Farms near Bruce Zone

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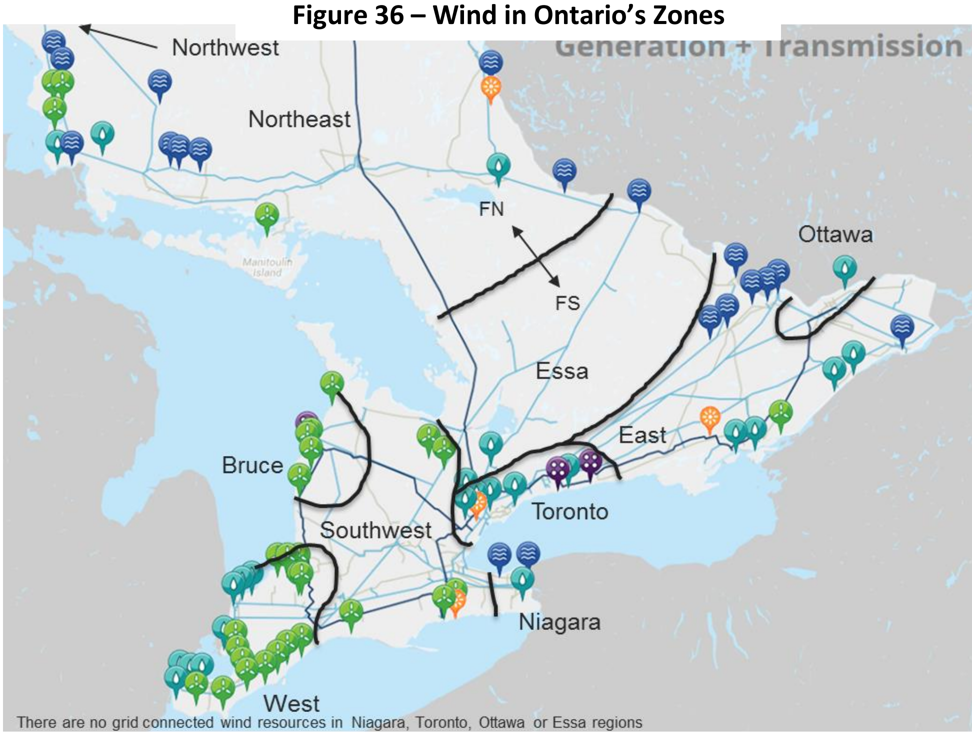
[30] Replicated from Ontario Transmission System, IESO, 2015

Energy generally flows into the Southwest Zone from the Bruce Zone (Bruce Nuclear Station and wind) and the Niagara Zone (hydroelectric stations). Energy then generally flows out of the Southwest Zone to the West, Essa and Toronto zones. This process effectively passes on the Nuclear and Hydro from Bruce and Niagara respectively into Central Ontario. Energy also tends to flow out of the Toronto Zone into the East Zone (delivering OPG Nuclear) and then to the Ottawa Zone. Energy rarely flows west from Ottawa (less than 2% of the time).

In the North, energy generally flows (75% of the time) from the Northwest Zone to the Northeast Zone; however, flow volumes are small at +/- 200 MW. The Northeast has two small interconnects with Quebec and a link with Essa. Essa flows, typically in the +/-500 MW range, are approximately 50/50 in terms of the direction of the flows.

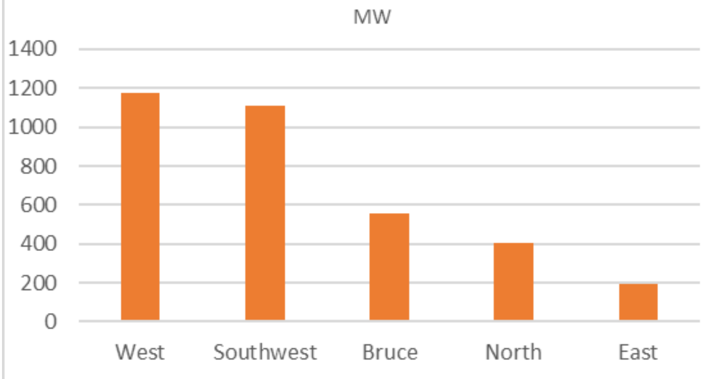
Figure 36 identifies where Ontario's wind assets are located.

Figure 36 – Wind in Ontario's Zones



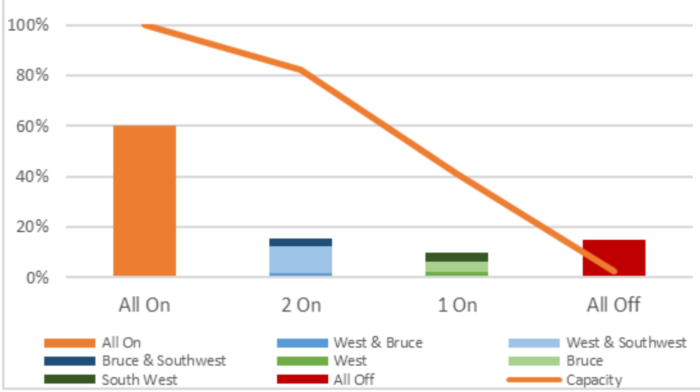
Most of Ontario's wind capacity is located in Southern Ontario's zones, over 800 km from the Quebec HVDC intertie near Ottawa. Most of the province's remaining wind resources are located in Northern Ontario, on the far western side of the province. Figure 37 summarizes the wind capacity located in each zone.

Figure 37 – 2015 Zonal Max Wind Capacity



Since Ontario's wind resources are located predominately in the southern and northwestern areas of the province, it is not surprising, as shown in Figure 38, that all the wind farms concurrently produce energy 60% of the time, and 80% of the capacity operates concurrently for about an additional ~20% of the time. This coincident operation leads to significant wind peaks being added to the grid with very little beneficial smoothing of the aggregated output by Ontario's wind portfolio.

Figure 38 – Wind Overlap in Southern Ontario

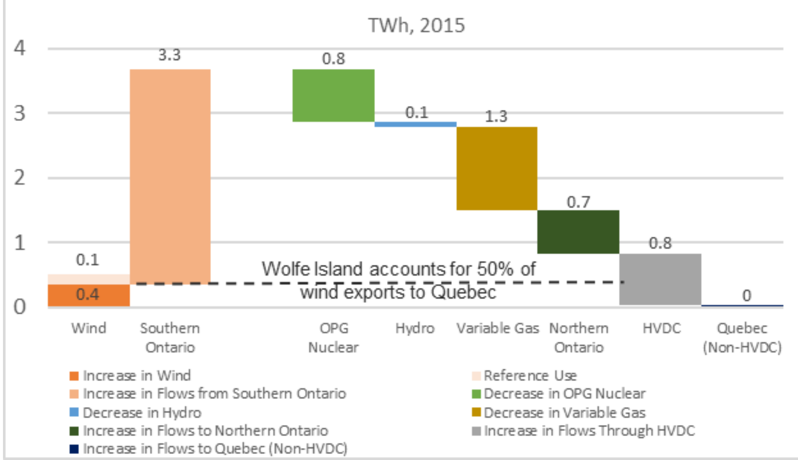


Detailed analyses of the West, Bruce, Southwest, and Ottawa Zones were conducted, as well as an assessment of several composite zone configurations:

- Southwest Zone with Niagara – to isolate the behaviour of the Niagara Falls hydro generation
- All of the Southwestern Ontario's regions, including Southwest, Niagara, Bruce and West, to present composite impact on the FETT Tx interface.
- A Central Ontario region that includes the Toronto, Essa, East, and Ottawa zones illustrates what is delivered to the Quebec interties.

The Central Ontario (Figure 39) composite region zone analysis provides several insights on the impacts of wind on specific generation sources. First, 3.3 TWh of Ontario's 9TWh comes into the Central Ontario region, primarily the Southwest zone. This gets added to the 0.4 TWh generated by the Wolfe Island wind farm near Kingston. As identified in the overall Ontario provincial analysis, the HVDC intertie responds to 0.8 TWh or 22% of the wind energy in the region. In the central zone, only 1.4 TWh of the 3.7 TWh of wind energy available is put to productive use in the region, through the offsetting of gas-fired generation or the assumed useable energy from the reference analysis. That is less than a 40% productive use of the wind energy. The rest of the energy results in curtailed nuclear generation, a small amount of curtailed hydro, and transmission to the Northern zone.

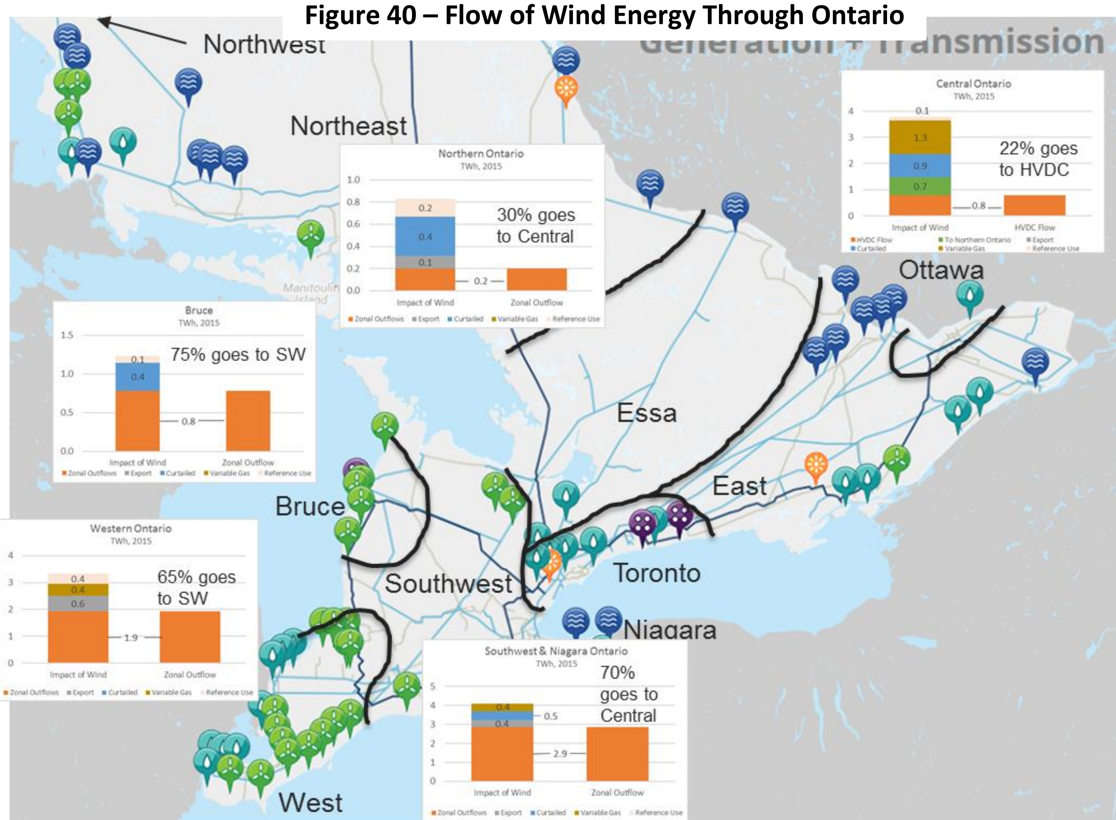
Figure 39 – Change in Central Ontario Supply When Wind Turns On



It could be argued that fully half of the wind energy delivered to the Quebec border may be coming from the Wolfe Island wind farm, suggesting that only 5% of the province's remaining wind energy moves through the Ontario system to arrive at the Quebec border.

Figure 40 summarizes how the wind energy in each zone is accommodated with surpluses flowing through the province.

