Ontario's Emissions and the Long-Term Energy Plan

Phase 2 - Meeting the Challenge

Final Report

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STRATEGIC POLICY ECONOMICS

Executive Summary

This report documents Phase 2 of a study intended to inform Ontario's Long-Term Energy Plan (LTEP) consultation with background analyses that relate to the province's emission reduction targets, the costs of emission reducing technologies, the carbon price within Ontario's Cap and Trade (C&T) program, and the supply mix choices being developed for the next LTEP. This report lays out an alternative supply mix option based on four electricity system design paradigm shifts identified through research and summarizes their associated cost, implementation, and economic considerations.

Since the global community of nations emerged from the COP21 Paris Climate Conference and subsequently ratified the Paris Accord at COP22 (Nov 2016), the urgency to combat climate change is now fully acknowledged by all key actors. To reverse the impacts of global warming, deep decarbonization of the global economy is now a priority for government action. Electrification across all economic sectors is considered a critical enabler for transitioning Ontario to a low carbon energy future. The LTEP's role is to provide for the energy infrastructure that will facilitate this transition.

The study is comprised of two phases:

1. Phase 1, *"Defining the Challenge",* was completed in November, 2016, and quantified the costs of Ontario's climate actions and identified the factors that the LTEP process should address if it is to achieve the province's emission targets. The outcomes of Phase 1:
    - Highlighted that ~90 TWh of new generation is required to meet the 2030 emission reduction targets, 80% more energy than the ~50 TWh provided for in the Ontario Planning Outlook (OPO) Outlook D.
    - Emphasized that an LTEP process focused on the province's climate change objectives is critical to lowering costs, meeting emission targets in a timely manner, and facilitating Ontario's transition to a low carbon economy.
    - Recommended that the LTEP should seek out the lowest cost emission free energy solutions that reflects the integrated costs of generation, transmission, and distribution.
2. Phase 2, *"Meeting the Challenge",* resulted in this report that presents a new supply mix, Scenario "S" – significantly different from the OPO options – developed to meet three key objectives:
    - Reduce dramatically the estimated annual cost of meeting Ontario's 2030 emission reduction targets;
    - Support the timely achievement of Ontario's emission targets and minimize the need to purchase emission credit allowances from other jurisdictions; and,
    - Ensure Ontario's competitive advantage through strategic investments in "made-in-Ontario" solutions that achieve the province's emission reduction targets and yield the highest payback for Ontarians.

Two conditions enable Ontario to rethink Ontario's energy supply mix: The research in Phase 1 identified the emerging development of many technology options that could change the paradigms of energy system planning; and, the expected contractual expiration of much of Ontario's existing generating assets facilitates the opportunity to change the supply mix. These opportunities are captured in Scenario "S". This Scenario provides significant cost and economic benefits to Ontario that support several recommendations being made to the LTEP consultation process.

Elements of a New Supply Mix Scenario

The new Scenario "S" Supply Mix reflects a paradigm shift in energy system planning. The scenario integrates new technologies that will radically reshape Ontario's energy future. The paradigm shift forces a rethinking of how Ontario should manage and plan its electricity system and includes:

1. **Embedded Distributed Energy Resources (DER)** integrated with LDC controllers.
    - *Shift: DER provides demand management for greater asset efficiencies and Dx and Tx system reliability.*
    - A Local Distribution Company (LDC) managed/controlled integrated solar generation/battery storage system, such as PowerStream's "PowerHouse" pilot, could shave peak system loads, manage local neighborhood loads and provide reliability services and unique customer value. Scenario "S" projects that a modest 2.7 GW of solar and 1.4 GW of battery storage would be needed.

2. **Integrating the "Wires and Pipes"** with hybrid natural gas/electric heating solutions in buildings.
    - *Shift: Natural gas in buildings is the electricity system's new winter peak reserve capacity.*
    - Hybrid devices – such as those being advocated by Enbridge – when integrated with LDC controlled DER enable natural gas to help reduce electricity system demand during cold winter days and achieve the emission reduction objectives.
    - Integrating the management of energy use and its value to the consumer will reduce the pressures to expand electricity generation, transmission (Tx), and distribution (Dx) infrastructure.

3. **The Hydrogen Economy** can provide capacity and reliability benefits to the electricity system.
    - *Shift: Hydrogen and natural gas storage is Ontario's equivalent to Hydro Quebec's James Bay reservoirs.*
    - The broader role of hydrogen, including reliability benefits, are being articulated by Hydrogenics, Enbridge, and NextHydrogen.
    - The estimated hydrogen production capacity that would be developed is sufficient to:
        - Smooth the seasonal differences in demand between summer and winter by leveraging the underground storage capacity of Ontario's natural gas system to seasonally adjust the electricity load of hydrogen production.
        - Provide the demand response (DR), peak reserve capacity, and other ancillary services required to fully support grid reliability and allow displacement of much of Ontario's natural gas-fired generating fleet.

4. **Nuclear** is the established clean and reliable energy source for ensuring Ontario's low carbon future.
    - *Shift: Nuclear is Ontario's low cost, clean energy advantage, the enabler of Ontario's coal retirement, and the backbone of achieving Ontario's climate strategy.*
    - Coupling 14 GW of new nuclear with the benefits of DER, wires and pipes integration, and the hydrogen economy could underpin Ontario's achievement of its emission reduction targets by providing a more affordable and efficient supply mix than projected in the OPO.
    - Scenario "S" integrates this new nuclear capacity with the foundation of life extended and refurbished nuclear and the rest of the OPO Outlook B projected clean supply of hydro, solar, biomass, low carbon electricity imports and low emission Non-Utility Generator (NUG)/Combined Heat and Power (CHP) capacity.

Embracing these four critical paradigm shifts allows the leveraging of Ontario's unique infrastructure advantages and offers a new cost effective pathway to achieving provincial emission reduction targets.

Benefits

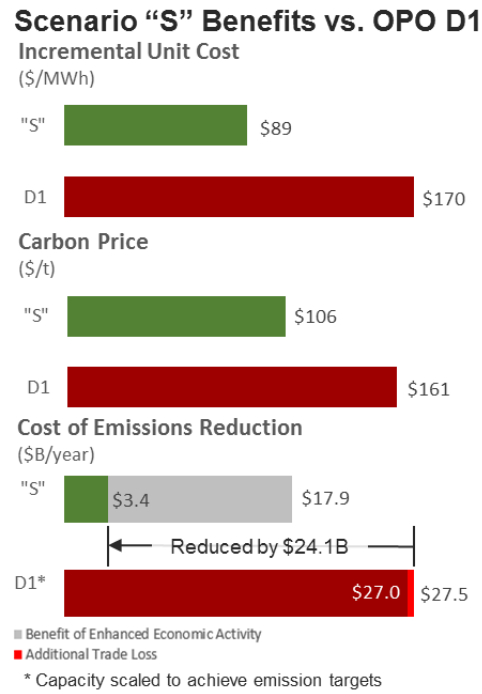
The Scenario "S" supply mix option has been developed to meet Ontario's long-term needs at a minimal cost to the economy while concurrently helping to stimulate innovation and improve Ontario's competitive advantage in the global marketplace. Scenario "S" provides the following benefits:

1. **Less Capacity Needed** – 80% more production with 20 GW less capacity than OPO Option D1:
   - Expiring contracts for existing wind and some natural gas-fired generation are assumed to not be renewed.
   - OPO Outlook "B" directed but uncommitted solar capacity is assumed to not be procured.
   - OPO D1 imports, wind and hydro is fully replaced by Scenario "S" nuclear capacity, DER, and DR.
   - OPO D1 need for $24B of new Tx capacity is replaced by a Scenario "S" provision of $4B.
2. **Lower Unit Cost of Power** – $89/MWh for incremental energy, half of OPO Option D1's $170/MWh.
   - Incremental system cost of $8.3B/yr is less than that of the OPO D1 and delivers 40 TWh more energy.
   - Cost savings of $2.5B/year compared to the Outlook B baseline by not contracting for unneeded capacities.
   - An average future total electricity system unit cost of $115/MWh, 20% less than today's $144/MWh.
3. **Earliest Path to Emission Reduction** – Making nuclear the mainstay of Ontario's electricity system within Scenario "S" is the earliest supply mix solution Ontario has for achieving its emission targets.
   - Developing the requisite DER, nuclear and hydrogen capacity in "blocks" in a systematic and incremental manner can be done faster and with less cost risk.
     - Darlington build is a logical first step to dovetail with the retiring Pickering Nuclear Generating Station.
   - Developing new hydro generation in Ontario or Quebec should be pursued as this capacity will be needed to achieve 2050 emission targets. But facilities similar in scale to Hydro Quebec's James Bay project require large reservoirs. Development risks affecting facility availability may prevent achieving 2030 targets.
4. **Economic Gain from Integrated Policy Solution** – Focussing environmental, energy, industrial, and economic policy objectives on the LTEP to leverage Ontario's unique capabilities can provide significant economic benefit and create a competitive advantage for Ontario, regionally and globally.
   - For less total cost than OPO outlook D1, Scenario "S" will reduce the overall cost of emission reductions:
     - Lower Ontario's cost of meeting the 2030 emission reduction targets to $18B/year, reducing the estimated $27B/year cost for Option D1 by $9B/year;
     - Lower the market carbon price to $106/tonne from the $161/tonne estimated for the OPO D1 to achieve Ontario's 2030 emission targets;
     - Remove 2.6 Mt/year of emissions from the electricity sector at no incremental cost.
   - Enhanced economic activity resulting from Scenario "S" will reduce the cost impact to Ontario of climate action to $3B/year or less:
     - Ontario's trade balance will improve by ~$6B/year from reduced imports of fossil fuels and electricity products/services and also avoid $1.4B/year of purchased emission allowances expected in OPO D1;
     - Industrial activity of ~$8.5B/year will be created in Ontario's nuclear and hydrogen economies;
     - Opportunities to further grow the trade balance and industrial activity benefits by increasing exports of high-value innovations and energy could eliminate the cost to Ontario of emission reductions and make climate change a net economic benefit to Ontario;
     - Opportunities for Ontario and Quebec to leverage each others' energy and capacity strengths will be enabled to optimize and further reduce the costs of electricity generation in both provinces.

Summary Observations and Recommendations

Canada's Long-Term GHG Strategy[1] shows that demand for electrification will steadily increase throughout the process of deep decarbonization that will be required to meet the 2050 targets and that this demand needs to be substantially met by hydro and nuclear resources. It is highly likely that all of the viable potential hydro resources in Quebec and Ontario will eventually be developed. However, these resources will be insufficient to meet the long-term electrification needs of Ontario. Considering the magnitude of the hydro and nuclear resources required and the associated development timelines, 2050 is not far away.

In the near-term, the benefits provided by Scenario "S" are significant and material to the health of Ontario's future economy. For example, this Scenario could shrink the annual cost of Ontario's emission reductions by over $24B compared to the OPO alternatives such as D1. Ontario has the opportunity to achieve its environmental goals with modest cost to Ontario's rate payers and tax payers. Scenario "S", including more nuclear generation, is Ontario's best solution and its development should start now. Given that Ontario's new C&T regime commences in 2017, the cost penalties associated with delaying the development of the requisite energy infrastructure is estimated to approach $65M/month.



The following recommendations are made for the LTEP process:

- The LTEP should consider the paradigm shifts and enabled solutions embodied in Scenario "S".
- The LTEP should integrate the objectives of Ontario's environmental, energy, industrial, and economic policies for the long-term future benefit of Ontarians.
- The LTEP should prioritize an early start for developing a site for new nuclear generation. The Darlington site is a prime early candidate. Additional locations for future units should be explored.

Although this study has focussed on Ontario and the LTEP process, the detailed analyses presented and the resulting implications for supply mix design criteria could be relevant to other jurisdictions in the Great Lakes-St. Lawrence Region. This may be particularly relevant for those with similar energy assets and options and that may be contemplating aggressive emission reductions, deep decarbonization, and government-mandated carbon pricing schemes.

[1] Government of Canada. Canada's Mid-Century Long-term Low Greenhouse Gas Development Strategy. 2016

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1.0 Introduction

This report documents Phase 2 of a study intended to inform Ontario's Long-Term Energy Plan (LTEP) consultation with background analyses that relate to the province's emission reduction targets, the costs of emission reducing technologies, the carbon price within Ontario's Cap and Trade (C&T) program, and the supply mix choices being developed for the next LTEP. This report lays out an alternative supply mix option based on four electricity system design paradigm shifts identified through research and summarizes the cost, implementation, and economic considerations.

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    - Recommend that the LTEP should seek out the lowest cost emission free energy solutions that reflect the integrated costs of generation, transmission, and distribution.
2. Phase 2, *"Meeting the Challenge",* researches and characterizes a new supply mix, Scenario "S" – developed to meet three key objectives:
    - Reduce dramatically the estimated annual cost of meeting Ontario's 2030 emission reduction targets;
    - Support the timely achievement of Ontario's emission targets and minimize the need to purchase emission credit allowances from other jurisdictions; and,
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Two conditions enable Ontario to rethink Ontario's energy supply mix: The research in Phase 1 identified the emerging development of many technology options that could change the paradigms of energy system planning; and, the expected contractual expiration of much of Ontario's existing generating assets facilitates the opportunity to change the supply mix. This report describes how demand characteristics, combined with emerging opportunities, can create a very different future electricity system supply mix option for consideration during the LTEP process.

Methodology

Phase 2 of this study involved several distinct steps:

1. OPO Option D was reviewed in order to summarize and highlight key parameters, such as capacity, production and cost, that provide a relevant comparison for alternative supply mix options.
2. Research was conducted to assess some of the implications of the OPO supply mix elements and to identify stakeholder ideas/concepts that could help form a new supply mix strategy and address the objectives established for this study.
3. Strapolec identified several paradigm shifts that would be necessary in order for Ontario to achieve a future low-cost, low carbon energy system.
4. The underpinning characteristics of these paradigm shifts were then integrated into a detailed hourly model of Ontario’s electricity system, as projected to meet the demand associated with achieving the 2030 emission reduction targets.
5. From this production and demand model, a supply mix was developed that best balances supply and demand given the objectives stated for Ontario’s future supply mix.
6. The cost and economic implications were then derived from the production information generated by the simulation as well as from benchmarks previously established by Strapolec.

Document Structure

This report provides a description of the drivers, assumptions, and implementation considerations for an alternative supply mix that should be considered during the LTEP process. It also identifies the impact on electricity and emission reduction related costs that Ontarians could pay and the potential benefit that could ensue to Ontario’s economy.

Section 2.0 provides background on the context for the findings presented in this study. A summary of Phase 1 results is provided regarding the projected electricity demand required to achieve emission reductions. The section also discusses the implications this additional energy demand presents with respect to the need for capacity development. OPO Outlook D capacity scenarios are described, including capacity, production and costs, along with projections of what those options might entail if they are scaled-up to meet the demand identified in the Phase 1 Report.

Section 3.0 of this document examines the production profile of the supply options described in the OPO and considers the implications that may affect their development.

Section 4.0 introduces the four electricity system planning paradigm shifts that have led to the recommended Scenario “S” supply mix option: Distributed Energy Resources (DER); integration of the wires and pipes; the supply mix benefits related to the hydrogen economy; and the rationale for a large nuclear component in the supply mix. The implementation characteristics of each element is described along with the modelling assumptions developed for the inclusion of Scenario “S” in a detailed hourly model of Ontario’s electricity system. A discussion is provided on how demand variability is impacted and what implications the new demand and Scenario “S” may have on the Dx system. The results of the simulation summarize the capacity, production, and surplus energy metrics of the scenario.

Section 5.0 summarizes the costs associated with this new Scenario “S” supply mix.

Section 6.0 provides an overview of the implementation considerations, including the management of waste, with a focus on the risks that are raised in the OPO. A possible pathway for the development of the Scenario “S” supply is presented.

Section 7.0 presents the economic benefits and implications that would accompany Scenario “S”, including the cost of achieving the emission reductions and the economic benefits that could accrue to the province from enabled industrial activity and improved trade balance.

Section 8.0 provides several recommendations related to the consideration of Scenario “S” in the 2017 LTEP consultation process.

Supporters of this study are acknowledged following the recommendations. The sources consulted during the research for this study are listed in Appendix A. A list of acronyms can be found in Appendix B.

2.0. Demand Context and the OPO Outlook D

Section 2.0 provides background information and context intended to be helpful in understanding this Study's findings.

First, a summary is provided of the Phase 1 projected electricity demand required to achieve the emission targets and the implications this demand may have on capacity development. The OPO Outlook D capacity scenarios are described, including capacity, production and costs, along with projections of what those options could entail if scaled-up to meet the demand identified in Phase 1. Finally, the OPO forecast regarding the expiry of the contracts for Ontario's existing supply mix is discussed.

This section concludes with a summary of the key findings.

2.1. Overview

Electricity demand driven by Ontario's emission reduction targets is central to the 2017 LTEP. Phase 1 estimated that over 90 TWh of new electricity demand will result from the initiatives undertaken across Ontario's entire economy to meet the province's 2030 emission reductions targets. Figure 1 illustrates the Strapolec demand forecast from Phase 1 compared to the OPO Outlooks B and D. The 90 TWh is incremental to the business as usual (BAU) OPO Outlook B forecast.

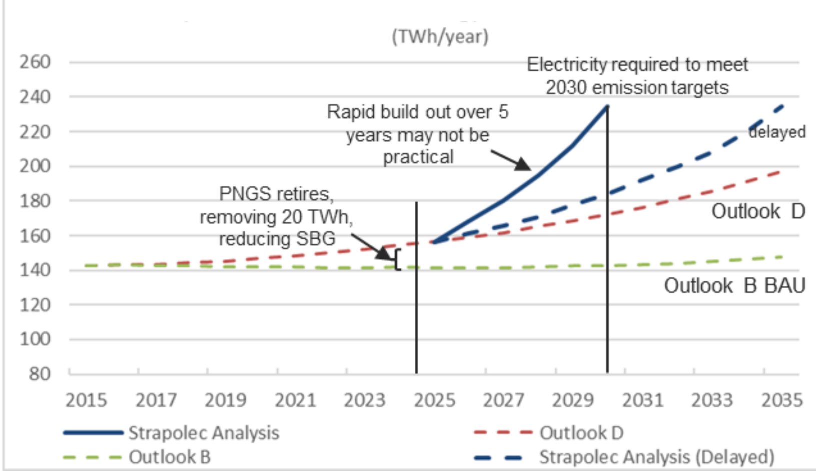
The IESO has provided several outlooks, two of which are illustrated in Figure 1[2]:

- Outlook B is a relatively flat demand profile assumed to represent the BAU forecast.
- Outlook D, which is the highest demand scenario in the OPO, reflects the impacts of Ontario's climate strategy. However, it is not clear whether this demand reflects what is needed to achieve the emission targets across the entire economy.

Phase 1 estimates that the electricity required to meet the 2030 emission targets will be needed sooner than shown in the OPO Outlooks. The Outlook D forecast is based on electricity demand ramping up gradually to 2035. By 2030, only 30-40% of the electricity supply required to achieve the 2030 emission reductions will be available. This suggests that Ontario could miss its 2030 targets by 60-70%.

[2] IESO, Module 2: Demand Outlook, 2016

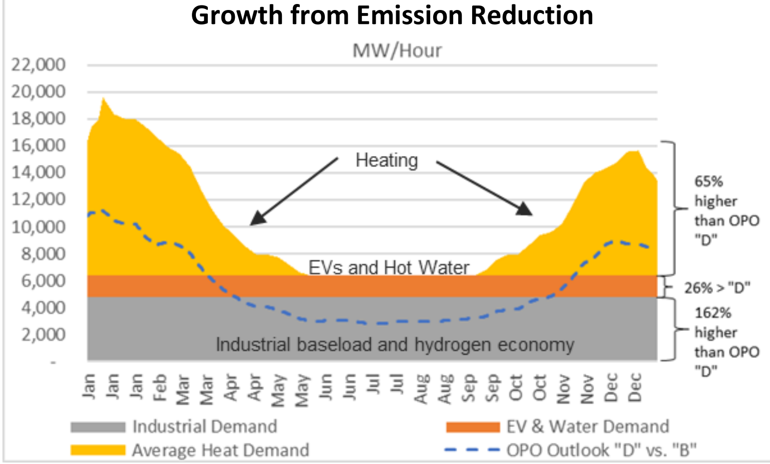
Figure 1 – Electricity Demand Growth Scenarios



Emission targets cannot be met without planning for new electricity infrastructure, the requisite timing of which is not reflected in the OPO. The ability to achieve Ontario's emission targets and the cost of doing so will be driven by the feasible pace at which new electricity generating capacity is developed to meet the new demand. If the infrastructure is not planned for, it will not be available. Achieving the needed supply in time is particularly important given the anticipated retirement of the Pickering Nuclear Generating Station (PNGS). The Phase 1 report recommends that the LTEP process should consider the need to rapidly make clean electricity generation available to help support the 2030 emission reduction targets.

Planning for the requisite electricity generation necessitates consideration of the type of energy source required. Addressing the heating requirement is central to achieving emission reductions, and will introduce a very different characteristic to Ontario's seasonal electricity demand profile. Figure 2 depicts Strapolec's forecast for the new annual seasonal demand profile compared to the incremental demand assumed by the OPO for Outlook D.

Figure 2 – Components of Electricity Demand Growth from Emission Reduction

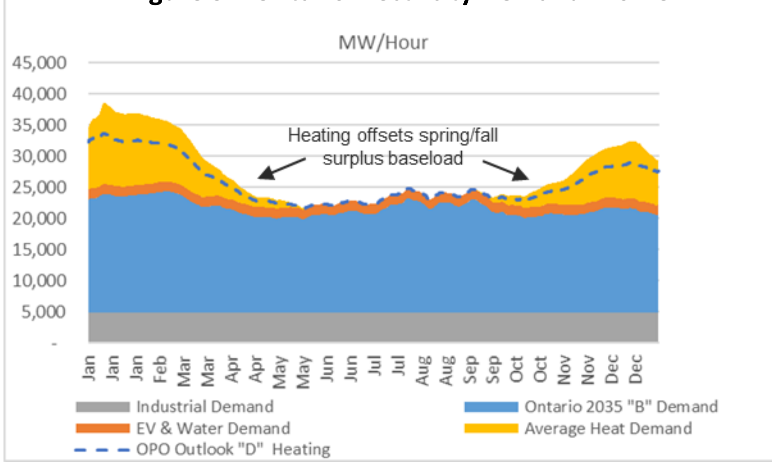


Analysis shows that there will be a significant ramp up of electricity required to supply home heating needs[3]. There are three types of new demand emerging from emission reductions:

- Home heating represents a new seasonal demand load that Ontario currently supplies from its natural gas system. This is considered the largest challenge to the system, particularly the Dx system. Strapolec forecasts 65% more electricity will be required for heating than outlined in OPO's Outlook D.
- Electric Vehicles (EVs) and water heating represent a daily demand profile driven by consumer behaviors. Some believe that much of this demand can be accommodated through smart controllers and hence depend upon the use of off-peak energy[4]. The Strapolec forecast suggests that EV and water heating related electricity demand will be 26% higher than the OPO Outlook D assumption. This is mostly due to the heating assumptions, since Phase 1 assumed fewer EVs than Outlook D.
- The industrial applications could be met by new baseload. The projected 5 GW of new baseload demand is 162% higher than reflected in the OPO Outlook D.

Overlaying the new demand profiles on existing demand yields the overall total system demand profile for the province, as illustrated in Figure 3. These new demand profiles smooth some of the seasonal variability, particularly for the spring and fall, but a significant new winter peak emerges. The winter peak remains an important consideration for future system planning, whether Outlook D or Strapolec's forecast is assumed. Winter heating demand is a low annual capacity factor load that will place upward pressure on electricity rates if it is supplied by a sub-optimal energy mix.

Figure 3 – Ontario Electricity Demand Profile



[3] Heating profile based on IESO Outlook D demand, EV and hot water demand profile based on IESO

[4] Haines, OEA Energy Conference remarks, 2016

2.2. OPO Outlook D Capacity Options

The OPO has identified four capacity options for Outlook D demand scenario that encompass most of the traditional generation source options. The capacity options are distinguished by the relative shares of hydro (or waterpower), natural gas-fired generation, nuclear, and wind.

Capacity

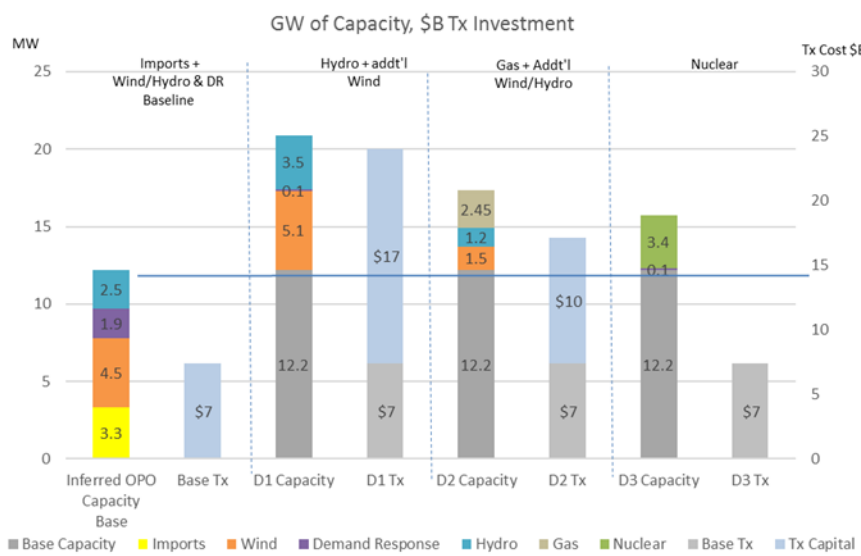
This subsection looks at the incremental capacity, production, and costs associated with the OPO Outlook D capacity options, which are summarized in Table 1.

