# Assessment of Hydro Quebec's Updated Electricity Import Proposal and Exploration of Options for Enhancing its Value to Ontario Ratepayers

Prepared for Discussion with Ministry of Energy

July 20, 2017

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Independent Electricity System Operator

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- This report is organized according to the following sections:

# Executive summary

## Hydro Quebec provided a new electricity sales proposal to the IESO on June 22, 2017. The following slides assess the new proposal and explore options for extracting greater value from an agreement with Quebec.

- Ontario regularly trades electricity with Quebec on the open market on a non-firm basis and has entered into electricity trade agreements with Quebec in recent years

- Hydro Quebec submitted an updated electricity import proposal to the IESO on June 22, 2017
  - The new "Amended and Restated Energy Sales and Energy Cycling Agreement" would replace the 2016 Ontario-HQ agreement and would see Ontario import, on a take-or-pay basis, 8 TWh of electricity per year for 20 years beginning in 2018 at the same price but with less flexibility as compared to 2.3 TWh in the current agreement for 7 years beginning in 2017.

- Upon Ministry of Energy request, the IESO has assessed the value of Hydro Quebec's updated proposal

- The IESO's assessment focuses on the value to Ontario electricity consumers. Imports from Quebec are evaluated from a number of perspectives including:
  - Impact on electricity supply mix, energy production, surplus energy, emissions, and cost of electricity
  - The conditions under which a trade with Quebec could yield net benefits for Ontario electricity consumers

- The following report summarizes the IESO's assessment of the updated Hydro Quebec proposal and explores additional opportunities to enhance its value
  - Analysis of options for enhancing the value of the updated proposal are consistent with scenarios developed by the Ministry of Energy for IESO analysis. These are described in the Ministry of Energy document entitled "ON-QC Discussions – Status Update" (July, 2017), as well as later in this report

# Summary of findings: on the updated Hydro Quebec proposal as submitted to the IESO

- In the context of the reference long-term supply and demand outlook, the updated proposal in its current form would:
  - Reduce Ontario electricity sector greenhouse gas emissions by an average of approximately 1MT per year, with an implied average abatement cost of $300/tonne over the planning period. Most of the emission reductions would take place from the mid-2020's or after the expiry of the existing agreement in 2023.
  - Increase surplus energy in Ontario by between 1 TWh and 6 TWh per year. Surpluses would be greatest before the mid 2020's and decrease to between 1 and 2 TWh per year thereafter. Higher surpluses result in higher costs.
  - Increase Ontario's total cost of electricity service by an average of $200M annually (2017$)
  - Increase average residential bills by an average $2.4/month (nominal, pre-OFHP)
  - Not help to meet Ontario's projected capacity requirements, as firm capacity is not offered and that capacity would have to be sought elsewhere
  - Provide break-even value to Ontario ratepayers if priced between $22/MWh and $36/MWh, which is less than HQ's proposed price of $61/MWh (2017$)

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# Summary of findings: on opportunities to enhance the value of the updated Hydro Quebec proposal to Ontario

- The value of Hydro Quebec's updated proposal might be enhanced by better aligning it with Ontario's electricity needs, including in terms of firm capacity, volume of energy, timing of delivery, length of term, and price. In general:
  - Imports with capacity or capacity-and-energy are more valuable to Ontario than imports with energy alone
  - Imports which provide flexibility to target the product towards periods of higher value within a given year are more attractive than imports that are take-or-pay and/or have fixed delivery periods
  - Incremental imports starting in the mid-2020's or later can provide potential value, as opposed to starting in 2018
  - The use of firm imports to meet requirements can provide higher value in lieu of new investments (not yet made) rather than to displace already existing resources in the province, whose costs are materially sunk and/or depreciated
  - Firm imports can provide value as alternatives to nuclear refurbishment if they have the same capacity, energy and reliability as the nuclear unit(s) in question, if they have the same start timing and length of term as the refurbished unit(s), and if they are lower in cost
  - In light of the above and consistent with needs identified in the current supply and demand outlook, a Hydro Quebec product with each of the following attributes could provide value to Ontario ratepayers:
    - 1,000 MW firm capacity
    - Up to 4 TWh of annual energy
    - Delivery starting in the mid 2020's
    - A price of about $60/MWh (2017$)

