POWER WORKERS' UNION

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Re: Ontario's 2017 Long-Term Energy Plan (EBR 012-8840)

The Power Workers' Union ("PWU") represents a large portion of the employees working in Ontario's electricity industry. Attached please find a list of PWU employers.

The PWU is committed to participating in public consultations to contribute to the development of energy policy that ensures a robust and sustainable electricity system and competitively priced electricity for Ontario consumers, and to ensure transparency and stakeholder participation in the implementation of policy. To this end, please find the PWU's comments on Ontario's 2017 Long-Term Energy Plan.

We hope you will find the PWU's comments useful.

Yours very truly,

Don MacKinnon
President

List of PWU Employers

Algoma Power
AMEC Nuclear Safety Solutions
Atlantic Power Corporation - Calstock Power Plant
Atlantic Power Corporation - Kapuskasing Power Plant
Atlantic Power Corporation - Nipigon Power Plant
BPC District Energy Investments Limited Partnership
Brant County Power Incorporated
Brighton Beach Power Limited
Brookfield Power Wind Operations
Brookfield Renewable Power - Mississagi Power Trust
Bruce Power Inc.
Canadian Nuclear Laboratories (AECL Chalk River)
Cogeco Peer 1
Compass Group Corporation of the County of Brant
Covanta Durham York Renewable Energy Ltd.
Entegrus
Erie Thames Powerlines
Erth Corporation
EthosEnergy Inc.
Great Lakes Power (Generation)
Great Lakes Power Transmission
Grimsby Power Incorporated
Halton Hills Hydro Inc.
Hydro One Inc.
Independent Electricity System Operator
Inergi LP
InnPower (Innisfil Hydro Distribution Systems Limited)
Kenora Hydro Electric Corporation Ltd.
Kinectrics Inc.
Kitchener-Wilmot Hydro Inc.
Lake Superior Power Inc. (A Brookfield Company)
London Hydro Corporation
Milton Hydro Distribution Inc.
New Horizon System Solutions
Newmarket Hydro Ltd.
Norfolk Power Distribution Inc.
Nuclear Waste Management Organization
Nuvia Canada
Ontario Power Generation Inc.
Orangeville Hydro Limited
Portlands Energy Centre
PowerStream
PUC Services
Rogers Communications (Kincardine Cable TV Ltd.)
Sioux Lookout Hydro Inc.
SouthWestern Energy
The Electrical Safety Authority
Toronto Hydro
TransAlta Generation Partnership O.H.S.C.
Westario Power
Whitby Hydro Energy Services Corporation

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EXECUTIVE SUMMARY

In this submission the PWU provides comments regarding the development of Ontario's 2017 Long Term Energy Plan ("LTEP"). The PWU's submission is informed by two interrelated reports by Strategic Policy Economics ("Strapolec") included in this submission as Appendix I, II and III:

I. *Ontario's Emissions and the Long-Term Energy Plan: Phase I - Understanding the Challenge*

II. *Ontario's Emissions and the Long-Term Energy Plan: Phase II - Meeting the Challenge*

III. *Extending Pickering Nuclear Generating Station Operations: An Emissions and Economic Assessment for 2021 to 2024*

General Comments

Electrification is increasingly gaining global recognition as the key enabler for transitioning to a low carbon economy while boosting economic growth. Deep decarbonisation of the global economy is now a priority for governments around the world.

Recently, the Government of Canada has announced that all Canadian jurisdictions will have a price on carbon pollution in place by 2018 and a Canadian framework for clean growth and climate change is being developed. Ontario has legislated the province's greenhouse gas ("GHG") emissions reduction targets, including a reduction of 37% below 1990 levels by 2030.

In addition to ensuring that Ontario has an adequate, reliable, safe, clean and reasonably priced electricity supply, the LTEP should recognize the value of the electricity sector to Ontario's economy and its indispensable role in realistically achieving Ontario's GHG emission reduction targets.

Specifically, the LTEP should:

- Recognize that Ontario's GHG emission reduction targets cannot be achieved without significant electrification of Ontario's largest GHG-emitting sectors - transportation, building and industry.
- Recognize the electricity sector's crucial role in enhancing the global competitiveness of Ontario's manufacturing, mining and trade sectors and in speeding up economic growth.
- Manage the province's existing generation and network assets as well as its highly skilled workforce to sustain their value and maximize their use for all Ontarians.
- In addition to the current principles of cost-effectiveness, reliability, clean energy, conservation, etc., include energy self-sufficiency and security as important principles in planning Ontario's energy future.
- Utilize the opportunity provided by Ontario's nuclear industry as a means not only to provide carbon-free, reliable and low-cost electricity supply to domestic consumers and to meet Ontario's GHG emissions reduction targets but also to enhance Ontario's economic growth through the export of energy and related expertise, technology and services.
- Focus on the long-term, yet recognize the importance of starting projects early given the associated long lead times required to develop transmission and generation infrastructure.

<u>Demand Outlook</u>

The PWU submits that the Ontario Planning Outlook ("OPO") demand outlooks contain numerous risks:

I. Inconsistent with Ontario's GHG Emission Reduction Targets

None of the IESO's four outlooks come close to meeting Ontario's GHG emission reduction targets. The OPO/LTEP's highest demand scenario (Outlook D) assumes 54 TWh of new electricity demand in 2035 over the current demand. According to analysis by Strapolec, a 65Mt GHG reduction by 2030 is required to meet the 2030 emission targets. In order to achieve a 65Mt reduction by 2030, electricity demand has to increase by 90 TWh, i.e. 80% greater than the 50 TWh presented in the IESO's highest demand scenario and 60% more than is consumed today. Moreover, this demand of 80% greater than IESO's electricity demand forecast occurs 5 years sooner. The demand for electrification will also steadily increase, driven by deep decarbonisation investments until the 2050 targets are met.

II. Unrealistic Conservation Achievement Targets

All four IESO outlooks incorporate the achievement of the 2013 LTEP conservation target of 30 TWh by 2032 and the near-term target set in the Conservation First Framework and Industrial Accelerator Program of 8.7 TWh by 2020. The IESO's 2016 Achievable Potential Study indicates that conservation targets have been too optimistic and are unlikely to be achieved. Moreover, details are not provided with respect to the nature of future CDM programs and initiatives that will be utilized to achieve the targets.

<u>Supply Outlook</u>

The Supply Outlook in the OPO is too optimistic and fraught with risks:

I. New additional resources, beyond existing and planned resources, would be required to meet any increased growth in demand, as in demand Outlooks C and D. This is confirmed by the IESO's own analysis of capacity surplus/deficit across the four demand outlooks. For example, Outlook D forecasts a deficit of 11,200 MW at winter peak in 2035.

II. More, new baseload supply is needed to meet the increase in demand for electricity that would be required to achieve the Province's GHG emission targets. The electricity required to meet the 2030 emission targets will be needed sooner than shown in the Outlooks. By 2030 only 30-40% of the energy supply required to achieve the 2030 emission reductions will be available. This suggests that Ontario could miss its 2030 target by 60%.

III. The unit outages required for the refurbishment of the Darlington and Bruce nuclear stations together with the current plan to close the Pickering NGS in 2024 pose a real risk of supply shortfall. Furthermore, increased use of the existing natural gas-fired fleet or new gas generation resources to fill the gap would increase emissions.

IV. The OPO assumes that all existing resources whose contracts expire (about 18GW of capacity) will continue to operate. For a number of economic and environmental reasons, it is unlikely that all of these assets with expiring contracts will continue operation. Nor is it clear that in all cases they will be the most cost-effective options to meet the province's electricity system needs.

Planning for the Right Supply-Mix

The OPO places significant emphasis on options that involve new firm imports from Quebec and wind generation capacity. These options represent unreliable and expensive choices for achieving Ontario's 2030 emission target. The 2014 IESO and OPA Report on the potential impacts and opportunities for Ontario's intertie connections indicated that significant upgrades would be required, including new intertie capabilities, transmission upgrades, and new generation in both Quebec and Ontario. This would involve significant costs and long lead times. Moreover, the suggestion that imported electricity from Quebec can effectively replace Ontario's 6,600 MW baseload supply from the Pickering and Darlington Stations is irresponsible. Imports of this scale would require billions of dollars in costly system upgrades for both provinces and would not provide the reliable, domestic supply of electricity that nuclear delivers to Ontario. Additionally, Quebec has a winter peaking system and is currently capacity limited in the winter. In fact, Ontario exports electricity to Quebec in the winter months. With the anticipated electrification of home heating systems in Ontario, the PWU expects Ontario to move from a summer-peaking to a winter-peaking system which would make reliance on electricity imports from Quebec even riskier than it is today.

Wind generation has not matched demand since its introduction in Ontario and over 70% of wind generation does not benefit Ontario's supply capability. Wind generation will not match demand in the OPO Outlooks as 50% of the forecast production is expected to be surplus/wasted. If 50% of the forecasted production is wasted, then its unit cost would double to $172/MWh from the $86/MWh assumed in the OPO. This suggests that wind generation is the most expensive generation option for Ontario, even without including the transmission related costs and other integration issues described in the OPO. No new wind generation should be added to Ontario's system beyond what is already under committed contract. Given these realities, the PWU supports the Government's decision in September of this year to cancel plans for procuring 1,000 MW of renewable generation, primarily from wind and solar.

Natural gas generation has operational value in meeting peak demand. However, it is essential that the emission reduction efforts achieved by Ontario's electricity sector are not reversed by increased reliance on high GHG-emitting generation e.g., natural gas for intermediate or baseload supply. The PWU recognizes that natural gas generation will be required for the foreseeable future to help meet peak demand; however, the PWU submits that the extension of contracts for existing facilities should be considered before building new gas plants.

Ontario should plan generation resources that provide affordable, reliable, safe, secure and clean energy. These resources are nuclear, hydroelectric, biomass, and hydrogen produced from electricity.

The PWU's submission proposes a supply mix option and related cost-effective transmission and distribution infrastructure. These recommendations can meet Ontario's long-term energy needs while maximizing economic value and helping to stimulate innovation and improve Ontario's competitive advantage in the global marketplace.

The proposed supply mix option recommends nuclear power as the most cost-effective resource capable of providing the earliest path for meeting Ontario's GHG emission targets. Nuclear generation is reliable, safe, cost-effective and GHG emission-free.

Nuclear generation accounts for only one-third of Ontario's installed capacity yet today it provides nearly 60% of Ontario's electricity. Only hydroelectric power has a lower cost per kilowatt-hour (kWh) than nuclear energy. Gas and wind are almost twice as expensive compared to nuclear, while solar costs nearly ten times more. Moreover, the LTEP should recognize that the OPO high electricity demand Outlook D and the even higher demand that would result from increased electrification needed to meet Ontario's emission reduction targets cannot be realistically and cost-effectively achieved without continued investments in nuclear generation. This includes: the refurbishment of all four reactors at Darlington and six Bruce units: the continued operation of Pickering, with the approval of the Canadian Nuclear Safety Commission ("CNSC"); and, the building of new nuclear units. The LTEP should make an early start for developing the Darlington site for new nuclear generation a priority.

The benefits of refurbishing the Darlington and Bruce units as well as building new nuclear generation go beyond just meeting Ontario's domestic energy and environmental needs. Specifically,

- With the increase in the national and global demand for clean energy, Ontario has a unique opportunity to use its nuclear industry to grow the economy through export of nuclear technology, products, expertise, services and international business partnerships.
- Only a nuclear enabled supply mix can create the $15B/year in economic benefits that would give Ontario an economic and globally competitive advantage in a decarbonized world.
- Nuclear is the low cost enabler in the supply mix that would achieve emissions reduction targets for $9B/year less than the OPO strategy.
- Absent a nuclear solution, Ontario would be spending over $1B/year in purchased allowances from foreign jurisdictions thereby increasing the cost of emissions reduction to almost $30B/year by 2030. The economic benefits of the refurbishment and the subsequent 30 plus years of operation of Darlington will total $89.9 billion and is projected to increase the number of jobs in Ontario by an average of 14,200 per year between 2017 and 2055.
- The refurbishment of the Bruce units will generate $4 billion in annual economic benefit and will create and sustain 22,000 direct and indirect jobs province-wide throughout Bruce's operating life to 2064.
- Extending the life of Pickering NGS to 2024 would save Ontario electricity customers up to $600 million, avoid eight million tonnes of GHG emissions and protect 4,500 direct jobs across the Durham Region.

Conclusions and Recommendations

- Ontario's long-term supply needs and the government's GHG emission reduction targets require significant electrification of the economy. This can only be achieved by the completion of the refurbishment of four Darlington and six Bruce NGS units and by planning for new nuclear units at Darlington. These are the lowest cost options.
- Extend the operation of the Pickering NGS, in accordance with the approval of the CNSC beyond the current planned retirement in 2020.
- Convert the idle Nanticoke and Lambton coal plants into carbon-neutral biomass/gas co-fuelled facilities to meet peak demand. Request that OPG rescind its decision to decommission the Lambton Generating Station in 2017.
- Cease planning for more wind and solar resources. These resources are unreliable and expensive and back up from gas generation would reverse the GHG emission reduction results already achieved by Ontario's electricity sector.
- Continue to explore commercially-viable opportunities to expand existing hydroelectric sites and to develop potential hydroelectric resources.
- Forgo reliance on imports of firm supply from Quebec. This requires significant investments for new generation and transmission upgrades making the costs of this electricity expensive. Moreover, such an arrangement subjects Ontario's energy security to unnecessary risks.
- Explore opportunities to create a hydrogen economy in Ontario by utilizing low cost baseload electricity to produce hydrogen.
- Use the proceeds from Ontario's Cap & Trade Program to promote electrification of the transport, building and industry sectors through investment in Electric Vehicle ("EV") and hydrogen infrastructure, incentives to EV and hydrogen fuel cell EV buyers and subsidies to residential and commercial electricity customers that incent fuel switching from gas to electric home heating/cooling.
- Commit to investments in transmission and distribution infrastructure to replace aging assets and ensure reliability and to ensure this delivery network has the capacity to accommodate the increased electrification of Ontario's economy.

- Make the investments that are required to ensure the availability and sustainment of a skilled energy workforce.

PWU'S COMMENTS ON LTEP 2017

1 INTRODUCTION

On October 13, 2016, the Ontario Government launched its review of Ontario's 2017 Long-Term Energy Plan ("LTEP"). The Government is consulting with the public to develop the province's LTEP to maintain a reliable supply of clean and affordable electricity. For that purpose, the Government has released:

- A discussion guide, titled: Planning Ontario's Energy Future, A Discussion Guide to Start the Conversation ("Discussion Guide")
- Ontario Planning Outlook ("OPO"), A technical report on the electricity system prepared by the Independent Electricity System Operator ("IESO")[1]
- Fuels Technical Report ("FTR"), prepared by Navigant Consulting, Inc.[2] ("Navigant")

2 POWER WORKERS' UNION'S ENERGY POLICY

The Power Workers' Union ("PWU") appreciates the opportunity to provide comments on the 2017 LTEP. The PWU has been a key and regular participant in Ontario's energy policy discussions for over 70 years. The PWU represents over 16,000 employees working in Ontario's electricity industry for more than 50 companies. The PWU's submission stems from its energy policy:

> **Reliable, secure, safe, environmentally sustainable and reasonably priced electricity supply and service, supported by a financially viable energy industry and skilled labour force is essential for the continued prosperity and social welfare of the people of Ontario. In minimizing environmental impacts, due consideration must be given to economic impacts and the efficiency and sustainability of all energy sources and existing assets. A stable business environment and predictable and fair regulatory framework will promote investment in technical innovation that results in efficiency gains.**

[1] Ontario Planning Outlook. September 1, 2016.
[2] Fuels Technical Report. Navigant Consulting, Inc. September 2016

In this submission, the PWU provides comments regarding the Discussion Guide, the accompanying Technical Reports and on other issues the PWU deems relevant to the LTEP. In addition to these comments, the PWU provides its responses to the direct questions in the Discussion Guide.

The PWU's submission is informed by three interrelated reports by Strategic Policy Economics ("Strapolec") attached to this submission as Appendix I, ll and III:

I. *Ontario's Emissions and the Long-Term Energy Plan: Phase I - Understanding the Challenge*

   This report informs the LTEP consultation with background analyses that relate to emission reduction targets, the costs of emission reducing technologies, the carbon price within Ontario's Cap and Trade ("C&T") program, and the factors the LTEP process should address if Ontario is to achieve the province's emission reduction targets.

II. *Ontario's Emissions and the Long-Term Energy Plan: Phase II - Meeting the Challenge*

   This report lays out an alternative supply mix option based on four electricity system design paradigm shifts and summarizes their associated cost, implementation, and economic considerations.

III. *Extending Pickering Nuclear Generating Station Operations: An Emissions and Economic Assessment for 2021 to 2024*

   This report quantifies the environmental and economic benefits of extending the operations to maximize the value of the station and identifies cost savings to electricity customers.

3 PWU's General Comments on the 2017 LTEP

Today, the role of the electricity sector in the economic and social wellbeing of societies is well recognized. Two concurrent challenges, the global recession and global warming have further contributed to this higher profile. First, as a result of the worldwide slowdown in, economic growth, governments have pursued strategies intended to resuscitate their manufacturing, mining and trade sectors. The second is the international community's consensus regarding the urgency of combatting global warming. Consequently, policy makers are embracing electrification—based on clean energy sources--across all sectors of the economy as a critical enabler for boosting economic growth and transitioning to a low carbon global economy. Since the global community of nations emerged from the COP21 Paris Climate Conference and subsequently ratified the Paris Accord at COP22 (Nov 2016), deep decarbonisation of the global economy has become a priority for governments.

The Government of Canada has announced that all Canadian jurisdictions will have a price on carbon pollution in place by 2018 and a Canadian framework for clean growth and climate change is being developed. Environment Minister Catherine McKenna unveiled Canada's "Mid-Century Strategy for a Clean Growth Economy" on November 16 at the UN climate talks in Marrakech, Morocco. Canada's plan envisages an 80 percent net reduction in emissions by 2050 from 2005 levels. The total increase in electricity generation required (compared to a 2013 reference year) ranges in the Strategy's different scenarios from 189 per cent at the lower end up to 295 per cent.

Ontario has legislatively mandated the province's greenhouse gas ("GHG") emissions to drop to 37% below 1990 levels by 2030, or from the business as usual forecast of 176 Mt/year to 111 Mt/year. The mandate to achieve these reductions falls under: (1) the C&T Program that will establish the carbon price; and (2) the Climate Change Action Plan ("CCAP") that will administer the use of the C&T proceeds.

In addition to ensuring that Ontario has adequate, reliable, safe, clean and reasonably priced electricity supply, the LTEP should recognize the value of the electricity sector to Ontario's economy and its indispensable role in realistically achieving Ontario's GHG emission reduction targets.

Specifically, the LTEP should:

- Recognize that Ontario's GHG emission reduction targets cannot be achieved without significant electrification of Ontario's largest GHG-emitting sectors - transportation, building and industry.

- Recognize the electricity sector's crucial role in enhancing the global competitiveness of Ontario's manufacturing and mining sectors and in speeding up economic growth.
- Manage the province's existing generation and network assets as well as its highly skilled workforce to sustain their value and maximize their use for all Ontarians.
- In addition to the current principles of cost-effectiveness, reliability, clean energy, conservation, etc., include energy self-sufficiency and security as important principles in planning Ontario's energy future.
- Utilize the opportunity provided by Ontario's nuclear industry as a means not only to provide carbon-free, reliable and low-cost electricity supply to domestic consumers but also to enhance Ontario's economic growth through the export of low carbon energy as well as expertise, technology and services.
- Focus on the long-term, yet recognize the importance of starting projects early given the associated long lead times required to develop transmission and generation infrastructure.

4 PWU's Specific Comments on Specific Aspects of the LTEP

4.1 Demand Outlook

The Discussion Guide and the IESO's OPO consider four possible demand outlooks for Ontario:[3]

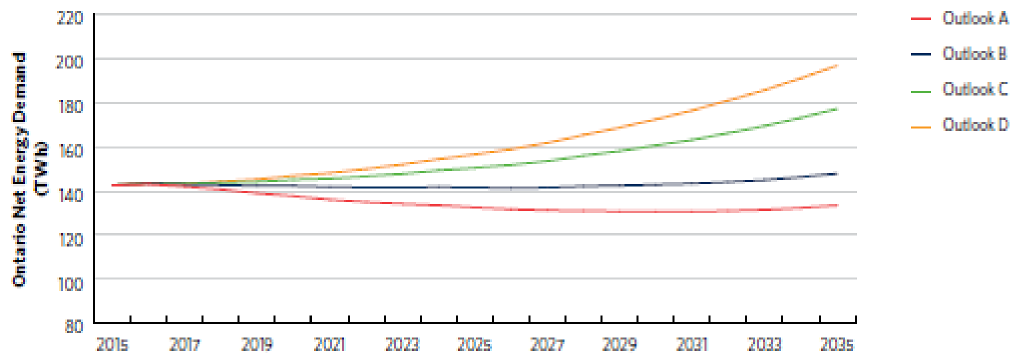
- **Outlook A [low demand outlook] examines a future of low demand, with the province using less electricity than it does now. In Outlook A, Ontario would use 133 TWh of electricity annually by 2035.**

- **Outlook B [flat demand outlook] is a continuation of the current pattern of flat growth in energy demand with an annual electricity use of 148 TWh over the same period. This is close to the 2015 consumption level of 143 TWh. With currently planned and existing resources, including conservation, Ontario will have sufficient capacity to meet the needs of a flat demand future.**

[3] Ontario Planning Outlook. September 1, 2016.

- **Outlooks C and D [higher demand outlooks] examine a future with a significantly higher use of electricity due to the increased electrification of transportation and changes in the heating and cooling of homes and businesses. In these outlooks, the annual consumption of electricity could increase to between 177 TWh and 197 TWh by 2035. Ontario would need to generate more electricity than it does today to meet these higher levels of demand. The increase in demand is not expected to occur until the mid-2020s, with significant increases in supply required after 2030.**

Figure 1: Ontario Net Energy Demand across Demand Outlooks



Source: OPO

4.1.1 PWU's Comment

The PWU submits that these demand outlooks contain numerous risks:

I. Inconsistent with Ontario's GHG Emission Reduction Targets

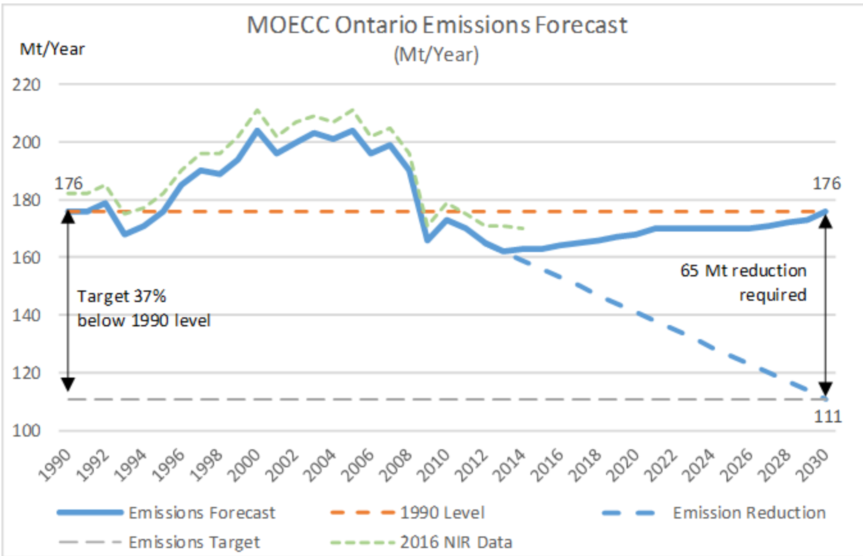
The demand outlooks including the two higher demand scenarios (Outlook C & D) are incongruent with the emission reduction targets established by the Climate Change Mitigation and Low-Carbon Economy Act, 2016 which commits the government to reducing emissions to:

- 15% below 1990 levels by 2020
- 37% below 1990 levels by 2030
- 80% below 1990 levels by 2050

None of the IESO's four outlooks come close to meeting these emission targets. Nor is there any publicly available documentation that indicates a connection between the Discussion Guide and the emission targets. According to the Ministry of the Environment and Climate Change ("MOECC"), Ontario's forecasted emissions for 2030 are similar to 1990 emissions (176 Mt/year).[4] The OPO/LTEP's highest demand scenario (Outlook D) assumes 54 TWh of new electricity demand in 2035 over the current demand.

According to analysis by Strategic Policy Economics ("Strapolec"),[5] a 65Mt GHG reduction by 2030 is required to meet the 2030 emission targets.

Figure 2



Source: Strapolec Report (Appendix I)

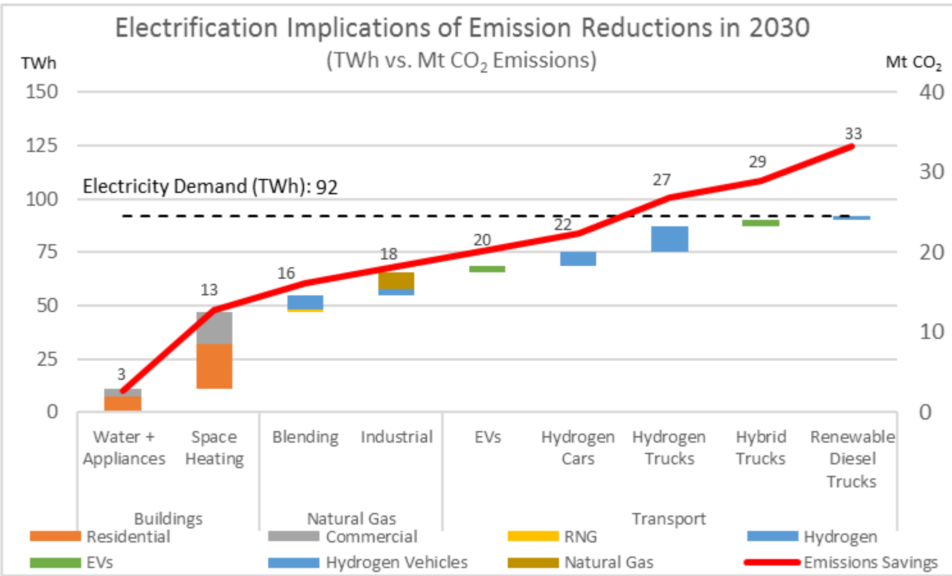
In order to meet the 2030 emissions target, significant electrification is required which in turn significantly increases electricity demand. Strapolec's analysis suggests that achieving a 65Mt reduction by 2030 would increase electricity demand by 90 TWh, i.e. 80% greater than the 50 TWh in the IESO's highest demand scenario and 60% more than is consumed today. Strapolec notes that even with the additional fuels-related actions/assumptions (Outlook F in the Navigant Report) the 65 MT reduction in emissions required to meet the 2030 emissions target cannot be achieved. The 90 TWh of new demand will require a commitment to low-cost, GHG emission-free generation options at the earliest stage in the LTEP process. Meeting the 2030 emission target

4 Ontario's Climate Change Update. 2014

5 Strapolec. Ontario's Emissions and the Long-Term Energy Plan: Phase I – Understanding the Challenge. 2016 (Appendix I)

depends on supplying this new demand with new generation on a schedule and capacity that is more realistic than reflected in the OPO.

Figure 3 – Electrification Implications of Emission Reductions in 2030



Source: Strapolec Report (Appendix I)

Note: The 92 TWh is the electrification associated with reducing 33 Mt of emissions. It is assumed that CDM and other methods will reduce the other 32 Mt of emissions required to achieve the 2030 target.

Figure 4 below illustrates Strapolec's demand forecast compared to the IESO Outlooks B and D.

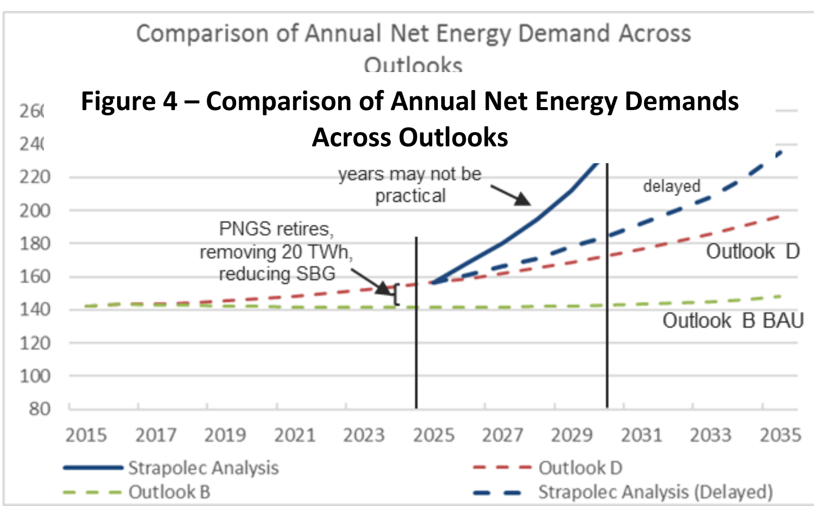


Figure 4 – Comparison of Annual Net Energy Demands Across Outlooks

Source: Strapolec Report (Appendix I)

The Outlook D forecast is based on electricity demand ramping up in 2035. By 2030 only 30-40% of the energy supply required to achieve the 2030 emission reductions will be available. This suggests that Ontario could miss its 2030 targets by 60%. As noted earlier, the FTR emission forecast shows that a 30% or 20 Mt emission reduction shortfall could occur in 2030. At ICF's forecast carbon price of $100/Mt[6], that 20 Mt shortfall in the FTR could cost $2B/year in higher costs in the form of externally purchased emission credits.

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 this increased demand. Having the needed supply in time is particularly important given the anticipated retirement of the Pickering Nuclear Generating Station (PNGS).

By 2025, under the OPO Outlook D assumptions shown in Figure 4, it is conceivable that the province will have 20 TWh of greater demand than it has today. Prior to PNGS retirement, Ontario's surplus can provide low cost electrification options to help meet this demand and help accelerate Ontario's CCAP objectives for 2020. Assuming the extended operation of the PNGS to 2024, the plant's retirement will remove 20 TWh of clean baseload power, effectively eliminating all of the useable low cost carbon-free surplus power.[7] This creates an imperative for developing 20 to 40 TWh of new clean baseload generation by 2025 to provide ongoing support for Ontario's emission reduction options.

II. Unrealistic Conservation Achievement Targets

All four IESO outlooks incorporate the achievement of the 2013 LTEP conservation target of 30 TWh by 2032 and the near-term target set in the Conservation First Framework and Industrial Accelerator Program of 8.7 TWh by 2020.[8] In June 2016, the IESO completed an Achievable Potential Study ("APS")[9] to assess the electricity conservation potential in Ontario. The APS concluded that within the current budget

[6] ICF International, Ontario Cap and Trade, 2016

[7] Strapolec, Extending Pickering Nuclear Generating Station Operations: An Emissions and Economic Assessment for 2021 to 2024. 2015 (Appendix III)

[8] OPO. Page 8

[9] IESO. 2016 Achievable Potential Study. http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Working-Groups/2016-Achievable-Potential-Study-LDC-Working-Group.aspx

assumptions, approximately 7.4 TWh of conservation can be achieved by local distribution companies by 2020 (that is 1.3 TWh short of target). The APS also found that in the longer term about 19 TWh can be achieved from distribution and transmission connected customers by 2035 (11 TWh short of target, even at the delayed timeline of 2035). The APS states that incremental conservation may be achievable at higher budget levels, which means the programs would become less and less cost-effective.

Moreover, details are not provided with respect to the nature of future CDM activities and programs. For example, almost half of the projected post-2015 conservation savings are assumed to come from new future programs, codes and standards without identifying what they will be, which makes the conservation savings and hence the demand forecasts questionable. Also, there should be a transparent and scientific assessment of the cost-effectiveness of existing and future programs. A 2015 Berkeley University[10] study found that the US Weatherization Assistance Program – a home retrofit program – predicted 2.5 times more energy savings than were actually realized. Moreover, the cost of the program per household was about twice the value of the energy savings.

In conclusion, achieving Ontario's 2030 emission reduction target will require an estimated 90 TWh of new electricity demand by 2030. This is 80% greater than IESO's electricity demand forecast, and is required 5 years sooner. Demand for electrification will also steadily increase driven by deep carbonization investments until the 2050 targets are met.

4.2 Supply Outlook

The OPO states that Ontario is in a strong *starting position* to reliably address any of the demand outlooks. This starting position is shaped by three factors:[11]

- **The combined capability of resources that exist today ("existing resources")**
- **Resources that have been procured but are not yet in service ("committed resources")**

[10] Fraser Institute, Demand-Side Mismanagement: How Conservation Became Waste, April 2016

[11] OPO. Page 8

- **Resources not yet procured or acquired but have been directed to meet government policy objectives outlined in the 2013 LTEP and elsewhere ("directed resources")**

The OPO also states that:

- **If all existing resources were to continue to operate after the expiry of their contracts, and if nuclear refurbishments, committed resources and directed resources come into service as scheduled, Ontario would have a total installed capacity of nearly 43 GW by 2035. In contrast, if all existing resources are removed from service after contract expiry [in the amount of 18GW], Ontario would have a total installed capacity of approximately 25 GW by 2035.**

4.2.1 PWU's Comment

In the PWU's view, the Supply Outlook is too optimistic and problematic for the following reasons:

I. The OPO states that "*provided that the planned resources come into service and existing resources continue to operate, Ontario's existing, committed and directed resources would be sufficient to meet the flat demand outlook*." In other words, more, new capacity will be needed to meet the new demand. This is confirmed by the IESO's own analysis of capacity surplus/deficit across the four demand outlooks, which shows that under Demand Outlook D, for example, there will be a deficit of 11,200 MW at winter peak in 2035.

II. Even more, new baseload supply is needed to meet the increase in demand for electricity that would be required to achieve the Province's GHG emission targets. The electricity required to meet the 2030 emission targets will be needed sooner than shown in the IESO Outlooks. Strapolec notes[12] that the Outlook D forecast is based on electricity demand ramping up gradually to 2035. By 2030 only 30-40% of the energy supply required to achieve the 2030 emission reductions will be available. This suggests that Ontario could miss its 2030 targets by 60%.

III. The refurbishment of the Darlington and Bruce nuclear units together with the current plan to close the Pickering NGS in 2024 pose a real risk of supply shortfall. According to the IESO, if a decision is made in 2017/2018 to not proceed with the continued operations of Pickering to 2022/2024, there will only

[12] Appendix I

be a window of about two to three years in which to have the required replacement resources in place. Should the nuclear off-ramps be exercised there would be a lead time of 4 to 5 years between the decision and when the impact of that decision would occur.[13] Increasing the use of the existing natural gas-fired fleet or adding new gas generation resources to fill the gap would only increase emissions. Continuing to maintain low or reduce GHG emissions in the electricity sector should be an important criteria when decisions are made about meeting the potential supply shortfall during the refurbishment period and or meeting the higher demand outlooks.

IV. The OPO assumes that all existing resources whose contracts expire (about 18GW of capacity) will continue to operate. It is unlikely that all of these assets with expiring contracts will continue operation. Nor is it clear they will be the most cost-effective options to meet the province's electricity system needs. Given that most of these generation assets are gas-fuelled and wind generation, the 2017 LTEP should assume that there may be environmental, operational and cost related reasons e.g., the impact of carbon pricing that could prevent some of these assets from continuing to operate. The OPO indicates that in the higher demand scenarios (Outlook C & D), Ontario will return to being a winter-peaking jurisdiction due to the increased use of electricity for space heating.[14] Ontario's future energy mix should reflect the shift from summer-peaking to winter-peaking demand and still maintain low or declining GHG emissions.

4.2.2 Planning for the Right Supply-Mix

Discussion Guide Question for Comment:

To meet a higher demand, what mix of new electricity resources would best balance the principles of cost-effectiveness, reliability, clean energy, community engagement, and an emphasis on Conservation First?

[13] IESO. OPO. Module 4: Supply Outlook. Page 22
[14] OPO. Page 5

The OPO places significant emphasis on options that involve new imports from Quebec, and building new hydro and wind generation capacity. According to Strapolec,[15] these options involve significant implementation and economic challenges that suggest they represent suboptimal choices for achieving Ontario's 2030 emission targets. These options represent a total system cost that is 25% higher than today's and could rise to $16B/year if the projected 92 TWh of demand is supplied.[16]

The electricity required to meet Ontario's 2030 emission targets requires the development of significant generation that may not be practically achievable prior to 2030. In the longer term, the demand for electrification will steadily increase due to the deep decarbonisation initiatives required to meet the 2050 targets. Given the magnitude of the resources required and the associated development timelines, 2050 is not that far away.

In the near-term, with the exception of new nuclear, there are no identified alternative supply options that can provide the required supply to meet the substantial demand growth estimated for Ontario to achieve its 2030 emission reduction targets.

In the report provided in Appendix II, Strapolec proposes a supply mix option that 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. Compared to the OPO's D1 scenario, Strapolec's proposed supply mix includes 14GW of new nuclear capacity at: an estimated unit cost of $89/MWh (compared to $170/MWh); a lower carbon price of $106/t (compared to $161/t); and, a lower emission reduction cost of $18B (compared to $27B). This supply mix option also provides the earliest path to emission reductions. Strapolec concludes that delaying the decisions to initiate the requisite new energy infrastructure development, i.e. nuclear, could start costing Ontario up to $65M/month beginning with the launch of Ontario's new C&T regime in 2017.

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[15] Strapolec. Ontario's Emissions and the Long-Term Energy Plan: Phase II - Meeting the Challenge. 2016 (Appendix II)

[16] Ibid.

The PWU expressed concerns on many occasions about choice and timing of Ontario's past generation resource decisions. The lessons learned from these choices should inform Ontario's future supply mix choices to ensure options that provide clean, cost-effective, reliable, and affordable electricity and that stimulate economic growth, are selected. This makes it important to critically and transparently assess the viability and suitability of supply mix options that are required to meet the higher demand outlooks in the LTEP and or the even higher demand that will be needed to achieve Ontario's GHG emission reduction targets:

I. Import of Electricity from Quebec

Ontario and Quebec have a capacity sharing agreement in place for 500 MW of seasonal peak capacity over a 10-year term. More recently, Ontario and Quebec signed a 7-year deal that will enable Ontario to import up to 2 terawatt hours of electricity from Quebec each year.

Such arrangements can help meet seasonal peak capacity shortfalls, e.g., in the summer when Ontario needs power and in the winter when Quebec needs more power. However, it would be irresponsible to suggest that imported electricity from Quebec could cost-effectively replace Ontario's 6,600 MW baseload supply from the Pickering and Darlington NGSs. The PWU agrees with the statements made by the Hon. Glenn Thibeault, Minister of Energy, in a November 1, 2016 letter to the editor of the North Bay Nugget titled, "*Imports won't replace Ontario's nuclear power"*. In direct response to Ontario Green Party leader, Mike Schreiner's call for the province to shut down the Pickering nuclear station and cancel the rebuild of reactors at the Darlington station, the Minister said:

> **"Ontarians can be proud that our nuclear industry is one of the best in the world, supporting thousands of jobs and helping grow our economy. The Darlington refurbishment project alone will create up to 12,000 jobs in Ontario, and provide almost $15 billion in economic benefits.**
>
> **Mr. Schreiner is wrong to suggest all of this could simply be replaced with electricity imports from Quebec. Imports on the scale that Mr. Schreiner suggests would require billions of dollars in costly system upgrades from both provinces, and still would not provide the sort of reliable, home-grown electricity that we get from nuclear… Nuclear power has been providing cheap electricity to Ontario for more than 40 years. It runs around the clock, 365 days a year, serving as the backbone of our electricity system. And best of all, it has zero**

emissions that cause climate change. As we look to the future, nuclear energy will continue to play a key role in our safe, clean and reliable electricity supply."[17]

The Minister's statements are consistent with the findings of a number of studies.

In 2014, the Energy Minister at the time, the Hon. Bob Chiarelli requested that the IESO and the OPA prepare a Report on the potential impacts and opportunities associated with the capabilities of Ontario's intertie connections to support the demand and reliability requirements of the province's power system. The review found that:[18]

- The current interconnection system was not designed to be used to replace a significant amount of Ontario's existing baseload capacity. At present, there is limited firm import capacity. Significant upgrades to Ontario's transmission system—new infrastructure and possibly intertie capacity would be required to meet any marked increase in firm imports.
- The cost of these enhancements would vary depending on the amount of capacity being imported. These costs would be in addition to those that would be required in the exporting jurisdiction.
- The ability of suppliers from outside Ontario to sell power at higher prices to markets in jurisdictions other than Ontario could potentially increase the costs of electricity imports to Ontario. For example, Hydro-Québec exports hydroelectricity to U.S. jurisdictions at a premium price. Transmission and intertie upgrades would involve long lead times given the associated regulatory and environmental assessment processes. These represent significant risks with respect to the feasibility of relying on firm import arrangements to meet the future baseload needs of the system as identified in the 2013 LTEP.
- These factors suggest that firm imports could cost significantly more compared to meeting Ontario's electricity needs with domestic resources. Additionally, firm energy imports should not be considered in long-term adequacy planning as these imports cannot be relied upon at all times. Ensuring Ontario's long-term energy security should be an underlying LTEP objective.

[17] http://www.nugget.ca/2016/11/01/imports-wont-replace-ontarios-nuclear-power
[18] IESO and OPA: Review of Ontario's Interties. October 14, 2014

- Moreover, relying on significant firm imports could result in stranded costs for Ontario's investments in existing generation and transmission assets. For example, the recently constructed new 500 kV Bruce transmission line was constructed in large part to deliver additional supply from the Bruce Nuclear Station.
- A firm energy arrangement could create operational risk to Ontario's electricity system. The interties provide operational and planning flexibility that could be compromised by locking up the interties to accommodate firm imports.
- Any substantial firm import deal with Ontario would likely involve both capacity and energy. Such an arrangement would likely require the construction of new generation and transmission infrastructure in the selling jurisdiction. This can be expected to push the price of these imports higher compared to current electricity prices.
- Today, Ontario and most of the northeast U.S. are summer peaking systems. This limits the availability of spare generating capacity for delivery to Ontario during summer peak periods.
- Currently, the firm import capability on the Quebec-Ontario interties that could be relied on for all hours is considerably restricted due to transmission issues in the Ottawa area. On a regular basis only about 500 MW of firm capability can be accommodated and this could be further limited during some extreme local conditions. This capability is expected to disappear in 2020.
- The following are examples of some of the transmission upgrades that could be needed to accommodate firm long-term arrangements between Ontario and Quebec beyond the current 500 MW capacity:[19]
    - **Imports of Up to 1,000 MW** - upgrades could cost up to $325 million and are estimated to take 3-5 years to complete.
    - **Imports of Up to 1,800 MW –** upgrades could cost up to $825 million and are estimated to take 5-7 years to complete.
    - **Imports of Up to 3,300 MW -** In order to add 1,500 MW of intertie capability for a total of 3,300 MW, the estimated cost for the Ontario

[19] IESO and OPA: Review of Ontario's Interties. October 14, 2014, page 43

> enhancements could be as high as $2.2 billion. The estimated lead time is 7-10 years reflecting the expected time for regulatory and environmental approvals, construction and commissioning. There would also be additional transmission build required in Quebec to supply the additional 1,500 MW along with the appropriate Quebec regulatory and environmental assessments.[20]

Furthermore, a firm import arrangement involving a large amount of capacity would have implications both for the Ontario and Quebec power systems, beyond the interconnections and transmission systems. Public documents indicate that Quebec currently has limited quantities of power available to export in the summer, and plans to add capacity in the coming years.[21] Consequently, any deal to supply baseload energy year-round, comparable to that supplied by Ontario's nuclear plants, would require the construction of new generation in Quebec. This new generation would be more expensive than Quebec's heritage generation as the costs of construction, including transmission would come at a higher cost, resulting in higher import prices for Ontario.

Similarly, Strapolec's analysis[22] shows that increasing firm electricity imports from Quebec would be an imprudent and expensive option for Ontario and that continuing to rely on low-cost, low-carbon baseload nuclear energy is Ontario's best option. Strapolec noted that the required intertie investments would be economically undermined by the lack of winter generation capacity in Quebec and the forecasted future generation shortages in both provinces.

Quebec has a winter peaking system and is currently capacity limited in the winter. In fact, Ontario exports electricity to Quebec in the winter months. With the anticipated electrification of home heating systems in Ontario, the PWU expects Ontario to move from a summer-peaking to a winter-peaking system, which would make reliance on electricity imports from Quebec even riskier than it is today.

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[20] Ibid., Page 26
[21] Ibid.
[22] Strapolec. Renewables and Ontario/Quebec Transmission System Interties: An Implications Assessment, June 2016, page i.

II. Wind

The Discussion Guide states that at the end of June 2016, the 4,500 MW of installed wind capacity represents the largest source of Ontario's non-hydro renewable generation and that approximately 1,600 MW of additional wind capacity is under contract and development. However, these renewable investments, predominately wind and solar have come at a significant cost. According to Ontario's Auditor General, electricity consumers have paid $9.2 billion more for renewables over the 20-year contract terms of the Ministry's current guaranteed-price program compared to what they would have paid under the previous program[23,24] The Auditor General found that the prices for Ontario's guaranteed-price program were double the market price for wind in 2014. Given the maturity of the technology, the rate of cost decline is expected to be slower than in the past[25] and therefore, wind will continue to be an expensive option.

The LTEP should consider the suitability and cost-effectiveness of increased wind generation prior to deciding on its inclusion in the supply mix required to meet the increase in demand resulting from electrification:

- 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 forecast intermittent production is expected to be surplus/wasted.

A comparison of wind generation to Ontario demand for the period 2013-2015 shows that wind production rises in the spring and fall when the supply is not required, and remains at its lowest in the summer when it is required most.[26] Additionally, wind generation does not perform well in the higher winter demand period. Wind generation cannot be matched to demand. With the forecasted winter-heavy demand profile, the contrasts in winter will become as stark as those in the summer. Moreover, total useful

[23] Office of the Auditor General of Ontario. Annual Report 2015
[24] The IESO calculates this amount to be closer to $5.3 billion, in order to reflect the time value of money
[25] IESO. OPO. Module 4: Supply Outlook. Page 13
[26] Strapolec. Appendix II, Page 20

wind energy therefore represents 4.3 TWh, or 47%, of the wind generation in Ontario.[27] Over 50% of wind generation in Ontario is not productively used by Ontarians; it is wasted through curtailments and/or via uneconomic exports to neighbouring jurisdictions.[28]

Since wind generation can only be productively used 50% of the time that it actually produces, 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 transmission related costs and other integration issues described in the OPO.

For these reasons (i.e. system reliability and efficiency, cost, and GHG emissions) no new non-dispatchable, wind generation should be added to Ontario's system beyond what is already under committed contract. The PWU supports the government's September 2016 decision to cancel the procurement for 1,000 MW of power from renewable energy sources, primarily wind and solar.

III. Natural Gas Generation

The electricity sector, accounting for less than 7 per cent of the total GHG emissions in Ontario, has achieved a significant reduction in GHG emissions over the last decade. While gas generation has operational value in meeting peak demand, it is essential that the emission reduction efforts achieved by the electricity sector are not reversed by increasing Ontario's reliance on high GHG-emitting generation e.g., natural gas for intermediate or baseload supply. Recognizing that natural gas-fired generation will be required for the foreseeable future to help meet peak demand, the PWU submits that the extension of contracts for existing facilities should be considered before building any new gas plants.

IV. Solar PV

Solar PV's role in meeting Ontario's winter-peaking is also limited. Solar output does not align with peak electricity demand in the winter as it usually occurs during the dark

[27] Appendix II, page 22
[28] Ibid.

mornings and dark evenings.29 Moreover, solar energy, like wind, is backed-up by GHG emitting natural gas-fired generation and any increased use of natural gas will increase emissions.

Fortunately, Ontario has, and can plan generation resources that provide affordable, reliable, safe, secure and clean electricity. These resources are nuclear, hydroelectric, biomass, and hydrogen produced from electricity.

V. Nuclear Generation

Nuclear generation is reliable, safe, cost-effective and is virtually GHG emission-free. Nuclear generation accounts for one-third of Ontario's installed capacity and today provides nearly 60% of Ontario's electricity. Only hydroelectric power has a lower cost per kilowatt-hour (kWh) compared to nuclear energy. Gas-fired and wind generation are almost twice as expensive per kWh as nuclear. Solar generation is nearly ten times more expensive.[30] A 2014 Intergovernmental Panel on Climate Change Report indicated that on a carbon emissions/kWh basis, nuclear power compares favourably with renewable energy sources and is well ahead of fossil fuels. For example, natural gas emits 29 times as much carbon as nuclear. OPG's virtually smog and GHG emission-free nuclear and hydro power is produced at a cost that is about 40% lower than other generation sources in Ontario.[31]

Darlington and Pickering NGSs represent 6,600 MW of OPG's 17,000 MW of capacity making nuclear generation an indispensable low-carbon resource in Ontario's energy-mix.

The refurbishment of Darlington will ensure the supply of 3,600 MW of clean, reliable and affordable electricity for another 30 years while delivering significant economic and environmental benefits to Ontarians. According to the Conference Board of Canada,[32] the economic benefits of refurbishment and the subsequent 30 plus years of operation

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[29] IESO. OPO. Page 13

[30] Ontario Energy Board, April 14, 2016, page 20.
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/RPP_Price_Report_May2016.pdf

[31] Jeff Lyash, President and CEO of OPG: Testimony to Canada's Senate Committee on Energy, the Environment and Natural Resources, June 2, 2016

[32] Conference Board of Canada, Refurbishment of the Darlington Nuclear Generating Station: Impact Analysis, October 2016

will total $89.9 billion. Moreover, Darlington's continued operation is projected to increase the number of jobs in Ontario by an average of 14,200 per year between 2017 and 2055, with five jobs created in the broader Ontario economy for each worker directly employed at the Darlington Station.

Refurbishing Darlington delivers significant emission reduction benefits. A report by Intrinsik Environmental Sciences[33] shows that the total reduction in GHG emissions resulting from the refurbishment and continued operation of Darlington for the period 2024 to 2055 is estimated to be 297 million tonnes of carbon dioxide. This represents an annual average reduction of 9.6 million tonnes or the equivalent of the emissions from two million cars. Even at a modest $30 per tonne carbon price, 297 million tonnes CO2 x $30/tonne = $8,910,000,000 of carbon savings over the life of the station.

Bruce Power returned its 8-unit site to its full potential of 6,300 MW in 2012 – the world's largest NGS. The station supplies about 30 per cent of Ontario's electricity. The planned refurbishment and life-extension maintenance activities will extend the station's operations to 2064. This resulting $4 billion in annual economic benefit will create and sustain 22,000 direct and indirect jobs province-wide throughout Bruce's operating life to 2064. The carbon avoidance benefits of the Bruce Power operation are enormous and will grow even further as Ontario's economy and environment transform to reduce carbon emissions through electrification.

Similarly, keeping the Pickering NGS in operation for as long as it can be operated economically and with CNSC approval beyond 2024 would ensure access to safe, clean, low-cost electricity during the refurbishment period while potentially avoiding millions of tonnes of GHG emissions annually. According to OPG, extending the life of Pickering NGS to 2024 would save Ontario electricity customers up to $600 million, avoid eight million tonnes of GHG emissions and protect 4,500 direct jobs across the

[33] Intrinsik Environmental Sciences: Greenhouse Gas Emissions Associated with Various Methods of Power Generation in Ontario, October 2016, page iii

Durham Region.[34] The benefits would be even greater if the Pickering NGS operates beyond 2024.

In addition, the LTEP should recognize that the OPO high electricity demand Outlook D and the even higher demand that would result from increased electrification required to meet Ontario's emission reduction targets cannot be realistically and cost-effectively achieved without new nuclear generation. New nuclear generation offers the earliest path to meeting emission reduction targets and as such the LTEP should prioritize an early start for developing a site, preferably at Darlington, for new nuclear generation. The benefits of new nuclear generation extend beyond meeting Ontario's domestic energy and environmental needs. With the increase in the national and global demands for clean energy, Ontario has a unique opportunity to use its nuclear industry to grow its economy through the export of nuclear technology, products, expertise, and services and through international business partnerships.

VI. Hydroelectric

The Discussion Guide notes that hydroelectric facilities provided the second biggest share of Ontario's electricity in 2015, producing 37.3 TWh of electricity or 23%. The OPO states that there is significant remaining hydroelectric potential in Ontario. The greatest potential is in the north with some opportunities in the south. These potential opportunities could provide a significant source of non-carbon emitting energy and opportunities to partner with First Nation and Metis communities. However, the expected costs of developing this potential would be higher than in the past and would require relatively longer lead times to develop. The 2013 LTEP calls for 9,300 MW of hydroelectric by 2025.

Hydroelectric generation plays a number of roles in the supply mix: provides minute-to-minute control to help ensure system reliability; provides some storage flexibility that helps accommodate peak demand and variable renewable generation, similar to natural gas-fired plants, but with lower emissions; and provides baseload power. The 8,000 plus MW of in-service hydroelectric power is Ontario's lowest cost generation.

[34] OPG President Brings Clean Air Message to Canadian Senate OPG Generation is more than 99 per cent free of GHG Emissions – June 3, 2016 http://www.opg.com/news-and-media/news-releases/Documents/20160603_CanadianSenate.pdf

Given the diversity in operational flexibility, continuing to upgrade and expand Ontario's existing hydroelectric assets can continue to contribute reliability, environmental and economic benefits. The LTEP should remain committed to the development of untapped resources that can be executed in a safe, environmentally responsible and cost effective manner and in consultation with concerned communities.

VII. Biomass

Ontario's vast renewable forestry and agricultural biomass resources provide an ideal opportunity to provide substantial environmental and economic benefits for the forestry, agricultural and transportation sectors while better positioning our province to compete in the rapidly emerging global bio-economy.

According to OPG, wood-based biomass compared to coal generation contains 75 per cent less nitrogen oxide and virtually no sulphur dioxide. It also produces 80 per cent less GHG emissions compared to combined cycle natural gas fired plants.

The conversion of OPG's Atikokan Generating Station (GS), now North America's largest 100 percent biomass-fuelled power plant, provides low-carbon, dispatchable, peak capacity electricity. The conversion of the Thunder Bay GS to use advanced biomass is the first of its kind in the world. Both investments have helped Ontario reduce its GHG emissions and improve system reliability while creating new jobs in forestry and transportation and in First Nations and Metis communities.

These conversions have also helped Ontario finance leading edge biomass research and development across the province help to positon the province as a global leader in biomass technologies.

To become a global leader, Ontario should take advantage of its biomass resources much like Denmark has by investing in their potential for biomass innovations. Today, Demark has three bio-refinery projects underway producing high value-chemicals, materials to replace those based on petroleum, and transportation fuels. The Maabjerg BioEnergy Complex, expected to be operational in 2017, integrates an existing combined heat and power plant, a new biogas plant using manure and industrial waste, and a planned bio-ethanol plant.

The LTEP should consider the conversion of the idle Nanticoke and Lambton stations to carbon-neutral biomass/gas co-fuelling for peak supply needs. This could further stimulate and advance growth in Ontario's bio-economy.

Converting existing generating units at Ontario's Nanticoke and Lambton GS to biomass and natural gas could deliver many benefits. The associated investments would recycle valuable, provincially-owned generating stations and transmission lines that are already sited, built and paid for. Conversion would cost far less than building new natural gas-fired plants and would reduce the need to site and build new natural gas plants and transmission lines. Ontario ratepayers would benefit from the resultant revenue stream and communities that want to keep these generating stations in operation would continue to receive social and economic benefits. Biomass fueled generation is more versatile than wind and solar generation. It could help to displace carbon-emitting natural gas consumption that is required: to back up intermittent renewable generation; help cover the forecast supply shortage during the refurbishment schedule; and, help reduce emissions by displacing overall natural gas consumption. Additionally, Ontario's energy security would be improved by lessening the province's dependence on imported natural gas. Concurrently, these conversion investments would support existing Ontario jobs and small business in the forestry, agricultural and transportation sectors while creating thousands more full-time jobs. Analyses suggest, annually this could contribute about $600 million to Ontario's GDP.[35]

OPG has the expertise, experience and resources, the sites (complete with transmission lines) and the capabilities required to execute these conversions. OPG completed the Atikokan GS conversion from coal to biomass (211 MWs) on time and on budget.[36] OPG also converted one of two units at the Thunder Bay GS from coal to advanced biomass ahead of schedule and under budget.[37]

On November 22, 2016, OPG announced its decision to decommission the Lambton GS in 2017. OPG states that the decision is "consistent with the government's efforts to

[35] http://www.opg.com/generating-power/thermal/stations/atikokan-station/Documents/Biomass_Conversion/Pembina%20Biomass%20Sustainability%20Analysis.pdf
[36] OPG website
[37] OPG website

reduce electricity costs as it will save customers $11 million." OPG also states that continuing to preserve Lambton beyond 2016 for future conversion is no longer economically feasible given the "flat demand forecasts in the Ontario Planning Outlook."

The PWU submits that OPG's reasons for decommissioning the Lambton GS are short-sighted and contrary to the electricity demand outlook analyses presented in this submission. It ignores the GHG emission reductions and economic benefits that the conversion of these stations to biomass/gas co-fuelling means to the community e.g., over 450 jobs. The PWU submits that OPG should be directed to rescind its decision to decommission the Lambton GS.

VIII. Hydrogen

Navigant's FTR only considers hydrogen as a fuel for hydrogen fuel cell vehicles due to the fact that most hydrogen is produced from methane or coal gasification which creates GHGs. Hydrogen can be made from almost any source of energy and it is only as clean as the energy source it's derived from.[38] Hydrogen can be produced in many ways e.g., electrolysis, that uses clean energy sources such as nuclear and hydroelectric electricity and produces no toxins, particles or GHGs.[39] The PWU supports hydrogen production from electricity, specifically from low cost, low carbon, baseload sources.

CANDU reactors are well suited to make hydrogen through electrolysis in off-peak electricity demand periods. Both the electricity and hydrogen could be exported to other jurisdictions, which in turn could help them reduce GHG emissions. Since 2003, Canada has had a hydrogen and fuel cell roadmap in place. Hydrogen and fuel cell technologies have many potential clean energy applications – e.g. running our vehicles, powering our cell phones and heating our homes. Since hydrogen fuel cells do not produce air pollutants or GHGs, they have the ability to significantly improve our environment and help Ontario achieve its emissions targets. Hydrogen also represents an opportunity to store energy that would otherwise be wasted.

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[38] Canadian Hydrogen and Fuel Cell Association http://www.chfca.ca/
[39] Canadian Hydrogen and Fuel Cell Association http://www.chfca.ca/

Strapolec's analysis[40] indicates that hydrogen generated with low cost nuclear energy is among the most economical emission reduction options which could deliver significant economic and competitive advantages for Ontario. By embracing the nuclear and hydrogen economies to accelerate over $10B/year of industrial activity, Ontario could reduce the costs of achieving the province's 2030 emission targets to under $5B/year.

The PWU recommends that the potential for the increased use of hydrogen from nuclear and hydroelectric electricity should be included in the LTEP.

5 ENERGY PRICING

The OPO indicates that the total real cost of electricity service grew by 32 percent between 2006 and 2015, primarily because of new investments in generation and distribution infrastructure. The cost is now approximately $20 billion per year in current dollars. Over the same period, reductions in overall demand increased the average unit cost of electricity in real terms by 3.9 percent per year; it is now approximately $140 per MWh in current dollars. As described in Section 3.7 of the OPO, these unit costs are expected to stabilize through the planning period. The OPO also indicates that in the flat Demand B outlook, the average unit cost of electricity service will decrease by an average of 0.3% per year in real terms over the next 20 years. In higher demand outlooks, additional investments in new resources (conservation, generation and transmission) would be required to meet the increase in demand (peak and energy requirements) and to keep emissions within the range of the flat demand outlook. The annual cost of electricity service would rise by approximately $4 billion to $10 billion by 2035 (2016$).[41] However, this would be driven by an increase in electricity consumption in the province. As a result, the average unit cost of electricity service would be within the range of the flat demand outlook.

[40] Strapolec. Appendix II
[41] IESO. OPO. Figure 21. Page 20

5.1 PWU Comments

The PWU appreciates many of the measures the government has taken recently to reduce ratepayer costs outlined in the Discussion Guide. These include the decision to suspend the second round of the Large Renewable Procurement and the Energy from Waste Standard Offer Program, which the government indicates will save up to $3.8 billion in electricity system costs compared to the forecast in Ontario's 2013 LTEP. The PWU asserts that the significant increase in electricity rates over the past several years is the result of regrettable choices made with respect to the integration of renewable resources into Ontario's supply-mix. The total cost of electricity service over the planning outlook will be a function of demand growth, the cost of operating the existing system, and the investments required in new resources to meet potential needs.

The best strategy for controlling electricity system costs and providing safe, clean, affordable and reliable electricity to the rate payer requires a plan that is based on the supply mix option recommended in this submission. And since Ontario's C&T Program starts January 2017 with an expected increase of $13 per month to the average household cost of home heating and driving a car,[42] the LTEP should prioritize low cost electricity choices that reduce the cost of carbon emission reduction initiatives. Strapolec estimates[43] that low cost electricity choices could reduce the cost of carbon emission reduction initiatives by up to 25% or $7 Billion/year and the IESO has identified nuclear as the lowest cost option in the OPO.[44] Strapolec also estimates[45] that the carbon price required to achieve the 2030 targets ranges from $120/tonne to $210/tonne depending on the cost of electricity and the effective management of the C&T proceeds. Low cost electricity supports a carbon price of $120/tonne.

Ontario's C&T Program is expected to generate about $1.9 billion/year in proceeds.[46] The PWU submits that the manner in which these proceeds are utilized will play a fundamental role in the future of electricity prices in Ontario. In recognition of the critical

[42] https://www.ontario.ca/page/cap-and-trade-ontario
[43] Strapolec. Appendix II
[44] Adoption of carbon emission reduction options are estimated in this report to potentially add costs of up to $27B/year to how Ontarians use energy.
[45] Strapolec. Appendix I
[46] https://www.ontario.ca/page/cap-and-trade-ontario

and strategic role that the electricity sector can play in decarbonising Ontario's economy, auction revenue from the electricity sector should be reinvested in Ontario's electricity sector in: emission reduction technologies; electricity infrastructure (EVs and hydrogen); fuel switching incentives; expanded electrification; training and education of a skilled workforce; and, research and development programs.

6 ONTARIO'S ELECTRICITY FUTURE

6.1 Distribution, Grid Modernization and Natural Gas Expansion

Discussion Guide Questions for Comment:

What are the significant challenges facing utilities and what can government do to meet them?

What are the most important benefits of a modern grid? Increased reliability? Greater information on your energy usage?

What additional policies should the government consider to expand access to natural gas?

6.1.1 PWU Comments

6.1.1.1 Challenges Facing Utilities

Utilities face many challenges including: significant infrastructure and asset renewal; keeping up with, and incorporating new technology; constantly changing government policy and regulation; the overall regulatory burden; uncertainty with regards to cost recovery; maintaining a safe and reliable network; responding to customer needs; addressing climate change; and, maintaining a skilled workforce. The PWU submits that utilities need regulatory predictability and administrative efficiency to ensure that they can fulfill the obligations in their business plans and recover all of their prudently incurred costs.

6.1.1.2 Important Benefits of a Modern Grid

The PWU is supportive of investments in the smart grid that improve the operation of the electricity system, stimulate innovation, and create jobs and economic growth. However, like any other investment, these decisions should be strategic, transparent and based on cost/benefit analyses that sustain the ageing power grid and the province's transmission and distribution assets.

Smart grid investments that support Ontario's transition to EVs provide a good example. Significant electrification is required to meet the 2030 emission target and Ontario could realize significant economic and environmental benefits by powering "made-in-Ontario" zero emission EVs with the province's low-carbon hydroelectric, nuclear and biomass electricity generation. These investments could also help Ontario better manage surplus baseload generation.

LDCs should have the flexibility to make smart grid investments as part of their overall investment plan for maintaining and improving service reliability and accommodating increased demand and customer growth including increases in EV adoption and fuel switching. With the increase in wind, solar, distributed generation and micro-grids, power flow on the distribution system will be bi-directional. This impacts the protection and control requirements of LDCs as well as the SCADA systems on the bulk transmission system. Sustaining existing assets and improving maintenance practises and service quality should be the priority criterion for making any investments in smart technologies beyond those that can be addressed by sustaining OM&A and Capital budgets.

6.1.1.3 Expanding Access to Natural Gas

Today, the primary source of carbon emissions in Ontario's electricity sector comes from natural gas-fired generation. Since, the Ontario government's climate change policy (i.e. carbon pricing mechanism) is focused on reducing GHG emissions; this should be a key factor when decision makers are choosing new generation capacity investments for meeting the province's near and long-term electricity requirements. Economic analysis of alternative generation resources such as nuclear vs. natural gas or nuclear vs. wind and solar should be based on the real cost of electricity that is based on the cost of emissions e.g., cost of natural gas generation back up of wind generation. This type of analysis should steer investments away from fossil fuels towards cost-effective emission reduction opportunities such as zero or low-carbon sources of energy and electrification.

The PWU submits that increased reliance on GHG-emitting natural gas will negatively impact Ontario's ability to meet the legislated GHG targets.

6.2 Electricity Transmission

Discussion Guide Questions for Comment:

How can Ontario continue to strengthen reliability of the transmission system in all regions of the province?

Is the current "user pay" model an effective way to meet Ontario's needs? Does it appropriately balance the goals of economic development and protecting taxpayers?