Table 1 - OPO Outlook D Installed Capacity Scenarios

MW Installed	D1	D2	D3	D4
Nuclear	0	0	3,400	2,500
Waterpower	6,000	3,700	2,500	1,850
Wind	9,600	6,000	4,500	4,250
Gas	0	2,450	0	2,050
Demand Response	2,000	1,900	2,000	1,750
Firm Imports	3,300	3,300	3,300	3,300
Total	20,900	17,350	15,700	15,700

Significant imports from Quebec and amounts of wind generation are assumed in all cases and are inferred to be a common capacity base. Figure 4 identifies the components of this common capacity base, and illustrates that it underpins each of the OPO capacity options: D1, D2, and D3. The fourth OPO option, D4, is an additional supply mix of the same supply types.

Figure 4 – IESO Outlook "D" Supply Mix Option Differences



The most significant components of the common capacity base are the 3300 MW of imports from Quebec and the 4500 MW of wind capacity. The common capacity base also includes 2500 MW of hydro and 2000

MW of Demand Response. Consequently, the OPO options are strongly biased towards imports and wind in the context of how the trade-offs are presented. The common capacity base is not presented in the OPO as being materially available for trade-off.

Option D1 requires the largest amount of new capacity at 21 GW, which is due to the low operating capacity factor of the added wind generation capacity. Option D3, in contrast, has the lowest amount of new capacity due to nuclear's high operating capacity factor. The blended Option D4, summarized in Table 1, has the same total capacity as Option D3. Therefore, Option D4 is not discussed further in this study as the primary reason for assessing the Outlook supply options is to better understand the cost behaviours of each supply type. This is not meant to infer a comment on the merits of Option D4.

Additional Tx capacity is also required in each scenario. The OPO only describes the Tx capacity in terms of total cost to service the options. There is an assumed base Tx cost of $7B associated with the capacity base. D1 has the highest additional Tx costs of $17B, for a total Tx cost of $24B. D3, the nuclear option, does not require additional Tx, beyond the $7B base assumption.

Production

Table 2 summarizes the production from the incremental capacity of each option. The common capacity base supply will produce the majority of the new production, a total of 39 TWh. The additional production from the Hydro (D1) and Nuclear (D3) options is 25 TWh and 26 TWh respectively. For the Outlook D incremental demand of 49 TWh, these options would result in significant surplus electricity. The Hydro and the Nuclear options have surpluses of 30% over the projected OPO demand. If these surpluses are attributed to the common capacity base supply, the surplus represents almost 40% of the production for that capacity. Section 3.0 shows how this surplus could be due to the wind component of the generation mix.

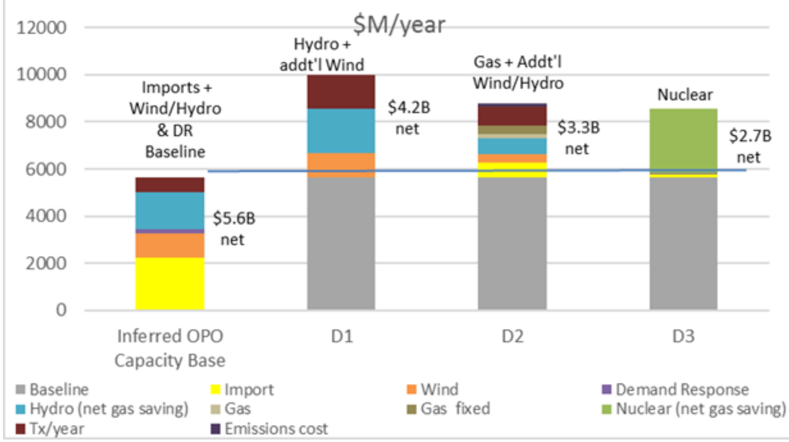
Table 2 - OPO Outlook D 2035 Production by Option

TWh/Year	**Capacity Base**	**D1**	**D2**	**D3**
Imports	16	0	4	1
Wind	12	12	4	0
Hydro	11	15	5	0
Gas		-2	3	-3
Nuclear				28
Subtotal	39	25	16	26
Base Supply		*39*	*39*	*39*
Total	**39**	**64**	**55**	**65**
Demand		*49*	*49*	*49*
Surplus	5-15	15	6	16
% Surplus	*38%*	*31%*	*12%*	*33%*

Cost

Understanding the cost implications of the various options warrants full consideration of all of the cost elements that may be impacted by the options. Figure 5 illustrates the incremental costs with respect to Outlook B, of options D1, D2, and D3. Special attention is paid to the common elements of each option. Figure 5 shows the Hydro option (D1) to have the highest total cost of $10B/year, which is $1.6B/year more than the lowest cost Nuclear option (D3), with a total cost of $8.3B/year.

Figure 5 – OPO Outlook "D" Supply Mix Option Costs



These values are materially different from the incremental total system costs identified in the OPO. The OPO incremental cost for option D1 is $8.5B/year in 2035. Table 3 shows the cost element assumptions from the OPO. Nuclear is the lowest cost baseload generation. Only the intermittent solar and wind generation assumptions are lower than nuclear, but these sources require significant backup/storage and entail other integration costs. The wind and solar cost implications are discussed further in Sections 3.0 and 4.0.

Table 3 - OPO Cost Assumptions

Incremental Resource	LUEC (2016$/MWh)	Capacity Cost ($/kW-year)
Simple Cycle Natural Gas-Fired Turbine	N/A	$135
Large Nuclear	$120	N/A
Waterpower	$140	N/A
Wind	$86	N/A
Solar PV	$90 (2030)	N/A
Bioenergy	$164	N/A
Demand Response		$100
Firm Imports (<1,250 MW)	$120	N/A
Firm Imports (Up to 3,300 MW)	$160	N/A

The detailed components of the cost build up are provided in Table 4.

Table 4 - OPO Outlook D 2035 Costs by Option				
$M/year	**Capacity Base**	**D1**	**D2**	**D3**
Import	2,240	0	640	160
Wind	1,032	1,032	344	0
Demand Response	190	10	0	10
Hydro	1,540	2,100	700	0
Gas	0	-120	180	-180
Nuclear	0	0	0	3,038
Tx/year	628	1,409	823	0
Gas fixed	0	0	331	0
Incremental	*5,630*	*4,431*	*3,018*	*3,028*
Emissions cost		-80	120	-120
Net Incremental	**5,630**	**4,351**	**3,138**	**2,908**
Baseline	0	5,630	5,630	5,630
Total	**5,630**	**9,981**	**8,768**	**8,538**
OPO Reference		*8,500*	*7,700*	*8,100*
Difference - Strapolec vs OPO		*1,481*	*1,068*	*438*
Diff as % of Tx costs assumed		*1*	*1*	*1*
Financing costs assumed		*1,557*	*1,110*	*480*
Option Incremental Cost with Tx ($/MWh)		*174*	*196*	*112*
Option Total Cost with Tx for 49 TWh ($/MWh)		*204*	*179*	*174*
OPO Option Incremental Cost for 49 TWh ($/MWh)		*173*	*157*	*165*

Some assumptions in Table 4 have been modified from the OPO values stated in Table 3. These adjustments include:

- Imports: An average of the two rates have been used for a net cost of $140/MWh;
- Nuclear: The OPO cost assumption reflects an 85% operating factor, but the incremental TWh amounts to a 94% operating factor, which is reasonable for new nuclear reactors. An operating factor of 94% results in a rate of $108/MWh. Strapolec considers this cost to be about 10% too high. The context for this conclusion is discussed in Section 6.0;
- Gas Variable production costs: The OPO did not contain a value. Strapolec has assumed a nominal value of $60/MWh based on derivations from previous Strapolec reports that have taken into account the EIA forecast cost of natural gas and projected those costs to the Dawn Hub;
- Carbon Price: a nominal value of $100/tonne has been applied to incremental gas-fired generation; and,
- Tx Costs: These have been incorporated based on IESO stated capital costs. The annualized values are based on a 50-year amortization at an assumed pre-tax Weighted Average Cost of Capital (WACC) of 8%.

As shown in Table 4, Strapolec's total cost estimates are higher than those in the OPO. An examination of these differences suggests that they may be accounted for by the financing assumptions Strapolec has applied to the Tx investments. It is not clear whether the "Total Capital Costs" quoted in the OPO include financing costs.

The incremental cost of the D1 options could be as high as $204/MWh, or 15% higher than the worst case assumption used in the Phase 1 report.

2.3. Implication of Higher Demand with OPO Capacity Options

To develop a baseline for cost comparison purposes, an OPO option needs to be scaled-up from a delivery capability of 49 TWh to a level that would deliver the expected 92 TWh of demand in Scenario "S".

OPO Option D1 was chosen as the reference case to which new capacity will be added. The new scaled-up D1 capacity was built in two steps. First, a reference capacity scenario was developed by adding the OPO D3 nuclear capacity of 3400 MW. The OPO D3 nuclear capacity produces 28 TWh of incremental energy which could provide the supply for the "S" industrial baseload demand. Adding this production to the original 49 TWh of D1 results in 77 TWh. The original D1 capacity is then scaled-up ~31% to deliver the remaining 15 TWh required to meet the increased heat load and the projected 92 TWh demand.

Figure 6 illustrates the process used to derive the scaled-up production and Figure 7 illustrates the scaled-up capacity and cost.

Figure 6 – Demand Driven Production Scale Factor

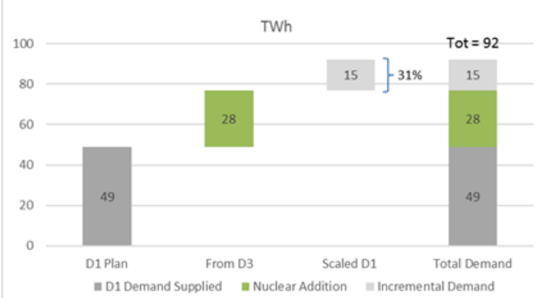
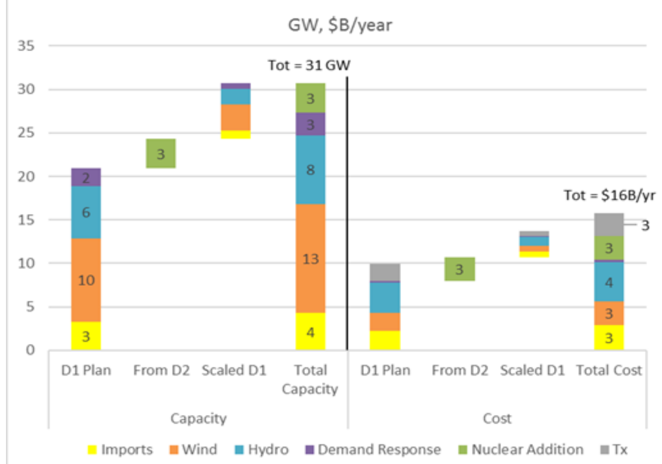


Figure 7 – Increase in D1 Capacity and Cost to Meet "S" Demand

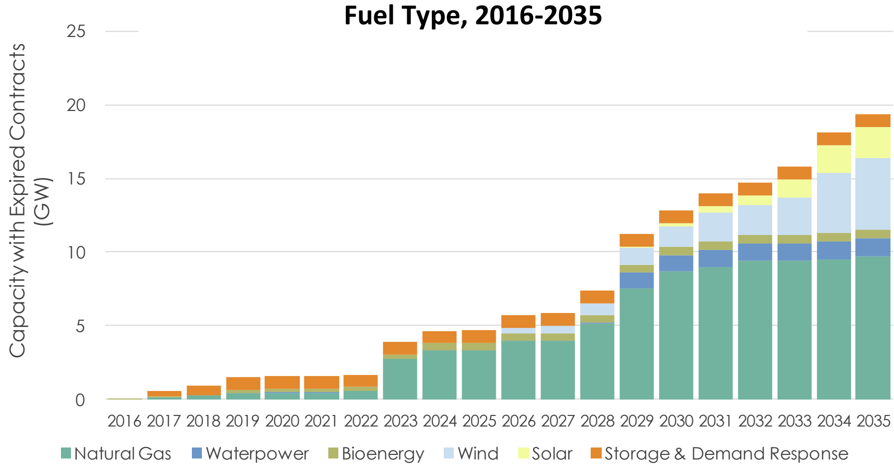


The increase in demand results in a need for 31 GW of new capacity, including 4.3 GW of imports, 12.5 GW of wind and 7.8 GW of new hydro along with 3.4 GW of new nuclear. These are staggering numbers with an expected total cost of $16B/year. This results in an expected average incremental electricity rate of ~$170/MWh for the scaled-up D1 option, assuming, as the OPO does, that there are no incremental costs to be incurred by the Dx system.

2.4. Ontario's Existing Capacity

The pending expiry of Ontario's currently contracted supply represents an opportunity for the LTEP process. Figure 8[5] from the OPO shows how much contracted capacity is expected to have contracts expire during the time horizon of the LTEP.

Figure 8 – Expiring Contracts, Installed Capacity by Fuel Type, 2016-2035



The projection shows that 18 GW of capacity can either be renewed or retired. The majority of this capacity is comprised of gas-fired and wind generation.

2.5. Summary

Phase 1 identified 92 (~90) TWh of new demand will be required to meet the emissions target in 2030.

The OPO lays out four supply mix options to address the new Outlook D demand of 49 TWh (~50 TWh). The incremental cost of the OPO D options all exceed $8.5B/year and represent a total system cost that is 25% higher than today.

New nuclear capacity is the lowest cost supply option included in the OPO Outlooks, which when included with the OPO D1 supply mix to scale up to the ~90 TWh of demand, lowers the unit cost of D1 from the estimated $204/MWh. A scaled-up OPO supply mix option that would meet the ~90 TWh of demand would have a total incremental cost approaching $16B/year and unit cost of electricity of $170/MWh.

The expected contract expiry of a large portion of Ontario's generation capacity over the next 15 years is an opportunity to rethink Ontario's supply mix in light of the new requirements stemming from Ontario's climate strategy.

[5] IESO, Module 4: Supply Outlook, 2016

3.0. Understanding OPO Outlook D Option Implications

This section examines the production profile of the supply options described in the OPO and considers the implications that may affect their future development in meeting Ontario's emission reduction driven demand growth. This Section provides information that is intended to help dispel some of the myths about the supply options available to Ontario. By clarifying the supply characteristics of each option, it should be easier to assess the optimality of the province's future energy choices.

Subsection 3.1 illustrates the production profiles of the supply options in OPO Outlook D supply scenarios. The characteristics of solar generation in Ontario are then briefly discussed, even though solar was not considered in the new supply capacity options in the OPO. The implications of developing hydro and imports from Quebec are presented followed by a description of the role nuclear has played in Ontario's clean energy system. Finally, the suitability of wind generation in Ontario's past, present, and future supply mix is assessed.

This section concludes with a summary of the key findings.

3.1. Overview of OPO Outlook D Supply Production Profile

The illustrated production profiles in OPO Outlook D show that imports are mostly targeted to meet Ontario's winter peak, with wind helping to offset the imports when available. However, wind generation also results in a surplus electricity.

A simulation was developed to illustrate how the OPO supply options could interact to supply the anticipated demand. The demand profile provided in the OPO has been combined with the supply constraints stated in the OPO for the capacity options in D1 and D3. Specifically, these constraints include:

- Hydro at winter peak is 56% of capacity and the overall annual production is assumed to be 50% of capacity. These are the characteristics of a baseload supply.
- Wind generation will be 30% of capacity, the level required to achieve the incremental production stated in the OPO.
- Imports were limited to 3300 MW as a maximum.

Figures 9 and 10 show the 2035 production profile for each integrated supply mix. Note that the demand line has been smoothed.

Each supply type performs a different function reflecting the assumptions made for the simulation.

- The incremental hydro and nuclear are both assumed to provide baseload supply in the scenario.
- Hydro is assumed to have the same production profile of that from Ontario's existing hydro resources.

- Wind generation production will be intermittent. A 2015 reference year has been adopted to provide the wind patterns. Wind in Ontario tends to arise at similar and coincidental times across the province[6].
- Wind is deemed surplus to the hydro or nuclear generation.
- Imports are called upon to meet the winter ramp if there is insufficient wind production.

The production results of the simulation matched favourably to OPO's defined generation for all supply types.

In section 2.2., It was observed that the OPO assumed over 15 TWh of surplus for both the D1 and D3 scenarios. The simulation results illustrated below show that wind may be able to "fill in" with the future imports, but does not integrate well with baseload hydro or nuclear. This intermittency results in over 40% of the wind generation becoming surplus generation in both the D1 and D3 options.

Figure 9 – Seasonal Supply & Demand Profile, D1

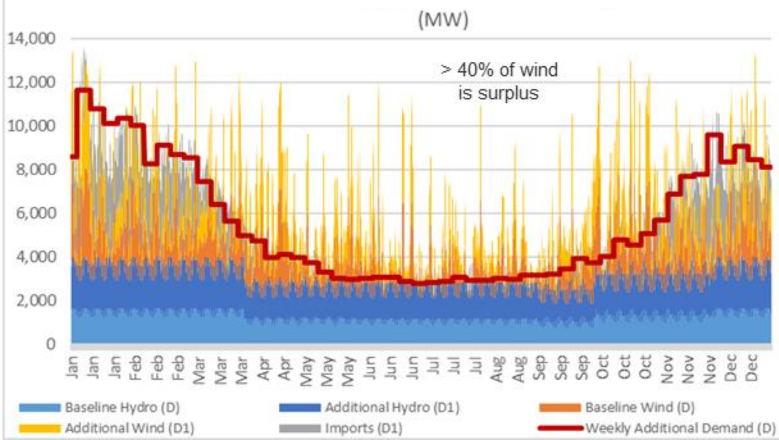
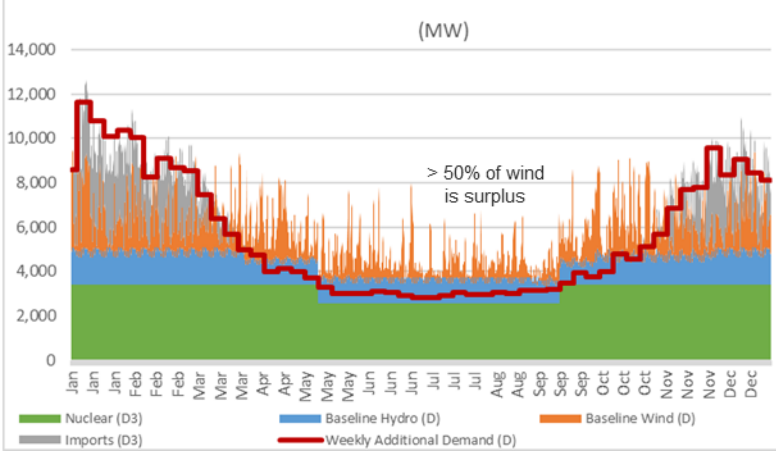


Figure 10 – Seasonal Supply & Demand Profile, D3



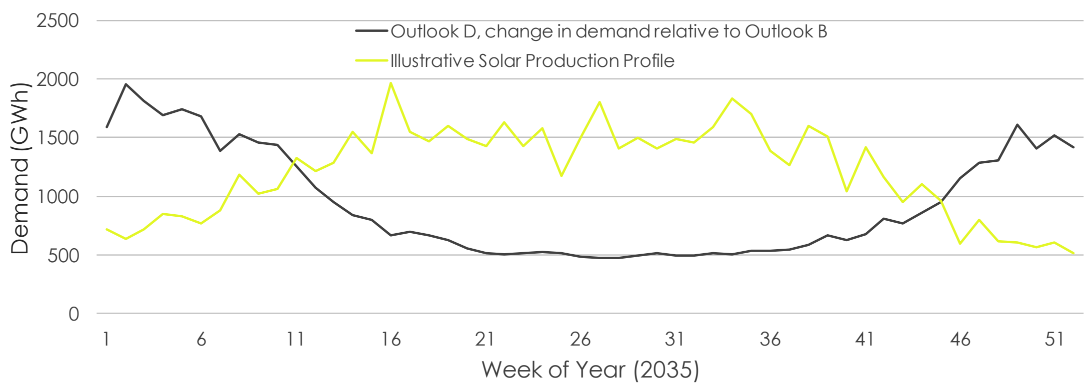
[6] Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016

The D2 option was also simulated. The results indicated that wind integrates well with natural gas-fired generation with little surplus, as would be expected, supporting the observation in Section 2.2. that the D2 option had 10 TWh less surplus than D1 or D3. Unfortunately, the D2 option is a natural gas-fired option with higher CO_2 emissions and no cost advantage. It will not be discussed further in this report.

3.2. Solar Generation

The OPO indicates that solar generation does not help meet the new demand profile. The OPO makes reference to DER and its challenges and potential benefits, but does not appear to have reflected any solar generation supply mix implications into the option assumptions. Figure 11[7], reproduced from the OPO, shows that the expected new demand profile is high in winter, while solar is at its peak in the summer.

Figure 11 – IESO Heating Demand and Solar Production Profiles



The OPO alludes to the mismatch between the sun's patterns and electricity demand. This mismatch is a challenge that is not unique to solar.

The role of solar in the integrated DER solutions is explored to identify any potential benefits in Section 4.2.

3.3. Developing Hydro and Imports

Securing additional hydro and imports as part of Ontario's future supply mix faces both physical and geographic challenges.

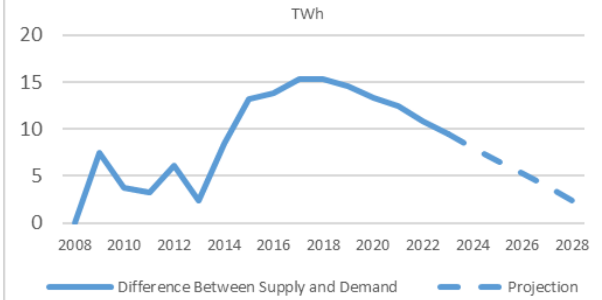
A firm import maximum of 3300 MW is included in all of the OPO D scenarios. The OPO states that opportunities exist for greater electricity trade with Ontario's interconnected neighbours; however, only Quebec and Manitoba have low carbon resources, and the ability for Ontario to import from Manitoba is

[7] IESO, Module 4: Supply Outlook, 2016

limited by significant Tx constraints. It is assumed that the imports in the OPO are intended to come from Quebec.

Strapolec's recent study[8] of the Ontario and Quebec interties indicated that Quebec will not have surplus generation by the late 2020s, as shown in Figure 12. Furthermore, Quebec is actively pursuing US market Tx expansion projects to facilitate the export of this surplus, which can be expected to accelerate the rate at which this surplus decreases.

Figure 12 – Difference Between Quebec Supply & Demand



Quebec is generation limited in winter, the time at which Ontario will most likely require these imports. The OPO also states that firm imports would not be available before 2028. This suggests that acquiring greater firm imports from Quebec to help meet Ontario's winter heating demand will need to be provided by new generation located in Quebec.

Since Quebec already meets its heating demand, there is less need for significant additional hydro generation to meet winter demand, unless it is developed for Ontario. According to Hydro Quebec's (HQ) President and CEO[9], Quebec does not currently have plans for new generation capacity. Although evaluations are being conducted to see if options should be included in their post 2020 strategy. Some have speculated that the output of Labrador's Muskrat Falls, a project experiencing major cost challenges, could potentially be wheeled to Ontario. However, the capacity of that project is only 825 MW, and the supply is already ear-marked to go east and south[10]. It is not a likely source for addressing Ontario's significant future supply challenges.

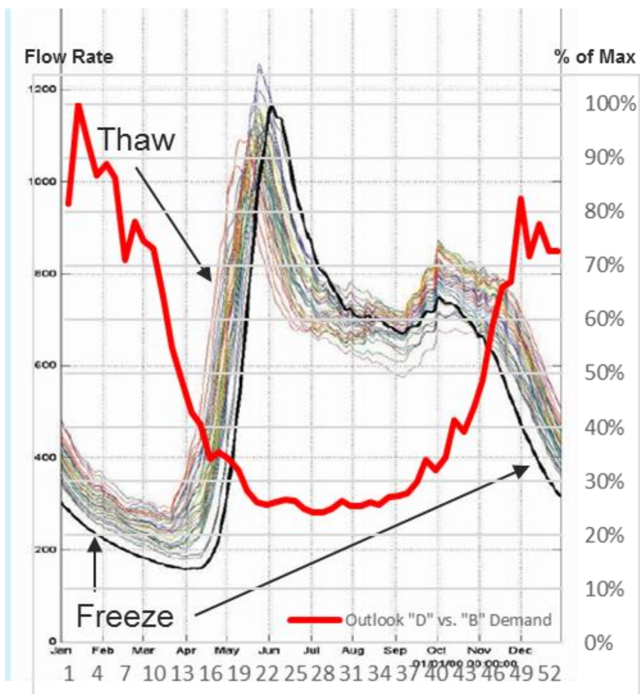
At present, HQ can export up to 1800 MW to Ontario without any Tx infrastructure expansion. Currently, these imports do not occur, except during times of peak demand, as Ontario also has surplus supply. Additionally, there are Tx related congestion constraints in the Ottawa area, which will be addressed over the next few years[11]. The full capacity of the interties is rarely used in either direction.

[8] Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016
[9] Martel, Opening Keynote from APPrO 2016, 2016
[10] Nalcor Energy, Muskrat Falls Project: Project Overview, 2016
[11] Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016

New hydro supplies could be viewed as potentially possible from either Ontario or Quebec as new waterpower generation could be constructed in either province. From a long-term energy perspective, the imports/hydro combination represents a collective supply challenge. Given the climate action policies in both provinces, going forward, both provinces can expect a need to accommodate emission reduction induced demand.

As with solar generation, building new hydro capacity necessarily involves managing the vagaries of mother nature's influence on the availability and flow of water. Figure 13 illustrates a hydrograph for Quebec that depicts the flow of water in the rivers of northern Quebec reflecting precipitation and temperature effects and how the flow changes over the year. The source chart was originally prepared to show how climate change may be altering these flows over time[12]. It demonstrates that Ontario's need for winter heating energy is at odds with the hydro production profile, due to the winter freeze and spring thaw of the northern lakes and rivers where the new hydro potential exists in Quebec.