Figure 40 – Flow of Wind Energy Through Ontario



3.2.4.3 Quebec Interties Capacity Profile

Figure 41 depicts the degree to which the capacity of the intertie is being used, whether wind generation is available or not. The export capacity of the HVDC is only approached less than 4% of the time. When the wind is not blowing, this limit is approached less than 2% of the time. Figure 42, replicated from Section 3.2.2.1 (Figure 28) of this report, shows on average how much additional capability exists to accommodate wind during the day and in the night when the challenge of surplus energy is much greater.

Figure 41 – Quebec South (Ottawa) HVDC Intertie Flow Wind On vs. Off

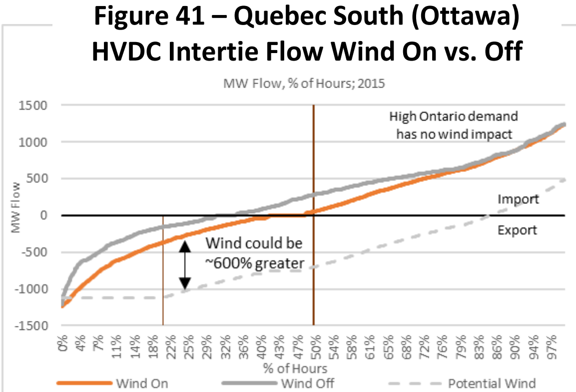
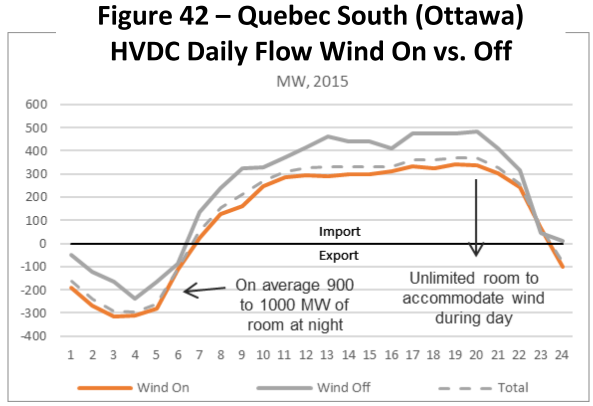


Figure 42 – Quebec South (Ottawa) HVDC Daily Flow Wind On vs. Off



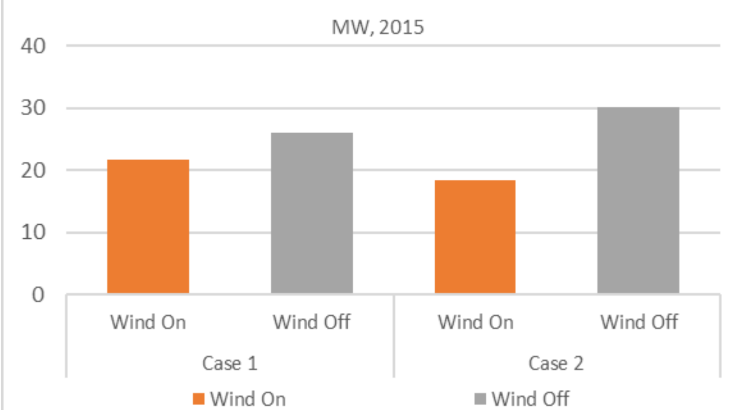
The data suggests that it is not the limitation of the intertie that is inhibiting wind energy from being delivered to Quebec, at least not for 96% of the time. If more wind energy could be delivered (or made available) to the intertie, and if Quebec wanted it, then the intertie could easily accommodate six times more wind energy than it is presently (at least 80% of the time). Considering that the intertie currently accommodates almost 10% of Ontario's wind production, this factor of 600% implies that up to 60% of Ontario's wind energy could be accommodated by the current interties, if the energy were delivered there. In 2011, Quebec imported twice as much energy at night than it did in 2015 as shown in Figure 24. It would appear that the limit may be more related to Quebec's need for Ontario's surplus energy for either export to other markets or for management of its reservoir levels. This is discussed further in Section 3.3.

3.2.4.4 Export Market Demand Implications

The previous section showed that the interties with Quebec are under-utilized and not the cause of surplus wind energy going unutilized. This section looks at the broader issue of supply and demand in the markets around Ontario.

The first indicator of a supply/demand imbalance is the price signal. Figure 43, using the two cases introduced in Figure 32 as reference, shows how the HOEP varies depending on whether wind generation is present or not. When wind generation is producing, the HOEP is 20% less in the winter and summer, seasons of high demand in Ontario, and 40% less in the spring and fall when demand is lower.

Figure 43 – Average HOEP Price by Case When Wind Blows in Ontario



These lower prices correlate with export activity in or to U.S. markets. Figures 44 and 45 show how exports to the U.S. are 10% higher, at most times of the day when the wind generation is available. Since demand and wind generation are not correlated, this observation can be assumed to align with the lower prices. With the U.S. markets being driven by the variable cost of gas-fired generation, the U.S. markets will purchase wind energy when it is offered at prices below that benchmark.

Figure 44 – Average Daily Flow to Michigan, Wind On vs. Off

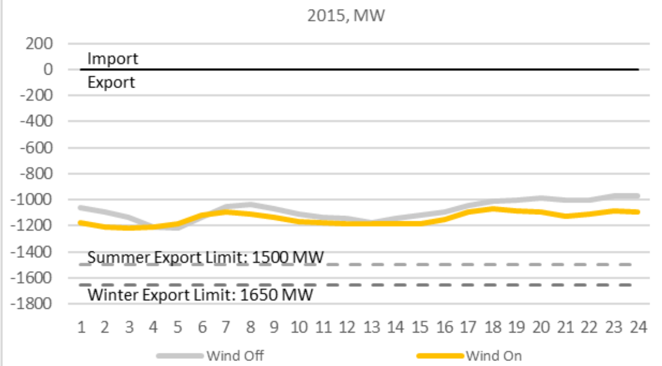
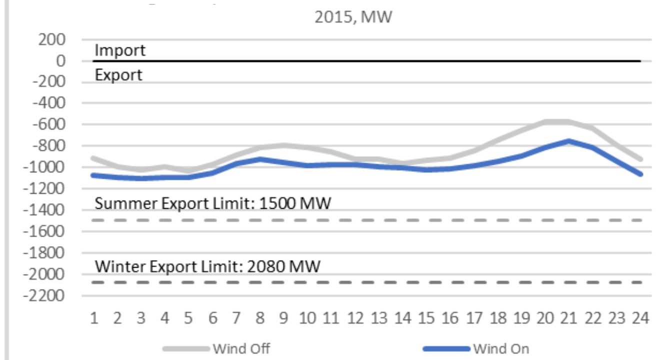


Figure 45 – Average Daily Flow to Michigan, Wind On vs. Off



There appears to be little difference between average intertie activity between noon and 2pm in the afternoon. This may correspond to peak demand in those states that are already being maximally served by the interties.

Figures 46 and 47 show the profile of intertie capacity usage for New York and Michigan, contrasting when wind generation is present or not.

Figure 46 – Michigan Yearly Intertie Usage, Wind On vs. Off

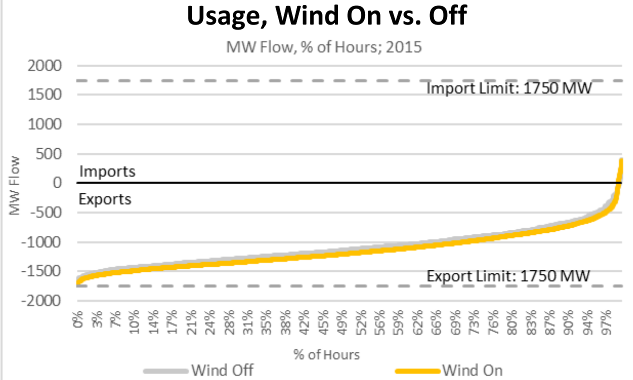
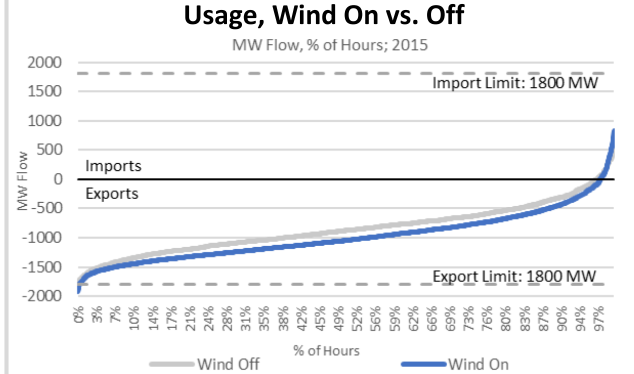


Figure 47 – New York Yearly Intertie Usage, Wind On vs. Off



The implication regarding the utilization of the interties is that Ontario may be exporting as much wind energy as these markets are willing to accept. It may also be that the interties are the limiting factor. The driver for the exports, however, is low cost electricity that is below the variable cost of natural gas.

The combination of limited intertie capacity with the U.S. for the wind surplus and limited demand from Quebec has forced the bottling of wind energy within the Ontario zones and created the need for the curtailment of Ontario's other low carbon energy sources.

The supply and demand situation in Quebec is discussed in Section 3.3.

3.2.5 Summary Implications

The challenge of smoothing renewables is largely confined to the large sporadic, intermittent, and unpredictable behavior of the wind generation. Over 50% of the generated wind energy in Ontario in 2015 was surplus and was wasted. An outcome that will most assuredly get worse as additional wind capacity is brought online in the next three years. The true cost to rate payers of the useable wind energy in Ontario is estimated here at over $300/MWh.

If the interties were upgraded to accommodate the full intermittency of Ontario's forecast wind capacity, the operating factor of the interties would be only 27%. Upgrading the interties solely for the purpose of smoothing wind energy production is a very high cost option that only adds to the overcapacity challenges that are driving up electricity costs in Ontario. The investments to enhance the interties, coupled with the need for wind energy to flow first to Quebec and then back to Ontario, would result in an effective cost to rate payers of recycled wind approaching $275/MWh. The enhanced intertie option provides no economic benefit over the current practice of "wasting" the wind energy. Using the interties to leverage the Quebec "battery" for smoothing wind energy would be a very inefficient and costly solution.

Moreover, the structure of Ontario's Tx system, coupled with the overall surplus of supply in Ontario and Quebec, inhibits the wind energy from being delivered to Quebec. Less than 10% of the output from Ontario's wind resources is currently delivered to the Quebec border. This is not due to imitations of the interties.

The supply and demand realities in Ontario are currently causing approximately 40% of the generated wind energy to be effectively bottled within the electrical zones of the Tx network. There is no demand from Quebec for this output east of Toronto. The need to consider building additional infrastructure to export 40% of Ontario's wind energy raises the critical question as to why Ontario has built that much wind capacity in the first place.

If Ontario's wind energy could be delivered, and assuming Quebec wanted it, the existing interties are capable of handling up to 600% more intermittent wind energy than they are today. To upgrade the interties beyond their existing capacity would only be beneficial if the Ontario grid and North American market demand would support delivery of the surplus wind energy to the Quebec border.

Given that the intertie capacity is underutilized, it is likely that there are additional factors in play that affect the exchange of energy between Ontario and Quebec. The next section looks at the future forecast supply mix of the two provinces.

3.3 Forecast Supply Reduction and Economic Implications

This section looks at the supply and demand forecast for Quebec and Ontario. First, Quebec is examined, including an assessment of the economic drivers behind Quebec's electricity exports. The cost of recent electricity generation investments in Quebec is summarized for reference, followed by a discussion of the province's practices for the purchase and sale of electricity with Ontario. The demand and supply mix forecast for Ontario is then discussed.

The findings in this section suggest that the future capacity retirements in Ontario and forecast demand growth in Quebec make all questions of peak capacity exchange and the smoothing of renewable surpluses moot. There will be insufficient low carbon energy sources to meet forecast demand in both provinces in the late-2020s and beyond.