6.2.1 PWU Comments

6.2.1.1 Strengthening Reliability

The PWU supports the major transmission investments made by Ontario between 2003 and 2015, as well as the current initiatives identified in the OPO. Changes in demand and supply patterns, regional planning, and the state of existing assets are expected to influence future transmission and distribution investments. A significant portion of the current infrastructure has reached end of service life and without a continued effort to upgrade and invest in new infrastructure, service reliability will be compromised. Moreover, decarbonising Ontario's economy by way of electrification with clean power will require additional investments in the transmission and distribution network to enable the integration of additional and new technologies, such as charging stations.

The PWU agrees that continued investment is required for the maintenance, sustainment and reinforcement of Ontario's existing transmission infrastructure and in new capacity to meet the demand growth expected in the high demand scenarios (Outlook C & D) and to ensure efficient and reliable operation of the electricity system.

Capital investments in existing transmission infrastructure ensure that the capability of the system is maintained to facilitate power transfers and accommodate new loads. Several methods are available to improve the existing capability of Ontario's transmission assets to enhance system operations and power transfers. These include: flexible AC transmission devices; and, the installation of series capacitors and static & dynamic VAR compensators. All of these would further leverage Ontario's existing assets and skilled workforce.

The PWU submits it is important that the different elements of Ontario's energy policy and the LTEP that impact transmission and distribution investments be better integrated to ensure the efficient utilization of current and future investments by Hydro One and other local distributors. Specifically, policies that incentivize distributed generation, conservation, storage, etc. should be properly assessed to determine their cost-effectiveness and impact on the efficient use of the transmission and distribution infrastructure.

6.2.1.2 "User Pay" Model

Given the OPO's higher demand outlooks C and D and the even higher demand increase required to meet Ontario's GHG emission reduction targets, electrification would require significant growth in Ontario's electricity supply, including new generation resources. In turn, additional investments in transmission would be needed to connect the generation to users. Transmission system enhancements can be minimized by maximizing utilization of existing generation sites that have existing transmission lines and rights of way e.g. Nanticoke. The development of large scale generation projects, for instance, hydroelectric projects in northern Ontario would require major transmission investments to connect the new generation to the grid, and to reinforce the network to accommodate greater flows of electricity. Under the current regulatory framework, these system costs would be shared by all electricity ratepayers.

On the other hand, if a specific customer requires a transmission upgrade to meet its own need, e.g., providing supply for a new industrial plant, the user pay model would require that the cost of this upgrade be paid for by that customer. The user pay principle ensures that the direct beneficiary bears the costs and not the other ratepayers.

The PWU submits that while the user pay principle has served rate payers well and should remain the guiding principle for investment, there might be instances where certain investments in generation and transmission infrastructure could be justified, and paid for by rate/tax payers, based on the social, economic and industrial benefits they bring to communities or the province at large. Such decisions should be made as part of the government's overall economic development and industrial policy and be subject to rigorous, transparent cost benefit analyses as the basis for such projects proceeding.

6.3 Conservation and Energy Efficiency

Discussion Guide Questions for Comment:

Should Ontario set provincial conservation targets for other fuel types such as natural gas, oil and propane?

To meet the province's climate change objectives, how can existing or new conservation and energy efficiency programs be enhanced in the near and longer term?

6.3.1 PWU Comments

6.3.1.1 Conservation Targets for Other Fuel Types such as natural gas, oil and propane

The primary source of carbon emissions in Ontario's electricity sector comes from natural gas. In the PWU's view, any cost benefit analysis of conservation programs for other fuels (i.e. natural gas) should explicitly include fuel switching as an alternative.

The efficacy of conservation programs in Ontario's electricity sector as a strategy to fight climate change is highly questionable. Ontario's highest GHG emission sources are the transportation, building and industry sectors. Ontario's Environmental

Commissioner (ECO) recently described Ontario's conservation efforts as "lopsided". Most of Ontario's fossil fuel based energy use – about 80 per cent − occurs outside the electricity sector, which only represents about 6 per cent the province's GHG emissions.[47] Any resources allocated for conservation programs in the electricity sector would be better directed towards other programs. For example, incentivising increased use of EVs, expanding the number of charging stations, and fuel switching from gas to electric home heating/cooling will all help lower GHG emissions from Ontario's larger GHG emitting sectors. For these reasons, the PWU supports setting conservation targets for fossil fuels that are largely used outside the electricity sector.

6.3.1.2 Enhancing existing or new conservation and energy efficiency programs in the near and longer term

Recently completed studies by the IESO and the OEB on the cost-effective savings that can be achieved in Ontario in electricity and natural gas indicate that:

- **Ontario's electricity conservation target of 30 TWh in 2032 is aggressive and that there is limited potential to achieve cost-effective conservation beyond this target; and,**
- **There is significant potential beyond current levels of activity for the cost-effective conservation of natural gas.**

The PWU submitted evidence in the past[48] indicating that if CDM targets are increased, but not achieved, both GHG emissions and electricity system costs would be higher than if supply planning had been based on the original targets. These results highlight the importance of setting CDM targets that are based on robust analysis that suggests they have a high likelihood of success.

The IESO has been directed to manage the $3.1 billion earmarked for conservation programs over the period 2015-2020.[49] Given that no transparent cost-benefit analysis has been presented that shows this and other investments would be prudent and cost-effective, these monies should be directed towards other GHG emission reduction programs e.g., electrification. Almost half of the projected post 2015 conservation

[47] More than 80 per cent of the province's energy needs are met by fossil fuels while conservation efforts have been targeted at electricity, which is "the smallest and cleanest of our major energy sources.", Dianne Saxe, Environment Commissioner of Ontario, Toronto Star, May 31, 2016
[48] Navius Research Inc. Electricity CDM in Ontario: Challenges and Opportunities
[49] Fraser Institute, Demand-Side Mismanagement: How Conservation Became Waste, April 2016

savings are assumed to come from new future programs, codes and standards. Given the potential risks, the LTEP should include a transparent, comprehensive assessment of the achievability and cost effectiveness of both existing and future programs.

7 CONCLUSIONS AND RECOMMENDATIONS

- Significant electrification of the economy is required to achieve the province's GHG emission reduction targets. In order to meet this need, Ontario's LTEP must secure low carbon electricity supply to higher than forecasted levels. This cannot be achieved without sustaining Ontario's commitment to the completion of the refurbishment of the Darlington and Bruce NGS units and by planning for new nuclear units at Darlington. These are Ontario's lowest cost long-term options.
- Extend the low cost, low carbon operation of the Pickering NGS, in accordance with approvals of the CNSC and Ontario Energy Board beyond the current planned retirement in 2024.
- Convert the idle Nanticoke and Lambton coal plants into carbon-neutral biomass/gas co-firing facilities to: meet peak demand; and, help mitigate the potential supply risk during the refurbishment of the Darlington and Bruce units. Request that OPG be directed to rescind its decision to decommission the Lambton GS in 2017.
- Cease planning for more wind and solar generation. These sources are unreliable and expensive and back up from gas-fired generation would reverse the GHG emission reduction results already achieved by Ontario's electricity sector.
- Continue to explore commercially-viable opportunities to expand existing hydroelectric sites and to develop potential hydroelectric resources.
- Forgo reliance on unrealistic, expensive imports of firm supply from Quebec. Such an arrangement would subject Ontario's energy security and affordability to

unnecessary risks and would transfer significant economic benefits away from Ontario to another jurisdiction.

- Explore opportunities to create a hydrogen economy in Ontario by utilizing low cost, low carbon baseload electricity to produce hydrogen.
- Use proceeds from Ontario's C&T Program to promote electrification of the transport, building and industry sectors through investment in EV and hydrogen infrastructure, incentives to EV and hydrogen fuel cell EV buyers and subsidies to residential and commercial electricity customers that incent fuel switching from gas to electric home heating/cooling.
- Commit to investments in transmission and distribution infrastructure to replace aging assets, ensure reliability and to prepare the network for the further electrification of Ontario's economy.
- Make the investments that are required to ensure the availability and sustainment of Ontario's skilled energy workforce.

All of which is respectfully submitted.

APPENDIX I - ONTARIO'S EMISSIONS AND THE LONG-TERM ENERGY PLAN:

PHASE I - UNDERSTANDING THE CHALLENGE

Ontario's Emissions and the Long-Term Energy Plan

Phase 1 - Understanding the Challenge

Final Report

Marc Brouillette

November, 2016

STRATEGIC POLICY ECONOMICS

Executive Summary

This study informs the Ontario Long-Term Energy Plan (LTEP) consultation with background analyses that relate to 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.

Since the global community of nations emerged from the COP21 Paris Climate Conference and its ratification 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 a pathway to a low carbon energy future. Beyond Ontario's electricity sector, transportation and the heating of buildings comprise the largest sources of emissions, creating an intersection of policy challenges for the environment, the economy, and Ontario's three energy systems: petroleum, natural gas, and electricity.

Ontario's next LTEP consultation process is underway, and the province's climate change strategy is a key driver. Ontario has legislated the province's greenhouse gas (GHG) emissions to drop to 37% below 1990 levels by 2030, or from the business as usual forecast of 176 Mega-tonne (Mt)/year to 111 Mt/year. The mandate to achieve these reductions falls under: (1) the C&T program that will establish the carbon price; and (2) the Climate Change Action Plan (CCAP) that will administer the use of the C&T proceeds. The LTEP's role, on the other hand, is to provide for the energy to enable Ontario's transition to a low carbon economy. However, publicly released reference materials do not draw an explicit connection between the LTEP and the legislated emission targets and the cost required to achieve them.

The Ontario Planning Outlook (OPO) prepared by the IESO identifies increased cost to the electricity system of $8B/year by 2035, and the Fuels Technical Report (FTR) prepared for the Ontario Ministry of Energy identifies $20B/year additional fuels costs. The relationship of these costs to the 2030 emissions targets is not clearly expressed.

This study comprises two phases.

1. Phase 1, *"Defining the Challenge"*, quantifies the costs of Ontario's climate actions and identifies the factors that the LTEP consultation process must address.
    - This report documents emission targets for each sector, identifies 45 emission reduction options posited by Ontario stakeholders, estimates the costs of each, and summarizes the aggregated cost to Ontarians and the implications for market carbon pricing, C&T program, CCAP implementation, and the LTEP.
2. Phase 2, *"Meeting the Challenge"*, will examine the cost and economic implications of options for Ontario's electricity supply mix in the 2017 LTEP.
    - The next report will examine the implications on supply arising from the new electricity demand, assess the costs and implementation considerations of the supply mix options put forward in the OPO as well as alternatives, and describe the cost and economic implications to Ontarians associated with those choices.

Although the primary focus of this study is the province of Ontario and its LTEP process, the detailed analyses within this report are potentially relevant for other similar jurisdictions in the Great Lakes-St. Lawrence Region, or more broadly, that may be contemplating aggressive emission reductions, deep decarbonization, and government mandated carbon pricing schema.

Key Findings: Phase 1

An LTEP process focussed on the province's climate change objectives is critical to lowering costs, meeting emission targets in a timely manner, and to allow the transition of Ontario to a low carbon economy. The LTEP should seek out the lowest cost incremental new electricity solution for Ontario that includes the integrated costs of generation, transmission, and distribution.

Four recommendations for the LTEP process are:

1. 90 TWh of new demand requires a decision at the earliest stage in the LTEP process for commitment to low-cost, emission-free generation options.
   - Forecast new demand for electricity is primarily for home heating and industrial baseload applications. This is 80% greater than the 50 TWh presented in the OPO Outlook D and 60% more than is consumed today.
   - Meeting 2030 emission targets depends on supplying this new demand with new generation. The timing for this consideration is not reflected in the OPO. Maximizing the safe economic life of the Pickering Nuclear Generating Station (PNGS) can support the transition.

2. Low cost electricity choices should be prioritized by the LTEP to reduce the cost of carbon emission reduction initiatives. Low cost electricity choices could reduce this cost by up to 25% or $7B/year.
   - With OPO Option D1, adoption of carbon emission reduction initiatives could potentially add costs of up to $27B/year to how Ontarians use energy, depending on the cost of electricity and the effectiveness of administrating the use of C&T proceeds. This cost could be reduced by the above mentioned 25%. The components contributing to the additional costs are:
     - Expected required carbon pricing within the C&T program would account for 60% or $16B/year of these costs which are to be directed towards subsidizing emission reduction initiative adoption;
     - As Ontarians make low emission choices, they will invest $9B/year to cover the unsubsidized portions of such things as new building heating equipment; and
     - Another $2B/year could be incurred by the administration and implementation of the C&T processes and dispensation of C&T proceeds.
   - The estimated carbon price required to achieve the 2030 targets ranges from $120/tonne to $210/tonne, also depending on the cost of electricity and the effectiveness of administrating the use of C&T proceeds.
     - Low cost electricity supports a carbon price of $120/tonne. The IESO has identified nuclear as the lowest cost option in the OPO.

3. Ontario's climate strategy initiatives should be integrated with the LTEP to match the pace of C&T emissions caps with the pace at which new electricity generation capacity can be built and alternative fuels provided.
   - Aligning emission targets to the availability of electricity and/or alternative fuels will minimize the likelihood that provincial targets will be missed.

- Missed emission targets caused by lack of generation could cost ~$1.2B/year in C&T allowance purchases from other jurisdictions.
- The integrated LTEP and climate strategy should consider the pathway to 2050 for deep decarbonization.
- The LTEP process should fully and transparently integrate emission targets, climate actions, electricity planning, and fossil fuels strategies.

4. Rigorous attention should be paid to the effective and efficient management of C&T proceeds use.
   - An effective program can accelerate emission reductions, get the carbon price much below $210/tonne, minimize the cost to Ontarians through effective subsidization programs. There is the potential of a $10B/year risk associated with ineffective policies.
   - A transparent evidence based process that considers all potential emission reduction technologies, such as hydrogen and nuclear, could lead to significant economic and competitive advantages for Ontario. Hydrogen generated with the lowest cost nuclear energy has emerged as among the most economical emission reduction options assessed in this study.
   - The effective use of C&T proceeds could make options economic at $120/tonne that would otherwise require a carbon price of $800/tonne.

Next Steps: Phase 2

The next report will examine the implications on supply that the new electricity demand necessitates, assess the costs and implementation considerations of the supply mix options put forward in the OPO, as well as alternatives, and describe the cost, schedule achievability, and economic implications to Ontarians associated with those choices.

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1.0 Introduction

This study informs the Ontario Long-Term Energy Plan (LTEP) consultation with background analyses that relate to 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.

Since the global community of nations emerged from the COP21 Paris Climate Conference[1] and its ratification 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 a pathway to a low carbon energy future. Beyond Ontario's electricity sector, transportation and the heating of buildings comprise the largest sources of emissions, creating an intersection of policy challenges for the environment, the economy, and Ontario's three energy systems: petroleum, natural gas, and electricity.

Ontario's next LTEP consultation process is underway, and the province's climate change strategy is a key driver. Ontario has legislated the province's greenhouse gas (GHG) emissions to drop to 37% below 1990 levels by 2030, or from the business as usual forecast of 176 Mega-tonne (Mt)/year to 111 Mt/year, a 65 Mt reduction. The mandate to achieve these reductions falls under: (1) the C&T program that will establish the carbon price; and (2) the Climate Change Action Plan (CCAP) that will administer the use of the C&T proceeds. The LTEP's role, on the other hand, is to provide for the energy to enable Ontario's transition to a low carbon economy. However, publicly released reference materials do not draw an explicit connection between the LTEP and the legislated emission targets and the cost required to achieve them.

The Ontario Planning Outlook (OPO) prepared by the IESO identifies increased cost to the electricity system of $8B/year by 2035, and the Fuels Technical Report (FTR) prepared for the Ontario Ministry of Energy identifies $20B/year additional fuels costs. These costs are additive for a total of $28B/year of new energy supply costs to Ontario. The relationship of these costs to the 2030 emissions targets is not clearly expressed. The absence of some key facts and analyses suggests that the anticipated outcomes of Ontario's climate change strategy actions may be optimistic.

This study comprises two phases.

1. Phase 1, *"Defining the Challenge"*, quantifies the costs of Ontario's climate actions and identifies the factors that the LTEP consultation process must address.
    - This report documents emission targets for each sector, identifies 45 emission reduction options posited by Ontario stakeholders, estimates the costs of each, and summarizes the aggregated cost to Ontarians and the implications for market carbon pricing, C&T program, CCAP implementation, and the LTEP.

[1] 21st Conference of the Parties, the 2015 Paris Climate Conference, http://www.cop21paris.org/about/cop21

2. Phase 2, *"Meeting the Challenge"*, will examine the cost and economic implications of options for Ontario's electricity supply mix in the 2017 LTEP.
    - The next report will examine the implications on supply that the new electricity demand necessitates, assess the costs and implementation considerations of the supply mix options put forward in the OPO as well as alternatives, and describe the cost and economic implications to Ontarians associated with those choices.

Although the primary focus of this study is the province of Ontario and its LTEP process, the detailed analyses within this report are potentially relevant for other similar jurisdictions in the Great Lakes-St. Lawrence Region, or more broadly, that may be contemplating aggressive emission reductions, deep decarbonization, and government mandated carbon pricing schema.

Methodology

This first phase of the study developed an estimate of the future cost of reducing Ontario's emissions, the associated dynamics impacting carbon pricing, and the implications that LTEP choices for the electricity system may have on these total costs. The five objectives of this study are to:

- Identify the emissions reductions in required in each sector to meet the 2030 targets;
- Investigate available emissions reduction options and estimate the emission benefits, the amount of electrification required, and the costs of the options compared to existing technology;
- Aggregate the provincial level demand for electricity and identify the implications this represents regarding new generation;
- Estimate the carbon price required to enable emission reduction options as economic choices for Ontarians; and
- Estimate the total cost to Ontarians of achieving the emission reductions and the sensitivity of that cost to both the incremental cost of electricity as well as to the government's policy choices for implementing the Cap and Trade (C&T) program.

For validation purposes, the directional findings of this study are compared to the assumptions in the IESOs Ontario Planning Outlook (OPO) and the Fuels Technical Report (FTR) prepared for the Ontario Ministry of Energy (MoE) in support of the LTEP consultation process.

Document Structure

This report provides a comprehensive description of the drivers, assumptions, and outcomes regarding Ontario's 2030 emission reduction targets, and their potential implications for the LTEP and the energy related costs Ontarians could pay.

Section 2.0 provides background for Ontario's emissions targets, the C&T program and Climate Action Plan and the degree to which these programs are expected to be successful. Illustrations of the sector specific emissions, Ontario's energy supply mix, and their relationship to the Buildings, Transportation, and Industry sectors provide context for the research priorities addressed in this study.

Section 3.0 of this document describes the methodology underpinning this assessment: the approach and assumptions used to characterize emissions, electrification, and costs including the premise upon which effective carbon prices have been calculated.

The findings are presented in four sections:

- Section 4.0 characterizes the emissions reduction targets that relate to alternatives that may require electrification;
- Section 5.0 estimates the demand for electricity that may arise from electrifying these emission reduction opportunities;
- Section 6.0 looks at the cost of the emission reduction options and estimates the carbon price that would enable implementation; and
- Section 7.0 considers the implications for provincial level management and governance required to cost effectively achieve the province's emission targets, including the importance of the associated prerequisite low-cost electricity.

Section 8.0 provides several recommendations to be incorporated into the 2017 LTEP consultation process and also identifies further work that could better inform it, including the second report from Phase 2 of this study.

Acknowledgements of those who supported this study are provided 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.

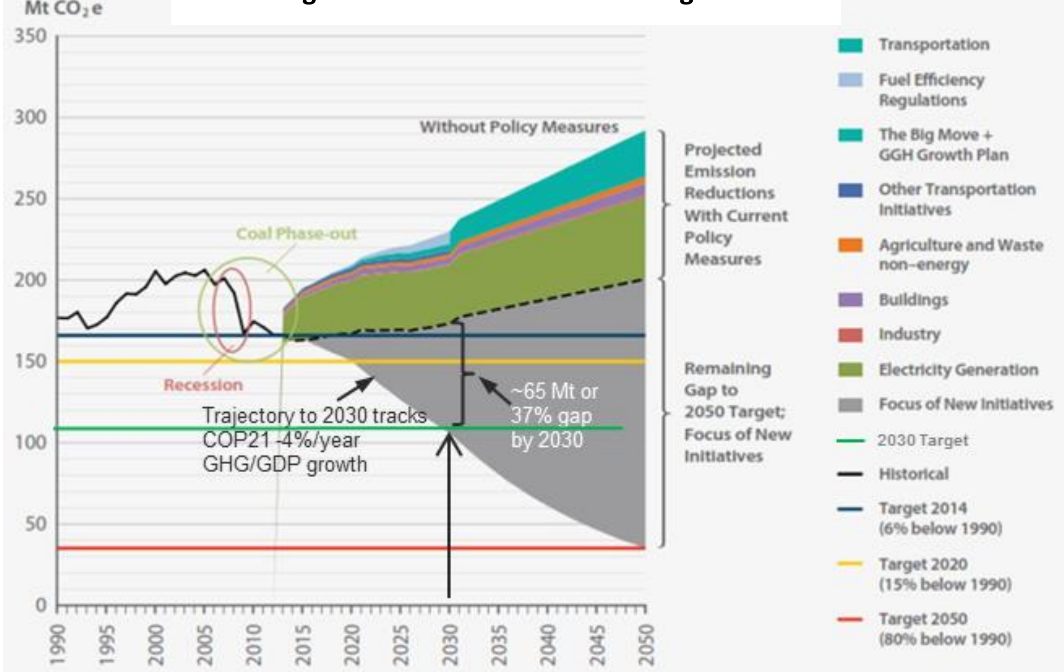
2.0. Background

To set the context under which the emission reduction initiatives have been identified and evaluated in this report, this section provides background on the emissions targets set by Ontario's Ministry of Environment and Climate Change (MOECC), the expectations of the C&T Program and the CCAP, and how energy is used in Ontario.

2.1. The MOECC's Climate Targets

The MOECC issued Ontario's Climate Change Strategy in the fall of 2015 prior to the COP21 meeting in Paris, France. Ontario's climate strategy identified the emission reduction targets shown in Figure 1. This included a new 2030 target to achieve emission reductions to 37% below 1990 levels.

Figure 1 – Ontario's Emission Targets

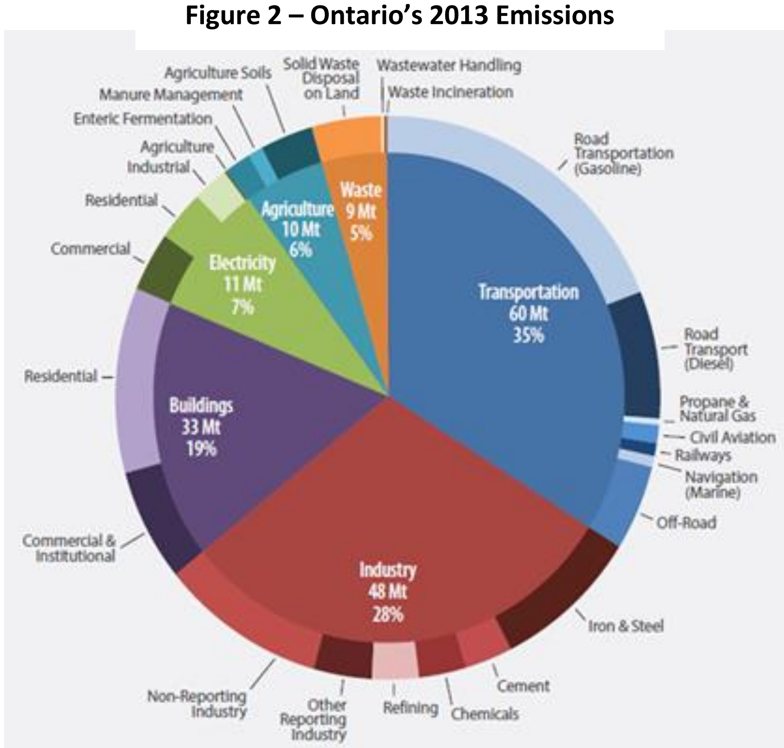


The Ontario Government's participation in the COP21 discussions was underpinned by these provincial targets. The COP21 event resulted in a global agreement on the approach to greenhouse gas emission (GHG) reductions. An annual GHG/GDP growth ratio of -4%/year to 2030 is a primary criterion used to set global emission reduction targets. At the global level, this criterion leads to an emissions target in 2030 that remains above global 1990 levels. Intended Nationally Determined Contribution (INDC) efforts communicated in Paris are recognized as being insufficient to avoid global disaster[2]. These post-2020 climate actions or INDCs were developed by each country following the COP21 agreement in 2015.

Since the COP21 agreement, Ontario has legislated a 2030 provincial emission reduction target to achieve 37% below 1990 levels[3]. This objective appears to be more aggressive than most of the INDCs, but aligns with the globally required target to maintain a ratio of GHG emissions growth divided by GDP growth of -4%/year to 2030.

Figure 2[4] shows the summary of provincial emission levels in 2013 for each sector of the economy as presented in the MOECC's Climate Strategy. The Transportation, Industry, and Buildings sectors are the largest contributors to this province's emissions.

Figure 2 – Ontario's 2013 Emissions



Heating and transportation are generally viewed as the low hanging, near-term fruit. The Building and Transportation sectors are also candidates for efficiency improvements and technology substitutions.

[2] Werksman, EU Climate Policy, 2016
[3] Bill 172, Climate Change Mitigation and Low-carbon Economy Act, 2016
[4] MOECC, Ontario's Climate Change Strategy, 2016

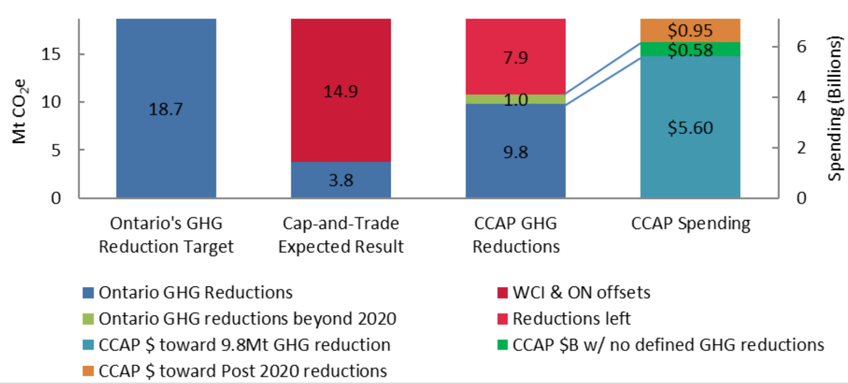
2.2. Expectations of the Cap and Trade Program and the Climate Change Action Plan

Both the C&T and CCAP programs currently focus on achieving the 2020 emission targets, while the post 2020 objectives do not appear to be addressed in any of the materials researched for this study. Ontario's 2020 emissions reduction target is 18.7 Mt. The MOECC initiatives outlined to date are not expected to achieve this near-term target.

For example, the MOECC's economic study[5] shows that Ontario's C&T program is expected to achieve only 3.8 Mt of emission reductions within Ontario by 2020 (20% of the target). As Figure 3 illustrates, this leaves 14.9 Mt of emission allowance to be purchased from other jurisdictions. The expected cost of these purchase allowances by Ontario GHG emitters is $250-$300M per year[6]. It is expected that Ontario's natural gas and gasoline distributors will be the primary buyers of these allowances as they manage the majority of the emitting fuels in the province. Consumers will pay these costs at the pump and on their natural gas bills.

Figure 3 – 2020 Cap and Trade and CCAP GHG Reduction and Associated Spending

(Mt CO_2e and $ Billions)



The CCAP[7] sets out to use $5.6 billion from the Greenhouse Gas Reduction Account (GGRA) to achieve approximately half (9.8 Mt out of 18.7 Mt) of the required emission reductions by 2020, as shown in Figure 3. CCAP spending of $0.95 billion is expected to contribute to emission reductions beyond 2020. An additional CCAP spending of $0.58 billion has no defined GHG reduction target. Assuming this budget can achieve the same $/tonne emission reduction as the first $5.6 billion in spending, this analysis suggests an additional 1 Mt of emission reductions may be achievable by effectively using the GGRA funds by 2020. The implication is that Ontario will need an additional 7.9 Mt of emissions reductions to meet the 2020 target.

[5] Dillon Consulting, Impact Modelling and Analysis of Ontario Cap and Trade Program. 2016
[6] ICF International, Ontario Cap and Trade, 2016
[7] MOECC, Ontario's Five Year Climate Change Action Plan, 2016

This suggests that the C&T and CCAP initiatives will not achieve the desired emissions reductions within Ontario by 2020. It is not clear if Ontario intends to reduce emissions within the province, or if policy makers consider that the purchase of allowances from other jurisdictions in support of their emission reductions is an acceptable way to meet the 2020 reduction target.

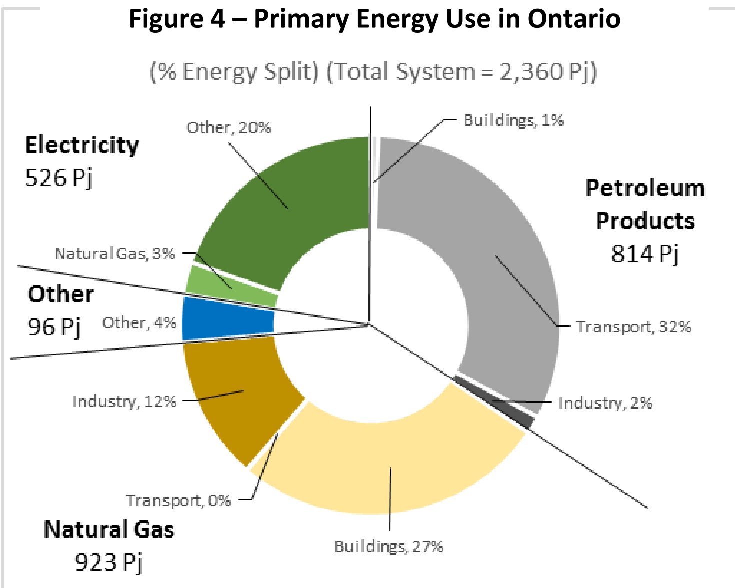
Given these uncertainties within the current MOECC climate initiatives, this study has been commissioned to help inform how the 2030 emission targets can be achieved, the costs of doing so, and any implications relating to Ontario's current LTEP process.

2.3. Ontario's Energy Use

Sector emissions are primarily driven by the fossil fuels each consumes. Assessing the nature of the fuel use in each sector can help with the evaluation of the potentially available technology option for reducing emissions. There are various sources of energy used in Ontario, each leveraged differently by the respective sectors. Figure 4[8] shows that there are three main sources of energy used in Ontario:

- Electricity (23%) – 20% of the 23% is from non-carbon emitting sources;
- Petroleum products (35%); and,
- Natural Gas (39%) – note an additional 3% of primary energy is used in natural gas-fired generators to produce electricity.

Figure 4 – Primary Energy Use in Ontario



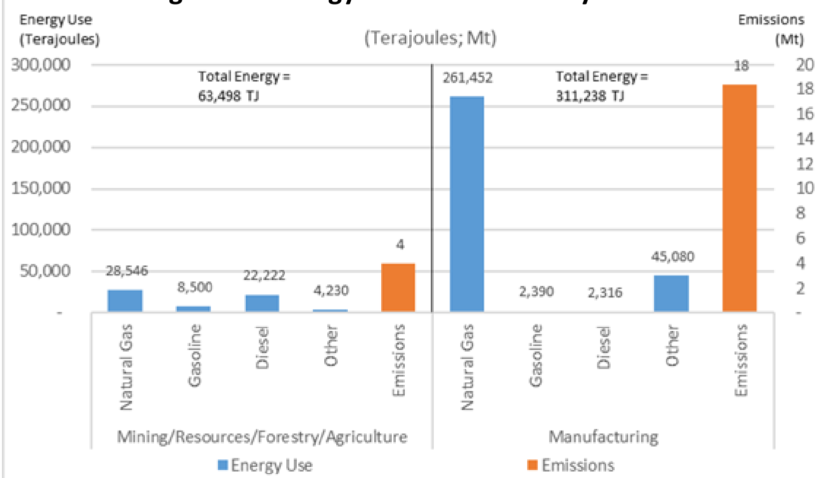
The total primary energy of 2360 Petajoules (PJ) includes the use of fossil fuels where 923 PJ (plus 71 PJ for electricity) are provided by natural gas and 814 PJ are provided by petroleum products.

[8] Statistics Canada, Report on Energy Supply and Demand in Canada, 2014

Petroleum products (gasoline and diesel) are mostly used in the Transportation sector, which represents 34% of Ontario's emissions. Natural gas supplies most of the energy to buildings and industry which in turn represent 19% and 28% respectively of the emissions in Ontario (shown in Figure 2).

Figure 5 illustrates the breakdown of energy consumption within the Industry sector and that natural gas is this sectors largest source of energy, with 90% of it being used in manufacturing. However, the 18 Mt of fuels related emissions represent only ~35% of the emissions from Industry. The remaining 30 Mt are related to emissions from industrial processes.

Figure 5 – Energy Use in the Industry Sector



Focussing on the largest sources of emissions, this study has prioritized the following areas for assessment:

- Buildings, where emissions are primarily related to the use of natural gas for heating;
- Transportation (gasoline/petroleum); and,
- Natural gas options that may also impact manufacturing, agricultural and waste sector emissions.

2.4. Summary

Ontario has legislated that provincial emissions must decrease to 37% below 1990 levels by the year 2030. The largest sources of emissions in Ontario in 2013 are the Transport, Buildings, and Industry sectors. These sectors are the focus for emission reduction opportunities in this study. The source of emissions stems from the use of (1) natural gas, primarily by Buildings and Industry, and (2) petroleum used primarily in Transportation.

3.0. Methodology

To better characterize Ontario's climate change challenge, this first phase of the study developed an estimate of the future cost of reducing Ontario's emissions, the associated dynamics impacting carbon pricing, and the implications that LTEP choices for the electricity system may have on these total costs. To provide these results, this study focused on the following five objectives:

- Identify the emissions reductions in each sector that are required to meet the 2030 targets;
- Gather insight on options to reduce emissions that may require electrification, and estimate the emission benefits, electrification required, and costs of those options;
- Aggregate the provincial level demand for electricity and implications on new generation;
- Estimate the carbon price required to enable options as an economic choice for Ontarians; and,
- Estimate the total cost to Ontarians of achieving the emission reductions and the sensitivity of that cost to the incremental cost of electricity.

To achieve these objectives, several assumptions, data gathering, and analytical methods were employed. The assumptions and methods were heavily influenced by the options identified for reducing emissions. The source for identifying emission reduction options forms the main content of this section. The methodology applied by this study is described through the following topics:

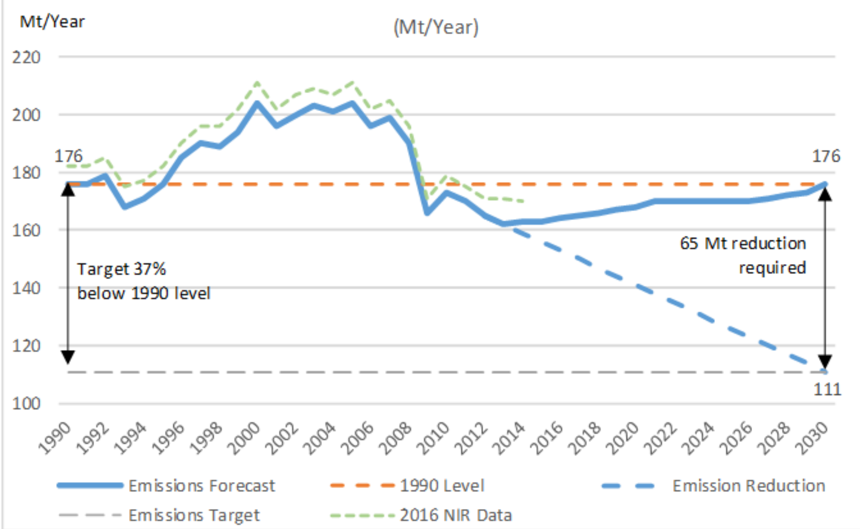
a) Overview of future emissions expectations, those addressed by this study, and relationship with the FTR;
b) Energy efficiency improvement assumptions not requiring electrification;
c) Emission reduction alternatives in Buildings, Transportation and Industry, and the electrification estimation approach;
d) Assumptions for costing of alternatives;
e) Method for calculating carbon price; and,
f) Approach to characterizing the C&T related economic implications for consideration by the LTEP.

3.1. Overview of Future Emission Expectations

The overall 2030 emissions expected for Ontario under a BAU case are based on the MOECC's 2014 Ontario Climate Change Update (based on 2012 data, the most recent which was contained in the 2014 National Inventory Report). In the Climate Change Update, the MOECC provided emission projections to 2030 that were based on the 2012 data actuals. The analysis in this study used this 2030 forecast as the reference case. The MOECC's forecast has been replicated in Figure 6[9], with the targeted emission reductions identified.

[9] MOECC, Ontario's Climate Change Update, 2014

Figure 6 – MOECC Ontario Emissions Forecast



Ontario's forecasted emissions for 2030 are similar to those realized in 1990. To meet the 2030 reduction target, Ontario must reduce its total forecast 2030 emissions by that same 37%, which represents a 65 Mt future reduction in annual emissions.

The 2016 National Inventory Report[10] (NIR) highlights differences in the data used in the MOECC's Update. The 2016 NIR contains data to 2014 and restated 2012 data. The 2013 data is now reflected in the current Ontario Climate Strategy materials, which are available on the Ontario government's website. These 2013 values are consistent with the 2016 NIR. Although the 2012 data has been restated, MOECC's emission forecast has not been updated.

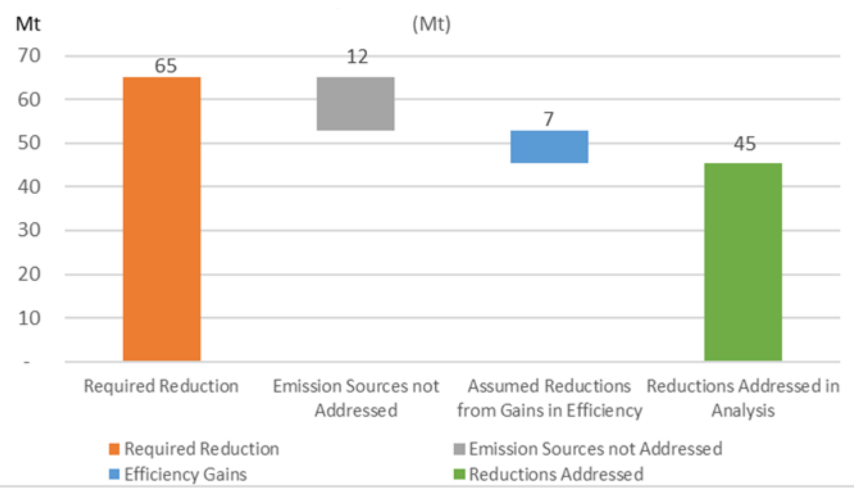
For the purpose of this study, the 2030 forecast obtained from the original 2012 data used by the MOECC has been adopted as the reference from which emissions must be reduced. This is likely a conservative assumption, given that Strapolec's analysis suggests that, had the higher 2012 restated emissions data been used in the 2014 MOECC Update, the future BAU emissions would now be higher than previously forecast. This means the forecasted electrification contained in this report may be marginally lower than what is potentially needed.

Emissions sources were analyzed to identify potential electrification needed to achieve the emission targets. The targeted emissions for Buildings and Transportation were determined using a top down assessment requirement to achieve 37% below the 1990 emission levels in each sector. For Industry, the approach was based on opportunities and ideas identified through the literature reviews conducted by Strapolec. Figure 7 illustrates the overall scope of this analysis. The targeted 65 Mt of emission reductions are categorized as either not addressed (12 Mt), addressed by efficiency improvements through actions such as the introduction of additional codes and standards (7 Mt), or emission reductions that may be

[10] Environment Canada, National Inventory Report, 2016

achieved via alternative technologies that can potentially increase the demand for electricity (45 Mt). The latter is the focus of the following analysis.

Figure 7 – Emissions Addressed in Study



With the focus on Buildings, Transportation, and Industry use of natural gas, 12 Mt of the required emissions reductions are not assessed by this study. It is assumed that this gap can be addressed by other strategies, as discussed in Section 3.1.1. Seven Mt of reductions are assumed to be achieved through additional efficiency improvements in Buildings and Transportation beyond the BAU assumptions. These innovations in efficiency improvements are assumed to not have electrification implications.

3.1.1. Excluded Emission Areas

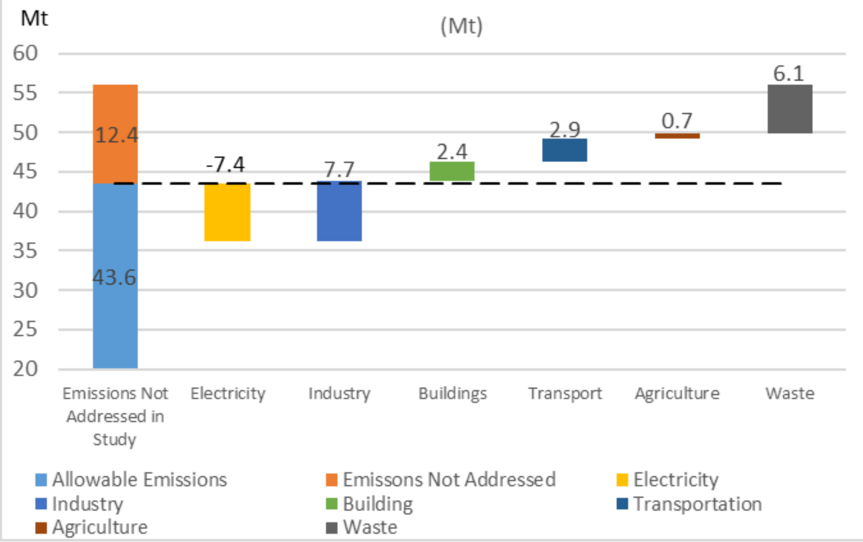
Figure 8 illustrates the emissions excluded from this study's scope:

- Agriculture, industry, and waste sectors;
- Air, rail, marine and other transport fuels beyond gasoline and diesel;
- Buildings use of oil, propane etc.; and,
- Electricity production.

Of particular note is the benefit that is accruing to the province from the reduction in emissions that have come from the coal generation phase out enabled by the return to service and the increased performance of Ontario's nuclear fleet[11]. The 7.4 Mt of reduced electricity system emissions can be used to offset emission reductions required from the remaining sectors. Achieving further reductions from the electricity sector may be challenged by new demand for electricity, and the time that that it may take to secure new sources of low-carbon electrical generation. This topic will be addressed in the Phase 2 report from this study.

[11] Strapolec, Extending Pickering Nuclear Generation Station Operations, 2015

Figure 8 – Emission Sources Excluded from Analysis



The category "Allowable Emissions" is the cumulative level of emissions allowable in these sectors after removing the 12.2 Mt required to meet the provincial emission target. Adding the 43.6 Mt of allowable emissions to the post-reduction emission levels of the sectors analyzed yields the provincially mandated 111 Mt of remaining emissions in 2030.

It is possible that additional electrification implications could result from emission reduction strategies for the sectors not assessed. Electrification forecasts in this study may be conservatively low.

3.1.2. Assessment of the Fuels Technical Report Emission Forecast

According to the 2016 NIR, the 1990 emissions level from energy fuels was 107 Mt. Applying the 37% target reduction criteria suggests the 2030 emissions target for energy fuels should be approximately 67 Mt.

The FTR projects a relatively flat BAU annual emissions forecast of approximately 120 Mt/year out to 2035. This profile is similar to that included in the MOECC's 2014 Climate Update. By 2035, which is the planning horizon for the FTR and the OPO, the most aggressive FTR emission reduction scenario, Outlook F, projects a 39% reduction to achieve 75 Mt from the forecasted BAU 2035 emission level, 10 Mt short of the 2030 target implied by the assumptions of this study.

In 2030, the FTR forecasts emissions for Outlook F of 87 Mt from fuel use. This is ~ 20 Mt higher than the ~67 Mt target inferred from a 2030 fuel sector target of 37% below 1990 levels.

A shortfall of 20 Mt at a carbon price of $100/tonne could cost Ontario ~$2B/year in externally purchased emission allowances, unless the reduction gap is made up from agriculture, waste, the electricity system, and industrial processes. This would be a difficult added challenge to these sectors which have their own emission growth forecast in the 2014 MOECC Update and hence must work to achieve their own reductions.

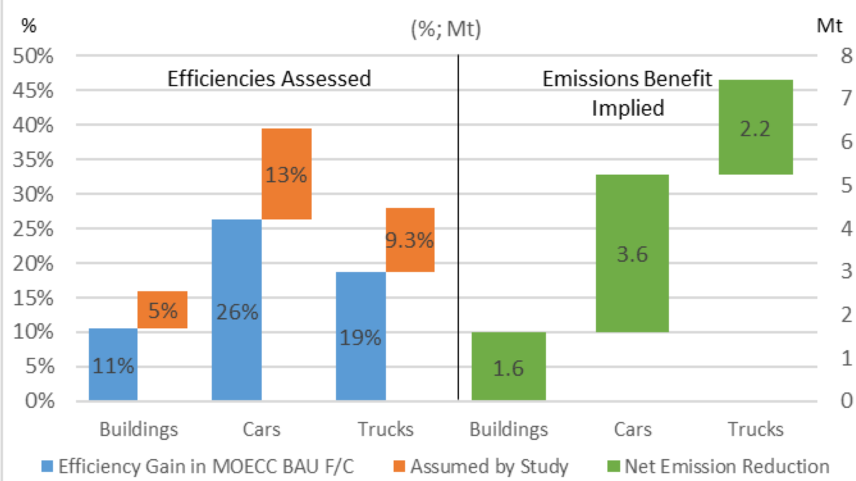
In contrast to the FTR, the unaddressed emissions described earlier in this study are 12 Mt.

3.2. Energy Efficiency Improvement Assumptions Not Requiring Electrification

The BAU efficiency improvements are based on the forecast from the MOECC's Update, in combination with the economic assumptions in the 2013 LTEP data tables and the recent 2016 OPO data tables. Efficiency improvement assumptions appear to be optimistic and aggressive.

Prior to assessing emission reduction solutions that may involve electrification, assumptions about what plausible energy efficiency initiatives could achieve have been applied to the Buildings and Transportation sectors. A simple approach has been adopted that involves assessing the status quo efficiency assumptions that are inherent in the BAU forecasts and then increasing these trended values by an additional 50%. Figure 9 illustrates the results of this approach.

Figure 9 – Emissions Avoided by Efficiency Gains



Based on the resulting trend analysis, the emissions model developed for this study assumes that 7.4 Mt of emissions will be removed though efficiency improvements: 1.6 Mt from the building sector, 3.6 Mt from passenger vehicles, and 2.2 Mt from trucks.

This is premised on optimistic efficiency induced emission reduction achievement forecasts, so as to provide a conservatively low electrification forecast. The objective of these assumptions is not to be "exact" but to identify areas that warrant serious consideration during the LTEP consultation process. Aggressive efficiency assumptions underscore the importance of considering the remaining options.

3.3. Identifying Alternatives and Electrification

Research was conducted to identify the concepts and ideas being put forward by Ontario stakeholders to achieve emission reductions. Table 1 represents a list these from major stakeholders and categorizes them as either energy solution providers, consumers, or interest groups. These organizations were chosen based on their involvement in Ontario's electricity sector and their size and the availability of recent publications regarding Ontario's C&T program, the MOECC's CCAP, and the 2017 LTEP.

Table 1 – Organizations Used as Sources for Ideas in this Study

Energy Solution Provider /Transmitters/ Distributers	Energy Consumers	Interest Groups
Association of Power Producers of Ontario (APPrO)	Association of Major Power Consumers of Ontario (AMPCO)	Canadian Environmental Law Association (CELA)
Canadian Biogas Association (CBA)	Association of Municipalities Ontario (AMO)	Clean Economy Alliance (CEA)
Canadian Electricity Association (CEA)	Building Owners and Managers Association of Canada (BOMA Canada)	Clean Energy Canada
Canadian Energy Efficiency Alliance (CEEA)	Business Council of Canada (BCC)	Environmental Defence
Canadian Gas Association (CGA)	Canadian Manufacturers and Importers (CME)	Greenpeace Canada
Canadian Nuclear Association (CNA)	Canadian Vehicle Manufacturers' Association (CVMA)	Ontario Clean Air Alliance (OCCA)
Canadian Solar Industries Association (CanSIA)	Ontario Chamber of Commerce (OCC)	Ontario Sustainable Energy Association (OSEA)
Canadian Wind Energy Association (CanWEA)	Ontario Home Builders' Association (OHBA)	Ontario Society of Professional Engineers (OSPE)
Electricity Distributors' Association (EDA)	Ontario Road Builders' Association (ORBA)	Ontario Trucking Association (OTA)
Decentralized Energy Canada (DEC)	Toronto Atmospheric Fund (TAF)	Pembina Institute
Energy Storage Ontario (ESO)		Pollution Probe
Ontario Energy Association (OEA)		Toronto Environmental Alliance (TEA)

Ontario Petroleum Institute (OPI)		
Ontario Waterpower Association (OWA)		

Materials on their websites were reviewed to identify their ideas regarding climate change in Ontario. Specific attention was given to energy consumers and their ideas for reducing emissions. As illustrated in Figure 10[12], energy consumers were found to be interested in topics such as GHG emissions, climate policy, C&T, the economy, costs of energy related solutions, investments needed, and sectors such as Transportation, Buildings, and Manufacturing. Stakeholders materials also contained options and ideas for reducing emissions in Transportation, Buildings, and through the use of alternative fuel options. These are summarized in Table 2.

Figure 10 – Energy Consumer Communicated Priorities

[12] Graphic was made by conducting a scan of what key energy sector players discuss in their publications and creating a word cloud based on the number of times each word was mentioned in their documents. The larger the word appears, the more it was mentioned.

Table 2 – Ontario Stakeholder Emission Reduction Ideas		
Transportation	**Buildings**	**Alternative Fuels**

• Biofueled vehicles
• Cycling and walking
• Electric vehicles
• Hydrogen fueled vehicles
• Natural gas fueled vehicles
• Increasing efficiency
  o Hybrids
  o Plug-in hybrids
  o Replacing old vehicles
	• Increasing efficiency through retrofits:
	  o New boilers
	  o Insulation
	  o Lighting
	  o Smart thermostats
	  o Stoves
	• Heat pumps (air & ground)
		• Biofuels
		  o Cellulosic
		  o Non-cellulosic
		• RNG
		• Power to Gas

In the Transportation sector, energy stakeholders are interested in the use of cleaner fuels such as electricity, hydrogen, biofuels and natural gas to replace conventional fuels used in compact cars, trucks, buses, and rail. In addition, there is interest in efficiency improvements via the replacement of old vehicles with newer, more energy efficient models, and by increasing the number of hybrid and plug-in hybrid vehicles (PHEVs).

In the Buildings sector, stakeholders focussed on increasing efficiency through retrofits such as improving insulation, installing newer and more efficient boilers, lighting, stoves, and smart thermostats to allow for better temperature control and demand management. It is also expected that switching from fossil fuel sourced space heating to air source heat pumps (ASHP) and ground source heat pumps (GSHP) will contribute to emission reductions in both residential and commercial buildings.

Another emission reduction option is to use alternative fuels for energy production. This includes Renewable Natural Gas (RNG) and mixing it with the current natural gas supply, cellulosic and non-cellulosic biofuels, and Power to Gas (P2G) solutions involving hydrogen that can be stored and used when needed.

The outcomes of this literature scan guided the scope of this project in selecting alternatives whose emissions, electrification, and costs could be quantified to provide a perspective on how climate change initiatives may impact the 2017 LTEP.

Specific ideas pursued in this study are discussed in the following sections.

3.3.1. Buildings

Research by the Ontario Society of Professional Engineers (OSPE)[13] was used to identify available applications for reducing emissions in the Buildings sector. Alternative technologies include electric resistance heating, ASHP and GSHP, and electric water heaters. Data on the characteristics of these devices, primarily the efficiency ratings, were obtained from Natural Resources Canada (NRCan) and the U.S. Energy Information Administration (EIA), as were the characteristics of new and existing natural gas furnaces and water heaters. The EIA also maintains forecasts for the efficiencies of future equipment. The Strapolec team integrated these future estimates with the NRCan data to produce the results used in this study.

NRCan household data on the existing use of devices in Ontario was used to calculate the electrification and emission reduction benefit. It was assumed that the incremental electricity generation created to meet the new decarbonisation driven demand will itself be zero emission. Both of the OPO Outlook Scenarios, D1 and D3, include the development of new clean generation[14].

3.3.2. Transportation

There are a number of pathways that may contribute to achieving emission reduction targets in the transportation sector in Ontario. These include:

- Improving the efficiency of vehicles, including hybrids;
- Introducing alternative fuel vehicles: Natural Gas Vehicles; Electric Vehicles (EVs); Hydrogen Fuel Cell Electric Vehicles (FCEVs); and
- Introducing alternative fuels such as renewable diesel.

There are two distinctly different segments within the transportation sector.

a) Light duty or passenger vehicles
b) Heavy duty (HD) trucks

a. Light Duty or Passenger Vehicles

Three passenger vehicle options are evaluated in this study: Natural gas conversions; Electric vehicles; Hydrogen vehicles.

The U.S. Department of Transportation statistics on emission differences between vehicle types were used to estimate the potential emission reduction benefits of natural gas vehicles.

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[13] OSPE, Ontario's Energy Dilemma, 2016
[14] IESO, Ontario Planning Outlook, 2016

Data on EVs was obtained from Plug'N Drive, which has collected a substantial catalogue of information about available vehicles and their characteristics, including average emissions saved and electricity consumed. These sources provided the foundation for this emissions and electrification analysis.

The analysis also used information on hydrogen vehicles from the U.S. National Renewable Energy Laboratory (NREL). As the FCEV technology and hydrogen production are both developmental technology pathways, the NREL forecasts of future efficiencies and costs enabled the cost comparisons for what may be relevant by the late 2020s when the new electricity generation may be available.

b. Heavy Duty/Trucks

The HD vehicles segment consists of two types:

- Short range vehicles such as off road, busses, local delivery and refuse vehicles which represent the rest of the diesel transportation emissions; and
- Class 8 long distance road transport vehicles (tractor trailers), which are assumed to represent 20% of the road emissions.

The HD vehicle sector is considered to be a significant emission reduction challenge. Four options are evaluated in this study for heavy vehicles: Renewable diesel; Natural gas conversions; Hybrid vehicles; and Hydrogen vehicles.

The FTR places significant emphasis on bio and renewable diesel to support emission reductions. However, the FTR states that bio-diesel's primary role is as a blending additive. The current plans to increase the additive requirements from 2% to 4% are considered in this study to part of the overall emissions reduction goals of ICE vehicles which are discussed in Section 4.0. The 4% goal will require about 500 million liters per year by 2035, which according to the Canadian Canola Growers' Association, is all of Canada's total potential production of both bio or renewable diesel from tallow, yellow grease, canola, and soy[15]. Current and planned production capacity in Ontario for bio-diesel is about 300 million litres/year[16]. This study has assumed no electrification implication from bio-diesel and therefore does not consider it further.

Renewable diesel, on the other hand, is more of a direct substitute for current diesel consumption and as such may have the potential for greater emission reductions than bio-diesel. As with bio-diesel, there are concerns regarding the availability of available feedstock for the production of renewable diesel. There are no existing renewable diesel plants in Canada. The FTR report assumes it will be imported primarily from the U.S.

Research shows that natural gas, plug-in hybrid trucks, and hydrogen powered trucks may all be options to achieve a lower emission short-range fleet. The impetus for identifying plug-in hybrids as a potential

[15] Natural Resources Canada, Study of Hydrogenation Derived Renewable Diesel as a Renewable Fuel Option in North America, 2012.; Strapolec analysis

[16] Navigant Consulting, Fuels Technical Report, 2016

option has arisen from research on a company called WrightSpeed, that offers such solutions[17] commercially. Hydrogen fuel cell buses, fork lifts, and rail applications are being adopted today.[18]

The Class 8 fleet options include natural gas, conventional hybrids being developed in the U.S. SuperTruck program, and hydrogen vehicles. Hydrogen vehicles are deemed to be potentially impractical and expensive, but are evaluated in this study as sufficient cost data is available to illustrate the carbon price implications for making this option economic.

A Discussion of Hydrogen in Transportation

The recent FTR did not mention any substantive benefits of hydrogen use. The primary reason cited by the FTR is that hydrogen is currently produced from natural gas and as such offers no emissions reduction benefit. This study examines the potential for hydrogen manufactured in Ontario through electrolysis. Given Ontario's carbon-free supply mix of hydroelectric, nuclear, wind and solar. Using electricity for hydrogen production is therefore a real possibility for the province and Canada as it represents a unique and significant potential emission reduction strategy. The opportunity that hydrogen vehicles present for Ontario is not addressed in the FTR.

The production process for making renewable diesel requires hydrogen. The FTR assumes that renewable diesel would be imported, e.g., from the United States. Given the emissions profile of the energy system in the United States, renewable diesel will not be emission-free. If renewable diesel is manufactured in Ontario, it will require electricity to produce the necessary hydrogen, unless natural gas is used in the Steam Methane Reforming (SMR) process. Using natural gas to produce hydrogen feedstock for renewable diesel would decrease emission reductions.

Finally, there are unaddressed emission reductions in both this study and the FTR. Hydrogen production and renewable diesel may be synergistic, particularly in the long-term as emissions reductions must continue to accelerate to meet Ontario's targets.

3.3.3. Industrial Sector

Several emission reduction opportunities related to natural gas were identified that are not specific to buildings. They have been grouped under the general classification of Industry. This grouping enables the targeted emissions and business cases for the building emission reductions to be done in isolation without incurring any double counting of emissions reduction estimates.

Four innovations were identified during the research phase that relate to the potential reduction of emissions from natural gas applications:

- RNG production from waste streams;

[17] Wrightspeed Powertrains, The Route Powertrain, 2016
[18] Hydrogenics interviews

- Hydrogen blending into the natural gas pipeline delivery system, referred to as P2G;
- Using electrolysis to displace the SMR process currently used to produce hydrogen from natural gas; and,
- Substitution of electricity for some natural gas applications in the industrial sector.

Renewable Natural Gas

RNG production reduces GHGs emitted to the atmosphere from several waste sectors in Ontario, primarily agricultural (manure & crop residues) and landfills but also includes source separated organics (SSO), municipal solid waste (MSW), and waste water treatment plants (WWTP). The literature has identified two distinct processes for the creation of RNG: Anaerobic Digestion (AD); and Gasification[19].

Only AD processes are addressed in this study. AD technology is available and is already used in North America. The technology for gasification is not included in this study as it is not well established and requires further development. Interviews with agricultural stakeholders also suggest that the gasification process may involve accessing carbon sources that have already been sequestered and/or could be used in alternative ways such as for fertilizer.

Research for this study surfaced several concepts related to synthetic natural gas; however, no costing information was available. The processes for gasification and synthetic natural gas both require the availability of low emission production and process capabilities for hydrogen and carbon capture[20]. These are expected to require electrification and incur additional costs to reduce emissions.

These opportunities have not been fully explored in this study due to lack of available data but may be relevant to Ontario’s emission reduction future, particularly if a low emissions hydrogen economy develops. These options could be among the potential solutions to Ontario’s long term emission reduction path to 2050.

Hydrogen blending into the natural gas system, also referred to as P2G

The P2G concept is designed to produce hydrogen for the purpose of blending it into the natural gas pipeline delivery system. P2G has two benefits:

- Reduces the emission content of the natural gas system; and,
- Uses hydrogen as an energy storage mechanism that stores electrical energy in hydrogen gas that can then be delivered by the natural gas pipeline system when needed.

The intent is to utilize electrical energy at optimum times, i.e. when relative demand and the cost of the electricity is lower, store the energy in the form of hydrogen and then deliver that energy through the natural gas network at periods of high natural gas demand, such as for meeting winter heating demand.

[19] Alberta Innovates, Potential Production of Renewable Natural Gas from Ontario Wastes, 2011

[20] Synthetic Natural Gas (SNG): Technology, Environmental Implications, and Economics, Climate Change Policy Partnership, Duke University, January 2009

Conceivably, this function could offer daily, weekly and seasonal smoothing benefits for meeting electricity system demand.

Electrolysis alternative to the SMR process for hydrogen production in refineries

SMR is currently used in Ontario's refineries to produce hydrogen from natural gas. Hydrogen is a necessary feedstock for many processes at a refinery. Substituting lower emitting technologies for hydrogen production can reduce the emissions from this non-energy use of natural gas. In this study, electrolysis is examined as an alternative.

Industry electrification of 10% of natural gas use

As with buildings, it is assumed that some of the industrial natural gas applications may be candidates for electrification.

3.3.4. Approach to Estimating Provincial Electricity Demand and Implications

The potential incremental provincial level demand for electricity arising from a range of electrification options can be computed by allocating a proxy market share for each of the various sectors. For example, if all electrical heating options envisioned for commercial buildings were assumed to be introduced in equal proportion until the targeted emissions were achieved, the total amount of required electricity could be estimated for that scenario. This is the approach employed for this electrification implication analysis.

3.4 Assumptions and Sources for Costing Alternatives

Data from the U.S. EIA was utilized for the estimated installed costs of all the devices examined for the electrification of building space and water heating. The dollar values were converted to Canadian currency based on an historical long-term exchange rate of 1.15[21].

The study assumes that all capital expenditures by residential consumers are financed over the expected life of the device using a 5% interest rate. A pre-tax interest rate of 14% was assumed for commercial investments.

The cost of electricity was assumed to be $180/MWh, all in, for class B consumers and $65/MWh for transmission (Tx) connected Class A industrial users. These values are based approximately on the OPO average unit cost of electricity of $140/MWh for 2030[22], for all scenarios, and the average cost of electricity today. Residential and commercial rate payers (Class B) pay more per MWh due to the process for calculating the Regulated Price Plan (RPP) and the additional costs for distribution that direct Tx connected customers do not incur. The use of common pricing assumptions for all options reflects a

[21] Strapolec analysis prepared for "Extending PNGS Operations: Emissions & Economic Assessment"
[22] IESO, Ontario Planning Outlook, 2016

presumption that, at the aggregated provincial level, the total costs of new generation obtained for the purpose of supplying emission reduction initiatives should be recovered by the economics of those aggregated initiatives. This is a simple "matching principle" inherent in accounting practices. Special pricing alternatives that cause some Ontarians to subsidize others are not addressed in this study.

The cost of natural gas delivered to homes and businesses was assumed to be $10.50/mmBtu, reflecting a Henry Hub price of $5 US per EIA forecast to 2030[23], a US to Canadian dollar exchange rate of 15%, a 9% DAWN premium[24], and today's Enbridge delivery costs to residential consumers[25]. Note that gas distribution rates on a per mmBtu basis could increase with declines in volume. This has not been modelled in this study.

RNG parameters have been acquired from Ontario Energy Board (OEB) submissions by Enbridge and Union Gas[26].

Hydrogen production costs have been obtained from NREL[27]. A number of sources were referenced to obtain SMR costs[28].

Costing has nominally used 2016$ as the base. Some imperfections in alignment of the assumptions from different years have introduced small errors (eg. 2015 vs 2016). These deviations are not deemed material to the directional outcomes pursued by this study, given the low inflation rate environment that has been assumed.

3.5. Calculating Carbon Price

The effective carbon price is defined in this study as the price of carbon required to render the costs of alternatives as an economic choice for Ontarians. This effective carbon price is calculated from the difference in the total cost of installing and operating new devices/processes compared to the existing alternative or new fossil based devices/processes. The difference in cost is divided by the emissions saved to identify the effective carbon price that make the costs equivalent.

3.6. Emission Reduction Costs, C&T, and Economic Implications for LTEP Consideration

The economic implications addressed by this study are focused on the degree to which electricity generation choices may impact the cost of emission reduction. The objective is to assess the total cost to

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[23] U.S. EIA, Annual Energy Outlook, 2016
[24] Strapolec analysis prepared for PNGS Report
[25] OEB, Estimated Monthly Gas Bill, 2016
[26] Union Gas, Renewable Natural Gas Applications, 2011
[27] Ainscough, Hydrogen Production from PEM Electrolysis, 2014
[28] Miller, 11.0 Hydrogen Production Sub-Program Overview, 2015; Stoll, Hydrogen – What Are the Costs, 2000; Simbeck, Hydrogen Supply, 2002; NextHydrogen

Ontarians of achieving provincial emission reductions and the sensitivity of that cost to both the C&T program's use of proceeds, as well as the incremental cost of electricity.

Two areas of investigation were pursued to determine the total cost and timing of the emission reductions:

- The cost of new generation; and,
- The effectiveness of managing the use of the C&T proceeds.

With a detailed cost and emissions build up based on individual alternatives for carbon emissions, it is possible to adjust electricity costs to illustrate the impact on effective carbon price required to make the options economic. This can be aggregated to provide a provincial total.

The proceeds of a C&T program can be beneficial if investing these proceeds to reduce emissions ultimately lowers the market price of carbon and makes the consumer investments economic. Alternatively, the proceeds can act as subsidies for otherwise uneconomic options. This study calculates the sensitivity of the market carbon price costs to the reinvestment of the proceeds.