Figure 13 – Projected Quebec 30 Year Hydrograph vs. New Heating Demand (as % of Max)



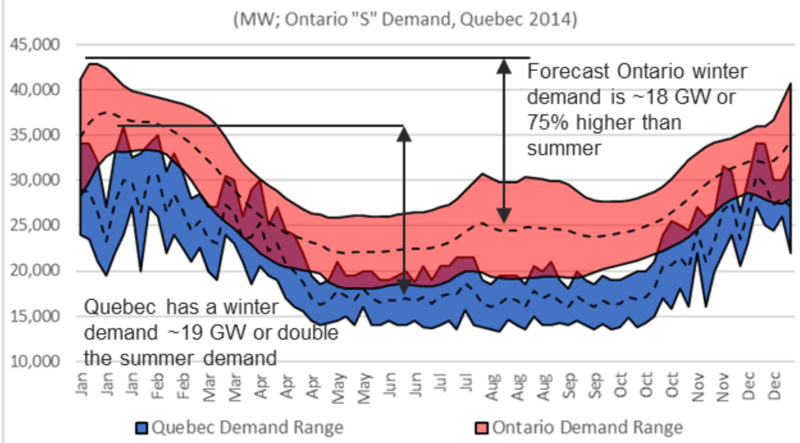
This means that "run of river" and the "far north" profiles are not well matched to Ontario's winter heating need, given this winter freeze. Meeting the incremental demand forecast and the winter heating load would require the construction of a new reservoir with seasonal storage capability like Quebec now has with James Bay. Seasonal storage involves flooding considerable tracts of land.

[12] Vescovi, The United Nations World Water Assessment Programme: Water and Climate Change in Québec, 2009

Combining the OPO expectations for hydro and imports suggests over 9 GW of required new generation in the OPO D1 option. As discussed in Section 2.2, scaling the D supply to meet the "S" demand may warrant 12 GW of combined imports/hydro, almost 16 GW if the solution does not include new nuclear. This would require a significant capacity build out of hydro in eastern Canada.

Figure 14 compares the projected heat demand needs of Ontario to Quebec's annual energy consumption profile. The difference between Ontario's average summer and winter peak electricity consumption is projected to be 18 GW. This profile only represents half of Ontario's heat load. Even though Quebec's overall energy consumption is expected to remain lower than Ontario's, the difference between the average summer and winter peak demand levels is a similar 19 GW. It is clear that Ontario is facing a significant electrification challenge since the winter peak to summer peak ratio may still double in the future.

Figure 14 – Ontario and Quebec Electricity Demand



The 12 GW to 16 GW of new hydro generation capacity that would be required to meet Scenario "S" demand is about the same magnitude as that of the 16 GW James Bay project, and is about 3 times the size of the Churchill Falls complex. The James Bay Project flooded 13,000 km^2 of land to compensate for the winter freeze and spring thaw cycle and to store water from the spring and summer to be able to meet Quebec's winter heating demand. This new capacity, whether built in Ontario or Quebec would require large-scale flooding, making it challenging to secure support from directly affected stakeholders. The recent Eastmain reservoir in Quebec covers an area about 600 km^2 to support a 480 MW hydro plant, a higher area to MW ratio than James Bay.

The OPO acknowledges that waterpower development comes with cost and consultation challenges. The OPO states that the remaining waterpower potential in Ontario is in remote northern regions without Tx access, which results in the significant Tx costs noted in the Outlook D1 option. The OPO also states that costs are expected to be higher than in the past, and that the projects will involve longer lead times. Only small opportunities for expanded hydro capacity exist in the south, including redevelopments at existing dams.

The Canadian Hydropower Association (CHA) suggests that Ontario has over 10 GW and Quebec over 40 GW of untapped hydro power potential[13]. Canada's recent Mid-Century Greenhouse Gas (GHG) Strategy[14] echoes the CHA's claim and also expresses several of the same caveats noted in the OPO.

The OPO refers to a Hatch report[15] that assessed hydro resource potential in Ontario. While focussed primarily on smaller opportunities in the 'Ring of Fire' area, Hatch suggested that a 10-20 year development cycle for large-scale hydro projects can be expected.

Potentially, 3.9 GW of hydro power could be developed in Ontario's far north. This would involve the Moose, Albany, Attawapiskat, Winisk and Severn rivers that flow north into Hudson Bay and James Bay. With the exception of the Moose River, these large northern rivers exist in an almost unaltered state. It is rare in a global context that rivers this size are undeveloped[16] suggesting that relatively long consultation times would be required.

Given the magnitude of the new capacity required, and the anticipated long lead times for development, it is unlikely that these resources would be available by 2030 or even 2035, the timeline that frames the OPO.

Hydropower developments in both Quebec and Ontario should be evaluated and pursued where viable. The pathway to 2050 deep decarbonization will require the development of these assets for future generations of Canadians. With a goal of reducing emissions by 80% by 2050 across the entire economy, Canada's Mid-Century GHG Strategy has a high hydro scenario that reflects more than a doubling of the above-mentioned capacity. The report states that this scenario approaches the technical limit of Quebec and Ontario resources.

For this study, options that are less reliant on hydro development are assessed to provide an alternative to those already presented by the OPO.

3.4. Nuclear Supply In Ontario

Three important facts about Nuclear are relevant to the LTEP consultation process:

- Nuclear is Ontario's low-cost clean energy advantage today and in the future.
- Nuclear has been Ontario's engine for reducing GHG and was the chief enabler of Ontario's coal retirement initiative[17].
- Nuclear provides a flexible supply that can be matched to seasonal demand.

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[13] Canadian Hydropower Association, Hydropower Potential, 2016

[14] Government of Canada, Canada's Mid-Century Long-term Low Greenhouse Gas Development Strategy, 2016

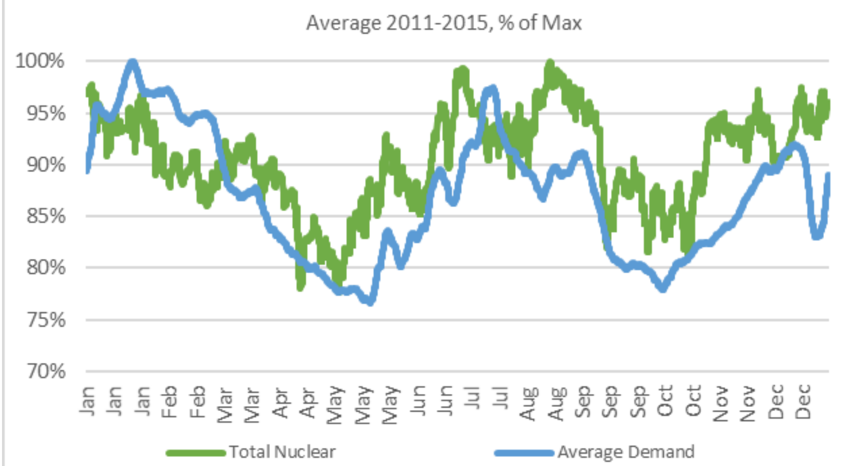
[15] Hatch, Northern Hydro Assessment, 2013

[16] EcoIssues, Hydroelectric Development in the Far North, 2015

[17] A detailed analysis of the role played by all the elements of Ontario's supply mix in achieving the elimination of Coal in Ontario is provided in: Strapolec, Extending Pickering Nuclear Generation Station Operations, 2015

Figure 15 shows that over the last 5 years, on average, the nuclear production profile adapts well to Ontario's demand.

Figure 15 – Ontario Demand vs. Nuclear Fleet Generation



This figure shows that nuclear can provide seasonal demand flexibility through the management of the regularly scheduled unit outages. Furthermore, each of the eight Bruce unit provides a flexible production capability to reduce their output by up to 300MW, for a total supply flexibility of up to 2400 MW[18]. This report will explore the potential role for nuclear in Ontario's future supply mix.

3.5. Wind Supply in Ontario

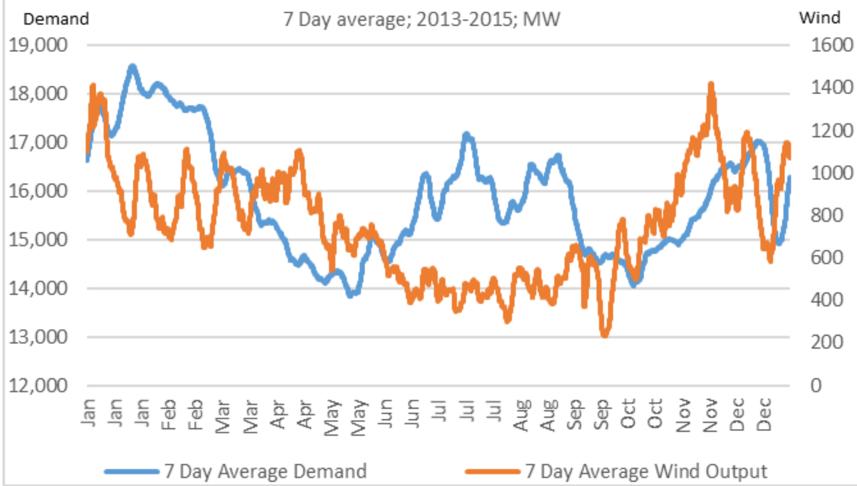
The significant increase in wind capacity in the OPO is questionable on three counts:

- Wind generation has not matched demand since its introduction in Ontario;
- Over 70% of wind generation does not benefit Ontario's supply capability: and,
- Wind generation will not match demand in the OPO Outlook future projections as 50% of the forecasted production is expected to be surplus.

Figure 16 compares wind generation patterns to Ontario demand for the period of 2013 to 2015. Over this three-year period, wind generation has increased in the spring and fall when Ontario doesn't need the supply, and is at its lowest when Ontario needs it most in summer. Peaking in the fall, wind generation does not contribute to its full supply capacity throughout the higher winter demand period. Wind cannot be matched to demand. With the forecasted winter-heavy demand profile, the contrast between wind generation and demand in winter will become as stark as those in the summer.

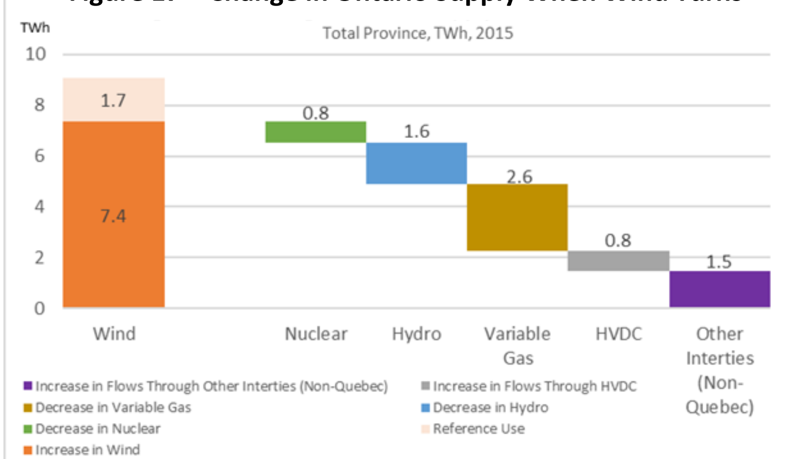
[18] Bruce Power, BPRIA Backgrounder, 2015; NECG, Nuclear Flexibility, 2015

Figure 16 – Average Yearly Wind Output vs. Demand



This mismatch leads to surplus energy. In a previous study[19], the degree to which wind energy is productively used by Ontario's electricity system was examined. The findings are summarized in Figure 17.

Figure 17 – Change in Ontario Supply When Wind Turns



When wind generation is present in Ontario, it causes three distinct reactions of similar magnitude in the dispatch of Ontario's supply resources:

- Curtailment (waste) of both nuclear and hydro;
- Export of wind generated electricity at prices well below cost of production[20]; and
- Reduction of natural gas-fired generation.

There are two components to useful wind energy production:

[19] Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016
[20] OSPE, Ontario's Energy Dilemma, 2016

(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.

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 and/or via uneconomic exports to neighbouring jurisdictions.

As discussed in Section 3.1, this historical surplus wind generation is reflected in the production forecast in the OPO D1 and D3 options. These results indicate that 40% to 55% of the planned wind capacity in the OPO may be surplus. This is a very important consideration given that the LTEP focuses on the lowest possible cost future. If wind generation can only be productively used 50% of the time, then its unit cost doubles to $172/MWh from the $86/MWh assumed in the OPO. This suggests that wind generation is the most expensive generation option for Ontario, not including the Tx related costs and other integration issues described in the OPO. Wind and imports represent the two most expensive options in the OPO, yet these options are given significant weight in the OPO. The LTEP process should address this contradiction.

Wind could have value if its intermittent capacity can be matched to a reservoir hydro source. This value proposition is referred to in the Canada Mid-Century report[21], which notes that pairing wind generation with hydro could economically reduce the size of the required reservoir. Otherwise there are no cost savings.

For the purpose of this study, alternative supply scenarios that do not include wind are explored.

3.6. Summary

The OPO places significant emphasis on options that involve new imports from Quebec, and new hydro and wind generation capacity. All of these options involve significant implementation and economic challenges that suggest they represent sub-optimal choices for achieving Ontario’s 2030 emission targets. This study assumes that the OPO has adequately framed these options. The alternative scenario explored in the next section focuses on solar, nuclear, and other potential solutions.

[21] Government of Canada, Canada’s Mid-Century Long-term Low Greenhouse Gas Development Strategy, 2016

4.0 Electricity System Planning Paradigm Shifts

This section summarizes the electricity system design drivers and introduces four electricity system planning paradigm shifts that have led to the Scenario "S" supply mix option: (1) DER; (2) integration of the wires and pipes; (3) the supply mix benefits related to the hydrogen economy; and (4) the rationale for a large nuclear component in the supply mix. The implementation characteristics of each is described along with the modelling assumptions developed for Scenario "S" in Strapolec's detailed hourly model of Ontario's electricity system. Information is provided regarding the impacts on demand variability and on the Dx system.

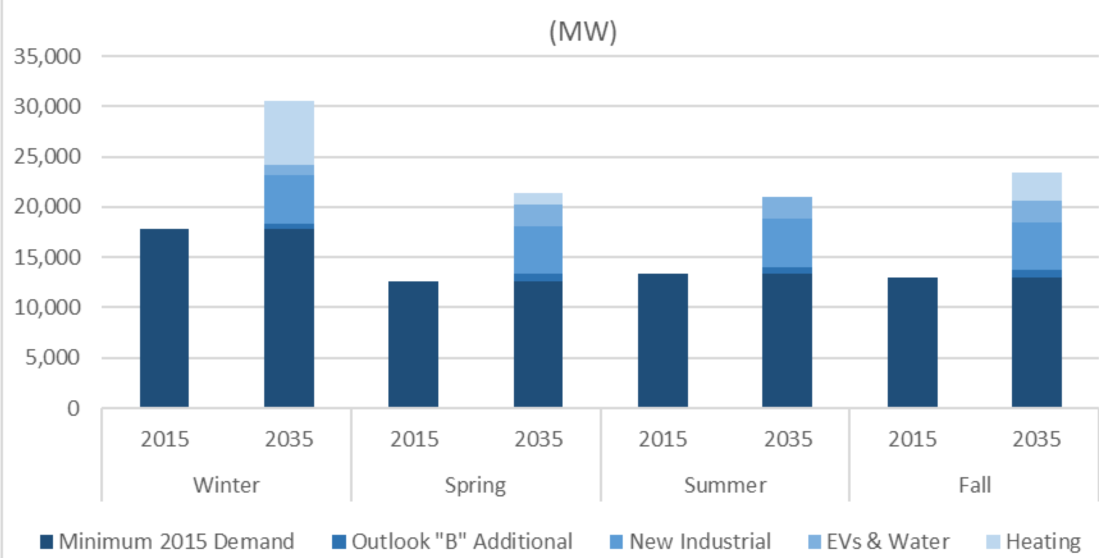
Finally, the results of the simulation related to the capacity, production, and surplus energy metrics of the scenario are summarized.

This section concludes with a summary of the key findings.

4.1. Overview of Electricity System Design Drivers and Four Paradigm Shifts to Address Them

The forecast demand arising from emission reduction initiatives will result in three significant changes to Ontario's electricity consumption profile: (1) an increased need for baseload energy driven by industry; (2) a much higher seasonal variability due to the need for more electricity for winter heating; and (3) a greater daily demand variability in winter, but smaller in summer. The relative changes to the baseload demand profile for Ontario are illustrated in Figure 18. This figure illustrates the minimum demand as the baseload requirement in 2015 by season. The additional elements of demand that alter the baseload include higher expected baseload in the BAU demand within Outlook B, the new industrial load within Scenario "S", and the implications from adding EVs and heating.

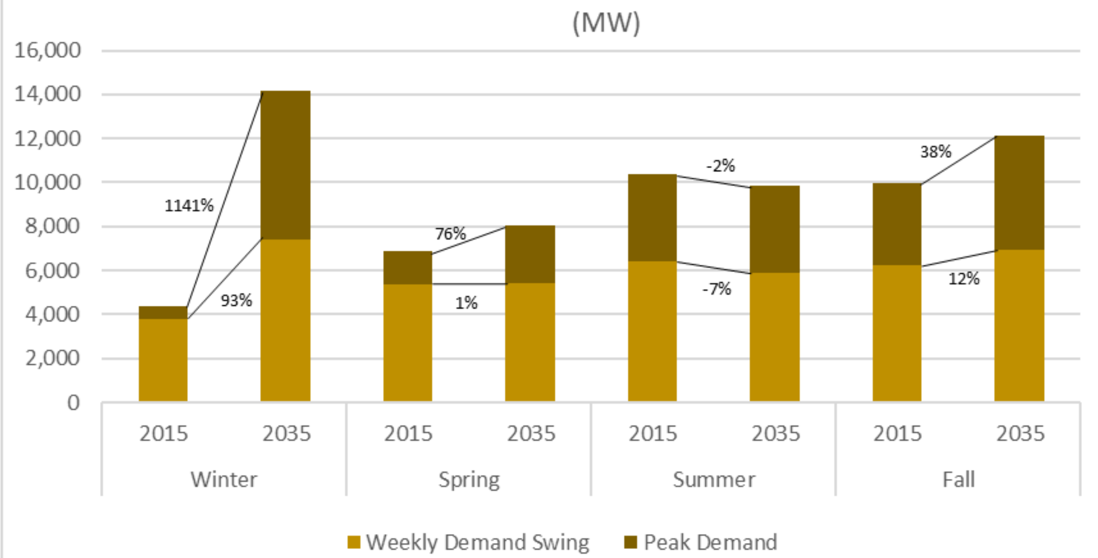
Figure 18 – Baseload Demand to Grid, 2015 vs. 2035



The changes in demand characteristics are very profound for winter, where an additional baseload capability of ~13 GW is estimated to be required.

Figure 19 similarly contrasts today's daily variability with that projected for 2035. The "Weekly Demand Swing" is defined as the lowest demand in any given week on a weekend day as compared to the highest demand in that week on a weekday. Figure 19 shows this weekly demand swing averaged over the quarter. The peak demand is the highest demand observed in the quarter.

Figure 19 – Variable Load Demand to Grid, 2015 vs. 2035



The daily variations of demand in winter almost double due to heating needs, or increase by almost 4 GW, with a peak increase of over 1000% to 14 GW. Adding the baseload requirements to the variability needs brings the total winter capacity that would need to be available to 44 GW of capacity, as compared to today's level of approximately 22 GW. Interestingly, in 2035, the variability of summer peak demand is expected to decrease reflective of the projected flattening of demand within OPO Outlook B.

These changes present very significant challenges for the existing electricity system. This study has endeavoured to develop an alternative approach to meeting these demands.

The new Scenario "S" Supply Mix reflects a paradigm shift in energy system planning. The scenario integrates new technologies that will radically reshape Ontario's energy future. The paradigm shift forces a rethinking of how Ontario should manage and plan its electricity system and includes:

1. **Embedded Distributed Energy Resources (DER)** integrated with LDC controllers.
   - *<u>Shift</u>: DER is demand management for asset efficiency and both Dx and Tx system reliability.*
   - A Local Distribution Company (LDC) managed/controlled integrated solar generation/battery storage system, such as PowerStream's "PowerHouse" pilot, could shave peak system loads, manage local neighborhood loads and provide reliability services and unique customer value.

2. **Integrating the "Wires and Pipes"** with hybrid natural gas/electric heating solutions in buildings.
   - *Shift: Natural gas in buildings is the electricity system's new winter peak reserve capacity.*
   - Hybrid devices – such as those being advocated by Enbridge – when integrated with LDC controlled DER enable natural gas to reduce electricity system demand during cold winter days and achieve the emission reduction objectives.
   - Integrating the management of energy use and its value to the consumer will reduce the pressures to expand the electricity generation, Tx, and Dx infrastructure.

3. **The Hydrogen Economy** can provide capacity and reliability benefits to the electricity system.
   - *Shift: Hydrogen and natural gas storage is Ontario's equivalent to Hydro Quebec's James Bay reservoirs.*
   - The broader role of hydrogen, including reliability benefits, are being articulated by Hydrogenics, Enbridge, and NextHydrogen
   - Hydrogen production capacity could:
     - Smooth the seasonal differences in demand between summer and winter by leveraging the underground storage capacity of the natural gas system in Ontario to seasonally adjust the electricity load of hydrogen production.
     - Provide the demand response (DR), peak reserve capacity, and other ancillary services required to fully support grid reliability and allow for the displacement of much of the natural gas-fired generating fleet.

4. **Nuclear** is the established clean and reliable energy that can underpin Ontario's low carbon future.
   - *Shift: Nuclear is Ontario's low-cost, clean energy advantage, the enabler of Ontario's coal retirement, and the backbone of achieving Ontario's climate strategy.*
   - Coupling new nuclear with the benefits of DER, wires and pipes integration, and the hydrogen economy could underpin Ontario's achievement of its emission reduction targets by providing a more affordable and efficient supply mix than projected in the OPO.
   - Scenario "S" integrates this new nuclear capacity with the foundation of life extended and refurbished nuclear and the rest of the OPO Outlook B projected clean supply of hydro, solar, biomass, low carbon electricity imports and low emission Non-Utility Generator (NUG)/Combined Heat and Power (CHP) capacity.

Embracing these four critical paradigm shifts allows a leveraging of Ontario's unique infrastructure advantages and offers a new cost-effective pathway to achieving emission reduction targets.

4.2. Embedded Distributed Energy Resources

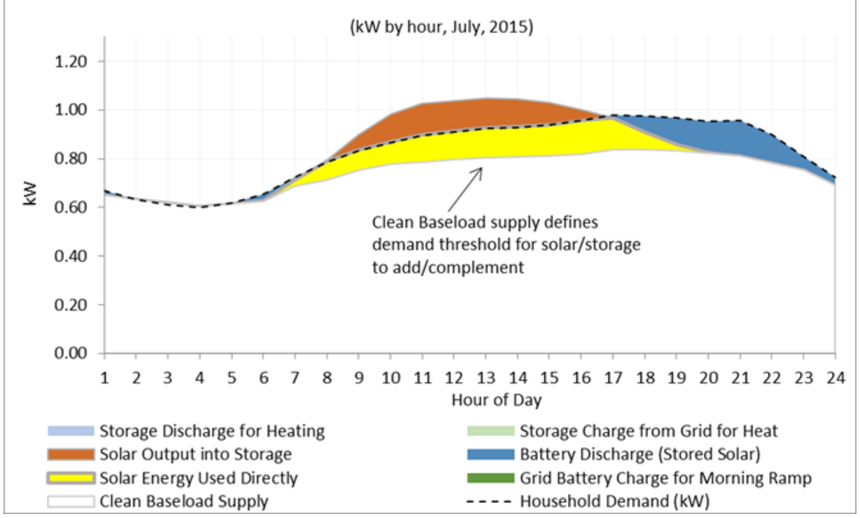
The shift to embedded DER will require integrating behind the meter solar/storage/demand/supply technologies to better regulate the power demanded from the grid and to reduce the need for the natural gas peaking power generation facilities. Such integrated technologies are currently being piloted by PowerStream[22].

Ontario's high peak electricity demand represents a large cost for the electricity system. In Ontario, natural gas-fired generation plants provide much of this peaking service. The current peak power generation facilities mostly sit idle, running only at times of high demand. This means these facilities have a low operating capacity factor and their costs must therefore be recovered during these periods of peak demand.

Sizing the DER Capability

This study determined the dimensions of a DER system based on the size of a solar panel and associated storage capability. Figure 20 shows the estimated average daily building demand and supply profile for the month of July. This mock-up of an average building has been used to demonstrate the potential for DER at an aggregate level. The month of July was selected to size the solar panel and storage system as this month experiences the highest average sunlight and also the greatest variability in demand between night and day. It also has peak loads that extend late into the evening.

Figure 20 – DER Solar/Storage Profile for Average of Building Electricity Demand



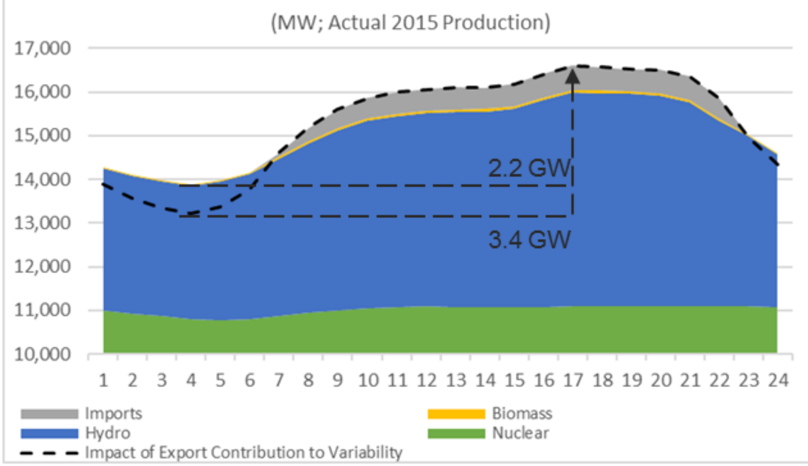
It is essential that the chosen DER capabilities can be married to the supply capabilities of the broader electricity system. The white area under the demand line reflects the ramping capability of Ontario's existing clean supply of hydro, biomass, nuclear and imports/exports with Quebec during the month of July. Figure 21 illustrates the average ramping capability of Ontario's clean energy supply sources during the summer of 2015. The flexible supply capability of the Bruce "B" units is reflected in Figure 21, based

[22] PowerStream, Ontario Smart Grid Forum Meeting, 2016

on its contribution in 2015. The flexible supply capability of the Bruce A units and the planned potential for load following flexibility from the refurbished Darlington units are not reflected.