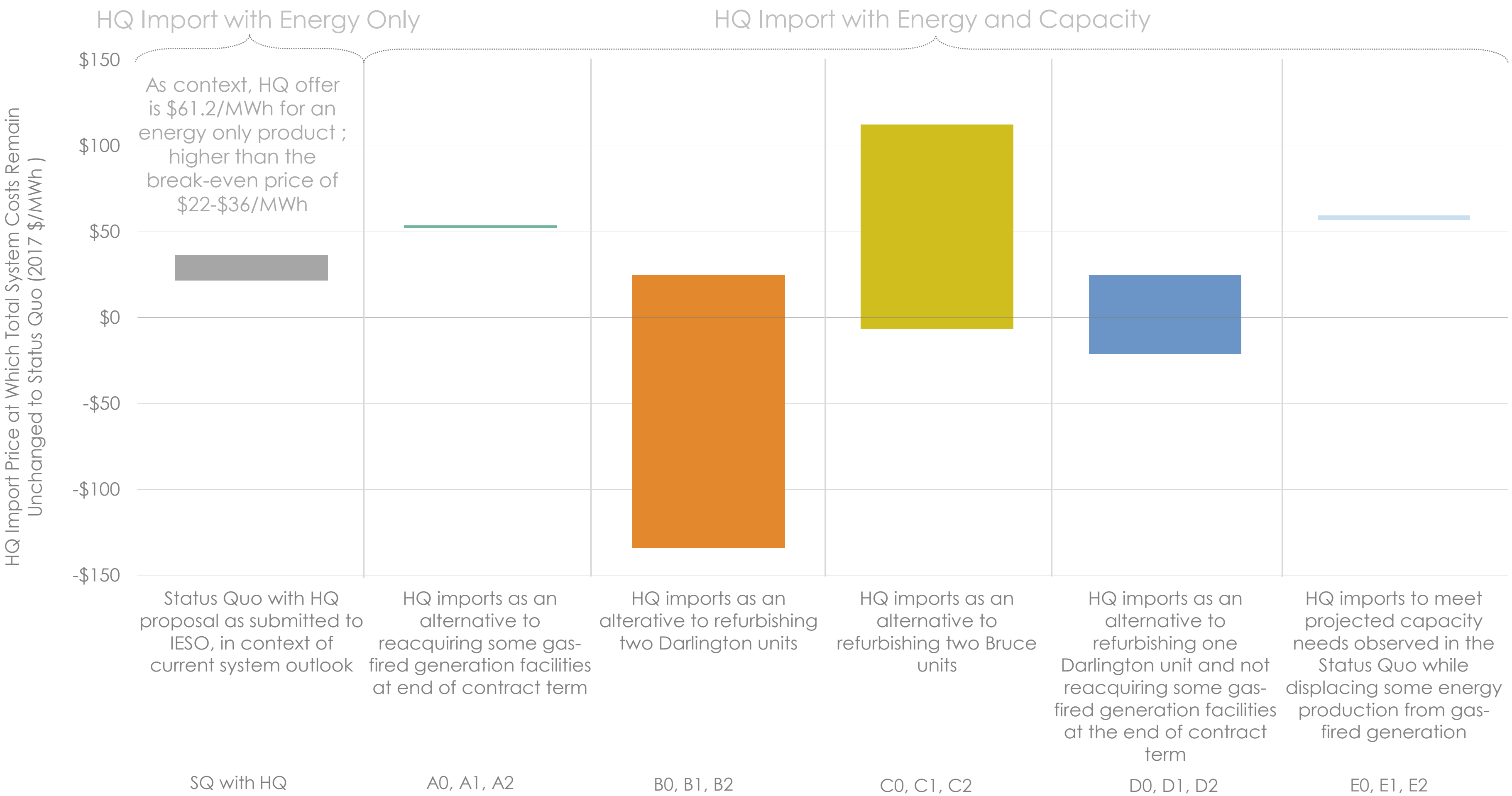
## The IESO considered a range of scenarios, sub-scenarios and sensitivities in its analysis of Hydro Quebec import options. These are summarized in the tables below and are described in greater detail later in this report. 28 combinations were analyzed in total, including the reference/Status Quo outlook, the updated Hydro Quebec proposal and various options for enhancing its value.