3.7. Point of Clarification on Outcomes Produced by this Report

The objective of this study is to establish a framework for estimating the broad implications of emission reduction on electrification and the price of carbon. It is not intended to provide guidance or opinion on the merits of individual solutions, nor which solutions may/should be adopted to a higher degree than others. In general, options have been assumed to be adopted by the market place in some proportional balance. Presenting the possible outcomes is intended to illustrate this "balanced" adoption. This includes the:

- Possible implications on the demand for the electricity system; and,
- A framework for assessing carbon price implications.

On balance, Strapolec has observed that the aggregated impacts on either the demand for electrification and/or the economic impact of the carbon price are relatively insensitive to specific assumptions regarding the market penetration of individual technologies. In other words, deciding how to price or cap carbon emissions matters more than deciding what technologies to favour.

3.8. Summary

In order to meet Ontario's 2030 emissions target of 111 Mt, 65 Mt of forecasted emissions need to be eliminated. Seven (7) Mt of emission reductions are expected to come from increased efficiencies in Ontario's main sectors. Another 45 Mt are expected to come from emission reduction technologies in the Transport, Buildings, and Industry sectors. Twelve (12) Mt of emissions have not been addressed in this study, and must be achieved from Ontario's remaining sectors.

The characteristics of the emission reduction options presented in this study are consistent with those in the OPO, FTR and associated source references. However, the FTR Outlook F emission reductions are 8 to 20 Mt short of the 2030 emission reduction target of 67 Mt for energy fuels (as compared to the 1990 level of 107 Mt).

- The FTR relies upon extensive penetration of renewable natural gas (RNG) as well as bio- and renewable diesel into Ontario's energy system. This study has modelled more modest expectations for RNG and bio and renewable diesel, primarily due to lack of readily available data on these fuels. The assumptions are not a comment on the potential viability or suitability of these options in supporting emission reductions.
- In contrast, this study evaluates several hydrogen-based alternatives not considered in the FTR. The FTR did not classify hydrogen as an emission reducing technology because it is currently produced from natural gas. This study includes several hydrogen options as hydrogen can be a 100% carbon free fuel if produced from Ontario's emission-free electricity generation.

Surveyed stakeholder materials have identified forty-five (45) opportunities for emission reductions in buildings, transportation and the natural gas system. These have been modelled as a sample portfolio to achieve 45 Mt of the legislated 65 Mt of emission reduction by 2030.

- The analysis presented here addresses only 75% of the required reductions. The remaining emission reductions are assumed to be achieved through efficiency gains (over 7 Mt) or some other means not assessed by this report (over 12 Mt).

Carbon prices are derived based on industry sourced cost estimates for the timeframe leading up to 2030 timeframe. The effective carbon prices are used in the context of the C&T program to estimate the cost of emission reductions to the provincial economy.

4.0 Characterizing Emissions Reduction Targets for Electrification Implications

This section describes the emission reductions objectives relevant to each sector being assessed. The first subsection starts with an overview of the emission reduction objectives for each sector and the criteria applied to establish them. The Buildings, Transportation, and Industry sectors are then each described in the ensuing subsections.

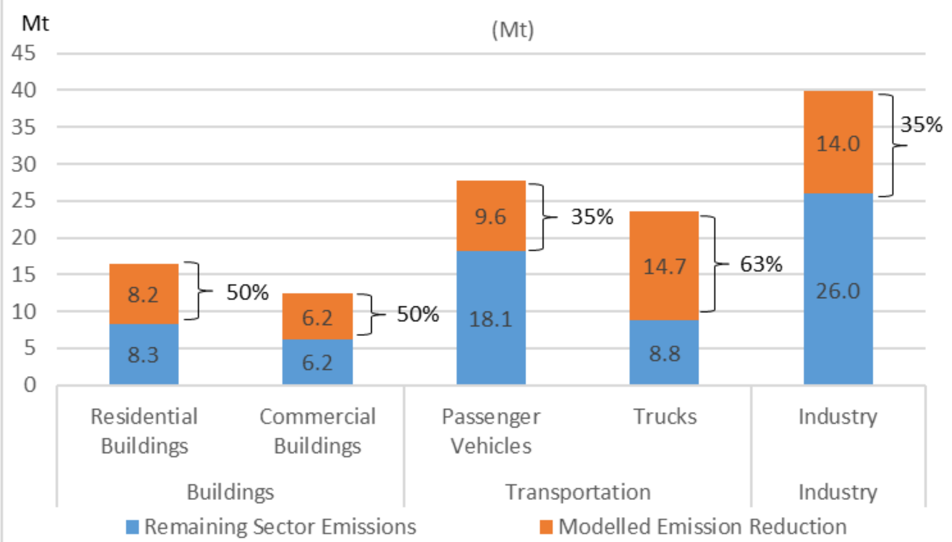
For each sector, the rationale for and the expectations assumed for emission reduction from efficiency improvements are provided. For each of the identified emission reduction options identified in section 3.0, the emission reductions objectives associated with electrification are defined.

This section closes with a summary of the key findings.

4.1 Overview of Emission Reduction Objectives

Figure 11 illustrates the emissions reduction objectives that are modelled to be achieved by the considered alternatives. Figure 11 summarizes the reductions required and the allowable emissions that can remain after the 65 Mt province level reduction objective is met.

Figure 11 – 2030 Target Emission Reduction by Sector



Two approaches were adopted for establishing the emission reduction objectives for this analysis.

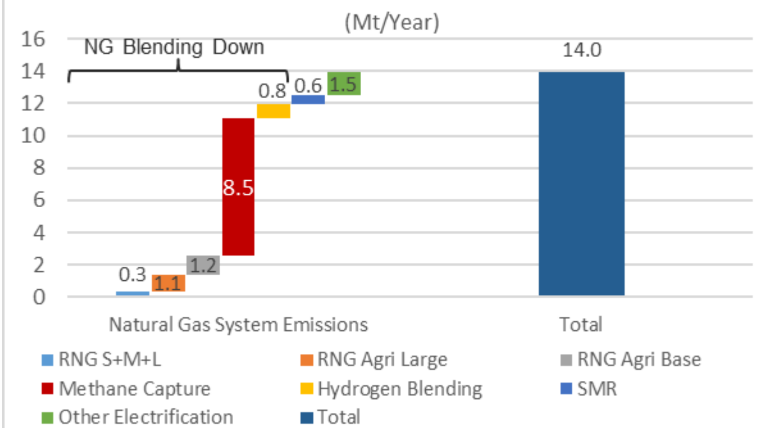
It is assumed the Buildings and Transportation sectors must each achieve by 2030 an emission level that is 37% below their respective 1990 levels. Since the BAU emissions are forecast to grow for these sectors, the future reductions required are greater than 37% from the BAU forecast:

- Buildings must reduce emissions by 50%; and,
- Trucks must reduce emissions by 63%.

The "Industry" category in this study pertains primarily to opportunities that reduce natural gas use in the province. Natural gas system emissions reductions were not derived from a target, but were examined based on the industry stakeholder ideas discussed earlier in Section 3.3.3. While it appears that the modeled emission reduction of 35% for Industry aligns with the 2030 target of 37% below 1990 levels, most of the emission reductions not assessed by this study are also required from the Industrial sector as described in Section 3.1.1. This "Industry" descriptor is loosely applied to recognize that none of the fuel "blending" assumptions for the natural gas system have been reflected in the Building assumptions. These emission reduction opportunities have all been credited in this study to the "Industry" targets, which should be interpreted to apply to all sectors where natural gas is used other than Buildings and Transportation.

The emission reduction potential for the natural gas displacement options attributed to industry are summarized in Figure 12.

Figure 12 – Natural Gas System Emission Reduction Options



Opportunities for emission reductions include:

- RNG production could reduce emissions from the following sources (up to 2.6 Mt):
  - Landfills (small, medium and large)
  - Large Agricultural operations (including large, aggregated and co-operative farms and also WWTPs)
  - Typical or Base reference agricultural operations (also includes SSOs, Industrial, and very small landfills)
- Methane capture from the production of RNG reduces emissions (~8.5 Mt)
- Blending Hydrogen into the natural gas system (<1Mt)
- Transitioning from the SMR process for hydrogen production to electrolysis (<1 Mt)
- Assuming that 10% of the use of natural gas in industry can be electrified (~1.5 Mt)

There are significant potential emission reductions associated with RNG. It should be noted that most of the emission reductions result from methane capture, and not from the displacement of natural gas with

RNG in the distribution system. While all of the methane capture related emission reductions are potentially achievable, some of them may be achieved through other initiatives that are independent of RNG.

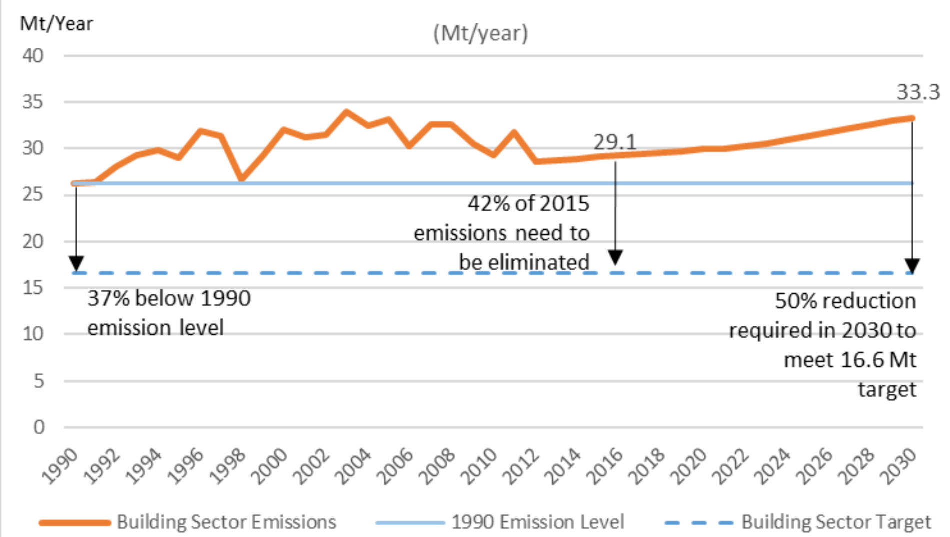
Clearly, there are different options for the sectors to reduce their emissions at different rates. The targets are an assumption made in this study to facilitate electrification estimates. As a result, these assumptions should not be interpreted as guidance on what will or should take place for any particular alternative discussed.

The following subsections address the specific emission reduction assumptions derived for each of the priority sectors, including the assumptions for emissions reductions achieved by efficiency improvements.

4.2. Building Efficiency and Alternatives Emission Reduction Objectives

Figure 13 shows the 2014 MOECC Update emissions forecast for Buildings. It indicates that a 50% reduction in emissions is required from the buildings sector in order to meet the target as a sector.

Figure 13 – MOCC Building Sector Emission Forecast



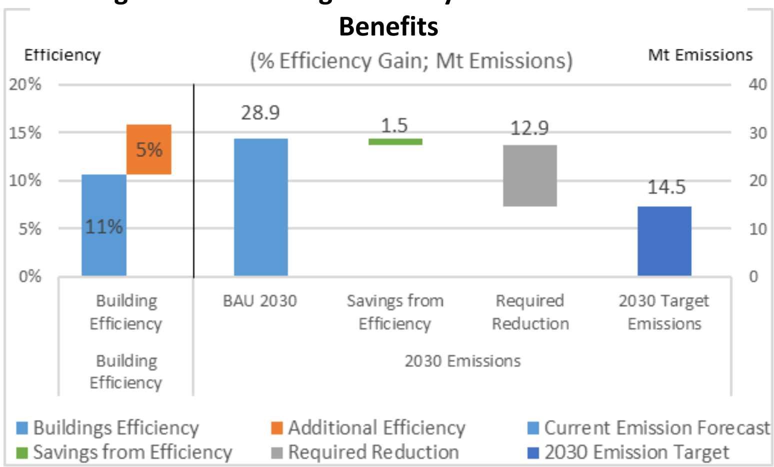
For the purpose of this analysis, it is assumed that the 50% reduction applies equally to both future residential and commercial building emissions. Such a target could be met in several ways:

- Improving the energy efficiency of all applications within buildings by 50%; or
- Replacing 50% of natural gas appliances and devices with electrical devices; or
- Reducing by 50% the CO_2 content of natural gas; or
- Some combination of the above.

These are very aggressive ambitions to achieve in 13 years.

The approach taken in this study allocates a provision for efficiency gains from alternatives that do not require electrification, and then assumes that the remaining reduction objectives must be met by substituting natural gas use with low carbon electricity. Figure 14 summarizes the results.

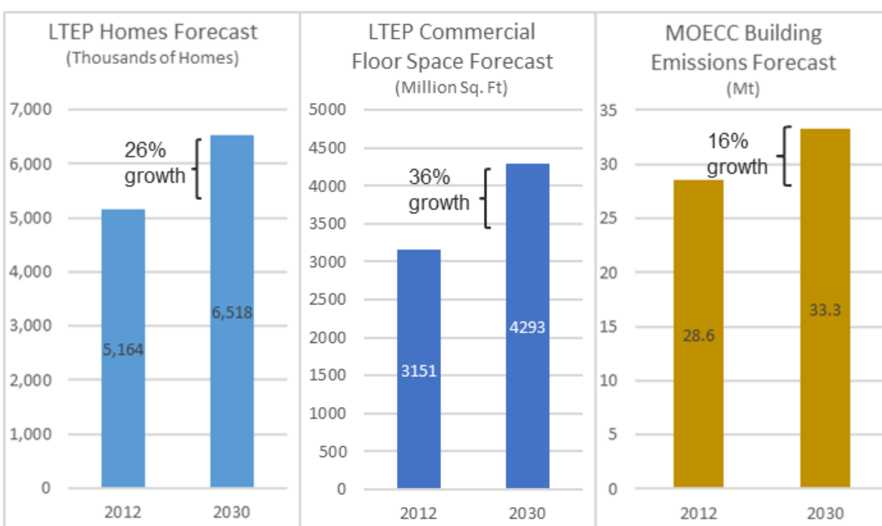
Figure 14 – Building Efficiency Gains & Emissions Benefits



4.2.1. Derivation of Building Efficiency Emission Reduction Target Assumptions

For the purpose of this study, emissions reductions have been estimated based on a comparison of the MOECC emission forecast to a forecast for building growth. IESO 2013 and 2016 data sets were used to develop building growth assumptions. It is assumed that these two data sets are reliable and mutually consistent. Figure 15 compares the various trends suggesting that a 10% per household emission reduction is embedded in the BAU forecast (26% growth in number of household less 16% growth in emissions). When combined with the 36% growth in commercial floor space, the effect of the differences in compound annual growth rate leads to an 11% net building efficiency BAU assumption.

Figure 15 – Building BAU Trends



In other words, it is assumed that within the MOECC BAU emissions forecast, Buildings have an embedded 11% energy efficiency improvement by 2030. The FTR also demonstrates that buildings have improved energy efficiency on average by 11% since 2005. This historical trend is consistent with the 11% forecast BAU trend assumed by this study.

An assessment of provincial building efficiencies indicates that Ontario is leading Canada[29]. Most Ontario homes have recently invested in efficiency improvements. There is not much obvious room for further improvement. The IESO OPO says 95% of assessed potential energy savings are already accounted for in Ontario's conservation program.

Notwithstanding these leading energy efficiency statistics for Ontario, this study assumes that an additional half of the existing efficiency assumption will be realized on top of the existing efficiency assumption, the equivalent of an additional 5.5% province wide average efficiency improvement above the BAU. This assumption requires a total of 16.5% of additional home energy efficiency improvements from today. This outcome will be dependent on the degree of penetration or rate of adoption of these new initiatives. Or example, it could mean that 25% of the homes in Ontario would have to find 66% energy efficiency improvements, or, equivalently, that 50% of the homes in 2030 would each achieve a 33% natural gas energy efficiency improvement over today.

The 5.5% efficiency assumption translates into a reduction in emissions of 1.5 Mt from natural gas use in the home. The FTR was consulted to assess the reasonableness of this assumption. The FTR allocated 6% efficiency improvement for commercial buildings and only 2% for residential homes by 2030. The net effect of the two FTR assumptions is a lower assumption regarding future building energy efficiency improvements than assumed here. This suggests the assumptions made by this study are conservative with respect to the remaining emissions that must be addressed through electrification.

The Natural Gas Conservation Potential report prepared by ICF International for the OEB[30] forecasts greater BAU emission growth in the Buildings sector than reflected in the 2014 MOECC Update assumed by this study. The BAU forecast in that report is 16% emission growth from 2015 to 2030, for a total of 32.5 Mt of emissions expected from natural gas use by 2030. This is in contrast with the 14% emission growth embedded in the model used here by Strapolec that projects future emissions of 28.8 Mt from natural gas. The difference between these values suggests a projected 3.7 Mt lower emission level than reflected in the OEB's BAU assumptions.

Adding the future efficiency emission benefit of 1.5 Mt assumed by Strapolec implies 5.2 Mt of emission reductions relative to the OEB's achievable potential savings case. This assumption is also double the OEB constrained achievable savings amount of 2.5 Mt, which is assumed to be based on existing programs (budgets), but less than the higher unconstrained potential savings options of 5.8 Mt in reductions. The FTR uses this higher unconstrained potential savings in their Outlook F.

[29] NRCan, National Energy Use Database, 2015

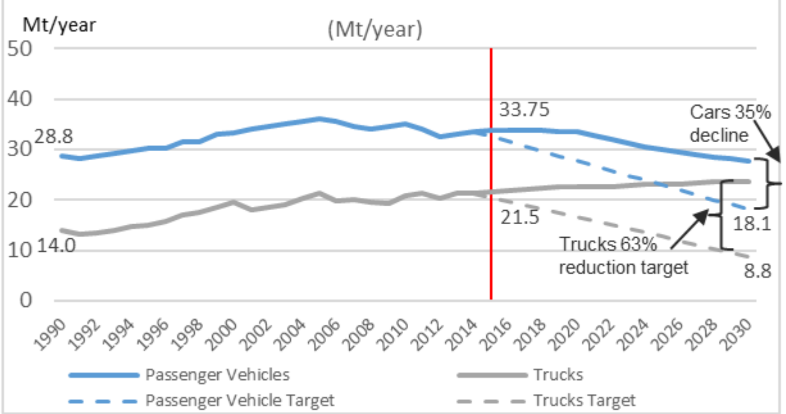
[30] ICF International, Natural Gas Conservation Potential Study, 2016

The emission reduction target for buildings in this study is 10.7 Mt beyond these compared efficiency improvement levels. The targeted reduction in this study is 16 Mt below the ICF forecast. The 16 Mt target assumed in this study approaches the ICF reported technical limit of 19.4 Mt of reductions from the Building sector, but remains within it. Given the higher growth forecasts and the expected technical limitations of reducing building emissions, there is little room for the Building sector to accommodate emission reduction shortfalls from other sectors that may be challenged to achieve their own respective 2030 targets.

4.3. Transportation Emission Targets

For this study, the Transportation emissions forecast is split into two segments: passenger vehicles and trucks. The historical and forecast emissions for these two segments and their 2030 emission targets are illustrated in Figure 16.

Figure 16 – Transportation Emission Forecast



The passenger vehicle segment aligns with the emissions framework in the MOECC's climate strategy document, and is defined as all light duty vehicles that use gasoline. To also align with the MOECC framework, the truck segment is defined as all heavy-duty vehicles that use diesel. This includes short-range vehicles such as garbage trucks, busses, delivery vehicles, and off-road construction vehicles. It also includes the heavy transport fleet for shipping freight. This facilitates a comparison of the two sectors on a fuel basis: gasoline vs diesel, as used in the FTR report.

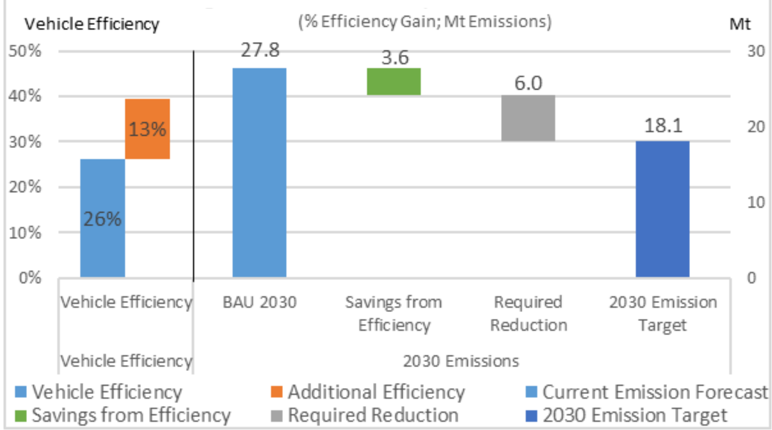
The emission reduction targets for these two sectors differ in magnitude. This is because, for 2015 to 2030, emissions from light vehicles are anticipated to decline, while emissions from trucking and off-road vehicles are expected to climb.

Strapolec assumes that both sectors must achieve emission reductions of 37% below the 1990 emissions levels. The passenger fleet must drop emissions from the forecast level of 27.8 Mt to 18.1 Mt, a drop of 35% or 9.7 Mt from BAU 2030 levels. The truck sector must drop emissions more dramatically from 23.5 to 8.8 Mt, a drop of 63% or 14.7 Mt from BAU 2030 levels.

4.3.1. Passenger Vehicles Efficiency Assumptions

For passenger vehicles, the splits of emission reduction expectations for efficiency improvement versus other alternatives are shown in Figure 17. The target for passenger vehicle emissions reductions is 6 Mt after accounting for 3.6 Mt in assumed efficiency improvements.

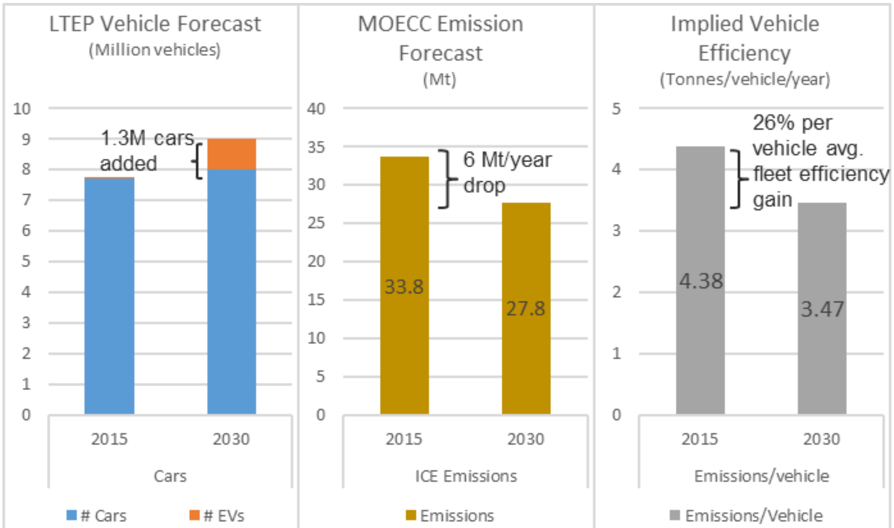
Figure 17 – Passenger Vehicle Efficiency Gains & Emission Benefits



As with the building efficiency forecast, the MOECC data was combined with the 2013 LTEP data tables to estimate the BAU efficiency assumptions made for the passenger vehicle fleet. The analysis is illustrated in Figure 18.

Assuming the OPO Outlook B forecast is similar to the 2013 LTEP forecast, of the estimated 9 million vehicles that will be on the road in 2030, 1 million of them will be EVs. This means 8 million Internal Combustion Engines (ICE) vehicles will produce the forecast emissions. The analysis demonstrates that the MOECC's data already includes a 26% passenger vehicle efficiency improvement within the BAU emissions forecast.

Figure 18 – Passenger Vehicle BAU Trends



The forecast 1 million EVs represent an important consideration for identifying the additional electricity that may be required. Electrification implications derived in this study assume that the electricity required for these first 1 million vehicles is already in the OPO Outlook B forecast.

Strapolec assumes that an additional 50% efficiency improvement will be achieved through climate change motivated innovations, for a total of a 13% increase in additional emission reductions. New emission regulations being introduced in both the US and Canada will require a 50% emission reduction for new vehicles sales across the fleet.[31]

- The "fleet" includes the use of hybrids and other vehicles
- It will take time for the fleet to "turn over" which has typically been at a rate of 7% per year[32].

It is further assumed that the introduction of additional fuel blends such as ethanol, as discussed in the FTR, will also contribute to the forecast for the overall efficiency improvement of the fleet that does not entail additional electrification loads.

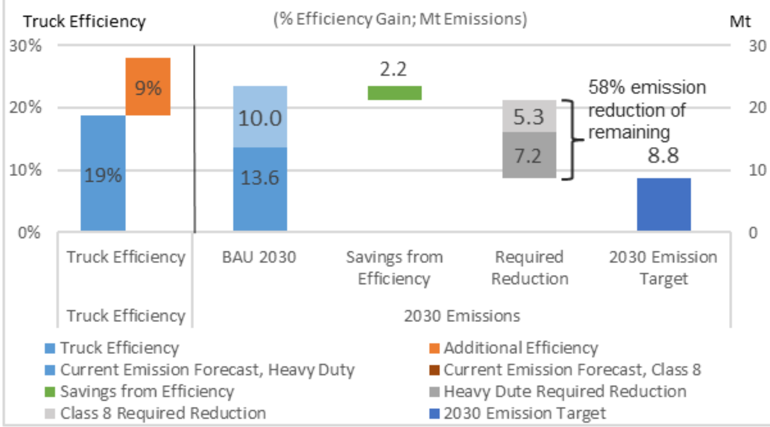
These additional efficiency improvements are anticipated to account for 3.6 Mt of emission reductions. This assumption facilitates the calculation of the emission reductions that must be generated by alternative vehicle options. These vehicle options will have to address 6.0 Mt of additional emission reductions.

[31] Atkinson, The Automotive Industry to 2025, 2016; GM, OEA Energy Conference, 2016
[32] GM, OEA Energy Conference, 2016

4.3.2. Efficiency Assumptions for Trucks

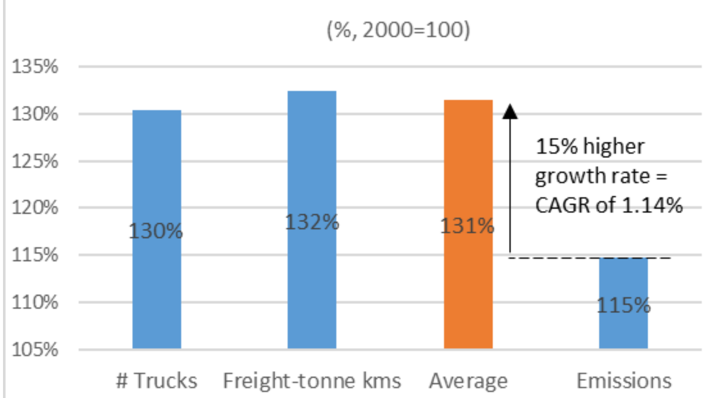
Figure 19 illustrates the efficiency and alternative emission reduction targets for trucks assumed in this study.

Figure 19 – Trucks Efficiency Gains & Emissions Benefits



Efficiency improvements of 18% from trucks appear to be reflected in the BAU forecast. Using MOECC data to assess the trucking efficiency improvements is more difficult as LTEP forecast data is not available for trucking. The opportunity for efficiency improvements in trucks are also less than for passenger vehicles (e.g. A lighter weight truck cab doesn't change the payload where all the weight is). This study assumes that the efficiency gains observed in the past will continue in the future. Figure 20 summarizes the efficiency analysis conducted based on the MOECC Update data.

Figure 20 – % Growth in Trucking Statistics



Trucking efficiency gains from 2000 to 2012 were estimated based on two methods:

- Trend in number of trucks
- Trend in freight-tonne kms

When these trend averages are compared to the trend in emissions, a compound annual growth rate (CAGR) difference of 1.14% is observed.

As Figure 20 illustrated, the MOECC emissions forecast tracks the emission trend from 2000 to 2012 and therefore it is assumed that ongoing efficiency gains are included in the freight forecast as well. For the period to 2030, extrapolating these CAGRs suggests an average efficiency gain of 19% can be assumed to be part of the BAU. Presuming an additional 50% incremental improvement on that trend would add a 9% fleet efficiency improvement resulting in an expected efficiency induced emissions reduction of 2.2 Mt off the trucking fleet emissions target.

The U.S. Department of Energy (DOE) SuperTruck Program anticipates that additional efficiency gains for ICE vehicles can be expected. The goal of the SuperTruck program is to develop and demonstrate a wide range of state-of-the-art, commercially feasible efficiency technologies for Class 8 long-haul tractor-trailers.[33]

Results from Phase I of the SuperTruck program[34] show an 80% improvement in mileage performance (40% emission reduction) as compared to 2009 emission performance. A new SuperTruck II program will focus on a 100% mileage performance improvement (50% emission reduction against 2009 standards). The SuperTruck II program also includes hybrid vehicle options that may provide an additional 20% fuel efficiency for tractor trailers.

As these are developmental programs, applying this efficiency assumption to the entire diesel fleet, including off-road vehicles, should be done with caution. One of the major areas of efficiency improvement aerodynamics, which does not dramatically affect slow moving vehicles like garbage trucks.

As indicated in Figure 19, the trucking segment has been split into two categories, short-range trucks and Class 8 tractor trailers. The emissions split has been estimated based on U.S. statistics that show Class 8 trucks represent 20% of diesel emissions. The target for emission reductions from alternative options from the truck fleet is 12.5 Mt, 60% or 7.2 Mt from the short-range trucks, and 5.5 or 50% from the Class 8 tractor trailer fleet.

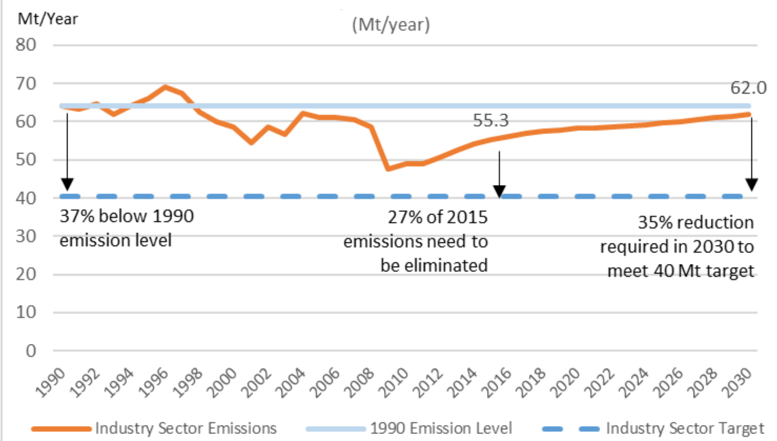
4.4. Industry Emission Targets

The Industry sector emission reduction targets are based on the concepts and ideas surfaced during the research phase of this study. Several opportunities exist to reduce emissions associated with natural gas use that are outside the heating objectives for buildings. The emission reduction potential is derived from an assessment of the market potential of the applications which are collectively referred to, and accounted for as being part of the emission reduction strategy for the industrial sector.

[33] TA Engineering, DOE SuperTruck Program Benefits Analysis, 2013
[34] U.S. DOE, SuperTruck Success, 2016

Figure 21 shows the MOEECC emission targets for the Industry sector. A 35% reduction in emissions, or 22 Mt of emission reductions are required. This study examines the options that could achieve 14 Mt, or 70%, of these reductions.

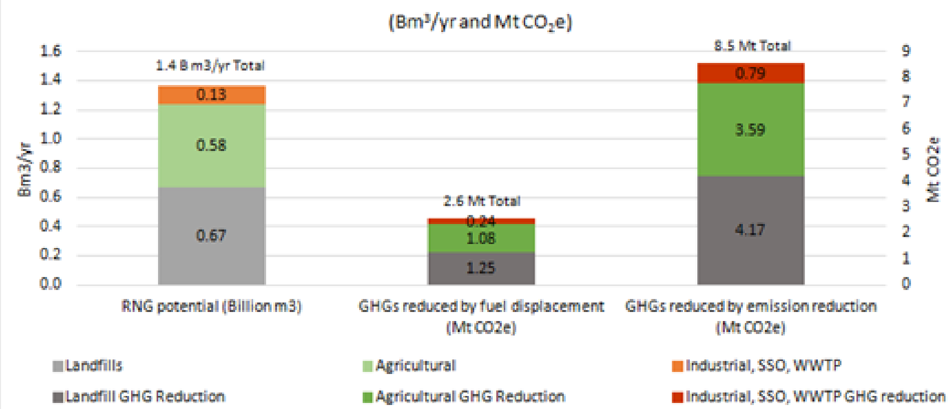
Figure 21 – MOECC Industry Sector Emission Forecast



4.4.1. Renewable Natural Gas

Strapolec's study assumes that processes required to support RNG could reduce emissions by up to 11.1 Mt, as shown in Figure 22. RNG displacement of natural gas could reduce emissions by 2.6 Mt while 8.5 Mt of emissions equivalent could result from the capture of waste methane.

Figure 22 –Annual RNG Potential from Ontario Wastes and Associated GHG Reduction



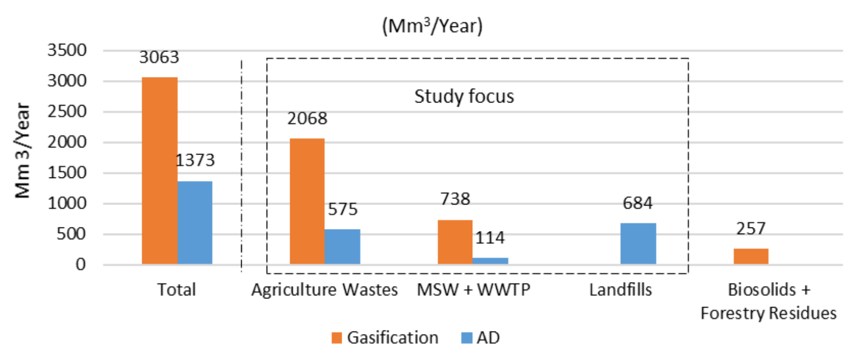
The volume of RNG is derived from the Alberta Innovates Report[35], widely considered a definitive source for potential RNG use in Ontario. The OEB Natural Gas Conservation Potential Report utilized this Alberta data. As shown in Figure 23, waste from the following sectors can be used to produce RNG in Ontario:

- Agricultural wastes (Manure & Crop residues)

[35] Alberta Innovates, Potential Production of Renewable Natural Gas from Ontario Wastes, 2011

- MSW + WWTP
- Landfill materials
- Biosolids + forestry residues

Figure 23 – RNG Potential for Ontario



The 2011 Alberta data indicates that, when combined, Ontario wastes have the potential to produce 4247 M m3/yr of RNG[36]. That represents 14.2% of Ontario's current natural gas supply. Two processes are considered for RNG production:

Anaerobic Digestion (AD)

- 1373 Mm^3/year of RNG can be produced from Ontario wastes representing 4.4% of Ontario's total gas supply
- AD technology is available and already being used in North America.

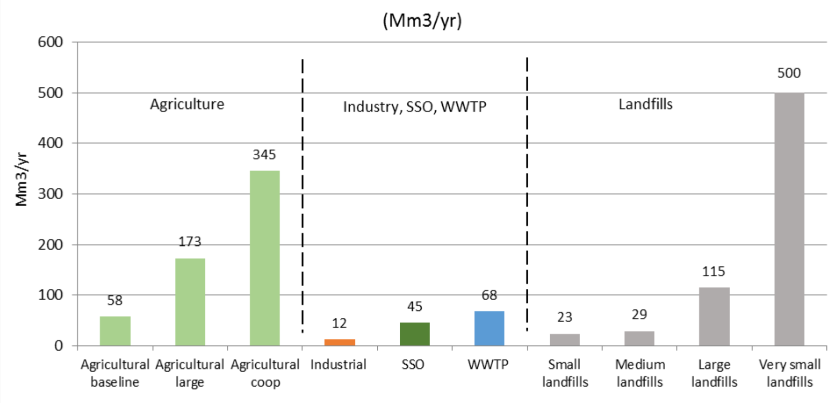
Gasification

- 3063 Mm^3/year or 69% of the RNG potential that is possible from waste streams requires the use of gasification. This represents 9.8% of Ontario's total current gas supply.
- RNG from gasification has limited availability in the short-term. Sources indicate the technology for gasification is not yet well established and requires further development[37]. Gasification potential is not included in the estimate of Ontario's RNG potential in this study as costing data for the production process was not available.

Claims that up to 15% of the natural gas system can be supplied by RNG assume that almost 10% can be derived from the gasification process. In this analysis, the focus is on the use of AD for the purpose of estimating Ontario's RNG potential from the waste sector. Figure 24 summarizes the RNG volume assumed to be available from each waste stream.

[36] Excluding Biosolids and Forestry Residues
[37] Alberta Innovates, Potential Production of Renewable Natural Gas from Ontario Wastes, 2011

Figure 24 – Assumed RNG Potential from Ontario Wastes



Agricultural farms have the potential to produce 575 Mm^3 of RNG, with the largest potential being from co-operative arrangements where the waste (manure and crop residue) is aggregated from several farms for processing at a central digester. The Industrial, Source-Separated Organics (SSO), and WWTP potential for RNG production is small, totalling 126 Mm^3/year. Landfills are the largest potential source of RNG, capable of producing 667 Mm^3/year, representing almost half of the total RNG potential from waste. Very small landfills (<10 kilotonnes/year weight received) are by far the largest potential source of RNG as there are many of these sites compared to small, medium, and large landfills.

The economics of obtaining RNG from the very small landfills has not been validated. Economic data is based on an Electrigaz report[38] used by Union Gas in an OEB submission, in which the economics for harvesting the potential from small landfills was not estimated. The amount of RNG available from very small landfills was limited to materials available from the 850 sites[39] currently open in Ontario. Based on an RNG production potential of 0.27 Mm^3/year per landfill[40] for 850 sites and using a multiplier observed in the Electrigaz report volume assumptions, 500 Mm^3/year of total RNG is assumed available from very small landfills.

AD related processes reduce GHGs emissions via two mechanisms: (1) fuel displacement; and (2) methane capture.

- Fuel displacement reflects all of the methane extracted from the waste sector is converted to RNG and injected into the natural gas delivery system to eventually become a fuel.
- Methane reduction is achieved by preventing the emission of methane into the atmosphere that would otherwise be naturally occurring absent an RNG process. Methane is a GHG with 21 times the warming potential of CO_2. By capturing that methane, the GHG emissions of that methane are

[38] Electrigaz, Economic Study on Renewable Natural Gas Production, 2011
[39] Government of Ontario, Small Landfill Sites List, 2016
[40] Alberta Innovates Technology Futures, Potential Production of Renewable Natural Gas from Ontario Wastes, 2011

avoided. The total GHG reduction potential from methane capture is 3.3 times the fuel displacement benefit or 8.5 Mt CO_2e.[41]

By displacing up to 1.4 billion m^3/year of natural gas, 2.6 Mt CO_2e can be eliminated per year.

The total RNG potential of 1.4 billion m3/year determined by this study is lower than the 4.3 billion m3/year presented by ICF International, Enbridge Gas Distribution, and Union Gas[42]. This is partially due to the discounting by this study of RNG potential from small landfills, but primarily because this analysis has excluded consideration of RNG potential from gasification due to the previously noted challenges.

While there is the potential to reduce methane emissions, it remains questionable as to whether these emission reductions can be attributed to the RNG process for the following four reasons:

1. There are regulations that require the capture of this methane, particularly for large landfills.
2. Once methane is captured, it can be flared. Using it for RNG may therefore only provide the smaller benefit of fuel displacement emission reductions.
3. Costs for capturing the methane have not been included in this report.
4. These methane emission avoidance benefits have similarly not been accounted for in the FTR either.

It is important to recognize that emissions reductions from these sources will result if RNG options are pursued, as the process relies on the capture of methane.

4.4.2. Hydrogen Blending Power to Gas

With proper natural gas network maintenance, hydrogen blends of 20% could exist. Higher blends are limited by safety margins and regulations. In Ontario, there is currently a technical limit on how much hydrogen can be injected into the natural gas system. This limit is estimated to be only 5% of the natural gas volume that can be replaced by hydrogen[43]. The limits arise from blend level restrictions in end use appliances[44]. For some appliances, no hydrogen blending would be acceptable. Higher blend rates may be possible over time as old appliances are changed out for new ones.

This study assumes a 5% blend for the next decade. The benefits of blending are further limited by the fact that the heat content by volume of hydrogen is only 30% of the heat content of natural gas. Blending hydrogen as 5% of the natural gas in the system only replaces 1.5% of heat content, thereby diluting the overall heat content of the system. To maintain system heat capacity, 3.5% more natural gas volume is required, resulting in only a 1.5% drop in the natural gas volume.

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[41] To avoid double counting, we remove the methane used for fuel displacement when tallying the GHGs reduced by preventing the direct emission of methane into the atmosphere

[42] ICF International, Results from Aligned Cap & Trade Natural Gas Initiatives Analysis, 2015.

[43] Industry interviews; OSPE, Ontario's Energy Dilemma, 2015

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

As a result, only 1.5% of the natural gas volume, or 15.2 BCF, can be displaced. Hydrogen blending is assumed in this study to reduce emissions by 0.8 Mt from the production of 110 million kg of hydrogen.

In the long run, if hydrogen becomes a technology of choice and end use applications are adjusted to the new burn characteristics, the hydrogen offset of natural gas could increase four-fold to reduce 3.2 Mt of emissions or 15% of currently required industrial emission reductions.

4.4.3. Displacing Steam Methane Reforming

Hydrogen is a product refineries use for their production processes. Currently, Ontario's refineries are estimated to use approximately 140 million kg of hydrogen annually[45].

SMR is the most commonly used production process for hydrogen. The SMR process uses natural gas as a feedstock to produce hydrogen and a CO_2 bi-product. Typically, Ontario refineries vent the CO_2 into the air[46]. The SMR production process potentially generates 1.4Mt of CO_2 emissions or 7% of the 22 Mt of required industry emission reductions.

Air Products Canada has recently commissioned a new plant in Sarnia to produce 80 million standard-cubic-feet-per-day (MMSCFD) of hydrogen for two nearby refineries—Shell and Suncor[47]. This equates to 74 million kg of hydrogen per year. Ontario has two other major refineries that are estimated to require an additional 68 million kg of hydrogen for a total of approximately 140 million kg.[48]

This study assumes that 50% of the existing hydrogen production can be converted to an electrolysis process. This is for two reasons: 1) not all SMR is from raw natural gas feedstock[49], some may be from waste products within the refineries which would still have to be addressed. 2) The remaining 50% is assumed to be an opportunity for post 2030 emission reductions in support of the 2050 targets.

Assuming 70 million kg of hydrogen is produced (50% of existing market production), and 8.29 kg of CO_2[50] avoided per kg of hydrogen produced, this equals 0.59 Mt of emissions that could be avoided by this process.

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[45] Canadian Hydrogen Survey – 2004-2005, for Natural Resources Canada, June 2005
[46] Industry interviews
[47] Air Products, Air Products' Sarnia, Ontario, Canada Hydrogen Plant Now On-Stream and Supplying Suncor and Shell Refinery Operations, 2006
[48] Dalcor Consultants Ltd, Canadian Hydrogen Survey – 2004-2005, 2005; Strapolec analysis
[49] Nyboer, A Review of Energy Consumption in Canadian Oil Refineries, 2010
[50] Hydrogen Analysis Research Center, Hydrogen Production Energy Conversion Efficiencies, 2016; Ruether, Life-Cycle Analysis of Greenhouse Gas Emissions for Hydrogen, 2005; Collodi, Hydrogen Production via Steam Reforming with CO_2 Capture; Linde Group, Hydrogen; Strapolec analysis

4.4.4. Industrial Natural Gas Use Displacement

Finally, Strapolec assumes that 10% of the natural gas used by Ontario's industry will be replaced by some form of electrification. This is consistent with the OPO. The Industrial sector in Ontario uses approximately 290,000 TJ of natural gas energy annually. Displacing 10% of this would represent approximately 29,000 TJ avoiding approximately 1.45 Mt of emissions.

4.5. Summary

This section outlined the emission forecast for Buildings, Transportation and Industrial use of natural gas, the required 2030 emission level, the BAU efficiency assumptions, and the pathway to reach emission targets through fuel substitution.

For buildings and transportation, the identified target is a 50% reduction in forecasted 2030 emissions. Total required emission reductions assumed in this study are 14.4 and 24.3 Mt respectively. Buildings are assumed to achieve 16.5% greater energy efficiency improvements than today reducing emissions by 1.5 Mt. Passenger vehicles are assumed to achieve 39% less emissions per vehicle than today's performance, saving 3.6 Mt from the BAU forecast and trucks are assumed to improve emissions by 28%, reducing 2.2 Mt from the BAU forecast.

Industry emission reduction expectations are specific to the emissions reduction options identified to displacing natural gas: RNG, SMR, P2G hydrogen blending, and general industrial use of natural gas. Emissions estimates are based on the volume of natural gas displaced which has been established by the actual volumes of alternatives than can be produced. Industry emissions must be reduced by 35% or 22 Mt. The opportunities assessed in this study identify 14 Mt, or 70% of the required Industry emission reductions.

5.0 Electrification Demand Implications

This section details the assumptions and analyses used to estimate the electricity that will be required to implement the identified emission reduction options being assessed by this report.

This section first summarizes the overall results, relating the emissions reduced in each major sector to the associated electricity required to achieve them. The results are compared to the contents of the OPO and FTR. Finally, the projected electricity required in 2030 that would enable meeting the 2030 emissions reductions is illustrated in two ways: (1) comparative forecast with respect to the OPO Outlook D; and (2) by the three types of energy demand – heat, consumer driven demand, and industrial baseload expected. The energy demand is then added to the OPO Outlook B projection to illustrate the total Ontario system demand expected in 2030 if the emissions targets assessed in this study are to be met.

The ensuing subsections then describe the detailed assumptions used to estimate the electricity required for each emission reduction option:

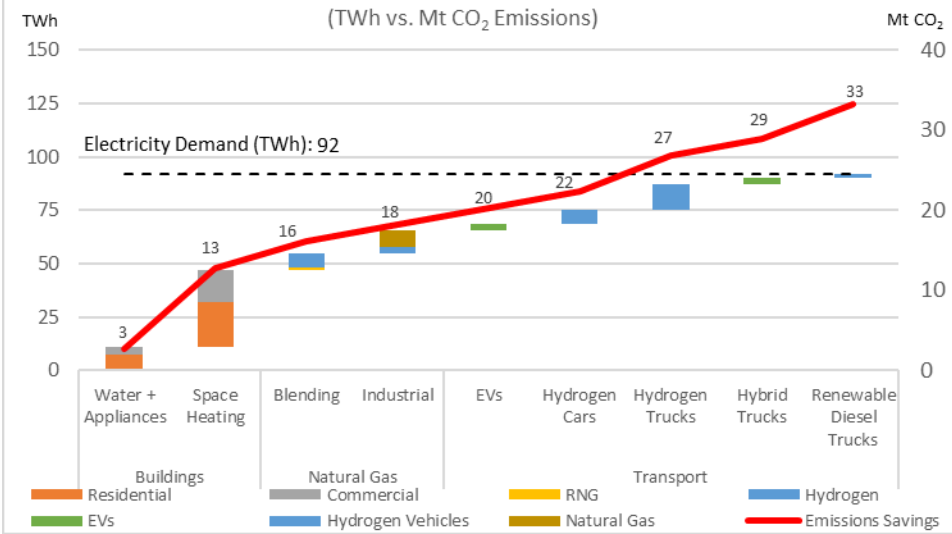
- Buildings, using residential space heating as an example of the methodology deployed for both residential and commercial space and water heating;
- Transportation, the passenger versus trucking segments; and,
- The four Industrial applications that have been assessed.

This section closes with a summary of the key findings.

5.1. Overview

The results of this study estimate that over 90 TWh of new electricity demand will arise from initiatives to reduce emissions to meet the 2030 targets. The correlation of emission reductions with electricity demand by sector is illustrated in Figure 25.

Figure 25 – Electrification Implications of Emission Reductions in 2030



Emission reductions and new electricity supply are highly correlated. Efficiency improvements previously discussed for buildings and vehicles are ongoing and assumed to occur without any implications for the electricity system. Note that the total emissions savings in Figure 25 (33 Mt) does not equal the total emission reductions modelled in the study (45 Mt), as Figure 7 indicated. This is because the figure only illustrates emission savings from technologies that require electrification. Emission savings from technologies such as natural gas vehicles (3.5 Mt) and methane capture (8.5 Mt) are not shown. The relationship between electrification and emissions differs by sector as summarized below with the associated assumption details discussed in subsequent subsections.

Buildings

- 47 TWh, or almost half of the new electricity demand of 92 TWh will result from reducing the use of natural gas for heating in buildings to save ~13 Mt of emissions.

Transportation

- 35% of the transportation fleet is assumed to have converted to natural gas. This assumption helps develop a conservatively low estimate of electrification required in the Transportation sector. As mentioned above, the associated 3.5 Mt of avoided emissions are not shown on Figure 25.
- Passenger vehicles could require 9 TWh for EVs and hydrogen FCEVs to save 4 Mt of emissions.
- Trucks represent the most difficult challenge as there are few options to address the needed sizeable emission reductions in this area. This analysis models 17 TWh to enable the removal of 12.5 Mt.
    - After examining the natural gas and hybrid vehicle options for replacing over half of the fleet, hydrogen and renewable diesel are used as the "plug" to achieve the requisite emission reductions for vehicles not considered as Class 8 tractor trailers. Large hydrogen fueled transport trucks are considered to be cost prohibitive. Nevertheless, there are no known alternatives to this approach.

Industry/Natural Gas System

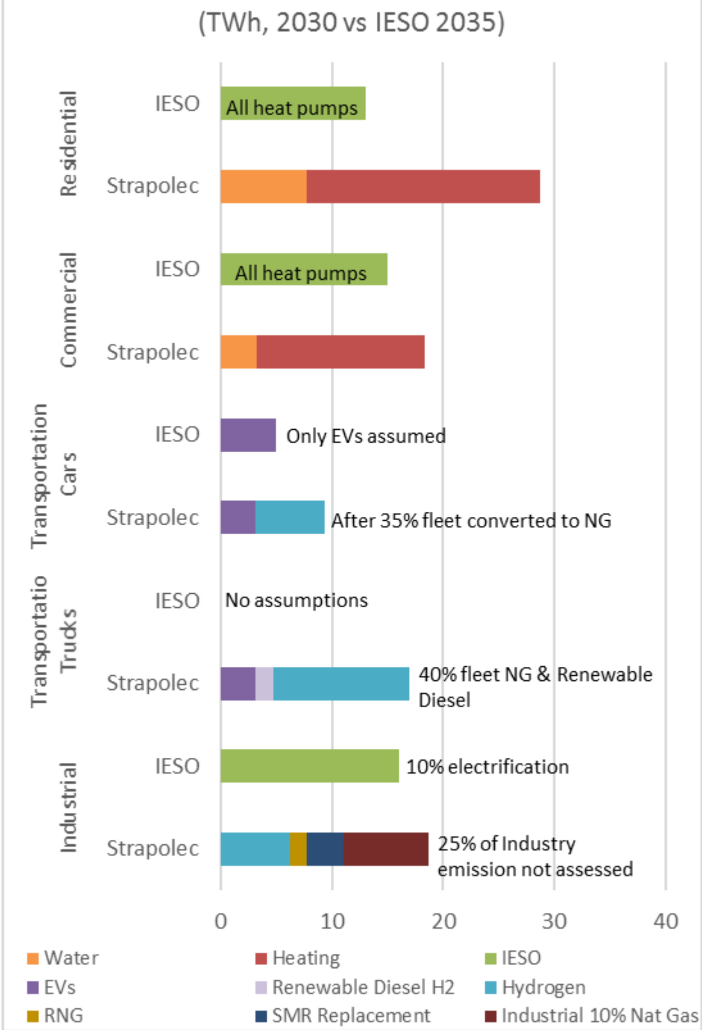
- Collectively, industrial applications related to natural gas substitution require about 19 TWh to achieve ~5 Mt of reductions.
- Approximately 8 TWh of electricity is required to inject RNG or hydrogen blending into the natural gas delivery system, and offer emissions gains of 3.4 Mt.

Other industrial processes, including SMR could require 11 TWh of electricity for 2 Mt of emission reductions.

5.1.1. Alignment of Demand Forecast with OPO Outlook D and the FTR

The results of this analysis forecast a need for over 90 TWh of additional electricity by 2030. This is an 80% greater electrification impact than noted in the OPO Outlook D "high demand forecast". The areas of alignment and differences between the two forecasts are summarized in Figure 26. The notable differences between Strapolec's forecast and the OPO Outlook D are primarily related to residential buildings and trucks.

Figure 26 – Emission Inspired Electrification



Buildings comparison suggest a gap in residential electrification estimates

The OPO reflects assumptions that 30% of the heating and 32% of water heating appliances are electrified by 2035, and all of them are assumed to be replaced by higher efficiency ASHPs. This study targets 44.5% of total future residential consumption switching away from natural gas. This assumption equates to 36% of the heat and 32% of water appliances becoming electrified with low efficiency units being addressed first. In order to meet emission targets, this means converting 15-20% more energy from natural gas applications to electricity than inferred by the OPO. Furthermore, the model assumes that the current market penetration of electric heating appliances carries forward: Electrical Resistance: 68%; ASHP 25%; and, GSHP 7%.

The commercial electrification assumptions are materially similar between the OPO Outlook D and this study. The differences in electricity demand stem from the assumption in this study that an equal proportion of resistance, AHSP, and GHSP devices are deployed commercially instead of the "all heat pumps" assumption reflected in the OPO.

This study assumed a mix of heating technology choices for both cases for several reasons: (1) Heat pump economics differ for different sized households and businesses; (2) Heat pumps will require a supplementary heat source[51], which may be electricity in some cases; and, (3) Smaller energy consuming locations may not choose the heat pump option. It is thus not an exact science to predict which choice may make the most sense to individual consumers.

Passenger vehicle assumptions are somewhat similar

The BAU Outlook B assumes 1 million EVs will be deployed in Ontario. For Outlook D, the electrification demand above Outlook B is assumed to come entirely from an additional 1.4 million EVs in Ontario's passenger vehicle fleet. Strapolec assumes that to meet the remaining emission targets, it will require a mix of 35% natural gas vehicles and 1.6 million non-emitting vehicles, that have been assumed to be equally split between battery electric vehicles (BEVs) and FCEVs, or 800,000 of each vehicle type. The 50-50 split was arbitrarily chosen so as not to bias the analysis by favouring one technology over the other. This study assumed 600,000 fewer EVs and 800,000 more FCEVs than are contained in the OPO Outlook D. For reference, the FTR assumes 300,000 FCEVs in Outlook F. The electrification load from the FTR Outlook F is not reflected in the OPO Outlook D.

Trucks represent a large challenge not addressed in the OPO

The study assumes a mix of renewable diesel, natural gas, plug in electric, hybrid and hydrogen vehicles. Emissions from the trucking sector form a large part of the reduction targets, and both the FTR and this study have made similar assumptions regarding the increased use of renewable diesel and natural gas in the Transportation Sector.

The OPO has made no provision for the electrification of trucks. This study has identified potential electrification implications for renewable diesel, hybrid electric trucks and hydrogen fuel-cell powered trucks. As stated previously, renewable diesel will require hydrogen for the production process and contribute to electricity demand growth.

Natural Gas/Industry → Emission reduction opportunities are similar with some caveats

The OPO Outlook D includes the assumption that 10% of the industry sector's energy use will be converted to electricity. This study has adopted a similar assumption.

This study further addresses the electrification implications for RNG production and hydrogen P2G blending with the natural gas distribution system. Additionally, switching hydrogen production from electrolysis to replace the SMR process will add an industrial baseload demand. Hydrogen blending and

[51] Energy Solutions Centre, An Evaluation of Air Source Heat Pump Technology in Yukon, 2013

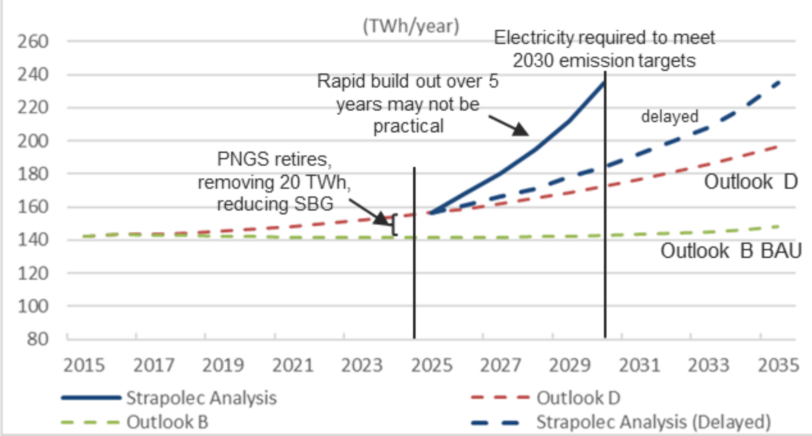
SMR displacement assumptions are unique to this study. The FTR has more significant RNG assumptions in its Outlook F, but no provision for the electricity needed to produce it.

This suggests that the estimates emerging from this study effectively provide an additional scenario, which should not to be compared directly to the OPO Outlook D, but viewed rather as a proxy for the electrification implications of the FTR Outlook F. Outlook F of the FTR appears more aligned with achieving Ontario's emission targets of 37% below 1990 levels, albeit by 2035 not 2030.

5.1.2. Profile of the New Demand for Electricity

Meeting emission reduction targets in 2030 will demand electricity much sooner than provided for in the OPO. If Ontario is to meet its 2030 emission targets, 90 TWh of new low carbon capacity is required by 2030. The 90 TWh is incremental to the BAU OPO Outlook B forecast. Figure 27 illustrates the demand forecast from this analysis compared to the OPO Outlooks B and D.

Figure 27 – Comparison of Annual Net Energy Demands Across Outlooks



The Outlook D forecast is based on electricity demand ramping up gradually to 2035. By 2030 only 30-40% of the energy supply required to achieve the 2030 emission reductions will be available. This suggests that Ontario could miss its 2030 targets by 60%. As noted earlier, the FTR emission forecast shows that a 30% or 20 Mt emission reduction shortfall could occur in 2030. At ICF's forecast carbon price of $100/Mt[52], the 20 Mt shortfall in the fuels report could cost $2B/year in higher costs in the form of externally purchased emission credits.

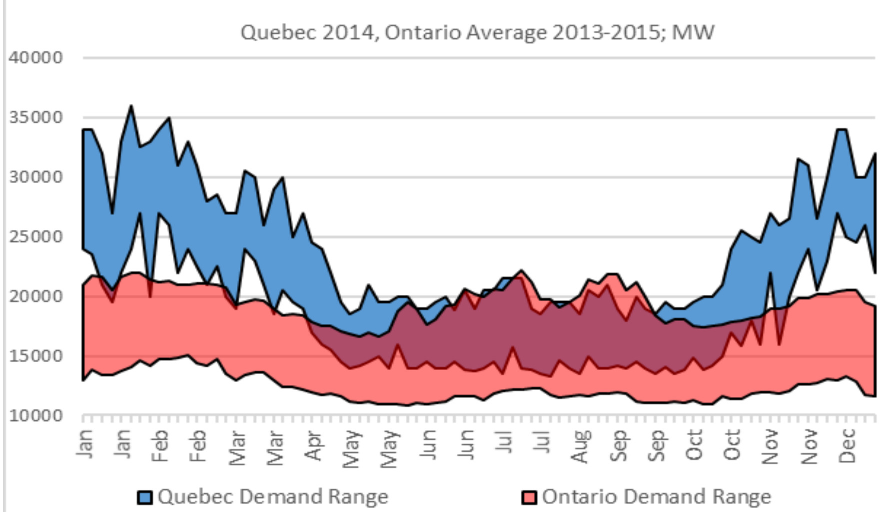
The ability to achieve Ontario's emission targets and the cost of doing so will be driven by the feasible pace at which new electricity generating capacity is developed to meet this demand. Achieving the needed supply in time is particularly important given the anticipated retirement of the Pickering Nuclear Generating Station (PNGS).

[52] ICF International, Ontario Cap and Trade, 2016

By 2025, under the OPO Outlook D assumptions shown in Figure 27, it is conceivable that the province will have 20 TWh greater demand than it has today. Prior to PNGS retirement, Ontario's surplus can provide low cost electrification options to help meet this demand and accelerate decarbonisation. This clean energy asset could also help accelerate Ontario's CCAP objectives for 2020. The expected retirement of the PNGS in 2024 will remove 20 TWh of clean baseload power, effectively eliminating all of the useable low cost carbon-free surplus power[53]. This creates an imperative for developing 20 to 40 TWh of new clean baseload generation by 2025 to provide ongoing support for the emission reduction options.

The LTEP process should consider the need to rapidly make clean electricity generation available to support the 2030 emission reduction pathway. This requires consideration of the type of energy source required. The importance of addressing the heating requirement is central to building emission reductions and will introduce a very different characteristic to Ontario's seasonal electricity demand profile. Figure 28 illustrates how the electricity demand profile in Quebec demonstrates the "face of home heating" as compared to Ontario's current demand profile.

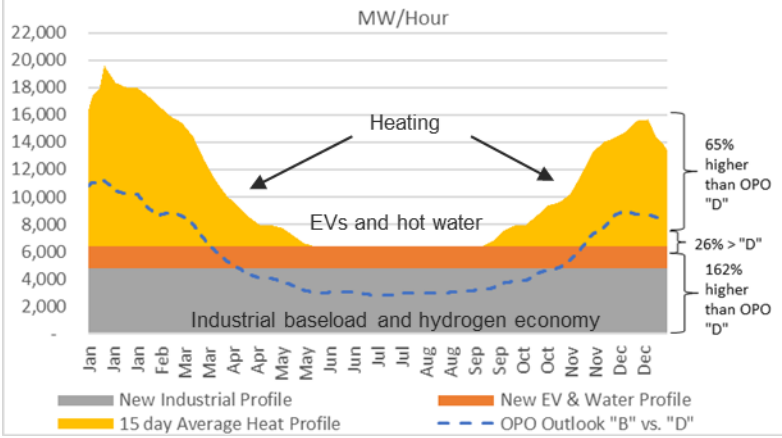
Figure 28 – The Face of Home Heating – Quebec vs Ontario Demand



Not all new electricity demand is the same. Figure 29 shows the nature of the new electricity demand from a seasonal profile perspective.

[53] Strapolec, Extending Pickering Nuclear Generation Station Operations, 2015

Figure 29 – Incremental New Ontario Electricity Demand Profile in 2030



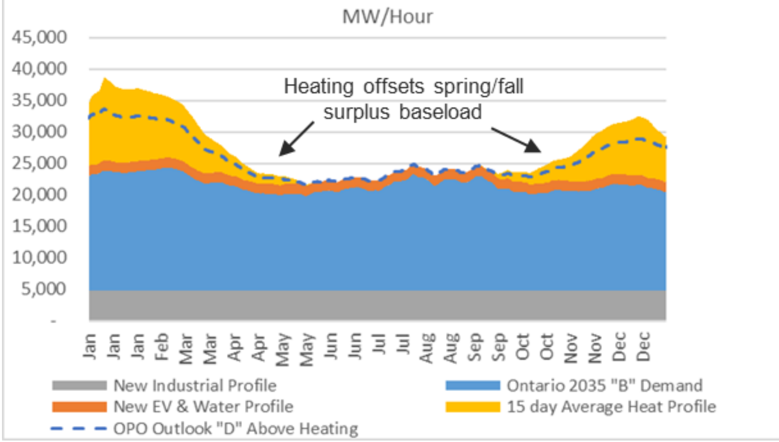
Ontario's current policy direction indicates there will be a significant ramp up of electricity required to supply home heating needs.[54] There are three types of new demand emerging from emission reductions:

- 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 distribution system.
- EVs and water heating represent a daily demand profile driven by consumer behaviors. There is a belief that much of this demand can be accommodated through smart controllers and hence the use of off-peak energy as much as possible.[55]
- The industrial applications and hydrogen economy could conceivably be provisioned by new baseload.

When these new demand profiles are overlaid on existing demand, some of the seasonal variability is smoothed, particularly for the spring and fall. The combined profile is illustrated in Figure 30.

[54] Heating profile based on IESO Outlook D demand, EV profile based on IESO
[55] Haines, OEA Energy Conference remarks, 2016

Figure 30 – Ontario 2030 Demand Profile



The way in which Ontario's electricity system evolves is a critical topic of the LTEP consultation process. Consider should be given to the changing demand profile that is emerging from the emission reduction options. The future may have greater baseload demand and a flatter seasonal spring/summer/fall demand profile. Planning for emission reductions should involve consideration of the costs of this transformation and the associated carbon prices that would incent related emission reduction investments. These subjects are explored in Sections 6.0 and 7.0 of this report.

5.2. Detailed Electrification Assumptions

This section provides a summary of the research conducted to develop estimates of the electricity required by each of the forty-five (45) emission reducing alternative technologies catalogued by this study. The descriptions are provided in three subsections, one for each of the following:

- Building electrification
- Transportation electrification
- Industry electrification, including RNG, SMR, and Hydrogen

5.2.1. Building Emission Electrification

Most Ontario buildings use natural gas for space and water heating applications. Figures 31 and 32 illustrate the use of natural gas for residential and commercial buildings. In 2013, a total of 572 PJ of natural gas was used in the Ontario building sector, with 352 PJ used by residential buildings and 220 PJ by commercial buildings[56].