Electricity exchanges between Ontario and Quebec enable electricity to be exported to Quebec at night and imported into Ontario during the day. Based on 2015 actual data, an average summer daily variation of 3.4 GW can be produced to support demand, taking into account night-time exports to Quebec.

Figure 21 – Summer Average Daily Production Profile of Clean Supply by Type

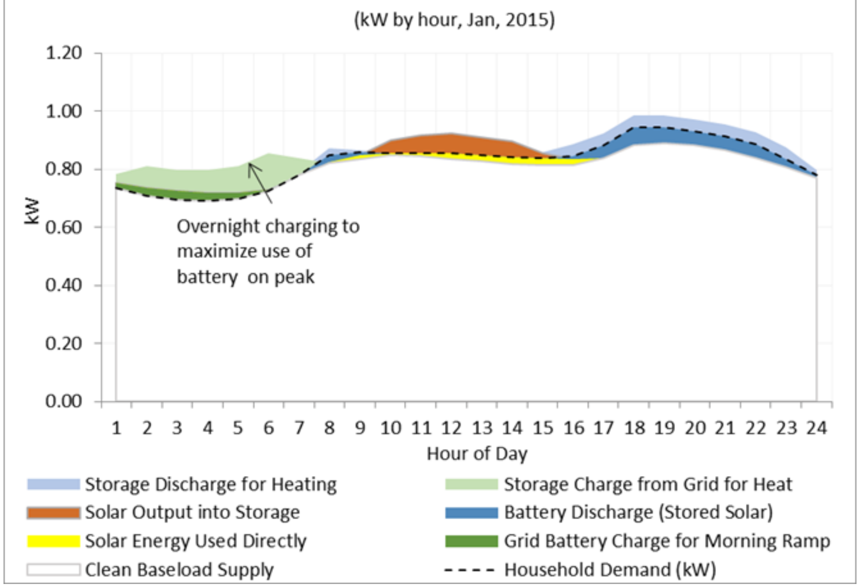


As illustrated in Figure 20, the solar array is sized by assuming its production not only supplies the demand above grid supply (yellow), but also creates sufficient surplus (orange) to charge a battery that can then supply all the demand above the grid supply, until these converge at the end of the day (blue). Based on this analysis, in aggregate, LDCs could install and manage 2.2 GW of solar capacity for DER in buildings. This is slightly less than is currently planned for Ontario. The solar capacity would be paired with 1.4 GW of battery capacity that can provide 6.7 GWh of battery energy storage.

Winter Model

In the winter, solar generation output is much smaller, but so is the current demand variability between overnight and peak daytime demand. These conditions are illustrated in Figure 22. The flatter day-night demand conditions in winter today do not support the full use of the battery capacity, which is sized for the month of July. However, during periods of low solar production such as in January, the battery could also be charged by off-peak grid supply.

Figure 22 – DER Solar/Storage on Average of Building Electricity Demand (Prior to Heating Demand)

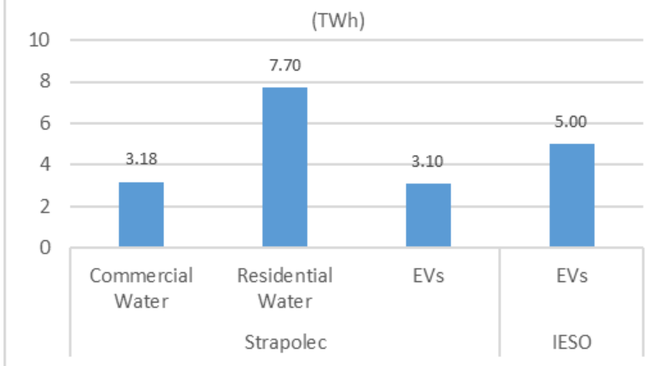


At first glance, this outcome may not appear reasonable as it significantly increases overnight load while creating surplus production during the day. Fortunately, these conditions are coincident with the projected need for winter electric heating supply. As a result, additional overnight electricity could charge the battery which then could be used to manage the need for heating supply during the day. The advantages of this process are explained more fully in the next section which focuses on the use of natural gas to support winter heating peaks.

The concept of embedded DER and the ability for it to be managed by the LDC enables many optimization function opportunities. For example, this energy can be used for EV charging and water heating, two demands that will be present throughout the year. As shown in Figure 23, water heating is likely to represent a much higher demand load than EV charging[23].

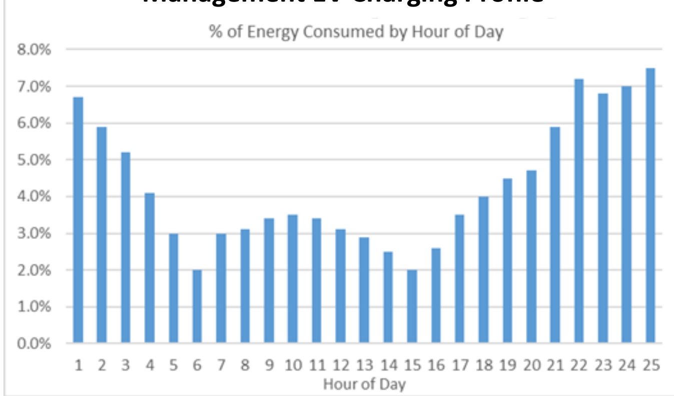
[23] Note that the "S" scenario has assumed 1.8 million EVs, or about 600,000 less EVs than the OPO has assumed. The basis for this assumption was that 800,000 hydrogen fuel cell vehicles are also assumed to be on the market when 2030 emission reduction targets are achieved. See Phase 1 Report.

Figure 23 – Electricity Demand From Consumers



The daily energy profile for heating water has been assumed to be the same as that for EV charging. It is presumed that these loads would have negligible variability on a day to day basis and would be consistent throughout the entire year. The IESO made a similar assumption for its EV charging profile for which they contemplated three different charging profiles. The OPO charging profile originally adopted for this study uses balanced overnight charging, which is illustrated in Figure 24[24].

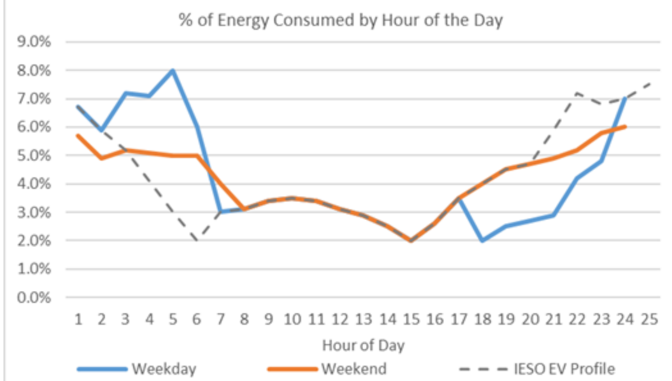
Figure 24 – IESO OPO Effective Load Management EV Charging Profile



While developing Scenario "S", a more optimal profile for EV charging and water heating was identified that could better moderate demand on the electricity the system. The model for EV charging and hot water demand has been simulated as illustrated in Figure 25.

[24] IESO, Module 2: Demand Outlook, 2016

Figure 25 – Adjusted Charging Profile for EVs and Water



In the future, the ability to remotely control energy applications at the LDC level will be further complemented by the commercialization of peer-to-peer energy exchange concepts currently being evaluated in the marketplace. These features will allow for the optimal smoothing of demand by balancing consumer preferences. This will allow for the efficient replication of the goals represented by the average demand profiles illustrated in this Section. Industry interviews with several LDC executives suggests that this future may be reasonably achieved in the 2030 to 2035 timeframe contemplated by this study.

Summary

An LDC managed integrated system comprised of 2.7 GW of solar (equivalent to existing solar capacity) with 1.4 GW of new battery capacity (with daily energy storage of up to 6.8 GWh) can mitigate peak system loads at both the Tx grid and LDC level, and provide other ancillary services that support reliability.

4.3. Integrating the Wires & Pipes - Natural Gas and Heat

This option requires a paradigm shift in energy planning that results in the functional and operational integration of "Wires and Pipes" infrastructure along with hybrid natural gas/electric heating solutions within buildings. Enbridge is currently advocating such an approach[25]. Ontario has natural gas infrastructure assets that span much of the province. As Ontario pursues decarbonization, the natural gas system could be negatively impacted as building heating is electrified, thereby displacing natural gas. However, this electrification initiative could result in Ontario's electricity system facing new, significant peak demand requirements that would have to be served by generation with low operating capacity factors and therefore higher levelized electricity costs. Alternatively, hybrid electric/natural gas home heating systems could enable the natural gas system to be used to cost-effectively supplement electricity consumption. If the hybrid devices are integrated with the DER LDC controlled infrastructure, natural gas could be used to mitigate the need for the electricity system to provide for peaking winter demand on

[25] Teichroeb, Presentation at Technology Innovation and Policy Forum, 2016

extreme cold days while still achieving the province's emission reduction objectives. This paradigm shift will require changes to the regulatory system.

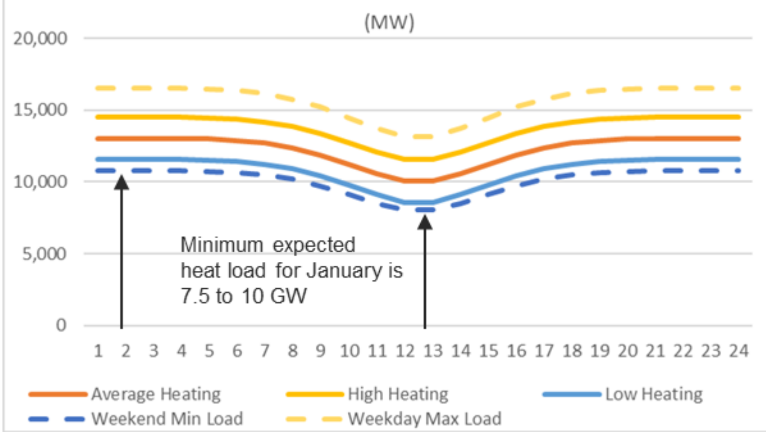
Leveraging the existing natural gas distribution system to provide peak supply during high winter heat loads could mitigate the identified need for new generation and enhancements to Dx and Tx infrastructure required to meet peak winter loads.

The following subsections examine the nature of the heating demand that could be imposed on the electricity system, how the peak requirements could be supported by the natural gas system to alleviate demands on the electricity system, and finally how the Dx system could be impacted.

4.3.1. Demand Profile for Heating

There is a significant heat load in the winter that will drive winter peaking energy requirements. The demand for heating energy has significant variability due to temperature variations. Figure 26 illustrates the potential variability of the heat load in January and the impact this demand will have on the electricity system.

Figure 26 – Average Daily January Added Heat



The average daily temperature can vary by +/- 3 degree in the month of January[26]. This temperature variation could result in the demand load on the electricity system varying by 7 MW at night or by up to 10 MW between the low weekend demand on a warm day and the peak weekday demand on a cold day.

Electrifying this heat load creates a new challenge, a "peaking load" supply requirement for only one season. Peaking capabilities are an inefficient use of electricity system assets – generation, Tx and Dx, and using gas-fired generation would have a negative emissions impact undermining the province's emission

[26] Current Results, Toronto Temperatures, 2016; Government of Canada, Canadian Climate Normals 1981-2010 Station Data, 2016

reduction objective. Leveraging the existing capability of the natural gas distribution system could be a cost-effective way to mitigate the costs of meeting this peak demand.

4.3.2. Shaving the Peak Heating Demand

The opportunity to use the natural gas system to mitigate the challenges on the electricity system stems from the province's long-term emission reduction objective that will still allow for emissions equivalent to 20% of 1990 levels. The capabilities of the natural gas system could be used as one of the pathways as Ontario transitions to a decarbonized economy. For example, 20% of the natural gas currently used to heat homes could continue and Ontario would still achieve its 2030 emission targets. Additionally, blending renewable natural gas and hydrogen into the pipeline network could further mitigate the emission impact of the natural gas system.

Leveraging the natural gas system to help mitigate electricity system peaks will require the use of hybrid heating devices that can use both electricity and natural gas. This would facilitate the switching of energy sources to occur behind the meter. For example, the Phase 1 report noted that Air Source Heat Pumps (ASHPs) require a supplementary heat source on very cold days. Significant delivery infrastructure already exists throughout most of Ontario that provides both electricity and natural gas to homes and businesses. With the LDC controllers discussed in the section on DERs, switching from electricity to natural gas can be programed to provide the required heat but also in a manner that manages overall system costs and prevents total power system demand from exceeding available total capacity during the winter peak load hours.

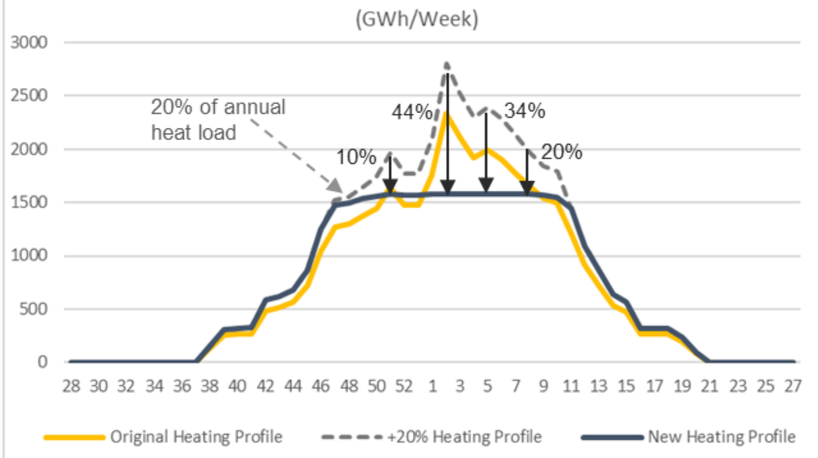
Seasonal Demand Profile Impact

To shave peak demand, the natural gas system will need to be managed differently for each month of the year. Figure 27 shows how using the natural gas system to shave peak demand will impact electricity system supply requirements over the winter season. Note that this figure places the winter weeks together in the middle of the chart. The amount of energy to be shaved will vary by month as shown.

Leveraging the use of the natural gas system while still achieving Ontario's emission targets will require calculating the same percentage of energy retained for natural gas needs and determining the equivalent percentage increase required by the homes that are electrified. In Strapolec's simulation, the emission target requires 44.5% of buildings to be electrified. If 20% of the energy is to be shaved and the 2030 emission targets achieved, 54% of the buildings must be electrified using this hybrid approach.

For the purposes of this analysis, the total electricity requirement was increased by 20% to reflect the additional homes. This is represented by the dotted line in the figure. The new heating profile was then reduced by shaving the peak from the highest demand hours until 20% of the total heat energy was removed. The solid black line shown on the chart represents the net electrification demand, including the additional homes that would be electrified. The total amount of electricity below the solid black profile represents the original expected total heating electricity required.

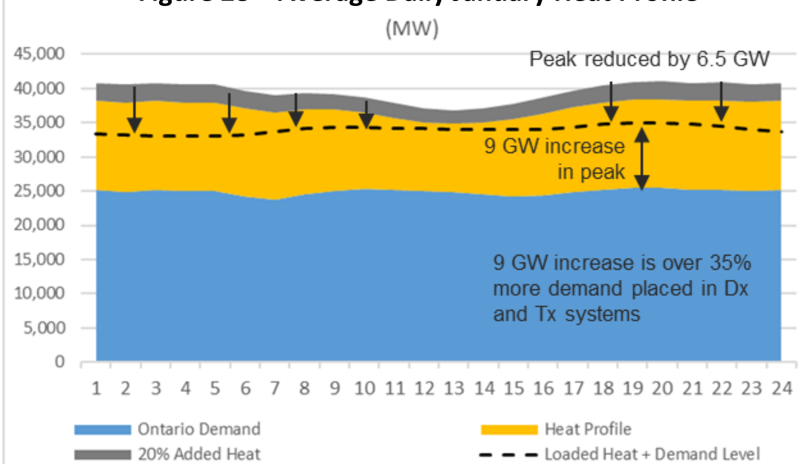
Figure 27 – Weekly Heating Profile



Daily Profile Impact

Using the natural gas system to minimize peaking electricity system requirements would notionally be best applied by shaving the top energy demand periods of the day as shown in Figure 28.

Figure 28 – Average Daily January Heat Profile



Strapolec's model has a demand line target above which any heat demand exceeding this demand line could be accommodated by the natural gas system. There is no restriction on the natural gas system as it is already sized to provide maximum heat delivery. As well, the electricity system could be managed to the "curtailed" line which will have far less variability associated with it. Minimum heat load is the baseload design target and variability to the new average would be small.

Winter (January) demand due to heating will still rise by 40%, or 9 GW. However, the natural gas system can accommodate most temperature variations and reduce the peak need by 6.5 GW on average. Since the main heating months of December to March coincide with low solar output, the DER storage capacity would be available to shift load profiles between night and day, as illustrated in the January DER profile in Figure 22.

By using the previously discussed LDC/DER controllers, the integrated system could be tuned to change the profile of the demand placed back on the grid as illustrated by the dotted line. The current simulation only has a 6% variation between night time load and daytime load, which may be insufficient to allow the existing Dx assets to cool down at night. This profile could be managed to any desired shape if the natural gas system is effectively integrated with the electricity system.

Net System Impact

The impact on-peak demand is illustrated in Figure 29. The natural gas system could effectively be used to trim the peak demand for electricity, achieving a 9.5 GW reduction in peaking supply.

Figure 29 – Wires & Pipes Integration Benefit on Heat Demand Profile

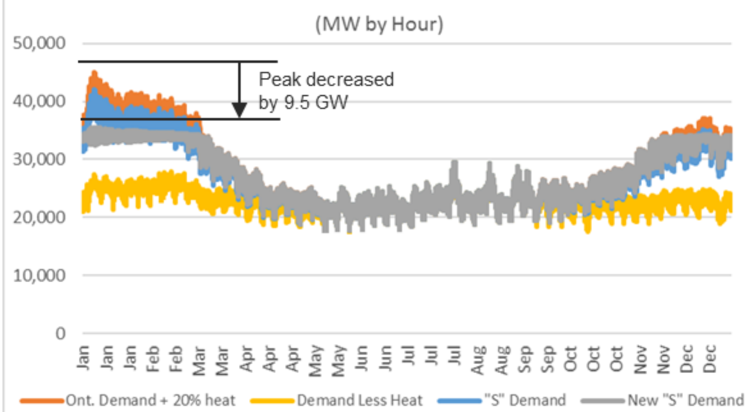
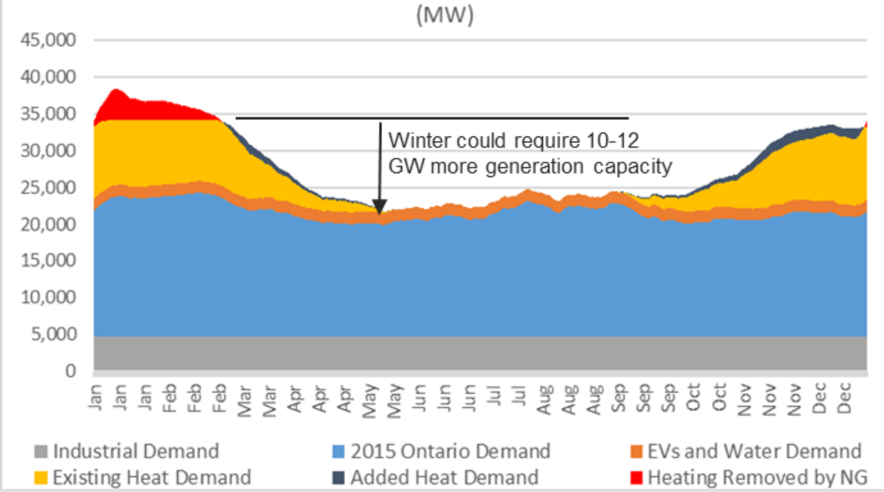


Figure 30 shows the impacts on average system electricity demand over the year resulting from the utilization of the natural gas system to shave the winter peak heating demand. The “trimming” effect resulting from using the natural gas system for peaking heat requirements could on average reduce the need for 4 GW of electricity system supply. An additional 10-12 GW of supply in winter will still be needed to supply the expected heating demands of Ontario’s buildings.

Figure 30 – Ontario Natural Gas Adjusted Heating Profile



Two additional benefits arise from this electricity system planning approach:

1. The compensating heat load from the additional homes is "spread" to the spring and fall, further smoothing the annual profile of demand for those traditionally low demand periods.
2. Using the natural gas system can limit the maximum electricity system demand to 34 GW and eliminate the need for electricity system reserve in the winter. No additional reserve is required as the natural gas system capacity inherently provides 9 GW of reserve capability.

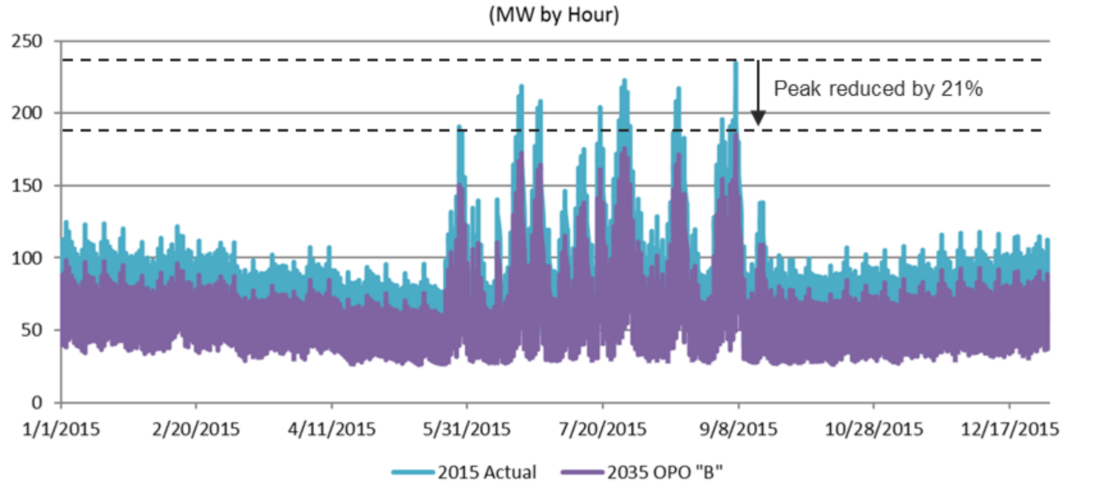
4.3.3. Implications for the Distribution system

Much discussion has occurred regarding the potential impacts and challenges EVs pose for Dx systems. Anthony Haines, CEO of Toronto Hydro, stated at the OEA 2016 conference that Toronto Hydro has 40% spare capacity and that, with the development of new controllers, it is anticipated that EVs will not be an issue[27]. This study assumes that Ontario's Dx system has significant spare capacity available to support EV charging. Accommodating future space and water heating may represent a greater challenge. The OPO has stated that no cost provisions have been included that would account for any additional costs in the LDC sector, however, the OPO also stated that increased costs should be anticipated.

There are two mitigating factors that suggest these Dx impacts may be manageable over the next 20 years. The OPO projects that average household energy use will decline by 21% by 2035 from today's average of 753 kWh/month to 594 kWh/month[28]. Figure 31 illustrates the expected impact on residential demand that could result from this 21% reduction due to future energy efficiency initiatives.

[27] Haines, OEA Energy Conference Remarks, 2016
[28] IESO, Module 2: Demand Outlook, 2016

Figure 31 – Sample Residential Hourly Demand Profile 2015 vs 2035

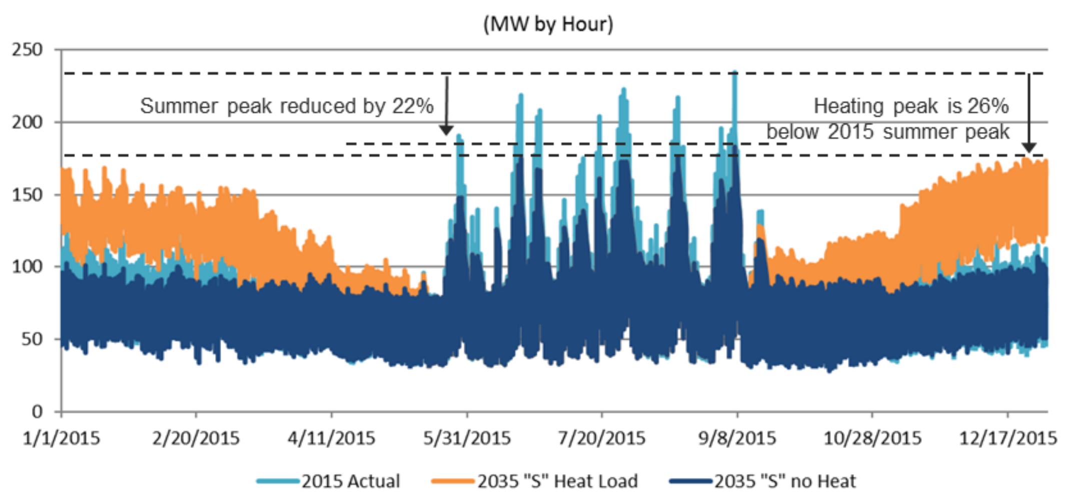


OPO "B" based on simple scaling of 21% per OPO table "Residential (kWh/HH/month)" table from Module 2: Demand Outlook

The data in Figure 31 represents the demand profile for 83,000 homes in the GTA. Assuming energy efficiency improvements will be achieved across all existing energy consumption patterns, the purple reflects the new demand that may be prevalent in a BAU world in 2035. This suggests that the 21% reduction in peak energy demands placed on LDCs could create enough capacity to accommodate new local demand, since the system has been designed to support existing summer peak with existing infrastructure.

The addition to this demand of the expected peak shaved heat load, as well as the load for EVs & water heating, is illustrated in Figure 32. It appears that this added heat load will not exceed the existing capacity of today's residential subdivisions, with the summer peak falling by 22%. The reduction in winter peak demand is even greater, with a decrease of 26% over the 2015 summer peak. The flexibility available in the DER and hybrid heating systems could be further optimized to broaden this margin.

