Appendix A:

Technical Summary

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POLLUTION PROBE

CLEAN AIR. CLEAN WATER.

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1. Context: Deriving the GTA's Share of the GHG Emission Increase Associated with Closure of Pickering NGS

1.1. Provincial GHG Impact of the Closure of Pickering

Pickering NGS was originally an 8 x 500 MW nuclear plant located about 40 km east of Toronto. Units 2 and 3 were shutdown about 20 years ago. Units 1 and 4 are scheduled to be shutdown at the end of 2022, followed by units 5 – 8 at the end of 2024. Pickering operates in a baseload mode, with each unit running continuously at maximum rating when it is available. Statistically, about 93% of its 3094 MW may be depended on to be available at the time of the summer or winter peak. Planners are assuming energy output of about 20 TWh per year from the full plant until 2022, and about 15 TWh per year from the 4 Pickering B units running to 2024.

1.1.1. When Pickering closes in 2022-24, not all the annual energy it produced as a baseload plant will necessarily have to be replaced to maintain adequate energy supply. The need to replace the plant's annual baseload energy depends on the energy shortage or surplus on the power system cumulated over each hour of the year. At times, there may be significant surpluses above market demand in Ontario. However, as the nuclear refurbishment program moves into high gear in the early 2020's, most of Pickering's capacity remains critical to satisfying power system reliability criteria. There is an ongoing need to protect against contingencies that might precipitate a shortfall in supply.

1.1.2. There will be a considerable difference between Ontario's demand/supply balance now, and in 2025. For the last few years, Ontario's electricity system has had a significant surplus of both capacity and energy.[1] In 2017, even with one unit of Darlington being refurbished, Ontario was exporting power in most hours of the year, and spilling/curtailing Surplus Baseload Generation (SBG)[2] in the off-peak. Exports were about 19 TWh and SBG is estimated to have been about 10 TWh.[3] If Pickering's 20 TWh had not been available in 2017, most of the adjustment could have been addressed through reduced exports and SBG. The more flexible (dispatchable) gas-fired peaking units would have had limited opportunity to make additional economic sales.

1.1.3. In 2025, except for nuclear, available generation capacity is likely to be about the same as today. However, in addition to Pickering closure, part of the nuclear fleet will be out of service for refurbishment. A series of planned 'refurb' outages at Darlington and Bruce have been scheduled from 2016 to 2032. For 2025-32, combining the closure of Pickering and refurbishment, nuclear supply will be about 5000 MW less than in 2015. Under these conditions, the IESO projects capacity adequacy in Ontario to be short about 3700 MW in 2025, diminishing to about 1600 MW by 2034. Nuclear energy production will be down

[1] This unusual excess supply situation occurred because Bruce Nuclear units 3 and 4 returned to service for the first time since the late 1990s, hydro units were benefitting from high water levels, and about 5100 MW of wind and 2600 MW of solar capacity had been added in the province since 2006, all in a decade in which there was a 10% decline in provincial net demand. This unusual excess supply situation occurred because Bruce Nuclear units 3 and 4 returned to service for the first time since the late 1990s, hydro units were benefitting from high water levels, and about 5100 MW of wind and 2600 MW of solar capacity had been added in the province since 2006, all in a decade in which there was a 10% decline in provincial net demand.

[2] Surplus Baseload Generation (SBG) occurs when baseload (operationally inflexible) generation such as nuclear, non-peaking hydro, wind, and solar exceeds Market Demand in Ontario at any point in time. The first response is to attempt to sell it into neighbouring markets. Failing that, it is spilled or curtailed.

[3] Environmental Commissioner of Ontario, 'Making Connections – Straight Talk about Electricity in Ontario', 2018, pg 105.

from over 90TWh now, to about 60 TWh in 2025-6, and getting back to about 75 TWh by 2035 assuming all the units to be refurbished return to service.

1.1.4. In the IESO's Reference case for the post-Pickering period, Net Ontario Demand is projected to be roughly what it was in 2015-18. With the large decrease in nuclear supply, natural gas-fired generation compensates, up 10 -15 TWh per year to about 25 TWh in 2025, somewhat less after that. The remaining nuclear energy gap is made up by nearly eliminating SBG and Exports.

1.1.5. The GHG emissions associated with 10 TWh of gas-fired generation per year would be about 4 MT if the source was entirely base-loaded CCGTs (Combined Cycle Gas Turbines) with an emission rate of about 0.4MT/TWh. In practice, the GHG emissions may be more like 4.5 MT, as the load profile on the gas units will be quite peaky. (More starts and stops result in gas plants that run less efficiently - the higher heat rate in turn increases their GHG emission rate per MWh generated.)

1.2. The GTA Share of the Provincial GHG Impact

A major objective of this project is to explore measures to mitigate the GTA's share of the additional 4.5 MT of GHG emissions attributable to the closure of Pickering. In the process, if the GTA can contribute to mitigating the province's capacity shortfall, that would also be helpful.

1.2.1. The GTA consists of the municipality of Toronto plus the regional municipalities of Durham, Halton, Peel and York. It has a population of about 6.5 million (2016 census), about 45% of the population of Ontario, and an area of 7124 square kilometers. For reference, the Municipality of Toronto has a population of 2.7 million (40% of the GTA) and an area of 630 sq. km (9% of the GTA).

1.2.2. The energy implications of Pickering closure for the province may be allocated to the GTA in a fairly straightforward way because the closure of Pickering is not expected to create transmission limitations on power supply to the GTA. With the in-service of the Clarington Transformer Station in 2018, Ontario addressed the major transmission system supply issue that may have arisen in the GTA East with closure of Pickering.

1.2.3. Without Pickering NGS to the east of the city, the GTA will become more dependent on power flowing east from the Bruce Nuclear site, the Beck complex at Niagara Falls and most of the province's gas plants. The transmission west of Toronto is being upgraded to manage these flows. Realigning power flows may require adjustments to how the system is operated, but that is expected to be manageable.

1.2.4. Obtaining electricity demand data for the GTA is not trivial as the region is supplied by multiple load serving entities, some of whom also serve load outside the GTA. Both the IESO and Hydro One have issued planning studies for the GTA. For the purpose of this paper, the electricity demand data for the GTA has been taken from Hydro One's Resource Integration Plans (RIP) for the GTA. Hydro One prepares RIPs for Metro Toronto, GTA East, GTA North and GTA West. These plans focus on providing transmission to meet coincident peak demands reliably - and rarely mention energy.

1.2.5. The sum of the coincident peak demand forecasts for 2025 in the 4 GTA RIPs is about 12,500 MW. The IESO's Net Demand forecast for the province in 2025 is about 24,000 MW. This implies the GTA requires about half of the province's connected capacity. Based on IESO energy data for Toronto Region (August 2019, Integrated Regional Resource Plan), the load factor4 in the GTA (61%) is about 10% lower than for the province as a whole (68%), implying a lower share of provincial energy demand than of peak demand. This may well be offset from an emissions point of view, as the high concentration of air-conditioning load in the GTA would result in its share of the gas-fired generation operating at a higher emission rate than for the remainder of the province.

1.2.6. These puts and takes suggest it is reasonable to work with 50% as the GTA share of the incremental provincial GHG emissions due to Pickering shutdown, about 2.25 MT.

1.2.7. The goal of displacing 2.25 MT of GHG emissions produced by the gas-fired generation resulting from Pickering closure in the GTA could be approached in several ways.

Option A: Replace grid gas-fired production with alternative local sources of clean electricity supply embedded in the distribution system, almost by definition Distributed Energy Resources (DER). These include small-scale renewables such as solar and wind with associated storage, or perhaps small renewable gas or biomass-fired generation. An economic question to consider is whether grid-scale renewables and storage are a more viable source of clean power for dense urban areas. In an area the size of the GTA, there may be some space on land, or off-shore, available for larger-scale renewables.