3.3.1. Quebec Supply and Demand Forecast

Figure 48[31] illustrates how Quebec's supply and demand has changed from 2008 and is forecast to 2028. In the near term, Quebec is in a surplus situation, which is expected to erode over the next 10 years. HQs 2009 strategic plan identified over 10 TWh of new capacity additions by 2013. From 2008 to 2020, HQ will have created 27.5 TWh of new generation capacity, 21.8 TWh with the retirement of the Gentilly II nuclear generating station in 2012. The new energy supply comes from the following sources:

- 8.7 TWh (8 TWh after Tx losses) from 918 new MW at Rupert, Eastmain 1-A and Sarcelle that leverage additional output from the James Bay complex
- 8 TWh (7.4 after losses) from the Romaine complex
- 10.8 TWh of wind energy from 4000 MW of wind
- 1.3 TWh of biomass and small hydro

Figure 48 – Quebec Forecast

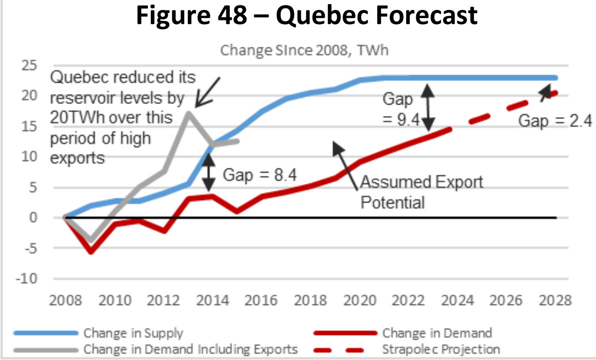
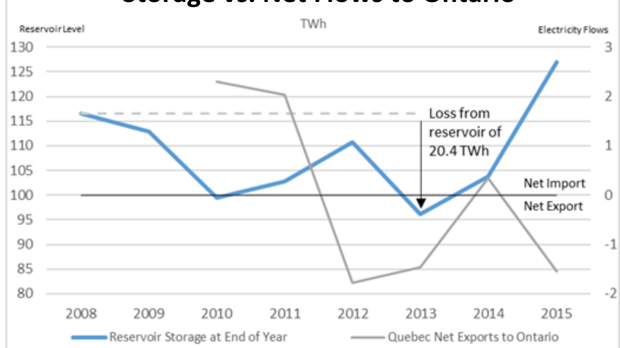


Figure 49 – Hydro Quebec Reservoir Storage vs. Net Flows to Ontario



[31] État D'Avancement 2014 Du Plan D'Approvisionement 2014-2023, Hydro Quebec Distribution, 2014; Annual Report 2015, Hydro Quebec, 2016; Maîtriser Notre Avenir Énergétique, Lanoue, R., Mousseau, N., 2014

Quebec's short-term energy supply surplus is supporting both higher levels of exports and enabling the replenishment of HQs reservoirs. As discussed earlier, the currently underway and planned capacity build outs are insufficient to meet Quebec's forecast peak capacity needs beginning in 2020.

In 2008, Quebec had a baseline 16 TWh of surplus, or 10% of its heritage pool. This surplus level was defined as "margin of flexibility and uncommitted energy". In its 2009 strategic plan, Quebec forecast a declining reservoir level from 116 TWh in 2008 to 99 TWh by 2013, a change of 16TWh. Actual reservoir levels, as shown in Figure 49[32], show the reservoirs dropped to a low of 95 TWh in 2013, coincident with a dramatic rise in exports reflected by the "change in demand plus exports" in Figure 48. HQ's 2015 annual report states that the reservoir levels have been restored to 123 TWh, reflecting the presence of the 2015 surplus.

The correlation of Quebec supply, its exports, and its reservoir levels also explains the results in Figures 24 and 25. In 2011, Quebec had a supply shortage. It nevertheless still pursued exports, at the expense of draining its reservoirs. Quebec needed energy from Ontario and subsequently took advantage of Ontario's low cost, nighttime supply. In 2015, Quebec had a surplus of supply, exported significant amounts of energy, and filled up its reservoirs. Currently, Quebec does not need any supply from Ontario and prefers to export during the higher priced daytime hours.

HQ is now forecasting demand will grow by 14 TWh by 2023, eroding the 2015 surplus of 13 TWh down to 9 TWh. Generally, Quebec's surplus energy is flexible in terms of when it is used. Yet, Quebec is forecasting that by 2023 it will need to begin importing 3 TWh every winter despite the overall provincial surplus at that time. Quebec is generation limited in winter even with large overall energy surpluses. Strapolec has extended the trend in HQ's projected demand growth to 2028 to illustrate how the supply gap may further tighten. The forecast supply gap in 2028 is only 3 TWh. This tightening of the gap between supply and demand suggests a need for Quebec to curtail its exports by 7 TWh, or by almost 25% from its 2014 levels of 27 TWh. This will return Quebec to export capacity levels similar to 2008.

This shrinking Quebec surplus and downward pressure on Quebec's export capacity undermines the potential for an increase in intertie capacity to actually enable Quebec hydro to flow in a net positive manner to Ontario.

3.3.2. Quebec Electricity Export Economics

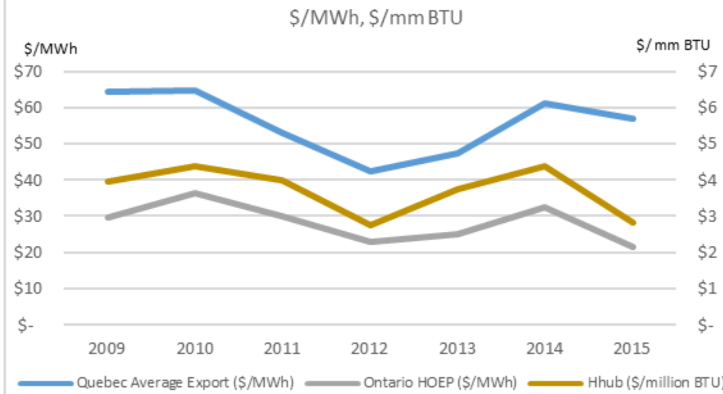
This section examines the economic benefits that Quebec is deriving from the export of electricity.

Figure 50[33] plots the average price that Quebec has realized from its exports of electricity since 2009 and compares the trend to the HOEP in Ontario and the reference price for natural gas from the Henry Hub

[32] Annual Report 2010, Hydro Quebec, 2011; Annual Report 2015, Hydro Quebec, 2016; IESO Data
[33] IESO Data; Henry Hub Natural Gas Spot Price, U.S. Energy Information Administration, 2016

(HHub) in Louisiana, the benchmark price setting exchange for natural gas in North America. It is very clear that the export market Quebec is selling into is heavily driven by the price of natural gas. Similarly, in Ontario, the HOEP is also determined by the variable cost of natural gas generation when that supply is on the margin.

Figure 50 – Average Yearly Electricity Price Comparison



The pricing of Quebec's exports declined from 2009 to 2012, but the margin gap between the HHub or HOEP reference appears to have recovered in 2014, likely due to the cold winter that year.

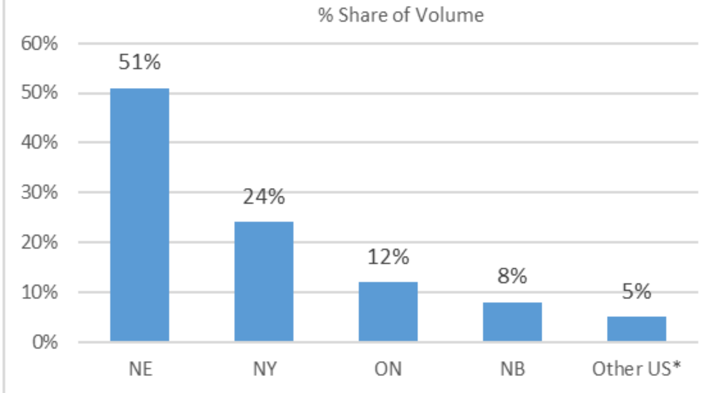
The declining value of Quebec exports is recognized in the province as being driven by recent market conditions, with five factors seen as impacting demand for Quebec's electricity exports and the price they can attract[34].

- Quebec domestic demand had softened, as it has in the entire region since the recession.
- U.S. markets have a "buy at home" policy, and are building their own renewables.
- Everyone has overbuilt non-hydro renewables, with wind in particular representing off peak surplus that is both depressing energy prices and increasing costs to consumers via the subsidies that have been provided.
- Investment in shale gas production has depressed both natural gas and electricity market prices.
- No premium is obtainable from the U.S. for clean hydro power.

Quebec's markets for electricity are summarized in Figure 51[35]. 80% of Quebec's electricity sales are bound for the U.S., with only 12% being to Ontario. Over 50% of Quebec's sales are to New England.

[34] Maîtriser Notre Avenir Énergétique, Lanoue, R., Mousseau, N., 2014
[35] Annual Report 2015, Hydro Quebec, 2016

Figure 51 – 2015 Hydro Quebec Exports by Location



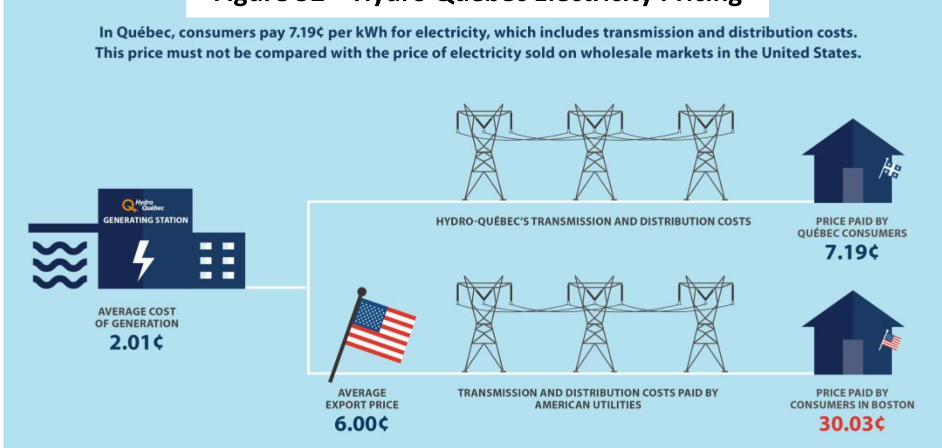
* Other refers to markets in the PJM interconnection (comprising electric utilities in 13 states in the eastern US and DC) and the US Midwest

As Quebec's prices have declined, HQ has been challenged regarding the sale price it has been receiving. In response, HQ has published an explanation of its pricing benefits as reproduced in Figure 52 which emphasises that Quebec's major reservoir assets cost close to 2 cents/kWh[36]. Hydro Quebec Production (HQP) suggests anything above that is margin. HQ makes this argument:

> *"This mistaken perception is often conveyed. Hydro-Québec does not sell its electricity at a loss on export markets—quite the contrary. Last year, electricity sales on neighboring markets generated profits of more than $800 million, a significant contribution to the dividend that will be paid to the Québec government. Energy generated in Québec at a cost of 2.01 cents was exported at an average price of 6.00 cents during the nine first months of 2015."*

Most of Quebec's energy is from James Bay and the Churchill Falls contract with NFLD-Labrador. A big chunk of the exported capacity comes from Churchill Falls purchases which are extremely cheap.