[56] NRCan, National Energy Use Database, 2015

Figure 31 – Residential Building Natural Gas Use

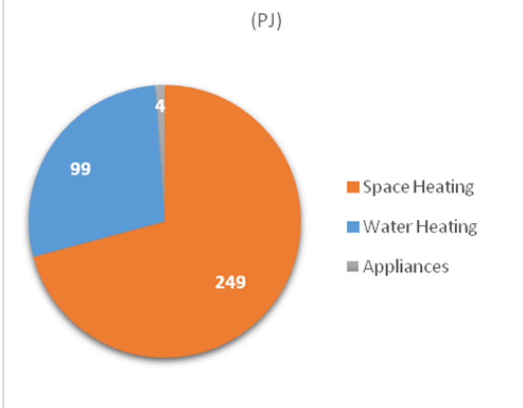
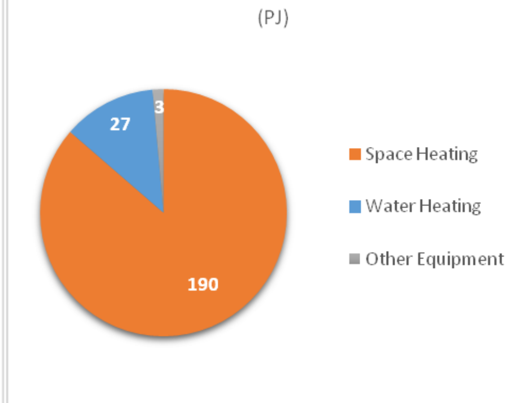


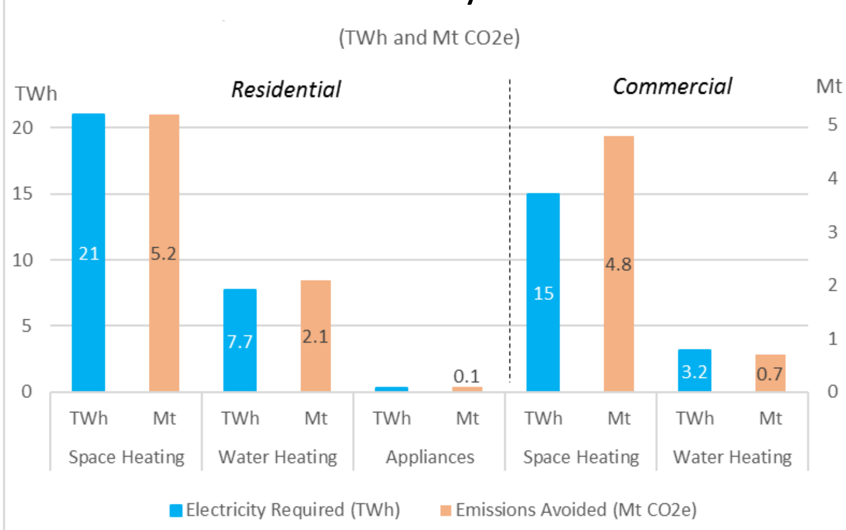
Figure 32 – Commercial Building Natural Gas Use



In 2013, residential buildings used 249 PJ of natural gas for space heating, 99 PJ for water heating, and 4 PJ for appliances such as clothes dryers and stoves. Commercial buildings used 190 PJ of natural gas for space heating, 27 PJ for water heating, and 3 PJ for other applications such as auxiliary equipment.

In this study, the target for emission reductions in buildings is 50% below 2030 levels. 5.5% of the reductions are achieved through energy efficiency improvements and the remaining 44.5%. are addressed by electrification options. The focus is on electrifying natural gas space and water heaters as these devices use the majority of natural gas in both residential and commercial buildings. Figure 33 summarizes the electrification implications of emissions reductions from natural gas displacement across these applications in the Buildings sector.

Figure 33 – TWh Required for Building Emission Reduction by 2030

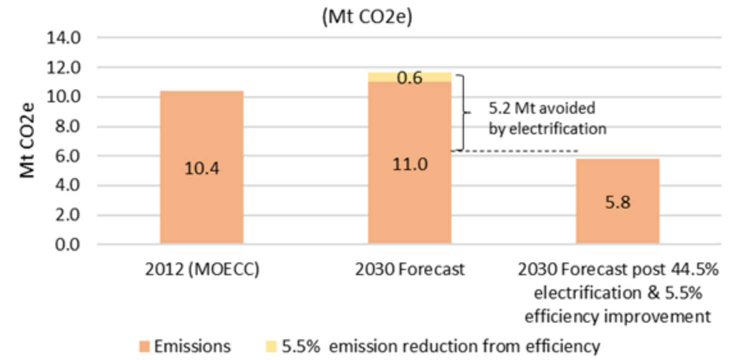


The methodology deployed in this study was common for all natural gas applications in buildings. An example is provided below for residential heating, the largest energy consumer in the Buildings sector.

Electrification scenarios for residential space heating

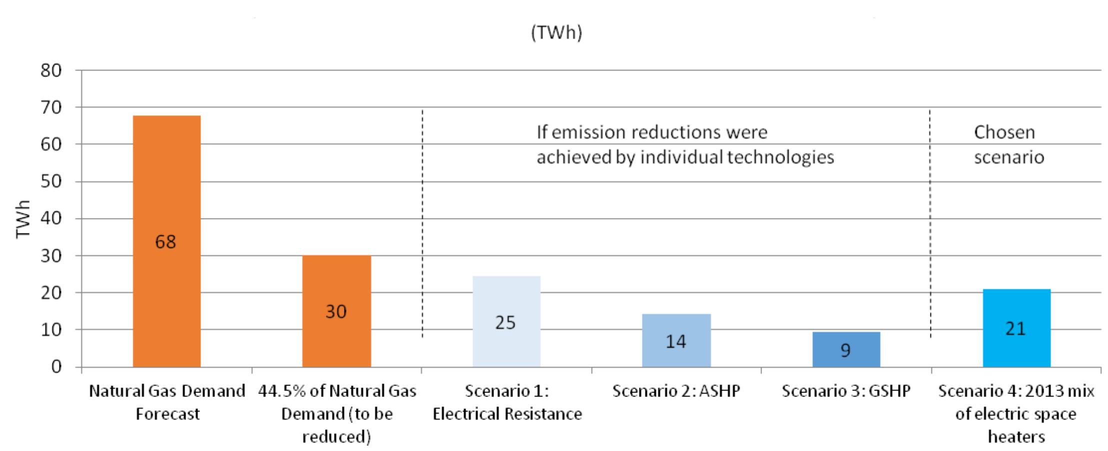
The 2030 energy demand and emissions for natural gas furnaces is based on the MOECC forecast of 2030 building sector emissions. Ontario's residential natural gas furnaces are expected to use 67.9 TWh of energy in 2030 and emit 11.7 Mt CO_2e. An emission reduction from efficiency improvements is assumed prior to estimating the electrification demand as illustrated in Figure 34. As discussed earlier, the efficiency improvement is assumed to be 5.5% which will reduce 2030 forecasted emissions by 0.8 Mt. The remaining gap is 5.2 Mt of emissions that need to be removed through electrification.

Figure 34 – Emissions Forecast for Residential Natural Gas Space Heaters



The analysis, using NRCan data is intended to determine the electrification required based on reducing the equivalent percentage of energy[57]. The energy equivalency model is illustrated in Figure 35 using energy units that have been converted into equivalent TWh's.

Figure 35 – TWh Required for Electrification of Ontario's Residential Natural Gas Space Heaters by 2030

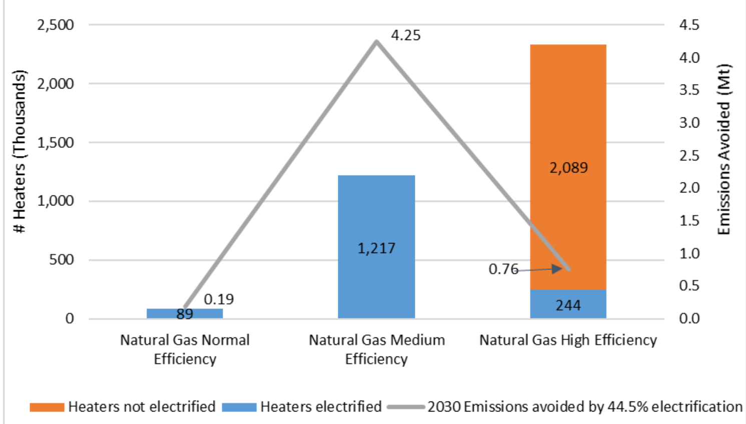


[57] NRCan, National Energy Use Database, 2015

It will be necessary to remove 30 TWh of natural gas energy use by 2030 in order to reduce natural gas emissions by 44.5%. Strapolec's approach to electrification assumed the least efficient furnaces will be converted first, representing the most optimistic scenario that minimizes the potential electricity required per emissions reduced. The distribution by efficiency rating of residential installations of natural gas furnaces in Ontario is shown in Figure 36. There are very few low efficiency furnaces remaining in Ontario.

Figure 36 – 2030 Emission Reductions Achieved by Electrification of 44.5% of Ontario's Residential Natural Gas Furnaces

(Mt CO2e)



Mapping the required emission reductions shows that all low and medium efficiency appliances need to be electrified as well as over 10% of existing high efficiency furnaces. The relative increase in efficiency from switching natural gas heaters to electric for each furnace type is reflected in the assumptions.

Scenarios were developed to determine the electricity required to remove all of the 30 TWh of natural gas energy use and associated emissions. Scenario 1 – electrical resistance heaters, requires 24.5 TWh of electricity to fully displace the natural gas energy. Scenario 2 – ASHPs, requires 14.4 TWh of electricity due to their 1.7 efficiency multiplier[58]. Scenario 3 – GSHPs, requires only 9.4 TWh of electricity due to an almost three-fold increase in energy efficiency.

Scenario 4 is the aggregated model to determine the potential provincial impact. This scenario assumes a mix of electric space heater technologies that mirrors the 2013 installed mix: 68% electrical resistance, 25% ASHPs, and 7% GSHPs. This scenario shows a need for 21.0 TWh of electricity and will avoid 5.2 Mt of emissions.

[58] NRCan, Heating with Oil

5.2.2. Transportation Emission Electrification

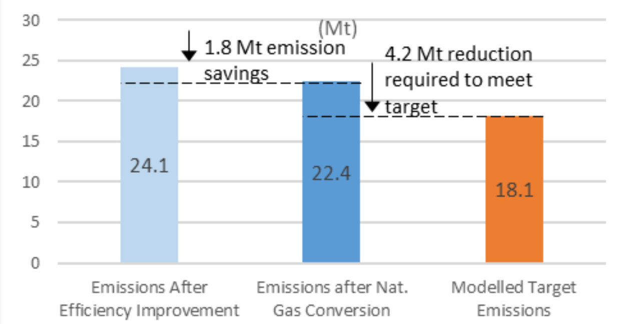
The transportation electrification estimates have been derived separately for the passenger and truck fleets.

Passenger Vehicles

The electrification requirements are driven primarily by an assumption based on the market penetration of the prevailing technology options. Three vehicle options have been modelled to reduce emissions in the passenger vehicle segment: Natural gas vehicles, BEVs and FCEVs. There is much discussion of BEVs in Ontario, with them figuring prominently in the CCAP. Recent market studies suggest there will be 20 million FCEV's globally by 2032[59] which suggests that this vehicle option should be given consideration. The approach to sizing the potential future electricity demand by BEVs and FCEVs is based on the emission reductions required, less the emissions reductions enabled by converting vehicles to natural gas, and then addressing the remaining emissions via equal numbers of BEVs and FCEVs.

The emission balance equation is summarized in Figure 37. It is assumed that 35% of the fleet will convert to natural gas. Based on U.S. Department of Transportation statistics[60], by 2020 Natural Gas vehicles will emit 21% fewer GHG emissions than conventional gasoline. Applying this emission efficiency factor to 35% of the future fleet should reduce emissions by 1.8 Mt, leaving 4.2 Mt to be addressed by the BEVs and FCEVs.

Figure 37 – 2030 Passenger Vehicle Emissions After Efficiencies

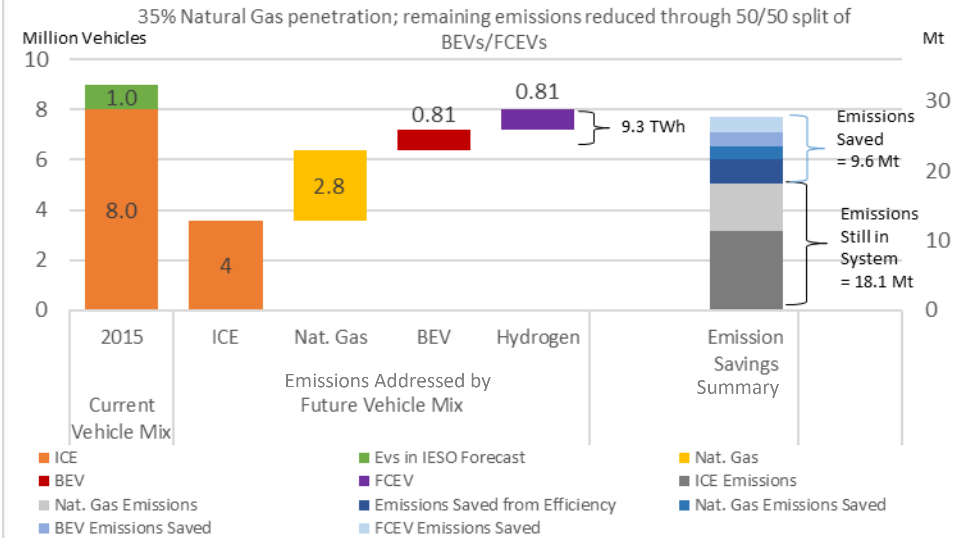


The resulting expected vehicle mix and associated emissions are summarized in Figure 38.

[59] Information Trends, "Hydrogen Fuel Cell Vehicles are Future of the Automobile", www.informationtrends.net/press-release.html regarding "Global Market for Hydrogen Fuel Cell Vehicles", 2016

[60] U.S. Department of Transportation, Transportation Statistics Annual Report 2015, 2015

Figure 38 – Passenger Vehicle Summary



It is assumed that there are no material electrification implications when portions of the fleet convert to natural gas use. To estimate the electrification required for BEVs and FCEVs, the fleet size had to be determined. This was based on forecasting the fuel efficiency assumption of the ICE fleet. It is estimated that average emissions per vehicle in the ICE passenger fleet that may be candidates for electrification will be approximately 2.63 tonnes/year/vehicle. As shown in Figure 37, dividing this value into the 4.2 Mt of emissions to be reduced results in 1.6 million vehicles.

This mix of electric vehicles (EVs) does not account for a mix of Plug in Electric Vehicles (PHEVs) and BEVs. Other studies have shown that when an analysis is based on an emissions reduction target, the number of vehicles may be affected by the vehicle mix, but the TWh/Mt of the fleet is relatively insensitive. Estimates for the EV related electricity demand have been developed from Plug'N Drive data sets and these numbers align well with the IESO's assumptions. Strapolec's model has increased the amount of expected electricity per vehicle, based on the assumption that larger vehicle models will become more common and hence the average electricity needed in the future will be higher than for the smaller vehicles in today's fleet. The assumed electricity required per year is 3.8 MWh/vehicle, based on an average driving distance of 16,000 km for a vehicle mix that would average 11.7 litres/100 kms today.

The electricity required for FCEVs has been obtained from the U.S. NREL studies[61], which show an increasing efficiency factor that should lead to 57 miles/kg of hydrogen by 2025. This is based on the NREL data reflecting expected electrolysis efficiency[62]. On this basis, operating hydrogen vehicles will require about twice the electricity consumed by BEVs, or 7.7 MWh/year. This estimate assumes that hydrogen production takes place at a Class A, Tx-connected industrial facility that avoids the line losses in the distribution system. Toyota estimates of its Mirai[63] vehicle fuel efficiencies and associated demand for

[61] Kurtz, Fuel Cell Electric Vehicle Evaluation, 2016
[62] Kurtz, Fuel Cell Electric Vehicle Evaluation, 2016; U.S. DOE, The Fuel Cell Electric Vehicle
[63] Toyota, The MIRAI Life Cycle Assessment Report, 2015

hydrogen are 76 miles per kg. This suggest 36% less energy required than derived from the NREL forecasts used in this study. This data sample suggests the electrification estimates and costs used in this study to support FCEVs may be high.

Based on 800,000 BEVs and 800,000 FCEVs, it is estimated that in 2030 about 9.3 TWh of electricity may be required to power this fleet.

Trucks

The first step in determining the electrification impact of trucks is to assume the potential market shares of the available emission reducing options. Strapolec's analysis indicates that constraints on the maximum market shares arise for options that emit the least number of emissions, such as the natural gas vehicles, Class 8 hybrids, and PHEVs. The emission-free options of renewable diesel and hydrogen vehicles, in equal proportion, were then used as the plug assumption for achieving the remaining emissions reductions required.

Table 3 summarizes the market share assumptions that were used to estimate the electrification implications. Priority was placed on the short-haul vehicle fleet, based on the assumption that many of the technology solutions would be most suitable to that market, such as the PHEV and hydrogen vehicle solutions. Research has not found cases where PHEVs are suitable for the Class 8 vehicles. While it is generally accepted that hydrogen vehicle solutions for long-haul trucking are not a low-cost alternative, there are specific freight routes where distances are manageable and economic for a hydrogen solution, such as with the ship to rail freight transfer corridor in California[64].

Table 3 - Trucks Emission and Electricity Implications

Heavy Duty Short Range	Natural Gas	Plug-in Hybrid	Hydrogen	Renewable Diesel
% of Fleet	15%	30%	28%	28%
Emission Savings (%)	27%	60%	100%	100%
Emission Savings (Mt)	0.49	2.18	3.43	3.43
Efficiency Gain	0%	20%	20%	20%
Electricity Demand (TWh)	-	3.17	9.72	1.21
Class 8 Tractor Trailer	**Natural Gas**	**Hybrid**	**Hydrogen**	**Renewable Diesel**
% of Fleet	30%	25%	10%	10%
Emission Savings (%)	27%	20%	100%	100%
Emission Savings (Mt)	0.75	0.45	0.91	0.91
Efficiency Gain	0%	20%	20%	20%
Electricity Demand (TWh)	-	-	2.56	0.32

The emission reduction and efficiency improvements for the PHEV options were obtained from the WrightSpeed vehicles. The emissions savings and efficiency gains for the Class 8 hybrids are based on the U.S. DOE Supertruck results and are expressed with respect to the gains the SuperTruck program has

[64] Hydrogenics interviews

reported for the remainder of the ICE fleet. It has been assumed that the SuperTruck program efficiency gains will have penetrated the market by the late 2020s. The assumptions presented here for Class 8 hybrid vehicle penetration are much higher than forecast in the SuperTruck business case assumptions.

In developing the market shares of emission reducing options, the maximum achievable emission reduction estimated for the short-distance truck segment was developed before assigning hydrogen and renewable diesel solutions to the Class 8 vehicle fleet. It has been assumed that the entire short= distance vehicle fleet will have been converted to lower emission options in the future.

The assumed market shares started a 30% natural gas fleet and 30% for either PHEVs for the short-range segment or hybrids for the Class 8 segment. This was subsequently moderated in order to achieve the emission targets. The renewable diesel and hydrogen penetration were used as the "plug" to represent emission-free options to achieve the target. Market shares of the other options were reduced and replaced by hydrogen/renewable diesel options until the targeted emission reductions balanced. Eighty-five percent of the Class 8 fleet will require alternatives.

In order to estimate the electrification implications for hybrid and FCEV truck options, the energy content and emission characteristics of diesel were compared to gasoline. Diesel produces 15% more energy per emission. Using this approach, electricity demand was estimated by scaling up from the PHEV and FCEV TWh/Mt ratios observed for light duty vehicle options. The electrification requirements of renewable diesel were based on research that suggests 33.5 g of hydrogen are required to produce a litre of renewable diesel[65]. Electricity demand was estimated based on this hydrogen electrolysis model.

The market share assumptions are intended to provide a frame of reference for estimating possible electrification implications in the aggregate. As previously noted, the FTR has assumed similar natural gas penetration in the overall transportation sector. To the degree that renewable diesel can become available, for example, the market shares of all the alternatives may be very different.

It may be unrealistic to expect that the entire fleet will convert to new technologies. However, if the trucking sector cannot achieve the emission reduction targets then other sectors will have to make up the shortfall. The purpose of this analysis is to simply identify electrification options. If similar TWh/Mt ratios are realized in other sectors that make up the shortfalls in trucking, the total demand for new electricity could be similar to that illustrated here.

5.2.3. Industry Emission Electrification

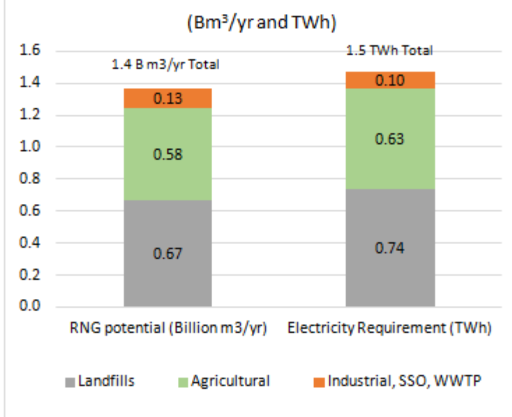
Electrification needed to displace natural gas emissions from the Industry sector are different for each of the four concepts/ideas evaluated in this study: RNG; Hydrogen P2G; SMR replacement; and industry electrification of natural gas use.

[65] Strapolec analysis based on the rapeseed model in: Natural Resources Canada. Study of Hydrogenation Derived Renewable Diesel as a Renewable Fuel Option in North America. March 30, 2012.

Renewable Natural Gas

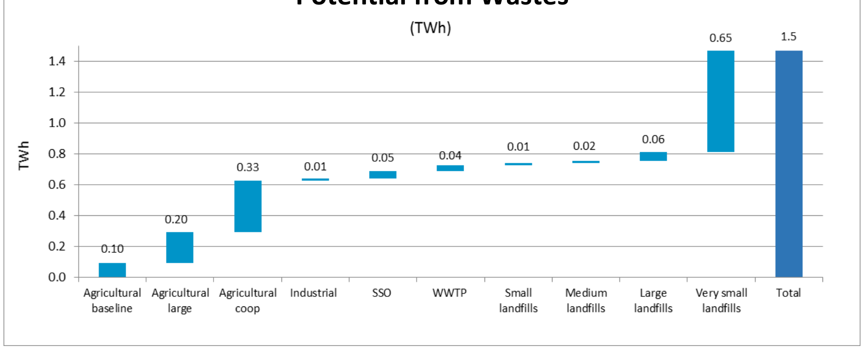
The Electrigaz report provided to the OEB contains business cases for most of the RNG options that have been contemplated for Ontario. Within these business cases, the amount of electricity required for each option is identified. The total expected electricity demand that may arise from RNG production is estimated at 1.5 TWh as summarized in Figure 39.

Figure 39 – Annual RNG Potential from Ontario Wastes and Associated Electricity Required



In proportion to the emissions saved, the greatest need for electricity arises in the production of RNG from landfills and agriculture applications. However, the electrification requirements differ substantially according to the characteristics and scale of the potential RNG sites. The distribution of electrical demand based on potential RNG sites by sector is shown in Figure 40.

Figure 40 – Electricity Required to Produce Ontario's RNG Potential from Wastes



Hydrogen P2G and SMR Displacement

The electrification requirements are estimated based on electrolyser efficiencies forecast by NREL. It is estimated that in the future, 47.7 kWh of electricity will be required to produce 1 kg of hydrogen.

The estimated volume of hydrogen to support P2G and SMR displacement was calculated in Section 3 of this report at 200 million kg. The net electricity required is estimated at 6.3 TWh for P2G hydrogen and 3.3 TWh to displace SMR production of hydrogen.

The combined impact of these two options suggest a need for over 1250 MW of baseload generation to support this hydrogen production requirement.

Industry Use of Natural Gas

It has been assumed that the energy content of natural gas used in Industry, when replaced with electricity will realize a 5% energy efficiency benefit. As a result, 7.6 TWh are assumed to be required to replace 290 Tera Joules of natural gas energy.

5.3. Summary

To reach Ontario's 2030 target emission level using a combination of efficiency savings and electrification, an estimated 90 TWh of new electricity will be required to enable the adoption of the forty-five opportunities assessed in this study for electrification in buildings, transportation, and industry.

The projected growth in electricity demand of 90 TWh is approximately 80% higher than the incremental 50 TWh identified in the OPO Outlook D, and would be needed 5 years sooner than the Outlook D provides for. The new demand arises primarily in the form of winter space heating and industrial level baseload consumption. Electric vehicles represent less than 10% of the expected new demand. Trucks represent the greatest challenge. The use of hydrogen in many applications suggests that hydrogen may be an important pathway to achieving Ontario's emission reduction strategy, a unique Ontario opportunity due to Ontario's virtually zero-emission electricity supply.

The ability to achieve emission reduction targets, and the cost of doing so, will be driven by the pace at which new electricity generation, transmission, and distribution capacity is developed. Developing new generation capacity prior to 2030 will be difficult to achieve.

Deferring compliance with the 2030 emission reduction target may be necessary, as implied by the OPO and FTR 2035 Outlooks, although there is no publicly stated indication that the province intends to be domestically non-compliant with the 2030 target. The pending retirement of the PNGS may further impede the ability to supply mid-term emission reduction initiatives with carbon free energy and could dampen the pace of subsequent progress to meeting the 2030 targets.

6.0 Cost of Emission Reduction Options and Carbon Price

This section provides an estimate of the incremental costs required to achieve the emission reductions and defines this cost in terms of the equivalent carbon price that would enable each option to be economic.

This section first provides an overview of the results of the analysis and then treats each sector individually, examining the incremental costs of each option as compared to the expected future costs of the BAU use of the fossil fuels. A summary of the total cost that can be expected to achieve emission reductions is provided along with a spotlight on the opportunities for natural gas displacement by hydrogen in the industrial sector.

The overview section portrays the electrification relationship with emissions reductions as a portfolio of options. The portfolio view is intended to highlight that collectively the options provide an informative view as to the aggregated emission reduction challenge that is emerging for the electricity sector.

For Buildings, residential space heating is provided as an example for the methodology applied for all buildings options, both residential and commercial. In Transportation, individual attention is given to passenger vehicles and trucks due to the number of alternatives evaluated and to best set out the special challenges that trucking represents.

This section closes with a summary of the key findings.

6.1. Overview

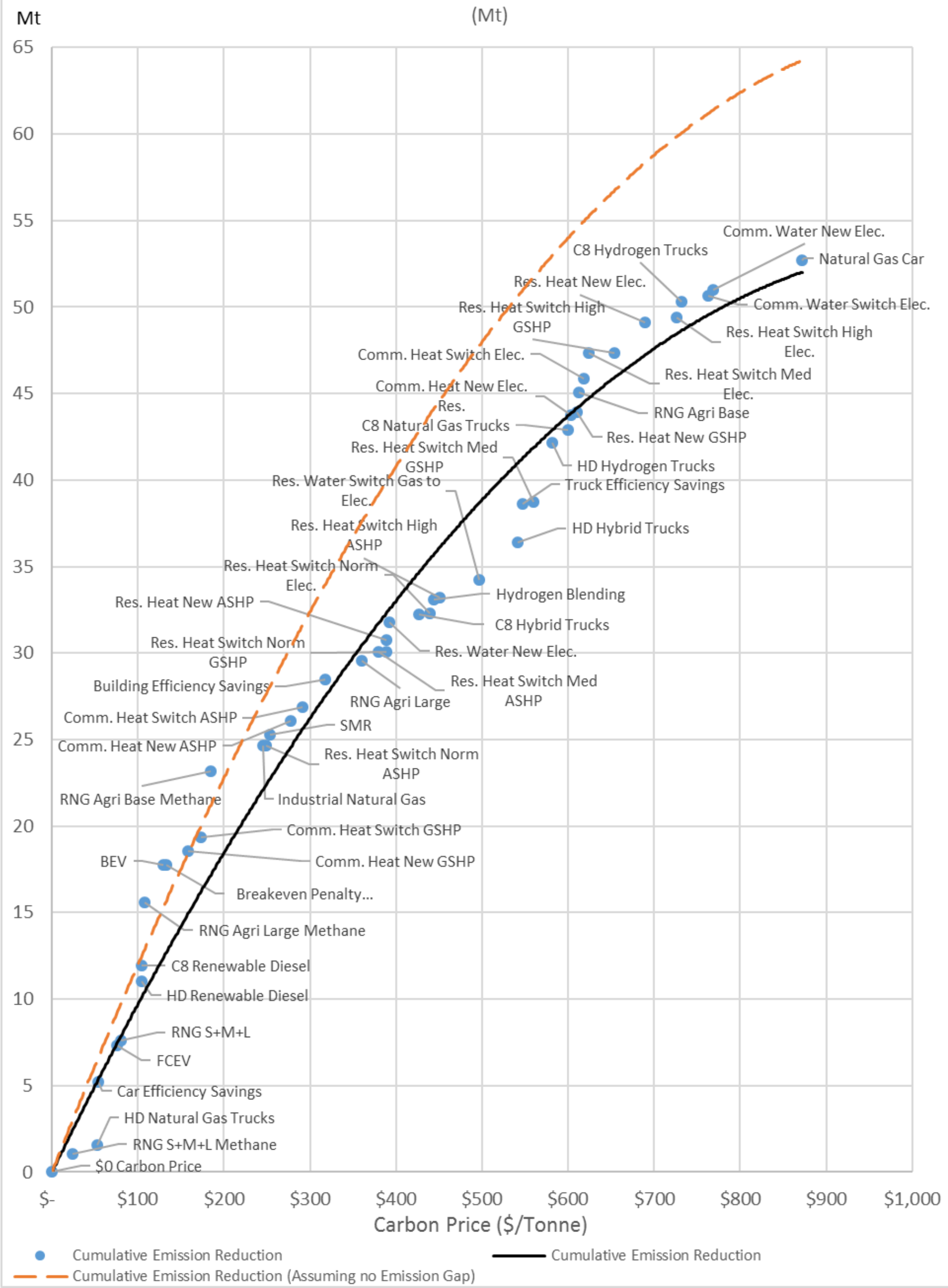
Incremental costs are defined as the change in costs associated with the switch from an existing emitting technology to using a low-carbon alternative.

A carbon price provides the framework for estimating the total incremental costs. The carbon price reflects the incremental cost of switching divided by the emissions avoided by the chosen alternative. A carbon price therefore reflects the breakeven market cost that enables user investment to switch to low carbon technologies. Each of the options has been costed to determine the carbon price that makes each technology choice economic for an end user.

Figure 41 illustrates the portfolio of emission reduction options and the associated carbon price implications. This illustrative portfolio is used in this study to develop the cost implications, but may also provide a useful benchmark for evaluating future innovations.

This study has not assessed emission reductions in certain areas. For the purpose of estimating the total cost, a margin has been added to the assessed data to reflect the costs that may arise when solutions to the remaining emissions challenges emerge. A simple percentage multiplier has been applied throughout the range of options consistent with earlier stated assumptions reflecting the expectation that innovations will occur in an equivalent incremental manner as reflected by the suite of existing options. This adjustment is represented by the dashed red line in Figure 41.

Figure 41 – Cumulative Emissions Reductions vs. Carbon Price



A high carbon price may be necessary before individuals choose the lower emission option. The cost of half of the emission reductions are in the $200/tonne to $600/tonne range, with an increasing potential incremental emission reduction benefit as the price of carbon increases. To fully realize the desired emission reduction of 67 Mt by 2030, a carbon price in excess of $800/tonne may be required as represented by the natural gas passenger vehicle option illustrated in Figure 41.

In addition to the emission reduction options assessed by this study, provisions have been made for:

- Costs to achieve efficiencies: Building efficiency improvements have been derived from 50% of the MOECC CCAP costs or about $320/tonne. Cars at $50/tonne. Trucks at $550/tonne based on increased capital costs to achieve the D.O.E.'s SuperTruck efficiencies.
- Cost to realize the 12 Mt of emission not assessed by this study have been assumed to be achieved proportionately throughout the cost curve (red dashed line).

The effective carbon prices that enable emission reductions are dispersed across all sectors and over a wide range of options. There is no apparent threshold that represents a magic target. Increasing the carbon price to enable one solution, may also enable the economic viability of several others. For lower cost options, higher carbon prices may also result in greater market penetration than has been assumed.

With this variability in carbon prices, and the innovations that will begin to accelerate as the battle against climate change progresses, these results speak strongly to the need for a transparent, evidence based decision making process to support the adoption of specific emission reduction solutions. Attempting to pick winners in a vacuum comes with significant risk.

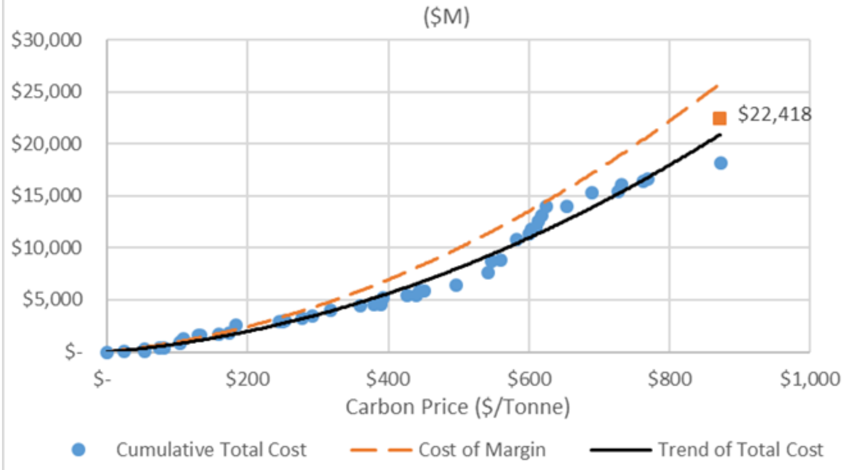
6.1.1 Assessing the Total Cost

A carbon price presents users with a choice between an emitting technology, that has the appropriate carbon price levy on it, versus a non-emitting option that a user would buy at that same net levied cost. This is the essential economic principle behind the C&T concept. In this perfect system, each user pays the cost for switching as it becomes more economic to do so.

When considering the challenge from a societal or total economy perspective, the minimum cost to achieve the emissions can be computed by taking the equivalent carbon price that enables a particular option and multiplying it by the incremental emissions saved by that choice.

When aggregated among all of the options, starting with the lowest cost and proceeding until the emission target is met, a total cost estimate can be developed. The minimum cost to achieve the 2030 emission target is $22B as shown in Figure 42 below.

Figure 42 – Minimum Cost of Achieving Emissions Reductions

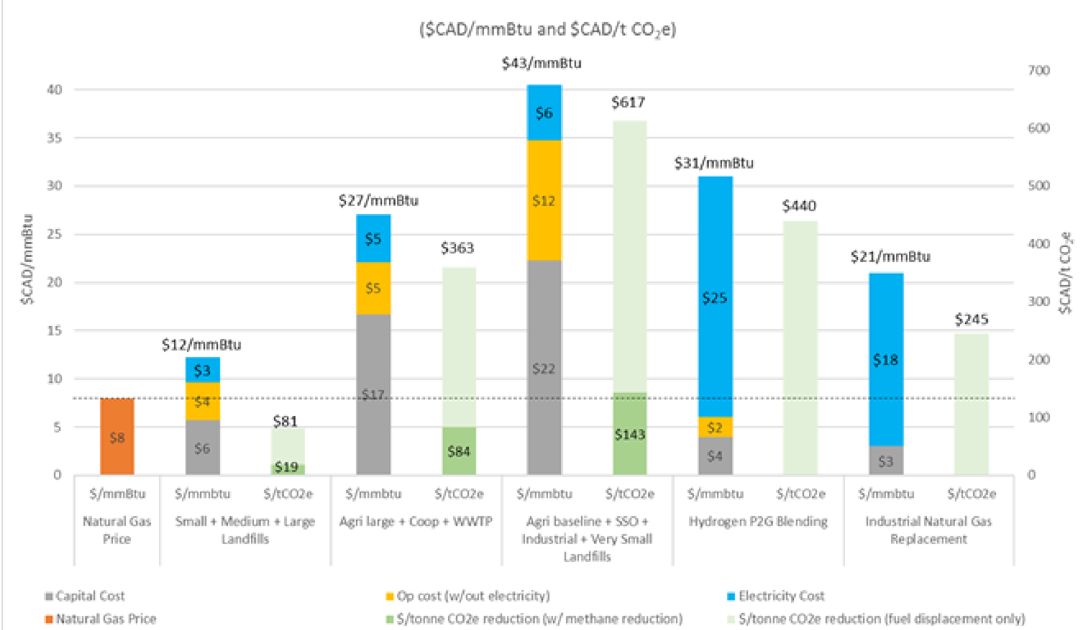


6.1.2 A look at Natural Gas Displacement and Hydrogen

This analysis points to an emerging role for hydrogen that could become important to Ontario's emission reduction strategy.

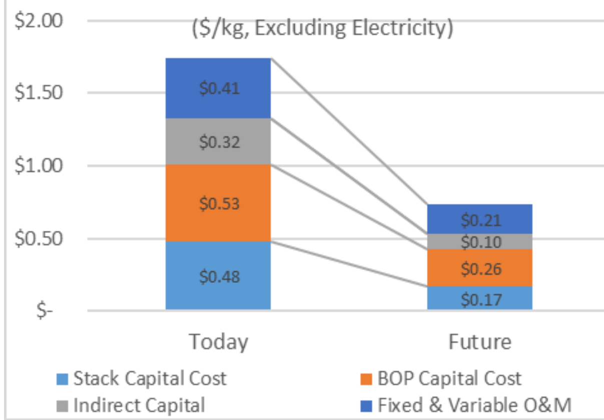
Figure 43 illustrates the incremental costs for the natural gas displacement technologies that have been examined. The RNG costs are based on the Electrigaz report submitted to the OEB by Union Gas. Other than the larger landfill gas RNG sites, most of the emission savings from RNG production will come at a high cost. The blending of hydrogen may be more economic in some circumstances.

Figure 43 – Cost of RNG Production Using Ontario Wastes



The evolving economics of low carbon hydrogen production from electrolysis are being studied by the U.S. NREL[66] and who have forecast the cost of hydrogen electrolysis facilities to decline by 60% over the next 5 to 8 years as shown in Figure 44.

Figure 44 – Cost of Central Electrolysis, Current vs. Future



The implications of this cost reduction will impact the economics for all of the hydrogen applications that have been identified for inclusion in this study. Figure 43 shows a range of carbon prices of $300 to $600 range are required to displace natural gas. In contrast, a $250/tonne carbon price as shown in Figure 45 to make hydrogen electrolysis economic compared to SMR for use in refineries appears modest.

The low cost of hydrogen also extends to FCEVs for the passenger vehicle market as summarized in Figure 46. Hydrogen FCEVs may become the lowest cost, zero-carbon vehicle in the next 10 years if the hydrogen supply is available.

Figure 45 – Future Costs of Hydrogen Production

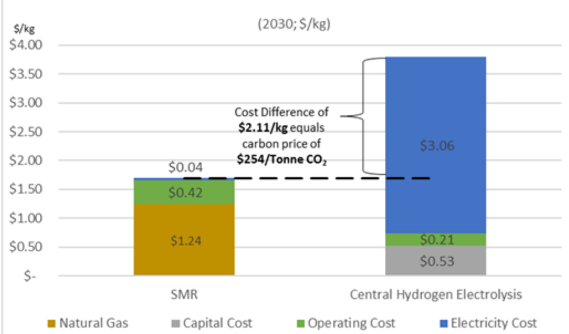
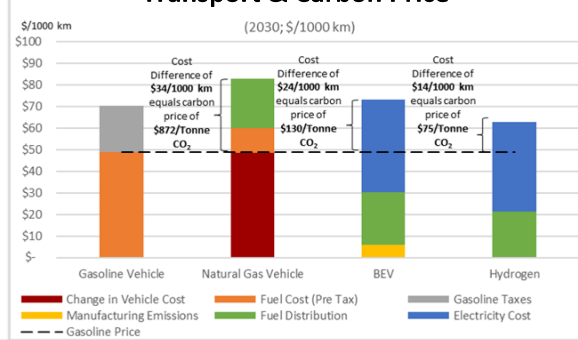


Figure 46 – Future Cost of Passenger Transport & Carbon Price



The detailed cost assumptions for the above findings are provided in the next subsections.

[66] Ainscough, Hydrogen Production Cost from PEM Electrolysis, 2014, FCH JU "Commercialisation of Energy Storage In Europe", March 2015

6.2. Detailed Costing Analysis for Building Options

This section examines the incremental costs for switching to the alternative heat generating equipment in buildings: space heating (electric resistance, AHSPs, GHSPs); water heaters; and, appliances.

Individual analyses were conducted for the residential and commercial building segments. An identical approach was taken for both segments and all the evaluated technologies. The incremental costs are determined by examining:

1. Capital costs to acquire the new equipment
2. Maintenance costs
3. Cost of fuel (natural gas or electricity)

The costing information has been derived from NRCan and EIA[67] sources.

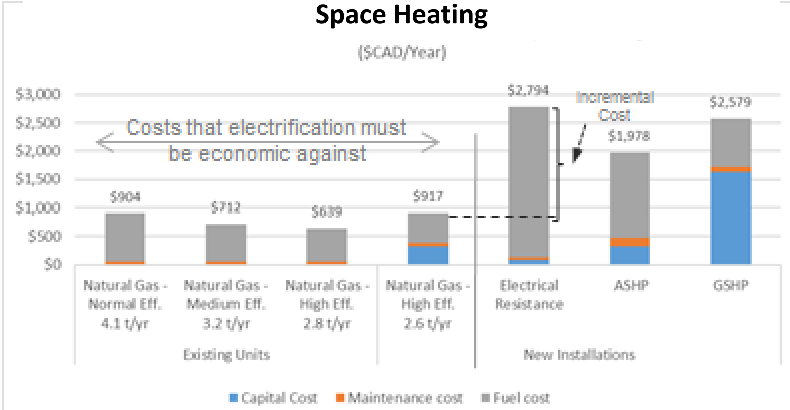
Two scenarios under which a user may choose to switch to a lower emitting technology were considered:

a) An end user is considering *switching* to a new and more efficient technology although the user's existing device may still have a useful remaining lifespan.

b) An end user needs a *new* device because the existing system has reached its end of life, or is being installed in a new building. The user must choose between a new natural gas or electric device.

The residential space heating example illustrates the approach. Figure 47 shows the incremental cost implications for residential space heating. Air Source Heat Pumps (AHSP) are the lowest cost means of electrifying residential heating.

Figure 47 – Cost of Residential Natural Gas vs. Electric Space Heating



The carbon price that makes each option economic differs between the scenarios based on the incremental cost difference and the emissions saved. Computing the incremental cost differences for

[67] Navigant Consulting, Technology Forecast Updates, 2014

each option and dividing it by the emissions saved yields the carbon prices shown in Figures 48 and 49 for both the *switching* and *new* scenarios.

Figure 48 – Carbon Price for Switching to Residential Electric Space Heating

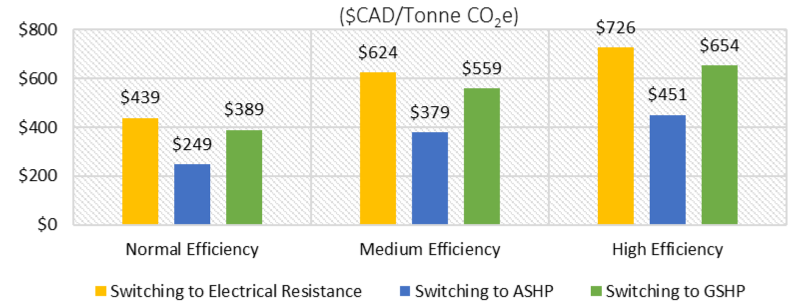
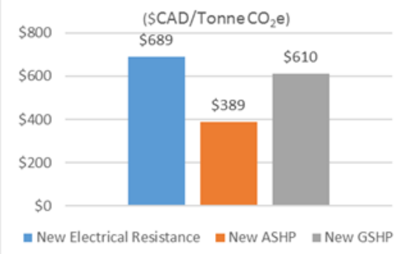


Figure 49 – Carbon Price to Avoid High Efficiency Natural Gas Furnaces



A carbon price of at least $379 per tonne CO_2e would be needed to enable the purchase of an AHSP to replace an existing medium efficiency unit. Subsequently higher carbon prices would facilitate medium and high efficiency natural gas furnaces to be electrified with an AHSP. The estimated carbon prices assume that the full cost of having a natural gas delivery connection has been saved.

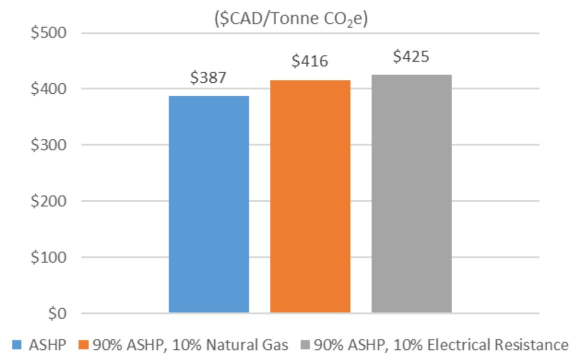
Electrical resistance furnaces are the next most economical option for residential applications with the largest contributor to cost over the product lifecycle being the price of electricity. The Class B consumer rate of $180/MWh is the assumed price of electricity in the illustrations.

Although the fuel cost for running a GSHP is much lower compared to other electric heaters due to the high efficiency of the device, the capital cost of installing a GSHP is significantly higher than other types of heaters. This is a limiting factor in bringing these devices to the residential space heating sector. GSHPs are the most economical for larger commercial applications.

It is generally expected that ASHPs require supplementary heating during very cold days[68]. Figure 50 illustrates the results of a sensitivity analysis conducted to determine the impact on the carbon price for ASHPs if 10% supplementary energy were required from a) natural gas; or b) electricity. The figure represents an aggregated blended average of all scenarios modelled for ASHPs. The natural gas supplementary case assumes the addition of a connection charge for accessing the natural gas supply.

[68] Energy Solutions Centre, An Evaluation of Air Source Heat Pump Technology in Yukon, 2013

Figure 50 – Carbon Price Impact from ASHP Only vs. ASHP with Supplementary Heat



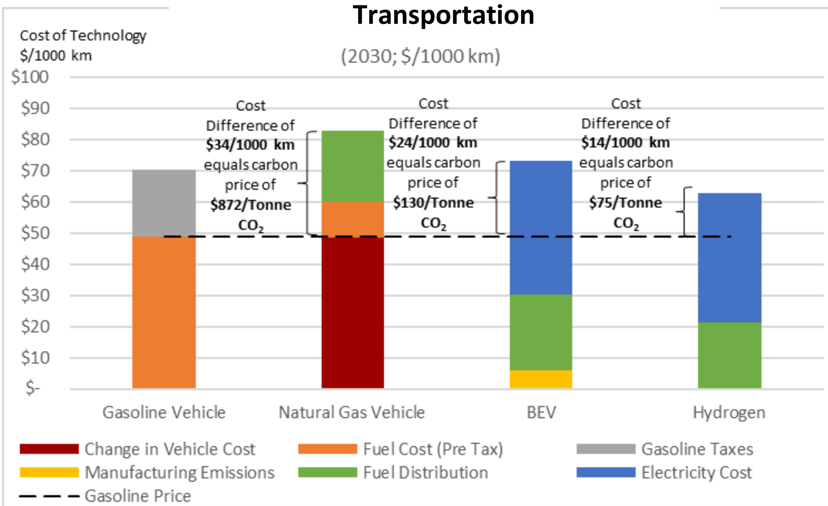
The carbon price for both options increases, with natural gas substitution being marginally less expensive than using electricity as the supplementary heating source. The comparison is sensitive to the natural gas connection delivery charge assumption, which for this scenario was estimated at $5/month. If a 10% supplementary energy is required, the challenge is that a 10% greater market penetration of these devices must be achieved to realize the same provincial level emission reduction.

6.3. Detailed Cost Analysis for Transportation

6.3.1. Passenger Vehicles

This section examines the incremental costs of switching from the future projected ICE vehicles to one of the three alternatives assessed in this study and presents the assumptions that lead to the effective carbon price. The results for passenger vehicles are summarized in Figure 51.

Figure 51 – Effective Cost of Carbon - Transportation



As this study is focused on the time period leading up to achieving the 2030 emission reductions target, costs relevant to that time frame are considered. Understanding the future state of ICE vehicles is a common element for assessing all technology options. Several assumptions have been made regarding the estimation of the cost of these future vehicles:

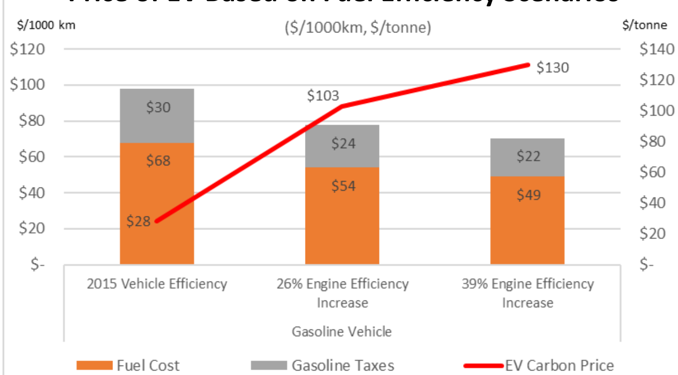
a) Vehicle Costs: According to Bloomberg, the future costs of the different alternative vehicles will converge to an average price[69]. The European Fuel Cells and Hydrogen Joint Undertaking has made a similar statement regarding hydrogen vehicles [70].

b) Cost of Fuel: Gasoline for ICE vehicles is expected to rise approximately 20% from today's levels[71].

c) Gasoline Tax: This tax is removed for comparison purposes as it represents government revenues that will still have to be recovered from somewhere and hence do not impact the incremental cost of the transportation options.

d) Emissions of ICE vehicles: Assumed efficiency improvements will put upward pressure on equivalent carbon prices as illustrated in Figure 52 for the EV scenario. In this scenario EV costs are held constant, just the emissions being offset are changed as the EV substitutes for more and more efficient ICE vehicles. The baseline assumption in this study for emission reductions resulting from efficiency improvement is 39%.

Figure 52 – Cost of Gasoline Vehicle vs. Carbon Price of EV Based on Fuel Efficiency Scenarios



Additional assumptions relevant to each technology option are as follows:

1) Natural gas vehicles
   a. It is assumed that natural gas vehicles will be based on the same platform and engine as ICE vehicles and hence the costs of these vehicles are assumed to be similar.

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69 Bloomberg, Here's How Electric Cars Will Cause The Next Oil Crisis, 2016

70 European Fuel Cells and Hydrogen Joint Undertaking, A Portfolio of Power-Trains for Europe, 2010

71 Growth of oil to $55/barrel in future from $47/barrel today (Porter, OEA 2016 energy conference). FTR suggests a similar assumption of slightly over 20% for residential gasoline use.

b. Natural gas vehicles require a compressed natural gas (CNG) tank which is estimated to add about $6000/car.

c. The cost of natural gas is forecast to be $0.56/litre equivalent pre-tax.

- Price of natural gas is split between the commodity cost of the natural gas and the distribution cost.
  1. The commodity price of natural gas is expected to be $0.19/L gasoline equivalent. This is based on double the 2016 price of natural gas, as per the EIA's 2016 Annual Energy Outlook.
  2. The distribution cost of natural gas is calculated based on the difference between the pump cost of natural gas (gathered from a natural gas service station located in Toronto), and the commodity price at the time[72].

2) EVs

a. Additional emissions created during manufacturing[73]

- EV batteries in Canada will either be sourced in the US (giga-factory) or in China and hence have a carbon component that should be subject to the carbon price.
- China is introducing a carbon pricing schema for their economy.[74]

b. Implications on the electricity distribution system

- Cost of charging infrastructure[75]
  1. at home: $2,500 Level-2 Charger
  2. for public use: $50,000 Level-3 charger.
- It is assumed that the local distribution system will need to be enhanced to accommodate the electric vehicles. Represented by allocating a 20% increase in the distribution cost component of a residential bill. This component is so small it is not visible on the chart.

c. Electricity for EV charging.

- Cost of future electricity for Class B consumers is assumed to be $180/MWh.

3) FCEVs

The incremental costs of FCEVs are comprised of three components:

a. Production cost associated with the electrolyser operations

[72] Data taken at two points in time. One in July 2010, the other September 2016. The average of these two dates is used to calculate delivery cost (Canadian Natural Gas Vehicle Alliance, Natural Gas Refueling Stations, 2016; OEB, Natural Gas Rates – Historical, 2016)

[73] 57.94 g/km additional manufacturing emissions above gasoline car (Nealer, Cleaner Cars from Cradle to Grave, 2015)

[74] Cheadle, China cap-and-trade market gives carbon pricing opponents 'nowhere to hide', 2016

[75] Bruce Power, Accelerating the Deployment of Plug-in Electric Vehicle in Canada and Ontario, 2016

- The costs of operating electrolysers, predicted by the NREL[76] as previously discussed, are expected to be approximately $0.74/kg. This equates to ~$8/1000km excluding the electricity inputs.
- The electrolyser operating costs are included in Figure 51 as part of the cost of electricity.

b. Cost of electricity to produce the hydrogen
   - The cost of electricity reflects the efficiency assumptions regarding the electrolysers, which is forecast to be 47.7 kWh/kg.
   - It is assumed that the larger scale central production model of 50 MW electrolysers will be eligible for Tx connected Class A industrial rates.

c. Cost to distribute the hydrogen (central model)
   - The distribution model assumed for hydrogen is to deliver by truck to gas stations with the truck trailer being left at the station as the storage device77. These costs include the dispensing costs of fueling customer vehicles etc..
   - The EU study on FCEVs identified that the distribution system cost for hydrogen is expected to be similar to that of EVs given charging station needs, etc.. The independently derived assumptions in this report is consistent with that observation.[78]

The breakeven carbon price is defined as the effective price of carbon that will make the cost of acquiring and operating an alternative the same net cost to the consumer as purchasing an ICE vehicle. This is calculated by assessing the cost to drive the electric vehicle, subtracting the cost to drive an ICE vehicle, and dividing the difference by the emissions saved. The FCEV has the lowest forecast required carbon price at $75/tonne, just over half the expected carbon price of $130/tonne for future EVs.

6.3.2. Trucks

As noted earlier, reducing emissions from the trucking sector will be challenging. All the options assessed in this report have been met with various levels of skepticism, largely on the basis of that the commercial viability is perceived to be unlikely. The economics of each option are addressed below.

The trucking segment has two distinct categories, each with its own specific cost comparators. Figures 53 and 54 summarize the carbon price calculations that would normalize the economics providing a basis for comparison when choosing between these vehicle options.

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[76] Ainscough, Hydrogen Production Cost from PEM Electrolysis, 2014

[77] Weil, H_2 Production and Delivery Cost Apportionment, 2012

[78] European Fuel Cells and Hydrogen Joint Undertaking, A Portfolio of Power-Trains for Europe, 2010

Figure 53 – Effective Cost of Carbon – Heavy Duty Short Range Trucks

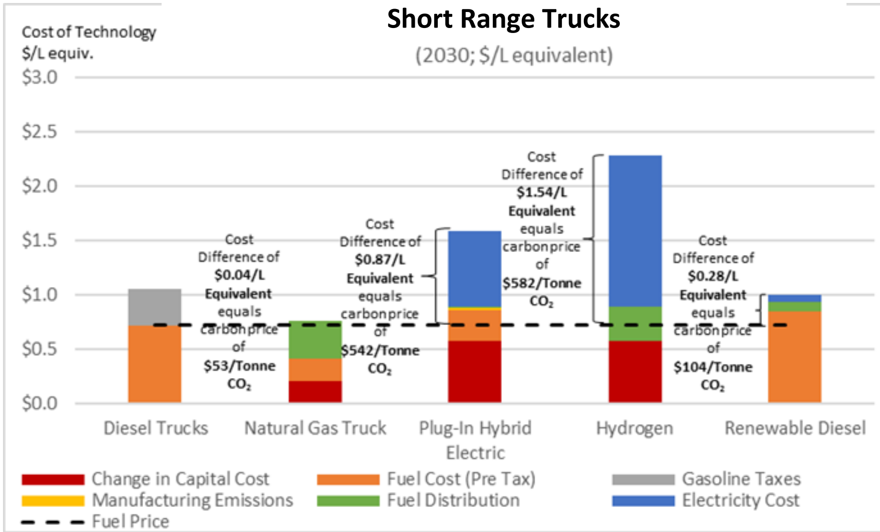
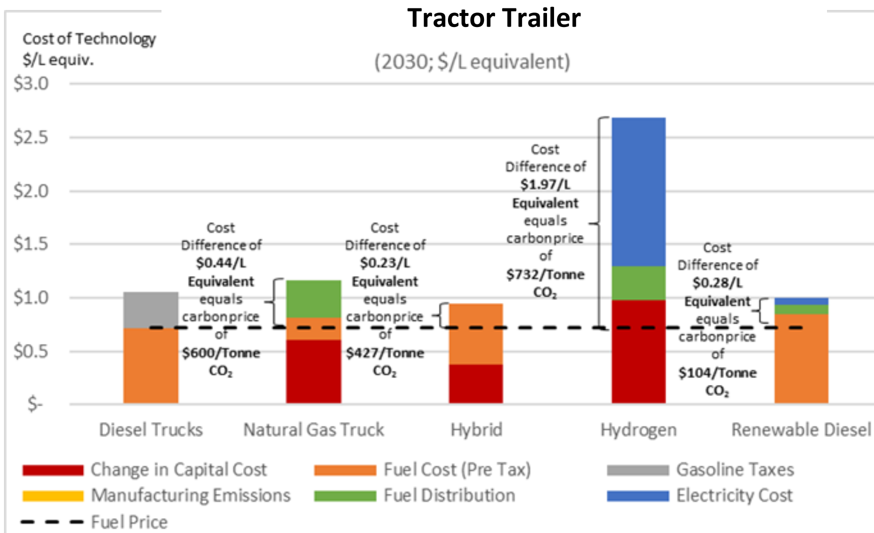


Figure 54 – Effective Cost of Carbon – Class 8 Tractor Trailer



Natural gas trucks appear to be the most economic for short-range vehicles with carbon prices in the $50/tonne range, slightly more economical than renewable diesel carbon prices in the $100/tonne range. As expected, hybrids and FCEV trucks would require much higher carbon prices in the $540 to $580/tonne range. The challenge with the natural gas vehicles is that they cannot, even at 100% penetration, achieve the trucking sector's emission reduction targets. Renewable diesel vehicles cannot achieve reduction targets either, due to real world constraints on the availability of feedstocks. Carbon pricing mechanisms will be required to make other vehicle options economic at some time before 2030.

For the Class 8 tractor trailers, other than renewable diesel, all options have high carbon prices, with hybrids potentially being the earliest adopted option requiring a carbon price just over $400/tonne. As indicated in the earlier market sizing section, the high cost of the hydrogen vehicles, particularly for Class 8 vehicles, will reduce their market share. However, the reality that the emissions must be reduced somehow may cause carbon pricing policies to ensure hydrogen vehicle options, or other alternatives not yet identified, are enabled.

Assumptions

The assumptions applied to each vehicle type are summarized in Table 4. All HD trucks are assumed to have a life of 450,000 km[79], and an efficiency of 4 km/L[80]. This measure is used to compare capital costs.

Table 4 - Trucking Emission Reduction Option Cost Assumptions

Heavy Duty Short Range	Natural Gas	Plug-in Hybrid	Hydrogen	Renewable Diesel
Costs	$60k	$120k	$60k + $37k	-
Emission Savings (%)	27%	60%	100%	100%
Efficiency Gain	0%	20%	20%	20%
Class 8 Tractor Trailer	**Natural Gas**	**Hybrid**	**Hydrogen**	**Renewable Diesel**
Costs	$60k	$37k	$60k + $37k	-
Emission Savings (%)	27%	20%	100%	100%
Efficiency Gain	0%	20%	20%	20%

Natural Gas Trucks

As with natural gas light duty vehicles, it is assumed that these vehicles have parameters identical to ICE truck vehicles with two caveats:

- For Class 8 vehicles, an additional $60,000 fuel tank with an ICE vehicle equivalent range of 1200 km range between fuelling[81]
- For short-range vehicles, a similar cost assumption is made based on the WrightSpeed findings that natural gas vehicle conversions cost $50,000 US[82].

Plug in Hybrid Electric Vehicle (PHEV) Short Range Trucks

- The costing assumptions for PHEV truck options are based on the research sample for WrightSpeed's after market hybrid vehicles. These are offered as post market upgrade kits that cost approximately $200K, which costs "$150K more than a natural gas conversion". Upgrades are typically done on older, soon to be retired diesel vehicles which makes the choice economic compared to purchasing a new vehicle. The turbine technology deployed can be fuelled with diesel, the assumption used here to make comparisons more direct.

[79] Assumed based on analysis from Canadian vehicle study (NRCan, Canadian Vehicle Survey, 2010)
[80] NRCan, Canadian Vehicle Survey, 2010
[81] Approximate estimate only derived from Canadian Natural Gas Vehicles Association informal discussions
[82] Berg, Wrightspeed's Tantalizing Turbine-Electric Drivetrain, 2015

- The electricity to charge the vehicles is assumed to be available at Class B consumer rates.

Hybrid Class 8 Trucks

- Based on the DOE's Supertruck program results, the hybrids are forecast to incur an additional capital cost of $37k/vehicle[83] and achieve 20% greater emissions reductions than the equivalent SuperTruck ICE vehicles. Part of the emissions reductions are derived from efficiency gains resulting from aerodynamic improvements.

Hydrogen Vehicles

- As with the light duty fleet, it is assumed that hybrid and hydrogen technology capital costs converge. As such, the hybrid capital cost of $37K/vehicle is applied to the hydrogen vehicle along with the assumption that the greater aerodynamic efficiencies will also be realized by FCEV vehicles.
- The compressed fuel tank, as with natural gas vehicles is a technical limit. It is assumed that the hydrogen vehicle cost will reflect this same fuel tank cost.
- Electricity and hydrogen production and distribution costs are assumed to be similar to those for light duty FCEVs.

Renewable diesel

- Costing assumptions for renewable diesel have been extracted from the FTR report using the bio-diesel values as the reference, and they are expected to be 19% higher than the price for diesel fuel.
- The cost of producing 33.5 g of hydrogen per litre has been included.
- A placeholder for distribution costs was set at 25% of the cost of natural gas distribution based on the notes in the FTR that significant infrastructure will have to be built in Ontario to accommodate production.

6.4. Summary

Forty-five carbon saving technologies have been identified to save emissions in the Buildings, Transport and Industry sectors. Carbon pricing is used to measure the incremental costs of switching between emitting technologies and the lower emitting alternatives that have been assessed to help Ontario achieve its emission reductions. A high carbon price may be necessary before individuals choose the lower emission option. The cost of half of the emission reductions are in the $200/tonne to $600/tonne range, with an increasing potential incremental emission reduction benefit as the price of carbon increases. To fully realize the desired emission reduction of 67 Mt by 2030, a carbon price in excess of $800/tonne may be required.

It is estimated to cost over $22B/year to achieve the emission reduction targets by employing these technologies. This cost estimating exercise is best viewed as a portfolio depiction of the potential costs.

[83] TA Engineering, DOE Supertruck Program Benefit Analysis, 2012

No single estimate may be an exact prediction, but in the aggregate the balance of options provides a string signal as to what may be expected. This illustrative portfolio is used in this study to develop the cost implications, but may also provide a useful benchmark for evaluating future innovations.

Air source heat pumps may be the best alternative for most building heating applications, but are expected to require supplementary heating options for extreme cold weather. Even so, carbon prices in the $400/tonne range may be required.

Hydrogen fuel cell vehicles (FCEVs) appear to be emerging as the low-cost passenger vehicle option in the late 2020s. Trucking remains a challenging area with no economical solutions identified that can achieve the required emission reductions. Other than renewable diesel which will be feedstock limited, trucking options appear to require carbon prices in the range of $600/tonne for natural gas conversions to $730/tonne for hydrogen options.

Using hydrogen to displace natural gas is as economic on a carbon price basis as RNG from sources other than landfills. At $245/tonne, producing hydrogen from electrolysis instead of the natural gas fed SMR process, is one of the least costly emissions reductions options assessed.

7.0 Managing Cost of Emission Reduction

This section aggregates the results of the earlier sections of this report to develop the cost and economic implications of the sensitivity of carbon price to electricity costs and administrative effectiveness.

This section first provides an overview of the net cost implications to the province including the sensitivity of carbon price. The relationship between the cost of electricity and emissions achievements and the need to purchase allowance credits for jurisdictions outside Ontario is presented.

A detailed discussion is then provided of how the use of proceeds process would impact the market carbon price within the C&T program. The cost risks associated with government administration of the use of C&T proceeds is then examined and the impact these risks could have on carbon price and total cost is estimated. Finally, an examination of the sensitivity of carbon price and total cost to the costs of the incremental electricity that may emerge from the LTEP is presented.

This section closes with a summary of the key findings.

7.1. Overview of the Cost to Ontario of Emission Reduction

The findings of this study suggest that the total cost of emission reductions may be as high as $27B/year by 2030, but moving the LTEP towards a low-cost electricity solution could save $6.9B/year.