Option B: Offset emissions from grid gas-fired generation with demand reduction, as well as the clean supply above. This approach could include enhanced conservation measures, particularly aimed at on-peak demands like residential/commercial air conditioning and commercial lighting or expand systems such as deep lake water cooling that reduce local air-conditioning demand.

Option C: If the objective is even less prescriptive, to reduce GHG emissions in the GTA by an amount equivalent to the increase attributed to Pickering closure, then a broader category of measures opens up: electrification of transportation and building space/water heating (also thermal storage and clean fuels for district heating). These measures reduce GHG emissions, as long as the replacement electricity has lower emissions than the original fuel use. However, they add to power demand and so exacerbate the need for additional clean energy supply.

2. Energy Supply and Demand Projections

Since 2014, the main source of publicly available Electricity Demand and Supply projections for Ontario has been in the documents the IESO prepared for the Ontario Planning Outlook (OPO) and the Government of Ontario's Long-Term Energy Plan (LTEP). The IESO Updated its Long-Term Electricity Outlook in September 2018. This summary was prepare before the 2020 Annual Planning Outlook was released and does not include updated figures from that report. However, the results are similar and the update does not materially change this summary.

Generators connected directly to the transmission system offer their services to the market by submitting time-ordered price/quantity pairs and the IESO dispatch algorithm selects the optimal dispatch of these grid-connected resources. Since the functions of the Ontario Power Authority were transferred to it, the IESO also provides longer-term Ontario power system planning advice to

[4] Load Factor is the ratio of the actual energy demanded to the amount of energy demanded if the maximum consumption level was sustained for 8760 hours of the year.

the Ontario government. To the extent that generation embedded within a distribution system meets load locally, it shows up in the planning process as a reduction in the demand for bulk power system generation and transmission resources.

The LTEPs were intended to act as guides to the procurement of demand management, generation, and transmission resources for the province. These provincial plans have been supplemented by local integrated resource plans. The process for procurement of resources to meet identified plan needs has been evolving. As part of its Market Renewal Project, the IESO had been planning to introduce an Incremental Capacity Auction (ICA) by 2024. This would provide a more market-based process for acquiring the resources to reliably meet projected *grid* demand for the bulk power system in Ontario. The purpose of the ICA is to use the auction to acquire the desired *bulk* power system resource mix at least cost. Small-scale embedded demand-side and generation resources would not compete in the IESO's ICA. The future status of the ICA is uncertain.

In September 2018, at its Technical Planning Conference, the IESO presented its 'Planning Processes and Long-term Electricity Outlook' that updated analysis for the 2016 OPO and 2017 LTEP. Key elements of the more recent outlook scenarios will be used here to infer the impact of the closure of Pickering NGS on the rest of the bulk power system, illustrated by several of the IESO's charts. In this document, the IESO's 2018 Reference Case is considered to be the Business-as-Usual (BAU) case.

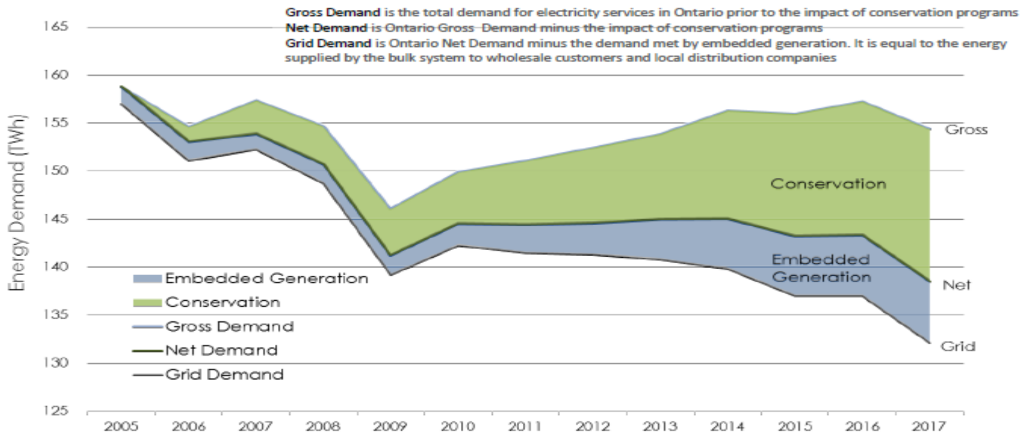
2.1. Trends in Electrical Energy Demand in Ontario

Planners develop forecasts for 'Grid Demand' starting with a forecast for the underlying customer demand, that is, what demand would be without the estimated impact of demand management such as conservation programs, standards and codes (sometimes called induced conservation, as opposed to natural conservation). The IESO calls this Gross Demand. Ontario Net Demand is the demand for the province as a whole after the impact of demand management is netted out. Grid Demand, the demand on the bulk power system operated by the IESO, is an adjustment to Ontario Net Demand for the expected amount of embedded generation, that is, supply connected to a local distribution system that reduces the demand to be served by the Grid. The OPO and LTEP reports, and subsequent updates, contain plans to meet Net Ontario Demand scenarios, taking into account associated projections of induced conservation and embedded generation.

2.1.1. From 2005 to 2009, Net Demand fell about 10%. It has been essentially flat since then. The initial drop in 2005-9 can largely be attributed to trends in global industrial restructuring and the appreciation of the $C from $0.64 US in 2002 to parity in 2010. The appreciation of $C, compounded by the global recession in 2008-9, were major drivers of industrial restructuring in Ontario in which there was a significant loss of heavy industry. Between 2009 and 2015 conservation, due to programs, codes and standards, and a 35% increase in average real electricity prices in Ontario, offset the recovery in gross demand in the residential and commercial sectors. Annual Provincial Net Demand is now several TWhs less than it was in 2009. In addition, Embedded Generation has grown to 6 TWh, mainly due to increases in solar (2.9 TWh) and wind (1.7 TWh). See plot below from pg 23 of the 2018 Update.

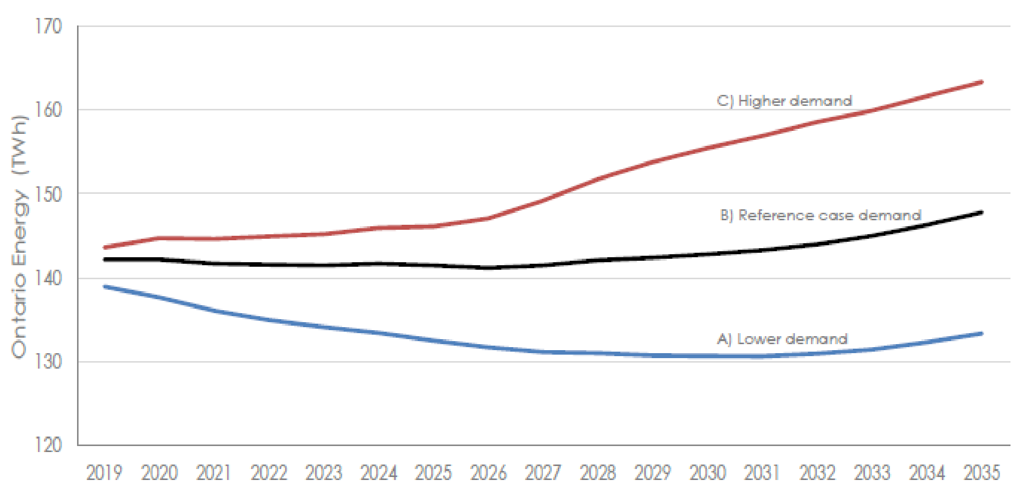
Historical demand: 2005 – 2017

- **Energy demand has been on a declining trend over the past decade, driven by changes to the economy, conservation savings, and embedded generation.**



2.1.2. The IESO's September 2018 (pg 27) Reference Net Energy Demand Case shown below remains at just over 140 TWh per year to about 2030, before starting to trend gently up. Ongoing technical advances in electricity end-use efficiency and other structural factors are expected to offset the underlying growth drivers: the increase in demand associated with the stimulus from a 25% decrease in residential rates from the Fair Hydro Plan in 2017; demographically-driven increases in residential housing stock and commercial floor space; and, the scale of industrial activity consistent with a standard long-term GDP outlook. The BAU outlook takes a very limited position on the implications of electrification of energy services now supplied by GHG-emitting energy forms, such as internal combustion engine modes of transportation and most space and water heating.