Figure 52 – Hydro Quebec Electricity Pricing



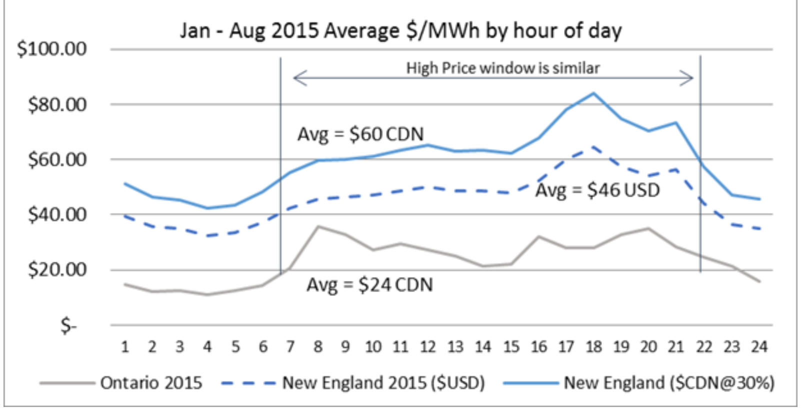
[36] Hydro Quebec website

The market price for Quebec's hydroelectricity is significantly impacted by the on-peak vs off-peak prices in Quebec's export markets. The export price realized is a function of market dynamics in those markets, which are driven today by the price of natural gas in the U.S.

The shale gas pricing challenge is equally relevant at the Quebec/U.S. border as it is with the Quebec/Ontario border. Ontario sells into the New York and Michigan markets which sets Ontario's HOEP during the peak hours.

Figure 53[37] shows how the electricity price in New England is much higher than in Ontario, at all times of the day. Ontario's low HOEP price is not only due to SBG but also to the general North American energy consumption patter of lower demand at night. New England's pricing thus reflects the same pattern of higher prices during the day. The commonality of peak demand times across the North American markets is echoed in the pricing profiles.

Figure 53 – Ontario vs. New England Hourly Prices



New England's pricing is much higher than Ontario's, even before currency exchange rate considerations, because it has natural gas delivery infrastructure bottlenecks[38]. This is likely to persist as New England continues to rollout new natural gas-fired generation in its strategy to reduce emissions.

The EIA's forecast for natural gas is shown in Figure 54[39]. The EIA's forecasts have been evolving in recent years and reflect an overall upward trend for gas prices in the future. The forecast price of natural gas in 2030 will approach ~ 5 cents USD million British Thermal Units (mmBTU), with or without the Clean Power Plan (CPP), almost double the price in 2015 where the HHub spot price for natural gas averaged $2.62/mmBTU, the lowest annual average price since 1995.

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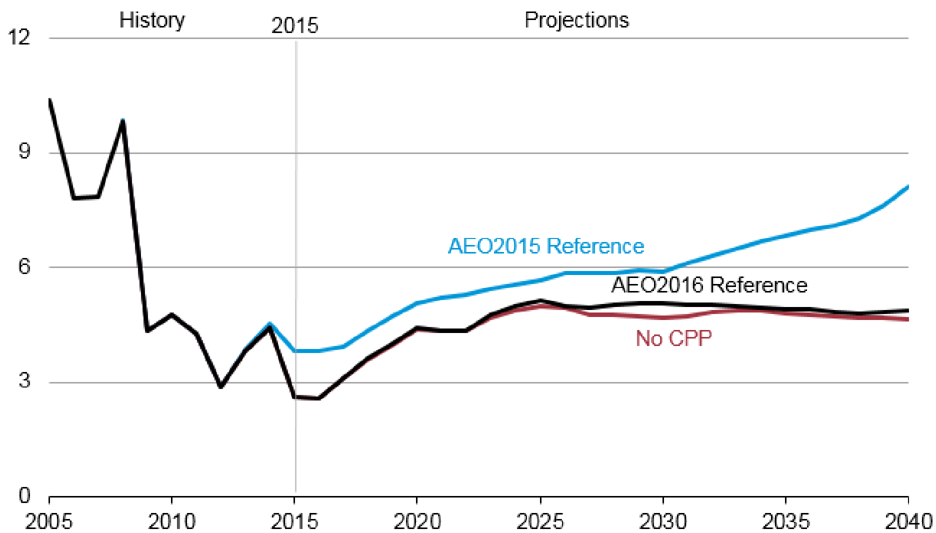
[37] ISO New England Data; Henry Hub Natural Gas Spot Price, U.S. Energy Information Administration, 2016. Figure assumes an exchange rate of $1.30 USDCAD
[38] New England Power Grid 2015-2016 Profile, ISO New England, 2015
[39] AEO2016

2015

Figure 54 – Average Henry Hub Spot Prices for Natural Gas

2015, $/ million BTU



Source: EIA, Annual Energy Outlook 2016

The implication for Quebec is that the New England market will continue to offer a higher premium on Quebec exports than Ontario. If the cost doubles as suggested by the EIA, then it is possible that Quebec will be seeking approximately $100/MWh in the future as the IESO suggested.[40]

3.3.3. Cost of Recent Quebec Electricity Generation Investments

The evolving supply mix in Quebec was discussed earlier in this section. A distinction exists between the HQP business and the Hydro Quebec Distribution (HQD) business. HQD pays 2.79 cents/kWh to HQP for the heritage pool[41]. HQP manages the James Bay hydro and other heritage pool assets, as well as the large new hydro generation station at La Romaine. HQD has invested recently in non-hydro renewables, which has offset its demand for the low cost reservoir energy from HQP. So there is a dichotomy within HQ itself that caught the attention of a recent Quebec commission report.[42]

The actual overall cost incurred for the new supply is between 8 cents/kWh and 9.4 cents/kWh. The blend is 8.1 cents/kWh, or $81/MWh as summarized in Table 10.

[40] Review of Ontario Interties, IESO, 2014

[41] Strategic Plan, 2009-2013, Hydro Quebec, 2009

[42] Maîtriser Notre Avenir Énergétique, Lanoue, R., Mousseau, N., 2014

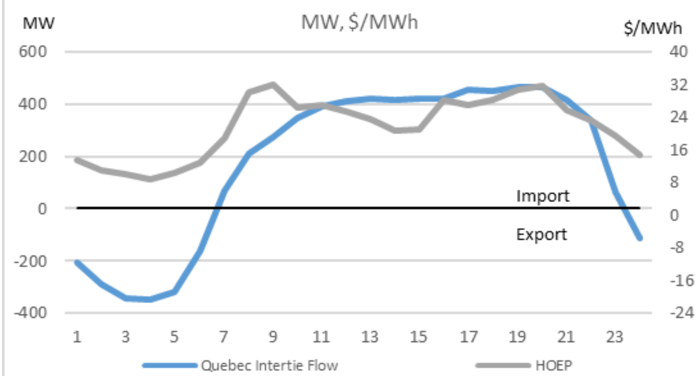
Table 10 - Cost of Recent Capacity Additions in Quebec			
	TWh	$M	$/MWh
New Supply	25.8	$ 2,064	$ 80.00
Latest Wind Procurements	2.2	$ 206	$ 93.64
Average			$ 81.07

Given the recommendations made in the 2014 commission report, it would be challenging for HQ to enter into long term firm contracts for new supply at less than cost. The IESO has also suggested that Quebec will not be willing to sell electricity at anything less than its cost to develop[43].

3.3.4. Quebec Purchase and Sale of Electricity with Ontario

Earlier sections of this report described the flows of electricity between the two provinces. Quebec is currently gaining a margin on the trading through the mechanism illustrated in Figure 55[44]. Ontario is importing electricity while the HOEP is high, and exporting it to Quebec when the HOEP is low.

Figure 55 – Average Daily Quebec Intertie Flow vs. HOEP Pricing



Peak hour prices are driven by marginal cost of gas. Off peak prices are a function of Ontario's SBG and the marginal cost of renewables and nuclear which are much lower than natural gas.

Table 11 shows Ontario paid Quebec on average $51M for imports in Spring/Summer/Fall, and sold $7M in exports, a difference of $44M. This $44M benefit to Quebec results from the difference of ~$22/MWh between the prices for on-peak imports to Ontario and the off-peak exports to Quebec that was transacted over the last three years. Outside of winter months, it is apparent that Quebec has benefited on average $44M/year for the last three years via this price arbitraging opportunity.

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[43] Review of Ontario Interties, IESO, 2014
[44] IESO Data; Henry Hub Natural Gas Spot Price, U.S. Energy Information Administration, 2016

Table 11 - Net Margin of Electricity Flows Through Quebec South (Ottawa) HVDC Intertie by Season; Average 2013-2015			
		Winter	Spring/Summer/Fall
GWh	Exports to Quebec	593	961
	Imports from Quebec	(607)	(1,755)
$M	Exports to Quebec	$ 29.50	$ 6.84
	Imports from Quebec	$ (24.51)	$ (51.02)
$/MWh	Price of Exports	$ 49.78	$ 7.11
	Price of Imports	$ 40.35	$ 29.07
	Net Margin	$ 9.43	$ (21.96)

Table 11 shows that exports to Quebec averaged 961 GWh while imports were 1750 GWh in the Spring/Summer/Fall for the past three years. The difference of approximately 800 GWh is coincidentally similar to the wind energy delivered to the Quebec border as discussed earlier (wind energy for the whole year). This difference could be interpreted as Quebec providing a storage service for the 800 GWh. At $22/MWh, Ontario is paying about $17.6M/year for the privilege of Quebec storing ~0.8TWh in the spring, summer, and fall and exporting it back during on-peak hours.

3.3.5. Ontario Supply and Demand Forecast

The IESO has recently communicated its supply mix update, largely reflecting the confirmation of the nuclear refurbishment program and the PNGS retirement in 2024. The supply contribution at peak was discussed earlier in this report. Strapolec has updated its Ontario market supply and demand forecast model to produce the following forecasted energy production mix.

Ontario's generation will be dominated by its flexible natural gas-fired fleet which will increase production by 60% after the PNGS retires as shown in Figure 56.

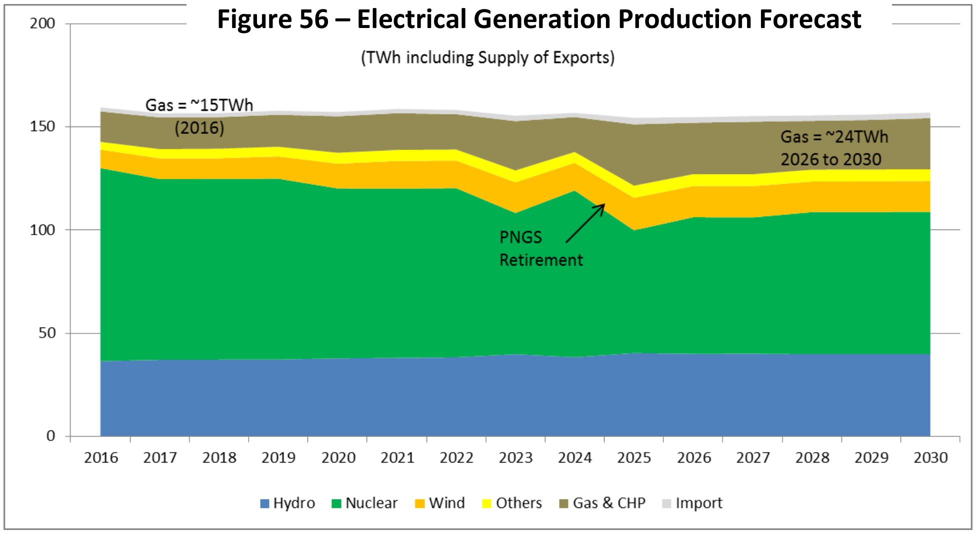


Figure 56 – Electrical Generation Production Forecast

The important aspects of the supply mix employed for this analysis are the forecasts for surplus energy and GHG emissions. Figure 57 shows that the forecast surplus baseload energy will decline significantly from the 15 TWh seen in 2015 to a predicted 4TWh post 2025. Wind surplus will persist in the 2 to 3 TWh range.