How C&T Reduces Carbon Price

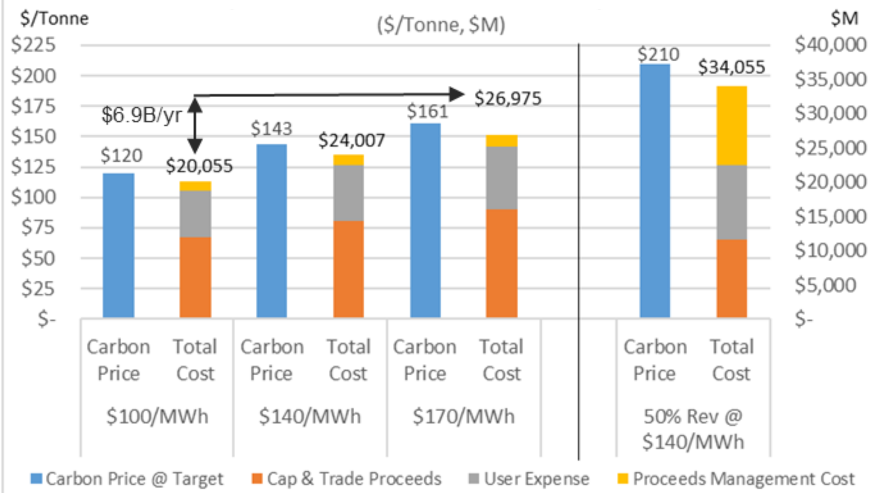
A government C&T or carbon tax program derives proceeds from those who have not yet switched fuels. An effective use of these proceeds would be to employ them to influence the purchase decisions of individual users through subsidies. In a perfectly administered system, the total cost of achieving the emission reduction should be the same as the minimum cost illustrated in Figure 42. The difference, or inherent advantage, is that the government carbon programs can spread the costs of emission reduction among the entire economy not just the individuals making the early decisions to reduce emissions. This can accelerate adoption and enable emission reductions at much lower market carbon prices than may otherwise be required.

Reinvesting C&T proceeds can also subsidize higher cost options to match the revenues obtained at the market carbon price level used to raise the funds. Funds are raised on allowable emissions, which at the outset are quite high. The proceeds can be applied to subsidize technologies that contribute smaller emission reductions towards meeting the target. This process can decrease the highest observed price of over $800/tonne to fully achieve the 2030 emission targets to a range of $120 to $161/tonne depending on the price of electricity.

The Cost of Emission Reduction

Figure 55 summarizes the implications on total cost and carbon price as a function of the cost of electricity and the effectiveness of the "use of proceeds management" scenarios.

Figure 55 – Implications of Different Electricity Cost



It is clear that a lower cost of electricity will drop the cost of carbon emission reductions, potentially by up to $7B, or more if management effectiveness is considered and addressed.

As shown in Figure 55, there are three costs that materialize in implementing an emission reductions program such as C&T.

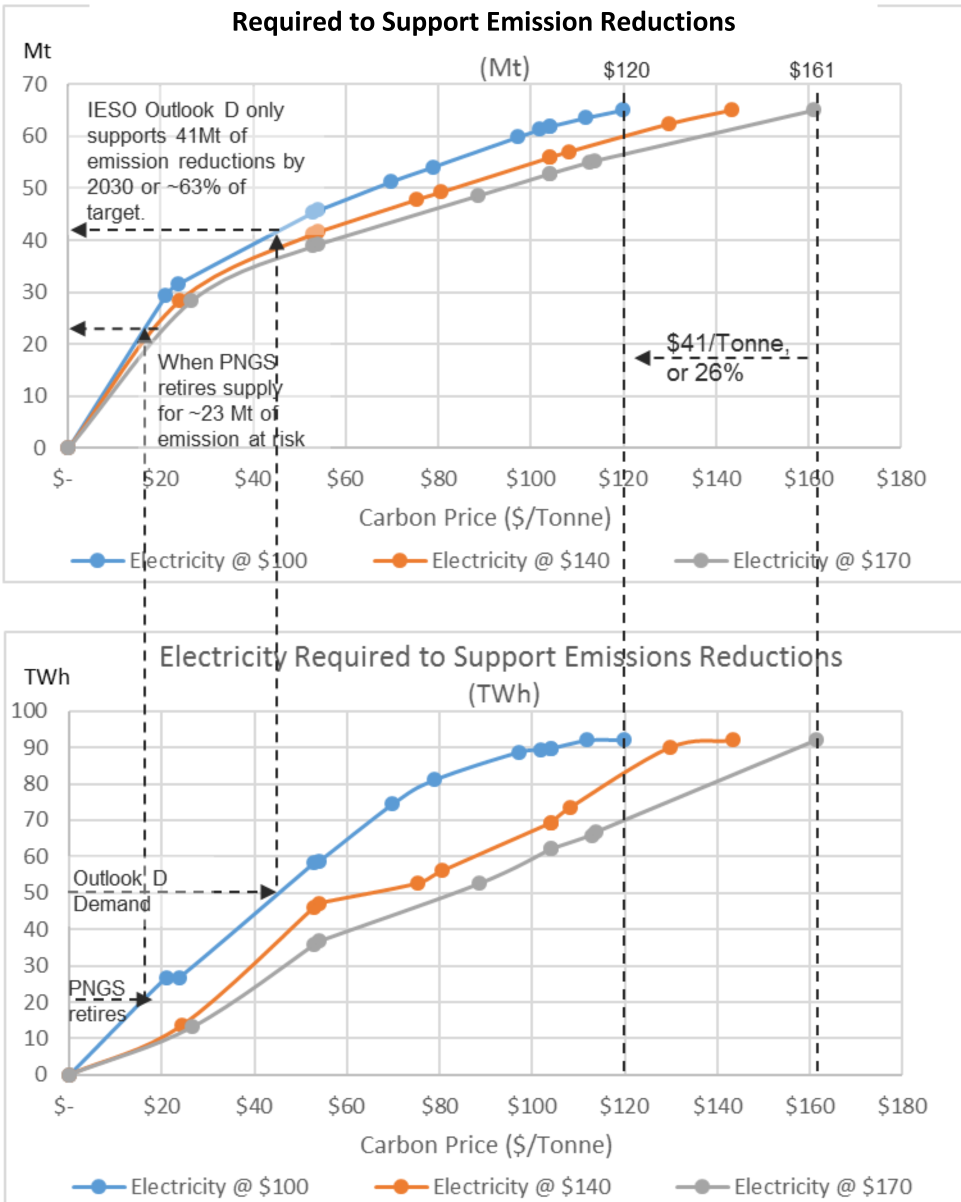
1. Reinvesting the generated proceeds either as incentives or subsidies
    - Proceeds are either raised through allowances administered in a C&T program or through a tax on emissions. These proceeds can be used as a subsidy to encourage technology switching.
2. The unsubsidized cost paid by a user when choosing to switch.
3. The cost of program administration and the cost implications from government prioritization of CCAP outcomes vis-a-vis the effectiveness of allocating proceeds to emission reductions
    - These costs would be deducted from, for example, the C&T proceeds and represent economic losses in the system.

The sum of the C&T proceeds reinvested and the user costs should equal the minimum cost to achieve the emission reduction, if those proceeds are effectively re-invested. The expenses in the administration of the system are a loss to the overall initiative and hence are an additional cost. Ineffective investment of the proceeds and ineffectual administration could result in an increased cost of $10B/year.

Relationship between Electricity Cost and Carbon Price

The cost of electricity can impact the minimum cost required to achieve the emission reductions by reducing the requisite carbon price that makes alternatives economic for users. The cost of electricity can also affect the success of the emission reduction initiative. The impacts of changing the cost of electricity on electricity supply, emission reductions and the price of carbon is shown in Figure 56.

Figure 56 – Cumulative Emission Savings vs. Electricity Required to Support Emission Reductions



Three scenarios have been modelled to reflect the possible future price of electricity:

1. High cost scenario of $170/MWh
   - This reflects the incremental cost for the large water power projects in Ontario as contemplated by the OPO Outlook D1 scenario.
2. Average cost scenario of $140/MWh

- This reflects both today's average price as well as that forecast average in the OPO Outlook D scenario.

3. Low cost scenario of $100/MWh
   - Reflecting a rounded value below the OPO Outlook D3 nuclear scenario's incremental cost.

Incremental costing is the correct approach for assessing the cost of emission reductions. Incremental costs reflect the matching of costs incurred to the benefits realized. It is the incremental electricity generation capacity that is used to provide the electrification. Other choices can be made but they would reflect pricing strategies not cost recognition.

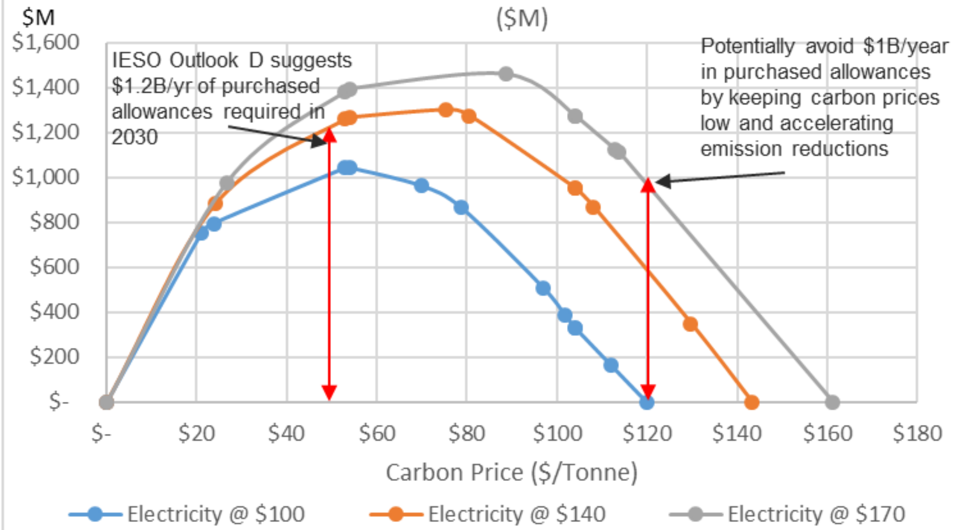
The carbon price and the availability of clean energy are related. With 50 TWh of incremental demand and supply, the OPO Outlook D will only support 41 Mt or ~60% of the targeted reductions, and do so by 2035 not 2030. A $50/tonne carbon price could facilitate the implementation of the required generation.

When PNGS retires, 20 TWh of clean generation will be removed from the system and Ontario's surplus baseload energy will evaporate. Portions of the first 23 Mt of emission reductions achieved by that date may be at risk. New clean generation of similar capacity is required to replace PNGS when it retires in order to support accelerating emission reductions required to achieve Ontario's 2030 target.

The LTEP process should plan to develop the lowest cost generation required to meet 2030 targets.

There is a cost associated with not meeting Ontario's legislated emission targets. This cost results from the need to purchase emission allowances from outside the province. If Ontario fails to reduce its domestically produced emissions, under C&T it can purchase emission allowances from other jurisdictions. It is recognized that Ontario has a greater challenge in meeting emission reductions as it already has a clean electricity system. A clean electricity system is the "low hanging fruit" opportunity in the U.S. and is the focus of their Clean Power Plan. A higher cost of electricity in Ontario will lead to a higher requisite carbon price, making it less likely users will be motivated to switch thereby reducing the emission reduction benefit from the investment of the C&T proceeds. These factors suggest an increasing probability that Ontario's 2030 goals will not be met. Figure 57 illustrates the beneficial impact of lower electricity costs on reducing the cost of purchased allowances from other jurisdictions.

Figure 57 – Carbon Price and Cap and Trade Purchased Allowances



Lower cost electricity could avoid purchasing up to $1B/year of external allowances, a saving that could accelerate the benefit of the use of proceeds towards achieving the targeted emission reductions. Externally purchased allowances of this magnitude are a significant trade balance burden that provides no value to Ontarians. They would represent a potential drain on Ontario's economy and as such are not likely a desired element of a sustainable public policy.

Achieving the Ontario government's legislated emission reduction targets could be advanced by mandating the pace of emissions caps within the C&T program be matched to the pace of the capacity buildout of low cost electricity generation within the LTEP.

7.2. Cap and Trade and the Price of Carbon

In a C&T program, or a carbon tax system, the government has the opportunity to raise funds via a carbon price levy on emitting activities and then to use the proceeds to subsidize desired emission reduction strategies. In a perfectly executed system, the carbon price will be managed to evolve and match the needed subsidies at the time required to achieve the targeted emission reductions. Effectively managing the use of proceeds can optimally reduce the required carbon price.

A C&T system has four cost components:

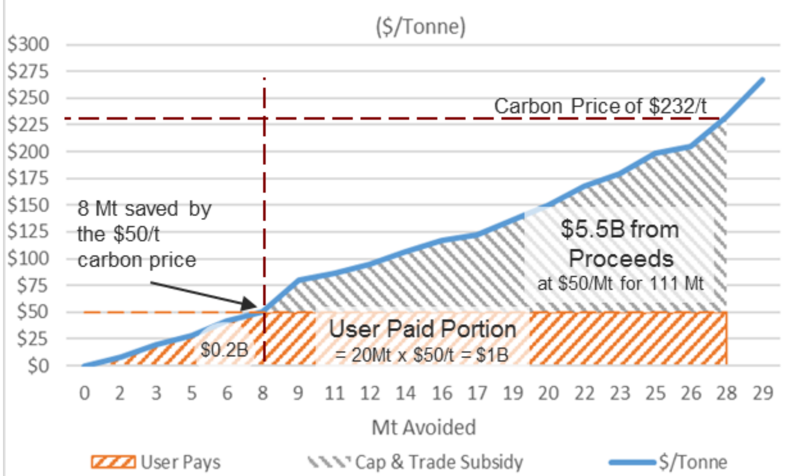
1. C&T proceeds are a cost added to existing energy expenditures.
2. Unsubsidized user costs associated with switching to low emissions technologies.
3. The penalty of not meeting the emission targets, which is manifested as the cost of purchased allowances from outside Ontario. These allowances are not available to subsidize domestic emission reductions.
4. Cost of inefficient government administration.

7.2.1. Cap and Trade Proceeds vs User Cost

C&T proceeds can be reinvested to subsidize the incremental costs of emission reducing technology options that would otherwise require a higher carbon price. C&T proceeds are calculated as the carbon price times the target level of emissions. For an example $50/tonne market carbon price, Figure 58 illustrates the balance between C&T proceeds and user cost. At the targeted 111 Mt of allowed emissions in 2030, a carbon price of $50/tonne will produce $5.5B in proceeds for reinvestment. This assumes no free allowances will be given out in the long run, such as for trade exposed industries. The proceeds would be used to subsidize the technologies that have a breakeven carbon price above $50/tonne.

Technologies will be subsidized until the cumulative required subsidy exceeds the C&T proceeds. In other words, until the proceeds are spent. In the process illustrated in Figure 58, spending of the $5.5B allows for the economic subsidization of any technology that would otherwise require a carbon price of up to $232/tonne.

Figure 58 – Use of Proceeds and Market Carbon Price



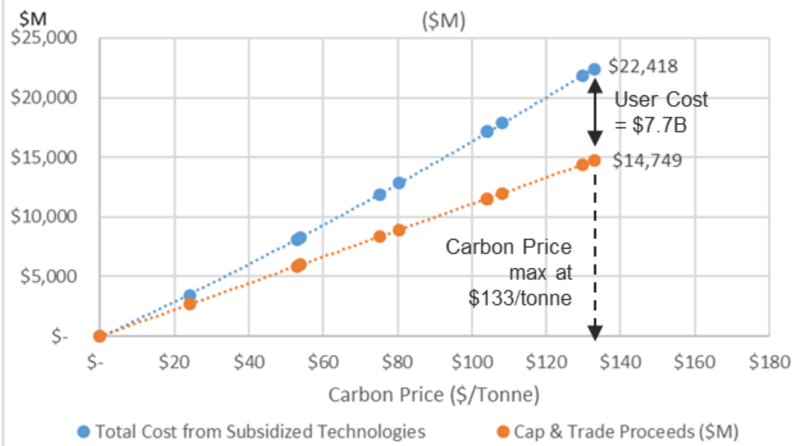
The user paid portion is indicated in Figure 58. The right edge of the grey shaded section reflects the maximum emissions that can be achieved by subsidizing technology options whose equivalent carbon price exceeds the $50/tonne market price level. The maximum achievable emission reduction is limited by the available C&T proceeds, which in this example is $5.5B. By reinvesting the proceeds, the required "Market" carbon price can be reduced, and even high carbon cost solutions can be accelerated.

The market carbon price reflects the cost presented to users. For a given market carbon price, users will make purchase decisions for lowest cost options while also considering of the cost of carbon emissions, e.g. from operating a new gas furnace. As such, options which are economic at, or below the prevailing carbon price will not need a subsidy and the users will effectively be paying for the price of switching away from carbon, and will do so as a matter of course. The orange area in Figure 58 illustrates this user paid portion of emission reduction investments in new technologies. For example, at the market level users will pay $50/tonne x 20Mt, or $1B, plus the amount ($0.2B) for items whose carbon cost is below the market price.

By reinvesting the proceeds to subsidize higher cost options, more emissions reductions can be achieved than at first intimated by the market carbon price.

Applying this methodology to the forty-five identified opportunities for emission reductions in Ontario, the total cost of achievable emission reductions as a function of carbon price is illustrated in Figure 59.

Figure 59 – Cost of Reductions - Perfect Proceed Reinvestment System



For the modelled Ontario situation, the breakeven carbon price for achieving emission reductions is $133/tonne, in lieu of the highest identified required carbon price of over $800/tonne shown earlier. In a perfect system, it would cost Ontario $22B to achieve the emissions target reductions. This total cost cannot be avoided, but the share of the cost is affected by the use of the C&T proceeds:

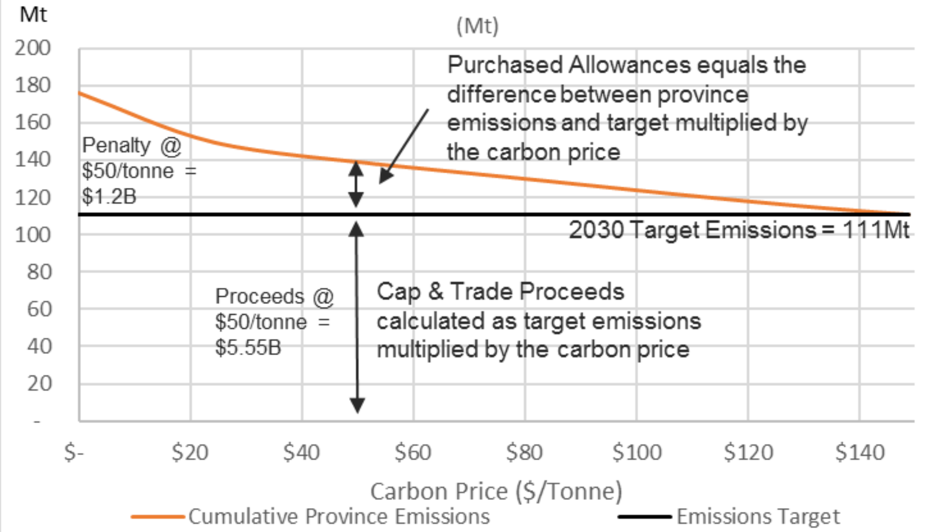
- $14.7B raised through C&T allowances sold at auction, recovered through higher prices charged at the pump or on natural gas energy bills;
- $7.7B in costs borne by consumers choosing to switch to low carbon solutions.

7.2.2. Aligning Targets with Enablers

Aligning targeted emissions with achievable results minimizes the "penalties" that arise in the form of allowances purchased from other jurisdictions. As described in the background section of this document, such purchases are expected by the government until at least 2020.

The "penalty" for not achieving emissions reductions is unique to the C&T program. This mechanism and the relationship to Ontario's emission reduction forecast are illustrated by Figure 60.

Figure 60 – Carbon Price and Purchased Allowances

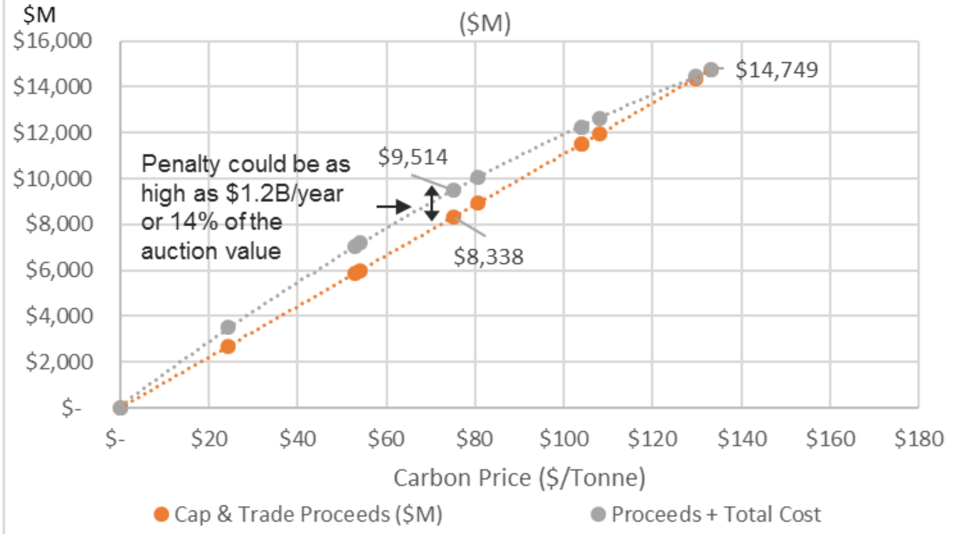


These purchased allowances are a penalty to the provincial economy, in that these costs leave the province in the form of revenues for the other jurisdiction and cannot be used as proceeds to offset further carbon abatement initiatives. Under a carbon tax system, the proceeds would remain in the province for use in abatement strategies. Under this scenario, Ontarians will pay for this economic leakage simply because the government's targets were not met.

The need for purchasing allowances from other jurisdictions arises from the cap setting process. In Ontario, the 2030 emissions "cap" has been legislated to be 111 Mt. In order to comply with this limit, for every tonne of emissions in the province that exceed this cap, allowances will have to be purchased at the prevailing carbon price. The costs of these allowances are inevitably borne by Ontarians as the majority of emissions in the province are associated with heating fuel and gasoline. The recovery of these costs will appear at the pump or on the home natural gas energy bill. For example, the natural gas carbon costs are regulated by the OEB by applying rate increases on the home energy bill. This ensures that the costs are recovered by Ontario's utilities who will be making the allowance purchases.

The cost of this "penalty" is a function of achieving the target as shown in Figure 61.

Figure 61 – Cost of Purchased Allowances When Targets Not Met



At $75/tonne, the purchased allowances could represent $1.2B that leaves the province. If the 2030 emission target is achieved, at the market carbon price of $133/tonne shown in Figure 59, there is no “penalty”.

7.3. Cost Risks of Administration of the use of C&T Proceeds

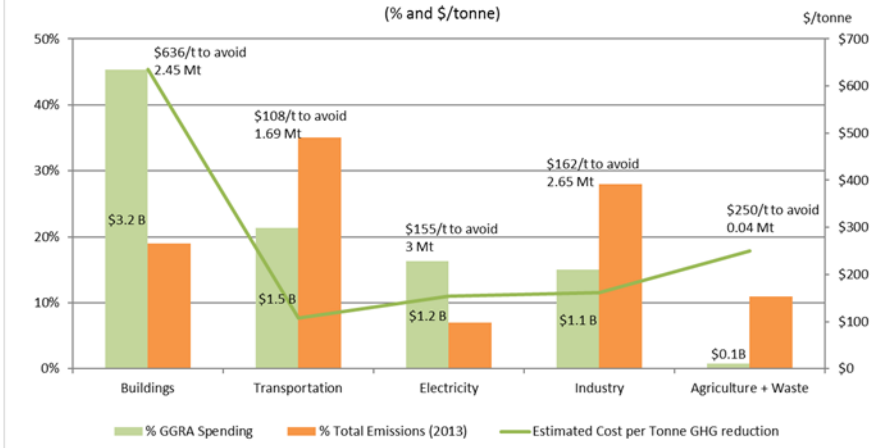
Governments have accountability for the effective administration of the proceeds generated from their programs. Carbon price programs where the government has discretion over the use of proceeds, allows the cost of emission reductions to be spread across the economy and have the inherent potential to lower the market carbon price needed to achieve the objectives.

Achieving the emissions reductions at the lowest cost identified is contingent upon the effective use of the proceeds by the government. The proceeds would have to be exclusively applied as subsidies to the optimal emission displacing solutions to achieve the minimum cost.

By its very nature, the cost of the approach is dependent on the effectiveness of the government at directing the use of proceeds to achieve emission targets for Ontario. The current Ontario CCAP is an example of how the Ontario government may apply the proceeds of the C&T program. Within the CCAP, targeted number of areas and actions have been identified for using the proceeds over the next 4 years. The stated purpose is to encourage emission reduction in various sectors of the economy and to achieve certain emission reduction targets.

Figure 62 compares Ontario’s expected CCAP 2020 emissions reductions by sector to the associated portions of the $8.3B in expected GGRA funding dedicated to lowering those emissions.

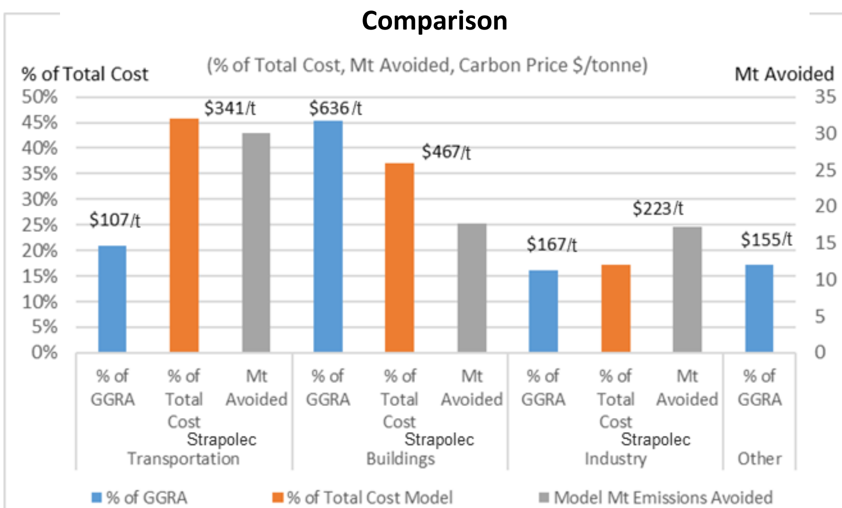
Figure 62 – Ontario 2013 Emissions, GGRA Spending and Cost of GHG Reduction by Sector



Although the building sector is the third largest source of emissions in Ontario, the CCAP dedicates the highest amount of funding to this sector (45% of GGRA funds) to avoid 1.69 Mt of emissions at an expected cost of $636/tonne. Twenty-one percent (21%) of the GGRA funding is dedicated to the transportation sector to avoid 2.45 Mt of emissions at an expected cost of $108/tonne. Sixteen percent (16%) of the GGRA funds have been dedicated to the electricity sector to avoid 3 Mt of emissions at an expected price of $155/tonne. Fifteen percent of the GGRA funds will contribute to avoiding 2.65 Mt of emission in the industrial sector at an expected price of $162/tonne.

Administration costs can arise simply from a misalignment of the optimal solutions. Figure 63 compares the distribution of funds within the GGRA to the priorities suggested by the modelling in this study. The associated implied carbon prices have been noted for the purpose of comparison.

Figure 63 – Sector Emission Saving and Cost – GGRA Comparison



Compared to the findings of this study, the planned GGRA has; (1) Lower than expected spending in transportation at a much lower than required carbon price ($107/tonne vs $341/tonne); (2) A greater share of government spending in the building sector at a higher than necessary carbon price ($636/tonne vs $467/tonne); and (3) An approximately equivalent emphasis on the industrial sector, but with lower than needed equivalent carbon pricing.

An allocation of the costs to electricity bills may not be the most effective tool on its own without a focus on targeted funding for specific initiatives that systemically support fuel switching from fossil fuels to low-carbon electricity. However, the CCAP program must, out of necessity, serve political objectives as well. The example evident in the spending is the use of proceeds to offset the general cost of electricity. This expenditure is defined as "*Keep Electricity Rates Affordable: Use cap and trade proceeds to offset the cost of greenhouse gas pollution reduction initiatives that are currently funded by residential and industrial consumers through their bills*.[84]" While subsidizing electricity costs can be rationalized as an administratively simple mechanism to support electrification, there are two inherent inefficiencies: 1) the benefits are thinly spread resulting in some consumers pocketing the savings instead of using it to reduce emissions; and (2) it offsets costs that are already assumed to be spent in establishing the BAU assumptions. At up to ~$1.2B, this element of the CCAP is ~14% of the expected GGRA funds.

Likewise, funding initiatives to make buildings more energy efficient may reduce GHG emissions, but cannot eliminate them. The more direct and efficient action may be to switch energy sources from fossil fuels to low-carbon electricity. It is reasonable to assume that a perfectly efficient application of the use of proceeds is not likely possible in any system and so scenarios of effectiveness have been developed to illustrate the potential impact.

Two scenarios are created to illustrate the potential impact for Ontarians resulting from the government's performance at directing the use of proceeds:

1. 10% of the proceeds are incurred for administrative purposes
    - There also unavoidable inefficiencies in the system and this scenario is offered as the most reasonable best case assumption.
2. 50% of the proceeds are reinvested
    - This would reflect the directional use of the proceeds towards less effectual policies or investing in solutions that prove to be less cost effective or do not get adopted. A 50% inefficiency assumption could be viewed as an unreasonably high cost outcome and is offered as an upper bound.

The results of these assessments are shown in Figures 64 and 65, respectively. The impact of government effectiveness at directing the use of proceeds carries a 50% cost risk, and could lead to an additional $10B/year in emission reduction costs.

[84] MOECC CCAP

There are two consequences from inefficient administration of the C&T program: (1) The cost of the program would increase proportionately to the inefficiency; and (2) The breakeven market carbon price would drift upwards reflecting less funds being available to subsidize higher cost emission reduction strategies.

The C&T program could cost between $24B/year and $34B/year by 2030 depending on the effectiveness of the governance. By comparison a perfect system cost would be $22B/year. The breakeven carbon price for meeting emissions targets could go up from the perfect system value of $133/tonne to $210/tonne under a misuse of funds scenario. It is the higher carbon price component that drives up the total cost.

Figure 64 – Cost of Cap and Trade with 10% System Inefficiency

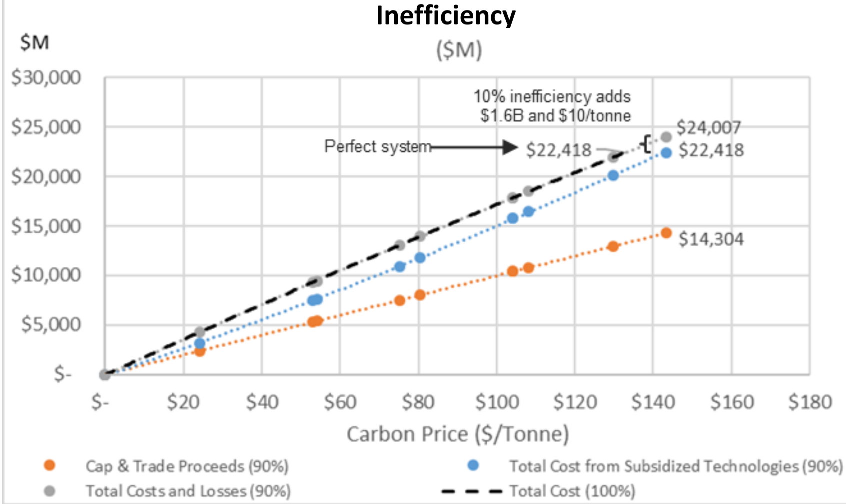
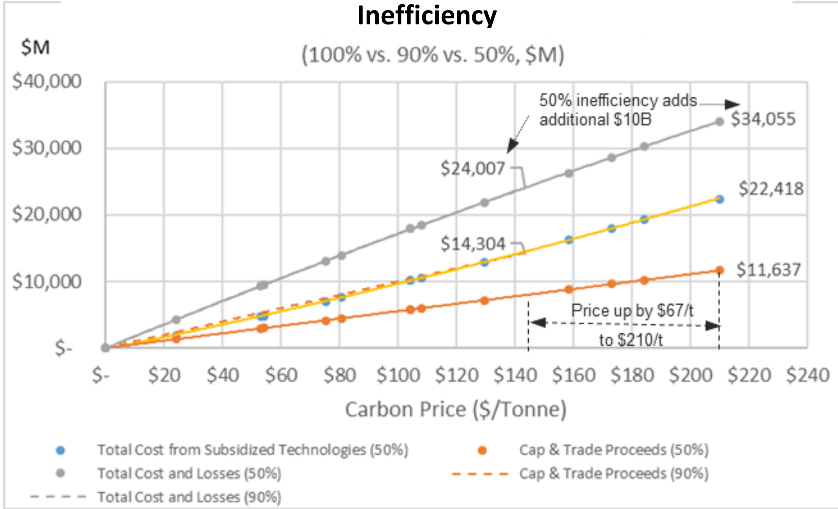


Figure 65 – Cost of Cap and Trade with 50% System Inefficiency



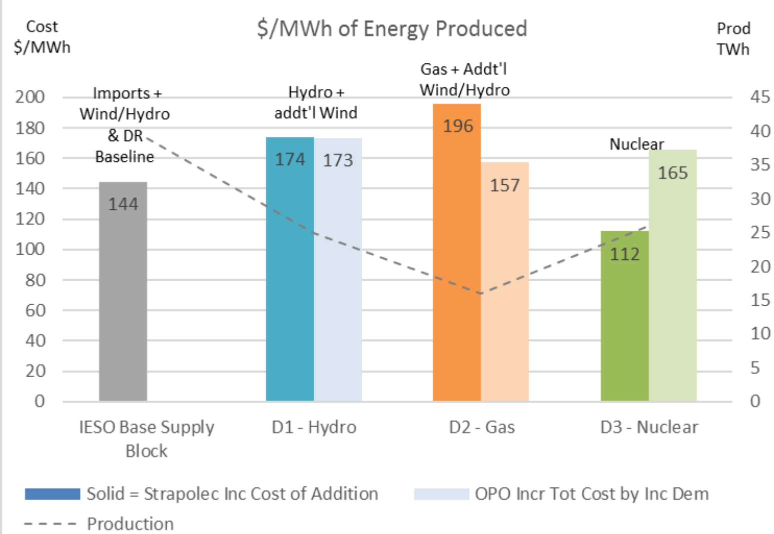
If the jurisdictional realities of Ontario's cost to decarbonize are driven by government policies and these costs become higher than neighboring jurisdictions, Ontario will likely face some difficult economic challenges. The carbon price differential can be a critical factor.

Strapolec suggests that the best mitigation for risks associated with the ineffective application of the C&T proceeds is transparency, fact-based decision making, and establishing an independent, arms-length process for managing the proceeds.

7.4. Low Cost Electricity and the LTEP

The cost of new electricity generation can have a large impact on the market carbon price and emission target achievement. The IESO provided an outlook of future electricity costs for various scenarios in the OPO. While the OPO tables for each scenario suggest similar cost outcomes, a deeper analysis shows that significant incremental cost differences exist among options. There are uncertainties within the data that Strapolec could not resolve in the time available. As a reference for bounding the electricity cost scenarios, Figure 66 illustrates estimates of the incremental costs associated with the capacity options included in the OPO Outlook D.

Figure 66 – OPO Outlook D Incremental Supply Cost



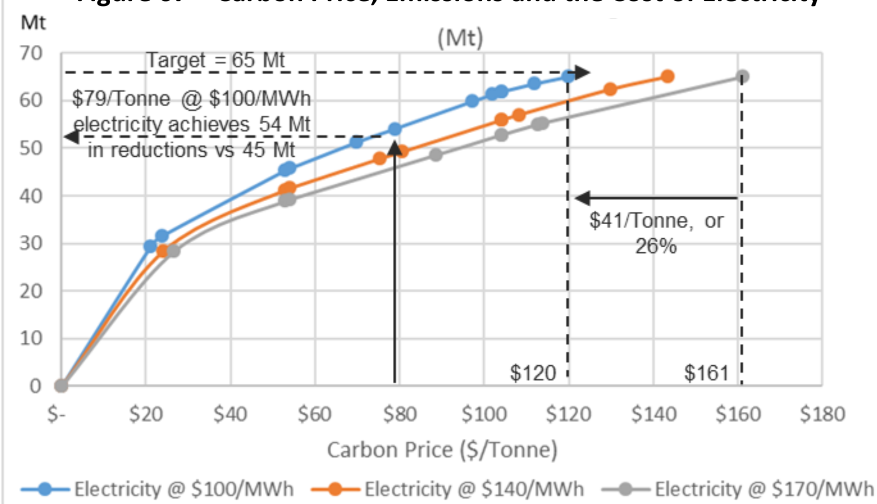
The incremental cost of the new generation has been calculated using two methods:

- OPO Outlook incremental total cost divided by incremental total demand
    - The results of method represents the incremental cost of the total additional supply of each option, including the production costs from the Base Supply Block of the entire electricity system after new capacity costs are added to existing system costs.
- Incremental cost of the capacity differences between the options (as added to the base supply common to all options) divided by the incremental production from that capacity difference

- This method estimates costs for each incremental supply type using the OPO stated cost assumptions for each of the Outlook D scenarios.
- The estimate of $144/MWh for the base supply block is the average cost of the full production from the base supply block capacity that is included in all the OPO Outlook D capacity options shown.
- The cost estimates used in this method consider related incremental transmission costs defined in the OPO, demand response (DR), changes in natural gas-fired generation output from existing assets, and accommodations for a carbon price on natural gas-fired generation.

The resulting estimates of electricity cost range from $112/MWh to $196/MWh for incremental new supply. To assess the impact of electricity cost on the of cost emissions reduction three scenarios were run: (1) Nominal case with expected average electricity costs of $140/MWh; (2) Low case at $100/MWh; and (3) High case at $170/MWh. The results are shown in Figure 67.

Figure 67 – Carbon Price, Emissions and the Cost of Electricity



At an average incremental electricity cost of $100/MWh, meeting the 65 Mt emission reduction target could be achieved with a 26% lower carbon price of $120/tonne as opposed to the $161/tonne needed to achieve the same reduction target at an electricity cost of $170/MWh.

The ability to achieve emission reduction targets is affected by the carbon price relationship to electricity cost. At an electricity cost of $100/MWh, a carbon price of $79/tonne would achieve 85% of the provincial emission reduction target. Conversely, at a higher electricity cost of $170/MWh, a carbon price of $79/tonne would achieve only 70% of the provincial target.

It is clear that the lower the cost of electricity, the lower the required carbon price to achieve emission reductions. This in turn implies that switching to low emission applications will become economic earlier. The sooner these applications are economically switched to low carbon options, the further the use of proceeds can be broadened. It is therefore important to achieve lower electricity costs.

The impact of electricity cost on the purchase of external allowances was discussed at the beginning of this chapter.

7.5. Summary

The analyses conducted in this study suggest that the total cost of emission reductions may be as high as $27B/year, unless low-cost sources of electricity are pursued. C&T proceeds of $16B/year could subsidize many new initiatives, but consumers will also face additional costs of approximately $9B/year for unsubsidized spending on low carbon emitting options. The cost of government administration of the use of C&T proceeds could be $2B/year.

Carbon price is dependent on both the cost of electricity as well as an effective and efficient process for reinvestment of C&T proceeds. A low-cost electricity system can save Ontario an estimated $6.9B/year. Low cost electricity can also save up to $1B/year in externally purchased allowances, accelerating the benefit of the use of proceeds to achieve emission reductions.

Reinvesting the C&T proceeds to fund emission reducing technologies can drastically lower the carbon price required from over $800/tonne to $133/tonne in a perfect system, or $210/tonne in an imperfect system with 50% inefficiency. Accelerating emission reductions with lower carbon prices through the use of C&T proceeds reduces the risk of needing to purchase over $1B/year in emission credits from other jurisdictions.

An inefficient use of C&T proceeds and/or ineffective governance could result in Ontarians paying an additional $10B/year to achieve the reduction goals. Administration of proceeds has the greatest potential for unproductively increasing the costs of emission reductions, a circumstance for which the government is obliged to take accountability and which can be best met by minimizing political influence on the use of the sizable funds that will emerge from the C&T program.

8.0 Recommendations and Further Work

The future demands on Ontario's electricity system resulting from the province's emissions reduction targets, combined with incentives to direct the new demand towards lower cost off-peak hours, will culminate in a need to secure sources of new low-carbon baseload capability and flexible seasonal winter supply.

Six recommendations to effectively achieve Ontario's emission reduction targets and objectives at the lowest cost have emerged from this study:

1. 90 TWh of new demand requires a decision at the earliest stage in the LTEP process for commitment to low-cost, emission-free generation options.
    - Forecast new demand for electricity is primarily for home heating and industrial baseload applications. This is 80% greater than the 50 TWh presented in the OPO Outlook D and 60% more than is consumed today.
    - Meeting 2030 emission targets depends on supplying this new demand with new generation. The timing for this consideration is not reflected in the OPO. Maximizing the safe economic life of the Pickering Nuclear Generating Station (PNGS) can support the transition.

2. Low cost electricity choices should be prioritized by the LTEP to reduce the cost of carbon emission reduction initiatives. Low cost electricity choices could reduce this cost by up to 25% or $7B/year.
    - With OPO Option D1, adoption of carbon emission reduction initiatives could potentially add costs of up to $27B/year to how Ontarians use energy, depending on the cost of electricity and the effectiveness of administrating the use of C&T proceeds. This cost could be reduced by the above mentioned 25%. The components contributing to the additional costs are:
        - Expected required carbon pricing within the C&T program would account for 60% or $16B/year of these costs which are to be directed towards subsidizing emission reduction initiative adoption;
        - As Ontarians make low emission choices, they will invest $9B/year to cover the unsubsidized portions of such things as new building heating equipment; and
        - Another $2B/year could be incurred by the administration and implementation of the C&T processes and dispensation of C&T proceeds.
    - The estimated carbon price required to achieve the 2030 targets ranges from $120/tonne to $210/tonne, also depending on the cost of electricity and the effectiveness of administrating the use of C&T proceeds.
        - Low cost electricity supports a carbon price of $120/tonne. The IESO has identified nuclear as the lowest cost option in the OPO.

3. The nature, breadth, and diversity of emission reduction options available to Ontario oblige the LTEP process to fully and transparently integrate emission targets, climate actions, electricity planning, and fossil fuels strategies.
    - Section 5.1.1 clearly establishes that time is of the essence in developing the electricity system that will allow for fuel switching to occur. The LTEP should prioritize identifying the *quickest route* to available large scale low emission electricity generation. This will enable achieving the maximum emission reductions by 2030 and to facilitate the emission reduction ramp to 2050.
    - Section 7.2 presented several views of the OPO Outlook costs that express which supply options carry the higher costs. To secure the support of Ontarians in bearing the costs of combatting climate change, the

LTEP should establish a publicly transparent evidence base supporting the most reliable, lowest cost electricity solutions, including generation, transmission, distribution, and the integration thereof. Clear full cost decision making could potentially save Ontarians up to $7B/year.

- Section 5.1.1 summarized how the different needs for electricity that will be driven by remission reduction options will point to the need for different types of supply. Some options require greater baseload capacity, some flatten seasonal demand and others create seasonal peaks, while others increase over night energy requirements, flattening the daily profile. The LTEP should explicitly recognize and address how emission reduction options may change the demand profile and best match cost effective supply options to those future needs.
- There are many emission reduction options identified by stakeholders, as summarized in Section 3.3, that may be unique to Ontario's circumstance. These may be opportunities to leverage existing Ontario advantages, such as the interplay between nuclear, hydrogen and demand response, that could enhance Ontario's innovation capabilities and international competitiveness.

4. Ontario's climate strategy initiatives should be integrated with the LTEP to match the pace of C&T emissions caps with the pace at which new electricity generation capacity can be built and alternative fuels provided.
   - Aligning emission targets to the availability of electricity and/or alternative fuels will minimize the likelihood that provincial targets will be missed.
   - This recommendation stems from the observation in Section 5.1.1 that, to meet the legislated emission reductions of 37% below 1990 levels by 2030, more new generation is needed than can likely be supplied by 2030.
   - This recommendation could moderate the pace at which carbon prices increase to reflect realistic emissions objectives, give certainty to Ontario's residents and businesses regarding how their energy costs will rise; and moderate the rise in energy costs until the affordable electricity required by alternatives can be made available. Missed emission targets caused by lack of generation could cost ~1.2B/year in C&T allowance purchases from other jurisdictions. Realistic achievable emission reduction targets will avoid the circumstances causing unnecessary purchases of allowances from outside the province as described in Section 7.0.
5. Rigorous attention should be paid to the effective and efficient management of C&T proceeds use.
   - An effective program can accelerate emission reductions, get the carbon price much below $210/tonne, minimize the cost to Ontarians through effective subsidization programs. There is the potential of a $10B/year risk associated with ineffective policies.
   - Section 7.0 provides an detailed examination of how carbon price, electricity price, and government administration of proceeds can affect the cost to Ontarians. Administration of proceeds has the greatest potential for unproductively increasing the costs of emission reductions, a circumstance for which the government is obliged to take accountability and which can be best met by minimizing political influence on the use of the immense funds that will emerge from the C&T program.
   - A transparent evidence based process that considers all potential emission reduction technologies, such as hydrogen and nuclear, could lead to significant economic and competitive advantages for Ontario. Hydrogen generated with the lowest cost nuclear energy has emerged as among the most economical emission reduction options assessed in this study as described in Section 6.1.
   - The effective use of C&T proceeds could make options economic at $120/tonne that would otherwise require a carbon price of $800/tonne.

6. The integrated LTEP and climate strategy should consider the pathway to 2050 for deep decarbonization.
    - This report has been focussed on assessing what is involved in meeting the 2030 targets. It is unlikely that the infrastructure c an be cost effectively built by 2030 to meet the challenge that has been established. Furthermore, the challenge only continues to rise as double the emissions reductions are needed between 2030 and 2050 to meet the 2050 target of 80% below 1990 levels.
    - The OPO, FTR and Section 5.1.1 of this report clear establish that the 15 years to 2030, or even the 20 years to 2035, is insufficient time to prepare Ontario to achieve the emission reduction objectives set for 2030.
    - Electricity generation options that cannot be implemented by 2030 will still need to be planned for in the current LTEP process to enable the availability of these options after 2030 or after 2035. To meet the electricity demand growth from emissions reduction initiatives that are anticipated in the future, the long lead nature of these significant infrastructure projects obliges the LTEP to consider the longer-term pathway beyond the 20-year window to 2035 that currently defines the LTEP planning horizon.

Further work

The next report to be produced by Phase 2 of this study will examine the implications on supply that the new electricity demand necessitates, assess the costs and implementation considerations of the supply mix options put forward in the OPO, as well as alternatives, and describe the cost, schedule achievability, and economic implications to Ontarians associated with those choices.

Acknowledgements

This study was conceived of and proposed by Strategic Policy Economics to fill a perceived void in transparent evidence based materials. Strategic Policy Economics deemed it fundamental to a successful LTEP consultation that this void be filled to best serve the interest of Ontarians.

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 of Newall Consulting Inc.

The Strategic Policy Economics team hopes this report provides a constructive contribution to the LTEP process.

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Appendix B - List of Abbreviations

AD – Anaerobic Digestion/Digester

AEO – Annual Energy Outlook

ASHP – Air Source Heat Pump

BAU – Business as Usual

Bcf – Billion cubic feet

BEV – Battery Electric Vehicle

C&T – Cap and Trade Program

CAD – Canadian Dollar

CAGR – Compound Annual Growth Rate

CCAP – Climate Change Action Plan

CO_2 – Carbon Dioxide

COP – Conference of Parties

CPP – Clean Power Plan

DOE – U.S. Department of Energy

EIA – U.S. Energy Information Administration

EPA – U.S. Environmental Protection Agency

EV – Electric Vehicle

FCEV – Fuel Cell Electric Vehicle

FTP – Fuels Technical Report

GDP – Gross Domestic Product

GGRA – Greenhouse Gas Reduction Account

GHG – Greenhouse Gas

GJ – Gigajoule (10^9 joules)

GSHP – Ground Source Heat Pump

GW – Gigawatt

GWh – Gigawatt Hour (one billion watts being produced for 1 hour)

HD – Heavy Duty

HVAC – Heating, Ventilation and Air Conditioning

ICE – Internal Combustion Engine

IESO – Independent Electricity System Operator

INDC – Intended Nationally Determined Contribution

Kt – Thousand Tonnes – also referred to as kilotonnes

kWh – Kilowatt hour (one thousand watts being produced for 1 hour)

L – Litre (one thousand mL)

LTEP – Long-Term Energy Plan

mmBTU – million British Thermal Unit

MMSCFD – million standard-cubic-feet-per-day

MoE – Ministry of Energy

MOECC – Minister of Environment and Climate Change

MSW – Municipal Solid Waste
Mt – Megatonne (equal to one million tonnes)
Mt CO2e – Megatonnes Carbon Dioxide equivalent
MW – Megawatt
MWh – Megawatt Hour (one million watts being produced for 1 hour, enough to power ten thousand 100W light bulbs for one hour)
NG – Natural Gas
NIR – National Inventory Report
NRCan – Natural Resources Canada
NREL – National Renewable Energy Laboratory
OEA – Ontario Energy Association
OEB – Ontario Energy Board
OPG – Ontario Power Generation Inc.
OPO – Ontario Planning Outlook
OSPE – Ontario Society of Professional Engineers
P2G – Power to Gas
PHEV – Plug-in Hybrid Vehicle
PJ – Petajoule (10^{15} joules)
PNGS – Pickering Nuclear Generating Station
RNG – Renewable Natural Gas
SBG – Surplus Baseload Generation
SCGT – Simple Cycle Gas Turbine
SMR – Steam Methane Reforming
SSO – Source-separated organics
t – Tonne (1,000 kg)
TJ – Terajoule (10^{12} joules)
TWh – Terawatt hour (one trillion watts being produced for 1 hour)
Tx – Transmission
U.S. – United States of America
WACC – Weighted Average Cost of Capital
WCI – Western Climate Initiative
WWTP – Waste Water Treatment Plant

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APPENDIX II - ONTARIO'S EMISSIONS AND THE LONG-TERM ENERGY PLAN:

PHASE II - MEETING THE CHALLENGE

Ontario's Emissions and the Long-Term Energy Plan

Phase 2 - Meeting the Challenge

Final Report

Marc Brouillette

December, 2016

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.

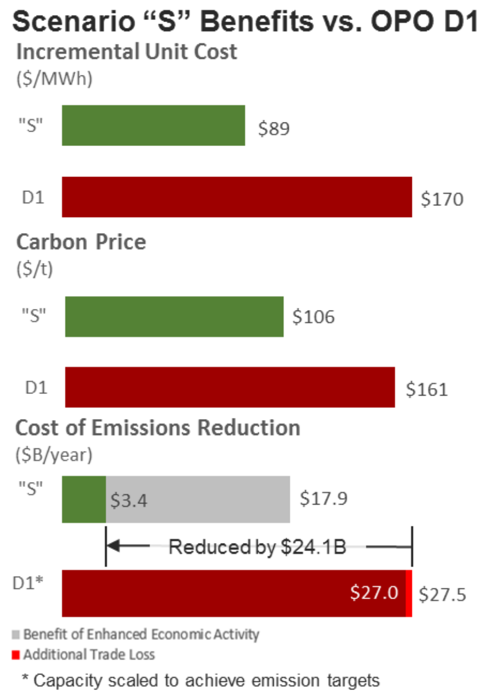
3. **Earliest Path to Emission Reduction** – Making nuclear the mainstay of Ontario's electricity system within Scenario "S" is the earliest supply mix solution Ontario has for achieving its emission targets.
    - Developing the requisite DER, nuclear and hydrogen capacity in "blocks" in a systematic 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.

Since the global community of nations emerged from the COP21 Paris Climate Conference and its ratification 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 to 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.
    - 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,
    - 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. 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.

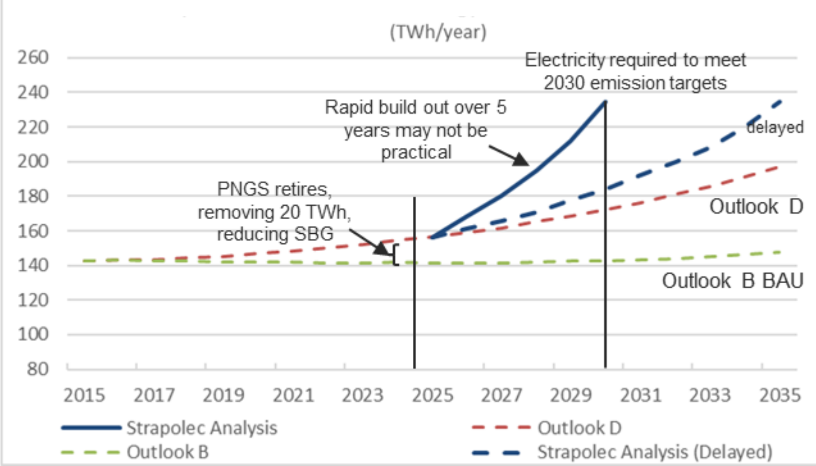
The IESO has provided several outlooks, two of which are illustrated in Figure 1[2]:

- 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

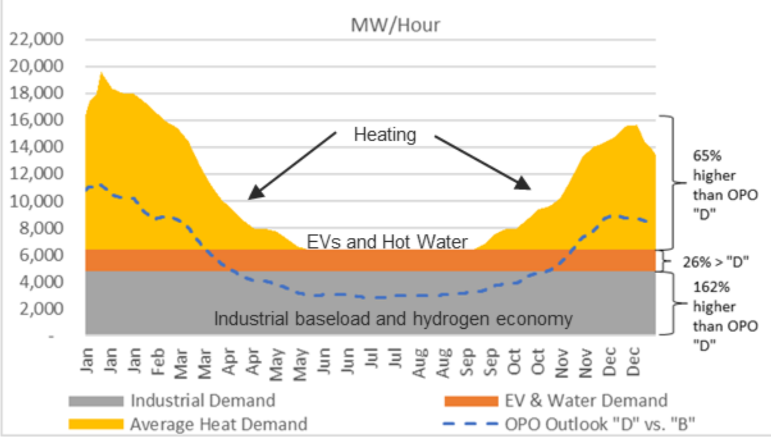
Figure 1 – Electricity Demand Growth Scenarios



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

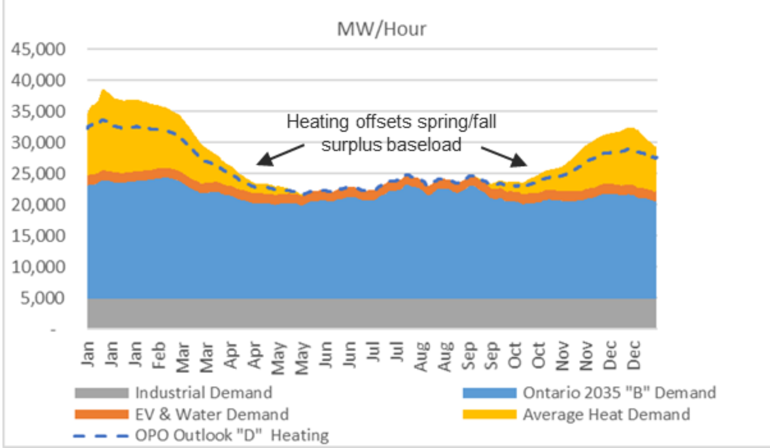


Analysis shows that there will be a significant ramp up of electricity required to supply home heating needs[3]. There are three types of new demand emerging from emission reductions:

- 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

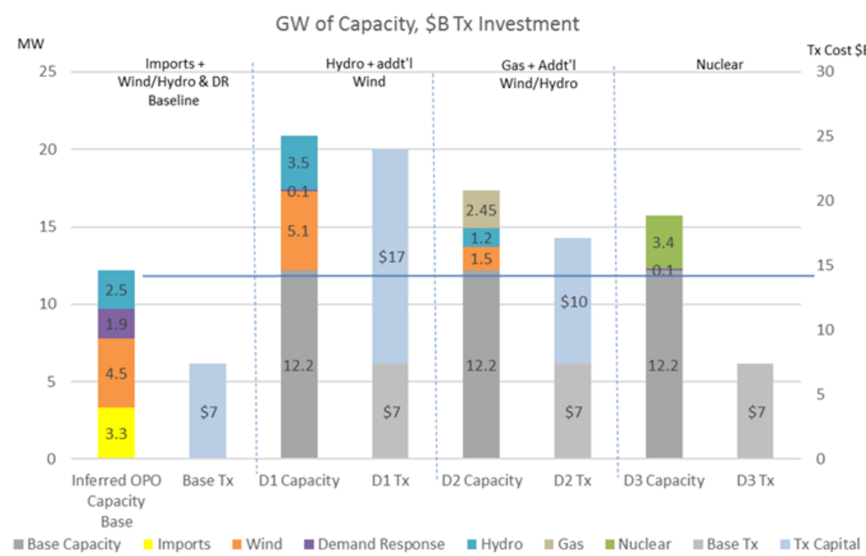
This subsection looks at the incremental capacity, production, and costs associated with the OPO Outlook D capacity options, which are summarized in Table 1.

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.

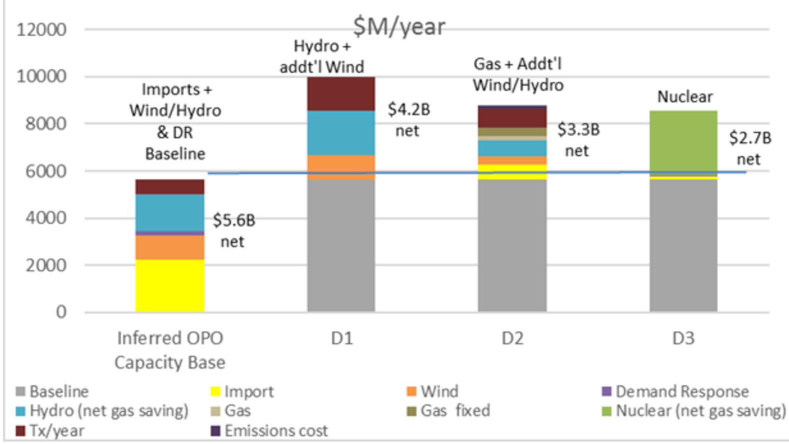
Table 2 - OPO Outlook D 2035 Production by Option

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

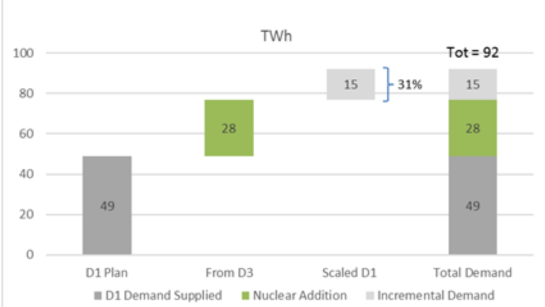
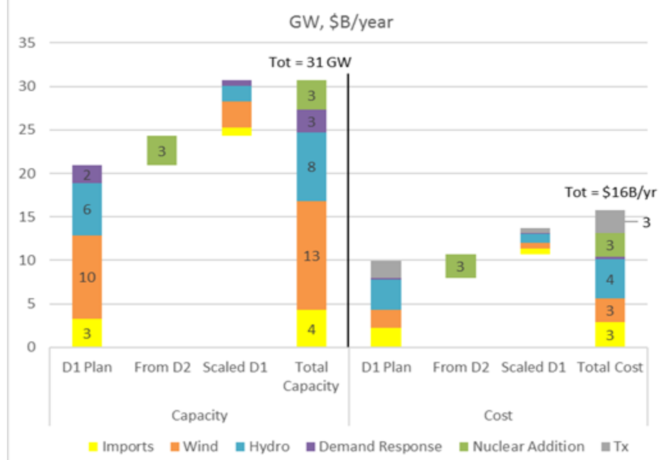


Figure 7 – Increase in D1 Capacity and Cost to Meet "S" Demand

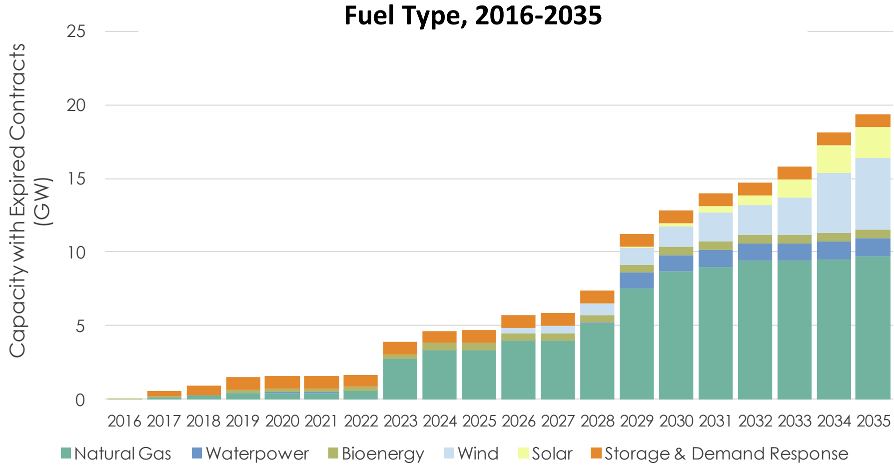


The increase in demand results in a need for 31 GW of new capacity, including 4.3 GW of imports, 12.5 GW of wind and 7.8 GW of new hydro along with 3.4 GW of new nuclear. These are staggering numbers with an expected total cost of $16B/year. This results in an expected average incremental electricity 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

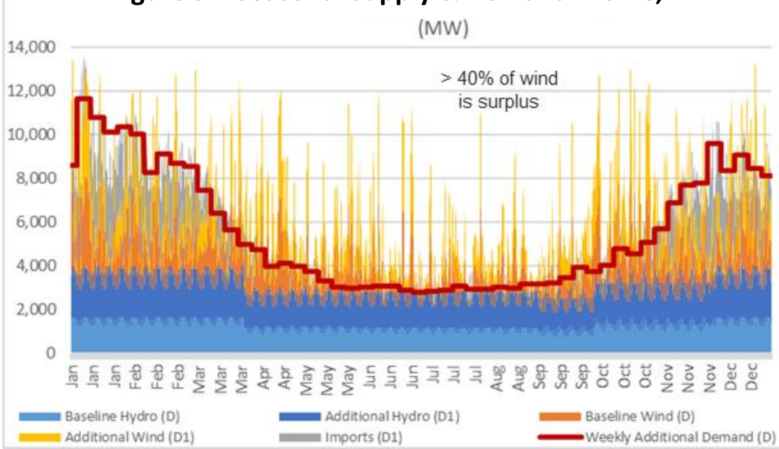
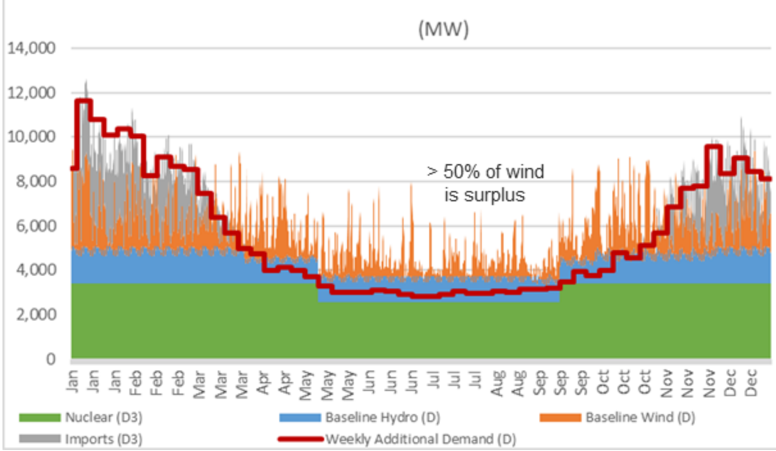


Figure 10 – Seasonal Supply & Demand Profile, D3



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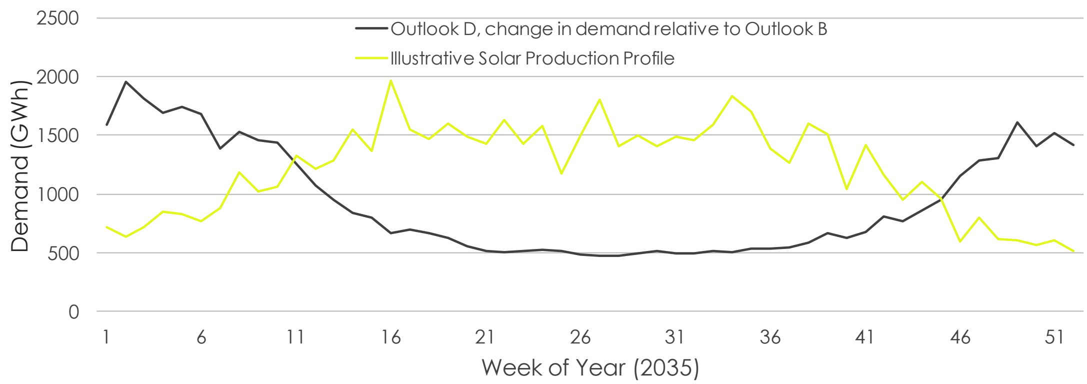
6 Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016

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.