Figure 8: Ontario Net Energy Demand across Demand Outlooks

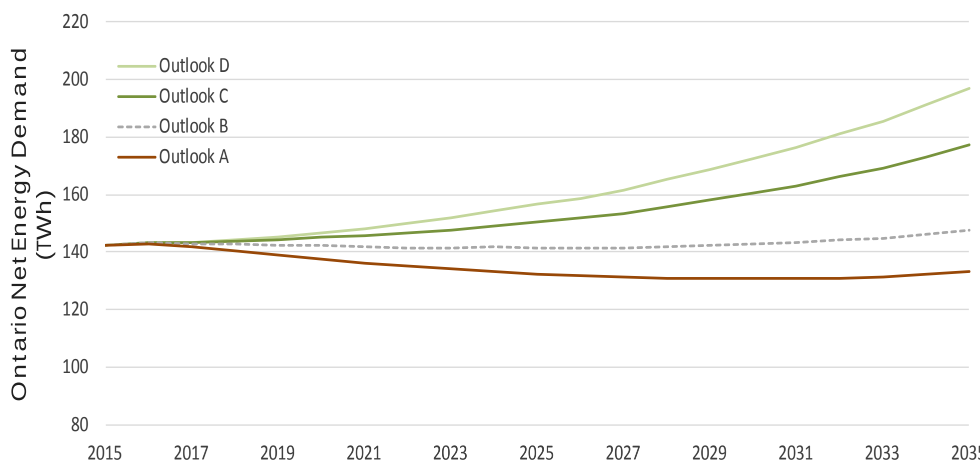


2.1.3. The transportation sector scenario has 1 million Electric Vehicles by 2035, about 12% of the forecasted 2035 vehicle stock in Ontario. Depending on the assumptions used to derive the electric energy required for a year of EV use, the average EV consumes about 4 - 5 MWh per year in the Ontario climate, so a million EVs adds about 4 – 5 TWh to demand.

The case also assumes completion of already announced mass transit projects which would consume about 0.5 TWh per year. Combined, these add roughly 5 TWh to electricity demand by 2035, which is a large part of the post 2030 growth.

2.1.4. The BAU base case ***does not address 2030 GHG emission reduction targets.*** The plot below is from the Ontario Planning Outlook published by the IESO in 2016 as background for the 2017 LTEP. Outlook B is very similar to the 2018 Reference Case. Outlooks C and D make more aggressive efforts to reduce GHG emissions. They are shown here to illustrate how planners have approached making further progress towards achieving Ontario's GHG emission reduction targets. The challenge is that reducing GHG emissions outside the power sector increases the demand for clean power.

The Demand Outlooks in the IESO's 2016 Ontario Planning Outlook



2.1.5. Scenarios C and D address major GHG-emitting energy end-uses: transportation, building space and water heating, and industrial processes. Significant emission reductions are achieved by replacing oil and gas-fired space and water heating with electric heat pumps in residential and commercial sector buildings (after weatherization, etc.), more rapid Electric Vehicle market penetration to 2.4 million EVs by 2035, and assuming 10% electrification of fossil-fuelled industrial processes. By 2035, the net demand scenario for Outlook D is 50 TWh higher than Outlook B, about 30% above the BAU case. Over half of the increase in electricity demand is associated with conversions to electric space and water heating. As heating load is concentrated in about 4 winter months and peaks in late January, Scenario D becomes winter peaking. Relative to Outlook B, the summer peak increases by 3.7 GW, while the winter peak is up 13 GW. (On the grid today, winter peak is currently about 2 GW lower than the summer peak.) Charging of electric vehicles is a year-round load, though it may be somewhat higher in summer months when more kilometers are typically driven. Nonetheless, reduced battery efficiency in cold weather and providing interior car-heat electrically may keep EV load fairly flat year-round.

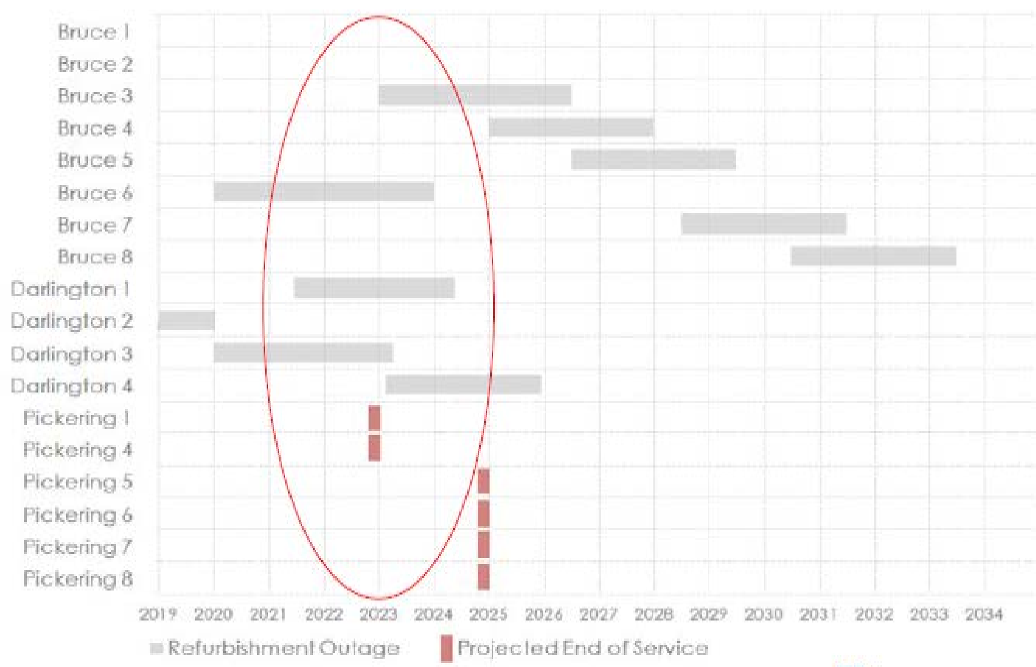
2.1.6. The OPO C and D Demand Outlooks were designed to lower GHG emissions for the province. They are most effective at that if they also minimize the contribution of gas-fired generation to the mix. In the OPO, several alternative supply mixes were proposed. As most of the projected demand increase is in winter, grid-scale wind was found to be a more effective source of renewable energy than grid-scale solar.

2.1.7. The challenge of how best to meet an increase in demand of 50TWh cleanly was not resolved in the OPO report. Even so, as the Environmental Commissioner's Office (ECO) has observed in its 2018 report 'Making Connections: Straight Talk About Electricity in Ontario' (Vol 1, pg 234), 'combining the D Scenario in the Electricity OPO with the remaining fuels use in the most aggressive emission reduction scenario in the complementary 'Fuels Technical Report' would not meet an Ontario 2030 GHG emission target consistent with the Federal Government's commitment to the Paris Accord.'