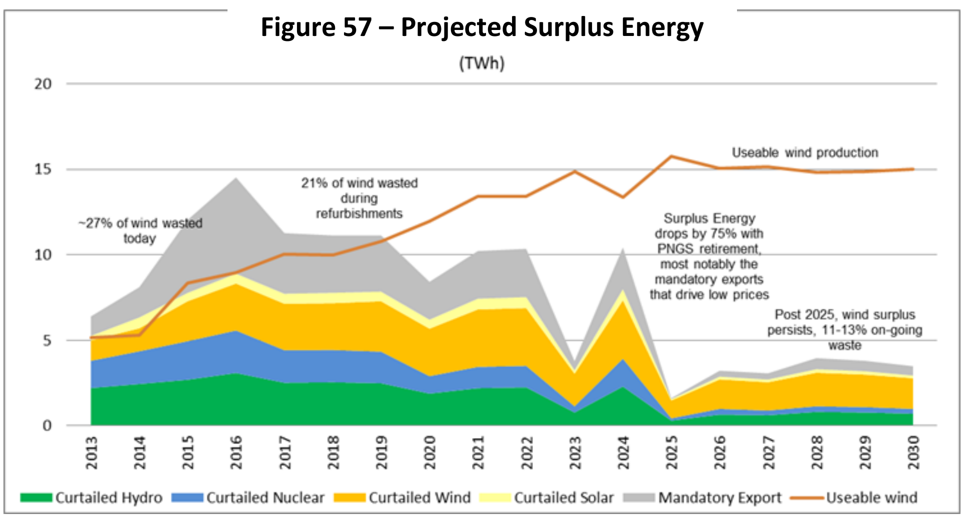


Figure 57 – Projected Surplus Energy

There are three implications from this decline in surplus energy:

1) There will be less energy to provide to Quebec at night

Along with the loss of its currently lucrative arbitrage opportunity, the inability to absorb Ontario's energy at night will erode Quebec's reservoir assets and limit its capability to provide the same level of exports to Ontario during the day.

2) Surplus wind energy will only be reduced by half

The modest reduction in wasted wind energy results primarily from the sheer magnitude of the wind capacity that is being installed. In the spring, for example, the wind could be 50% of the supply at any given time. Nevertheless, the forecast surplus wind will be 20% to 30% less in magnitude than the wind surpluses assessed in this report for 2015. In this situation, the urgent need to address intertie capacity for this purpose will be lessened as the analysis presented earlier in this report indicated. The ongoing cost of the excess wind remains in the $200M to $300M/year range throughout the forecast period.

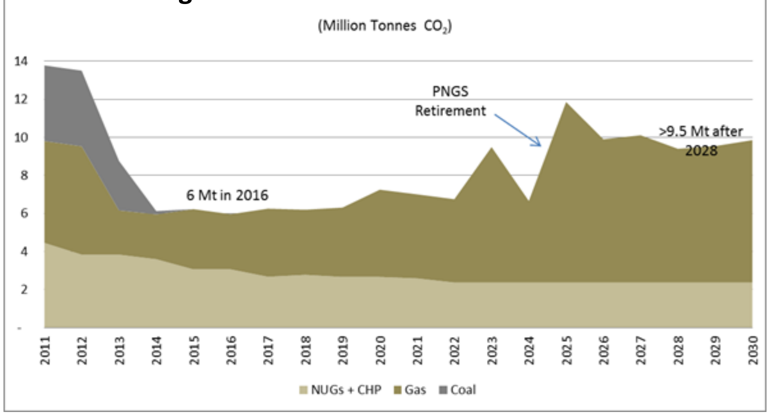
The drop in surplus energy resulting from the replacement of nuclear capacity with natural gas-fired generation occurs because gas-fired generation is well suited for accommodating intermittent wind and solar generation.

It is for this reason that these non-hydro renewables are being embraced in the U.S. Energy companies can move to natural gas-fired generation in tandem with the introduction of renewables as they move to phase out the use of coal.

3) GHG emissions will rise

Unfortunately, even though the PNGS retirement will result in less surplus energy in Ontario, as shown in Figure 58, it will come with a penalty. With the retirement of PNGS, GHG emissions will rise by 3.5 Mt/year, increasing Ontario's annual emissions from the electricity sector by ~60%.

Figure 58 – GHG Emissions Post PNGS



This emissions forecast does not reflect the possibility of supplying Quebec during its forecast winter peak needs. Supply to Quebec will come when gas-fired generation is on the margin. Any support to Quebec to meet its emerging supply needs in winter will cause GHG emissions to rise in Ontario unless new low carbon energy sources are developed.

3.3.6. Summary Implications

The findings in this section suggest that the future nuclear baseload capacity retirements in Ontario and forecast demand growth in Quebec render the question of enhancing the interties to enable smoothing of renewable surpluses moot.

Quebec has a near term surplus created by recent investments in several hydro facilities and the introduction of wind energy in the province. However, Quebec is now forecasting higher industrial demand growth and their current surplus is forecast to erode within the next 10 years.

Quebec currently trades 5 times more energy with the U.S. than it does with Ontario because electricity market prices make the U.S. more attractive. Quebec's largest market is New England which has much higher electricity prices than in Ontario. Electricity prices in the region are influenced by the price of natural gas in the U.S. which is projected to double in the next 15 years. At ~$81MWh, Quebec's recent investments in generation are much more expensive than its heritage supplies at $20-$27/MWh.

The data suggests that Quebec's export practices with Ontario are largely motivated by existing price arbitrage opportunities, which benefits Quebec with a premium of $22/MWh. Net flow to Ontario averaged less than 1 TWh over the last three years.

In Ontario, the supply and demand forecast mix shows that there will be a shortage of low carbon generation after the PNGS retires in 2024 with natural gas-fired generation increasing by 60% from 15 TWh/year in 2016 to 24 TWh/year in the last half of the next decade. This change in the supply mix will reduce the surplus energy problem from 15 TWh/year to less than 4 TWh by 2030. Quebec will no longer be able to profit from surplus trade with Ontario and their available reservoirs will be negatively impacted. However, an ongoing surplus of 2 to 3 TWh of wind generation will continue until the wind assets begin to retire as GHG emissions increase by 60%.

Finally, even if Quebec was willing to sell its hydro generation to Ontario, for both the market-based reasons cited and the emerging constriction of supply in Quebec, imports from Quebec can be expected to be at higher prices.

These conditions show that there will be insufficient low carbon energy sources in both provinces in the late-2020s and beyond to meet forecasted demand without increasing emissions. The feasibility of Ontario accessing low cost hydro power from Quebec is not supported by these findings.

3.4. Firm Import Scenario Trade-off

This section evaluates the implications of seeking firm imports from Quebec to offset the baseload electricity provided by Ontario's nuclear capacity. The IESO assessed the concept of using firm imports from not only Quebec but all neighboring jurisdictions in order to address the Ontario supply shortfall defined by the 2013 LTEP. This shortfall was predicted to result from the nuclear refurbishments and retirement of the PNGS. For cost reasons, the IESO recommended against the option of upgrading the interties for this purpose. This scenario considers leveraging Quebec hydro imports in the context of supplementing wind energy in Ontario backup to the two from natural gas-fired generation.

Baseload generation is best reviewed in the context of Ontario's demand and supply. The forward looking supply environment for Ontario was recently provided by the IESO[45]. The supply picture presented showed that Ontario will facing supply decisions across its entire supply mix within the time frame of its next LTEP. As a result, the trade-off illustrated in this section is an analysis of two approaches to address Ontario's future baseload supply options. This is the reason for assessing the hydro/wind/gas scenario against the characteristics of a nuclear supply scenario.

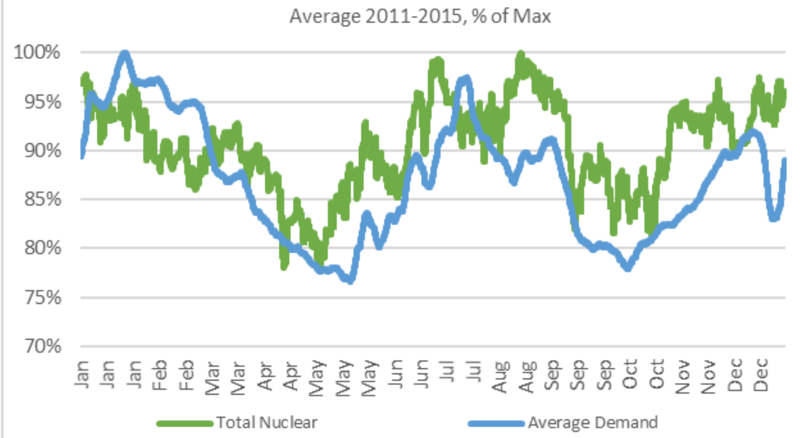
A description of the role nuclear plays in meeting Ontario's demand is first provided along with a description of the DNGS generation capacity. DNGS is used as the reference case capacity for sizing the wind/hydro capacity in the case study. This is followed by a brief summary of the primary modelling assumptions. The simulation results for the requisite energy production from wind, Quebec hydro imports, and gas-fired generation are then presented, including the implications of costs to rate payers and for provincial emissions. The last section examines the economic implications to jobs and gross domestic product (GDP) in Ontario.

3.4.1. Nuclear Baseload Generation and Demand in Ontario

A significant, characteristic of nuclear energy in Ontario is that its output is to some degree well matched to demand in the province as shown in Figure 59. Ontario's large nuclear fleet can be managed as a portfolio facilitating the planning of the maintenance cycles of the units to optimize the available capacity for when it is most needed. Figure 54 shows how the average nuclear output over the last 5 years has tracked demand. Nuclear capacity is lowered in the spring and fall and brought to full production during peak demand times in winter and summer. The drop in demand during the spring is slightly larger than the decrease in the fall. The nuclear capacity tracks accordingly, but with a more aggressive decline in capacity in the spring, somewhat supported by leveraging the extra hydro capacity that accompanies the spring freshet.

[45] Preliminary Outlook and Discussion, IESO, 2016

Figure 59 – Ontario Demand vs. Nuclear Generation



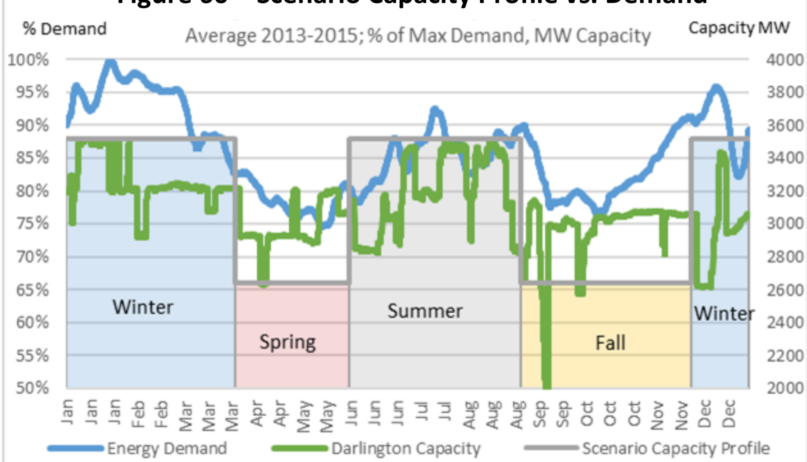
The degree to which nuclear generation is matched to demand starkly contrasts to the anti-cyclical patter of wind generation output discussed earlier in Figure 20.

3.4.2. The Darlington Nuclear Generating Station Case Study

The option of obtaining firm imports from enhanced interties is contrasted against replacing the output from the Darlington Nuclear Generating Station (DNGS).

The operational profile of DNGS for the last three years is illustrated in Figure 60, with the blocks of energy that are used as a reference in the simulation.