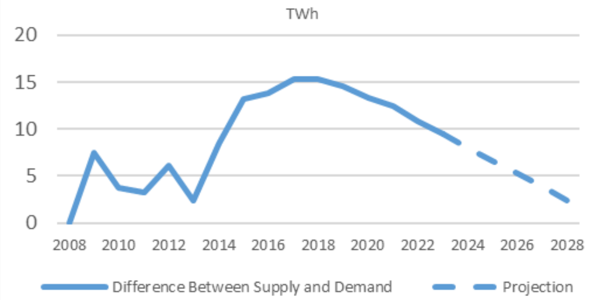
A firm import maximum of 3300 MW is included in all of the OPO D scenarios. The OPO states that opportunities exist for greater electricity trade with Ontario's interconnected neighbours; however, only Quebec and Manitoba have low carbon resources, and the ability for Ontario to import from Manitoba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

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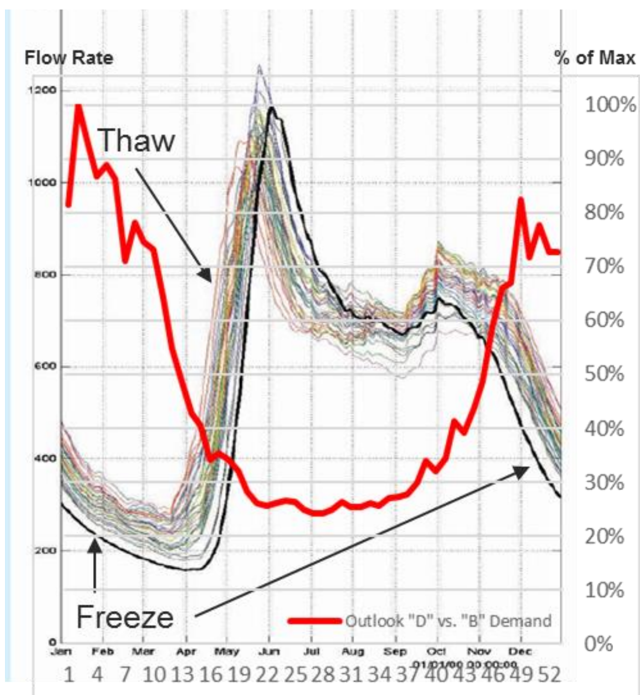
[8] Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016
[9] Martel, Opening Keynote from APPrO 2016, 2016
[10] Nalcor Energy, Muskrat Falls Project: Project Overview, 2016
[11] Strapolec, Renewables and Ontario/Quebec Transmission System Interties, 2016

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)



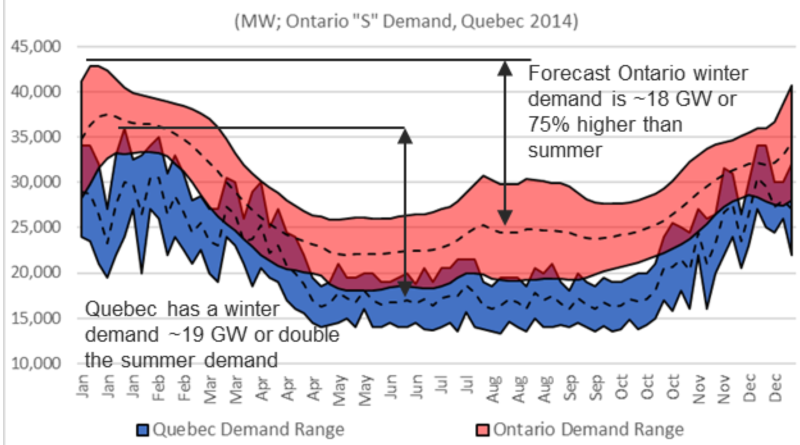
This means that "run of river" and the "far north" profiles are not well matched to Ontario's winter heating need, given this winter freeze. Meeting the incremental demand forecast and the winter heating load would require the construction of a new reservoir with seasonal storage capability like Quebec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

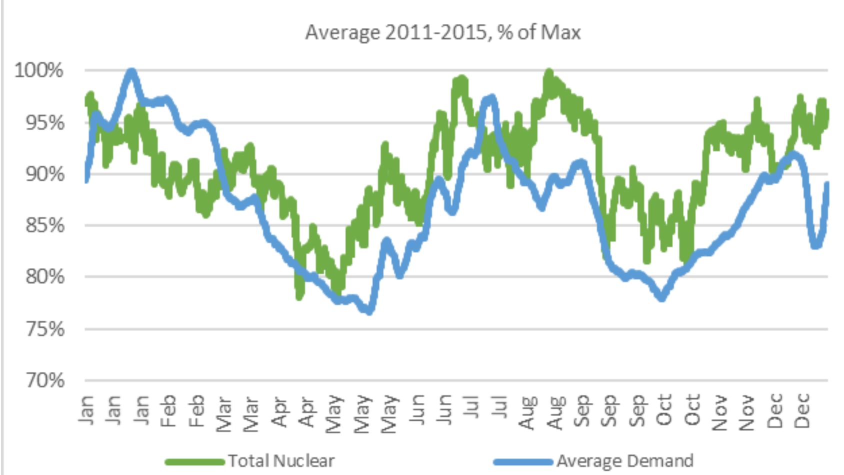
[15] Hatch, Northern Hydro Assessment, 2013

[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

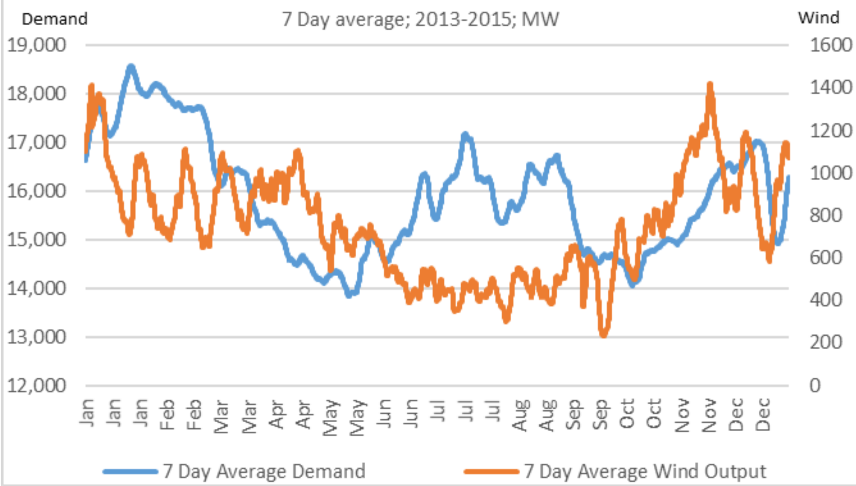
The significant increase in wind capacity in the OPO is questionable on three counts:

- 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.

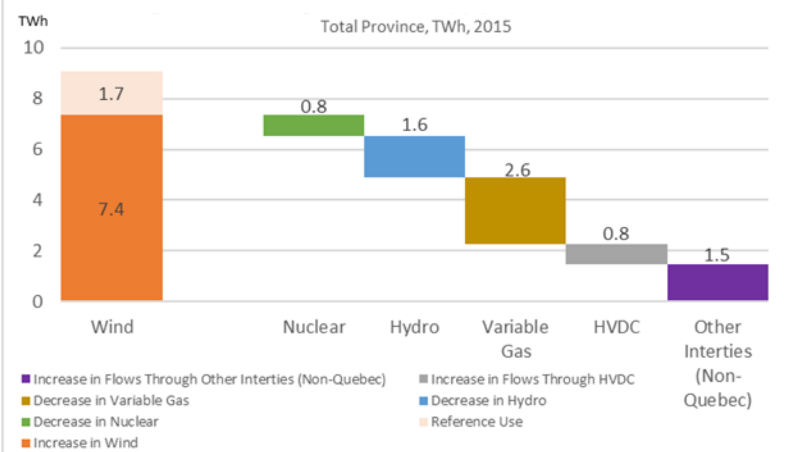
[18] Bruce Power, BPRIA Backgrounder, 2015; NECG, Nuclear Flexibility, 2015

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.

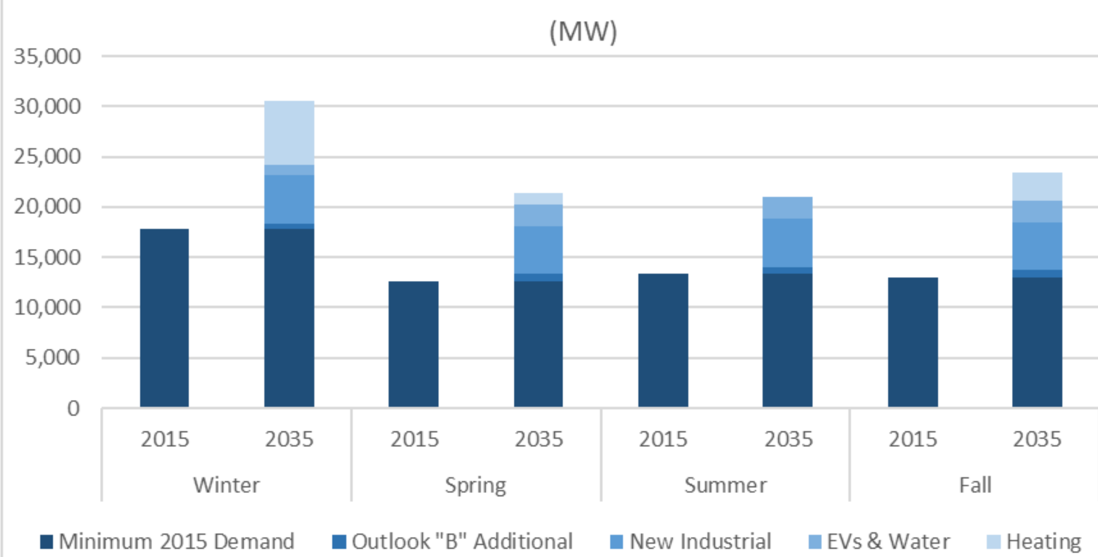
Finally, the results of the simulation related to the capacity, production, and surplus energy metrics of the scenario are summarized.

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.

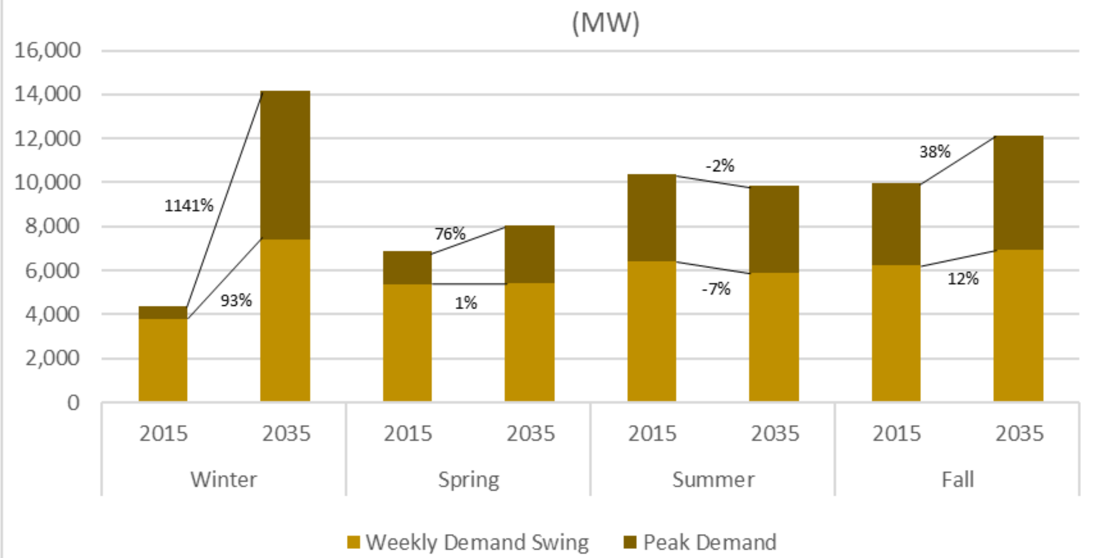
Figure 18 – Baseload Demand to Grid, 2015 vs. 2035



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.
   - *Shift: 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

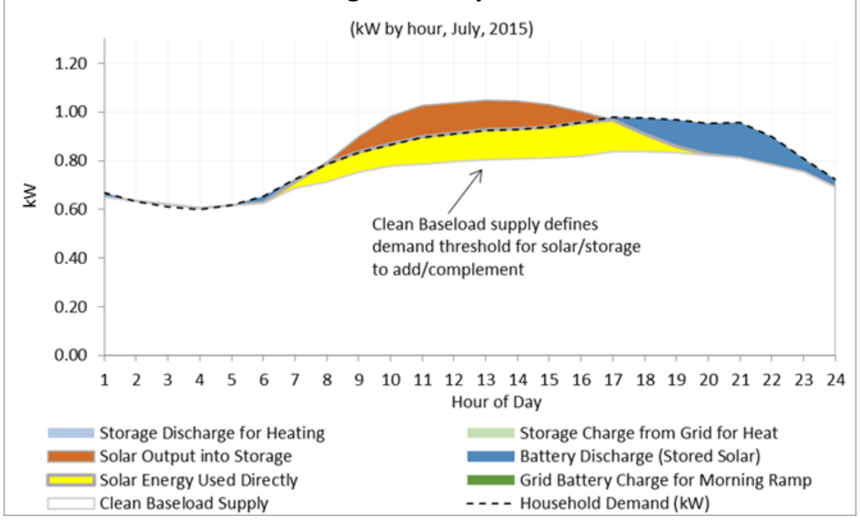
The shift to embedded DER will require integrating behind the meter solar/storage/demand/supply technologies to better regulate the power demanded from the grid and to reduce the need for the natural gas peaking power generation facilities. Such integrated technologies are currently being piloted by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



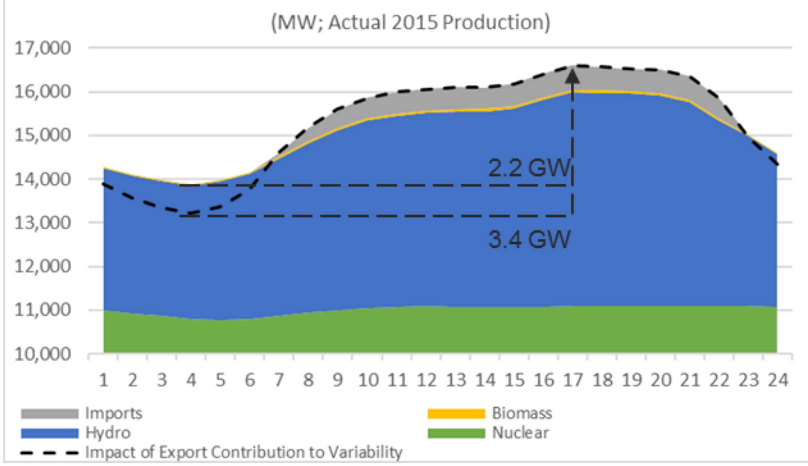
It is essential that the chosen DER capabilities can be married to the supply capabilities of the broader electricity system. The white area under the demand line reflects the ramping capability of Ontario's existing clean supply of hydro, biomass, nuclear and imports/exports with Quebec during the month 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

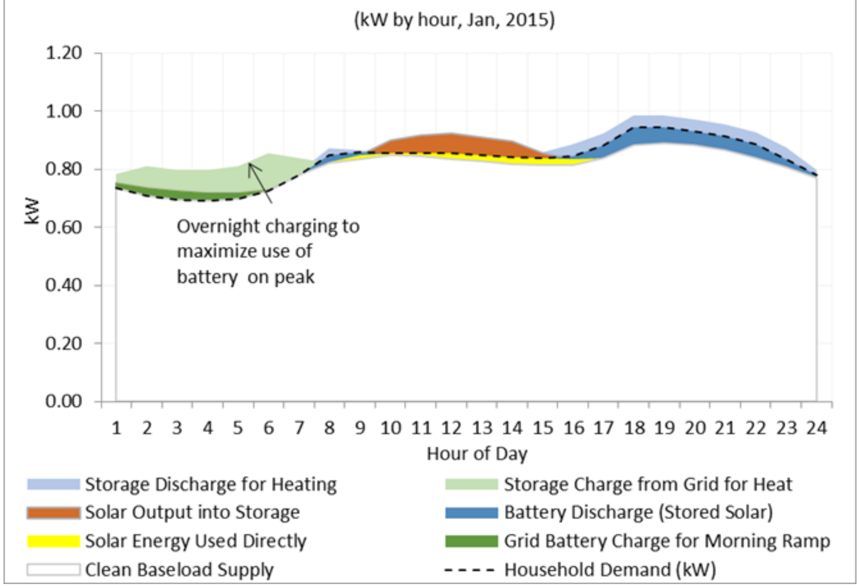


As illustrated in Figure 20, the solar array is sized by assuming its production not only supplies the demand above grid supply (yellow), but also creates sufficient surplus (orange) to charge a battery that can then supply all the demand above the grid supply, until these converge at the end of the 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)

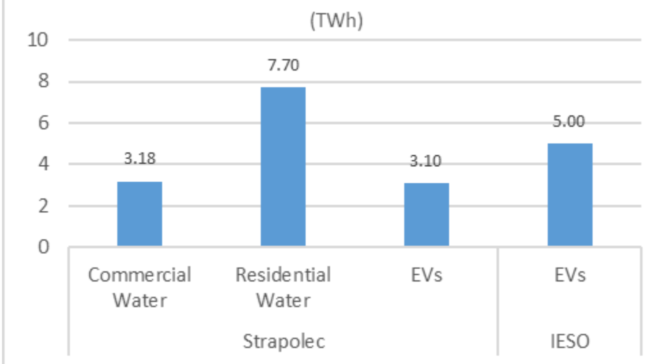


At first glance, this outcome may not appear reasonable as it significantly increases overnight load while creating surplus production during the day. Fortunately, these conditions are coincident with the projected need for winter electric heating supply. As a result, additional overnight electricity 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].

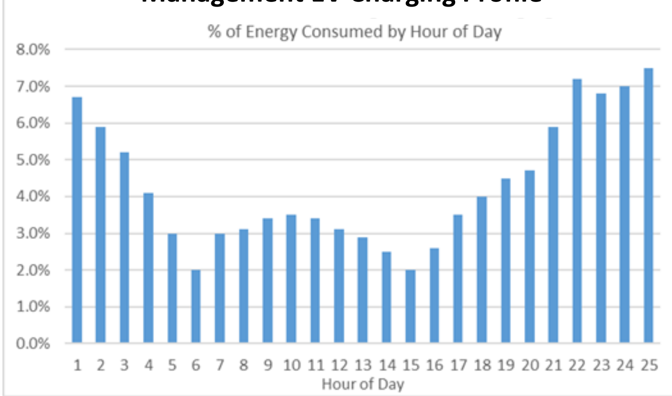
[23] Note that the "S" scenario has assumed 1.8 million EVs, or about 600,000 less EVs than the OPO has assumed. The basis for this assumption was that 800,000 hydrogen fuel cell vehicles are also assumed to be on the market when 2030 emission reduction targets are achieved. See Phase 1 Report.

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].

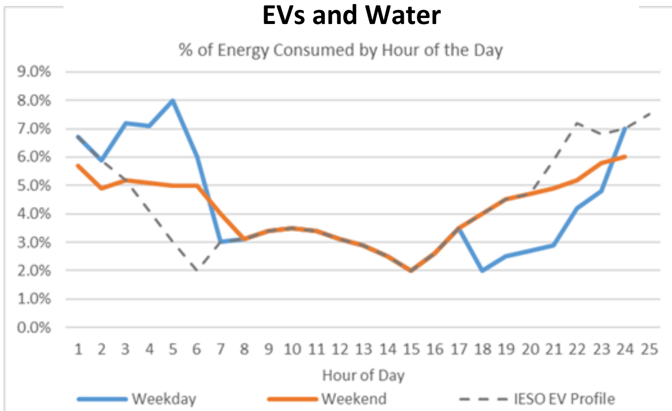
Figure 24 – IESO OPO Effective Load Management EV Charging Profile



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.

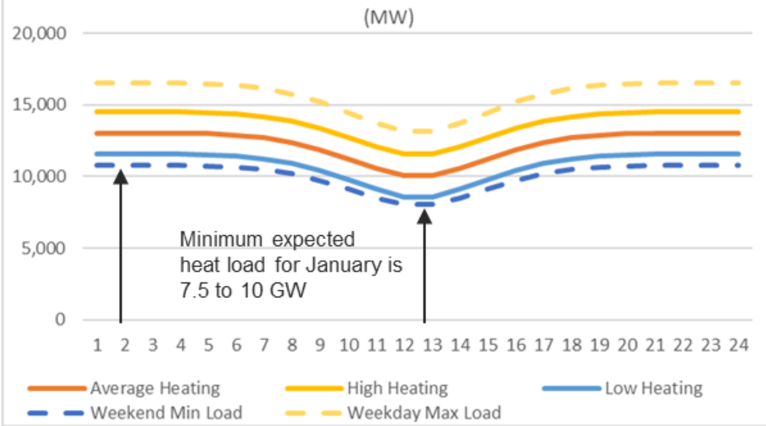
Leveraging the existing natural gas distribution system to provide peak supply during high winter heat loads could mitigate the identified need for new generation and enhancements to Dx and Tx infrastructure required to meet peak winter loads.

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.

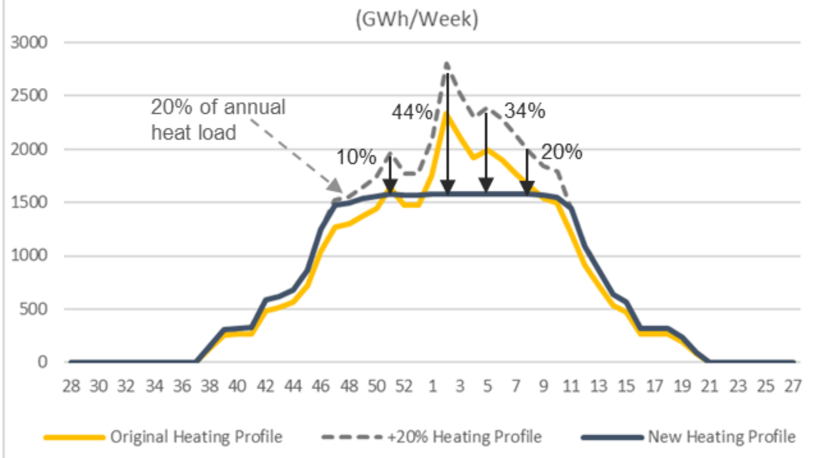
Seasonal Demand Profile Impact

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.

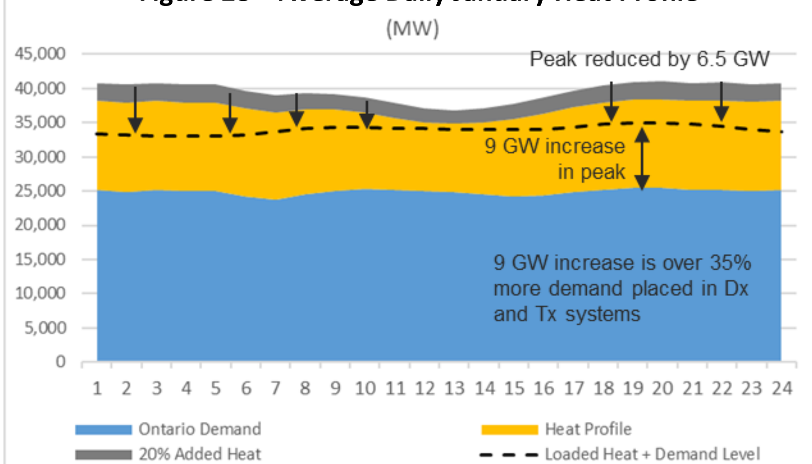
Figure 27 – Weekly Heating Profile



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

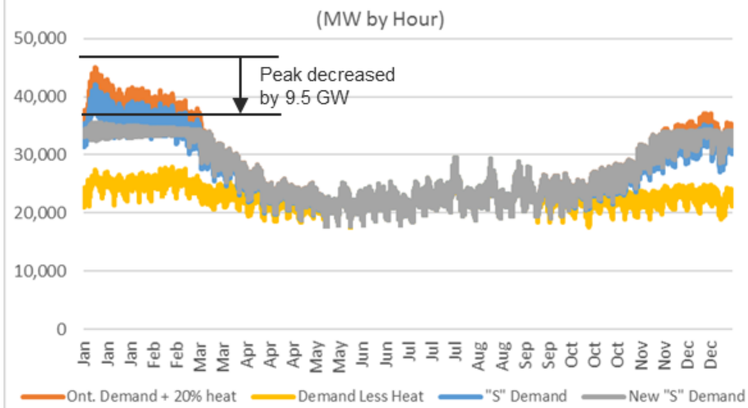
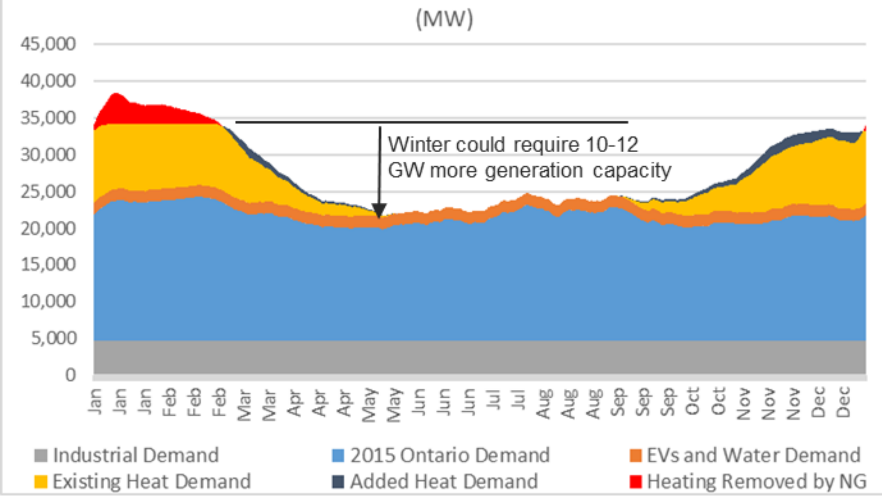


Figure 30 shows the impacts on average system electricity demand over the year resulting from the utilization of the natural gas system to shave the winter peak heating demand. The "trimming" effect resulting from using the natural gas system for peaking heat requirements could on average reduce the 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.

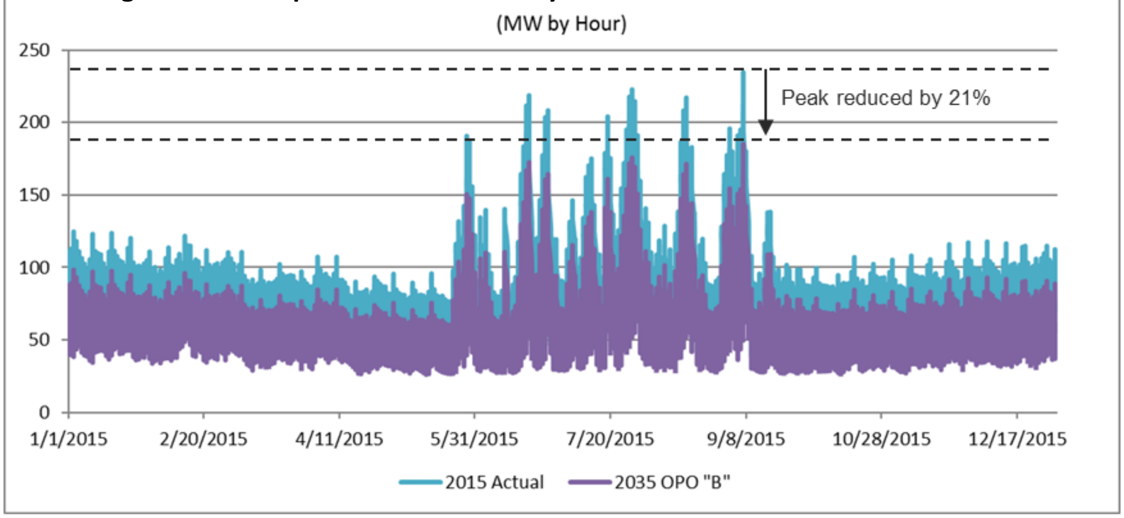
4.3.3. Implications for the Distribution system

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

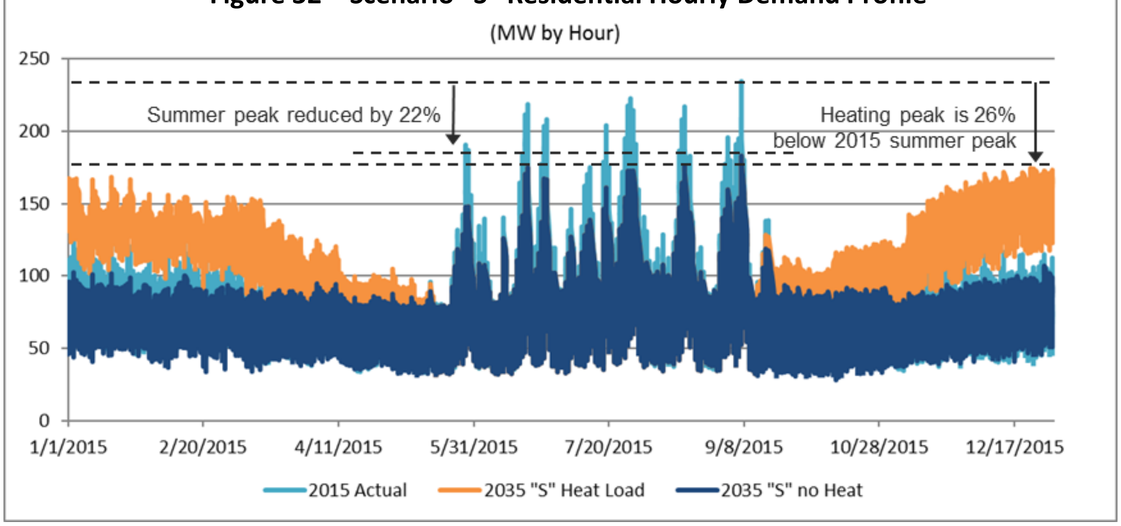


OPO "B" based on simple scaling of 21% per OPO table "Residential (kWh/HH/month)" table from Module 2: Demand Outlook

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.

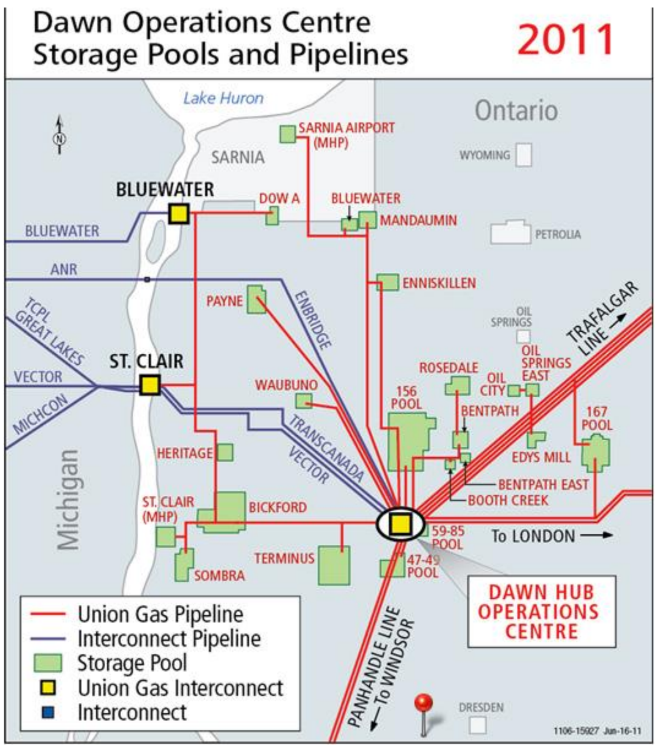
The following subsections explore the prerequisite enablers that could permit this paradigm shift to significantly reduce the cost of energy in Ontario.

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.

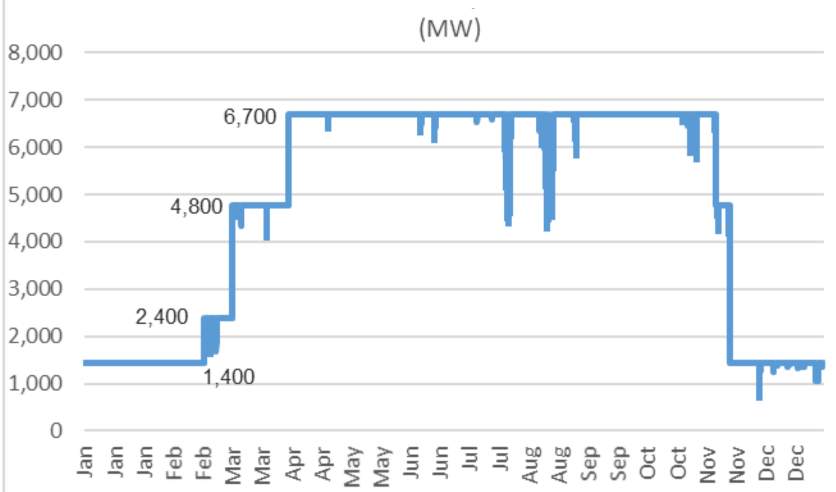
The hydrogen economy paradigm shift most relevant to the Scenario "S" 2035 projection reflects the eventual growth in hydrogen production that runs at higher operating factors. It would not be based on Ontario's existing intermittent renewables, but rather the optimised low-cost electricity system of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

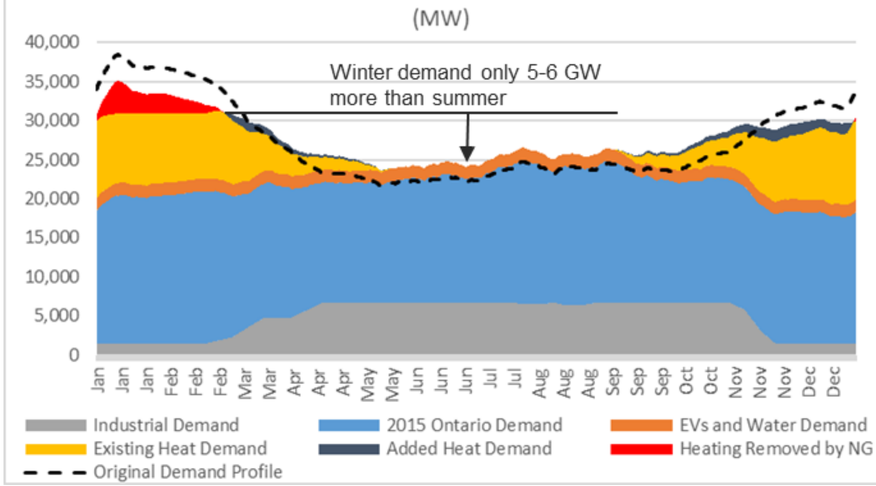


The results of the analysis suggest that the hydrogen economy could provide 6 GW of DR in the summer. Additionally, shifting production to the summer could increase summer demand by 2 GW with a corresponding reduction of 3.4 GW in the winter, substantially smoothing the seasonal supply needs of Ontario's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



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

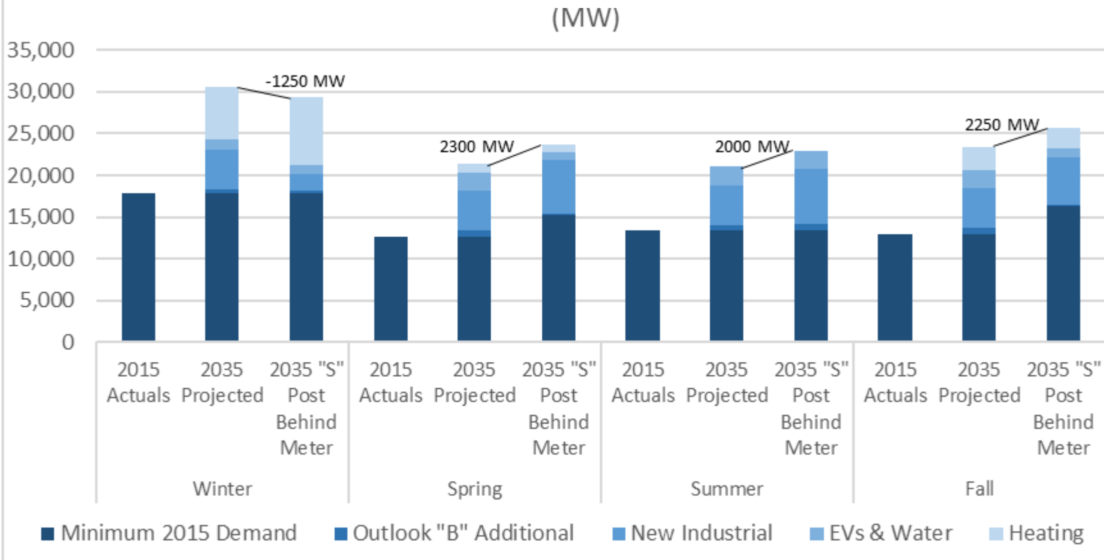
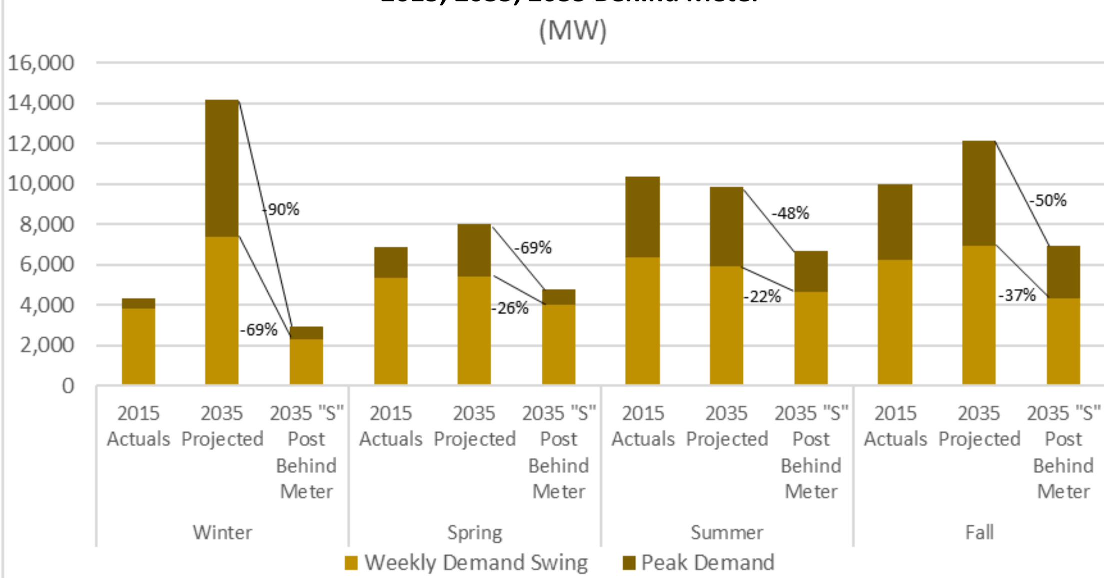


Figure 37 – Scenario "S" Changes to Variable Load Demand to Grid; 2015, 2035, 2035 Behind Meter



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

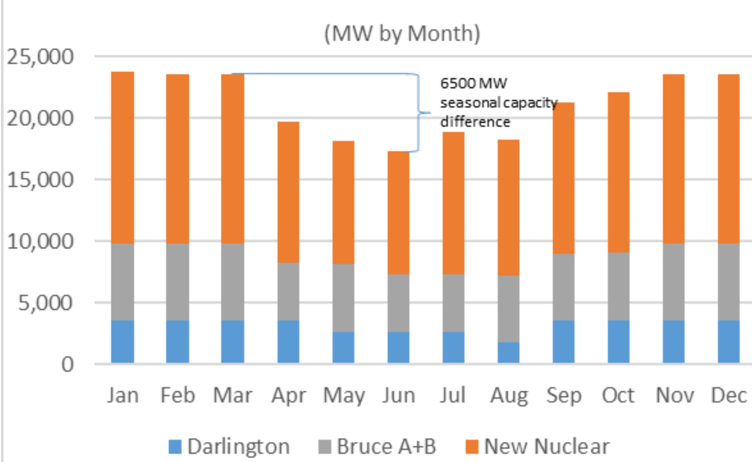
The following assumptions were made regarding the existing and planned supply mix that establish the pre-requisite base for the development of a scenario that includes new nuclear capacity:

- 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:

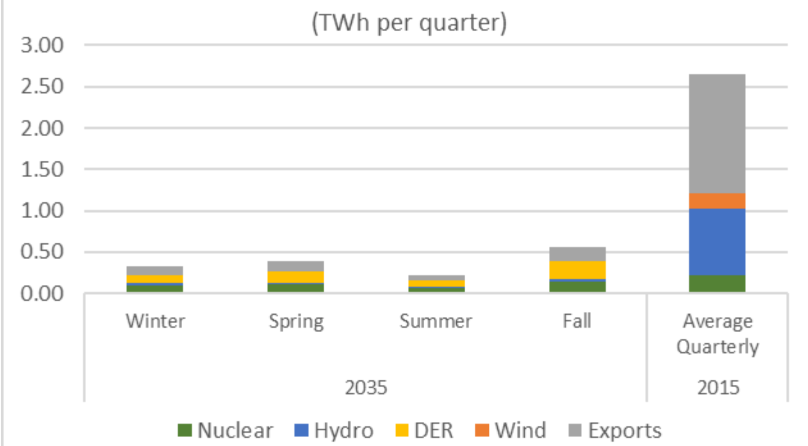
- Curtailed discharge from the LDC controlled DER batteries, deferring the use of the energy instead of wasting it;

- 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"

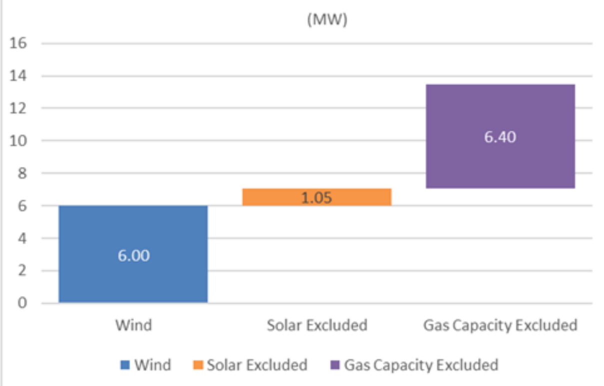
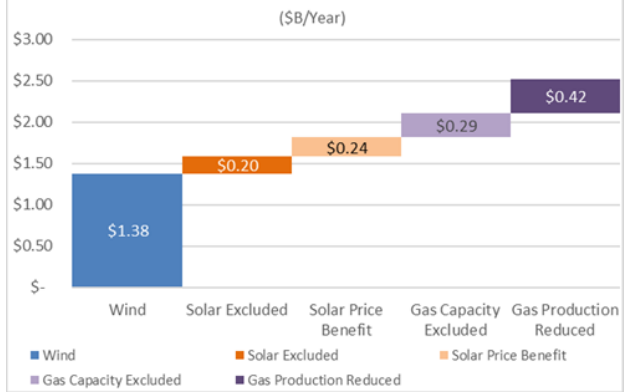


Figure 42 – Expiring Contracted Capacity Costs Avoided in Scenario "S"



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

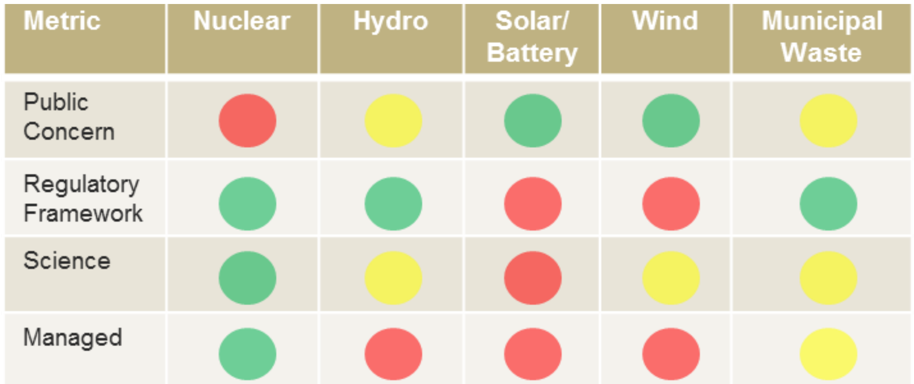


Figure 44 suggests that the nuclear industry is the only industry in Canada that has a comprehensive program in place that safely and responsibly manages its life-cycle wastes. The following provides some additional comments on the indicators noted above:

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

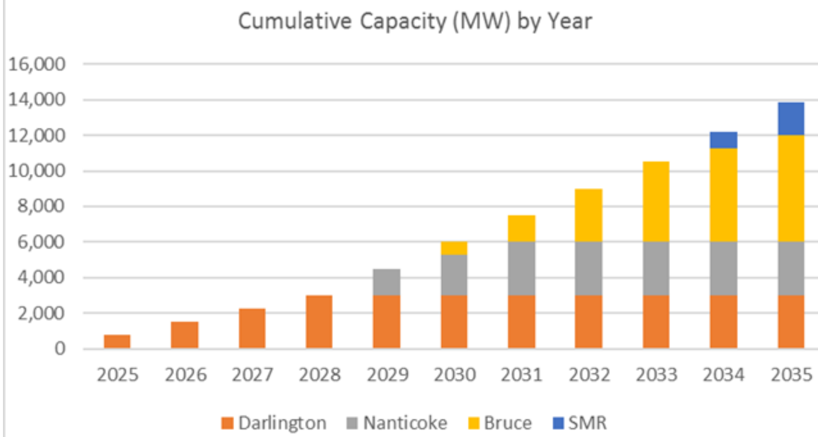
The following presents a potential schedule for deploying new nuclear capacity in a manner that would allow for Ontario to achieve its 2030 emission reduction targets by 2035. A distinct advantage of nuclear

[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.

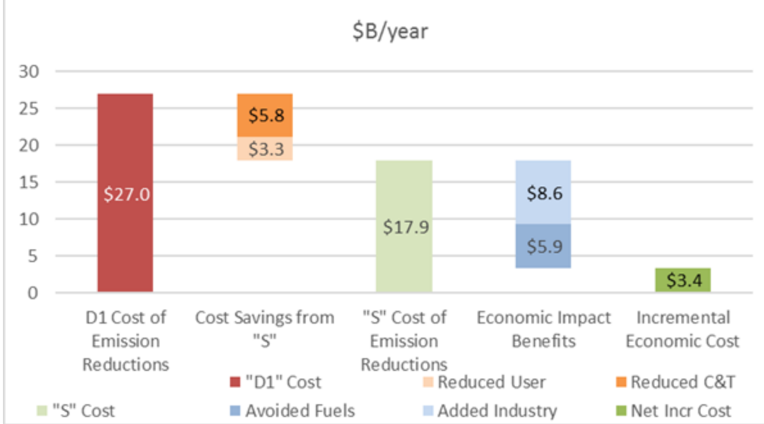
This Section concludes with a summary of the key findings.

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

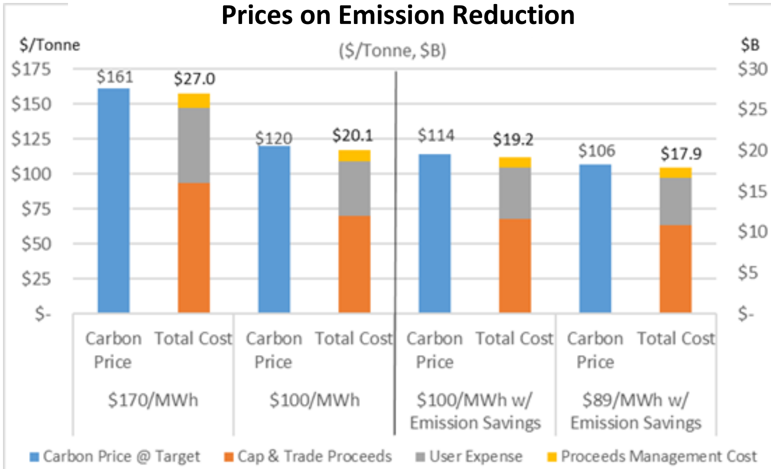


Table 11 - Impact of Scenario "S" on Cost of Emission Reduction					
	Phase 1 Report Estimate		Scenario "S"		Total Savings
	OPO D1	Ref Case	2.6 Mt Reduction	Net "S" Impact	
	$170/MWh	$100/MWh	$100/MWh	$89/MWh	"S" vs. D1
Carbon Price ($/t)	$ 161	$ 120	$ 114	$ 106	$ 55
C&T Proceeds ($B)	$ 16.1	$ 12.0	$ 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

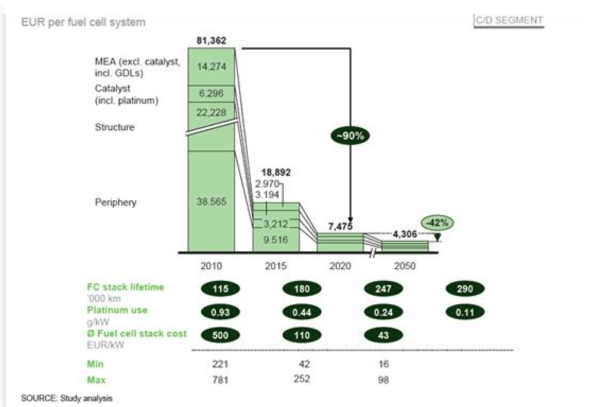


Exhibit 21: The cost of a fuel cell system falls by 90% by 2020

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

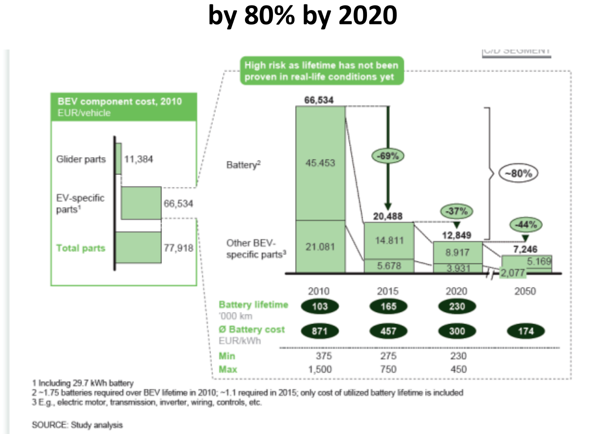


Exhibit 22: The cost of BEV components falls by 80% by 2020

[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:

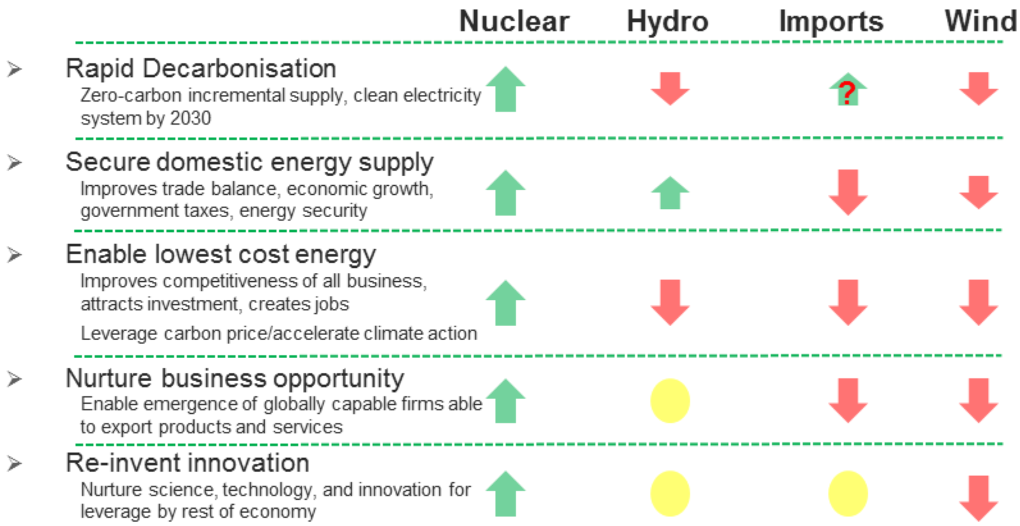
- There are significant opportunities for Ontario and Quebec to leverage each province's respective energy strengths and assets to optimize and reduce the cost structures for electricity generation in each province.
- Scenario "S" provides both capacity flexibility and economic opportunities resulting 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.

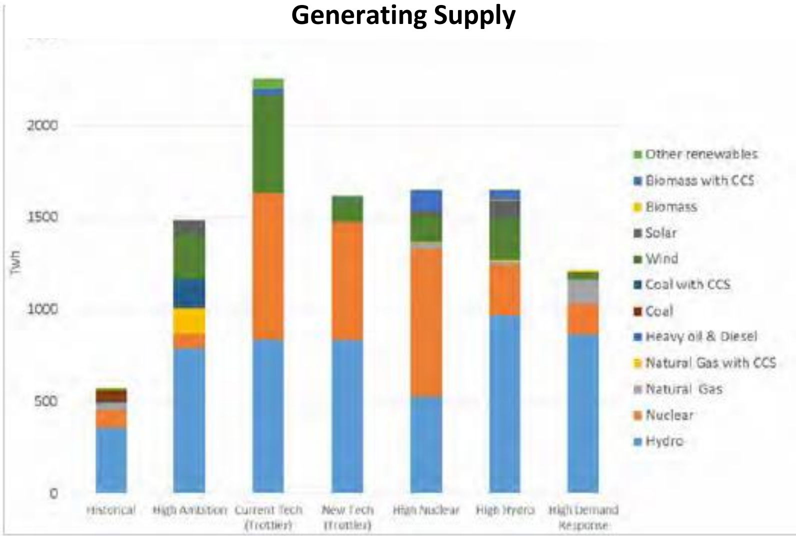
8.0 Looking Forward Observations and Recommendations

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

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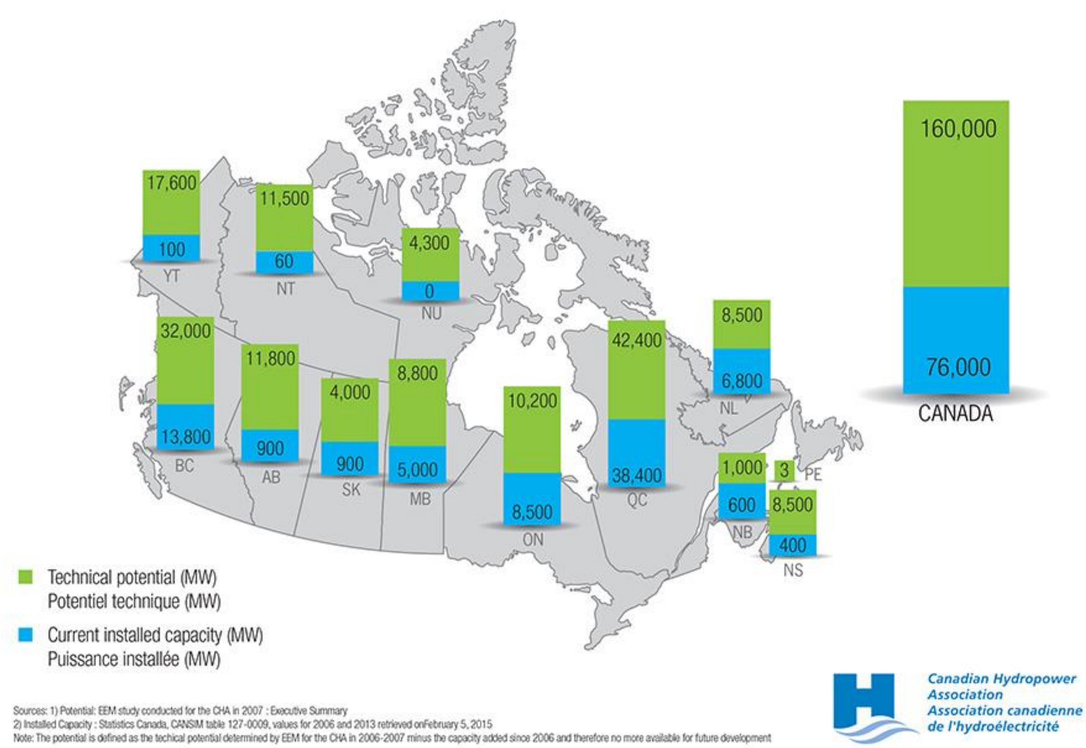
[65] Government of Canada, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, 2016

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.

The Strategic Policy Economics team would like to thank Bruce Power, the Organization of Canadian Nuclear Industries (OCNI), PowerStream, and the Power Workers Union (PWU) for their support in substantially funding the preparation of this report.

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- Michael Fowler, Professor of Chemical Engineering at the University of Waterloo, specializing in alternative fuels and the hydrogen economy
- 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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APPENDIX III - EXTENDING PICKERING NUCLEAR GENERATING STATION OPERATIONS: AN EMISSIONS AND ECONOMIC ASSESSMENT FOR 2021 TO 2024

Extending Pickering Nuclear Generating Station Operations

An Emissions and Economic Assessment for 2021 to 2024

Final Report

Marc Brouillette

November 16, 2015

STRATEGIC POLICY ECONOMICS

Executive Summary

Ontario's Minister of Energy recently indicated[1] that steps were being taken to commence a review of the province's 2013 Long-Term Energy Plan (LTEP). Two challenges will substantially impact the elements and investment decisions associated with the next version of the LTEP:

1. Expected doubling in greenhouse gas (GHG) emissions

   GHG emissions from Ontario's electricity sector are expected to more than double from current levels, reversing most of the reductions achieved since 2011. These reductions were made possible by the closure of the province's coal stations, with the last station ceasing operation in 2014. This is counter to the province's objectives outlined in the Premier's mandate letter to the Minister of the Environment and Climate Change, Ontario's Climate Action Plan and commitment to participate in a Cap and Trade program with Quebec and California - initiatives aimed at reducing GHG emissions[2].

2. A system reserve capacity gap equivalent to the Pickering Nuclear Generating Station (PNGS)

   Ontario's Independent Electricity System Operator (IESO) has identified a 2,000 to 3,000 megawatt (MW) gap in reliability reserve capacity that will occur with the scheduled closure of the Pickering Nuclear Generating Station (PNGS) in 2020. This gap is currently expected to persist through to 2032. Ontario will need to fill this gap to comply with the requirements of the North American Electricity Reliability Corporation (NERC) and the Northeast Power Coordinating Council Inc. (NPCC) that govern the integrated operation of Ontario's grid within the North American system.

This report examines the option of extending the operations of two Pickering A units for two years and four Pickering B units for four years to address these challenges and thus defer accordingly the need to construct 2,000 MW of new natural gas-fired generation plants[3] that are otherwise necessary in 2021.

Three categories of demonstrable benefits were evaluated for the four-year period of PNGS extended operations. The major observations are:

a) ***Lower GHG emissions*** – over 18 million tonnes (Mt) of CO_2 can be avoided, equivalent to avoiding a 55% increase in electricity system emissions and a 25% increase in overall provincial emissions from natural gas usage in all sectors of Ontario's economy. The PNGS option exemplifies Ontario's legacy of nuclear being practically responsible for Ontario's electricity system GHG emissions success.

b) ***Lower electricity system cost*** – potentially reduced by over \$1.5 billion (B) due to PNGS operating cost advantages and avoidance of the risks of natural gas-fired generation dependence.

c) ***Positive Jobs and Gross Domestic Product (GDP) created –*** from the power of domestic spend

   - ***Jobs Sustained*** – 40,000 Person Year Equivalent (PYE) jobs.
   - ***Net New Ontario Domestic GDP*** – \$7B enabled through replacing \$4B of imported energy with domestic nuclear generation.

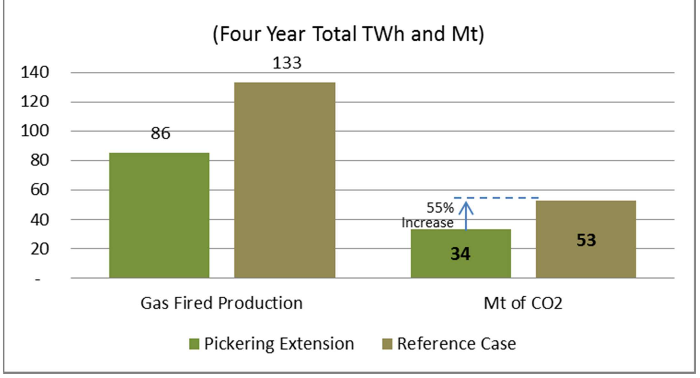
[1] OEA Energy Conference, 2015
[2] Government of Ontario, 2014. Wynne, 2014. Office of the Premier of Ontario, 2015
[3] IESO, October 2014

Detailed Description of the Three Benefit Categories

a) Reducing GHG emissions is an important policy objective to which extending the operations of the PNGS contributes in three ways:

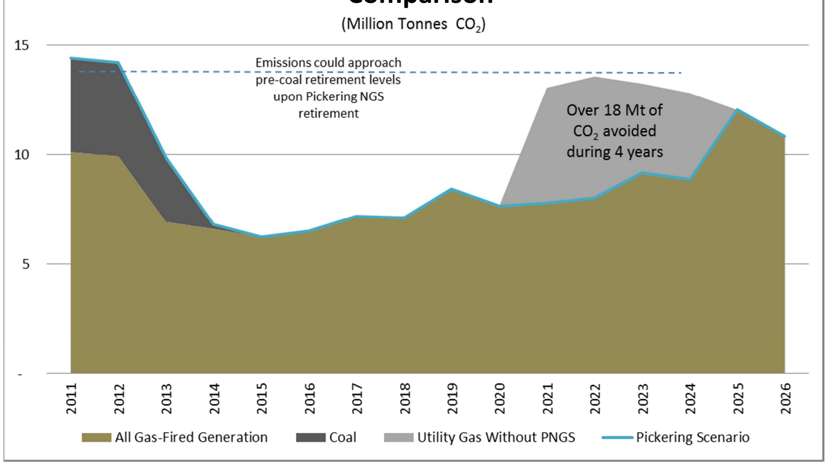
i. Figure ES1 shows that extending PNGS operations for four years would reduce Ontario's natural gas-fired generation production from 130 tera-watt hours (TWh) to less than 90 TWh. This reduced reliance on gas-fired generation would eliminate the production of over 18 Mt of GHG emissions[4], equivalent to avoiding a 55% increase in emissions by the electricity system.

Figure ES1 – Gas Fired Generation and CO_2 Emissions



ii. Figure ES2 highlights the reduced emissions profile of extended PNGS operation that sustains nuclear's GHG reduction success and defers a return to pre-coal retirement emissions levels[5].

Figure ES2 – GHG Historical Emissions and Projection Comparison



iii. In a broader context, natural gas is not only used for the generation of electricty but also many other residential, commercial and industrial applications. Absent the PNGS, the province's overall emissions from the use of natural gas from all sectors will increase by 25%.

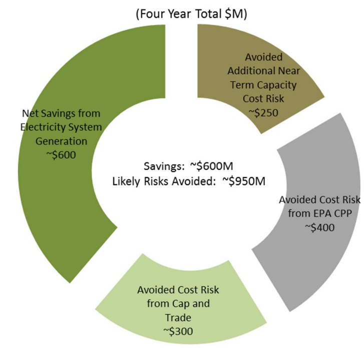
[4] CO_2 emissions calculated based on a system-wide blended rate of approximately 400 kg/MWh.
[5] Near term CO_2 forecast is consistent with recently published IESO actual and forecast GHG emission data. All sources consulted indicate higher emissions throughout the forecast than suggested in the LTEP.

b) *Cost of electricity* to Ontario ratepayers could be reduced as shown in Figure ES3 by over \$1.5B in two ways:

i. Avoid ~\$600 million (M) in system cost reductions resulting from cost differences between PNGS and natural gas-fired generation.
   - Reduced system costs would avoid 4% and 1% rate increases for Class A industrial and Class B residential rate payers respectively.

ii. Avoiding over \$950M in emerging costs risks emanating from the United States' Clean Power Plan, Ontario's Cap and Trade program and the province's need to contract additional capacity, all stemming from a growing dependence on natural gas-fired generation.

Figure ES3 – System Cost and Risk Reduction Benefits to Rate Payers



c) *New domestic GDP* of over \$7B generated through the power of domestic spend across four mechanisms as shown in Figure ES4:

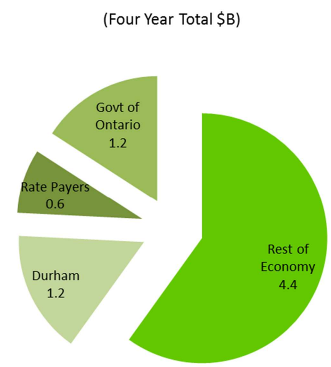
i. Improves the Government of Ontario's fiscal position by almost \$1.2B from taxes on the new gross domestic product (GDP) and cost savings from Ontario Power Generation (OPG).

ii. Reduced electricity costs will enable ratepayers to inject over \$600M back into the economy through indirect benefits.

iii. Continues a stimulus of \$1.2B of economic activity to Durham Region where OPG is the largest employer.

iv. Adds approximately \$4.4B to the rest of the provincial economy.

Figure ES4 – Share of Total Economic Benefit



Economically, the province can only benefit by selecting the PNGS extension option. There is a high degree of domestic content embedded in Ontario's nuclear production. As a result, the observed benefits to Ontario are insensitive to the uncertainties in the input assumptions. For example, if PNGS costs proved to be higher than assumed, any impacts to rate payer benefits would be balanced by benefits from higher GDP and revenues for the Government of Ontario.

Recommendation:

The Ontario Government should direct the Minister of Energy, the IESO, and Ontario Power Generation to consult with the Canadian Nuclear Safety Commission (CNSC) for the purpose of securing approval for the longest possible period of continued safe operation of the PNGS beyond 2020 in order to:

(1) Sustain the substantial environmental and economic benefits that can accrue to Ontario for every year it operates; and

(2) Provide the government with the maximum time for assessing longer term options for the eventual replacement of the PNGS.