2.2. Trends in Power Supply

In the IESO's Sept 2018 Technical Planning Conference presentation, the Reference Case production outlook is based on existing and committed resources, nuclear units refurbished and retired as planned, and the assumption that existing contracted resources (mainly natural gas-fired) will be available in some form after their contracts have expired.

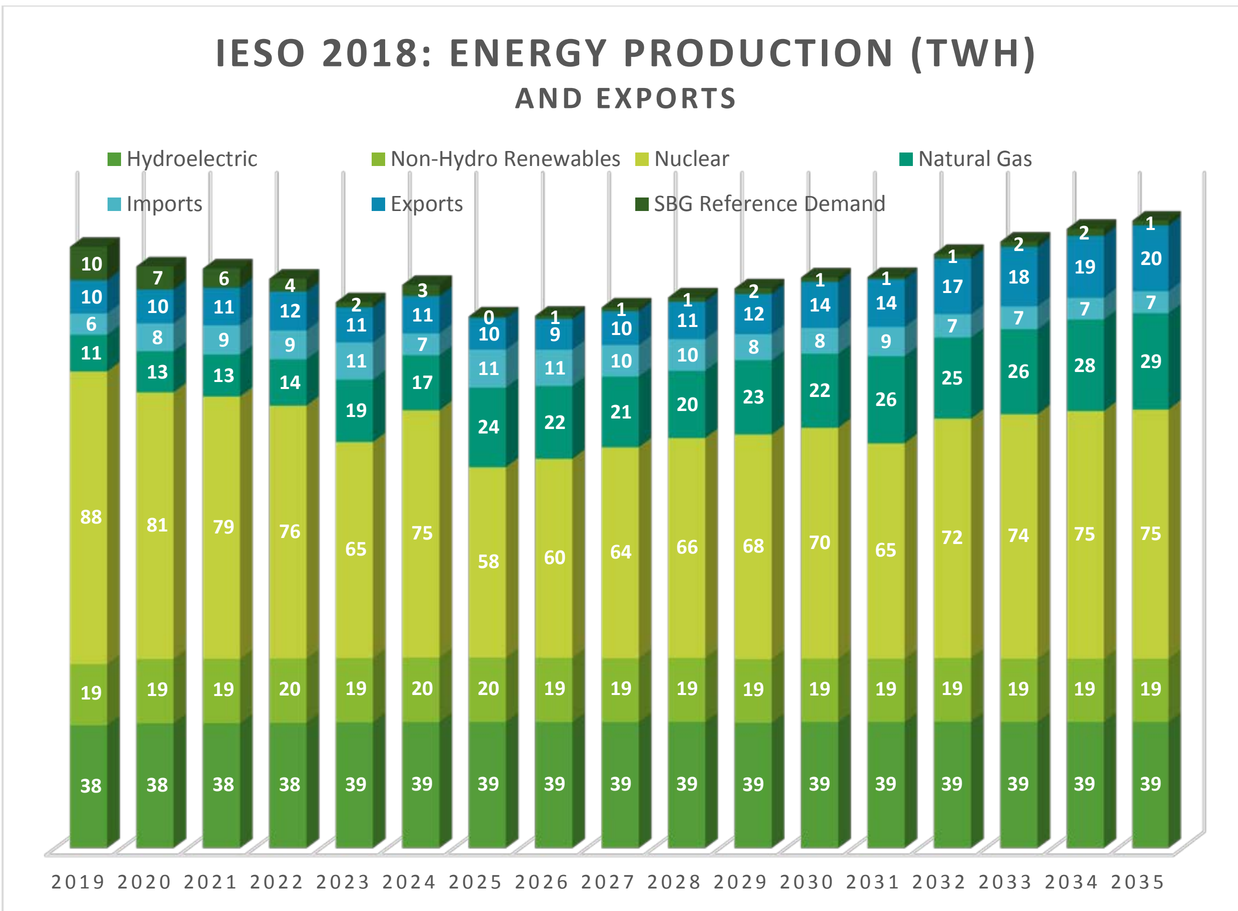
2.2.1. The IESO's nuclear refurbishment and Pickering shutdown schedules are plotted below (pg. 41). During the 2020's, the outages associated with the nuclear refurbishment schedule have the same order of magnitude impact on power supply as Pickering shutdown.



The Darlington Unit 2 refurb started at the end of 2016 and is now expected to return to service in early 2020; the remaining Darlington refurbishment schedule has not been changed from the 2017 LTEP. Bruce Power's Major Component Replacement (MCR) Project will begin with Unit 6 in 2020. The power system will be stressed in 2023 by the overlapping of 2 x 900 MW Darlington unit outages and 2 x 825 MW Bruce unit outages in the year after the retirement of

2 x 500 MW Pickering units at the end of 2022. In 2025, the year after the remaining 4 x 500 MW Pickering units shut down, there will be a similar dramatic reduction in nuclear supply.

2.2.2. Energy Supply: The IESO's Reference Case energy production outlook is plotted below in a slightly different format than on page 57 of their presentation using the datafiles supplied with the September 2018 Technical Planning Conference.[5] This is the scenario used by the IESO to assess Energy Adequacy for Ontario. Based on the evolving annual energy mix shown, it is possible to infer the approximate increase in gas-fired generation associated with Pickering closure.



In the IESO Reference Case plotted above, hydro and non-hydro renewables are projected to produce essentially the same annual energy throughout. In 2022, all six Pickering units are in service to year-end, generating about 20 TWh. By 2025, when that energy is gone, the change in nuclear output shown between 2022 and 2025 is 18 TWh (from 76 TWh to 58 TWh) which

[5] Export data are included in the bar to enable derivation of net exports, part of the market adjustment mechanism when Pickering closes. Exports plus Ontario Net Demand constitute Market Demand in Ontario. The link to the IESO's datafile is http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/tech-conf/2018-Technical-Planning-Conference-Data--0181129.xlsx

suggests that production by the rest of the nuclear fleet is up about 2 TWh between those two years, an amount readily attributable to annual variations in maintenance and the refurbishment outages for the rest of the nuclear fleet. The adjustments for Pickering closure show up in the changes between 2022 and 2025 in the other elements of the chart above: natural gas-fired generation +10 TWh (to 24 TWh), imports +2 TWh, exports -2 TWh and SBG -4 TWh.

Natural gas-fired generation is the swing resource. One of the goals of Market Renewal is to provide market incentives for the current fleet of CCGTs to become more flexible, to shift them from their current intermediate load factor operation to perform more like Combustion Turbines (CTs) to better cope with the residual generation peaks created by the dynamics of the renewables.