Figure 60 – Scenario Capacity Profile vs. Demand



The modelled scenario profile represents the energy scenario that would need to be satisfied by the combined hydro, wind, and gas-fired generation. The full capacity of the DNGS is about 3500 MW, 24 hours a day in winter and summer. The modelled scenario capacity is 25% less in spring and fall to reflect when nuclear units are assumed to be taken offline for planned maintenance outages.

Caveats to the Analysis:

- This situation is assessed to bring out the relevant considerations regarding the interties. It is recognized that the Ontario government has already decided that refurbishing DNGS is the best way for Ontario to meet its long-term energy needs. This case study is conducted for illustrative purposes only. Using DNGS as a case study simply permits the use of available and objective quantitative data.
- There are two important energy concepts relevant to the modelling of the scenario: energy supply and peak generation capacity at any one time. If the demand being met is flat, then the capacity and production are highly correlated. However, Ontario demand is not flat over the year, neither on a daily nor a seasonal basis, and so the relationship between capacity and energy demand is important to characterise. The intertie question is a capacity question. The maximum energy that can be extracted from Quebec during peak times is also a capacity limitation consideration. Finally, the size of Quebec's hydro reserves establishes the total energy that Quebec can supply as demand is followed.
- As discussed earlier in this report, Quebec is not forecast to have sufficient energy or capacity to address Ontario's needs under the scenario being simulated.
- The Tx system constraints discussed earlier in this report are ignored. However, Tx system constraints are an important reality to consider. Ontario's system has been built around delivering energy from its nuclear units and major assets like Niagara Falls. As the IESO pointed out, the interties were not designed for accommodating large volumes of firm imports.[46]

3.4.3. Modeling Assumptions

Replacing the baseload capacity of DNGS with the variable and/or intermittent supplies such as wind and hydro requires mutual backup capacity. The replacement capacity will need to be committed three times. Gaps in the availability of both hydro and wind capacity requires gas-fired generation to compensate.

The assumption made in the analysis for this scenario is that wind generation will be leveraged first, hydro from Quebec will be called upon to back it up, and then, finally, natural gas-fired generation will be deployed to fill any final gaps required to match the DNGS output being simulated by the mix. This approach recognizes that wind cannot be dispatched and consequently should be used when available to minimize wasted energy. Next, hydro flexibility is considered as it is low carbon and the premise for examining a firm import arrangement with Quebec, and finally the gas-fired generation is applied as the supply of last resort for this scenario.

With these priorities in mind, the required capacities of each supply type can be identified. The required wind capacity is set equal to the maximum DNGS output. This allows for maximum wind output in

[46] Review of Ontario Interties, IESO, 2014

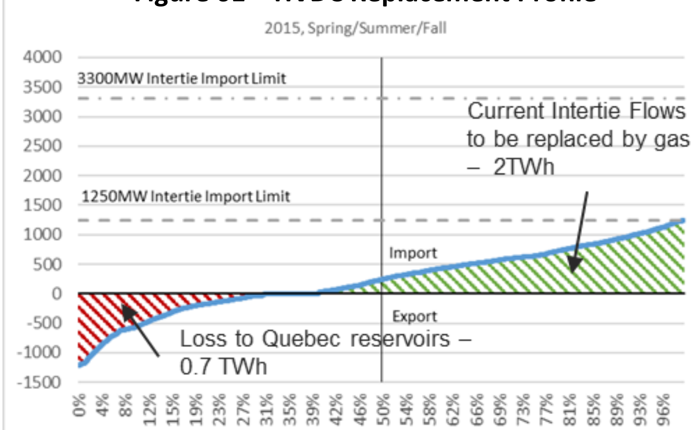
winter and summer and at peak demand times, with the least waste of wind energy. This assumption results in some small surpluses of wind energy at peak production times in the fall and spring when the simulated generation need is reduced by 25%.

Hydro interties would be enhanced to a maximum limit of 3300 MW to align with the level used by the IESO when it calculated its cost estimate. This maximum is required to support the summer peak demands in the best way when wind generation is at its lowest. However, the associated generation capacity is not available from Quebec in the winter. The limitations of Quebec hydro supply in winter and the assumed role for hydro to act as a backup to wind, lead to the expected operating factor of the interties being less than 100%.

As illustrated in Figure 61, this simulation considered several other limitations with respect to Quebec:

- Quebec will lose the ability to import energy from Ontario at night, a capability it has used to help support its reservoir levels and leverage the afore-noted arbitrage opportunity.
- Existing imports will continue and so intertie capacity lost for that purpose will need to be provided by natural gas-fired generation.

Figure 61 – HVDC Replacement Profile



Gas capacity will be needed for three reasons: (1) to supplement the lack of available Quebec hydro in winter. The capacity required is modelled as 4000 MW to accommodate a 12% derating to yield 3500 MW at winter peak; (2) 200 MW of constant generation output to account for the shortfall between the 3300 MW intertie capacity and the 3500 MW nuclear output; and (3) offsetting supply for the status quo imports from Quebec that are assumed to continue.

As a result of these assumptions, this case study effectively models a range of uses of the HVDC intertie, including the smoothing of non-hydro generation, firm imports, and using natural gas generation to address Quebec's winter peaks.

3.4.4. Simulation Results

Figure 62 illustrates the results of the simulation, showing how much electricity of each generation type will be drawn upon to meet the needs of the two scenarios. The capacity assumptions are shown along the left axis of the Figure. The graph on the left shows the required capacity levels for winter/summer, and the one on the right for the spring/fall. A small surplus of wind energy occurs in the spring/fall.

Figure 62 – Wind/Hydro/Gas Mix to Replace Nuclear Baseload

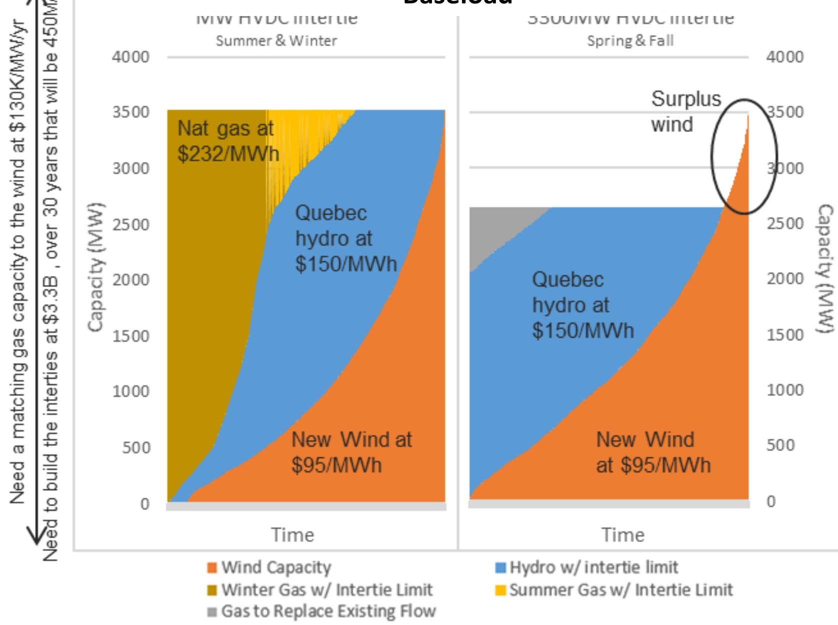


Table 12 provides the cost implications resulting from the simulation. Replacing DNGS would cost \$4.1B/year with a blended cost per MWh of the energy of ~\$150/MWh, if it were feasible. This is approximately double the cost of the Darlington refurbishment that has been estimated at between \$70 and \$80/MWh by the Ontario government[47].

[47] Ontario Moving Forward with Nuclear Refurbishment at Darlington and Pursuing Continued Operations at Pickering to 2024, Ontario Ministry of Energy, 2016

Table 12 - Cost of Wind + Hydro Scenario						
		$/MWh				Total Cost
Supply Type	TWh	Variable Cost	Fixed Cost	Premium	Unit Cost	($M)
Wind	10.0	$ 86	$ 7	$ 2	$ 95	$ 946
Hydro (3300MW)	4.7	$ 81	$ 97	$ 30	$ 208	$ 978
Hydro (1250MW)	7.0	$ 81	$ -	$ 30	$ 111	$ 773
Hydro	11.7	$ 81	$ 39	$ 30	$ 150	$ 1,751
Gas	6.0	$ 65	$ 127	$ 40	$ 232	$ 1,390
Total Used	27.6				$ 148	$ 4,087
Surplus Wind	0.1					$ 11
Total	27.6				$ 148	$ 4,098

The costs assumptions reflected in Table 12 are as follows:

- Wind generation costs
  - The $86/MWh variable cost based on the latest IESO contracted values announced[48]
  - The $7 fixed cost is the average of the EIA and Quebec estimates of Tx costs discussed in Section 3.2.4.1.
  - The $2 premium is the cost for additional reserve margin identified in Table 5.
- Hydro generation costs
  - The $81/MWh variable cost is the blended mix of new Quebec generation calculated in Table 10.
  - The $30 premium includes two components: (1) the value that Quebec has been realizing from its current trading practices with Ontario ($22 calculated in Table 11), plus (2) a Tx loss of 10%, or $8/MWh, on the cost of the new energy estimated to be $81 for generator received prices as shown in Table 10.
  - The $97 fixed cost is the recovery of the $3.3B investment based on 4.7 TWh per year over 30 years (summarized in Table 3)
  - The cost of hydro is comprised of two tranches.
    - First, a scenario was run where the intertie was limited to the existing 1250 MW capacity. This scenario identified how much hydro could be imported under the simulated conditions if no investments were made in the interties beyond those which Ontario already intends to purse to address congestion issues within its Tx network.
    - The second tranche represents the additional energy that would be enabled by the expansion of the interties
- Gas-fired generation cost
  - The $65 variable cost is based on Strapolec's analysis using the recent EIA AEO forecast for natural gas and estimated operations and maintenance costs[49].

[48] Large Renewable Procurement, IESO, 2016

- The $127/MWh fixed costs are estimated from the $130k/MW fixed costs using the 11% duty cycle produced by the simulation.
- The $40 premium is the carbon price premium based on ICF's forecast of ~$100/tonne price of carbon in Ontario post 2030[50].

The results of the simulation suggest a net cost of $150/MWh. This result reinforces the IESO's findings that pursuing large firm imports could bear a net average energy cost of over $130/MWh[51]. Even the IESO's estimate is 60% higher than the $80/MWh high end of the range quoted by the Ministry of Energy regarding the cost of refurbishing Darlington[52].

Emissions Implications

The simulation results in Table 12 show that approximately 6 TWh of incremental gas-fired generation will be required. Assuming natural gas-fired generation produces approximately 400 kg of carbon dioxide (CO_2) emissions for every MWh, 6TWh of gas fired generation will produce ~2.4 Mt of CO_2. This is approximately 40% more emissions than Ontario's entire electricity system is producing today.

Energy Dependence Considerations

The hydro/wind/gas scenario relies on purchased energy resources from outside Ontario, as shown in Table 12: 11.7 TWh of hydro from Quebec; and 6 TWh of natural gas-fired generation. The fuel for the latter is increasingly becoming dependent upon imported shale gas from the U.S. Of the 28 TWh required to replace the Ontario's nuclear baseload, almost 18 TWh, or 65%, will be dependent on sources outside of the province. This has economic implications for Ontario as discussed in Section 3.4.5.2.

Quebec Perspective Considerations

As stated earlier, Quebec does not have the generation to support this scenario. The identified 11.7 TWh of imports from Quebec would require either new generation capacity be developed or the diversion to Ontario of Quebec's existing exports to the U.S. The import of 11.7 TWh into Ontario represents approximately half of Quebec's exports to the U.S. Quebec would thus have to consider redirecting 50% of its current U.S. bound exports to Ontario. Given that the attractiveness of the U.S. market to Quebec is expected to increase, there is no obvious net financial gain for Quebec in making this choice. If it were a realistic consideration, the costs for Ontario may be higher than modelled.