| Scenario | Role of Hydro Quebec Import |
|---|---|
| A | Alternative to reacquiring some gas-fired generation facilities at the end of contract term |
| B | Alternative to refurbishing two Darlington units |
| C | Alternative to refurbishing two Bruce units |
| D | Alternative to refurbishing one Darlington unit and not reacquiring some gas-fired facilities at the end of contract term |
| E | Helps meeting projected capacity shortfalls in the status quo outlook while displacing some production from gas-fired resources |

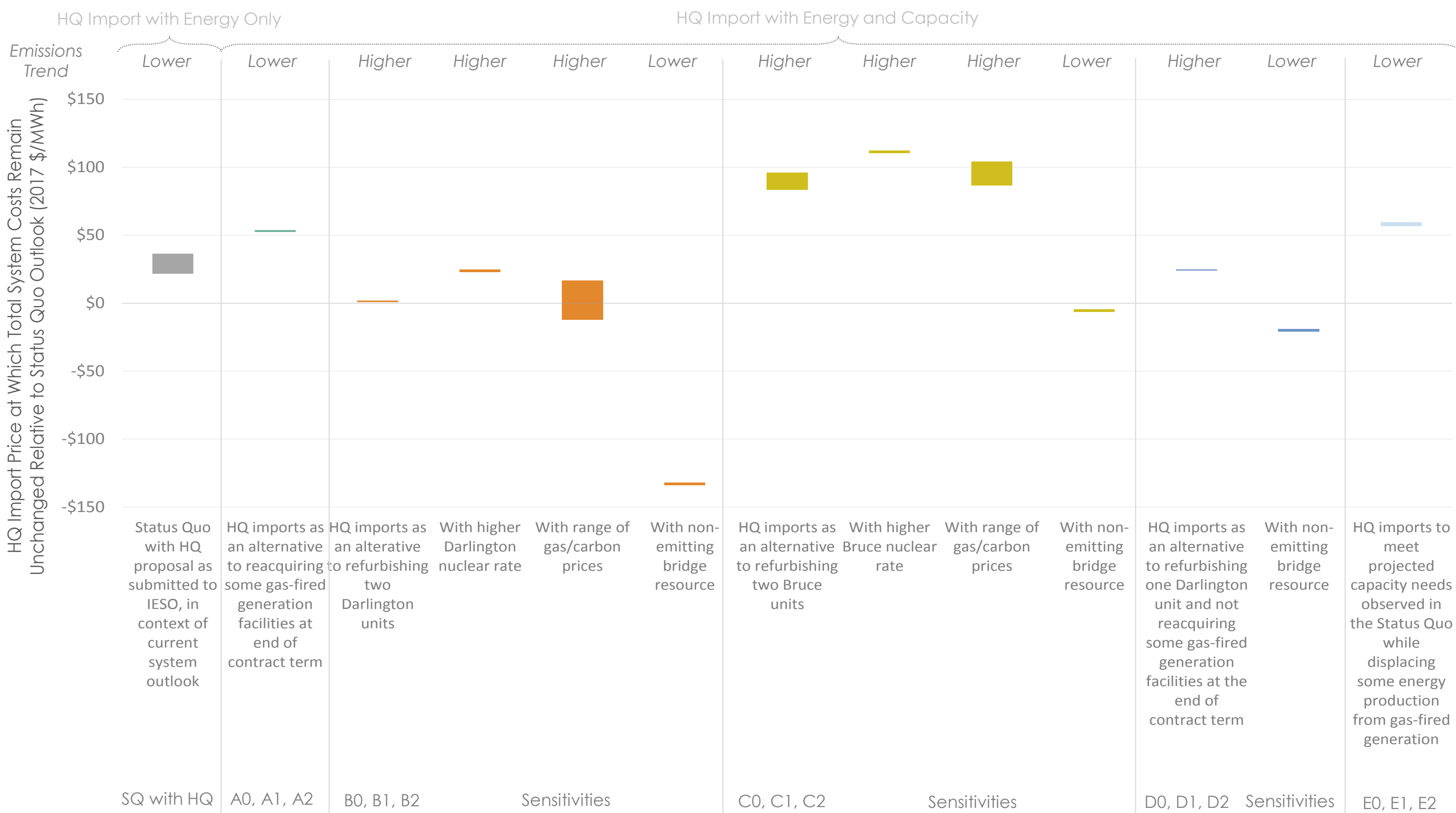
| Sub-Scenarios | Size, Delivery Timing and duration of Hydro Quebec Import |
|---|---|
| 0 | 8 TWh energy and 1 GW firm capacity, for 20 years, beginning in 2023 |
| 1 | 8 TWh energy and 1 GW firm capacity, for 20 years, delivery aligned with the timing of when gas-fired generation facilities are no longer reacquired at contract expiry or when foregone nuclear refurbishments are retired |
| 2 | Up to 8 TWh energy and up to 1 GW firm capacity, for 20 years, delivery aligned with resource needs (a variation of Sub-Scenario #1) |