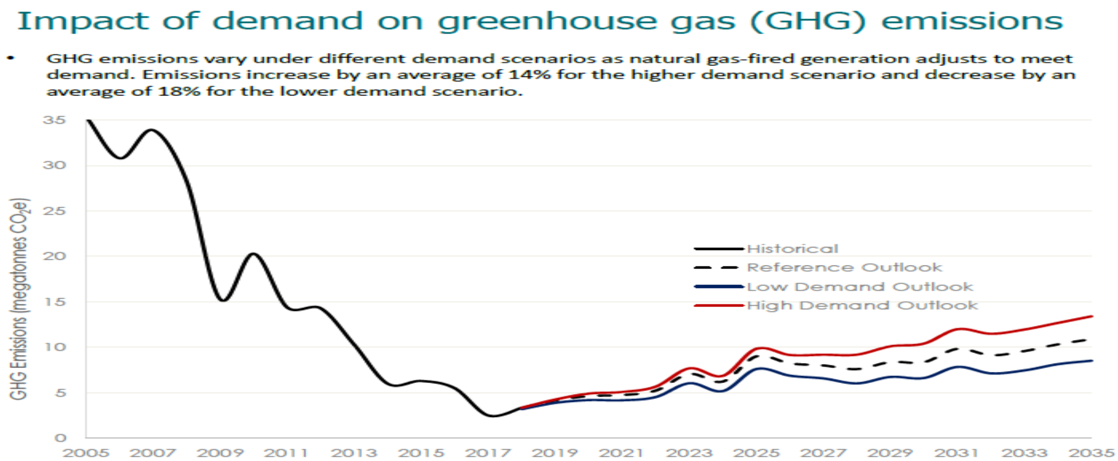
As nuclear refurbishment is completed between 2025 and 2033, other things equal, the increment to natural gas-fired generation might be expected to decline. Looking at the Energy Production chart above, in 2034, the first full year after refurbishment is complete, nuclear production is projected to be 75 TWh, an increase of 17 TWh from 2025. Despite that, natural-gas-fired generation is shown to be 28 TWh, which is 4 TWh *more* than in 2025, not back to the 2024 level of 17 TWh when nuclear production was last 75 TWh. Arithmetically, the 11 TWh increase in gas-fired generation between 2024 and 2034 in the IESO Reference Case is accounted for by a 4 TWh increase in Net Demand and an 8 TWh increase in *net* Exports combined with 1 TWh less SBG.

The IESO's forecast of Net Ontario Demand in 2035 in the Reference Case is only up 4 TWh from its value in 2016 of 143 TWh, a year with 13 TWh of net exports, and about 8 TWh SBG (ECO Straight Talk pg 105). With 15 TWh less nuclear baseload in 2035,[6] Ontario would be returning to a power market with some surplus baseload generation, the annual amount depending on weather conditions (such as heating and cooling degree days), water levels, wind speed and insolation, as has been experienced in the past few years, only somewhat less severe.

The expectations for gas-fired generation going forward may not yet be adjusted for the impact of the Day-Ahead market coming as part of the IESO's Market Renewal. It should result in better scheduling of Ontario's peaking hydro plants and the Beck PGS. By time-shifting their generation, these flexible hydro resources act as storage systems, and so would substitute for some of the CCGT gas-fired generation that is currently scheduled before hydro. In the GTA, this could be complemented by more distributed storage paired with embedded renewables.

2.2.3. The IESO's estimates of the GHG emissions for the Reference Outlook are shown in the plot below from their September 2018, Electricity Planning Outlook Update, pg. 79. The increase shown in Reference Case GHG emissions from 2022 (5 MT) to 2025 (9 MT) is about 4MT; by 2035, it is about 5 MT.

[6] The difference is not the full 20 TWh of Pickering most probably because the refurbished units produce a bit more energy each than they did previously.



3. Capacity Supply and Demand

The installed capacity of a power plant is its intended full-load sustained output measured in MW. For thermal generators, where the fuel or steam supply is controllable, its actual operational output may be quite close to its rated installed capacity. For renewables, where the 'fuel' is variable, effective or available capacity is defined to be the capacity that can be relied upon (with a specified confidence level) at the expected time of system peak. To the extent power demand may have distinct peaks at different times of the year, in Ontario it is useful to make a distinction between the summer and winter effective peaks. With rapid growth in the use of air conditioning, Ontario became a summer peaking system in the late 1990's, and that is assumed to continue in the Reference Case going forward. Depending on the extent to which the province pursues GHG emission reductions from building heating through electrification, Ontario could become winter peaking again.

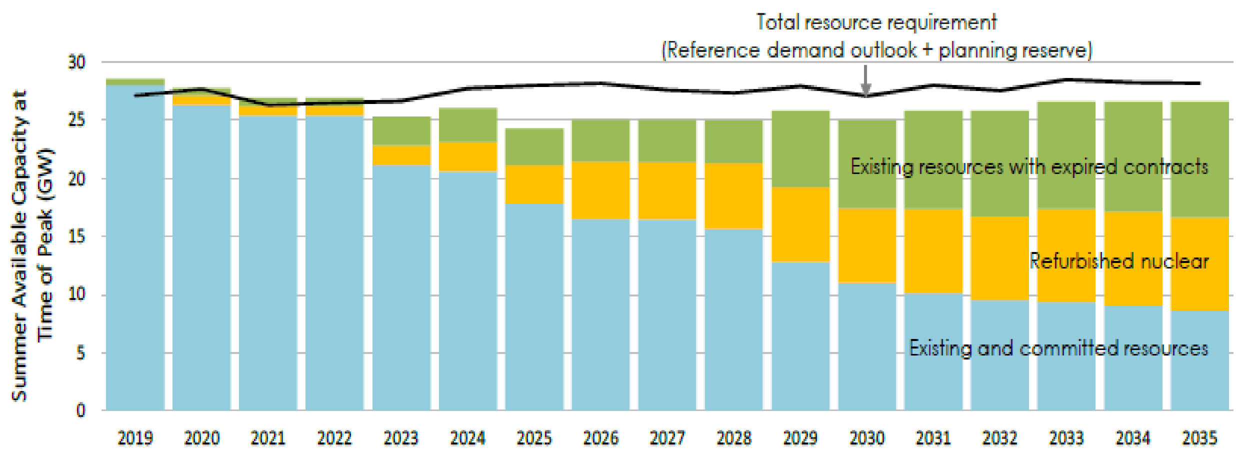
Current Planning Assumptions	Bioenergy	DR	Gas	Nuclear	Solar	Water	Wind
Summer Available Capacity, % of Installed	92%	90%	80%	93%	33%	68%	11%
Winter Available Capacity, % of Installed	92%	90%	86%	94%	5%	74%	27%

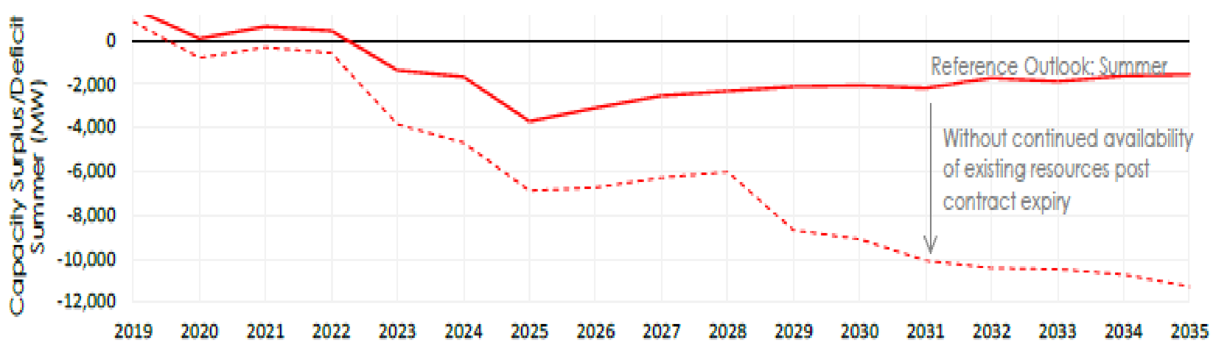
The plots below are for summer available capacity at the time of peak from the IESO's 2018 Planning Update (pages 50, 51) relative to the Reference Case Total Resource Requirement (TRR). TRR is the weather normal peak demand for the Reference Grid Demand Case plus a planning reserve. The reserve is intended to keep the system reliable, that is, to keep the likelihood of unsupplied energy due to insufficient generation at the NERC[7] standard of no more than one day in 10 years. It does this by increasing the required supply to take into account the uncertainty in the peak demand forecast, the performance of the generators, their 'fuel supply', and the duration of the refurbishment outages.