Figure 32 – Scenario "S" Residential Hourly Demand Profile



In conclusion, embracing the DER and natural gas paradigm shifts could help Ontario achieve its emission targets over the next 20 years. Achieving the 2030 targets may not be impeded by LDC infrastructure. Additionally, LDCs may not have to incur any additional costs under this Scenarios "S". In fact, a higher utilization of LDC infrastructure may translate into per MWh cost reductions. This is definitely not true for OPO D scenarios. The OPO says expected LDC costs were not yet reflected but may be substantial. If OPO options are pursued, the LTEP should consider the challenges that will be faced by the Dx systems.

4.4. The Hydrogen Economy and Energy Balancing

A hydrogen economy represents a grid level demand management paradigm shift that could unlock significant efficiencies to make the decarbonization challenge economically more manageable. This paradigm shift and its impact on electricity system planning is enabled by the anticipated substantial and controllable electricity load of electrolysers. Realizing the full potential of this paradigm shift would be supported by the integration of Ontario's wires and pipes infrastructure. With such integration, hydrogen production from electrolysis could provide the electricity system with four flexible operating benefits: (1) offset seasonal demand differences; (2) allow for the extremely efficient use of generation and Tx/Dx assets; and (3) reduce the need for peaking supply plants by providing significant DR; and (4) provide other ancillary and reliability benefits to the electricity system. The Ontario-based hydrogen technology company, Hydrogenics, is already advancing the ancillary benefits that electrolysers could provide to the grid[29].

Phase I identified hydrogen as an enabler for many of the emission reduction options available to Ontario. The forecast need for hydrogen for these many applications to help meet 2030 emissions targets creates a need for an electricity intensive commercial/industrial hydrogen production facility(ies), potentially Tx connected. Blending hydrogen in the natural gas delivery system results in several emission reduction benefits: it reduces the emissions footprint of the overall natural gas system; displaces the use of natural gas in the steam methane reforming process to create hydrogen at refineries thus increasing the renewable content in gasoline, diesel and jet fuel; and facilitates the penetration of light and heavy (e.g. rail) fuel-cell vehicles in the marketplace. Increasing the number of fuel-cell vehicles could also displace some of the electricity demand for EV charging. This could help reduce the demand on LDC networks as the increase in clean transportation would be split between hydrogen and electric vehicles and reduce the daily peak demand on both electricity generation and Dx assets that would arise with electric rail.

The estimated production capacity required to meet the 2030 emissions targets could exceed 500,000 kg/year with the associated electrolyzers providing DR and summer peak reserve capacity capabilities of up to 5 GW, as well as other ancillary services that support reliability.

The natural gas system's storage assets could be leveraged to seasonally smooth hydrogen delivery for many industrial applications. Leveraging the underground storage capacity of the natural gas system in

[29] Wilson, Power-to-Gas: Utility-Scale Energy Storage, 2012

Ontario offers flexibility for meeting the seasonal winter heating demand by reducing baseload winter demand by up to 3 GW.

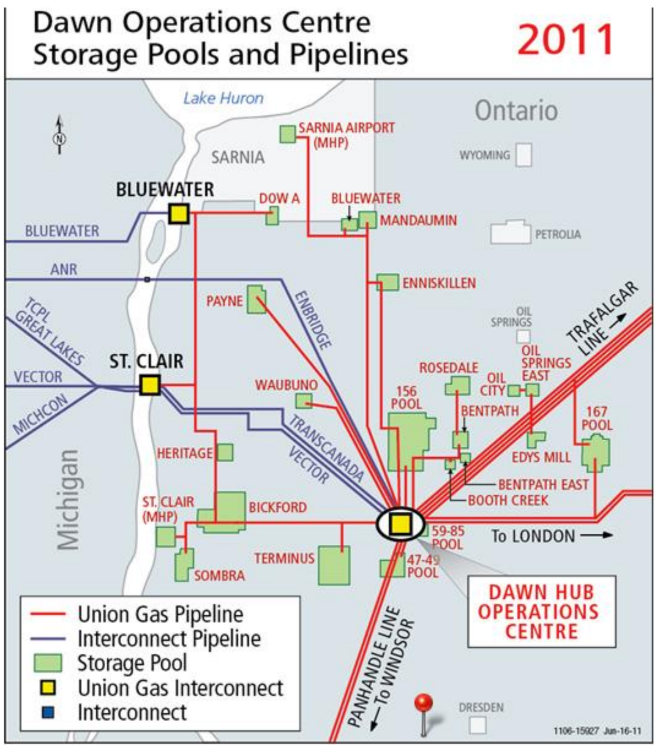
The following subsections explore the prerequisite enablers that could permit this paradigm shift to significantly reduce the cost of energy in Ontario.

4.4.1. Ontario's Natural Gas Storage

Ontario's significant natural gas storage capability in the southwestern part of the province represents a substantial energy asset[30]. The concept of leveraging Ontario's natural gas system storage capability to support the use of hydrogen is not new. The concept is generally referred to a P2G, which has been an area of development globally. Several studies have explored the implementation of P2G in Ontario[31], including assessments related to a possible clean energy hub in the vicinity of OPG's retired Nanticoke coal plants[32].

The natural gas storage capacity in Ontario consists of many independent "pools" as shown in Figure 33[33].

Figure 33 – Dawn Operations Center Storage Pools and Pipelines



30 Navigant Consulting Inc, 2015 Natural Gas Market Review, 2015

31 Teichroeb, Hydrogen Energy Storage for Grid & Transportation Services, 2014

32 Canadian Hydrogen and Fuel Cell Association, Analysis of a Potential Clean Energy Hub in the Nanticoke Region, 2008; Maniyali, Energy Hub Based Nuclear Energy and Hydrogen Energy Storage, 2013

33 Union Gas, The Dawn Hub, 2016

This natural gas storage system could be integrated with the hydrogen economy and leveraged in two ways:

1) Blending hydrogen within the natural gas system allows the hydrogen to be accessed through two methods:
   a) Coincident with the seasonal demand profile for placing the natural gas into storage, hydrogen could be injected into storage and blended with the natural gas for later use by the natural gas system.

      This process can begin almost immediately and be scaled-up concurrent with demand as its value increases with the cleaning of the carbon content of electricity. There is a current operational restriction of a 5% blend of hydrogen in the system by volume[34] that is associated with end use applications, such as burner equipment. This limitation may relax over time as experience with P2G expands globally.

   b) The potential exists to dedicate a subset of Ontario's storage pools for higher concentrations of hydrogen in the mix.

      Storage volume may become available for this purpose as the need for storage declines with the decarbonization of Ontario's economy. Under this concept, the mixed gas in the storage pools would need to be "down-blended" prior to injection into the natural gas system.

   The storage costs for simple blending of hydrogen into the natural gas system for its use as a fuel additive by end users are negligible[35]. Using the natural gas distribution system to distribute hydrogen to other end use applications has been assessed by NREL. NREL reports that it could cost $3-$8/kg to extract hydrogen from a natural gas system if the hydrogen is blended at the low concentrations anticipated[36].

2) Dedicated pure hydrogen storage could benefit other distribution channels.

   Pure hydrogen storage will likely require dedicated salt caverns, as the existing storage pools have "heritage" contaminants, e.g. many are depleted oil and gas repositories. Such options reportedly exist in Ontario, but their suitability would need to be confirmed. Salt caverns are reportedly the least expensive mechanism for storing hydrogen[37]. As demand for hydrogen transportation increases, the hydrogen may be distributed directly for the refueling of vehicles and rail. Use of the pure hydrogen in Ontario's economy would require the development of a central distribution model for trucking the

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[34] Restrictions are described in the Phase 1 Report

[35] Walker, Benchmarking and Selection of Power-to-Gas Utilizing Electrolytic Hydrogen as an Energy Storage Alternative, 2015

[36] Melaina, Blending Hydrogen into Natural Gas Pipeline Networks, 2013

[37] European Fuel Cells and Hydrogen Joint Undertaking, Commercialization of Energy Storage In Europe, 2015; Maniyali, Energy Hub Based on Nuclear Energy and Hydrogen Energy Storage, 2013

hydrogen to end users. A trucking distribution system for hydrogen has been estimated to add a cost of $2/kg to the cost of hydrogen production[38].

Depending on the circumstances, delivery through the natural gas system may be less expensive than trucking hydrogen to end use locations, particularly if hydrogen becomes a significant volume of the gas flow. Given the hydrogen related technology R&D that is currently occurring around the world, advancements with respect to delivery are anticipated.

The pace of storage pool conversion or development of new facilities could be managed over time commensurate with the demand for hydrogen in support of the decarbonization of Ontario's economy.

The degree to which these centralized models for hydrogen production and distribution are developed will be determined by the demand from end users. For example, some end users may have sufficient scale or the economic base to support their own electrolysers, such as example high traffic highway fuelling stations or for rail refuelling. The Phase 1 report summarizes NREL studies on fuel-cell electric vehicle (FCEV) applications for hydrogen delivery that suggest the net costs are similar between the centralized and distributed production models in many cases.

4.4.2. Matching Hydrogen Production to Demand and Supply

Leveraging the underground storage capacity of Ontario's natural gas system to store hydrogen offers flexibility to the electricity system in meeting the new seasonal load profile by increasing hydrogen production in the summer and by reducing production in the winter. This could increase summer demand for electricity and decrease winter demand for electricity, resulting in a more seasonally moderate demand profile for the grid.

Ontario's hydrogen community is advocating for the utilization of the province's current surplus of clean energy to produce hydrogen. In turn, this hydrogen would provide a flexible production capability that could be married to the supply/demand characteristics of the electricity system. This is a well-established concept that offers a transition pathway to the future. In the short-term, the P2G concept could use Ontario's surplus clean electricity to produce hydrogen, keeping the benefits in Ontario rather than exporting the electricity at low prices. The hydrogen could be injected (blended) into the natural gas system to be used with existing natural gas applications. Utilizing the natural gas system in this manner could facilitate the blending of higher hydrogen concentrations resulting in a lower natural gas system CO_2 footprint and the potential need for storage assets. In turn, these hydrogen products and services could become available for transportation applications over time.

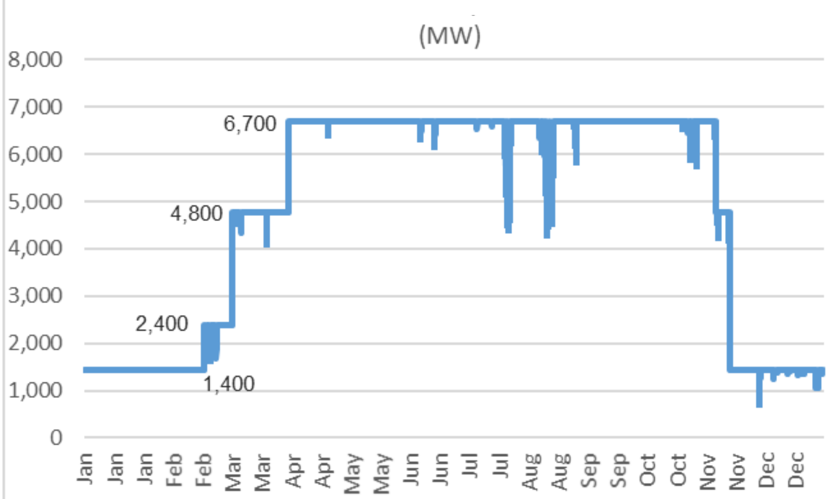
The hydrogen economy paradigm shift most relevant to the Scenario "S" 2035 projection reflects the eventual growth in hydrogen production that runs at higher operating factors. It would not be based on Ontario's existing intermittent renewables, but rather the optimised low-cost electricity system of Ontario's future. Higher operating factors lead to more efficient hydrogen operations resulting in lower

[38] Described more fully in the Phase 1 report

costs since the capital assets are used more effectively. At higher operating factors, electrolysers could in aggregate, become a dispatchable load. This would provide a reliability benefits in planning the electricity system.

Figure 34 shows a possible optimized demand profile for hydrogen production reflecting such a leveraged natural gas storage system. Assuming an average annual hydrogen production electricity demand of 4.8 GW, approximately 40% more production capacity could operate in the summer (~6700 MW of demand), and approximately 60% less production in the winter months (~1400 MW of demand). A simulation of the demand response required to accommodate peak needs illustrates the potential capability to reduce hydrogen production to avoid instances of grid peak demand. It is evident that substantial capacity would be available to provide for the need for peak reserve capacity in the summer months.

Figure 34 – Optimized Industrial Demand Profile



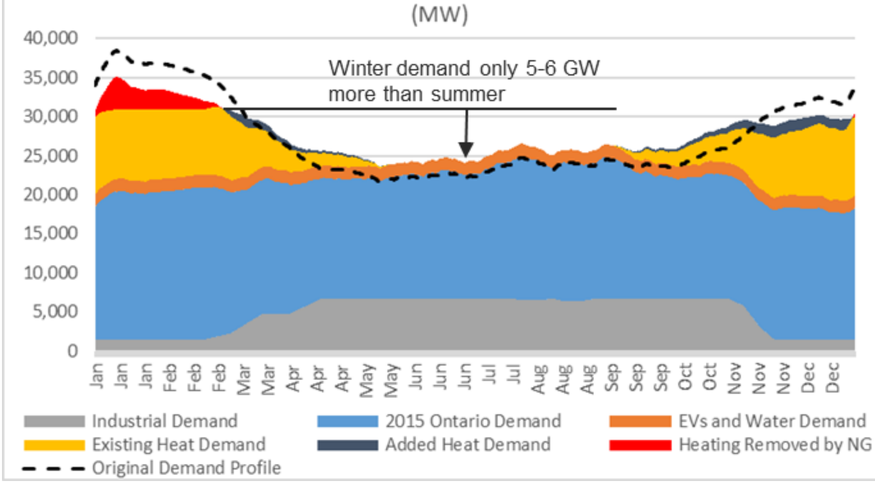
The results of the analysis suggest that the hydrogen economy could provide 6 GW of DR in the summer. Additionally, shifting production to the summer could increase summer demand by 2 GW with a corresponding reduction of 3.4 GW in the winter, substantially smoothing the seasonal supply needs of Ontario's electricity system.

4.4.3. Resulting Impact on Electricity System Demand for Generation

The net impact on integrated system demand overlaid with the original Scenario "S" demand is shown in Figure 35. With the adoption of the aforementioned paradigm shifts, the variability between average summer demand and winter demand can be reduced to only 5-6 GW from over 15 GW.

Figure 35 – Ontario 2035 Profile of Demand on the Transmission Grid

(MW)



This materially moderated seasonal difference between the winter and the summer demand enables consideration of an alternative baseload supply mix for Ontario.

4.5. The Need for Supply and New Nuclear

This paradigm shift recognizes the significant low carbon contribution nuclear can make to Ontario's energy and economic future. Nuclear can cost-effectively supply most of Ontario's forecast low carbon electricity demand. The limitations related to wind generation's contribution to Ontario's clean supply mix were discussed earlier in this report.

This section identifies the characteristics of demand that remain to be supplied, and then demonstrates how the nuclear capacity profile is well matched to meet it.

4.5.1. Demand Characteristics to be Supplied

Ontario's electricity system must have the capability to meet baseload and variable demand through each season of the year. Figures 36 and 37 illustrate how these requirements have been modified by the three paradigms discussed previously.

Winter baseload needs have been moderated to balance more closely to the summer as shown in Figure 36. This results in a difference of ~6000 MW. Figure 37 shows how variability needs have been reduced in all cases to levels below those observed for the electricity system today. The most significant challenge to the grid is the need to reduce peak winter demand on the system by 90%.

Figure 36 – Scenario "S" Changes to Baseload Demand to Grid; 2015, 2035, 2035 Behind Meter

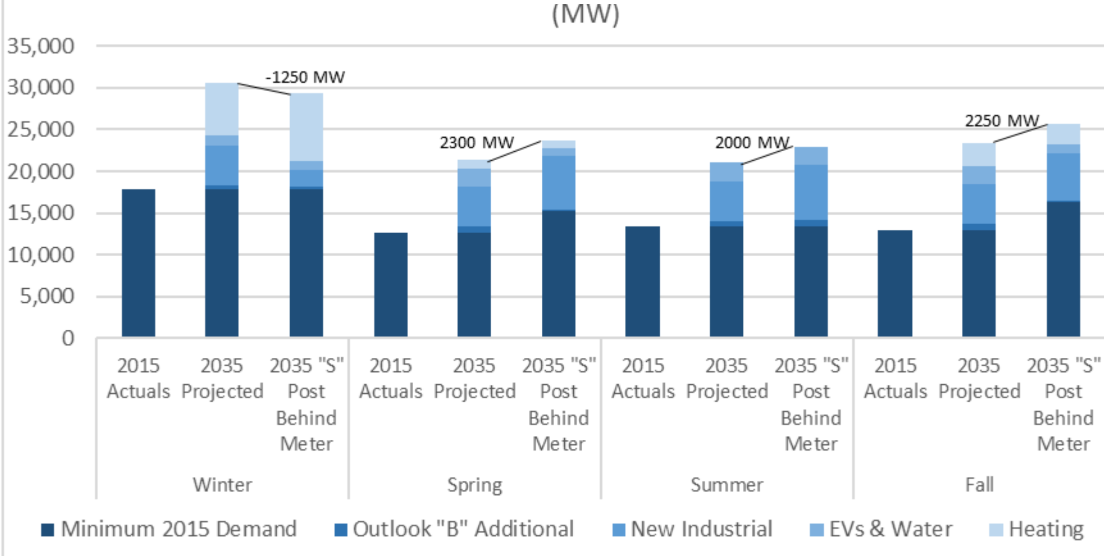
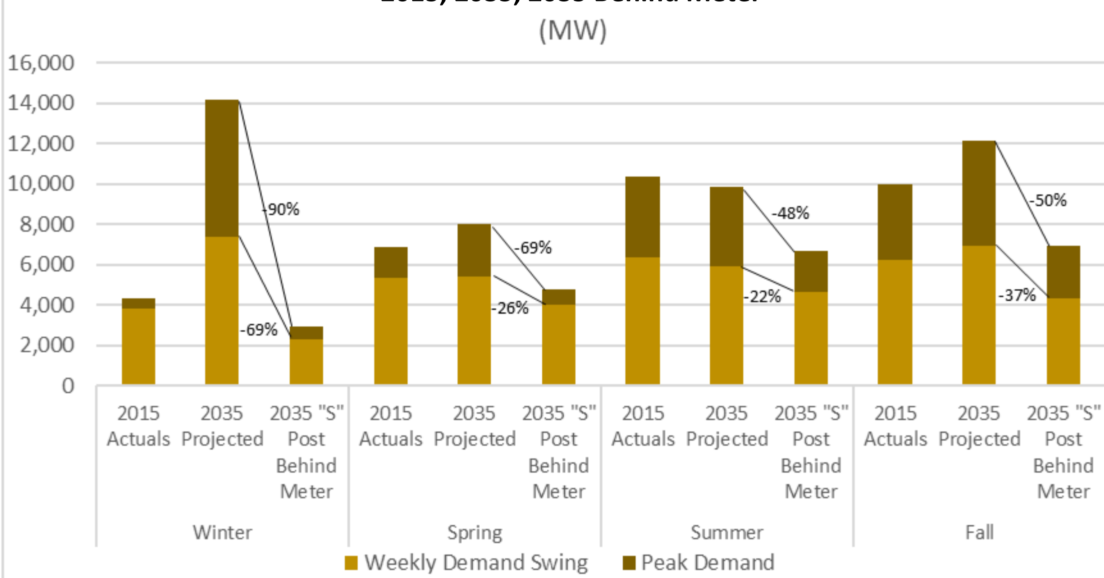


Figure 37 – Scenario "S" Changes to Variable Load Demand to Grid; 2015, 2035, 2035 Behind Meter



Adopting the afore noted three paradigm shifts – DER, integrated wires and pipes, and the hydrogen economy – significantly reduces variability and winter baseload demand.

4.5.2. The Nuclear Supply Profile

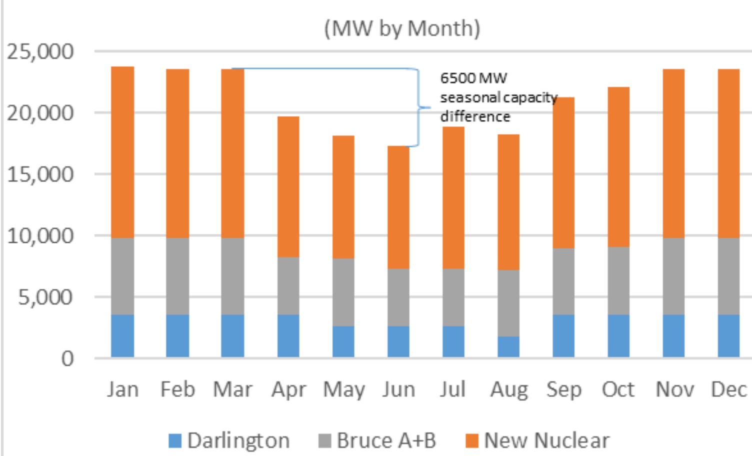
The following assumptions were made regarding the existing and planned supply mix that establish the pre-requisite base for the development of a scenario that includes new nuclear capacity:

- Clean supply carried forward to the new scenario includes planned, committed and directed hydro, biofuel, NUGs/CHP and imports from Quebec as described by the OPO for Outlook B;
- Refurbishment and life extension of Ontario's 10 nuclear reactors as the enabler going forward;
- 2.7 MW of embedded solar as discussed in the DER analysis;
- 200 MW of grid connected solar was retained as not being integrated with DER, for a total assumed solar contribution of 2.9 GW. This is approximately 1.1 GW less than planned for in Outlook B by 2035. This assumption is consistent with the decision by the Ontario government to defer LRP II[39]; and,
- Imports from Quebec are assumed to be restricted to the 1800 MW operating limit identified by the HQ CEO[40], subject to Quebec's winter generation limitations.

By design, this scenario does not include any wind capacity, back up supply, or capacity from natural gas generation. It is intended to present another option for consideration in the LTEP process.

It is estimated that 14 GW of new nuclear could be required to meet the new demand. When combined with the refurbished units, the regularly scheduled maintenance outages of the fleet can be managed to deliver an operating profile that matches demand. Figure 38 illustrates the resulting nuclear capacity profile by month needed to meet system requirements.

Figure 38 – Scenario "S" Nuclear Capacity Profile



The 6.5 GW of additional supply that could be provided by nuclear to service the peak winter heating season is sufficient to meet the projected demand profile.

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[39] Ministry of Energy, Ontario Suspends Large Renewable Energy Procurement, 2016

[40] Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016; Martel, Opening Keynote from APPrO 2016, 2016

4.6. Scenario "S" Production Profile

The monthly production profile of each element of the Scenario "S" supply mix is summarized in Table 5.

Table 5 - Demand And Production Summary

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply													
Hydro	3.99	3.49	3.37	3.33	3.50	3.54	3.43	3.39	2.84	2.99	3.16	3.78	40.8
Biomass	0.01	0.03	0.06	0.04	0.04	0.06	0.06	0.05	0.04	0.02	0.05	0.07	0.5
NUGs/CHP	0.74	0.77	0.70	0.57	0.51	0.54	0.58	0.58	0.61	0.64	0.55	0.57	7.4
Imports	0.36	0.50	0.42	0.26	0.31	0.52	0.52	0.73	0.14	0.29	0.22	0.30	4.6
Nuclear	17.70	15.82	17.46	14.17	13.44	12.46	14.00	13.54	15.21	16.38	16.89	17.48	184.5
Solar	0.01	0.02	0.02	0.03	0.04	0.04	0.04	0.04	0.03	0.02	0.03	0.01	0.3
DER Supply	0.30	0.30	0.30	0.32	0.35	0.42	0.54	0.50	0.37	0.39	0.28	0.23	4.3
Total Supply	23.12	20.92	22.34	18.72	18.19	17.56	19.18	18.83	19.25	20.74	21.18	22.43	242.5
Surplus Supply Curtailed	0.01	0.01	0.14	0.09	0.18	0.06	0.06	0.02	0.20	0.07	0.12	0.07	1.0
Demand													
Base Outlook B	13.92	12.96	13.02	11.34	11.48	11.56	13.00	12.73	12.23	11.66	11.63	12.32	147.8
EVs/Water	1.19	1.07	1.19	1.15	1.18	1.15	1.19	1.18	1.15	1.19	1.15	1.19	14.0
Heat	6.78	5.74	5.22	1.79	0.42	0.00	0.00	0.00	0.64	2.34	5.65	7.61	36.2
Industry	1.07	0.96	2.74	4.31	4.98	4.82	4.93	4.89	4.82	4.97	2.60	1.06	42.2
DER Demand	0.17	0.18	0.02	0.02	0.00	0.00	0.00	0.02	0.10	0.19	0.07	0.19	1.0
Total Demand	23.12	20.92	22.20	18.62	18.06	17.53	19.12	18.82	18.94	20.35	21.09	22.37	241.1
Exports	0.00	0.00	0.07	0.07	0.05	0.00	0.02	0.00	0.20	0.38	0.04	0.03	0.9
Total Demand and Exports	23.12	20.92	22.27	18.69	18.11	17.53	19.14	18.82	19.14	20.73	21.13	22.40	242.0
Exported Surplus	0.00	0.00	0.07	0.04	0.08	0.03	0.04	0.01	0.10	0.01	0.05	0.03	0.5

Significant alignment is evident between the Scenario "S" production and the OPO Outlook B expected production for the identified common elements of capacity.

- Hydro is identical.
- Solar + DER + Biomass less DER demand matches OPO renewables less solar and wind capacity assumptions.
- NUGs/CHP match today's production figures.
- Imports are marginally greater than today, the OPO does not specify future expectations for imports in Outlook B.
- Exports are significantly down from today reflecting both a lower surplus and a lower gas-fired generation based exports. The OPO assumes that gas-fired exports will be eliminated based on the expectation that carbon prices will make Ontario's gas-fired generation uneconomic for export.

The new nuclear capacity is assumed to operate with a 92% operating factor and the refurbished capacity is assumed to operate at a 90% operating factor. The 90% operating factor for the refurbished fleet is the average for the period 2025 to 2033 used in the OPO. The nuclear fleet provides all of the needed replacement and additional supply. Combined with the existing nuclear, 184 TWh of nuclear supply would be produced.