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1.0 Introduction

This study was undertaken to assess how extending the operations of the Pickering Nuclear Generating Station (PNGS) may impact on Ontario's publicly stated environmental and economic objectives.

Background

Ontario's Minister of Energy recently indicated[6] that steps were being taken to commence a review of the province's 2013 Long-Term Energy Plan (LTEP). Two challenges will substantially impact the elements and investment decisions associated with the next version of the LTEP:

1. Expected doubling in greenhouse gas (GHG) emissions

   GHG emissions from Ontario's electricity sector are expected to more than double from current levels, reversing most of the reductions achieved since 2011. These reductions were made possible by the closure of the province's coal stations, with the last station ceasing operation in 2014. This is counter to the province's objectives outlined in the Premier's mandate letter to the Minister of the Environment and Climate Change[7], Ontario's Climate Action Plan[8] and commitment to participate in a Cap and Trade program with Quebec and California[9] - initiatives aimed at reducing GHG emissions.

3. A system reserve capacity gap equivalent to the Pickering Nuclear Generating Station (PNGS)

   Ontario's Independent Electricity System Operator (IESO) has identified a 2,000 to 3,000 megawatt (MW) gap in reliability reserve capacity that will occur with the scheduled closure of the Pickering Nuclear Generating Station (PNGS) in 2020. This gap is currently expected to persist through to 2032. Ontario will need to fill this gap to comply with the requirements of the North American Electricity Reliability Corporation (NERC) and the Northeast Power Coordinating Council Inc. (NPCC) that govern the integrated operation of Ontario's grid within the North American system.

Objective

This report examines the option of extending PNGS operations to address the above challenges and considers three impacts this could have on Ontario:

1) Greenhouse Gas (GHG) emissions of carbon dioxide (CO_2)
2) Cost to the electricity system and rate payers
3) Economic implications to Ontario, including jobs and Gross Domestic Product (GDP)

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[6] OEA Energy Conference, 2015
[7] Wynne, 2014
[8] Government of Ontario, 2014
[9] Office of the Premier of Ontario, 2015

Approach

Strapolec modelled two scenarios of Ontario's electricity supply mix for the four year period from the beginning of 2021 to the end of 2024 inclusive:

1) ***Construct 2,000 MW of new gas-fired generation*** - the LTEP contemplated new Simple Cycle Gas Turbine (SCGT) generation as part of the assumed "planned flexibility" to address the capacity gap.[10]

2) ***Extend PNGS operations*** – the two-unit Pickering A Station extends operations for two years to 2022 and the four-unit Pickering B station for four years to 2024.

Structure of this document

This report provides a comprehensive description of the drivers, assumptions and outcomes of the assessment conducted regarding the benefits to Ontario of extending the operations of the PNGS to 2024.

Section 2 summarizes the characteristics of the emissions and reserve capacity challenges facing Ontario and why there is potential for considering the PNGS option as a solution. Section 3 presents the definitions of two scenarios created to contrast the emissions and economic impacts of extending the PNGS operations versus what may be the only alternative in a gas-fired generation solution.

Section 4 presents the detailed findings of the assessment of GHG emissions that would result from the two scenarios considered.

Section 5 discusses the cost implications for the electricity system, the cost assumptions that have been modelled, implications for rate payers, and the cost risks that should be considered.

Section 6 presents the findings of the economic impact assessment including how different stakeholder groups may be impacted. Section 7 expands on the benefits to the Government of Ontario.

Finally, Section 8 summarizes the findings and presents the recommendation that has emerged from this study.

The detailed assumptions that were compiled for building up the cost and economic parameters used in the analysis are provided in Appendix A and the sources consulted during the course of the research effort are listed in Appendix B.

[10] IESO, October 2014

2.0. Background

This project has evaluated the emissions and economic impacts of leveraging an extension of operations at the Pickering Nuclear Generating Station (PNGS) to support Ontario in addressing two major challenges:

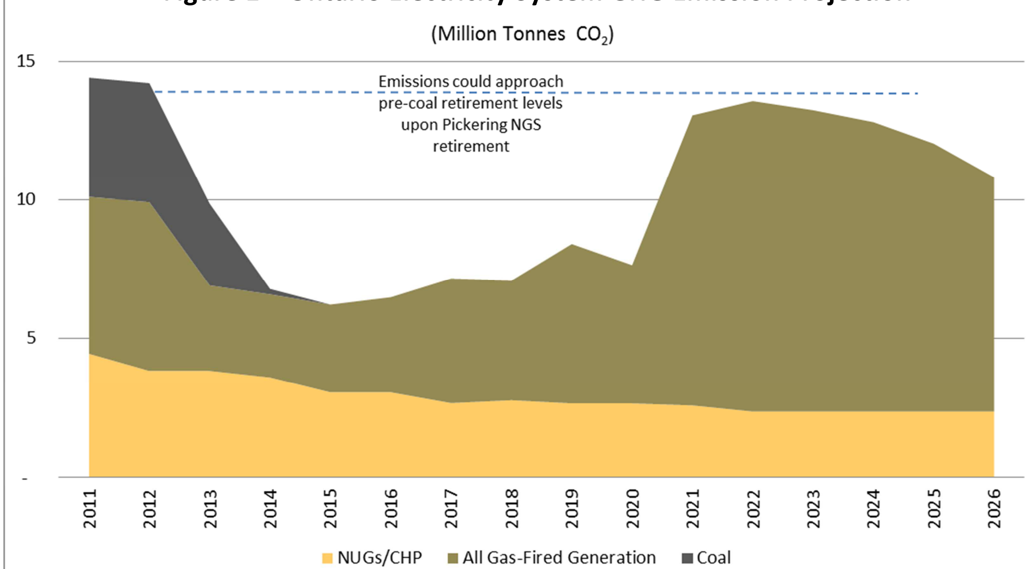
1. The GHG Emissions Challenge
2. Ontario's System Reliability Reserve Capacity Gap

This section describes the nature of these challenges to help explain how extending PNGS operations may contribute to their resolution.

2.1. The GHG Emissions Challenge

Ontario's electricity generation supply mix and production forecast has evolved to reflect the guidance contained in the 2013 LTEP. The forecast currently depends on natural gas-fired generation to support two conditions: (1) supplement nuclear electricity generation while Ontario's nuclear refurbishment program is underway; and (2) to replace the 3,100 MW of nuclear capacity when PNGS goes off-line after 2020. Figure 1 illustrates that GHG CO_2 emissions will, by 2022, be double 2015 levels[11]. This will return Ontario to emissions levels similar to 2011 and 2012, when Ontario had coal generating stations still in operation. The option to use natural gas-fired generation to compensate for lost nuclear generation will significantly erode the CO_2 emissions reductions achieved through the closure of the province's coal stations since then, a central strategy for the 2010 LTEP.

Figure 1 – Ontario Electricity System GHG Emission Projection



[11] Gas fired generation emissions are included for all of the Utility Gas generators, NUGs, and CHP sources. CO_2 emissions post 2020 calculated based on a system wide blended rate of approximately 400 kg/MWh

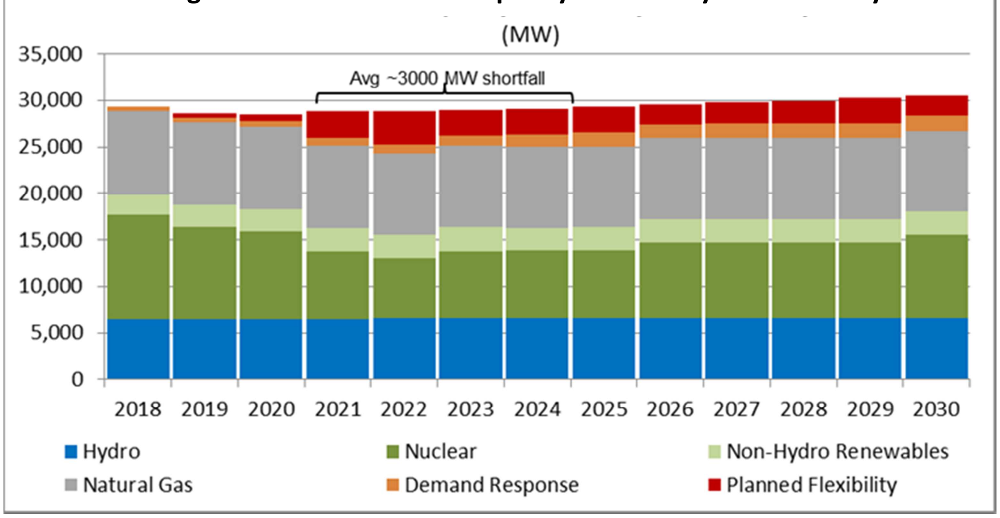
As elaborated more fully in Section 4, the associated growth in demand for natural gas usage within the electricity sector after the PNGS retires represents a 25% increase in the total emissions that arise from the use of natural gas across Ontario's economy. This outcome is counter to the province's climate change objectives and initiatives aimed at reducing GHG emissions.

2.2. Ontario's System Reliability Reserve Capacity Gap

Ontario's 2013 LTEP identified the expected shortfall with respect to the peak capacity reserve capability that is necessary for Ontario to be a compliant member of NERC and NPCC. These two organizations govern the integrated operation of Ontario's grid within North America. This shortfall has arisen directly from the need to refurbish Ontario's nuclear fleet and the decision to retire the PNGS in 2020, the same factors cited above for causing the expected increase in GHG emissions.

Figure 2 illustrates the capacity gap identified in the 2013 LTEP and shows that the average gap for the period from 2021 to 2024 is approximately 3,000 MW.[12]

Figure 2 – Summer Peak Capacity Availability for Reliability



The 2013 LTEP included "Planned Flexibility" to address the capacity gaps Ontario must close in order to comply with the North American system reliability requirements. Planned Flexibility covered several elements: Conservation; Non-Utility Generator (NUG) re-contracting; coal station conversion to natural gas; new procurement; and electricity imports.

In its 2014 review of Ontario's interties[13], the IESO considered the feasibility of the import option and concluded electricity imports would not likely be available for 10 years, even if the pre-requisite transmission planning, approvals, and investments in interties were to commence immediately.

- Transmission infrastructure investments to allow for imports were estimated to approach $5B.

[12] IESO, 2014
[13] IESO, October 2014

- Importing electricity at the required levels could cost over $100/mega-watt hour (MWh).

The IESO has concluded that an unresolved capacity gap remains today for which Ontario continues to require a cost effective solution. Figure 3 replicates the data provided by the IESO in its September 2015 NUG framework assessment[14]. It includes an updated forecast for the capacity gap and shows how it compares to the 2013 LTEP assumptions. The IESO's report reflected the recently announced Ontario/Quebec capacity exchange agreement and other developments since the 2013 LTEP. While somewhat mitigated from the 2013 LTEP version, the current IESO estimated capacity gap remains similar in size to the PNGS's de-rated capacity and aligns with its retirement post 2020[15].

Figure 3 – IESO Current Reserve Capacity Perspective

Extension of the PNGS operations has been identified by the IESO as a potential contributing solution to the capacity reserve challenge. However, the IESO also noted that the technical and financial viability and implications were not yet known. An objective of this study is to help inform a better understanding of any potential implications.

2.3. Implications Summary

The GHG emissions and capacity reserve challenges are material issues for Ontario that require solutions. Both rate payers and taxpayers will expect the province to seek out cost effective and responsible strategies to address them. This report investigates the implications of extending the PNGS operations. The results are intended to help inform the province of the merits of this option, both for addressing the key issues and for the delivery of additional benefits for Ontario.

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[14] IESO, September 2015

[15] IESO's updated capacity gap reduction in 2024 represents a refurbishment schedule altered from the LTEP, the details of which were not obtained.

3.0. Scenario Definitions

Assessing the implications of extending the PNGS operations is through a comparative analysis between two options. Two options or scenarios have been defined for evaluation that may represent the only viable alternatives that Ontario may have: (1) the PNGS scenario; and (2) a reference scenario that relies on natural gas-fired generation. The scenarios are to be compared on GHG emissions impacts and cost differences. This section addresses three elements of the scenario definitions:

1. Capacity Assumptions and Considerations

   Provides an overview of the characteristics used in the scenario analysis to enable an objective assessment of the options.

2. Scenario Production Differences

   Summarizes production differences between the scenarios that stem from of a stable PNGS baseload supply contrasted with the variable supply capability of natural gas-fired generation being deployed for a largely baseload operation. System supply mix production differences arise due to how these two supply types interact with the rest of Ontario's supply mix.

3. Impacts on Surplus Baseload Generation (SBG)

   Describes the SBG implications that stem from the scenario production differences.

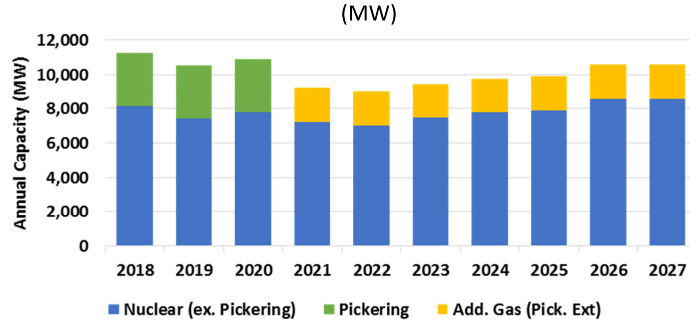
The following sections describe each of these topics to provide the basis for interpreting the environmental, financial, and economic outcomes presented in the latter sections of this report. The section closes with a summary of the implications of the assumptions.

3.1. Capacity Assumptions

Two scenarios have been defined to support a comparison of the production mix, emissions and cost over the four year period from the beginning of 2021 to the end of 2024.

The two scenarios represent: (1) a reference scenario reflecting Strapolec's view of the province's supply mix option from 2021 to 2024; and (2) a scenario to reflect the capacity changes representative of extending the operations of the PNGS. The capacity profiles of these two scenarios are illustrated in Figures 4 and 5.

Figure 4 – Reference Case Capacity Scenario
(MW)



1. Reference Case Scenario – LTEP Status Quo

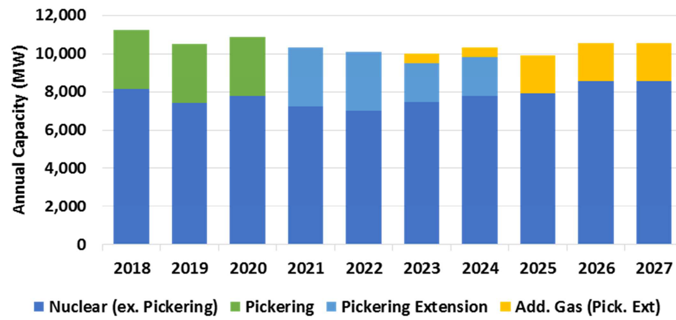
- 2,000 MW of natural gas-fired generation capacity to be commissioned in 2021 to coincide with the expected retirement of the PNGS and the capacity gap that result.

- This is chosen to reflect the minimum capacity that will be required to close the gap identified by the IESO. From a cost perspective, this is likely a conservatively low assumption as additional fixed costs could arise should more capacity be needed.

2. *Extended PNGS Operations Scenario*

- The PNGS 3,100 MW of capacity is extended.
  - Pickering is assumed to operate at a 75% annual operating factor due to planned maintenance outages throughout the year and hence the capacity is deemed comparable to the reference case gas-fired capacity plants for the simulation.

Figure 5 – Pickering NGS Capacity Scenario
(MW)



- As illustrated in Figure 5, the PNGS scenario has all six units operating for the first two years and then only the four “B” units operating for the next two years.
- 500 MW of gas-fired generation capacity is added in 2023 to compensate for the retirement of the PNGS “A” units, again to retain similar reserve capacity profiles to that of the reference case.

All assumptions on capacity, productivity and regulated/contracted pricing for all other sources of supply in the provincial supply mix are the same between the two scenarios. Although not part of this analysis, after 2025 both scenarios would have identical assumptions regarding 2,000 MW of gas-fired generation.

3.2. Scenario Production Differences

The expected generation levels of the PNGS extended operations is central to a consistent set of assumptions that align capacity, supply mix characteristics and the cost assumptions. Generation has been modelled as 20 tera-watt hours (TWh) per year from the six PNGS units in 2021 and 2022 and then 14 TWh per year from the Pickering B units in 2023 and 2024. These selections are based on rounded 2013 PNGS production levels and reflect a 75% operating factor.

The electricity system impact analysis was conducted using Strapolec’s proprietary model of Ontario’s electricity system[16]. This model assesses the full daily, weekly and seasonal demand, supply, and pricing dynamics using hourly generation estimates to compile a full annualized representation of the production from Ontario’s supply mix. The model determines the impacts of capacity changes on the need for imports, natural gas-fired generation, and curtailment of other supply sources. It also forecasts

[16] Strapolec, 2013

the Hourly Ontario Electricity Price (HOEP), and the total electricity system cost. Strapolec's system model applies normally expected production assumptions to all supply sources and then adjusts any variable supply production amounts to meet demand on an hourly basis. The net effect of all the hourly results yields the resulting mix of supply in a year.

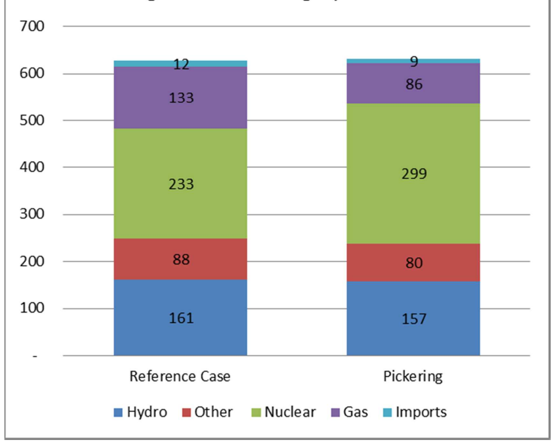
Figure 6 compares the total four year generation from all supply sources. The generation production results show that retaining PNGS capacity increases nuclear production by 66 TWh and:

- Reduces the need for imports by 3 TWh.
- Displaces 47 TWh of gas fired generation or about 37% of that generation.
- Displaces 8 TWh of other generation and 4 TWh of hydro

The total useable generation from the PNGS is 62 TWh. The remaining 6 TWH of the 68TWh of PNGS production consist of 2 TWh of curtailed nuclear energy and a need to export an additional 4TWh of SBG.

Figure 6 – Scenario Generation Mix Comparison

Existing Plan vs Pickering 4 year Total TWh



3.3. Impacts on Surplus Baseload Generation (SBG)

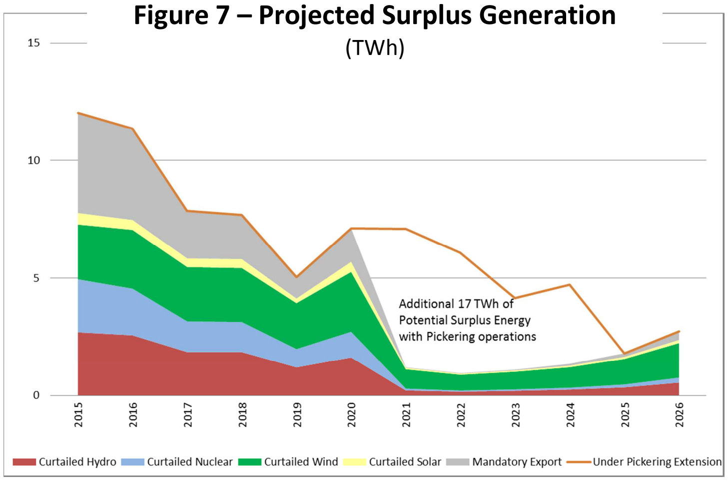
The presence of SBG resulting from Ontario's supply mix is well known and understood. Figure 7 shows the components of SBG for the reference case and highlights that 17 TWh of new SBG is created by the extended PNGS scenario. The PNGS induced SBG includes the 2 TWh of surplus PNGS production and 4 TWh of exported SBG mentioned above, as well as the 12 TWh of hydro and other generation that is displaced (the totals do not equate due to numerical rounding). The total of 17 TWh is 25% of expected PNGS production.

Even within the PNGS extended operations, the forecast SBG will continue to decline from the levels that the system is producing today.

- The low SBG forecast for the reference scenario in 2021 to 2024 reflects that natural gas-fired generation can adjust rapidly to demand changes.
- Figure 7 also illustrates that the ongoing surplus wind generation remains even without PNGS continued operations.

Figure 7 – Projected Surplus Generation

(TWh)



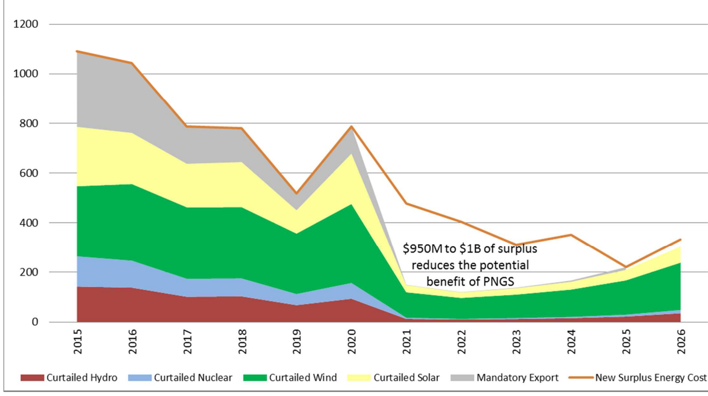
The surplus energy illustration is based on a curtailment assumption within the Strapolec simulation that curtails the highest contractual cost supply first. This allowed for the calculation of the cost impact when the renewables were added. It is understood that the IESO may be moving to a similar curtailment strategy and away from the current strategy that curtails hydroelectric and Bruce nuclear output before variable renewable output.

Figure 8 summarises the cost implications of SBG under the two scenarios. The PNGS extension scenario will have an additional $950M to $1B in SBG. The cost of the additional SBG is computed using the expected PNGS unit cost of production.

The net costs of the produced "surplus" energy are reflected and included in the total cost depictions compared in Section 5.

Figure 8 – Comparing Cost of Surplus Generation

($M)



3.4. Implications Summary

Contrasting the two scenarios of stable nuclear supply versus flexible natural gas-fired generation is a trade-off of the production of one for the other. However, since PNGS production is not flexible by its nature, additional surplus energy will be created. Due to the cost advantages of the PNGS operation, the cost of the surplus energy is absorbed by the system and still enables the net energy cost benefit to rate payers described in Section 5.

4.0. Electricity System GHG Emissions of CO_2

This section presents the results of the GHG emissions comparative analysis, specifically as it pertains to CO_2 emissions. The context for why these emissions are important to Ontario and how the province plans to address them is provided in Section 2. The findings of this section suggest that Ontario's GHG emissions forecast may be improved by extending the operation of the PNGS. Four topics are discussed:

- Forecast Emissions

  The forecasts for the two scenarios are presented, compared, and related to the natural gas-fired generation that drives them.

- History of Emissions and the Nuclear Symbiosis

  The history of emissions reductions in Ontario is presented along with the compelling evidence that shows Ontario's achievements are almost entirely due to the contribution of nuclear generation.

- Forecast Use of Natural Gas in Ontario

  The broader context of the role natural gas plays in Ontario for residential, commercial, and industrial applications in addition to electrical generation is discussed along with an observation of how the usage mix may change absent PNGS.

- US Shale Gas GHG Emissions Footprint

  Emerging research is showing United States (US) shale gas sources to be worse emitters than traditionally assumed for natural gas.

4.1. Forecast Emissions

Measured GHG emissions in Ontario's electricity system today stem from the production of electricity by natural gas-fired generating plants. These plants include the NUGs, many of which are co-generation facilities, as well as the Combined Heat and Power (CHP) facilities initially under contract with the Ontario Power Authority (OPA) but now with the IESO. All of these sources are treated collectively but with the system simulation attributing the appropriate duty cycles to their individual operations (e.g. NUGs operate virtually continuously in support of their co-generation function). This analysis establishes that reductions in GHG emissions are directly correlated with the degree to which natural gas-fired generation is displaced by PNGS.

The production profiles of Ontario's natural gas-fired generation fleet for the two scenarios are illustrated in Figure 9. Under the PNGS scenario, the forecast natural gas-fired generation reduces from 130 TWh to less than 90 TWh in the four year period studied. As would be expected, the four year profile shows how more gas-fired generation is displaced when all six PNGS units are operating. In Figure 9, the displaced generation is the difference between the production levels of the two scenarios.

The annual benefits decline as the Pickering A units are retired in 2022 as there is less nuclear production available to offset the natural gas-fired generation.

Figure 9 – Gas-Fired Generation Emissions Comparison
(TWh/year)

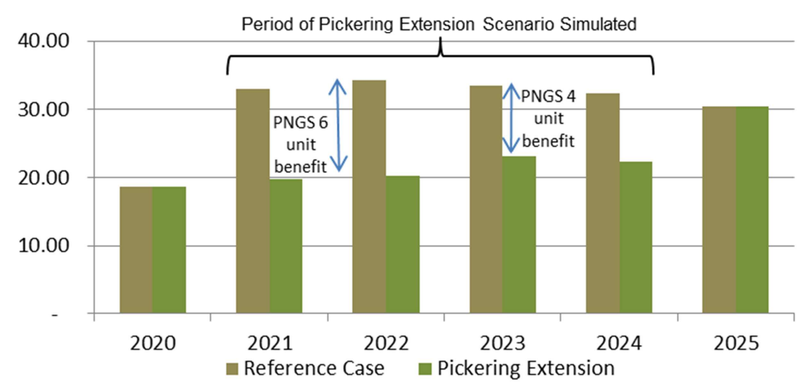
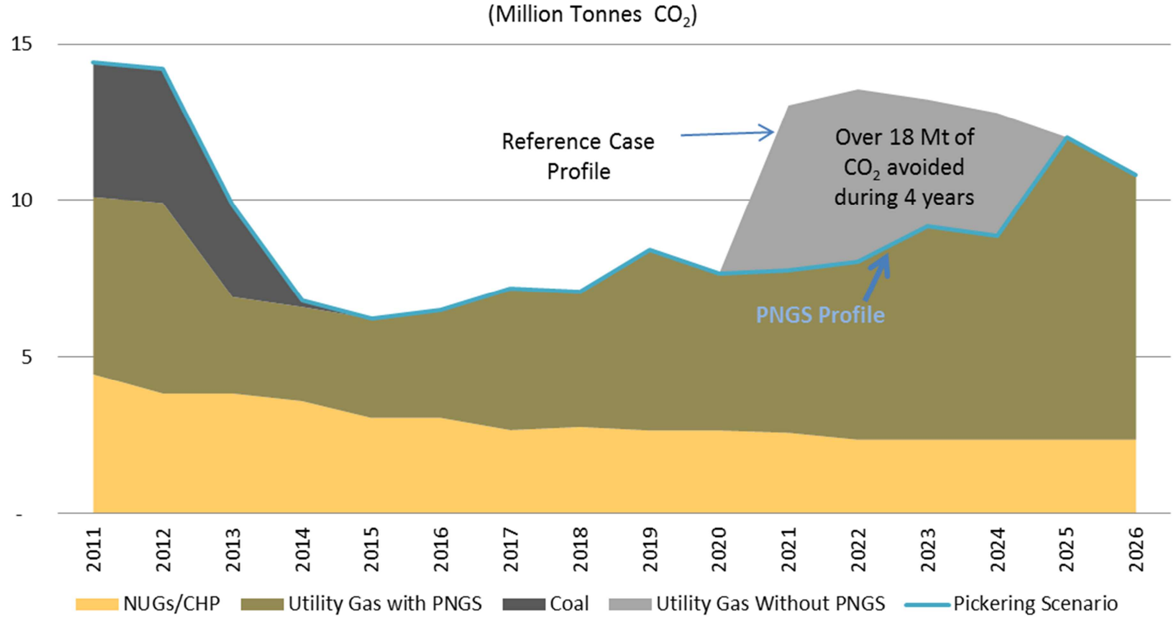


Figure 10 illustrates the fifteen year context for the emissions implications that stem from the differing natural gas-fired generation production levels of the two scenarios. By reducing the need for natural gas-fired generation, continued PNGS operations avoids 18 million tonnes (Mt) of GHG emissions. This is equivalent to avoiding a 55% growth in emissions that will otherwise arise from Ontario's growing dependence on natural gas-fired generation.

It is clear from Figure 10 that extending the operations of the PNGS will effectively defer if not largely avoid a return to the pre-coal retirement emission levels.

Figure 10 – GHG Emissions Projection Comparison

(Million Tonnes CO_2)

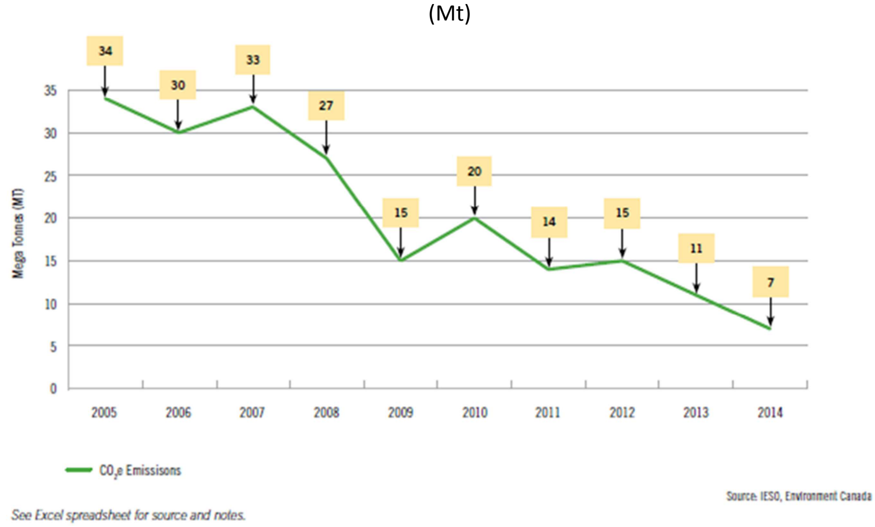


4.2. History of Emissions and the Nuclear Symbiosis

The historical perspective presented in this section examines how Ontario has achieved its GHG emission reductions. There are several enablers that allowed Ontario's coal stations to be retired and to also limit rising production of natural gas-fired generation in its place. The discussion focusses on CO_2 emissions, as documented by the IESO, and then examines both capacity and generation additions that have occurred between 2002 and 2014. This historical perspective on CO_2 emissions shows that the GHG emission reduction achieved by Ontario has been driven by increased nuclear generation.

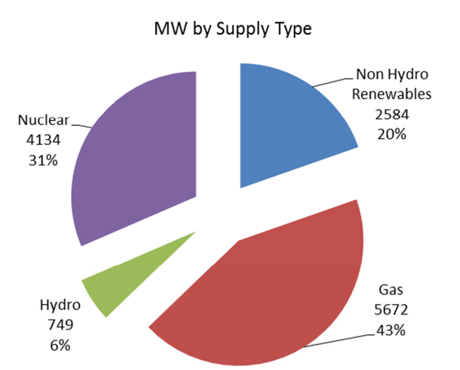
The IESO, in its quarterly Ontario Energy Outlook, reports on the CO_2 emissions from Ontario's electricity sector. Figure 11 is an excerpt from the IESO's Q4 2014 report which shows how emissions of CO_2 have declined from 34 Mt in 2005 to 7 Mt in 2014.[17]

Figure 11 – CO_2 Emissions for the Ontario Electricity Sector
(Mt)



Many point to the significant capacity increase in natural gas and non-hydro renewables generation as being the enablers that allowed for the retirement of coal fired generating plants and the associated reduction in GHG emissions[18]. Figure 12 summarizes the total capacity additions that have been made in Ontario since 2002. In that time frame, over 7,500 MW of coal capacity was retired. This capacity was replaced by 5,600 MW of natural gas-fired generation, 2,600 MW of non-hydro renewables, 4,100 MW of nuclear and 750 MW of hydro.

Figure 12 – Capacity Change Since 2002

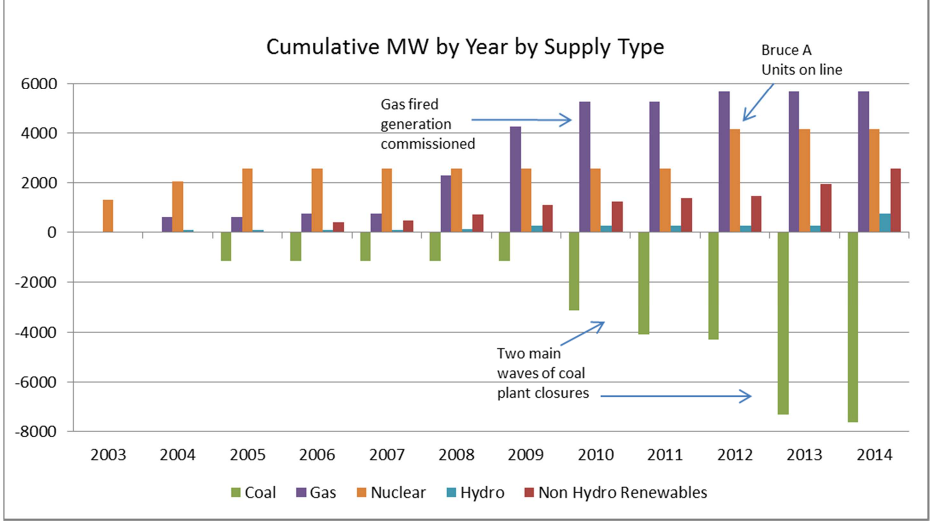


[17] IESO, 2014. Note that these IESO reported actuals are materially higher than forecast by the 2013 LTEP, a bias that Strapolec's forecast suggests will hold throughout the period being analyzed.
[18] Ontario Ministry of Energy, 2013

Natural gas and renewables generation accounts for 63% of the new capacity additions since 2002, while nuclear accounts for 31%.

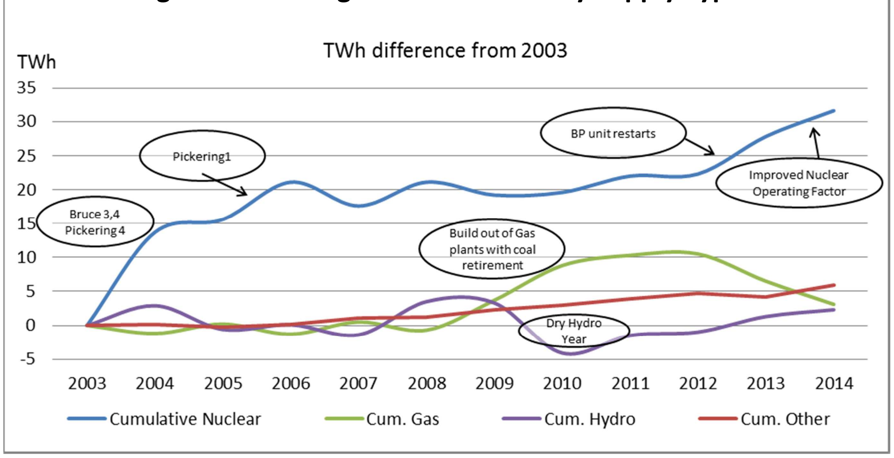
Figure 13 presents the timeline of the capacity additions and retirements since 2002. Correlating the annual capacity additions with the coal capacity retirements shows that the coal plant closures occurred in two phases: (1) the initial closures occurred the year after new gas-fired generation was commissioned in 2010/2011; and (2) the latter coal plant closures coincided with the year following the return to service of the refurbished Bruce A nuclear units which came on line 2012.

Figure 13 – History of Capacity Additions



However, it is the source of actual power generation, not the presence of alternative capacity that drives emissions down. Figure 14 shows the net cumulative increase in generation from all supply sources. Compared to 2002, most supply types today have only marginally increased their generation levels, with the very notable exception of nuclear generation. It is also evident that the increased natural gas-fired generation production in 2010 was in part due to the 7.5 TWh drop in hydro production that occurred in that year.

Figure 14 – Changes in Generation by Supply Type



The subsequent ramp down of gas-fired generation going into 2014 is clearly associated with the increased production from nuclear after the Bruce A units came online and the recovering hydro production. Since 2010 and the first coal plant closures, non-hydro renewables have only marginally increased production.

Figure 15 illustrates the history of CO_2 emissions from 2003 to 2014 and highlights relevant major events alongside the CO_2 emission profile. The portrayal shows how sustained achievements in GHG reductions correlate with increased nuclear generation events in the last 12 years.

Figure 15 – GHG Emissions 2003-2014

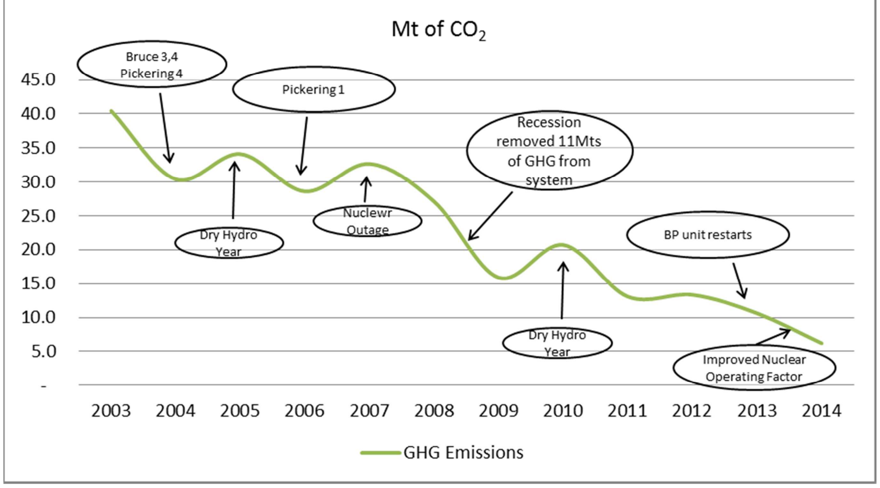
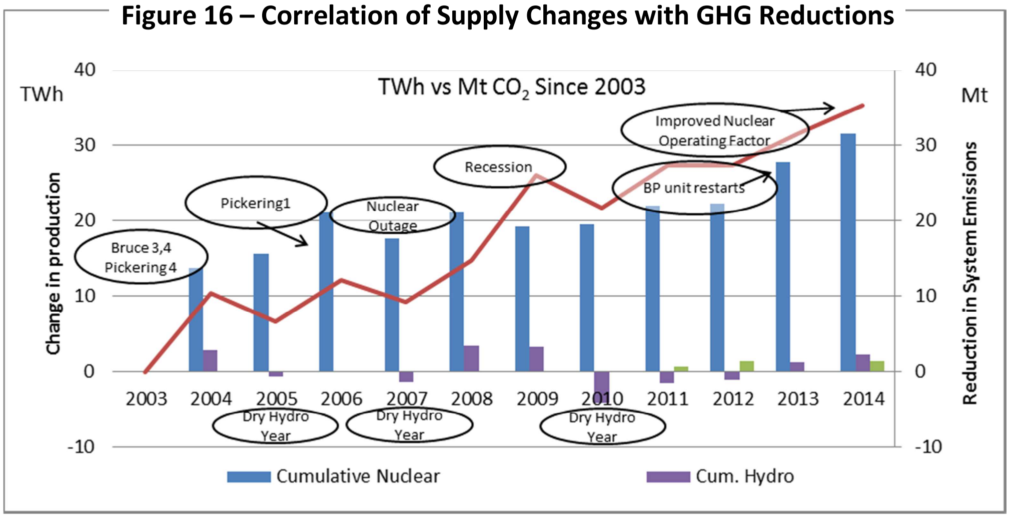


Figure 16 summarizes the net annual production change by supply type that has occurred since 2003 and contrasts that with changes in CO_2 emissions. When cumulative GHG emission reductions are compared to cumulative changes in generation by supply type, the role of nuclear is evident. Trends are clear that every time hydro or nuclear generation has decreased, GHG emissions have risen and vice versa. Noteworthy is the sustained decrease in demand resulting from the 2008 recession. The recession led to a marked drop in coal-fired generation and an 11 Mt reduction in CO_2 emissions.

Figure 16 – Correlation of Supply Changes with GHG Reductions



During the time frame when Ontario's coal stations were being retired, overall nuclear production increased by 32 TWh and CO_2 emissions decreased by 35 Mt. While nuclear capacity remained flat from 2005 through to 2012 (ref. Figure 13), generation was steadily increasing as nuclear operating performance continued to improve. Nuclear is the only low carbon energy supply that has materially increased since 2003.

The strong relationship between emissions reductions and nuclear generation growth is as evident in the last five years as it is for the entire period since 2002. The coal retirements began in 2010 amidst an offsetting increase in gas-fired production and a drop in hydro production as the 2010 LTEP was being rolled out. During this period, wind and solar capacity more than doubled. However, the generation impacts since 2010 are starkly different:

- Nuclear generation has grown by 12 TWh.
- Hydro output grew by over 6 TWh, recovering from previous dry years but still remaining less than 2004 levels despite capacity additions in 2014.
- By contrast, emission offsetting production from non-hydro renewables has only grown by 1.5TWh since 2010, when discounting the contribution of these sources to surplus baseload generation.[19]

Nuclear generation is responsible for offsetting the generation from the retiring coal plants and new natural gas-fired generation plants built to replace them. Nuclear generation accounts for over 87% of the clean or low carbon energy generation that has grown over both time frames measured and discussed above: since 2003; and similarly since 2010.

4.3. Forecast Use of Natural Gas in Ontario

This section examines the degree to which changes in the use of natural gas fired generation in the electricity sector may impact the emissions profile for the total use of natural gas across all sectors of Ontario's economy. The relevant conclusions of this section are that, absent a PNGS extension, natural gas use in Ontario will rise by more than 25% over the relevant period and may also produce greater than historical emissions per unit of energy produced due to the shift of Ontario's natural gas supply to shale gas resources from the US.

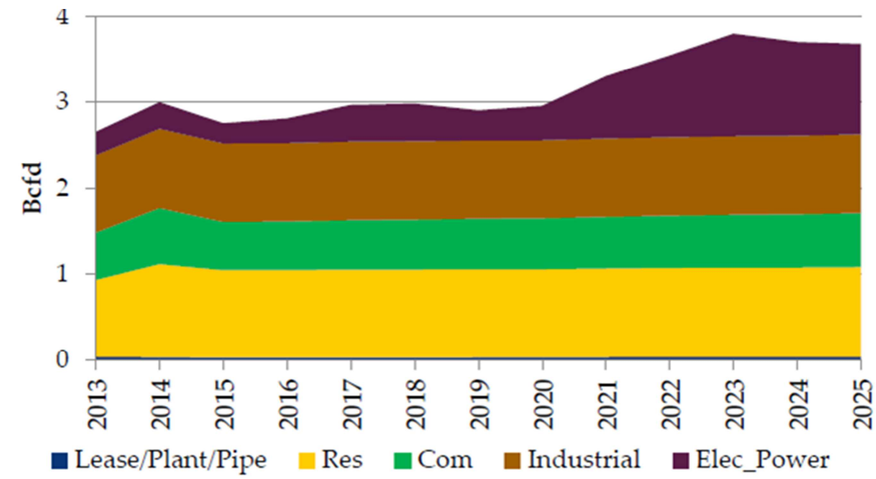
Natural Gas Usage

Figure 17 replicates the forecast usage of natural gas in Ontario produced by Navigant Consulting in a report to the OEB[20]. The forecast shows natural gas consumption by the electricity sector will triple soon after the PNGS is retired. Natural gas use in Ontario has been typically dominated by residential heating

[19] Computed using Strapolec's production forecast model
[20] Navigant Consulting, December 2014

and industrial users. Forecast natural gas-fired electricity generation will increase Ontario's overall consumption of this fuel by more than 25%, making electricity the largest source of consumption.

Figure 17 – Ontario Natural Gas Demand by Usage



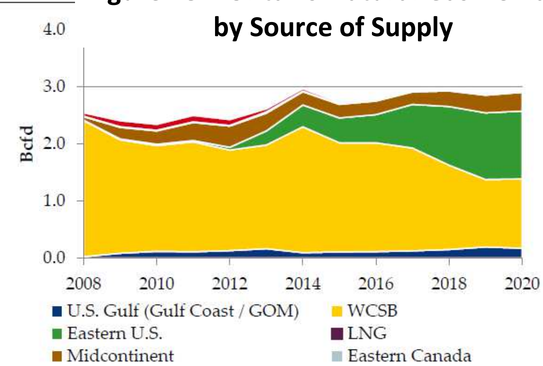
Source: Navigant Mid-Year 2014 Outlook

As a result, at a minimum, the change in usage by the electricity sector will cause an equivalent 25% increase in GHG emissions from that fuel source. Decisions to further increase the use of gas-fired generation will consequently have a material impact on Ontario's ability to meet its overall climate change objectives.

Natural Gas Supply

In the same report, Navigant forecast that Ontario will dramatically shift its source of natural gas supply from Alberta, or specifically the Western Canadian Sedimentary Basin (WCSB), to US shale gas reserves. This shift is illustrated in Figure 18 where the forecast supply growth from the Eastern US is highlighted. As a result, Ontario can expect that on the margin, natural gas required to fuel the replacement of the PNGS generation with natural gas-fired generation will be from the US shale gas resources.

Figure 18 – Ontario Natural Gas Demand by Source of Supply



Source: Navigant Mid-Year 2014 Outlook

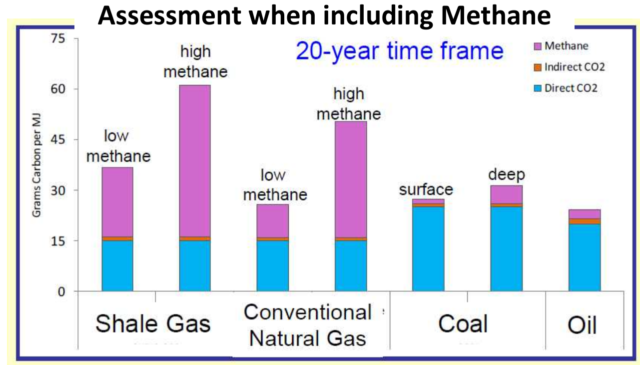
4.4. US Shale Gas GHG Emissions Footprint

Analysis by Howarth[21] of several shale gas emissions studies indicates that US shale gas may have a higher GHG emissions footprint than not only traditional natural gas supply sources, but also that of coal. As a result, although not modelled in this analysis, the move to the US shale gas supply may come with the risk of higher life cycle GHG emissions.

It is well accepted that natural gas produces roughly half the CO_2 of coal. However, leakage in the production system used to extract and deliver natural gas may make the overall lifecycle emissions potentially higher than coal.

Figure 19 replicates the findings of the Howarth study regarding the contribution of methane leakage to the life cycle emissions forecast of various gas and coal reserves. The Howarth study suggests that leakage from the shale gas production system, due to the extraction technology, could be putting more methane into the atmosphere. Methane is a stronger accelerator of climate change than CO_2, albeit a shorter lived one. Methane dissipation from the atmosphere is measured in decades while CO_2 dissipation is measured in centuries.

Figure 19 – Recent Emissions Assessment when including Methane



The shift towards use of US shale gas potentially represents an unquantified upward risk to Ontario's GHG emissions as the province embarks on its climate change actions and initiatives.

4.5. Implications Summary

Increased reliance on natural gas-fired generation to replace production from the PNGS post 2020 could reverse the GHG emission reductions achieved since 2011 through the closing of Ontario's coal stations. The province's forecast supply dependence on US shale gas could exacerbate this challenge.

The upcoming review of Ontario's 2013 LTEP provides an opportunity for the province to select options that continue to support GHG reduction objectives. As shown by this analysis, extending the operation of PNGS can ensure that Ontario continues to benefit from the GHG emission reductions achieved so far in the province's electricity sector.

[21] Howarth, 2014

5.0. Cost to the Electricity System and Rate Payers

This section presents the cost implications to Ontario's electricity system and rate payers that are expected to arise from continuing the operations of the PNGS. The energy sector underpins Ontario's economic competiveness, yet residential and industrial electricity rates have been steadily rising over the last decade. Industrial rates have risen 16% since 2013 and are expected to rise 13% over the next five years.[22] As a result, any cost increases resulting from future decisions regarding electricity supply options are important considerations.

The following cost discussion addresses five topics:

- Forecast Electricity Generation Costs

  An overview is provided of the cost differences between the scenarios and the anticipated benefit.

- Rate Payer Implications

  How the HOEP, Class A Industrial rates, and Class B residential rates are expected to change is illustrated along with the impact on the affected stakeholders and rate payers.

- Unit Cost Comparison

  The unit costs of PNGS extended operations are compared to the equivalent unit costs of natural gas-fired generation including the combined fixed and variable elements.

- Cost Risks

  The risks presented by evolving energy policies in Ontario and the US are discussed. On balance, these policy induced risks suggest the PNGS option may have a greater cost advantage than shown by this analysis.

- Other Benefits & Considerations

  A summary is provided of other factors uncovered during research efforts that may be relevant to the decision to extend PNGS operations.

The section closes with a summary of the key implications of the findings of this section of the report.

5.1. Forecast Electricity Generation Costs

Section 3 summarized the production implications of the two scenarios. When the costs are applied to those production levels, the net financial impact on the electricity system can be determined. From a

[22] Ontario Chamber of Commerce, 2015

supply mix perspective, there are two stages to the PNGS extension scenario that impact on the cost results:

1. Both PNGS Stations A and B will operate for the first two years, and only station B for the last two.
2. The capacity of the nuclear units under refurbishment decreases in 2023, the last two years of the PNGS scenario, which increases the base "other" costs.

Figure 20 illustrates the total cost of electricity generation expected in 2022 and 2023, the years before and after the mid-point in PNGS' extended operations. The changing supply mix leads to overall cost increases from 2022 to 2023 for both scenarios.[23] The cost of extending PNGS operations is expected to be approximately $170M less than the reference scenario in 2022 and approximately $210M less in 2023.

Figure 20 – Total System Cost Comparison by Scenario

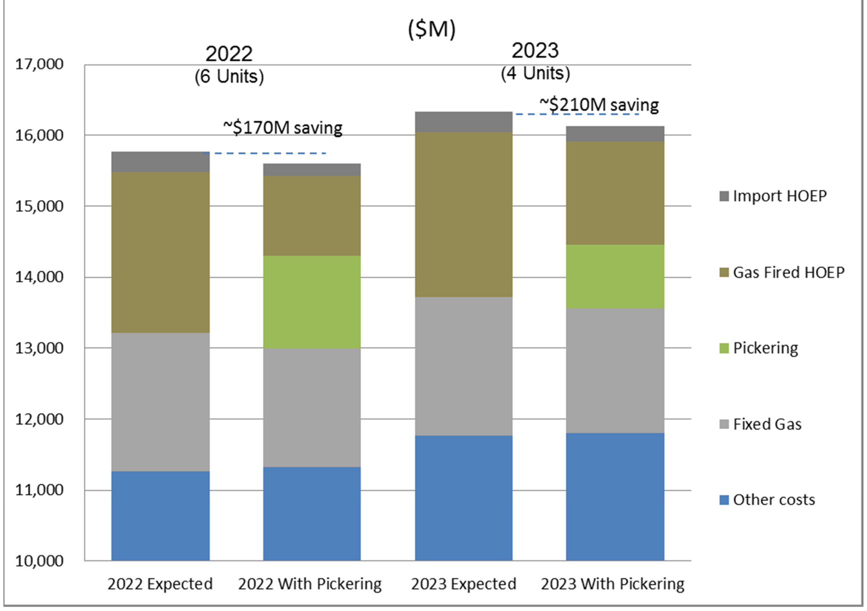
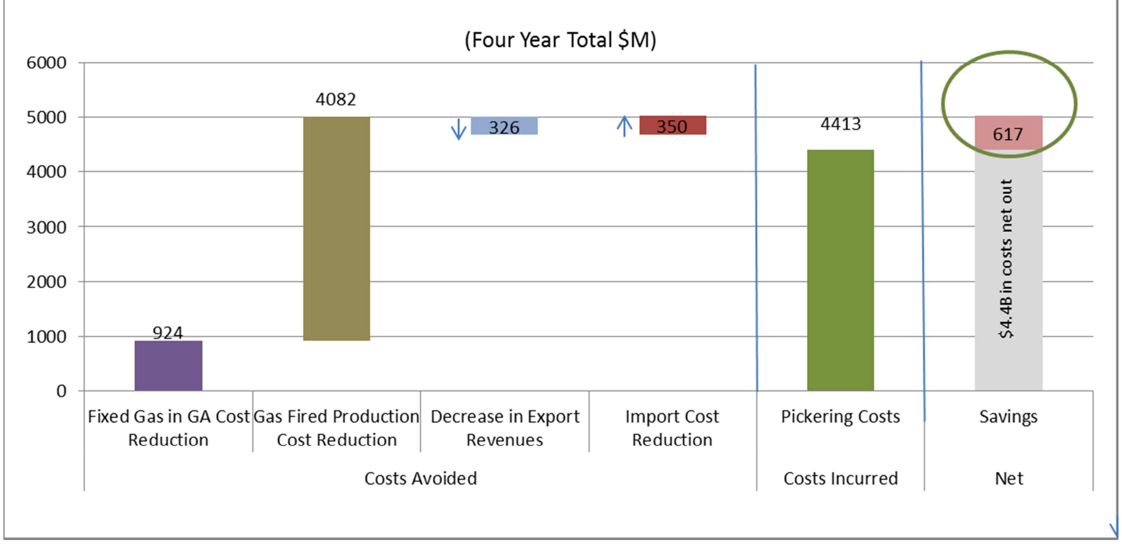


Figure 21 shows the cost elements that differ between the two scenarios. The figure frames the costs in the reference scenario that are avoided if the PNGS extended operations option is selected and contrasts them against the PNGS costs that would be incurred. Over the full four year period of PNGS extended operations, Ontario's electricity system cost is forecast to be over $600M[24] less than may be incurred if natural gas-fired generation is used to replace PNGS capabilities.

[23] In simulation, gas-fired generation and import costs driven by the HOEP forecast model. Costs in nominal dollars

[24] Throughout this report, numerical values have been rounded down from the values in the exhibits. This is done for two reasons: (1) to avoid connotation of false precision and (2) to add a degree of conservatism to the findings.

Figure 21 – Savings from Electricity System Generation



Cost savings are realized by the lower cost PNGS generation displacing the higher cost natural gas-fired generation and capacity. Avoiding the gas-fired generation removes $5B of cost from the system. The sources of this saving include:

- Avoided need to recover natural gas-fired generation plant fixed costs of over $900M in the four year period as contracting of new plants is deferred.
- $4.1B cost reduction in variable natural gas-fired generation due to the reduced volume of fuel required.
    - The decrease in natural gas-fired generation also has the effect of reducing the HOEP to the benefit of industrial rate payers which is discussed in a subsequent section.
    - The reduction in natural gas-fired generation variable costs is partially offset by a $325M reduction in export revenue stemming from the lower HOEP that occurs when natural gas-fired generation is not on the margin.[25]
- Avoided $350M in the costs of electricity imports as the need for these imports will be reduced.

The $5B in avoided costs of natural gas-fired generation will be offset by the approximately $4.4B in PNGS operating costs that will be required for the 4 years of extended operations:

- The costs reflect two years of Pickering A operations and four years of Pickering B operations.
- A blended rate of $63/MWh is derived based on the modelled 68 TWh of generation.

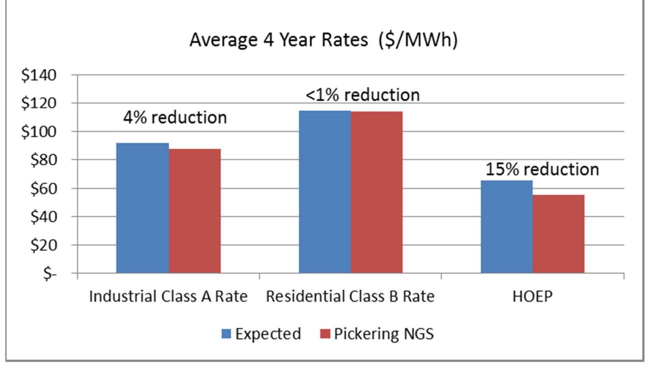
The benefit to the electricity system is the difference between the costs avoided and the costs incurred. The analysis suggests over $600M in savings to rate payers will result from the four year period studied.

[25] Voluntary export volume assumptions are held constant for both scenarios

5.2. Rate Payer Implications

The forecast lower total system costs associated with the PNGS option will result in reductions to consumer electricity rates. Figure 22 summarizes the rate impacts for both industrial and residential consumers and also indicates the impact on the HOEP.

Figure 22 – Rate Payer Cost Comparisons



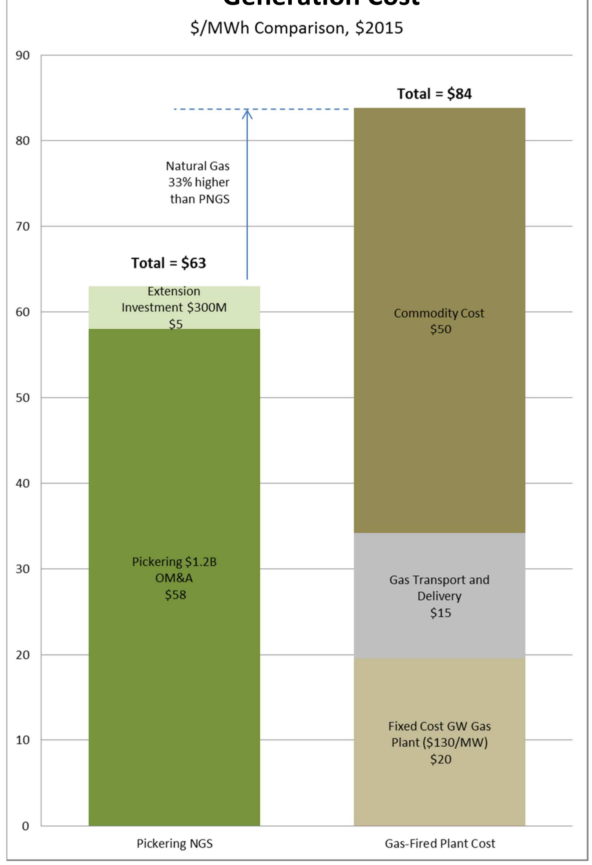
The analysis indicates that Industrial rates could drop by 4%, a benefit for Ontario's recovering manufacturing sector. Residential rates are only expected to be marginally affected. Of note is the 15% expected decline in the HOEP portion of the costs of the electricity system.

Differences in expected rate benefits between industrial and residential rate payers stem from the method used by the OEB to determine the Class A and Class B rates. Class A industrial rates are more heavily weighted to the value of the HOEP than residential rates.

5.3. Unit Costs of Generation

This section summarizes the cost assumptions applied to the PNGS and natural gas-fired generation options and compares them on an equivalent $/MWh basis. Figure 23 summarizes the results.

Figure 23 – Pickering NGS vs Gas-Fired Generation Cost



PNGS Cost Assumptions

The costs for continuing the operations of the PNGS were derived from Ontario Power Generation (OPG) disclosures to the OEB regarding PNGS extensions[26]. The costs presented by OPG in its business cases reflect the incremental costs to the corporation as compared to the PNGS retirement scenario. The incremental costing approach explicitly considers the net impact on OPG should the PNGS option be implemented:

- Under a PNGS retirement scenario, OPG will retain some fixed costs to support the Darlington NGS (DNGS)

[26] Ontario Power Generation, September 2013

operations that had been previously allocated in a split manner to both the PNGS and DNGS stations.

- Taking an incremental approach vis-a-vis these costs results in lower than the fully attributed costs represented during the 2014 OEB decisions.
- OPG has taken this approach in their 2010 and 2012 OEB submissions on this matter.

Strapolec believes this to be a prudent and fiscally responsible approach.

2013 production levels were assumed at 20 TWh for the A and B units and 14 TWh for only the PNGS B units. The total PNGS costs to be recovered were modelled as $63/MWh (2015 dollars) which includes two components:

- $58/MWh in 2015 dollars is required to recover the approximately $1.2B/year of PNGS Operations, Maintenance and Administration (OM&A) costs for the six units.
- A $5/MWh adder is included to recover $300M of investment which Strapolec has assumed would be required to enable the extended operations. The investment estimate is based on the $200M discussed in the previous OPG submissions to the OEB, but with margin and escalation added to provide a conservative value.

It was assumed that when PNGS A closes, the same rate of $63/MWh would continue to apply for the ongoing generation from the B units. This represents an assumption that 70% of the OM&A costs would continue after PNGS A units are retired, which may be a conservatively high cost assumption.[27]

Gas-Fired Generation Cost Assumptions

Strapolec's market model of Ontario's hourly production and the pricing dynamics behind the HOEP was used to compute the variable costs of natural gas-fired generation. However, an illustration of comparative unit rates is useful in interpreting the results. The illustrative comparable rate is $84/MWh as shown in Figure 23 and is comprised of the following:

- *Fixed monthly costs*

  The fixed costs of natural gas-fired generation are based on LTEP 2013 assumptions which have been escalated to a 2015 dollar value of $132,000/MW per year. This value is applied to the 2,000 MW of SCGT assumed in the reference case. The equivalent cost of the fixed monthly payments on a per MWh basis is calculated from the natural gas-fired production displaced by PNGS operations as determined by Strapolec's simulation. The full fixed annual cost is included in the comparative analysis as the need for contracting the gas capacity is deferred beyond the period of the PNGS extended operations. Strapolec analyzed the cost of building a new SCGT based on values obtained from the EIA 2015 AEO. At $132,000/MW/year, very little variable costs can be recovered by those payments.

[27] Based on a number of units criteria, removal of two PNGS A units could reduce the costs by a third to 67%, potentially a 5% reduction from the costs assumed for PNGS B.

- *Variable costs*

  To illustrate a comparative rate, Strapolec developed an estimate using forecasts of Henry Hub gas prices, Dawn Hub premiums, heat rates, exchange rates and the costs of delivering natural gas in Ontario. The comparative estimate is based on the costs at the margin. Specifically, the additional production required to replace PNGS from the existing fleet will cause the plants to operate at higher utilization factors than they are today. At the margin, full transportation and delivery costs are expected to contribute to the future value of the HOEP.

These assumptions suggest that the equivalent costs of natural gas-fired generation on a per MWh basis are about 33% more than the PNGS unit costs. As mentioned in Section 3, part of this saving is not realized due to the contribution of SBG.

5.4. Cost Risks

This section examines the degree of conservatism deployed in this analysis as well as the risks and other cost sensitivities inherent in the modelled assumptions and discusses how they may impact the findings. An overview of the estimated cost impact of some of the risks is provided below followed by individual sections on the broader North American trends that may potentially impact the future cost of natural gas supply. These trends are largely related to the US Environmental Protection Agency's (EPA) Clean Power Plan (CPP) and which could also impact on the outcomes related to Ontario's Cap and Trade initiative.

Forward Looking Risks on the Cost of Natural Gas

To characterize the degree of conservatism used in this analysis, the modelled assumptions can be compared to other third party estimates of future costs. Three factors suggest the assumptions used in this analysis are conservative:

1. Assumptions have been conservatively informed by current industry data[28]:
   - Strapolec developed its own estimate based on Henry Hub forecasts, Dawn Hub premiums, heat rates, exchange rates and costs of delivering natural gas in Ontario, and recovery of monthly fixed costs.
   - PNGS cost rate of $63/MWh is based on previous OPG incremental cost business cases submitted to the OEB and an assumed $300M investment to prepare the PNGS for the extension.
2. Other sources point to alternatives that would have higher costs:

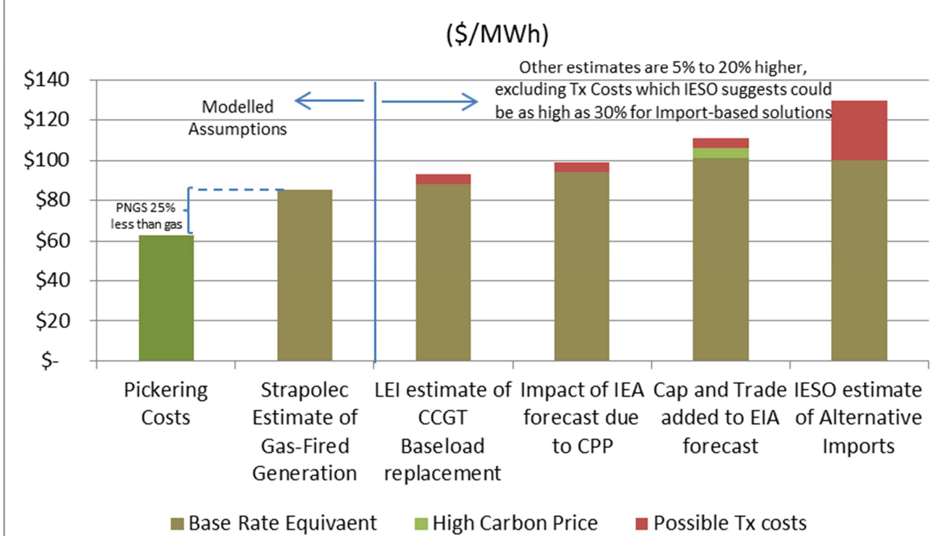
[28] See appendix A for the detailed assumptions

- London Economics International (LEI) has produced an estimate for a baseload Combined Cycle Gas Turbine (CCGT) installation in Ontario. A CCGT may be an alternative to the lower cost SCGT if the expected operational duty cycle is reasonable for a CCGT. The LEI estimate for a CCGT is 5% higher than the costs of natural gas-fired generation assumed here but predicated on a 6% lower fuel price than the Energy Information Administration (EIA) is currently forecasting.[29]
- The IESO's assessment of Ontario's interties[30] and their ability to accommodate increased imports, indicates that the volume of required electricity imports will likely cost $100/MWh. The IESO also suggested that there may be a need for up to an additional $30/MWh for transmission investments.