These plots show that with the refurbished nuclear units on schedule, and some form of re-contracting with existing resources (mainly gas-fired generators whose contracts are expiring in the planning period), a capacity gap emerges in 2023, the year after Pickering A shuts down. The capacity gap increases in 2025 – the largest for the planning period – after the final 2000 MW of

[7] North American Electricity Reliability Council

Pickering are taken out of service at the end of 2024. Part of the increase in TRR in 2024/5 reflects an additional reserve included as the contingency for the possibility that there is some delay in the completion of the three refurbishment outages scheduled to return to service in 2024.





The capacity gap is 3700 MW in 2025 after Pickering's 3000 MW is completely shutdown. It converges to about 2000MW within a couple of years and remains at that level for the rest of the period to 2035. The IESO's 2018 Update observes that the Demand Response auction could eliminate the gap until 2023. No particular generation plan is proposed to address the gap Post-Pickering. Going forward, the IESO has been relying on the Incremental Capacity Auction (ICA) to procure the least-cost mix of resources to reliably meet Grid Demand.[8]

In the current approach to the post-LTEP, post-Pickering world, the avenue to providing incentives for Distributed Energy Resources (DERs) lies with the Load Serving Entities and the Regional Integrated Resource Plans. As noted earlier, increased local supply will manifest itself in reduced Grid Demand for the IESO's ICA.

The IESO's Reliability Outlook for July 2019 to June 2024 (pg. 2) states:

[8] The ICA is only open to Market Participants with a minimum capacity of 1 MW (Pg 66, IESO Incremental Capacity Auction High-Level Design). Resources connected behind the meter will not be eligible to participate. Resources must be connected directly to the IESO grid, a distribution system, or connect to a load and participate as a Demand Response resource. In July 2019, the Ontario Government cancelled the ICA.

> In the coming years, Ontario's capacity requirements will be addressed through resources such as demand response, capacity-backed imports, generators that are coming off long-term contracts, uprates of existing facilities and energy efficiency. Addressing these capacity needs will provide generators with greater flexibility to schedule outages in the future during off-peak periods.

3.1. Resource Options – The Pieces of the Puzzle

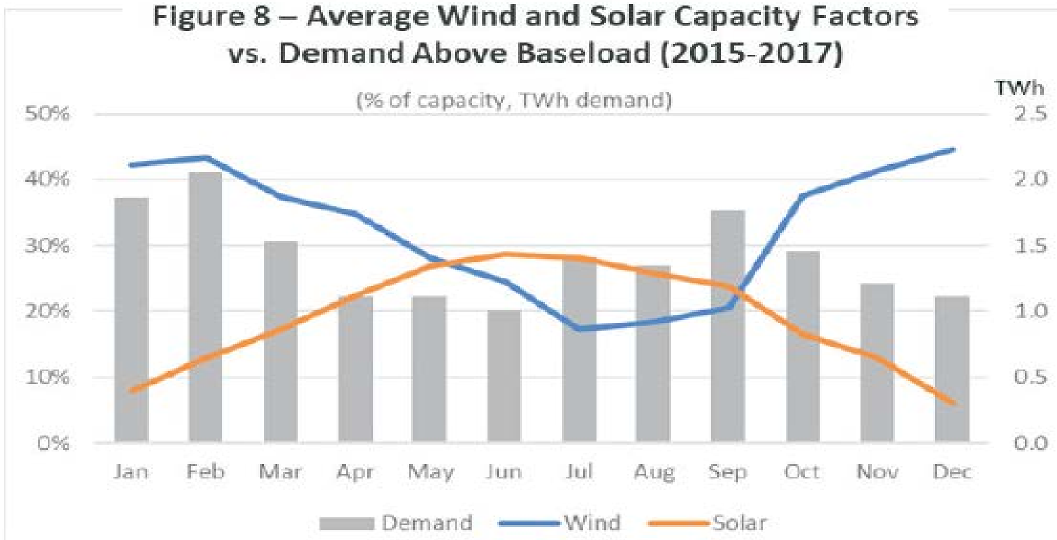
The table below summarizes some of the key performance characteristics of the major categories of resources available in Ontario for developing integrated generation plans (Pg 62, 2018 Planning Outlook). The variety of options and their range of capabilities makes planning a reliable system quite challenging.

Resource	Capacity	Energy	Operating Reserve	Load Following	Frequency Regulation	Capacity Factor	Winter Peak Contribution	Summer Peak Contribution
Conservation	Yes	Yes	No	No	No	Depends on Measure		
Demand Response	Yes	No	Yes	Yes	Limited	N/A	90%	90%
Solar PV	Limited	Yes	No	Limited	No	15%	5%	33%
Wind	Limited	Yes	No	Limited	No	30-40%	27%	11%
Bioenergy	Yes	Yes	Yes	Limited	No	40-80%	92%	92%
Storage	Yes	No	Yes	Yes	Yes	Depends on technology / application		
Waterpower	Yes	Yes	Yes	Yes	Yes	30-70%	74%	68%
Nuclear	Yes	Yes	No	Limited	No	70-95%	94%	93%
Natural Gas	Yes	Yes	Yes	Yes	Yes	up to 65%	86%	80%

These are the major categories of demand- and supply-side resources that were considered by system planners for building alternative resource plans for the 2017 LTEP. Only waterpower and nuclear are likely out of bounds for the GTA. Operating Reserve, Load Following and Frequency Regulation are important ancillary services when comparing alternatives, but they will not be explored here. Capacity Factor, and Winter and Summer Peak Contributions are important summary statistics. They provide an indication of the profile of the energy and capacity delivered, but more detailed monthly, or even hourly, generation profiles are needed to better understand how these options might be fitted together and could be blended with the assistance of storage technologies to meet the Ontario demand profile. The challenge is to put these pieces together in a way that reliably meets a range of objectives.

Solar power's fuel depends on latitude and cloud cover. Compared to jurisdictions closer to the equator, insolation in Ontario is relatively limited. The low number of daylight hours, especially in the winter, is mainly responsible for the low ACF of 15%[9] shown in the table. In the southern US, the ACF can be nearly twice that, and in those jurisdictions, they don't have a winter space-heating problem. Solar is positively correlated with temperature and is effective at serving the extra summer load due to air conditioning. In an average year, Ontario has about 6 heat waves lasting 3-4 days each. Solar is particularly valuable in displacing peaking gas-fired generation on those occasions. Solar is quite ineffective in winter to support heating load, lighting, or for directly charging EVs at night.

[9] Likely a blend of about 14% for rooftop solar with about 19% grid solar at the Ontario mix.



Source: IESO, Strapolec Analysis.

As illustrated in the plot above,[10] solar energy production in the winter months is about one-third of its production in the summer months. Its capacity contribution in winter is almost zero, because the winter system peak occurs after the sun sets. In the summer, solar's capacity contribution began around the 33% shown in the IESO table above (which first appeared in the OPO in 2016). However, as most solar in Ontario is embedded, and as its installed capacity has grown to nearly 3000 MW in Ontario, it has shaved grid peak demand in summer, moving the grid summer peak from July into September and the timing of the daily grid peak from the afternoon into the evening. It will not take much additional solar capacity on the Ontario system for the grid peak to occur after the sun sets in September. At that point, there will be no grid capacity value to additional solar – its economics will depend on the energy it displaces.