4.6.1. A Perspective on Surplus

Surplus energy occurs in almost any supply mix. Scenario "S" assumes this surplus energy is assumed in four ways:

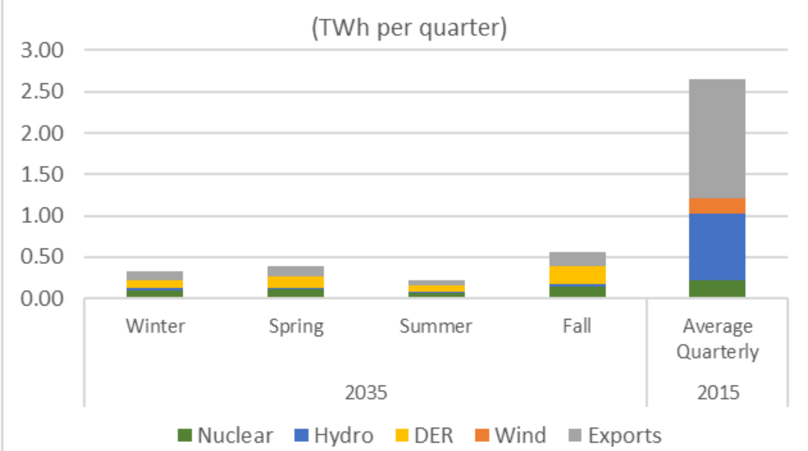
- Curtailed discharge from the LDC controlled DER batteries, deferring the use of the energy instead of wasting it;

- Increased exports to the U.S., subject to the maximum hourly limits observed in 2015, reflecting current practice. This is the most economic (achieves the wholesale market price) and least intrusive way to handle the surplus as it avoids curtailing the operation of Ontario's generating assets.
- Spilling water at hydro facilities, to the maximum spilled for the equivalent timeframe in 2015;
- Reducing nuclear to the maximum flexibility limit available, first from the Bruce B units; and, then from the Bruce A units.

The curtailment strategies deployed in the simulation for hydro and exports are limited by the maximum observed for that hour in the equivalent month in 2015.

The forecast total surplus supply under Scenario "S" is expected to be much lower than today. Figure 39 shows the Scenario "S" quarterly projected profile of surplus energy in comparison to 2015 actuals. The supplies that have been curtailed are also shown. Scenario "S" suggests a quarterly surplus is that is forecast to be less than 0.5 TWh, higher in the spring and fall as is traditional for Ontario. The total annual surplus is projected to be under 2 TWh or 0.6% of demand. The total surplus in 2015 was 10.6 TWh[41] or 7.5% of demand. The average quarterly surplus in 2015 was over 2.5 TWh. As described in Section 2.0., the projected surplus for OPO D1 is 15 TWh in 2035, 50% higher than in 2015. Scenario "S" surplus is projected to be 80% less than 2015.

Figure 39 – Surplus Baseload Supply by Season; 2035 vs. 2015



Incorporating 14 GW of new nuclear with the demand smoothing capabilities of DER, wires and pipes integration, and a hydrogen economy could provide the backbone of a very efficient supply mix. Compared to the OPO, this supply mix would result in over 13 TWh/year less surplus electricity. With

[41] Office of the Auditor General of Ontario, 2015 Annual Report, 2015; OSEP, Ontario's Energy Dilemma, 2016; OPG, 2015 Annual Report, 2016; IESO, 2015 Electricity Production, Consumption, Price and Dispatch Data, 2016

this supply mix, the simulated surplus electricity projections are so modest that the future potential flexibility capabilities of the Bruce A and Darlington Units were not necessary to be included.

4.7. Summary

This section outlined four paradigm shifts for electricity system planning and design, and described an alternative Scenario “S” based on these paradigm shifts that could deliver several benefits:

1. **Embedded Distributed Energy Resources**

   An LDC managed/controlled integrated system comprised of 2.7 GW of solar (equivalent to existing solar capacity) with 1.4 GW of new battery capacity (with daily energy storage of up to 6.8 GWh) can mitigate peak system loads at both the Tx grid and LDC level, and provide other ancillary services that support reliability.

2. **Integrating the “Wires and Pipes”**

   Hybrid natural gas/electric heating solutions are integrated with the DER LDC controlled infrastructure with natural gas used to mitigate the need for up to 10 GW of peaking winter electricity system demand on extreme cold days while still achieving Ontario’s emission reduction objectives.

3. **The Hydrogen Economy**

   Leveraging the underground storage capacity of the natural gas system in Ontario can offer flexibility for meeting the seasonal winter heating demand challenge by reducing baseload winter demand by 3 GW.

4. **Nuclear**

   Incorporating 14 GW of new nuclear with the demand smoothing capabilities of DER, wires and pipes integration, and the hydrogen economy could provide the backbone of a supply mix with over 10 TWh/year less surplus energy than projected in the OPO.

5.0 Costs

This Section summarizes the costs associated with the Scenario "S" supply mix.

A summary of the overall results is presented first, including the various components that contribute to the cost impacts. The subsequent subsections discuss each cost assumption adopted from the OPO, followed by a description of the estimates of the total costs for Scenario "S". Next, the costs avoided from the BAU Outlook B that is the common reference for both Scenario "S" and OPO Option D1 are presented.

Section 5.0 concludes with a summary of the key findings.

5.1. Overview of Scenario "S" Incremental Cost

The total direct costs of Scenario "S" is projected to be $10.8B/year as summarized in Table 6. This total direct cost can be offset by the avoided costs of not renewing the capacity contracts from Outlook B. With these offsets, as shown in Table 7, the incremental cost of Scenario "S" is expected to be $8.3B/year.

Table 6 - Scenario "S" Costs of Supply

Supply Source	Unit		Cost/Unit ($M)	Total ($B)
Nuclear	14	GW		
	112	TWh	$93	$10.4
DER	1400	MW	$0.05	$0.1
Transmisison	$4	$B	$340/year	$0.3
Total Annual Costs				$10.8
Note: Tx assumption is a placeholder reflecting a new Milton Line				

Table 7 - Impact of Costs Avoided

Supply	$B/Year
Wind (6 GW avoided)	$1.4
Solar (1 GW not procured, 2.7 GW at lower cost	$0.4
Gas (6.4 GW retired, 7 TWh less production)	$0.7
Total Savings	$2.5
Scenario "S" cost	$10.8
Net Incremental Cost	$8.3
Production assumption (TWh)	93
Effective $/MWh on increment	$89

On a per MWh basis, the incremental cost is projected to be on average $89/MWh when the entire portfolio of new nuclear units, DER, and Transmission are commissioned.

Each of these cost elements is discussed in the following subsections.

5.2. OPO "D" Cost Assumptions

The following reviews the cost assumptions contained in the OPO for the various generation types. Three supply types are considered as shown in Table 8. The Energy Information Agency's (EIA) Annual Energy Outlook (AEO) 2016[42] Levelized Cost of Electricity (LCOE) estimates are provided in Table 9 as a point of reference. These EIA cost estimates are referenced in Canada's Mid-Century GHG goals report[43].

[42] U.S. EIA, Annual Outlook 2016 with Projections to 2040, 2016

[43] Government of Canada, Canada's Mid-Century Long-term Low Greenhouse Gas Development Strategy, 2016

Table 8 - OPO Generation Cost Assumptions	
Generation Type	IESO OPO Estimate ($Cdn/MWh)
Hydro	140
Solar	$90 (in 2030)
Nuclear	$120 @ 85%
	($111 @ 92%)*

*Strapolec estimate based on scaling the Op Factors

Table 9 - EIA AEO 2016 Cost Estimation ($2015)						
2022 Enter Service	Minimum	Simple Regional average	Capacity-weighted average	Maximum	2040 Estimate (simple regional average)	% Change 2022 to 2040
Hydropower	59.6	67.8	63.7	78.1	65.3	3.8%
Solar	65.6	84.7	74.2	126.2	71.2	19.0%
Nuclear	99.5	102.8	99.7	108.3	93	10.5%

The hydro costs in the OPO appear to be high.

- The maximum EIA estimate is $78/MWh, but the EIA emphasizes that this value relates to smaller, accessible projects in the U.S., and that such project specific considerations have a material impact on costs. At the same time, HQ confirms that the current La Romaine project cost should be under $70/MWh.
- The 2013 Hatch study referenced in the OPO suggests that large northern hydro projects in Ontario should have a LCOE in the range of $50/MWh, but the smaller more accessible hydro projects could be in the $60 to $78/MWh range.
- Industry interviews put recent hydro projects in the range reflected in the OPO. Ontario's LRP I was $175/MWh[44]. Strapolec has no basis for suggesting alternate costing.

Solar costs in the OPO appear to be reasonable.

- The EIA AEO shows that there is a large range of solar cost experience. The EIA is clear that solar installation costs are variable and are affected by jurisdiction and project specific factors.
- The EIA 2040 estimate of $71USD/MWh would convert to about $82/MWh CAD. Strapolec has no basis to suggest alternate costing for the solar assumptions and has adopted OPO's $90/MWh for the DER components of Scenario "S".

Nuclear costs used in the OPO appear to be slightly high.

- The OPO states that the assumed $120/MWh cost for new nuclear generation is based on 2013 references and an 85% capacity factor.
  - It is expected that the capacity factors for new nuclear will be in excess of 90%, which is also the reference assumption used in the EIA AEO LCOE calculations. A one month planned outage for each unit every year results in a 91.7% operating factor. Applying this operating factor to the OPO estimate suggests a LCOE of $111/MWh.

[44] Zawadzki, LRP I Results, 2016

- The EIA AEO 2016 released in Sept 2016 suggests an average LCOE for new nuclear is currently in a narrow range of $99/MWh to $103/MWh.
  - In the longer term, EIA estimates that the average LCOE for generating plants entering service between 2036 and 2040 will drop by over 10% to $93/MWh. Applying a 15% long-term USD to CAD exchange rate for the 20% of foreign content in a typical Canadian nuclear plant suggests a long-term cost of $96/MWh.
  - Industry interviews support the EIA estimates that put new nuclear at under $100/MWh.
- The EIA cost estimates for nuclear include a 15% contingency.
  - Strapolec suggests, as in Scenario “S”, that if a major nuclear program is contemplated in Ontario involving multiple units built to a staggered scheduled, this contingency would decline and disappear for the later units. Furthermore, the nuclear build and site conditions in Ontario are well understood. Without the 15% contingency, the future cost of a plant entering service in the 2036 to 2040 according to the EIA could be $83/MWh in $2015.
- For the purposes of this study, the average of the future $/MWh rate without a contingency and today’s rate results in $93/MWh (averaged over the entire new reactor fleet).

A sensitivity analysis was conducted to illustrate the impact the assumed nuclear costs could have on the incremental cost of Scenario “S”. The results are summarized in Table 10, which shows that a high nuclear cost could result in a $103/MWh net incremental cost of power. This is similar to the low-end cost of electricity assumed in the Phase 1 report, and significantly less than the $170/MWh calculated in Section 2.2 of this report.

Table 10 - Nuclear Cost Sensitivity Analysis

	$/MWh	Cost ($B)
Assumed future cost	$93	$10.4
OPO D Assumptions @92% Op Factor	$105	$11.7
Difference		$1.3
Net Incremental		$9.6
High end Incremental cost	$103	

5.3. Scenario “S” Cost Assumptions

Three cost components were estimated for the development of Scenario “S”. The first was nuclear, discussed in the previous section, and the other two costs are related to implementing the DER solution and potential Tx investments.

Solar/Battery DER Cost Assumptions

Cost estimates were examined from several sources. The IESO[45] and Navigant[46] have both recently developed reports suggesting the solar/battery DER option is not yet mature and commercially available.

[45] IESO, Energy Storage, 2016

[46] Navigant Consulting Inc, Ontario Smart Grid Assessment and Roadmap, 2015

Navigant suggests this option could offer positive business case results post 2020, with a recent Massachusetts report also supporting the same timeframe[47].

In the Massachusetts report, the capital cost for a storage project is assumed to be $600/kWh in 2016, $450/kWh in 2018, and $300/kWh in 2020. The EU report on commercialization of future storage technologies[48] predicts that 8-hour storage will cost €200/kWh by 2030 as shown in Figure 40.

Figure 40 – Storage Technologies – Key Parameters and Costs

Low (optimistic) range of cost estimates

	Parameter	Storage round-trip efficiency	Storage capex/kW	Storage capex/ kWh	Storage opex fixed	Storage opex fixed	Storage opex variable	Cycle lifetime	Storage lifetime
	Unit	Percent	EUR/kW	EUR/kWh	EUR/kW	EUR/kWh	EUR/MWh	Thousand	Years
Li-ion	2013	85	0	375	10	0	2	3	12.5
	2030	88	0	200	10	0	2	6.5	12.5
NaS	2013	78	150	500	35	0	0	7.5	12.5
	2030	85	35	80	35	0	0	7.5	12.5
Flow-V	2013	68	1000	300	25	7.5	0	10	20
	2030	73	600	70	15	2	0	15	20
PHES	2013	78	500	5	4	0	8	>50	55
	2030	78	500	5	4	0	8	>50	55
CAES-A	2013	65	1,000	40	30	0	0	20	35
	2030	65	700	40	21	0	0	20	35
CAES-D	2013	65	500	50	15	0	-30	20	35
	2030	65	400	40	12	0	-30	20	35
Lead-acid	2013	78	150	100	6	0	0	1	10
	2030	81	105	70	6	0	0	3	10
LAES-A	2013	57	1,500	50	38	0	0	20	30
	2030	67	1,200	40	30	0	0	20	30
LAES-A	2013	36	1,850	0.2	37	0	10	10	15
	2030	40	1,000	0.2	20	0	10	10	15

Costs include electronics and civil works but exclude grid connection.

SOURCE: ISEA RWTH 2012: Technology overview on electricity storage; coalition input

A recent article by ComputerWorld[49] suggests that storage capital costs could drop to $100/kWh over the next 30 years. Assuming half of this decrease occurs results in a capital cost of $200/kWh by 2030.

The Massachusetts study estimated the total costs of a storage project that included LDC control of the assets behind the meter. This study suggests a 93 MW solar plus battery schema managed by a utility would cost $53M over 10 years. That equates to $5.3M/year or $44/MWh if operated to match solar output. The cost of electricity from the solar panel would be in addition to the $44/MWh cost.

Assuming a 2030 storage cost of $200/kWh, instead of the 2020 $300/kWh used in the Massachusetts study, the storage cost could shrink to $33/MWh. However, in the DER model developed for Scenario "S", the storage required is 1.6 times larger, on a per kWh basis, than assumed in the Massachusetts study. Strapolec estimates a system cost of $41/MWh in 2030. If solar is $90/MWh, as suggested by the OPO for

47 Massachusetts Department of Energy Resources, Massachusetts Energy Storage Initiative, 2016
48 European Fuel Cells and Hydrogen Joint Undertaking, Commercialization of Energy Storage in Europe, 2016
49 Mearian, Move over EVs; hydrogen fuel cell vehicles may soon pas you by, 2016

2030, and a 10% efficiency loss occurs, this package equates to a cost of $140/MWh for the energy delivered from of the storage device.

On a simple business case basis, the value equation is whether the cost of the solar plus battery storage option to reduce peak demand is less than the cost of a natural gas peaking plant. There are two cost components for a gas-fired generation peaking plant – fixed and variable costs.

- The fixed cost of a peaking gas plant is assumed to be $135,000/MW/year capacity as defined in the OPO for an simply cycle gas turbine (SCGT). If the gas plant is run at the same duty cycle as a solar panel, or 15% in Ontario, then 8760 operating hours multiplied by the 15% operating factor yields a rate of $100/MWh.
- Variable costs are assumed at $60/MWh to $100/MWh. The $60/MWh represents Strapolec's estimate of the cost of gas-fired generation based on fuel at the assumed delivered cost of $8/MMBtu in 2030. The higher cost includes an additional $40/MWh to reflect the impact of a $100/tonne carbon price.

The total cost of a peaking gas-fired generating plant in 2030 could be $200/MWh, or ~40% greater than the estimated DER solar/battery costs.

Transmission Costs

There are several locations near existing Tx lines (e.g. Darlington) where new nuclear reactors could be built. Incremental Tx costs are anticipated to be moderate at these locations. There are other sites that may require new Tx construction.

Strapolec's Tx cost estimate is derived from IESO reported costs for upgrading the Ontario/Quebec intertie[50]. The benchmark is $1.9B for 2300 MW of capacity. If the Bruce plant, for example, were to have 6000 MW of new nuclear, a Tx investment of $5B might be required. Since such a Bruce Tx line would be shorter than the distance between Quebec and Toronto, a $4B capital cost has been assumed. For the purposes of this study, it is assumed that a total provision of $4B is adequate to illustrate a Tx cost potential for all potential new nuclear capacity additions. Since this represents 3% of the annual cost, the conclusions contained in this report are not sensitive to this value.

5.4. OPO "B" Costs Avoided

The design of Scenario "S" eliminates the need for 16.5 GW of existing capacity as summarized in Figure 41. The potential cost reduction is $2.5B/year in avoided costs for the capacity that is otherwise included in the OPO BAU Outlook B total system cost. These avoided costs are summarized in Figure 42.

[50] Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016

Figure 41 – Expiring Contracted Capacity Not Renewed in Scenario "S"

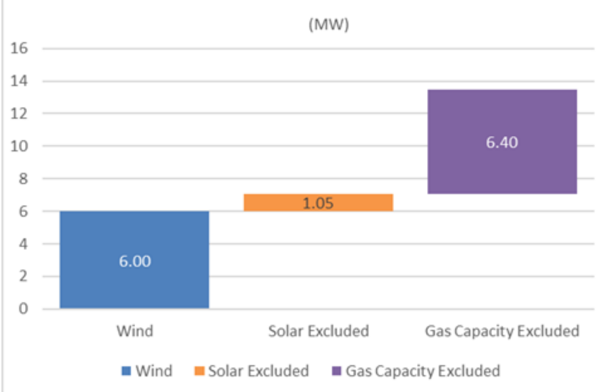
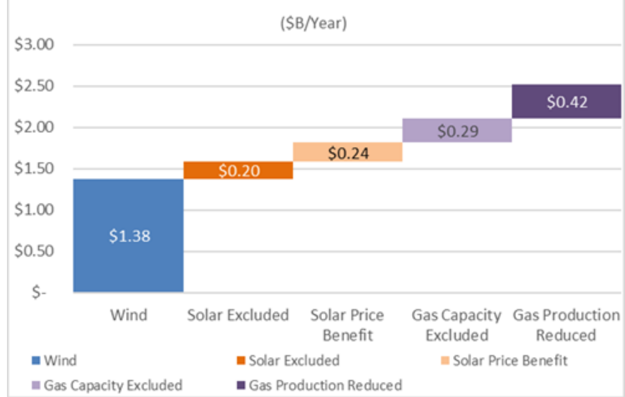


Figure 42 – Expiring Contracted Capacity Costs Avoided in Scenario "S"



Avoided Wind Costs

Contracts for 6 GW of wind that are anticipated by 2035 in Outlook B do not need to be renewed. This wind generation would generate about 16 TWh. At the expected renewed cost of $86/MWh stated in the OPO, the avoided costs would be $1.4B/year.

Avoided Solar Costs

Scenario "S" does not include 1.05 GW of solar capacity contained in Outlook B. At the OPO assumed $157/MWh LRP price, this would represent a savings of ~$220M/year.

The 2.7 GW of solar included in the DER of Scenario "S" is assumed to be contracted at the future solar cost of $90/MWh, not the LRP price of $157/MWh assumed by the OPO for renewed contracts. Scenario "S" will save the difference of $67/MWh. With an assumed 15% operating capacity factor, this equates to $250M/year of avoided costs.

Avoided Gas-Fired Generation Costs

The OPO states that gas-fired electricity exports are not expected to continue, significantly reducing the forecast for the use of these assets. Scenario "S" eliminates the need for production from Ontario's large gas-fired plants. The OPO identifies 11.3 GW of gas-fired capacity by 2035. The modelled scenario retains 1.9 GW of NUG/CHP capacity. Therefore, 9.4 GW of gas-fired generation may not be needed. The IESO may still require "offline" capacity (i.e. not operating capacity) that would be available as emergency reserve should planned assets be out of service for extended periods. Assuming that 3 GW of this type of reserve will be required (10% of demand after DR), 6.4 GW of gas plant contract renewals may be avoided.

Capacity costs of $135K/MW/year for SCGT and $180K/MW/year for combined-cycle gas turbine (CCGT) are assumed. The OPO states that renewed contracts will retain only 20% of the capital portion of the capacity charge. The EIA summarizes the relative contribution of capital versus operating cost within the LUEC. This cost breakdown is:

- CCGT LUEC fixed costs are 90% capital, 10% O&M
- SCGT LUEC fixed costs are 85% capital, 15% O&M

Based on an average blend, these costs result in an estimate of future avoided capacity costs (if the gas fleet is retired) of approximately $45k/MW/year. For 6.4 GW of capacity, this equates to $290M/year.

The need for production from these gas-fired generating assets would also be eliminated in Scenario “S”. OPO outlook D has 14 TWh of gas production. It is assumed that the production from the 1900 MW of NUGs and CHP facilities will be retained as per today’s production levels, which is ~7 TWh. This would avoid 7 TWh of gas-fired generation. At an assumed variable cost of $60/MWh for gas-fired generation, the savings would be ~$420M/year

Net savings from the OPO Outlook B baseline are expected to total $2.6B per year.

5.5. Summary

The incremental unit cost of energy in Scenario “S” could be as low as $89/MWh by supplying 80% more energy at a total cost of ~$8.3B/year. This is similar to the OPO Outlook D estimated total system cost. Section 2.3. indicated that the possible future cost of a scaled-up D1 option could be ~$16B/year, which is approximately double the incremental cost of Scenario “S”.

The OPO Outlook D1 option has an incremental cost of ~$170/MWh as stated in Section 2.3.

Cost benefits for Scenario “S” arise from: (1) the expected lower long-term costs of the new nuclear portfolio ($93/MWh); (2) new solar generation for DER assumed at the $90/MWh from the OPO; (3) no incremental cost incurred for DR from the new hydrogen production facilities; and (4) minimal new Tx investments given that no new imports or hydro capacity is required and that many potential sites for new nuclear capacity are near existing Tx.

Scenario “S” could achieve cost savings of $2.5B from the Outlook B baseline cost. Scenario “S” does not require the OPO Outlook “B” directed (uncommitted) solar capacity (1 GW), the capacity associated with expiring contracts for existing wind (6 GW) and other natural gas-fired generation (6.4 GW). The cost savings results from not renewing the expiring contracts for these capacity assets, and from not continuing with the, as of yet, uncommitted but directed solar capacity.

Under Scenario “S”, the overall average electricity system cost could be reduced to $115/MWh from the BAU OPO estimate of $131/MWh and from the OPO Option D1 average of $142/MWh. Scenario “S” could represent a cost drop of 20% from today’s cost of $144/MWh.

6.0 Implementation Considerations

Scenario "S" is intended to offer an additional supply mix option that would be materially different from those in the OPO. Scenario "S" is distinguished by the substantial amount of nuclear capacity it includes.

This section subjectively discusses the considerations and challenges raised in the OPO regarding the implementation of the available generation supply types, including the management of associated wastes, and provides comparative frameworks for assessing these challenges. A possible pathway for the development of the Scenario "S" nuclear supply and the implementation considerations are then presented.

This Section concludes with a summary of the key findings.

6.1. Overview of Nuclear Implementation

Any large-scale infrastructure project has development risks. Implementing a portfolio of infrastructure projects that can be staged over a planning horizon can help mitigate these risks. The process for developing such a nuclear implementation pathway is well defined. A fleet of new reactors could be built to help Ontario achieve the 2030 emission targets by 2035.

6.2. Project Portfolio Risk Considerations

This Section outlines the challenges facing the development of each supply type that was identified in the OPO. The following supply types include:

Firm imports – The OPO states the interties provide benefit when the costs are below that of domestic resources and that scale / economics depends greatly on the need for new Tx infrastructure between the exporter and importer of the electricity. → *A Cost and Stakeholder caveat.*

Waterpower – The OPO states that the remaining waterpower potential in Ontario is located in remote northern regions of the province without Tx access. The costs are expected to be higher than in the past and involve longer lead times. There are few opportunities for increasing hydro capacity in the southern part of Ontario, including redevelopments at existing dams. → *A Cost and Schedule caveat.*

Wind – The OPO states that, while wind may have a low generation cost, it comes with high integration, Tx costs, and related emissions consequences if back up is provided by carbon-emitting generation. → *A Cost and Emissions drawback caveat.*

Nuclear – The OPO states that opportunities for baseload development are limited by growth in baseload demand, and that nuclear baseload resources have limited capability to load follow making supply matching a challenge. Construction costs are stated to be an area of considerable uncertainty. → *A Cost and Suitability caveat.*

Figure 43 puts all of the supply options into a common framework defined by the caveats stated above. The noted nuclear caveats are also applicable to all of the other options, particularly the caveat regarding cost. The relevance of each caveat to each individual supply type is characterized by a colour: green (favorably suited); red (the supply is not suited); and, yellow (suitability may depend on several factors).

Figure 43 – Stated Nuclear Caveats are Equally Applicable to Other Sources

Demand Matching Supply

The OPO indicated that there is not a clear demand for new nuclear baseload supply. Strapolec's analysis establishes that there is a substantial need for new nuclear baseload power. Scenario "S" suggests a minimum 5 GW and potentially up to 14 GW. Conversely, it can be argued that given the natural flow of water and wind patterns, as described in Section 3.0, demand does not match these supply resources, and requires either large reservoirs or backup facilities to function. This results in additional costs.

Load Following

Ontario's experience dispels the myth that nuclear is unable to match demand. Nuclear has the capability to load follow as demonstrated by the Bruce units. This capability is described in Section 3 and is inherent in the design of Scenario "S". Any plans for new nuclear would require determining how much load following flexibility is required and the associated cost implications. Ontario's hydro generation is capable of load following, i.e. by spilling water. Quebec has large reservoirs that reduce wasting energy in this manner. Imports from Quebec potentially could load follow, constrained only by distance considerations. Wind generation, on the other hand, cannot load follow but can be curtailed.