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[49] Extending Pickering Nuclear Generating Station Operations, Strapolec, 2015; AEO2016 Early Release, U.S. Energy Information Administration, 2016

[50] Ontario Cap and Trade: Overview and Scope of the Challenge, Ontario Energy Association, 2016

[51] Review of Ontario Interties, IESO, 2014

[52] Ontario Moving Forward with Nuclear Refurbishment at Darlington and Pursuing Continued Operations at Pickering to 2024, Ontario Ministry of Energy, 2016

3.4.5. Economic Implications

The rate based annual cost difference between the two scenarios is extremely large. At $4.2B/year, the Wind/Quebec Hydro option is approximately a factor of two greater than the $2.1B/year cost for the refurbishment of Darlington.

There are two phases that would have distinct economic impacts: (1) the investment phase; and (2) the operating phase. The rate payer impact of a $2.1B/year difference between the cases is a combination of both these costs, but do not take into account the economic implications for Ontario's economy. The costs associated with these two phases are segregated in the following analysis. Given the magnitude of the cost differences, a simplified economic impact can be used to develop directional estimates based on a few metrics.

3.4.5.1. Investment Phase

The nuclear refurbishment project's impact on Ontario's economy has been assessed by the Conference Board of Canada (CBoC)[53]. This $11.3B investment program is estimated to create 150,000 person years of employment (PYEs), referred to here as jobs, and contribute almost $15B to the province's GDP.

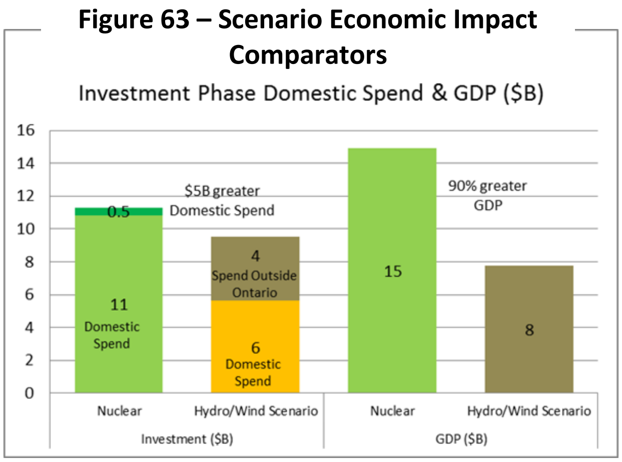
In 2012, the CBoC assessed the economic impact for investments in electricity infrastructure in general, including both generation and Tx[54]. Metrics from this report have been applied as a proxy to the aggregated hydro/wind/gas capacity scenario.

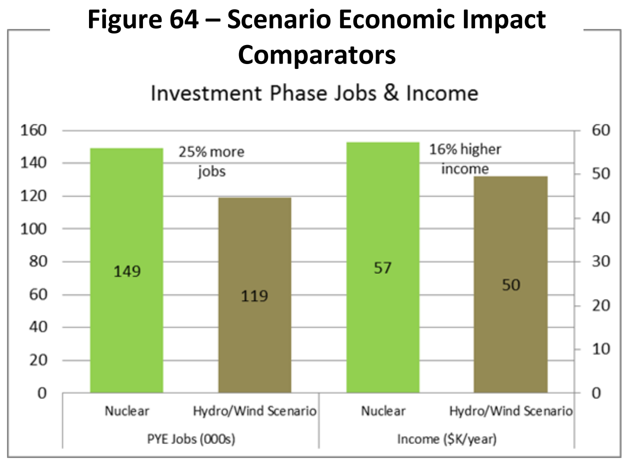
Figure 63 summarizes the results of the economic comparisons of the investments of the two scenarios.

Based on the CBoC metrics, the Darlington refurbishment will:

- Generate $7B, or 90%, greater GDP than would be created by investing in 3500 MW of wind capacity, gas-fired generation plant capacity, and intertie upgrades.
- Create 25% more jobs. This employment is expected to realize 16% higher incomes.

[53] Refurbishment of the Darlington Nuclear Generating Station, CBoC, 2015
[54] Shedding Light on the Economic Impact of Investing in Electricity Infrastructure, CBoC, 2012



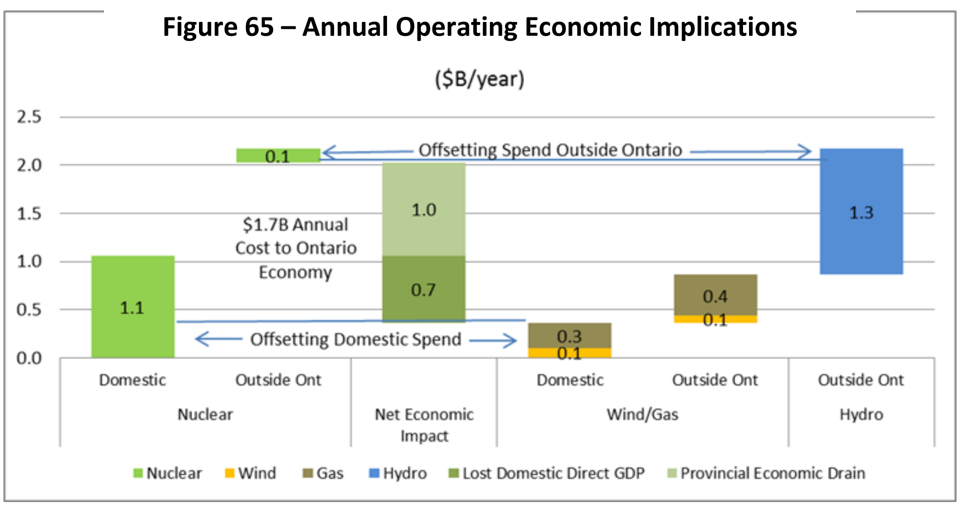


3.4.5.2. Operations Phase

The economics of the operations phase are far more dramatic. Nuclear is characterized by significant domestic content in its operations[55]. CBoC stated that DNGS's operating costs are approximately $1.2B/year. This equates to about $45/MWh.

The hydro/wind/gas scenario relies on purchased energy resources from outside Ontario: hydro from Quebec and natural gas increasingly being sourced from the U.S.

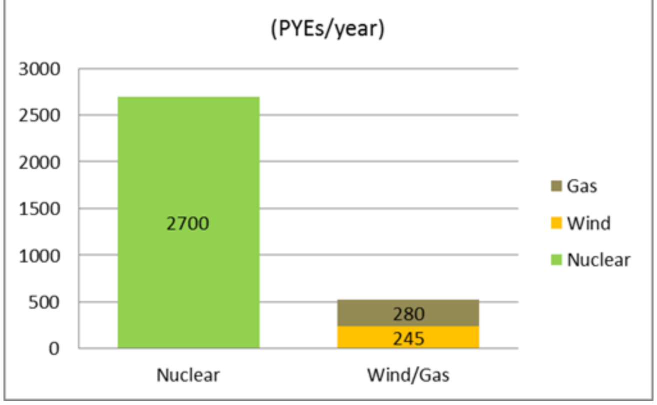
Figure 65 contrasts the operating costs of the two scenarios to highlight the annual impact to Ontario's economy, which could total approximately $1.7B/year were such a hydro/wind/gas scenario pursued.



Ontario's nuclear plants have a large workforce. The CBoC report stated that operations at the DNGS would employ 2600 to 2800 personnel. In contrast, Strapolec estimates that the equivalent wind and gas capacity would employ slightly more than 500 PYEs/year.[56] Figure 66 illustrates this comparison.

[55] Ontario Electricity Option Comparison, Strapolec, 2013

Figure 66 – Operating Jobs by Scenario



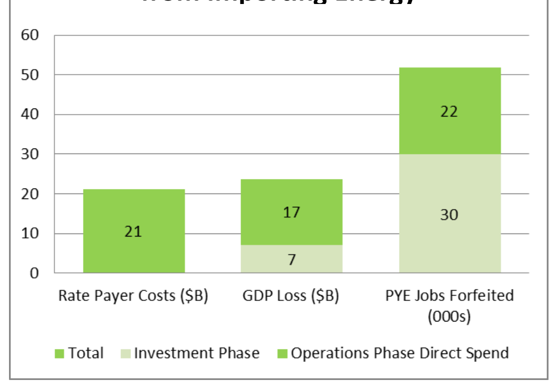
3.4.6. Summary of Wind + Hydro Option Assessment

The portfolio of nuclear generation in Ontario is well matched to the demand profile of the province. As an alternative to nuclear baseload generation, attempting to leverage wind, whose supply profile is anti-cyclical to Ontario's demand, with Quebec hydropower, which is constrained in the winter, leads to a composite supply mix that includes over 20% natural gas-fired generation. Furthermore, available hydro resources in Quebec have generation limited below the levels implied by the scenario evaluated. Quebec would have to consider redirecting 50% of its current U.S. exports to Ontario.

If hydro resources were available in Quebec to replace 3500 MW of nuclear baseload, then a Hydro/Wind leveraged supply option would negatively impact Ontario's economy in several ways as shown in Figure 67:

- Rate payers would pay a blended cost of $150/MWh or $2.1B/year more: $21B after the first 10 years of operation.
- The economy of Ontario would suffer a loss of over $2.4B /year for a total of $24B for the first 10 years of operation.
  - The investment difference accounts for $0.7B/year.
  - The economic drain resulting from using imported hydro and natural gas in lieu of the primarily domestic operating costs of DNGS represent a cost of $1.7B/year.
- 52 thousand jobs would be forfeited.

Figure 67 – 10 Year Economic Loss from Importing Energy



[56] Ontario Electricity Options Comparison, Strapolec, 2013

Furthermore, Ontario would become dependent on sources outside of Ontario for 65% of the province's energy supply. Provincial GHG emissions would increase by 2.4 Mt of CO_2, or approximately 40% more than Ontario's entire electricity system is producing today.

Pursuing firm imports from Quebec in lieu of a nuclear baseload option, as represented by the Darlington refurbishment, is not an attractive option for Ontario's economy.

4.0. Looking Forward

With the capacity retirements forecast for Ontario and the demand growth forecast for Quebec, insufficient low carbon supplies exist in these two provinces to meet the demand forecasts, even before the province's climate change plan initiatives are implemented. In the 2030 timeframe, with climate change strategies being developed for emission reduction and carbon pricing, it is widely accepted that increased demand for electricity will result from the electrification of applications currently using fossil fuels.

4.1. Climate Change and Ontario Energy Needs

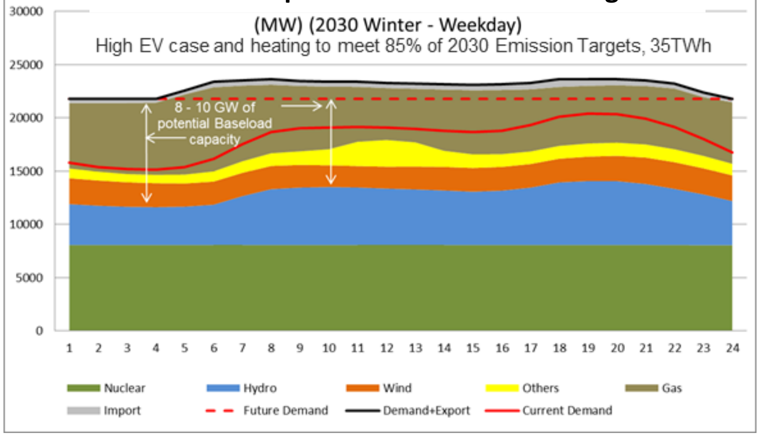
In Ontario, the most recent demand forecast from the IESO includes explicit statements that the forecasts do not yet reflect the potential impacts of the province's recently released climate action plan. To meet Ontario's 2030 emissions reduction targets of 37%, just for transportation and building heating, Strapolec analyses suggest an additional low carbon energy supply in excess of 35 TWh/year may be needed by 2030.