The 15% Annual Capacity Factor (ACF) for solar in Ontario means that 3000 MW of solar would generate about 4 TWh per year. The 3000 MW Pickering nuclear plant, with an ACF of about 75%, produces about 20 TWh a year. If solar alone were to replace the entire *energy* produced by Pickering, 15000MW, of solar would be required. As noted earlier, about half of Pickering's output actually will be replaced by gas-fired generation for Ontario use in 2025 and half of that would be GTA's share, so an additional 3750 MW of solar would provide the ***equivalent energy*** needed to replace the gas-fired generation, *if solar's profile matched the timing of the gas plant dispatch*. In practice, there will be a significant mismatch between the annual solar production profile and the required gas-fired profile. To have solar energy available whenever gas-fired generation may run would require a significant overbuild of solar ***capacity***.

Solar takes up a fair bit of space, about 25 km^2/TWh/year in southern Ontario. So, about 100km^2or about 1.5% of the GTA's area would be required for 3750MW (more in practice), though, of course, a portion of this would be on rooftops.

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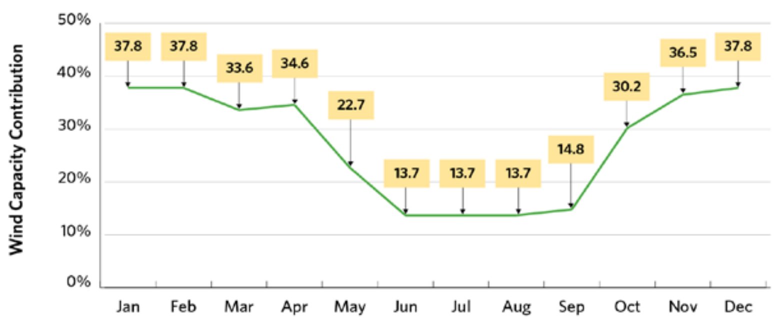
[10] "Renewables-based Distributed Energy Resources in Ontario: A Three-Part Series of Unfortunate Truths, Part 1: Intermittency Considerations", Marc Brouillette, pg 4, April 2019 CCRE Commentary

The **wind power** in Ontario is, for the most part, grid-connected. One consequence is that there is better performance data available from the IESO for the last decade of its operations in Ontario's conditions. The plot below is from the IESO's July 2019 18 Month Reliability Outlook (Pg 18). Wind *capacity contribution* in Ontario in winter is about 3 times what it contributes in summer. It is inversely correlated with temperature in our geography - quite low on the peak load days in a heat wave, relatively strong in the colder months. Based on the Strapolec plot above, wind *energy* production in the summer is about half of its contribution in the winter months. Relative to solar, wind is well matched to support electric space-heating load (air and ground source heat pumps, thermal storage and battery storage).



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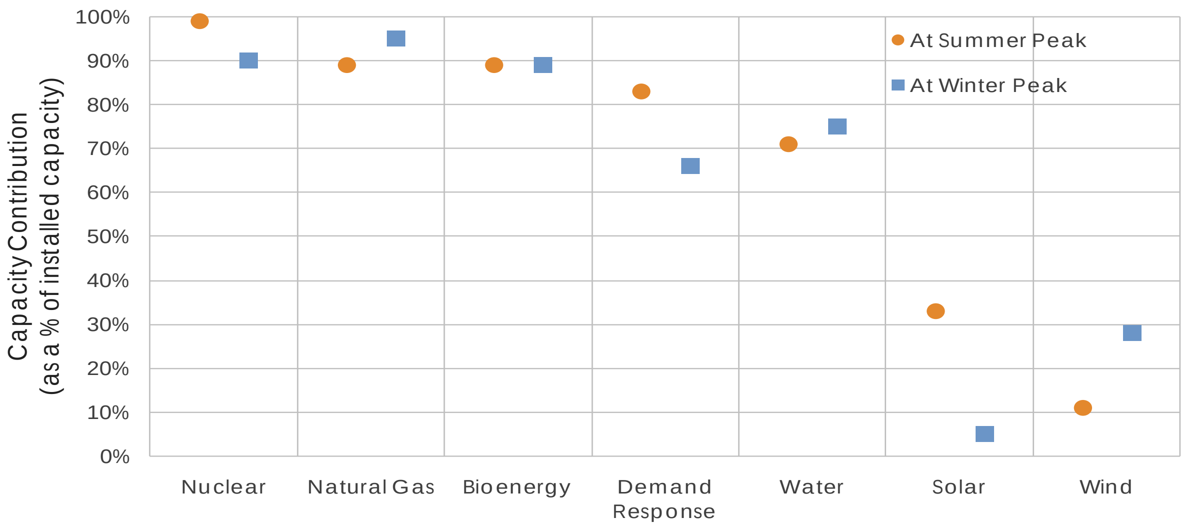
With an ACF of about 35%, wind does have a much higher ACF than solar. This translates to needing about 1700 MW of wind capacity to replace the GTA share of Pickering, if it were replaced only by wind, and, as with solar, *if its profile matched the timing of the gas plant dispatch*. In practice, much more wind capacity would be required to substitute for the role gas-fired generation plays.

Wind takes up about five times the land area that solar does, about 125 km^2/TWh/year. It would require more than 7.5% of the GTA's area if it were relied on completely.

Matching the profile of the gas-fired generation that replaces Pickering is not easy. Toronto has one of the wider ranges of temperature sensitive load anywhere. Very few power systems have to cope with *both* the extreme cold and the extreme heat experienced in Ontario. As wind and solar here are effectively complementary, in attempting to replace nuclear, the analysis is about finding the best combination of the two technologies that compensates for their low capacity contribution and low annual capacity factors. Storage systems (see below) can play a role in shifting solar or wind output in time to better track the demand minus baseload gap. Needless to say, jointly determining the appropriate scale of storage capacity required to shift mismatched output intra-day or inter-day to valuable hours is non-trivial in the projected Ontario context. The longer the energy is stored before being discharged, the higher the effective cost of storage, as this implies fewer charge/discharge cycles. Even more challenging, and essentially not viable in Ontario, is shifting power between seasons, from summer to winter, or vice versa.



Storage systems have the ability to time-shift energy, to smooth out a portion of the intermittence and timing problems of wind and solar. They can respond rapidly, performing like peaking generation and providing various ancillary services. Storage earns money by shifting energy from lower marginal cost (baseload resources) periods, to higher marginal cost periods (on-peak, gas-fired resources) periods, using the price differential between charging and discharging to pay for the physical equipment (battery, pumped storage hydro, compressed air energy storage) and to offset energy losses in the charge/discharge cycle. As a result, the economics of storage are sensitive to the number of times a year the equipment can capitalize on wide peak/off-peak price differentials. After the closure of Pickering at the end of 2024, and while 2 Bruce units are also offline for refurbishment from 2025 to 2033, there will be very few summer hours when baseload units will be at the margin at night. While intra- and inter-day shifting with local/distributed storage will be helpful to building owners, grid storage will not have an incentive to shift from off-peak to on-peak. (There will be somewhat more opportunity for that in the winter.) The economics of daily energy shifting for grid storage will be poor until the system rebalances, with baseload units at the margin off-peak and an alternative to gas required on-peak.

The challenge for distributed storage is dealing with the strong seasonal profiles that both solar and wind have in Ontario. Shifting solar from summer to winter, or wind from winter to summer, gives very little opportunity to recover the cost of storage equipment. Almost by definition, seasonal shifts only occur a few times a year. A major technology breakthrough will be required to make seasonal storage economic.

The successful examples of seasonal storage in operation today are massive hydro reservoirs such as in Quebec, which needless to say, are difficult to replicate. Importing from Quebec, essentially buying Quebec's stored energy and recharging it with surplus Ontario baseload has been on system planners', and politicians', minds for some time in Ontario. Conceptually, it would be excellent, but agreeing on a forward price has been difficult. The planners in HQ understand very well the value of their resource in a period with little baseload at the margin in Ontario, and have alternative options for their product.