The need for load following may be a moot point in the future. Given the anticipated flattening of demand, flexibility in DER, and extensive demand response, the simulation for Scenario "S" shows that the load following capability of the existing nuclear fleet is sufficient to meet future needs.

Cost Risk

The OPO identifies cost risks or uncertainties for all of the supply types. Strapolec suggests that the cost risks associated with nuclear are lower than all other low carbon generation options. The EIA cost ranges for nuclear projects, shown in Table 9 in Section 5.2, are far more narrow, based on the relative certainty of nuclear project costs versus the other options. Given today's $100/MWh low-cost of nuclear versus the OPO hydro and imports cost assumptions of $140 and $160/MWh, significant cost overruns for new nuclear would need to occur before the expected costs of these other options are exceeded. The wind and solar costs in the OPO are deceiving, as outlined earlier. The full cost associated with wind's variable production profile is $172/MWh and $131/MWh for solar, as determined from the OPO assumptions described in this report for 2035.

A Note on Generally Accepted Principles Regarding Cost Risks of Large Projects

The contemplated nuclear, hydro, requisite Quebec new hydro, and extensive Tx projects all represent significant infrastructure projects. Cost risks are endemic to large-scale projects and all large-scale projects in Canada are executed by the same Engineering, Procurement, and Construction (EPC) companies, who dominate the global marketplace.

The hydro and import options involve "one of a kind" projects that are accompanied by higher risk profiles compared to the "nth" of a kind project characteristics of the nuclear build in Scenario "S". Hydro projects have historically on average seen a doubling of costs over the course of the projects[51], witness the recent challenges with Muskrat Falls[52]. Recent projects by Hydro Quebec (La Romaine) and Ontario Power Generation (Lower Mattagami) have not experienced these same challenges. The scope of several of the proposed hydro and Tx projects exceeds the scale of the individual nuclear projects.

The nuclear profile in Scenario "S" requires multiple units to be developed over an extended time period. This staggered schedule should reduce cost risks by capturing and acting on lessons learned at each stage.

Government run mega-projects of any type are subject to the most significant cost risks[53]. Innovation in business models involving the private sector in governance/ownership/partnerships may help mitigate and manage large project risks, particularly of the type associated with a nuclear fleet deployment. These options should be explored by Ontario.

A discussion of Environmental Implications

COP21 has established a political consensus regarding the relationship between man-made GHG and the environmental effects of global warming. This has resulted in leaders across the globe calling for action. Each climate change solution presents its own unique environmental impact.

In this regard, the management of nuclear waste is a topic that is frequently raised. Since Scenario "S" represents the renewal of Ontario's nuclear fleet and the construction of new assets to meet Ontario's future energy clean energy needs, the topic should not be ignored. The environmental impacts of the other low carbon supply options deserve equal attention. Figure 44 summarizes several relevant factors

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[51] Siemiatycki, Cost Overruns on Infrastructure Projects, 2015
[52] Bailey, 'Project was not the right choice', 2016
[53] Siemiatycki, Cost Overruns on Infrastructure Projects, 2015

related to the environmental risks associated with these options. Green represents a favourable rating, red unfavourable, and yellow marginally unfavourable.

Figure 44 – Low Carbon Electrification Option Environmental Considerations

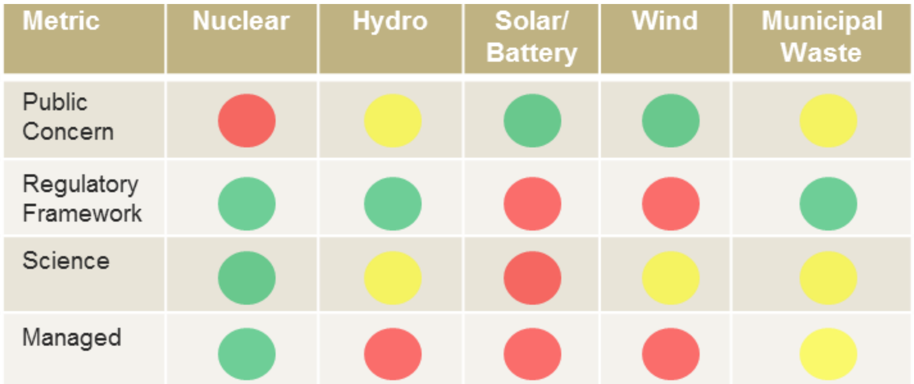


Figure 44 suggests that the nuclear industry is the only industry in Canada that has a comprehensive program in place that safely and responsibly manages its life-cycle wastes. The following provides some additional comments on the indicators noted above:

a) Hydro & Imports from Quebec

- The kind of hydro needed in the future will involve large dams and reservoirs. The reservoirs will flood thousands of square kilometers of land.
- Environmental assessments and regulations are in place to address public concerns.
- The science has established that the ecosystem will be disrupted by habitat destruction, material GHG emissions are generated in the short term from the decaying biomass impacted by the flooding, and silting can become problematic in some river basins.

  The public is expected to accept these consequences in order to make use of hydro power.

b) Wind

- Opposition to wind projects has been evident in Ontario and other jurisdictions. Specific concerns have been expressed about human health impacts, nuisance effects related to noise and the visual presence of the wind turbines on the landscape, bird deaths and disturbance to the habitat of rare fauna and flora.
- Research is underway in several jurisdictions e.g., Germany and Sweden related to the decommissioning, recycling and disposal of wind turbines and the associated infrastructure.
- No clear accountability and or funding arrangements are evident in Ontario to manage the decommissioning, recycling and disposal of components of existing and or planned wind projects

c) Solar & Batteries

- Solar panel and battery wastes during manufacture and decommissioning are large in volume and contain many toxic materials.

- Research is underway to develop safe and responsible decommissioning, recycling and disposal practises in several jurisdictions. However, there are no evident plans to address this waste[54].
- No clear accountability and or funding arrangements are evident in Ontario to manage the decommissioning, recycling and disposal of the solar panels and batteries.

d) Municipal Waste

- Projects related to the management of municipal waste, especially toxic materials and potential impact of ground water quality typically receive public attention.
- The siting and construction of new landfill projects involve lengthy consultation and approvals processes.

e) Nuclear

- There is public concern about the management of nuclear wastes. Yet Canada has safely managed used nuclear fuel, intermediate waste (used reactor components) and low-level waste (minimally radioactive waste such as mops, rags and protective clothing) in an environmentally responsible way for over four decades. The full waste life cycle is funded within the electricity rates for nuclear power.
- All waste management facilities and nuclear power plants are licensed and regulated by the Canadian Nuclear Safety Commission (CNSC), an independent agency of the Government of Canada that reports to Parliament through the Minister of Natural Resources. The CNSC provided a leadership role in incorporating within both Canada's regulatory environment and the international regulatory frameworks the lessons learned by the global nuclear industry that stemmed from t the Fukushima event.
- Used fuel nuclear waste management can be effectively addressed with engineered solutions. Two projects are underway in Ontario: OPG's proposed Deep Geological Repository for the long-term management of low and intermediate waste; and, the Nuclear Waste Management Organization's process to find a long-term solution for used nuclear fuel. Both processes are based on best international practises—Sweden, Japan, Germany and the United Kingdom. The NWMO is using a public participation model to establish a publicly acceptable solution that is being emulated around the world.
- Multi-national research and development efforts are underway to find ways to recycle the used fuel and make use of the massive residual energy. Canadian technology is being commercially developed to recycle nuclear fuel to reduce waste volumes[55].

6.3. Nuclear Deployment Considerations

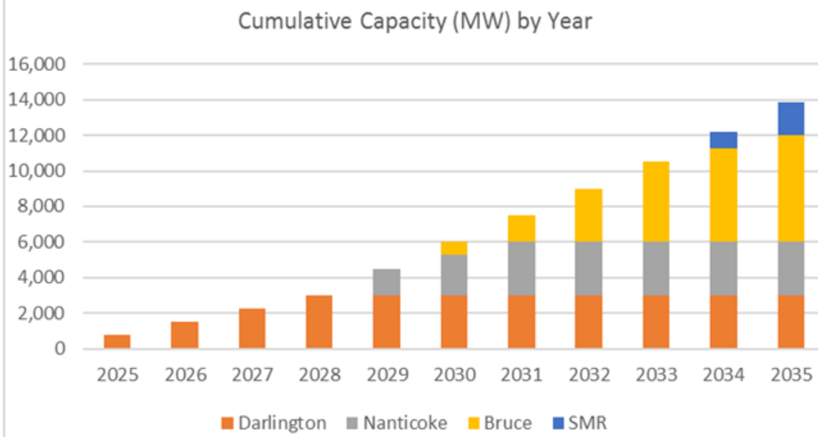
The following presents a potential schedule for deploying new nuclear capacity in a manner that would allow for Ontario to achieve its 2030 emission reduction targets by 2035. A distinct advantage of nuclear

[54] Petrunic, Remarks at CCRE 2016 Technology Innovation & Policy Forum, 2016
[55] SNC Lavalin, SNC-Lavalin signs an agreement in principle…, 2016

technology is that new reactor units can be developed in a manner that delivers the capacity when needed.

An illustrative development schedule is shown in Figure 45.

Figure 45 – Potential New Nuclear Capacity Rollout Schedule



Candidate sites are referenced in the illustrative schedule for the following reasons:

Darlington is a natural first choice for new nuclear build. There is a near ready site, a willing host community, a completed environmental assessment and nearby Tx infrastructure. Potential workforce synergies exist where the PNGS workforce could be transitioned to operate the new unit(s).

Nanticoke is another candidate site that also has nearby Tx infrastructure. Nanticoke has previously been considered for new nuclear build.

Bruce is a logical choice for additional units given it is a large licensed site with ample available space, a supportive host community and nearby Tx infrastructure, although new Tx capacity may be required. Bruce Power is currently focused on completing the refurbishment of the existing reactors at the complex. As a result, new nuclear build at this location is scheduled later in this illustration.

Small Modular Reactors (SMRs) could be commercially available within the timeline over which new nuclear deployment could occur. A key benefit of SMRs is their small, scalable size which could facilitate strategic deployment in support of achieving the province's emission reduction targets and potential to reduce costs over time.

While this illustrative schedule may be considered optimistic and aggressive, it is feasible that the first of the new nuclear capacity could be available by the mid to late 2020s. As such, this deployment could be coordinated with the retirement of PNGS to ensure a continued reliable, affordable, low carbon supply of electricity. This could help avoid the costly purchase of emission allowances from foreign jurisdictions.

The importance of dovetailing new supply with the retirement of PNGS is a critical consideration. There are five additional cost factors that should be considered regarding PNGS's retirement:

1. The pending implementation of a C&T program;
2. The intent to link Ontario's program with other jurisdictions;
3. The minimum carbon price of $50/tonne being imposed by the Federal government by 2022;
4. The expected increase in demand by 2025 resulting from emission reductions, even assuming the modest profiles contained in Outlook D; and,
5. The absence of an alternative replacement for the PNGS 20 TWh of low carbon supply.

In March of 2016, the IESO projected that the emission impact of the retirement of PNGS would increase[56]. The IESO forecast was consistent with Strapolec's analysis that calculated the increase to be 3.5 Mt/year[57] for the BAU forecast. While the OPO reflects the aspirational view that emissions will not rise when PNGS is retired, as discussed in Section 2.2., it contains no new supply to replace PNGS. Nor does the OPO suggest any changes to the supply mix. Furthermore, the OPO states that enhanced exports from Quebec will not be available prior to 2028. Under a linked C&T program with California, at $50/tonne, 3.5 Mt will cost Ontario $175M/year in purchased allowances. If the forecast increase in demand is met by replacing PNGS production with natural gas-fired generation, the required 20 TWh would produce 8 Mt of emission, at a cost of $400M/year for the purchase of additional allowances. At the $100/tonne price projected for Ontario in 2030[58], that cost could approach $800M/year.

Notionally, this means that each year of delay in initiating the development of new low carbon capacity, could cost Ontario up to $800M, or over $65M/month. As recommended in the Phase 1 report, the LTEP should make it a priority to initiate the earliest development of low-cost, low carbon new generation capacity. Such a process should start in early 2017.

6.4. Summary

The risk profile of the nuclear component within Scenario "S" is more moderate than the profiles of the alternatives. New nuclear represents the earliest achievable capacity that can be developed in time to meet Ontario's emission targets. This nuclear capacity could be built in a strategic manner, using small blocks of capacity, at less cost than the other low-carbon options.

This new nuclear capacity can potentially be located at several sites that would require modest new Tx infrastructure investments post 2030. The Darlington site should be a first priority.

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[56] IESO, Preliminary Outlook and Discussion, 2016
[57] Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016
[58] ICF International, Ontario Cap & Trade, 2016

The findings of this study suggest that a nuclear capacity development program be started immediately and that the other available options be given consideration for achieving the long-term goals as part of Ontario's pathway to deep decarbonization by 2050.

7.0 Economic Benefits and Policy Integration

This Section considers the implications of Scenario "S" to deliver economic benefits to Ontario, including the cost reductions associated with achieving Ontario's emission target and reversing the province's energy trade balance. Additionally, there is the potential for additional economic stimulus resulting from the managed confluence of policy objectives that could be materially impacted by today's energy choices for Ontario.

The first subsection describes how Scenario "S" could reduce the costs of Ontario's emission reduction initiatives. An examination of the potential benefits of the energy trade balance that could result from the Ontario's emission reduction initiatives follows. Next, the potential incremental contributions to Ontario's gross domestic product (GDP)[59] that could result from the domestic energy production underpinning Scenario "S" are discussed. Additionally, consideration is given to how Ontario's industrial, economic, environmental and energy policies could be integrated within the LTEP. This is particularly important as the strategic integration of these policy objectives could help Ontario leverage its domestic advantages to develop a world leading, low-carbon, export-focused economy.

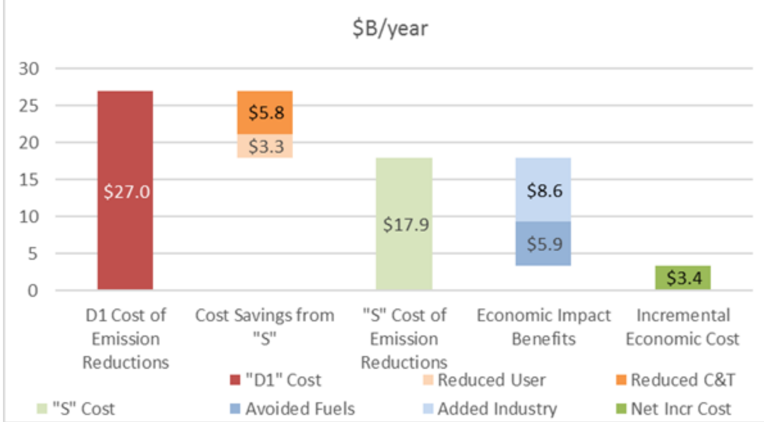
This Section concludes with a summary of the key findings.

7.1. Overview of Economic Benefits

Integrating Ontario's industrial, economic, environmental and energy policies to leverage the province's unique advantages and capabilities could provide significant environmental and economic benefits including a competitive advantage for the province in the global marketplace. Three sources of potential economic benefit for Scenario "S" are illustrated in Figure 46:

1. A lower emission reduction cost ($9.1B/year);
2. A shift in Ontario's energy trade balance resulting from lower purchases of natural gas and crude oil from outside the province ($5.9B/year);
3. Increased industrial activity associated with:
   a. Electricity system domestic spend implications ($6.7B/year);

Figure 46 – Cost of Emission Reduction Under Scenario "S"



[59] While potential contributions to Ontario's GDP are noted for the purpose of illustration, this study is not a comprehensive economic impact assessment. Contributions identified in this document are estimates of revenues that could then be fed into a calculation of GDP.

b. The hydrogen economy ($1.9B/year).

Under Scenario "S", the total cost of Ontario's emission reductions is estimated to be $17.9B/year, which is $9.1B/year less than for the OPO Option D1. These savings arise from the expected carbon price of $106/tonne for Scenario "S" versus the expected $161/tonne in the D1 scenario.

Unique to Scenario "S", the nuclear and hydrogen economies could create business activities that could contribute to Ontario's economy. Under Scenario "S", these opportunities would be accelerated by the low-cost of electricity and the associated low carbon price. These activities could generate ~$8.6B/year in GDP contributions and provide an offset to the cost of emission reductions when these factors are aggregated at the provincial level. Combined with the $5.9B benefit resulting from lower imports of fossil fuels, the incremental economic cost of combatting climate change could be $3.4B/year. OPO Option D1 does not enable these benefits.

Scenario "S" provides a potential pathway for Ontario to build a world leading competitive advantage and warrants further study.

7.2. Reducing the Cost of Emission Reductions for Ontario

Phase 1 of this study developed a model of the total cost of emission reductions as a function of electricity costs. Based on the incremental costs of Option D1, the total cost of emission reductions is estimated to be as high as $27B/year by 2030. Phase 1 determined a low-cost electricity solution could materially reduce this cost. The model has been updated for Scenario "S" with the results provided in Figure 47 and Table 11. These illustrations show Scenario "S", with an electricity cost of $89/MWh, could reduce the total cost of emissions by $9.1B/year as compared to the OPO Option D1 scenario with an electricity cost of $170/MWh.

Figure 47 – Implications of Different Electricity Prices on Emission Reduction

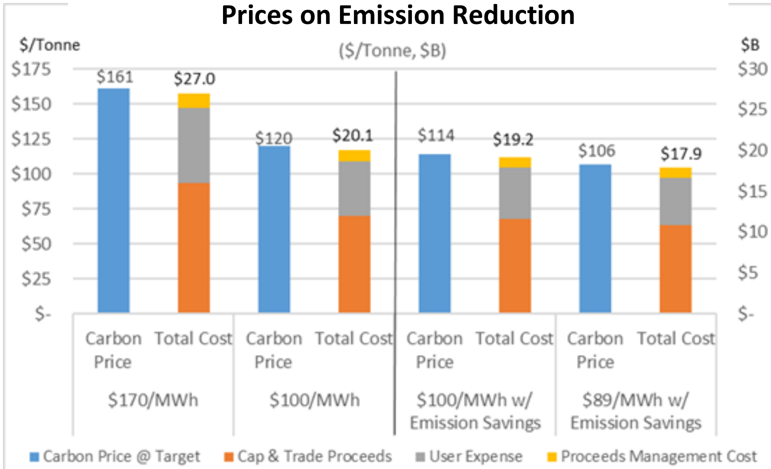


Table 11 - Impact of Scenario "S" on Cost of Emission Reduction					
	Phase 1 Report Estimate		Scenario "S"		
	OPO D1	Ref Case	2.6 Mt Reduction	Net "S" Impact	Total Savings
	$170/MWh	$100/MWh	$100/MWh	$89/MWh	"S" vs. D1
Carbon Price ($/t)	$ 161	$ 120	$ 114	$ 106	$ 55
C&T Proceeds ($B)	$ 16.1	$ 12.0	$ 11.7	$ 10.9	$ 5.2
Management Cost ($B)	$ 1.8	$ 1.3	$ 1.3	$ 1.2	$ 0.6
User Expense ($B)	$ 9.1	$ 6.8	$ 6.2	$ 5.8	$ 3.3
Total Cost ($B)	$ 27.0	$ 20.1	$ 19.2	$ 17.9	$ 9.1

A portion of the $9.1B/year savings in the total cost of emission reductions in Scenario “S” occurs because the scenario reduces emissions from the electricity sector by 2.6 Mt/year by eliminating the need for 6.6 TWh of the gas-fired generation output. This emission reduction was not accounted for in the Phase 1 estimates, but could be achieved by Scenario “S” at no incremental cost. The resulting cost benefit can be viewed from two perspectives: (1) The reduced emissions could lower the overall cost to Ontarians of achieving the 2030 targets by $900M/year. Crediting this benefit of Scenario “S” to the greenhouse gas reduction account (GGRA) results in an incremental cost of electricity approaching $75/MWh. This is a low-cost option that any other jurisdiction would have difficulty surpassing. (2) Alternatively, if under the OPO Option D1, no opportunity or innovation is adopted that could otherwise achieve these emission reductions from other sectors of the economy, the resulting cost in the OPO Option D1 scenario could be a carbon price of $100/tonne. This would mean purchasing emission allowances from other jurisdictions at a cost of $280M/year. It could be argued that the “swing” benefit of Scenario “S” is the sum of these two values or $1.2B/year.

These two outcomes of Scenario “S”, lower emissions and a lower electricity system cost, represent a combined cost reduction of $9.1B/year. These impacts are evident in Table 11:

- The carbon price required to achieve the 2030 targets drops to $106/tonne from the projected high case of $161/tonne;
- Costs to Ontario’s economy to generate the C&T proceeds drop to $12.1B/year from $17.9B/year, a savings of $5.8B/year to the economy (including management costs); and,
- The costs that will be borne by users making technology choices will decline by $3.3B/year, likely accelerating consumer uptake.

7.3. Energy Trade Balance Benefits

Ontario’s energy trade balance will be impacted in at least two ways:

1) Reduced imports of fossil fuels
2) Increased purchase of emission allowances

Reducing the consumption of imported fossil fuels such as natural gas and crude oil for gasoline/diesel could significantly alter Ontario’s trade balance in a beneficial manner. Diverting these outbound expenditures to support domestically produced goods and services would provide economic capital to the province. This economic capital will be injected into Ontario’s economy by consumers as they pay for their alternative emission reduction choices. These costs are not covered by the C&T system or the user paid portions associated with the carbon prices discussed in Section 7.2 above. These costs are “below the line" used to calculate those values. These costs will be spent by Ontarians, out of their existing energy budget.

These energy trade balance benefits could contribute $5.9B/year to Ontario's economy as summarized in Table 12. This benefit arises in the scaled-up OPO Option D1 as well as in the Scenario "S" option.

Table 12 - Trade Balance Impact

	Unit (millions)	Unit Cost ($)	Total Cost ($B)
Natural Gas (mmBTU's Avoided)	**225.4**	**$ 7**	**$ 1.58**
Home Heating	98.0		$ 0.69
Gas-Fired Generation	52.8		$ 0.37
Hydrogen Blending, RNG	63.6		$ 0.45
SMR	11.1		$ 0.08
Petroleum (Barrels Avoided)	**78.6**	**$ 55**	**$ 4.32**
EVs/FCEVs	25.1		$ 1.38
Trucks	53.5		$ 2.94
Total			**$ 5.90**

The conditions that drive the purchase of emission allowances are discussed in the Phase 1 report. Outlook D1 does not provide sufficient generation capacity to meet the emission reduction targets. With only 55% of the generation capacity (e.g. Option D1 can produce 49 TWh but 92 TWh are required), it is assumed that only 55% of the emission targets can be achieved. Based on the expected carbon price for the level of emissions that may be achieved by 2035, the analysis in Figures 56 and 57 of the Phase 1 report shows that $1.4B of emission allowances can be expected to be needed in 2035 under a D1 option scenario. If the Scenario "S" capacity is developed by 2035, then the $1.4B/year in allowances will be saved.

7.4. Electricity System Domestic Spend Benefits

Part of the cost of achieving emission reductions is the cost of producing the new electricity. Restructuring Ontario's supply mix potentially impacts the provincial spend on domestic and foreign electricity system products and services. Improving the domestic content of Ontarians' spend on energy could improve Ontario's GDP and overall trade balance.

Table 13 summarizes the cost components of the scaled-up OPO Option D1 and Scenario "S", where those cost components may differ between the scenarios. Three implication observations are made: (1) Total Costs; (2) Domestic Spend; and (3) Foreign Spend;

Total Costs

The cost of the new supply mix components for Scenario "S" is $10.8B/year discussed in Section 5.0. The incremental cost of Scenario "S" is only $8.3B/year, which is calculated by removing the $2.5B/year in avoided costs from the Outlook B supply mix.

The total costs of the scaled-up Option D1 are shown as $18.6B/year, $7.8B/year more than Scenario "S". This additional $7.8B is a drain on Ontario's economy as it is extra cost that does not provide any supplementary value. It is unnecessary and avoidable. The savings are best left with consumers to drive other sectors of the economy.

Table 13 - Domestic Spend Implications, Scenario "S" vs. OPO D1

Energy Cost Source Assumptions				**Outlook D1 Spend Balance**			**Scenario "S" Spend Balance**		
	Production (TWh)	Unit Cost/year	% Domestic Spend	Total Cost ($B)	Domestic Spend ($B)	Foreign Spend ($B)	Total Cost ($B)	Domestic Spend ($B)	Foreign Spend ($B)
Outlook B Incremental Assumptions									
Wind	16	86	50%	1.4	0.7	0.7			
Solar not procured	1.3	157	50%	0.2	0.1	0.1			
Repriced Solar	3.5	67	50%	0.2	0.1	0.1			
Natural Gas	7	0.7	30%	0.7	0.2	0.5			
Sub Total "B"	28			2.5	1.1	1.4	*-2.5*	*-1.1*	*-1.4*
Outlook "D1" Assumptions, Scaled to "S" demand									
Imports	21	140	0%	2.9		2.9			
Hydro	34	140	80%	4.8	3.8	1.0			
Wind	31	86	50%	2.7	1.3	1.3			
Tx ($B)	24	2661	80%	2.7	2.1	0.5			
Nuclear	28	108	80%	3.0	2.4	0.6	2.6	2.1	0.5
Sub Total "D" Costs	117			16.1	9.7	6.4	2.6	2.1	0.5
"S" Assumptions									
Nuclear (net of scaled D1)	84	93	80%				7.8	6.2	1.6
DER	1.4	43	50%				0.04	0.02	0.02
Tx ($B)	4	340	80%				0.3	0.3	0.1
Total				18.6	10.8	7.8	10.8	8.6	2.2
Cost Reductions of "S" over Scaled D1							**7.8**	**2.2**	**5.6**
Nuclear (net of scaled D1) reflects the 112 TWh of production from new nuclear less the 28 TWh of new nuclear in the scaled D1 option									
Natural Gas costs include fixed costs of capacity not renewed									
For reference: Cost differences between of "S" and Original D1				*12.5*	*6.7*	*5.8*	*2.0*	*-1.7*	*3.7*

Domestic Spend

Table 13 illustrates differences in domestic spend based on approximated domestic content percentages[60]. The incremental Scenario "S" capacity adds $8.6B/year in domestic spend. Domestic spend contributes significantly towards Ontario's GDP. Offsetting the lost domestic spend form the Outlook B avoided capacity, leaves Scenario "S" with a positive contribution to domestic spend of $7.5B/year. This value is carried forward in the summary of the economic benefits of this scenario.