3. Emergent cost risks stem from the CPP and Ontario's Cap & Trade program objectives:
   - The EIA 2015 assessment of the CPP forecasts natural gas price in the timeframe of the PNGS extended operations could be on average 10% higher than assumed.
   - The Ontario Cap and Trade program will add at least 8% to the cost based on the assumption that Ontario's price will reflect the current carbon price of $12/tonne in Quebec and California and escalated by 5%/year in accordance with regulatory requirements of these two jurisdictions. If industry forecasts resulting from the CPP are realized, the impact on the cost of natural gas-fired generation could be 15% higher.

Figure 24 summarizes the impacts of the potential risks identified and compares them to the baseline cost assumptions used here. This comparison shows that a natural gas-fired generation option could cost 40% to 60% more on a per MWh basis than extending PNGS operations. In a worst case of relying on imports, the costs of alternatives could be double that of the PNGS extension.

Figure 24 – Risks and Conservatism in Cost Estimates



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[29] LEI assumed the cost of natural gas from the EIA AEO 2014 report. EIA AEO 2015 forecasted Henry Hub prices are 6% higher than when IESO and LEI provided their estimates.

[30] IESO, 2014.

Cost Sensitivity of Findings to PNGS Assumptions

Figure 24 addresses the perceived risks that could increase the cost of natural gas-fired generation. Based on research, Strapolec did not uncover any evidence suggesting that a different planning reference for the cost of natural gas should be used that could be materially lower than assumed. Similarly, Strapolec believes it is unlikely that the PNGS cost assumptions used could be materially low. For the identified $600M benefit to be reduced to a breakeven condition, the future price of natural gas would have to be 15% less than forecast. On the nuclear side, costs would similarly have to be over 15% higher than assumed. For reference, Strapolec has derived from the OEB 2014 decision that the fully allocated PNGS rate is $62/MWh (or 8% higher). At this stage in the life of PNGS operations, one would expect the OPG estimates for PNGS OM&A costs to be mature.

Furthermore, given the substantial provincial domestic content contained within the costs of nuclear production, the overall observed benefits to Ontario are insensitive to the uncertainties within the nuclear input assumptions. For example, if the PNGS costs proved to be higher than assumed, some of the $600M in identified rate payer benefits may be reduced. However, additional GDP and revenues for the Government of Ontario would then arise, balancing the overall result of economic benefits from the PNGS option. Section 6 provides additional details regarding these cost sensitivities.

The next sections provide an overview of the major implications to Ontario that could emanate from the US EPA CPP initiative and Ontario's intentions to participate with Quebec and California in a cap and trade program.

5.4.1. CPP Impact on the Price of Natural Gas Supply

Based on the EIA assessment of the CPP, future conditions in the US can be expected to place further upward pressure on natural gas prices during the expected period of the PNGS extension.

The CPP was developed in response to President Obama's Climate Action Plan[31]. The CPP can be expected to further increase demand for natural gas over and above what the EIA assumed in its recently released 2015 Annual Energy Outlook (AEO).

EIA's analysis of the EPA's proposed CPP rule forecasts major changes in the fuel mix used to generate electricity in the United States.[32] The EIA noted that "Under the proposed Clean Power Plan, natural gas, then renewables, gain generation share". The EIA's analysis uses the Annual Energy 2015 AEO Reference Case as its baseline for assessing CPP implications. Under the CPP Base Policy case, the EIA suggests that the main compliance strategy to lower GHG emissions rates is to increase natural gas-fired generation to displace and ultimately surpass coal-fired generation. As a result, the EIA now says that natural gas

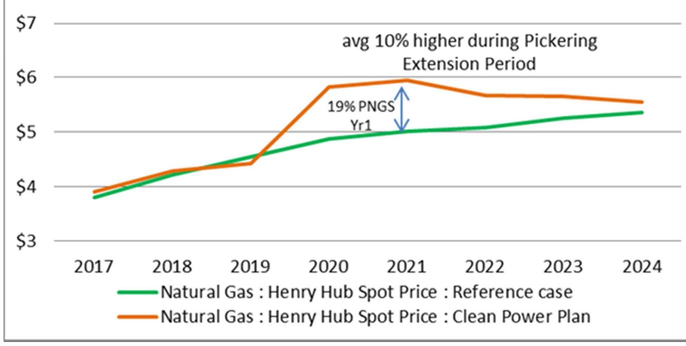
[31] Executive Office of the President, 2013
[32] U.S. Energy Information Administration, May 2015

demand in the electricity sector will be almost 25% higher in 2020 than predicted in the 2015 AEO forecast and almost 10% higher in 2030 than the 2015 AEO forecast.

The timing of the CPP will create a peak capacity challenge during the anticipated PNGS extension horizon. Figure 25 illustrates the EIA's CPP based forecast that has the cost of gas rising by an additional 19% at the start of the proposed PNGS extension, when all six PNGS units will be operating. Over the four-year PNGS extension period, the increase in the cost of natural gas is forecast to average 10%.

Figure 25 – EIA Projected Impact of CPP on Henry Hub Price

$USD/mmBTU 2013



Canada's National Energy Board (NEB)[33] notes that the natural gas markets in Canada and the United States operate as single integrated market. Ontario can expect that these price increases will likely make their way to Ontario and be amplified by the province's expected increased reliance on US natural gas supply and the typical trends observed between Dawn and Henry Hub prices exhibited when supply constraints occur.

5.4.2. CPP Impacts on Reliability Reserve Requirements

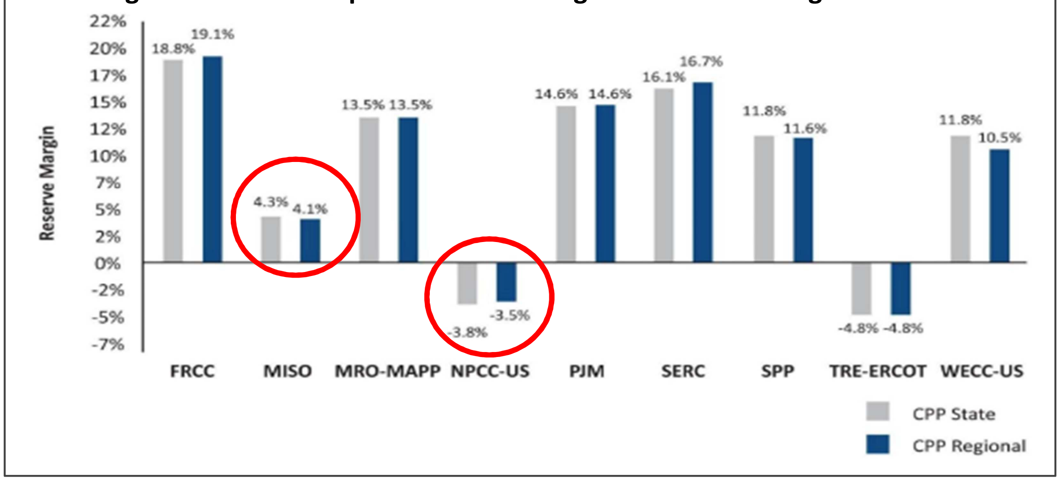
The North American Electricity Reliability Corporation (NERC) has also assessed the implications of the CPP on the North American grid and its reliability reserve capabilities.[34] It concludes that with the forecast changes to the generation mix that are anticipated to result from the CPP, resource adequacy is likely to be negatively impacted by two factors:

1. Uncertainty and variability of renewable resources (such as wind and solar) will need to be accounted for in establishing new target reserve margins. This means the future margin requirements will likely be higher
2. Higher forced-outage rates would also result in higher reserve margin targets, as each electricity system area would need to carry more reserve capacity to balance the uncertainty.

Figure 26 replicates the NERC findings that show how certain jurisdictions – particularly the Northeast Power Coordinating Council (NPCC-US), to which Ontario is a member, and the Midcontinent Independent System Operator (MISO) that border Ontario, will face the most significant resource adequacy concerns in 2020, the time when PNGS is scheduled to go off line.

[33] National Energy Board, 2011
[34] North American Electricity Reliability Corporation, November 2014

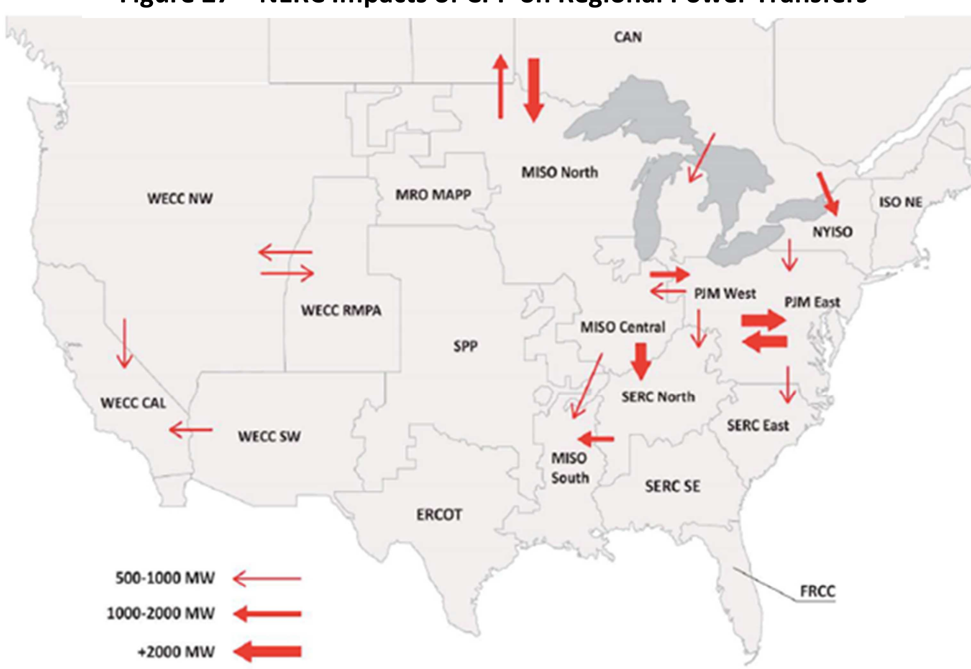
Figure 26 – NERC Impacts of CPP on Regional Reserve Margins in 2020



In addition, reliability could be impacted by other factors, for example, when the timing of forecasted inadequate resource events occurs in certain electricity system areas. In regional trading cases, areas with lower incremental CO_2 reduction options can displace higher-cost options in adjoining states or power pools. Overall, net transmission flow activity between regions is expected to increase by 19,230 MW under the state compliance plan (versus no CPP).

According to NERC, the CPP can be expected to change the power flows in many major power areas. Power flow changes anticipated by NERC are illustrated in Figure 27 which replicates the depiction created by NERC. These power flow changes, both in direction and volume represent potential challenges in the planning and operation of the US NERC Bulk Power System (BPS).

Figure 27 – NERC Impacts of CPP on Regional Power Transfers



The CPP will impact intertie flows and demand for energy from Ontario. Canada is anticipated to export three times more power to the United States, mainly to states in the NPCC and MISO grids. Absent the PNGS, very little low carbon on peak power will be available from Ontario as it will be needed to serve Ontario's needs.

This result would further compromise any alternative supply options that Ontario may be contemplating with regards to accessing US generation for electricity imports into Ontario. New capacity is going to be required across the NPCC/MISO grids. By extending PNGS operations, Ontario may mitigate the risks associated with the peak constraints that have been identified by the EIA and NERC.

5.4.3. CPP Impact on Carbon Prices

The impetus behind the CPP is to reduce the consumption of carbon emitting fossil fuels in the United States. In general, carbon pricing is expected to increase as climate change pressures mount in North America. The US federal government currently uses carbon prices ranging from \$11 to \$57 (2013 USD/short ton) for their long range planning purposes. [35] The CPP is expected to put further upward pressure on carbon prices.

Synapse Energy Economics assessed several studies that reviewed the implications of the CPP on carbon prices. These studies included those by the various market operators (e.g. peers of the IESO). Collectively the studies suggest carbon prices could be in the range of \$20 to \$40/short ton of CO_2 (USD) as shown in Figure 28.

Synapse used these analyses to develop their own forecast shown in Figure 29 (converted by Strapolec to CAD per tonne). The average price of carbon during the PNGS scenario is \$30/tonne or \$12/MWh.

Figure 28 – Summary of CPP CO_2 Price Estimates
($2014/short ton)

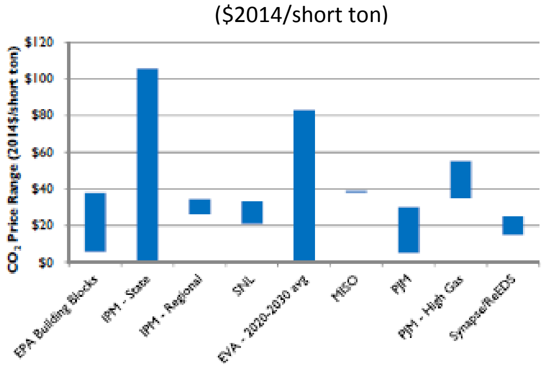
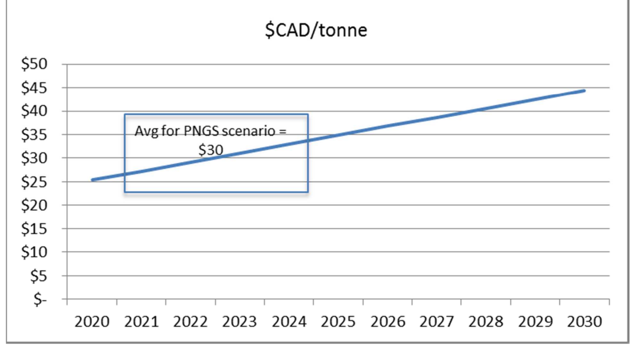


Figure 29 – US Carbon Price Forecast



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[35] Synapse Energy Economics, 2015

5.4.4. Cap and Trade and Premium on Gas-Fired Production

The potential impact of the CPP on carbon prices is relevant to Ontario given its signalled participation in a collaborative Cap and Trade program with Quebec and California. Carbon prices in California are set through an auction mechanism[36]. Figure 30 shows how the California prices have recently hovered around $12/tonne of CO_2. Both California and Quebec have instituted a minimum auction price which is to escalate by 5%/year[37]. For Quebec, the result is in an average price of $17.25/tonne during the proposed PNGS extended operations as shown in Figure 31.

Figure 30 –Carbon Trading Prices in California

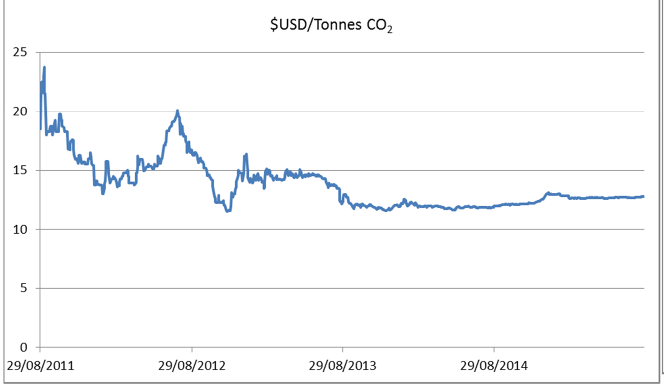
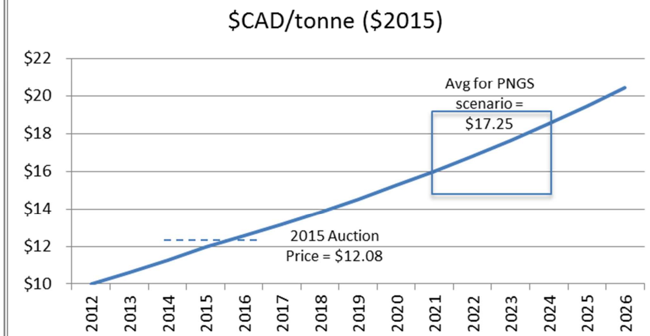


Figure 31 – Minimum Carbon Price Forecast Quebec



Since over 25% of the forecast increase in provincial carbon emissions from natural gas will be coming from natural gas-fired electricity generating plants, it is assumed that Ontario's participation in the cap and trade programs would lead to the carbon prices becoming reflected in the province's electricity costs. Assuming further that Ontario's participation in the collaborative cap and trade program will result in matching the Quebec minimum price of $17.25/tonne, this would equate to per unit cost of about $6.90/MWh (400 kg/MWh) or an 8% premium on the full recovery blended unit cost rate assumed in this study.

The forecast impacts on carbon prices resulting from the CPP suggest that this 8% annual increase in the cost of natural gas-fired generation derived from the Quebec minimum auction price is conservative. Given that there is a single North American market for natural gas, carbon prices could coalesce around the higher 15% US premium implied in Figure 29 as the cap and trade programs mature.

5.5. Other Benefit Considerations

Other benefits that may result from the PNGS option include the following:

1. Existing risks to system planning or reliability may be avoided:

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[36] California Carbon Dashboard, 2015

[37] California Air Resource Board, 2014

- Timeline for developing and obtaining the social license for new natural gas fired generation plants.
- Environmental assessment and process for siting new natural gas-fired generation plants.
- Cost of transmission connections for new natural gas-fired generation plants.

2. Avoided additional reserve capacity costs that would only be needed for a short time:

- An additional 1,000 MW of capacity (for a total of 3,000 MW) could be occasionally required during the 2020 to 2024 time horizon.
- Given electricity system requirements in neighboring jurisdictions and the intertie limits, this capacity will likely have to be built.
- This could result in an additional $2.6B+ commitment over 20 years if an additional 1000 MW of gas capacity needs to be built.

3. Benefit of stable supply:

- Lower reserve capacity required with the benefit of costs saved.
- Ontario protected from cost risk associated with natural gas price volatility as the world moves to low carbon generation options.

4. Potential to support the Ontario Cap and Trade Initiative and CPP:

- The additional baseload nuclear generation could be linked to Ontario's Cap and Trade program to develop new low cost zero emission electricity offers in off-peak hours.
- The spare baseload capacity, currently modelled as producing SBG, may support off peak needs in the US as the coal plants are retired in that critical timeframe.

5. Benefits previously recognized by OPA:

- *"Hedge against factors including increased demand, delay in achieving conservation targets, higher natural gas prices or carbon prices, nuclear refurbishment delays, or delays in the in-service of directed resources"*[38].

5.6. Implications Summary

Extending PNGS operations instead of constructing 2,000 MW of new gas-fired generating plants is estimated to reduce the cost of electricity to Ontario rate payers by between $600M and over $1.5B over the four-year period. Figure 32 describes the major elements of the potential $1.5B in savings discussed in this section. The savings arise because PNGS operations are $600M less costly than natural gas-fired generation.

[38] Ontario Power Authority, April 2012

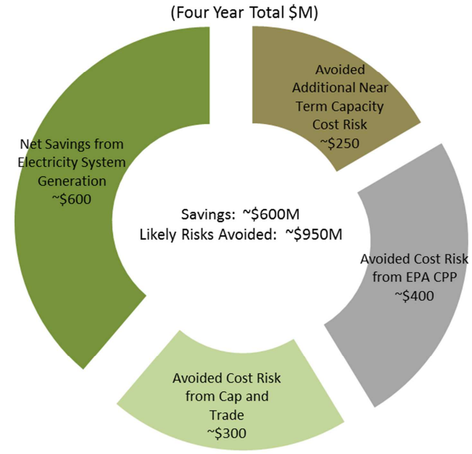
$950M of cost risks associated with being reliant on natural gas as a fuel are also avoided. Three factors contribute to the over $950M in avoided cost risks:

- Clean Power Plan ($400M)
- Ontario Cap and Trade program ($300M)
- Potential need for contracted reserve capacity in 2021/22 ($250M)

Lower electricity costs and avoided risks will ease the cost increases that Ontario's rate payers have experienced. Strapolec believes that the assumptions used in this study are conservative and valid for planning guidance purposes.

Figure 32 – System Cost and Risk Reduction Benefits to Rate Payers

(Four Year Total $M)



6.0. Economic Implications to Ontario

This section describes the results of the economic impact assessment of the PNGS option versus the natural-gas fired generation alternative. Considerations addressed in this section include measures of jobs and provincial gross domestic product (GDP).

By the end of 2013, Ontario had shed 290,000 jobs in the manufacturing sector since the recession with only 11% of the Ontario workforce being employed in manufacturing compared to 18% in 2000. Additionally, Ontario's historical workforce of steady full-time jobs is shifting to more part-time, lower paying positions. Since 2000, part-time positions increased by 25% compared to an increase of 16% in full-time positions.[39] The energy sector has been an important element of Ontario's economy, with nuclear energy in particular providing over 20,000 direct, well paying, full time jobs.[40]

As such, the benefit to the economy should be a major consideration when comparing a domestically based energy supply such as nuclear to an energy import based option like natural gas-fired generation. This section provides an overview of the findings and description of the assumptions associated with the following:

- Framework for Economic Impact Assessment
- Job Implications
- GDP Implications
- Benefits to Durham Region

Benefits to the Province of Ontario are detailed in Section 7.

6.1. Overview of Forecast Economic Impacts

Extending PNGS operations will result in three primary economic benefits:

1. Jobs: *almost 40,000 direct, indirect and induced Person Year Equivalent (PYE) jobs over the four year period*

    - Direct jobs include approximately 4,000 incremental annual PYE jobs at OPG as well as others within Ontario's nuclear supply chain.
    - Multipliers used in the industry (CME 2012, and NEI) have been applied to determine indirect and induced jobs.[41]

2. GDP: *up to $7B net new growth for Ontario*

[39] Tiessen, March 2014
[40] Canadian Nuclear Association, October 2012, OCI, Strapolec analysis
[41] Canadian Manufactures and Exporters, 2012

- By displacing electricity imports and natural gas purchases with domestically sourced energy, the direct, indirect and induced GDP of Ontario could be increased over the four years by ~$7B.
- GDP growth in Ontario is realized in three ways:
    - Indirect spend by rate payers who have new disposable income
    - Income and supply chain direct, indirect, and induced spend in the region of Durham
    - Income and supply chain direct, indirect, and induced spend in the rest of the province
- Figure 33 summarizes the GDP benefits expected and how these benefits will be distributed.

3. Durham Region: *30% of the jobs along with associated economic benefits*

- OPG is among the largest employers in the region with many of the employees living in Durham.
- Figure 34 summarizes the direct and indirect jobs expected in the first year of the PNGS extended operations and the split between Durham Region and the rest of the province.

Figure 33 – Incremental GDP Created by Extending Pickering NGS Operations

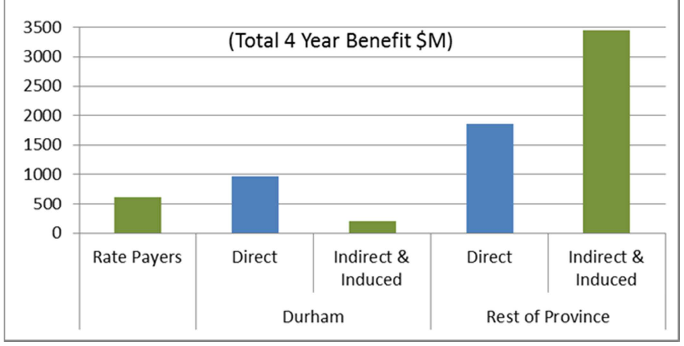
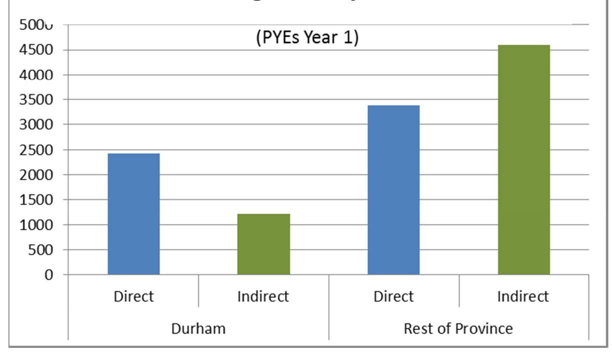


Figure 34 – Jobs Sustained by Extending Pickering NGS Operations



6.2. Framework for Assessing Economic Impact

A comparative framework is used as the basis for estimating the economic impact of a potential extension of PNGS operations. Three factors have been considered in assessing the GDP impacts:

1) Labour income and domestic supply chain purchases are the relevant factors used to compute GDP contributions.

2) The purchases of imported supplies, goods or services do not add to GDP and in fact represent a leakage out of the province.

3) The financial recovery components of a utility's revenue do not contribute to GDP. For example, capital recovery mechanisms (depreciation, amortization and interest expenses) are paying for investments for which the GDP would have been accounted for when the associated capital projects

were implemented. Profits may be returned to shareholders, perhaps not in Ontario, and may not be invested in new capital projects in Ontario. While corporate profits do in general result in some induced GDP contribution, that level of fidelity has not been considered in this study.

The two scenarios can be compared across these three dimensions.

6.2.1. GDP Driving Characteristics – The Power of Domestic Spend

Economic benefits to Ontario are stimulated by:

1. Avoiding the GDP leakage represented by the cost of imported electricity and the cost of purchased natural gas supply. The avoided leakage is turned to economic advantage by applying the funds to the PNGS operations and creating new GDP.
2. Reducing the overall cost of the electricity system and stimulating the broad based indirect GDP benefits resulting from rate payer savings.

Five unique characteristics drive the predicted economic benefits of the traded-off scenarios:

1) Incremental Cost to Extend PNGS

   PNGS extended operations is economically assessed on an incremental activity addition basis with respect to the existing plans. This has been advocated by OPG to the OEB.

2) PNGS Operating Costs are Domestic

   PNGS incremental operating costs are 60% labour with 80% of the remainder being spent on Ontario domestic supply chain resources.

3) Natural Gas Variable Costs are Imports

   Natural gas-fired generating plant variable operating costs are dominated by the purchase of fuel from outside the province. This purchase represents a $3.6B GDP leakage.

4) Natural Gas Fixed Costs are Financial

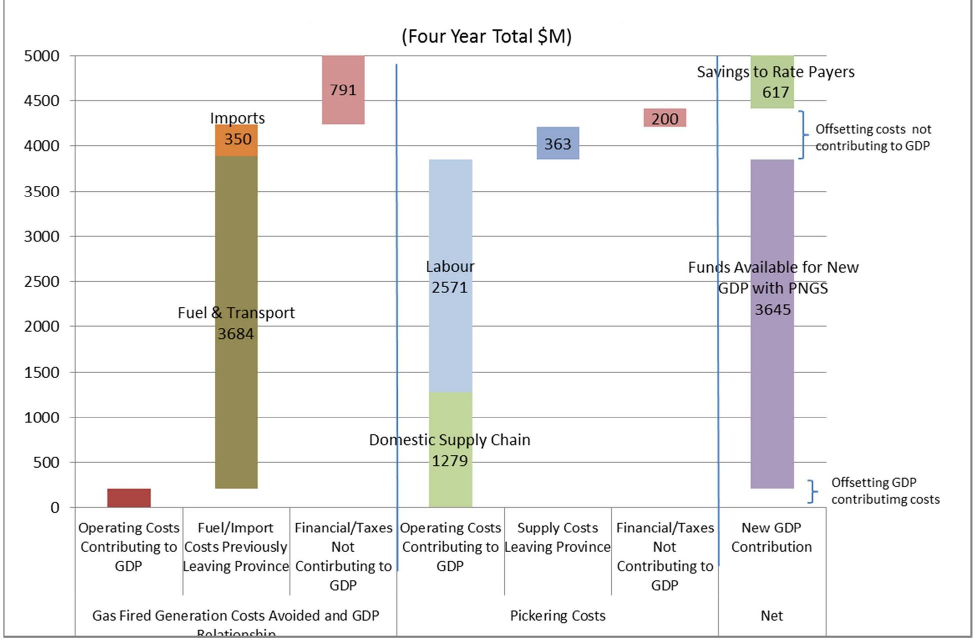
   The monthly fixed costs to the electricity system of new natural gas-fired generating capacity are avoided by deferring construction of new plants. The monthly payments avoided are largely financial recoveries that would otherwise contribute very little to GDP.

5) Avoiding Electricity Imports

   Imports of electricity entail spending outside of the province representing $350M in GDP leakage.

Several of the costs within both options fall into the non-contributing GDP factors previously described. Figure 35 categorizes the cost components of each scenario into the GDP contributing vs non-contributing categories. The figure illustrates the relationships between these costs in a comparative manner. Collecting the common GDP contributing factors as well as the non-GDP contributing factors, and characterizing them as GDP leakage or financial factors, highlights where the GDP contributing costs will arise from. Aligning those items with common GDP impacts and then removing the amounts from each scenario that overlap graphically demonstrates the incremental approach used to identify the impacts that differentiate the two options. This approach ensures that the economic contributions of the natural gas-fired generation scenario are recognized in the comparative analysis.

Figure 35 – Comparison of GDP Contributing Factors



As mentioned earlier in this report, the economic impact of constructing new natural gas-fired generating plants has not been considered in this portion of the analysis. While the relevant plants will still need to be built, their commissioning is only slightly deferred until the eventual retirement of the PNGS. These investments will still occur within the time frame of the scenarios analysed and hence does not represent an incremental factor.

The results of this approach to the comparative analysis shown in Figure 35 demonstrates that there are net new funds of about $3.6B that are available to pay for the PNGS operations and create net new economic benefit. The rate payers' savings benefit of ~$600M also results from what would otherwise be non-GDP creating financial cash flows for the natural gas-generation fixed assets. The resulting net economic contribution of the PNGS is approximately $4.2B before considering the indirect and induced factors associated with the PNGS operations.

A discussion of the economic assumptions for each scenario is provided in the next two sections.

6.2.2. Natural Gas-Fired Generation Economic Impact Assessment Assumptions

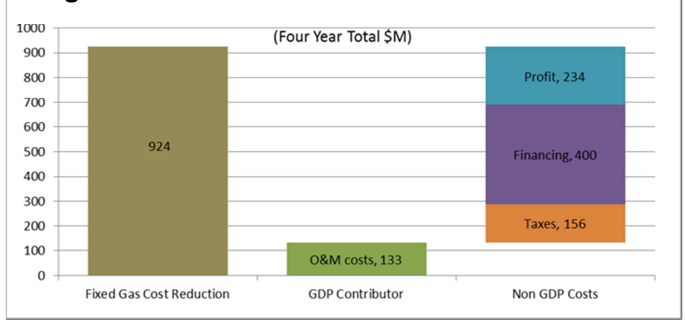
Figure 35 showed how $5B of natural gas-fired generation costs would be displaced by extending PNGS operations. Natural gas-fired generation costs in Ontario have two major and distinct components within the overall cost structure of the electricity system. These components pertain to the Global Adjustment (GA) and separately to the HOEP. Elements of both cost components are subject to displacement by PNGS operations.

1) Monthly fixed costs recovered through the Global Adjustment (GA) ($920M 4-year total reduction):

IESO indicated that the LTEP had assumed monthly fixed costs of $130,000/MW/year or $260M/year for the 2,000 MW modelled in this analysis. These fixed monthly charges cover primarily the financial returns of the plant and the relatively small fixed operating costs of a peaking supply plant.

Figure 36 shows the components of these monthly fixed costs and how they may contribute to GDP. Only the ~$130M fixed operations and maintenance (O&M) costs contribute to GDP[42]. The remainder of the costs, or ~$800M, are funds that can be converted from non-GDP contributing to GDP contributing costs with the PNGS option.

Figure 36 – Gas Fixed Cost Economic Contributors

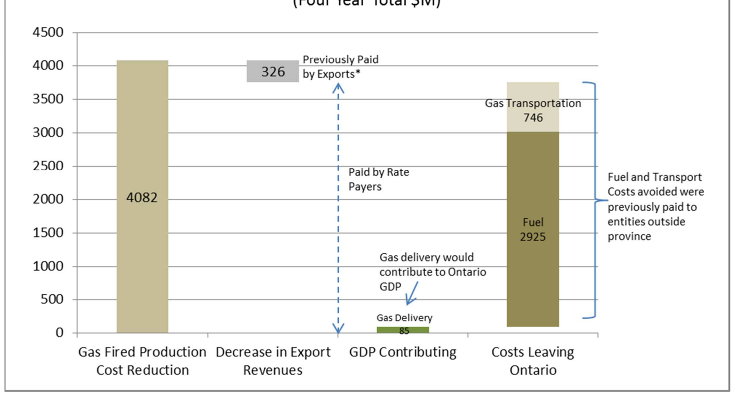


* GDP impacts of previous exports is not material to study given 95% import content of supply

2) Variable costs of production recovered through the HOEP ($4B 4-yr total reduction)

The variable costs of production dwarf the fixed cost payments by a factor of four. Figure 37 shows how the majority of these costs are for fuel and the costs of the national pipeline systems that deliver the natural gas to Ontario[43].

Figure 37 – Gas-Fired Generation Economic Components



Only ~$85M of the costs would contribute to Ontario's GDP through the local delivery

[42] The economic impact benefits of new gas-fired facility construction has been excluded from this analysis as the need for the facilities is merely deferred by 2 to 4 years in the simulation and will likely still occur within the time frame being assessed. The net present value (NPV) benefit due to the deferrals is considered immaterial to the findings in this report.

[43] Details are provided in appendix A

charges of Enbridge and Union Gas. The remaining $3.6B in fuel and transportation costs leave the province.

The share of gas-fired generation in exports is lower with PNGS, reducing export revenues. The lower export revenues offset the cost savings of reduced production by $325M. These are not a lost GDP opportunity as 95% of the underlying variable costs are for imported supplies. The material difference between the PNGS and reference case aspects of this topic therefore net to a zero sum impact on Ontario's trade balance and GDP.

The GDP contributing elements from the gas plants that arise from the fixed cost O&M and local delivery costs are likely less than $300M over the four years. In the incremental analysis approach, these are offset against PNGS generation O&M costs. The remainder of the natural gas-fired generation costs arising from both the $800M in fixed financing costs and from the $3.6B in imported fuel costs are non-GDP generating. Displacing them represents $4.4B in electricity system costs that can be directed to support the costs of the PNGS extended operations and create net new GDP.

6.2.3. PNGS Economic Impact Assessment Assumptions

PNGS costs of $4.4B stimulate almost $4B[44] in GDP contributing activities over the four years. The incremental costing approach discussed in Section 4 considers the costs and employment that will remain at OPG upon PNGS retirement in order to conduct the operations at the Darlington NGS.

The incremental impact approach is also justified for use in the economic impact analysis for the following reasons:

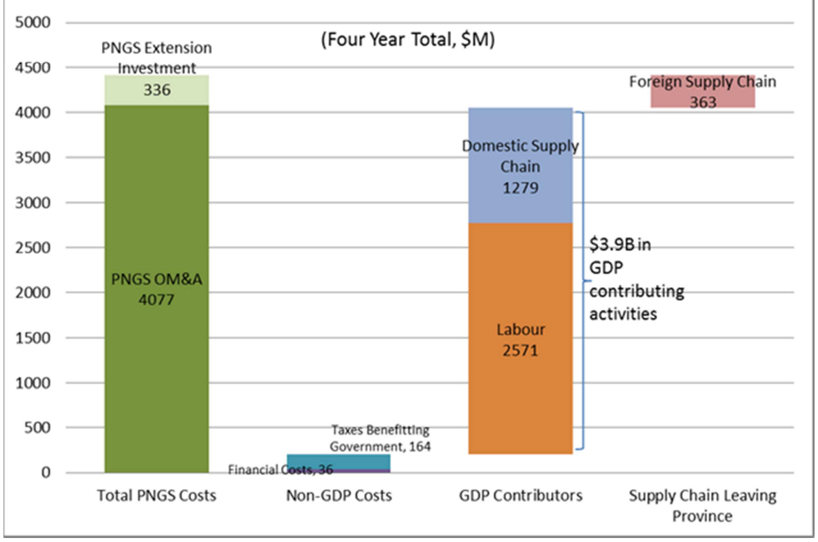
- The retirement of PNGS is being deferred only for a short time,
- Any operational ramp downs that may be planned, will simply be deferred,
- The economic impacts that may arise from decommissioning activities are simply being deferred.

The incremental approach simplifies down to evaluating the impact of four years of PNGS operations activity.

The breakdown of PNGS operating costs discussed earlier provides the basis for identifying the economic impacts. Figure 38 summarizes the cost components that make up the investment and OM&A costs of extending the PNGS operations. Furthermore, as the plant is already depreciated, one advantage of continued operations is that only a small portion of the costs are for financing purposes, i.e. those related to the extended operations preparatory investments. Almost 90% of the $4.4B rate base, or $3.9B over the four year period, contributes to jobs and GDP.

[44] Note: Impact due to timing of cash flows has not been rigorously considered

Figure 38 – Incremental PNGS Extended Operations GDP Contributors



Note: Simulation costs are prorated based on composition of OM&A and investment cost elements

6.3. Jobs Implications

Extending the operations of the PNGS is forecast to generate almost 40,000 PYEs of employment over the four year term studied. This number of PYE jobs is derived from two factors: number of personnel employed at OPG in support of PNGS operations; and (2) the number of Ontario domestic jobs sustained in the supply chain that would continue to provide products and services to the OPG PNGS related activities.

The derivation of the jobs that are sustained by the PNGS option is summarized in Table 1. OPG incremental employed personnel quantified as Full Time Equivalents (FTEs) is estimated at 4,000 per year when all six units are operating. Strapolec has assumed this will reduce by 30% when PNGS A operations are discontinued. The OPG labour composition assumptions are described more fully in appendix A.[45]

Direct jobs in the nuclear supply chain have been estimated based on the PNGS supply chain spend prorated against the size of the nuclear industry's supply chain employee base and estimates of the supply chain's other revenues. Total industry jobs and their distribution across the country have been obtained from the Organization of Canadian Nuclear Industries (OCI).[46]

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[45] Ontario Power Generation, 2013; Strapolec analysis
[46] OCI, 2013

The total number of jobs also includes indirect and induced jobs. The multipliers used have been obtained from the Canadian Manufacturers and Exporters (CME) association studies conducted for the Canadian Nuclear Association (CNA) in 2012.

Table 2 shows how the annualized values of Table 1 will produce 40,000 direct, indirect and induced jobs when spread over the four year period of the PNGS option.

Table 1 - Summary of Approximate Job Impacts (FTEs/Year)				
	Direct Jobs	Indirect Multiplier	Indirect Jobs	Total
Pickering Incremental for OPG	4,000	1	4,000	8,000
Supply Chain jobs	1,800	1	1,800	3,600
Total Jobs	5,800		5,800	11,600
Notes:	Supply chain job estimates based on CME reported OCI jobs			
	OCI data prorated based on expected Pickering supply chain spend			
	Multipliers using CME factors per CNA			

Table 2 - Net Job Impact of Assessed PNGS Extended Operations				
Total Job Impacts	% Jobs Included	Per Year Jobs	# of Years	Total Jobs
6 Unit operations	100%	11,600	2	23,200
4 Unit operations	70%	8,120	2	16,240
Total				39,440
Notes:	Jobs scaled similar to expected costs per TWh assumption			
	Jobs are in terms of Person Years of Employment (PYEs) or Full Time Equivalent jobs (FTEs), both used synonomously in this report			

The above jobs analysis is conservative as it does not reflect any induced jobs benefits resulting from the $600M savings that would be realized through rate payers. Induced jobs could be as high as 3,000 PYEs, or 8% higher than the total of approximately 40,000 PYE jobs noted above. Based on the estimated $600M in benefits mostly accruing to industrial rate payers, additional job growth should be anticipated in the province's industrial sector. After tax, these job creating benefits could be approximately $400M based on CME's estimate of the total corporate tax burden in Ontario (approximately 30%). CME's assessment of the contribution to job creation by after tax corporate profits suggests that about 8,000 jobs are created for every billion dollars in after tax profit.[47] As a result, the rate payer savings could generate 3,000 additional induced jobs.

[47] Canadian Manufacturers & Exporters, 2011; Strapolec analysis

6.4. GDP Implications

GDP estimates have been developed based on several assumptions recently used in the nuclear sector. The fundamental economic multipliers and principles described in the CME's 2012 study (referred to in the 2013 LTEP) have been applied here. Income has been based on total labour costs at OPG, less a burden of 40% over salary for fringe benefits, etc., applied here as a rule of thumb by Strapolec.

Table 3 shows the breakdown of the approximately $7B in GDP benefits that could arise in Ontario by extending the PNGS operations by four years.

Table 3 - Calculation of GDP Benefits ($M over 4 years)

	Direct	Indirect Multiplier	Indirect GDP	Total GDP Impact
Labour Income	1,836	1.4	2,571	4,407
Supply Chain (net of Gas O&M)	983	1.1	1,082	2,065
Rate Payer Savings			617	617
Total	2,820		4,270	7,089
Notes:	Labour multiplier is 1.4 times income per CME			
	Income ~ 70% of labour costs (typical overhead)			
	Supply Chain multiplier based on CME report			

6.5. Benefits to Durham Region

The important role that OPG plays in the economy of the Durham Region is widely recognized. In their submissions to the OEB, OPG continually reiterates that the PNGS is a major employer within the Durham Region with 2,700 people directly employed at the PNGS stations in 2009. Based on the locations where PNGS related employees live[48], Strapolec estimates that approximately 2,400 direct jobs are filled by residents of the Durham Region.

OPG's nuclear operations, of which the six PNGS units represent the largest operation, have "attracted nuclear related businesses, helping to establish a Durham Energy Industry Sector cluster (e.g. Eastern Power, Eco-Tech, Black and MacDonald, AREVA, New Horizons Systems Solutions, etc.)."[49]

The annualized economic contribution to the region is summarized in Table 4. Over the four-year period, more than 12,000 jobs and almost $1.2B of direct, indirect, and induced local GDP will be

[48] Gartner Lee, 2000, OCI, 2013, PWU, Strapolec analysis
[49] Ontario Power Generation, 2013

sustained. Local multipliers used for this analysis have been based on the Nuclear Energy Institute (NEI) report[50]. These multipliers are typical of those observed in the US.

Table 4 - Summary of Approximate Economic Relevance to Durham Region					
Annualized	Direct	Multiplier	Indirect & Induced	Annual Total	4 Year Total
Supply Chain Output ($M)	17	4%	1	17	GDP
Income ($M)	267	22%	59	325	1,165
Jobs (PYEs)	2,424	50%	1212	3,636	12,362
Sources:	Nuclear Energy's Economic Benefits - Current and Future, 2014,Nuclear Energy Institute (NEI)				
	Applied NEI ratios to national CME assumptions				

6.6. Implications Summary

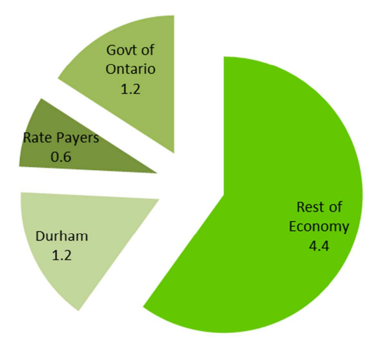
The PNGS option represents a significant opportunity to provide over $7B of economic benefits for a range of Ontario stakeholders.

Figure 39 summarizes the elements of the $7B in benefits that arise by extending the operations of the PNGS, mostly enabled by the power of domestic spend arising from the displacement of $4B in energy imports. The benefits identified include:

- Reduced electricity costs of over $600M to Ontario ratepayers.
- Continued $1.2B in economic stimulus for the Durham Region.
- Improved the Government of Ontario fiscal position of almost $1.2B.
- Adds approximately $4.4B to the rest of the provincial economy.
- Sustains 40,000 person year equivalent direct, indirect and induced jobs.

Figure 39 – Share of Total Economic Benefit

(Four Year Total $B)



The next section discusses the direct benefits to the Government of Ontario.

[50] Nuclear Energy Institute, April 2014

7.0. Benefits to Government of Ontario

Extending the operations of the PNGS by four years would improve the fiscal position of the Government of Ontario by over $1.1B (cumulative).

Incremental tax revenues, estimated at over $900M and representing 13% of the new GDP created, is the largest contributing factor. The 13% share of incremental GDP is an approximation based on research that indicates most economic impact studies identify Ontario provincial government revenues as being 12% to 14% of incremental GDP created. [51] By contrast, overall government revenues are greater than 16% of Ontario GDP and so the 13% assumption may be conservatively low.

Two additional benefits have been included that would accrue to the Ontario government as a result of its shareholder stake in OPG operations. These have been previously identified by the OPA and include:

1. Operating income of OPG to the Government of Ontario.
2. Severance costs deferred and savings from deferring the decommissioning activities, which allows more time to potentially increase the value of the decommissioning liability funds.

The benefits that will accrue to the Government of Ontario are summarized in Table 5.

Table 5 - Benefits to Ontario Government ($M over 4 years)		
Total GDP	7,089	
Taxes from GDP	922	13%
Income from OPG	45	net of lost gas plant tax revenue
Deferred Decommisioning	201	per OPA assessment 2012
Total Ontario Benefit	**1,168**	

These benefits suggest that extending the operations of the PNGS will sustain an Ontario budget contribution to the Province of almost $300M/year for the four-year period instead of creating an equivalent deficit in the provincial budget for those years.

Implication Summary

Extending the operations of PNGS represents a significant opportunity for the Ontario Government to positively support its fiscal position while simultaneously reducing the cost burden of its taxpayers and electricity rate payers. Besides enhancing Ontario's fiscal position by over $1.1B, the PNGS option enables the province to achieve further substantial reductions in GHG emissions while also meeting the province's reliability capacity reserve gap.

[51] Conference Board of Canada, 2012; Dungan, 2014; Ontario Ministry of Finance, 2015

8.0. Summary and Recommendation

The emissions and economic benefits of extending the PNGS operations are clear and compelling. The PNGS option helps address two significant challenges facing the province: (1) it supports achieving Ontario's GHG reduction objectives by avoiding an increase in GHG emissions of 55%; and (2) helps mitigate Ontario's near term reliability reserve capacity gaps. The benefits of extending the PNGS operations include:

- ***Lower GHG emissions*** – over 18 million tonnes (Mt) of CO_2 avoided, which is avoiding both a 55% increase in electricity system emissions and a 25% increase in the total provincial emissions from natural gas usage across all of Ontario.
  - The PNGS option exemplifies Ontario's legacy of nuclear being practically responsible for Ontario's electricity system GHG emissions success.
- ***Lower electricity system cost*** – potentially reduced by over $1.5 billion (B) due to PNGS operating cost advantages and avoidance of the risks of natural gas-fired generation dependence.
  - $600M cost reduction to Ontario's electricity rate payers.
  - Mitigation of almost an additional $1B in costs risks that can potentially arise from far reaching developments in the U.S. electricity system that could significantly increase natural gas prices and reserve capacity requirements in Ontario.
- ***Positive Jobs and Gross Domestic Product (GDP) created –*** from the power of domestic spend
  - Over $7B dollars of benefits will accrue to rate payers, the Government of Ontario, and, significantly, to the provincial economy.
  - ***Jobs Sustained*** – 40,000 Person Year Equivalent (PYE) jobs.
  - ***Net New Ontario Domestic GDP*** – $7B enabled through replacing $4B of imported energy with domestic nuclear generation.
- ***Allowance for more time*** to develop a solution to Ontario's longer term grid reliability and emissions challenges.

Recommendation:

Given these significant benefits, the Ontario Government should direct the Minister of Energy, the IESO, and OPG to consult with the Canadian Nuclear Safety Commission (CNSC) for the purpose of securing approval for the longest possible period of continued safe operation of the PNGS beyond 2020 in order to:

- Sustain the substantial economic and environmental benefits that accrue to Ontario for every year the PNGS continues to operate.
- Provide the government with the maximum time for assessing longer term options for the eventual replacement of the PNGS.

Appendix A - Scenario Cost Assumptions

This appendix summarizes the detailed cost related parameters that have been used in the economic assessments. Four specific areas are described in this appendix:

- Basis of Derivation of Pickering Cost Assumptions
- Natural Gas-Fired Generation Fixed Plant Costs
- Variable Costs for Gas-Fired Generation
- Expected cost of natural gas as a fuel for gas-fired generation.

A.1. Basis of Derivation of Pickering Cost Assumptions

Pickering costs were developed based on an incremental cost approach. This means that the costs to extend PNGS operations are those that would be incurred as additional to OPG's baseline assumptions of only the Darlington NGS (DNGS) being operated post 2020 as per the LTEP. These costs are not incremental to the decommissioning program which is simply deferred. The benefits of that deferral are discussed as benefits to the provincial government in Section 7.

This incremental costing approach is the method OPG used in their OEB submissions in 2010 and 2013 in support of the PNGS continued operations post 2015.

Since a total system cost model is being used that factors in the DNGS cost rates assumed in the LTEP, the incremental cost approach is legitimate for this simulation as all costs are properly captured for comparison purposes.

A summary of the assumptions that build up the $63/MWh rate used to depict the PNGS costs in this analysis is provided in the table below.

Mock-up for Incremental Pickering Business Case Assumptions to Support Economic Impact		
Cost Element	**Cost ($M)**	**Notes**
Fuel	126	Average of 2017 to 2019 in 2013 Bus Case, escalated to 2015$
O&M Labour	690	Computed based on 2015 average compensation and 4000 FTEs
O&M Supply Chain	298	Estimated based on remainder of costs from total estimated
Financing	0	Assume that Pickering will have been fully depreciated
Income (EBIT) & Prop Taxes	47	Added to reflect return required in consumer rates
Total	1160	
Rate Calculation		
Assumed TWh	20	In 1st and 2nd year, 3rd and 4th years will reduce to 14
Assumed Rate ($/MWh)	$ 58	
Investment Recovery ($/MWh)	$ 5	$300M recovered over 68 TWhs over 4 years
Total Rate ($/MWh)	**$ 63**	
Notes	Rate is held constant for simulation assuming a proration of costs when Pickering A operations end and B continue at 14 TWh/year	
	Fuel and supply chain costs are treated similarly for economic impact assessment	

The incremental business case cost assumptions have been developed primarily through leveraging the OPG data provided in support of the OEB submissions as follows:

1. OPG cost estimates from the OEB submissions were obtained and escalated to 2015 dollars.
2. OPG's staffing plan was obtained from OEB submissions.
3. Staffing and FTE assumptions were developed based on OPG representations of incremental costs for support and corporate services as stated in the OEB submissions.
4. Labour costs for the economic impacts were estimated from the expected FTE counts and the average salaries identified in the OEB record of decision.
5. Fuel and supply chain costs were estimated from the average fuel costs in the 2013 OPG business case with the supply chain expenditures accounting for the rest.
6. It is assumed that the Pickering asset has been completely depreciated prior to the extension and that any new capital expenditures will be paid for through rates applied during the extension period.
7. A 4% surcharge was also assumed in the rate to reflect the typical income for OPG's shareholder.

Estimating Incremental Pickering NGS Costs for Extending Operations			
Cost in 2017	Incremental costs ($M)	Cost in 2015$	Average of Estimates
2010 Business Case (2010$)	1060	1159	1114
2013 Business Case (2012$)	1013	1069	
Notes	2017 picked as a Reference year as it appears to capture the full annual operating costs		
	Total OM&A & Capital includes station OM&A (base, outage, projects) and sustaining capital projects and the stations share of incremental allocated nuclear and corporate support costs. These costs do not include severence costs associated with each scenario		
Source	OPG business cases submitted to OEB in 2010 and 2013		

For reference, Strapolec has derived from the OEB 2014 decision that the fully allocated PNGS rate is $62/MWh excluding considerations for the $300M extension investment. This is only 8% higher than the $58/MWh for PNGS OM&A costs assumed based on the incremental approach.

Estimated Annualized FTE Jobs from Extending Pickering NGS Operations				
	Estimated Current FTE Allocation	% Jobs Retained with Extension	Jobs Retained (FTEs)	Scenario with Incremental Costs Weighted More on Labour
Nuclear Support	2130	68%	1449	1585
Corporate Staff	1888	28%	529	801
Pickering NGS Staff	1,830	100%	1,830	1,830
Total Staff	5849		3807	4216
Source:	FTEs from OPG Nuclear Resources Staffing Plan and JPSCA analysis cited in OEB Decision 2014 based on EB-2013-0321			
	% costs retained assumption from OPG Pickering Business case in EB-2013-0321			
Notes	Current staff estimated based on a 60%-40% Pickering to Darlington ratio based on number of units. Strapolec created reference to assess possible range			

Estimated OPG 2015 Labour Costs			
	FTEs	Compensation ($/year)	Labour Cost ($M)
Management	1076	$ 205,914	222
Society	2965	$ 176,508	523
PWU	5300	$ 163,458	866
Total	9341		1611
Assumed for Pickering Business Case			
	4000	$ 172,491	690
Source:	OEB Decision with Reasons, 20 November 2014		

A.2. Natural Gas-Fired Generation Fixed Plant Costs

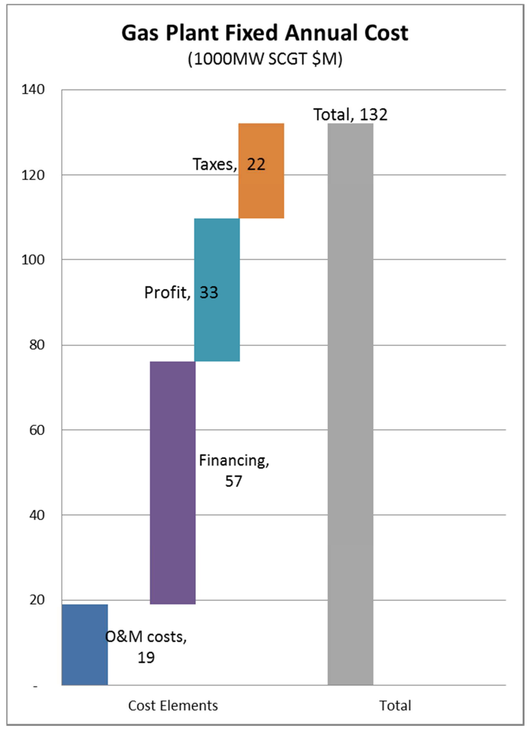
Strapolec developed a financial model of the fixed portion of a new 1,000 MW Simple Cycle Gas Turbine (SCGT). Cost assumptions have been obtained from the EIA 2015 AEO. Comparing the required financial returns to a fixed cost payment of $11,000/month per MW of capacity shows that this level of budget is mostly attributable to financial cost and return recoveries.[52]

The financial assumptions are summarized in the table below with the financial model outputs depicted in the accompanying figure. Only 15% of the annual $132M payments, or $19M of the on-going cost, is for operating and maintenance activities that contribute to GDP.

Based on the financial mock-up of parameters, there is little room within the assumed fixed cost payments to address any of the variable cost components.

[52] IESO, October 2014; Ontario Ministry of Energy, 2013; EIA, April 2015; Strapolec Analysis

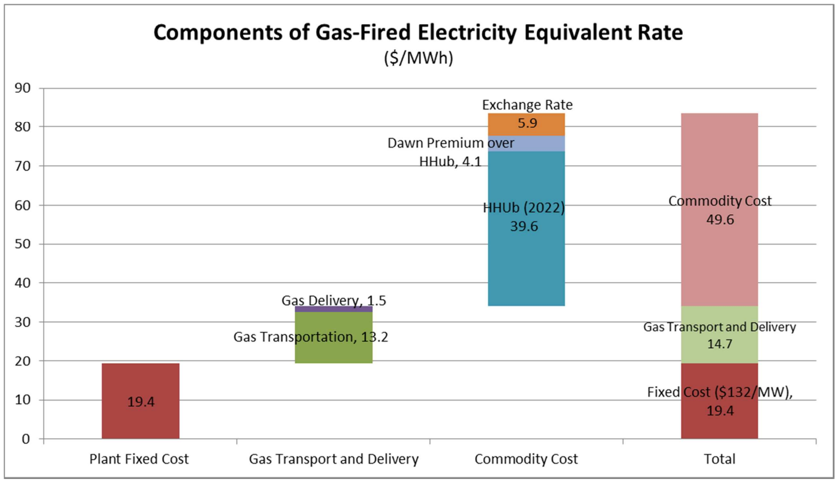
Assumptions	
Financing leverage	60%
Debt interest rate	6%
After tax return on equity	15%
Income tax rate	40%
Nameplate Capacity (MW)	1,000
Fixed revenues($/MW/Month)	$ 11,000
Capital cost ($M)	750



A.3. Variable Costs for Gas-Fired Generation

The breakdown of costs that have been used to estimate an equivalent rate for 2022 (in 2015 dollars) is illustrated in the figure below. The predicted variable costs are $65/MWh which includes $49.60/MWh for the commodity and $14.70/MWh for transportation and delivery of the natural gas fuel to the gas-fired generating plants.

The basis for this breakdown of the comparative unit costs stems from the perspective that in the reference scenario, the natural gas-fired generation fleet will be operating at higher operating factors than seen recently. As such, for the purposes of PNGS comparison the incremental variable costs will be occurring on the margin of this higher capacity. It should therefore be expected that all of the variable costs of generation will be impacting on and reflected in the HOEP.



Many inputs have been used to establish the assumptions underscoring the predicted $66/MWh:[53]

- Delivery and transportation costs: are currently 7 cents/cubic meter = ~$2/ per million British Thermal Units (mmBTUs) based on Enbridge Class 125 rates. This consists of approximately 6 cents/m^3 NEB regulated rate for transportation and approximately 1 cent/m^3 for local delivery.
    - Note that the Enbridge cost of transportation is much higher than that for Union Gas in southwestern Ontario, where the Dawn Hub is located. The Enbridge rate has been used for this analysis on the assumption that the natural gas-fired generation plants most likely to be called upon to replace PNGS generation would be those in the GTA, the source of the demand for PNGS.
- Heat Rate: Analysis assumed a value of 7.54 BTU/Wh based on the relationship of observed actual production and coincident GHG emissions combined with the assumption that the future gas generation mix will reflect the same composition of supply as there are generators. In contrast, the EIA stated value for 2014 of the average US heat rate is 7.95 BTU/Wh. As a result, the heat rate assumption used here is potentially conservative, particularly if SCGT supply contributes to the production, which is likely.
- Henry Hub price is based on the average price forecast (2013 dollars) of $5.20 per EIA 2021-2024.
- Dawn premium over Henry Hub is assumed at 9% based on historical relationship prior to the weather and constrained supply events of 2014 and 2015.
- Long term USD vs CAD exchange rate premium = 15%.
- Note that the EIA average forecasted US delivery cost to the electricity sector is 18% of commodity costs in the relevant time frame. Transportation and delivery costs for Ontario are estimated in this analysis to be 23% of the fuel costs. Part of the difference between US and

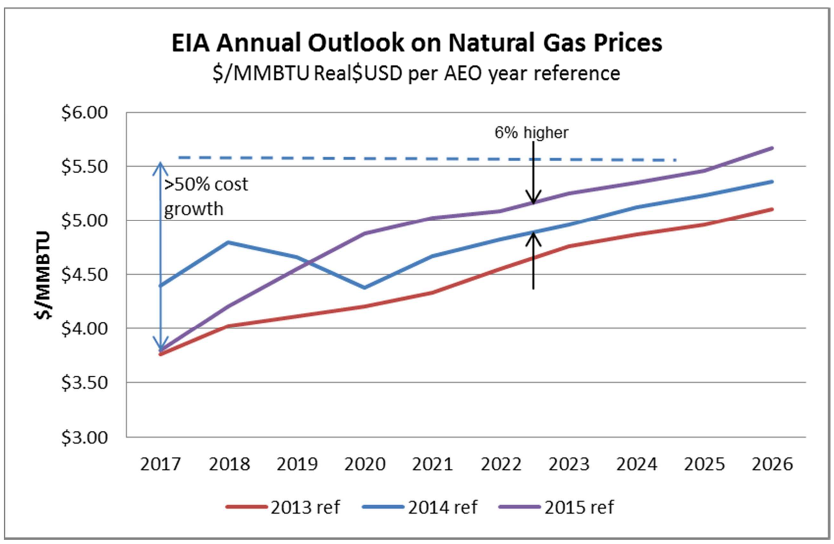
[53] Strapolec analysis; IESO, October 2014; Ontario Power Authority, April 2012; U.S. Energy Information Administration, 2015; Ontario Energy Board, 2015; National Energy Board, 2011; Enbridge, 2015; Union Gas, 2015; Bloomberg, 2015

Canadian transportation costs is that the costs of natural gas transportation to Ontario have been rising in the last decade as demand for natural gas in this province has been declining.

A.4. Forecast Cost of Natural Gas

The cost of natural gas fuel represents the largest component of the cost of gas-fired generation and hence assumptions about the fuel price are critical to understanding the sensitivities of any resulting analysis. There are two main components to the cost of fuel in Ontario: (1) The benchmark North American reference of the cost of natural gas as obtained from the Henry Hub in Louisiana; and (2) A cost differential that exists between the Henry Hub and the Dawn Hub that supplies Ontario.

The source of the forecast Henry Hub price is the EIA 2015 Outlook. The last three EIA forecasts have predicted increasingly higher future commodity prices as illustrated in the figure below. In the period of interest for this study, the EIA's 2015 AEO forecast is 6% higher than the forecast in the previous 2014 AEO. The latest average for 2021 to 2024 is $5.20/mmBTU in USD.

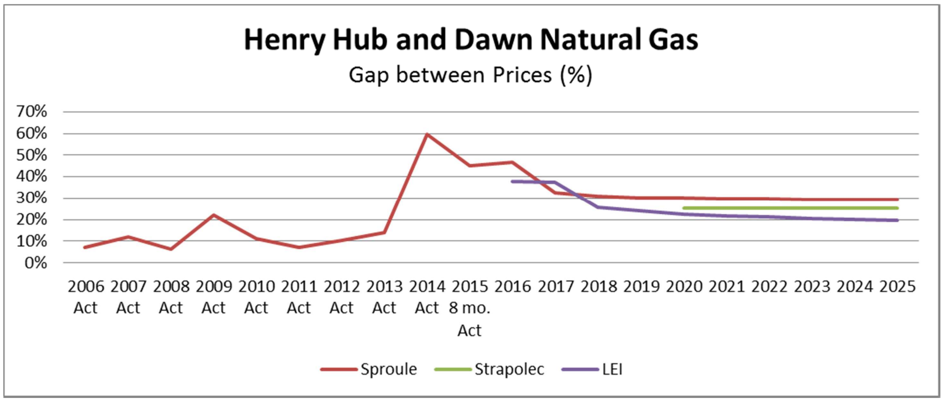


Ontario acquires natural gas from the Dawn Hub in southern Ontario. The Dawn price differs from Henry Hub due to system and market costs for transporting the fuel to Ontario[54]. The Strapolec forecast is based on a 9% observed historical price premium at Dawn up to 2013. The premium price difference was much higher than 9% in 2014 and 2015 due to a number of environmental and gas system constraint issues.

Two sources were consulted regarding the long term price difference between Henry Hub and Dawn. Sproule and LEI both offer long term gas price forecasts of Dawn and Henry Hub. These have been

[54] Energy Information Administration, 2013, 2014, 2015; Sproule, 2015; London Economics Institute, 2015; Strapolec analysis

illustrated in the figure below alongside the assumption used by Strapolec in this analysis. Strapolec has assumed a 1.15 CDN/USD long term exchange rate post 2020 which has also been applied to the LEI forecast illustrated below.



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Appendix C - List of Abbreviations

AEO – Annual Energy Outlook
BCFD – Billion Cubic Feet per Day
BPS – Bulk Power System
BTU – British Thermal Unit
CBoC – Conference Board of Canada
CCGT – Combined Cycle Gas Turbine
CHP – Combined Heat and Power
CME – Canadian Manufacturers & Exporters
CNA – Canadian Nuclear Association
CNSC – Canadian Nuclear Safety Commission
CO_2 – Carbon Dioxide
CPP – Clean Power Plan
DNGS – Darlington Nuclear Generating Station
EIA – U.S. Energy Information Administration
EPA – U.S. Environmental Protection Agency
FTE – Full Time Equivalents
GA – Global Adjustment (36)
GDP – Gross Domestic Product
GHG – Greenhouse Gas
HOEP – Hourly Ontario Energy Price (wholesale market)
IESO – Independent Electricity System Operator
LEI – London Economics International
LTEP – Long Term Energy Plan
MISO – Midcontinent Independent System Operator
mmBTU – million British Thermal Unit
Mt – Million Tonnes
MW – Mega-watt
MWh – Mega-watt Hour (one million watts being produced for 1 hour, enough to power ten thousand 100W light bulbs for one hour)
NEB – National Energy Board
NEI – Nuclear Energy Institute
NERC – North American Electricity Reliability Corporation
NPCC – Northeast Power Coordinating Council Inc
NPV – Net Present Value
NUG – Non-Utility Generator
O&M – Operations and Maintenance
OCI – Organization of Canadian Nuclear Industries
OEA – Ontario Energy Association
OEB – Ontario Energy Board

OM&A – Operations, Maintenance and Administration
OPA – Ontario Power Authority
OPG – Ontario Power Generation Inc.
PNGS – Pickering Nuclear Generating Station
PYE – Person Year Equivalents
SBG – Surplus Baseload Generation
SCGT – Simple Cycle Gas Turbine
StatsCan – Statistics Canada
TWh – Tera-watt Hour (one trillion watts being produced for 1 hour)
US – United States
WCSB – Western Canada Sedimentary Basin

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