Natural gas-fired generators are flexible. They can respond to dispatch instructions with varying degrees of efficiency to address mismatches between demand and baseload supply. CCGTs have a high minimum load and can take hours to ramp up. In current market conditions, this production profile results in higher gas-fired generation than needed. CTs have much lower minimums, respond more quickly and have rapid ramp rates. The Ontario system would benefit from a higher proportion of fast start CTs.

3.2. Putting the Puzzle Together

To meet demand every hour, power system operators take the nuclear, hydro, wind and solar baseload generation offered to the wholesale power market and dispatch flexible resources, including imports, to make up any gaps with Ontario market demand. Price is set by the marginal Ontario resource. In order to make sure their energy is dispatched, baseload resources offer at low prices reflective of their marginal costs. Gas-fired generators recover their fuel and other operating costs in their price offers, and so tend to be priced higher. The amount of energy from gas-fired generation or storage that might be dispatched in any hour depends on the size of the gap between demand and baseload.

Reference Case

Over the next 15 years, demand minus baseload will go through a long cycle starting from large numbers of hours per year with excess baseload, moving to relatively few hours per year after Pickering closes, and then back up closer to where we are today by the time nuclear refurbishment is complete. The largest driver of the pattern in demand minus baseload will be the amount of nuclear generation operating on the system. In turn, this will determine the extent to which gas is on the margin off-peak as well as on-peak, or whether baseload (effectively low marginal cost supply) is on the margin in both on-peak and off-peak hours. In either of these cases, there is no value to energy shifting. Storage thrives in well-balanced (optimized) systems where baseload is on the margin off-peak and gas would otherwise be on the margin on-peak. The resulting price signals and price expectations are what should drive the economics of demand management, storage systems, and investment in new storage capacity.

When gas-fired generation is on the margin, spot market power prices (HOEP) will reflect North American natural gas market price trends and the extent to which carbon prices ratchet up going forward. Given current low natural gas prices, it will fall on carbon pricing to induce the commercial take-up of clean generation options or conservation measures.

As noted earlier, 2017 was characterized by high exports and SBG combined with low prices (HOEP averaged $16/MWh). By 2035 in the IESO Reference Case, the province could be back in a milder version of the same state with a variety of small fixes to cope with the capacity gap as described in the latest Reliability Outlook quoted on pg. 12.

Addressing GHG Targets

For the most part, this note has centred around the IESO's 2018 Planning Outlook Reference Case. For a robust plan, it is pertinent to consider alternative scenarios. What if the provincial objective changed (back?) to meeting its share of the 2030 and 2050 international GHG emission reduction targets? The new Reference demand case in that world might look something like Outlook D from the 2016 OPO reprinted in Section 2.3.4: electrical energy demand about 50 TWh or 35% higher in 2035 than in 2015. In Outlook D, the power system peaks in the winter about 13 GW above the current summer peak (22 GW). The extent of the demand change would become evident by the late 2020's. The province would need to add significant capacity that was effective in the winter. As it would take a decade or more to bring on major new nuclear or hydro capacity, the focus in the interim would likely be on smaller-scale demand and supply options or imports.

Against a more aggressive GHG scenario, the impact of the closure of Pickering would require a higher proportion of gas-fired generation replacement than in the BAU/Reference Case focussed on here. The analysis would increasingly need to compare the cost of carbon abatement opportunities for the power system, with those in the transportation, building and industrial sectors.

4. Summary: Implications for the GTA of Pickering NGS Closure

In the IESO's 2018 Planning Outlook Reference Case, taken to be Business-as-Usual for this note, a reasonable estimate of the incremental gas-fired generation induced by the closure of Pickering in 2024 is 10 TWh per year, creating an extra 4.5 MT of GHG emissions. The demand outlook in the BAU case is almost flat to 2035. Scenarios that pursue GHG emission targets for 2030 and beyond typically have a significant component of electrification, hence stronger electricity demand, and would yield a higher gas-fired generation impact from Pickering closure.

The GTA's share of the provincial gas-fired generation impact of Pickering closure is about 50%, roughly 2.25 MT. This is derived from an estimate of the GTA's share of provincial energy demand recognizing that the GTA has a peakier demand profile than the rest of the province. With the in-service of Clarington Transformer Station in 2018, the major transmission issues related to Pickering closure were addressed. Toronto will depend more heavily on power flowing east to Toronto from the Bruce Nuclear station, the Beck complex at Niagara and the gas-fired generation in the southwest, but this should be manageable.

Section 1.2.7 outlined 3 generic strategies for offsetting the increase in GHG emissions attributable to the GTA from the shutdown of Pickering. Options A and B focus on power system measures, on the supply and demand side respectively, which offset the incremental gas-fired generation that otherwise would have been induced in a Business-as-Usual/Reference Case world. Option C considers Pickering closure in the context of attempting to meet longer-term international GHG emission targets. Achieving the required GHG reductions in the GTA could take place in whatever end-use or sector it is least cost to do so, even if bulk power system gas-fired generation was not reduced in the process. Option C is included for completeness. The focus of this project is to find solutions that offset the incremental bulk system gas-fired generation emissions induced by Pickering closure. Focussing on Options A and B avoids a major issue often found in deep decarbonization studies: that eliminating fossil fuels tends to lead to significant electrification, and in turn, the need for substantial amounts of additional non-emitting power generation.

Option A

This note has attempted to summarize the context in which supply options that could be put in place inside the GTA would operate in the post-Pickering period. The incremental bulk power system gas-fired generation profile to be replaced is not a simple one, but rather the volatile residual of the hourly gaps between grid demand and the change in baseload generation. The total amount of gas-fired generation to be replaced by the GTA was estimated to be about one quarter of Pickering's annual output, 5 TWh. It would take 3750 MW of solar or 1700 MW of wind to generate that much energy without GHG emissions. However, as the supply profiles of wind and solar generators are driven by the variable timing and seasonal patterns of their inputs, it would in practice take much more than these capacity estimates to be confident of eliminating the gas share attributable to the GTA. Detailed market simulations could help to estimate the optimal mix of wind and solar for replacing gas, and also to determine the role that storage systems, either in homes and buildings, or on the grid, could play in time-shifting the renewable production to better match the gas-fired generation profile.

The Project is seeking input from developers on the role for solar, wind and storage were the GTA to attempt to displace its share of the incremental gas-fired generation attributable to Pickering closure. Are there other supply technologies which the GTA needs to explore in this context? What are the incremental costs of GHG emission reduction that can be anticipated in replacing the gas-fired generation that would otherwise fill the gap between demand and baseload supply?

Option B

Conservation programs addressing the major residential and commercial sector end-uses of electricity have been in place for over a decade in the GTA. They have focussed on peak-hour loads like commercial sector lighting, and air-conditioning in both the residential and commercial sectors. What are the most viable remaining measures that could target grid gas-fired generation, and what would be their associated incremental costs of reducing GHG emissions?

Option C

Focussing only on increasing clean electricity supply, or reducing current electricity demand at times when bulk power system gas-fired generation may be running, could exclude a large number of options that may offer a more cost-effective way to achieve equivalent GHG emissions in the GTA. This option looks beyond the electric sector for GHG emission reductions to offset the increased emissions from gas-fired generation after Pickering closes. The GTA could explore a path that many deep decarbonization studies have taken - develop a 'marginal cost of carbon abatement' curve for the region, a plot of measures that could reduce GHG emissions in the GTA ranked in order of increasing life cycle cost of GHG emission reduction. It would then set about finding the least cost 2.25 MT of GHG reductions. What does the remaining carbon abatement curve look like for the GTA? The major category of options that would be added to the mix is the largest GHG emitting sector in Ontario, transportation.