In contrast, the total domestic spend of the D1 option is $10.8B/year, or $2.2B/year more than that created by Scenario "S". However, this extra domestic spend comes at an additional cost of $7.8B/year

[60] 80% domestic content assumption reflects that in the CME economic impact study for nuclear new build: CME, The Economic Benefits of Refurbishing and Operating Canada's Nuclear Reactors, 2012. Same value is applied to Hydro for illustrative purposes. Other renewables are simply assumed at 50%. Natural gas 30% illustrative assumption reflects fuel will be the largest component of the future reduced fixed cost components of gas plant contracts in Ontario.

to ratepayers. As a result, the difference in domestic spend may net to zero on a GDP basis (money not spent on energy may be spent on other products and services).

Foreign Spend

Scenario "S" foreign spend is $2.2B/year for the new supply mix components. However, when offset against the $1.4B/year foreign spend reductions from the avoided Outlook B capacities, the net increase in foreign spend is only $0.8B/year. This change in foreign spend is related to the net benefits of the avoided fossil fuel imports as previously discussed. Offsetting this $0.8B/year yields a net trade balance benefit it $5.1B/year for Scenario "S". This adjustment is accounted for in Figure 46 in Section 7.1 by adjusting the domestic spend benefit down to $6.7B/year.

OPO Outlook D1 increases foreign spend by $6.4B/year over the Outlook B assumptions. This not only effectively undermines the $5.9B/year benefit to Ontario's economy from decreasing the province's dependence on imported fossil fuels, but adds an additional economic drain of $0.5B/year. Option D1 eliminates the economic benefit of reducing the use of imported fossil fuels.

Scenario "S" also reduces the foreign spend by $5.6B/year vis a vis OPO D1. This trade balance reversal represents funds that would leave Ontario under the OPO Option D1, i.e. the additional $7.8B/year cost. Electricity imports from Quebec account for $2.9B/year of the extra cost.

Scenario "S" retains the full trade balance benefit for the fossil fuel trade reversal, while OPO D1 loses that through additional foreign spend on electricity supply and infrastructure. These kinds of economic trade-offs should be addressed in the LTEP process.

7.5. Enabled Industrial Production Capabilities

The emission reduction initiatives described in Phase 1 identified many new business opportunities for Ontario. These include the commissioning and operation of renewable natural gas (RNG) facilities, the potential for domestic renewable diesel production to offset the expected reduction in refinery output, and the hybrid home heating and management systems that will become integral to the success of DER programs. These opportunities are deserving of further study. In particular, two hydrogen economy related opportunities could provide significant economic benefit to Ontario. High level estimates of the economic potential are:

1. The opportunity for global leadership in hydrogen production capabilities.

- Ontario companies, such as Hydrogenics and NextHydrogen, are already succeeding in the global marketplace.
- Hydrogen facilities in Ontario could be needed to produce over 550 million kg of hydrogen each year. The production facility costs, both capital and operating, were estimated in Phase 1 to be $0.75/kg by

2030. The hydrogen production contribution to GDP, excluding the cost of electricity could be ~$400M/year.

2. The opportunity for FCEV manufacturing.

- Development of a hydrogen economy in Ontario should include hydrogen fuel-cell manufacturing businesses. Canada already has a global position in hydrogen fuel-cells which began with Ballard Power in BC. Hydrogenics in Ontario is currently providing fuel-cells for trains in Germany.

- According to a European study on the future costs of power trains[61], the costs of FCEVs and battery electric vehicles (BEV) vehicles will converge by 2030. The costs of hydrogen fuel-cells and BEV batteries were both expected to see similar declines over the next few decades as shown in Figures 48 and 49. Current average costs for batteries are $400/kWh[62], which amounts to a cost of about $12,000 USD per vehicle for a 30-kWh battery, or $15,000 CAD/vehicle. A 50% reduction in these costs by 2030 (e.g. a $200/kWh battery as assumed in section 5.3.) would result in a cost of $7500/vehicle CAD. Assuming the ongoing parallel nature of the fuel-cell and battery costs suggest $7500/vehicle for fuel-cells as well.

- If FCEV production in Ontario achieves 200,000 vehicles/year by 2035 (e.g. 20% of Ontario's new vehicle market), the domestic production of fuel-cells alone could be $1.5B/year. This could help retain full vehicle assembly capabilities in Ontario's auto sector. Producing 200,000 vehicle represents about 1% of projected global market share of FCEVs[63].

The potential for $1.9B in domestic economic activity would be directly related to the energy trade balance shift resulting from the reduced purchases of natural gas and crude oil.

Figure 48 – The Cost of a Fuel-cell System Falls by 90% by 2020

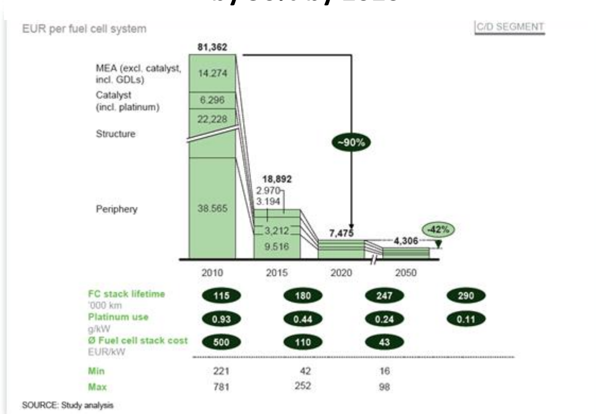


Exhibit 21: The cost of a fuel cell system falls by 90% by 2020

Figure 49 – The Cost of BEV Components Falls by 80% by 2020

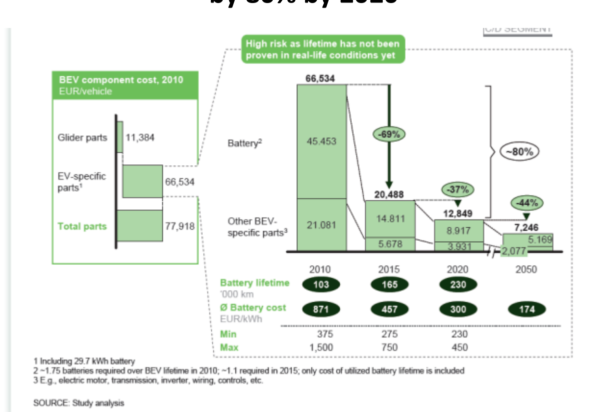


Exhibit 22: The cost of BEV components falls by 80% by 2020

[61] European Fuel Cells and Hydrogen Joint Undertaking, A Portfolio of Power-Trains for Europe, 2010
[62] Mearian, Move over EVs; hydrogen fuel cell vehicles may soon pass you by, 2016
[63] PR Newswire, Hydrogen Fuel Cell Vehicles are Future of the Automobile, Says Information Trends, 2016

7.6. Benefits of an Integrated Policy Framework

Ontario's Climate Change Action Plan framework suggests that a discussion of industrial policy is relevant to Ontario's long-term energy planning process. The World Economic Forum regularly assesses the competitiveness of nations. Their innovation index includes a measure of the effectiveness of government procurement. Canada has ranked 29th for the effectiveness of government procurement in stimulating innovation[64]. In the context of emission reduction objectives, the Ontario government is creating a $7B/year (2022) to $16B/year (2030) funding pool that should be deployed in accordance with a strategic industrial policy. This could be deployed to leverage Ontario's resource and energy advantages. Particular attention should be given to developing high-value, technology exports with a focus on maximizing the economic benefits and improving Ontario's competitive position in the global marketplace.

Ontario's leadership in addressing "the great challenge of our time" – climate change – represents a significant opportunity to achieve these objectives through the LTEP process.

Ensuring Ontario continues to have a reliable, low carbon, affordable baseload electricity supply is a prerequisite for success. This in turn provides the potential for increased energy exports – electricity and hydrogen – particularly during the summer months. Scenario "S" represents the most effective approach for the following reasons:

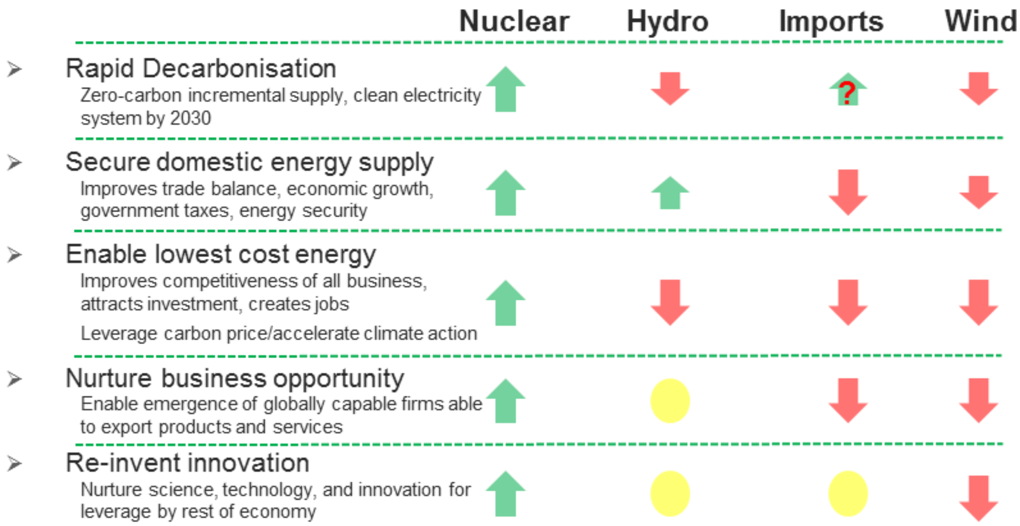
- There are significant opportunities for Ontario and Quebec to leverage each province's respective energy strengths and assets to optimize and reduce the cost structures for electricity generation in each province.
- Scenario "S" provides both capacity flexibility and economic opportunities resulting from increased exports of low carbon electricity to the U.S.
- Integrating Ontario's natural gas distribution system with that of neighboring states and blending hydrogen into the natural gas system represents another export opportunity for Ontario's clean electricity via P2G.

Leveraging Ontario's resources and advantages to develop new nuclear and hydrogen capabilities provides a pathway for developing new high-value innovations in the areas of nuclear power technology, hydrogen electrolysers, fuel-cells, and related technologies and products. This base creates significant new world-leading export opportunities stimulating further economic growth.

The success of Ontario's suite of policy objectives depends on how the C&T proceeds are spent and the cost of electricity. Consequently, it is critical that the LTEP considers and recommends the right choices. Multi-billion dollar investments are in play that have the potential to either positively or negatively impact Ontario's economy. The province's next LTEP should present a supply mix that creates the best competitive advantage for Ontario's economy. Figure 50 summarizes the impact of each supply type against a range of policy objectives. Scenario "S", with its nuclear component, represents a more favourable option across all the dimensions.

[64] KPMG, A Report on the Contribution of Nuclear Science and Technology (S&T) to Innovation, 2014

Figure 50 – Impact of Supply Types Against Policy Objectives



7.7. Summary

Integrating industrial, economic, environmental and energy policy to leverage Ontario's unique resources and energy advantages could provide significant economic benefits and enhance Ontario's competitive advantage regionally and globally. Scenario "S" could:

- Lower the cost to Ontario of meeting 2030 emission target from the $27B/year (estimated in the Phase 1 report for Option D1) to $17.9B/year (~$18B), a savings of $9.1B/year (~$9B). The market carbon price to achieve the 2030 targets is estimated at $106/tonne compared to the carbon price of $161/tonne in OPO D1.
- Reduce the emissions from the electricity sector by 2.6 Mt/year by eliminating the need for much of the gas-fired generation fleet.
- Shift Ontario's energy trade balance.
    - Reducing fossil fuel imports could generate $5.9B/year (~$6B) that could be injected into Ontario's economy via consumers paying for their emission reduction choices.
    - Increase domestic spend by $6.7B/year representing new industrial activity. Enables new industrial activity such as hydrogen production and domestic fuel-cell manufacturing with a potential benefit of another $1.9B/year. This new activity leads to total Industrial activity creation of $8.6B/year (~$8.5B) in Ontario's nuclear and hydrogen economies
    - Avoids $5.6B/year in OPO D1 spending outside the province on energy products and services.

Scenario "S" could provide other significant opportunities:

- Ontario and Quebec could leverage their respective energy strengths and assets to optimize electricity generation in each province.
- Supplying low carbon electricity to the U.S.

- Blend hydrogen into the natural gas system for export via P2G.
- Export high-value, Canadian innovations in the areas of nuclear power technology, hydrogen electrolysers, fuel-cells, and related technologies and products.

An integrated policy approach has the potential to give Ontario a world-leading economic and competitive advantage and deserves further study.

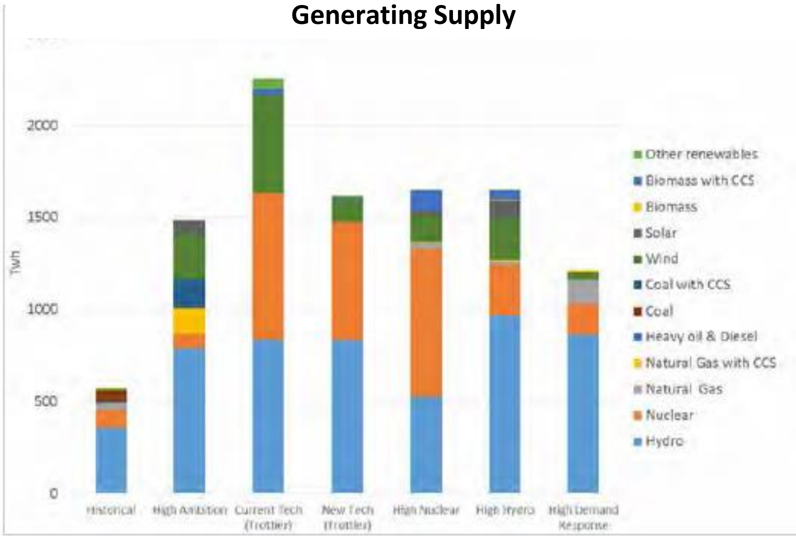
8.0 Looking Forward Observations and Recommendations

This Section examines the long-term Canadian context for developing electricity generating resources and makes several recommendations related to Scenario “S” being considered in the 2017 LTEP consultation process.

The electricity required to meet Ontario’s 2030 emission targets requires the development of significant generation that may not be viable prior to 2030. Demand for electrification will also steadily increase until the 2050 targets are met as driven by deep decarbonization investments.

Figure 51 from Canada’s Mid-Century Long-Term Low-Greenhouse Gas Development Strategy shows the results of six simulations for possible future electricity demand in Canada[65] and compares them to the historical demand in 2015. Total electricity demand in Canada is forecast to at least double, if not quadruple by 2050, with a median expectation of about a tripling. Since Ontario represents 38% of the energy consumption in Canada, but only 28% of the electricity, much of the new electricity demand may originate in Ontario, and Ontario’s growth rate can be expected to be higher than the average bringing its share of electricity closer to its share of total energy. Scenario “S” suggests that electricity demand will increase by 60%, to 240 TWh, to achieve Ontario’s 2030 emission target of 37% below 1990 levels. These 2050 forecasts suggest that Ontario’s demand may rise to over 500 TWh by 2050 in order to meet the emission targets of 80% below 2005 emission levels. This could require 3 times more incremental capacity than is reflected in Scenario “S”. This would be the equivalent of over 42 GW of additional nuclear or almost 80 GW of additional hydro capacity (assuming hydro’s existing operating factor of 50%).

Figure 51 – Scenarios of Canada’s Non-Emitting Electricity Generating Supply



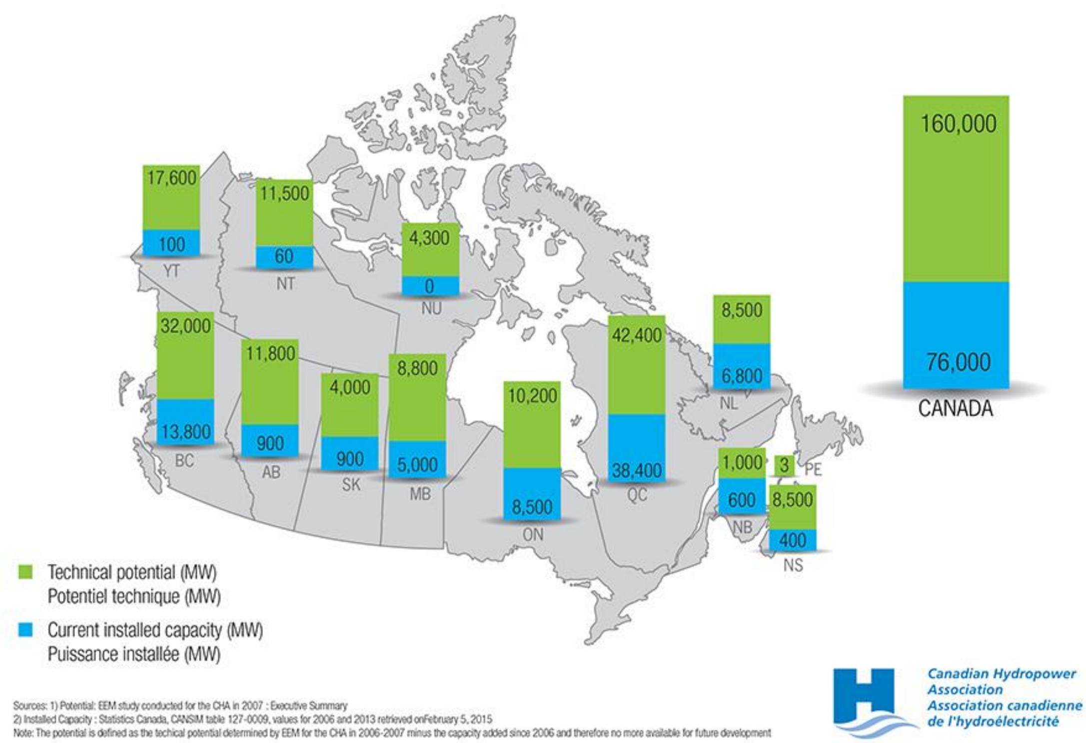
CANADA’S **MID-CENTURY LONG-TERM LOW-GREENHOUSE GAS** DEVELOPMENT STRATEGY

[65] Government of Canada, Canada’s Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, 2016

Figure 51 also identifies the supply mix associated with each demand scenario. Five of these six scenarios involve 2 to 8 times as much nuclear capacity as exists today. The one scenario that just sustains existing nuclear capacity depends on natural gas and is not a fully non-emitting solution like the others.

Within these scenarios, the use of hydro (blue) is forecast to increase by 50% to 172%, with the latter growth resulting in a capacity that approaches 75% of the technically available hydro in Canada. This same scenario assumes Canada's nuclear capacity (orange) triples. The technically available hydro is illustrated in Figure 52[66].

Figure 52 – Canadian Hydro Capacity and Potential
(MW)



Ontario has about 10 GW of the 160 GW of undeveloped hydro potential in Canada, representing only 6%. The available additional potential in Canada is just over double the existing Canadian installed capacity. Quebec has over 25% of the undeveloped hydro potential, 110% more than is currently operational in that province. Since demand is expected to approximately triple, it is likely that Quebec will need most of this potential for itself and then additional generation beyond that.

Most of the undeveloped hydro in Canada that could conceivably be exported by the host province is in BC and the western Territories. Making this energy accessible to Ontario would require significant trans-

[66] Canadian Hydropower Association, Hydropower Potential, 2016

mountain Tx that would span across the continent. The costs of such a proposition is the primary reason the scenarios illustrated in Figure 51 highlight the forecast need for more nuclear generation in Canada.

Canada's Long-Term GHG Strategy[67] shows that demand for electrification will steadily increase throughout the process of deep decarbonization that will be required to meet the 2050 targets and that this demand needs to be substantially met by hydro and nuclear resources. It is highly likely that all of the viable potential hydro resources in Quebec and Ontario will eventually be developed. However, these resources will be insufficient to meet the long-term electrification needs of Ontario. Considering the magnitude of the hydro and nuclear resources required and the associated development timelines, 2050 is not far away.

In the near-term, the benefits provided by Scenario "S" are significant and material to the health of Ontario's future economy. For example, this Scenario could shrink the annual cost of Ontario's emission reductions by over $24B compared to the OPO alternatives such as D1. Ontario has the opportunity to achieve its environmental goals with modest cost to Ontario's rate payers and tax payers. Scenario "S", including more nuclear generation, is Ontario's best solution and its development should start now. Given that Ontario's new C&T regime commences in 2017, the cost penalties associated with delaying the development of the requisite energy infrastructure is estimated to approach $65M/month.

The potential benefits of an optimized supply mix as shown by Scenario "S" are significant and material to the health of Ontario's future economy. The following recommendations are made for the LTEP process:

- The LTEP should consider the paradigm shifts and enabled solutions embodied in Scenario "S".
- The LTEP should integrate the objectives of Ontario's environmental, energy, industrial, and economic policies for the long-term future benefit of Ontarians.
- The LTEP should prioritize an early start for developing a site for new nuclear generation. The Darlington site is a prime early candidate. Additional locations for future units should be explored.

Although this study has focussed on Ontario and the LTEP process, the detailed analyses presented and the resulting implications for supply mix design criteria could be relevant to other jurisdictions in the Great Lakes-St. Lawrence Region. This may be particularly relevant for those with similar energy assets and options and that may be contemplating aggressive emission reductions, deep decarbonization, and government-mandated carbon pricing schemes.

[67] Government of Canada. Canada's Mid-Century Long-term Low Greenhouse Gas Development Strategy. 2016

Acknowledgements

This study was proposed by Strategic Policy Economics to fill a perceived void in publicly available evidence-based materials. Strategic Policy Economics posits that a successful LTEP consultation and subsequent plan should be based on transparent, fact-based analysis that focuses on the best way to serve the interests of all Ontarians. Phase 2 of the study was inspired by two individuals: (1) the Honourable John Godfrey—at the 2015 APPrO conference he made an appeal to the entire electricity sector for ideas on how Ontario could best achieve it's climate objectives; and (2) the Honourable Bob Chiarelli, then Minster of Energy, when speaking at the 2016 CNA conference he challenged industry to develop a multi-sector perspective for the LTEP process that could offer an integrated energy system solution for the betterment of Ontario. Strategic Policy Economics hopes this report provides such a constructive contribution to the LTEP process.

Overview of Strategic Policy Economics

> Founded by Marc Brouillette in 2012, Strategic Policy Economics helps clients address multi-stakeholder issues stemming from technology based innovations in policy-driven regulated environments. The consultancy assesses strategic opportunities related to emerging innovations or market place conditions and identifies approaches that will achieve positive benefits to affected stakeholders. Strategic Policy Economics specializes in framing strategic market, science, technology and innovation challenges for resolution, facilitating client teams in determining their alternatives, developing business cases and business models, and negotiating multi-stakeholder public/private agreements. Marc has worked directly with federal and provincial ministries, crown corporations and regulators, as well as with the private sector, municipalities, and non-profit organizations.
>
> The Strategic Policy Economics team deployed to develop this report included Marc Brouillette, Scott Lawson, and Andisheh Beiki.

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- Paul Acchione, former chair of the Ontario Society of Professional Engineers (OSPE)
- Paul Newall, President, Newall Consulting Inc.

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Appendix B - List of Abbreviations

AEO – Annual Energy Outlook
ASHP – Air Source Heat Pump
BAU – Business as Usual
BEV – Battery Electric Vehicle
BTU – British Thermal Unit
C&T – Cap and Trade Program
CAD – Canadian Dollar
CCGT – Combined Cycle Gas Turbine
CHA – Canadian Hydropower Association
CHP – Combined Heat and Power
CNSC – Canadian Nuclear Safety Commission
COP – Conference of Parties
DER – Distributed Energy Resource
DOE – U.S. Department of Energy
DR – Demand Response
Dx – Electricity Distribution
EIA – U.S. Energy Information Administration
EPC – Engineering, Procurement, and Construction
EV – Electric Vehicle
FCEV – Fuel Cell Electric Vehicle
GDP – Gross Domestic Product
GGRA – Greenhouse Gas Reduction Account
GHG – Greenhouse Gas
GW – Gigawatt
GWh – Gigawatt Hour (one billion watts being produced for 1 hour)
HQ – Hydro Quebec
IESO – Independent Electricity System Operator
kWh – Kilowatt hour (one thousand watts being produced for 1 hour)
L – Litre (one thousand mL)
LCOE – Levelized Cost of Electricity
LDC – Local Distribution Company
LTEP – Long-Term Energy Plan
LRP – Large Renewable Procurement
MMBtu – Million Btu
MOECC – Minister of Environment and Climate Change
Mt – Megatonne (equal to one million tonnes)
MW – Megawatt
MWh – Megawatt Hour (one million watts being produced for 1 hour, enough to power ten thousand 100W light bulbs for one hour)

NREL – National Renewable Energy Laboratory
NUG – Non-Utility Generation
NWMO – Nuclear Waste Management Organization
OEA – Ontario Energy Association
OCI – Organization of Canadian Nuclear Industries
OPG – Ontario Power Generation Inc.
OPO – Ontario Planning Outlook
OSPE – Ontario Society of Professional Engineers
P2G – Power to Gas
PNGS – Pickering Nuclear Generating Station
PWU – Power Workers Union
R&D – Research and Development
RNG – Renewable Natural Gas
SBG – Surplus Baseload Generation
SCGT – Simple Cycle Gas Turbine
SMR – Small Module Reactor
t – Tonne (1,000 kg)
TWh – Terawatt hour (one trillion watts being produced for 1 hour)
Tx – Electricity Transmission
U.S. – United States of America
USD – United States Dollar
WACC – Weighted Average Cost of Capital
WISE – Waterloo Institute of Sustainable Energy

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