As well, it does not appear that Quebec has reflected the expected increase in demand from the electrification of fossil energy applications in the demand forecast produced by HQ in the fall of 2014. Applying a similar emissions reduction estimation methodology to Quebec suggests it may require an additional 10-15 TWh of electrical energy. Such an amount would consume four-fold the entire surplus for Quebec that is otherwise projected for 2028.

Regardless of whether Canada's economy and the energy consumption habits of Canadians can be transformed that rapidly, the emerging energy needs driven by emission reduction targets are well beyond the capacity of the existing fleet of low carbon baseload generation in both Ontario and Quebec. Technologies are being developed to smooth out the daily profile, reduce the need for peaking gas-fired generation, and to supply this energy most cost effectively. The smart management of electric vehicle (EVs) charging, for example, could result in a flattened daily demand load in the next 15 years.

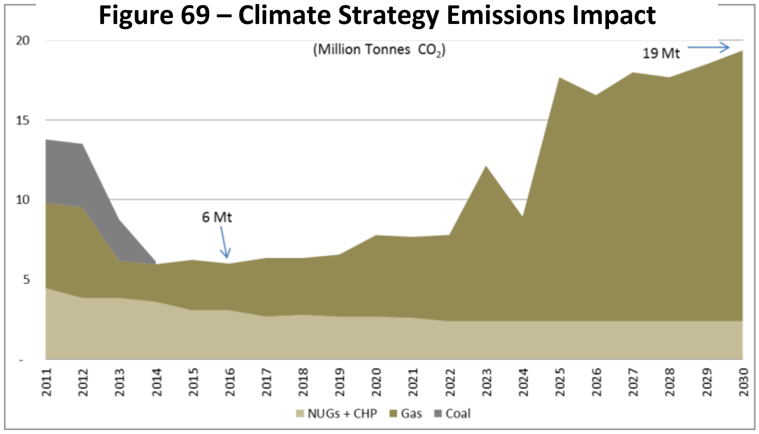
As indicated in Figure 68, for Ontario to meet its emissions targets and divert new demand to off-peak times, an estimated 8 to 10 GW of low carbon baseload power would be needed by 2030 in lieu of the current gas-fired peaking facilities in Ontario's supply mix. Unfortunately, reliance on gas-fired generation arises commensurately with the build out of wind capacity, until the perceived panacea of cost effective storage solutions emerge decades from now.

Figure 68 – Potential Ontario Electricity Demand Impact Due to Climate Strategies



The estimated gap of low carbon baseload generation will undermine the achievement of Ontario's emission targets if gas-fired generation continues to be relied upon. The consequence of a higher reliance on natural gas-fired generation is illustrated in Figure 69. It shows that emissions can be expected to triple as the PNGS closes and emissions reduction strategies begin to take effect by 2030.

Figure 69 – Climate Strategy Emissions Impact



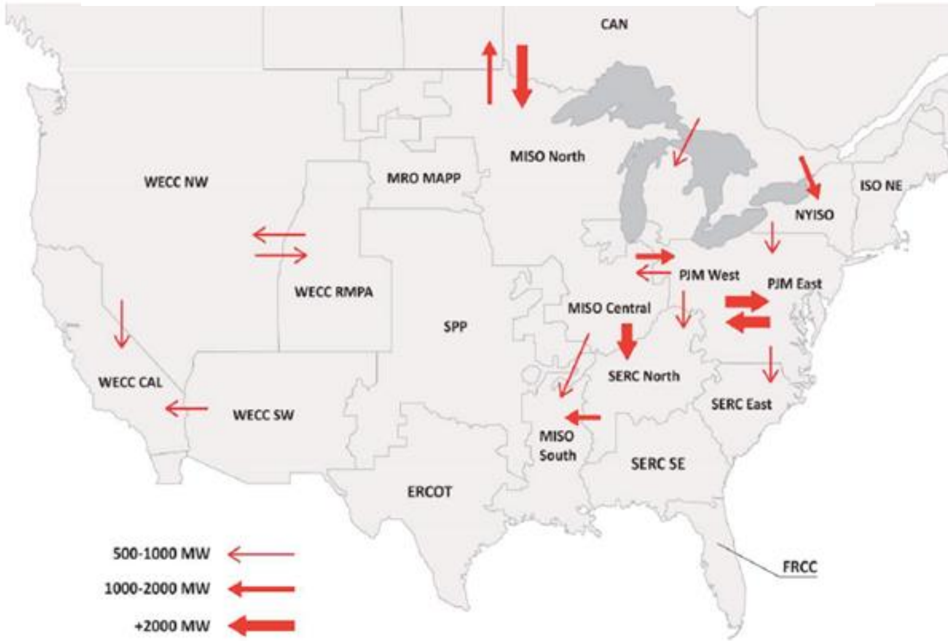
New low carbon generation is going to be required. Enhanced interties could facilitate the location of such new low carbon generation. An efficient use of Tx resources is best achieved with high utilization suggesting a cost an advantage for "baseload" type energy transfers between the provinces. Collaboration to economically enhance low carbon baseload generation could establish the basis for expanding Tx capabilities between Ontario and Quebec.

4.2. Climate Change and Impact on the U.S. of the Clean Power Plan

The U.S. will also be facing decarbonisation challenges as they pursue the implementation of the U.S. Environmental Protection Agency's (EPA) CPP. New capacity is going to be required across the NPCC/MISO grids. The U.S. is currently favoring natural gas-fired generation as a replacement for coal.

According to NERC, during the transition the CPP can be expected to change the power flows in many major power areas. Power flow changes anticipated by NERC are illustrated in Figure 70.

Figure 70 – NERC Impacts of CPP on Regional Power Transfers



The CPP is expected to impact intertie flows and demand for energy from Ontario, particularly in the 2020s. Canada is anticipated to export three times more power to the United States, mainly to states in the Northeast Power Coordinating Council (NPCC) and Midcontinent Independent System Operator Inc. (MISO) grids. However, very little low carbon on-peak power will be available from Ontario as it will be needed to serve Ontario's needs.

The U.S. market could become more attractive to Quebec as carbon pricing takes hold, incenting Quebec to continue to focus their investments in the intertie assets with the U.S. This may be a dissuading factor for Quebec investments in expanded interties with Ontario if, as indicated in this study, it comes at the expense of serving the U.S. market. However, depending on where the new low carbon energy capacity is sourced, increasing the intertie capacities such that low carbon electricity can flow between the two provinces and also be exported to the U.S. markets could provide a low cost clean energy option for all jurisdictions. The caveat is that Ontario and Quebec would have to provide lower cost low carbon energy solutions than the U.S. could domestically.

The current U.S., Ontario and Quebec market structures trade electricity at the wholesale clearing price. Both sides of the border are now driving their wholesale market to reflect only the marginal (variable) cost of production, which, due to the predominance of fossil generation in the U.S., is the marginal cost of natural gas-fired generation. This undermines the business case for constructing new low carbon generation for the purpose of exporting electricity. Most of the costs of new low carbon generation options (hydro, wind, solar or nuclear) are capital and fixed cost intensive with little variable costs. Unless potential producers can get their fixed costs covered by export trading regimes, there will be no business case for supplying export markets with new build low carbon generation. The U.S. is beginning to recognize this emerging issue and will have to address it as the capital intensive low carbon supplies increasingly emerge as an important component of the U.S supply mix. This report has shown that the lack of demand in the export markets has led to Ontario's surplus wind energy being bottled within Ontario. While this report has not addressed the complexity of reforming electricity markets, it is apparent that for any investment in interties to tap potential export markets to be economical, reform of the electricity markets in North America will likely be required.

4.3. Recommendation:

Given the significant emission, cost and GDP implications associated with expanding the Tx assets and constructing new low carbon generation supply, it is recommended that Ontario and Quebec consider the most optimal way to provide the low carbon generation they both require. As the emerging climate strategies mature, the provinces should assess the merits of building generation and Tx capacity that optimizes a low cost electricity system for industry within the two provinces. Such collaboration could maximize the net economic and emissions benefits to each, enable the collaborative export of low cost low carbon energy to the U.S., and encourage initiatives to support electricity trading market reform.

5.0. Conclusion

The analyses conducted for this study support the following key findings regarding expected benefits of expanding the interties at this time:

1. The interties, expanded or not, cannot simultaneously address Ontario's energy challenges and realize all the suggested benefits of leveraging Quebec's low carbon hydroelectric resources.

2. Absent changing the forecast supply mix of both provinces, increasing intertie capacity is an imprudent and expensive option for addressing Ontario's energy challenges.

    - Expanded interties to smooth wind would at best lead to a wind cost of $275/MWh.
    - A firm import arrangement would have a blended cost of $150/MWh, double the cost of the Darlington refurbishment, increase emissions by 40% and cost Ontario 52,000 jobs.

3. The current surplus of wind energy has been caused by Ontario and Quebec's overinvestments in capacity that exceeds demand and reduces the export of energy from Ontario to Quebec.

    - While Quebec can manage its surplus via its reservoirs, Ontario is now a net importer from Quebec, despite Ontario's surplus, due to the misalignment of wind supply with demand.

4. Ten years hence, there will be insufficient low carbon generation in the two provinces.

    - Lower supply and increased demand will limit the future ability to export low carbon energy.
    - Enhancing the interties may offer future benefits for firm energy transfer and enhanced exports (if accompanied by electricity market reform) if new low carbon generation is developed.

Given the significant emission, cost and GDP implications associated with expanding the Tx assets and constructing new low carbon generation supply, it is recommended that Ontario and Quebec consider the most optimal way to provide the low carbon generation they both require. As the emerging climate strategies mature, the provinces should assess the merits of building generation and Tx capacity that optimizes a low cost electricity system for industry within the two provinces. Such collaboration could maximize the net economic and emissions benefits to each, enable the collaborative export of low cost low carbon energy to the U.S., and encourage initiatives to support electricity trading market reform.

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Appendix B - List of Abbreviations

AEO – Annual Energy Outlook
CBoC – Conference Board of Canada
CO_2 – Carbon Dioxide
CPP – Clean Power Plan
DNGS – Darlington Nuclear Generating Station
EIA – U.S. Energy Information Administration
EPA – U.S. Environmental Protection Agency
GDP – Gross Domestic Product
GHG – Greenhouse Gas
GW – Gigawatt
GWh – Gigawatt Hour (one billion watts being produced for 1 hour)
HOEP – Hourly Ontario Energy Price (wholesale market)
HQ – Hydro Quebec
HQD – Hydro Quebec Distribution
HQP – Hydro Quebec Production
IESO – Independent Electricity System Operator
LTEP – Long Term Energy Plan
MISO – Midcontinent Independent System Operator
mmBTU – million British Thermal Unit
MOU – Memorandum of Understanding
Mt – Million Tonnes – also referred to as megatonnes
MW – Megawatt
MWh – Megawatt Hour (one million watts being produced for 1 hour, enough to power ten thousand 100W light bulbs for one hour)
NERC – North American Electricity Reliability Corporation
NHR – Non-Hydro Renewables
NPCC – Northeast Power Coordinating Council
NUG – Non-Utility Generator
OEA – Ontario Energy Association
OPG – Ontario Power Generation Inc.
PNGS – Pickering Nuclear Generating Station
PYE – Person Year of Employment
SBG – Surplus Baseload Generation
SCGT – Simple Cycle Gas Turbine
TWh – Terawatt hour (one trillion watts being produced for 1 hour)
Tx – Transmission
U.S. – United States of America

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