| Sensitivity | Description of Sensitivity |
|---|---|
| Gas/Carbon Price | Lower and higher natural gas and carbon prices |
| Nuclear Costs | Higher nuclear costs at Darlington and Bruce |
| Bridging Resources | Where resources are required to bridge the difference between Ontario resources removed and Quebec imports added in, two types of book ends are examined – in one case, the bridge is natural gas-fired generation; in the other case, a combination of wind and storage resources as a proxy for a non-carbon emitting resource |

The "break-even" represents the price of a Hydro Quebec import product at which the total cost of electricity service in Ontario would remain unchanged relative to the Status Quo outlook, after considering applicable costs and/or cost savings and key sensitivities. A lower break-even price indicates lower value to Ontario, a higher break-even indicates higher value. The figure below summarizes indicative break-even prices across the range of scenarios and sensitivities considered.



# The ranges illustrated on the previous slide are disaggregated in the figure below to show the effects of key sensitivities, including around timing of delivery, natural gas and carbon prices, nuclear rates and cost of resources to bridge any difference between Ontario resources removed and Quebec imports added in



## The estimated ranges of break-even prices are also summarized in the table below, along with corresponding changes in cumulative carbon emissions compared to the reference Status Quo outlook

| | Scenario | HQ Import Price at Which Total System Costs Remain Unchanged (Break-even) Relative to Status Quo Outlook ($2017/MWh)** | Cumulative Change in Emissions over Break-even Period Relative to Status Quo Outlook (MT $CO_2$)*** |
|---|---|---|---|
| HQ Import with Energy Only | Status Quo with HQ proposal as submitted to IESO, in context of current system outlook | $22 to $36 | -29 to -19 |
| HQ Import with Energy and Capacity | A. HQ imports as an alternative to reacquiring some gas-fired generation facilities at end of contract term | $52 to $54 | -34 to -33 |
| | B. HQ imports as an alterative to refurbishing two Darlington units | With gas resource as bridge: -$12 to $25<br>With non-emitting resource as bridge: -$134 | With gas resource as bridge: +49 to +56<br>With non-emitting resource as bridge: -11 |
| | C. HQ imports as an alternative to refurbishing two Bruce units* | With gas resource as bridge: $83 to $112<br>With non-emitting resource as bridge: -$6 | With gas resource as bridge: +49 to +55<br>With non-emitting resource as bridge: -13 |
| | D. HQ imports as an alternative to refurbishing one Darlington unit and not reacquiring some gas-fired generation facilities at the end of contract term | With gas resource as bridge: $24 to $25<br>With non-emitting resource as bridge: -$21 | With gas resource as bridge: +29 to +31<br>With non-emitting resource as bridge: -7 |
| | E. HQ imports to meet projected capacity needs observed in the Status Quo while displacing some energy production from gas-fired generation | $57 to $60 | -25 to -27 |

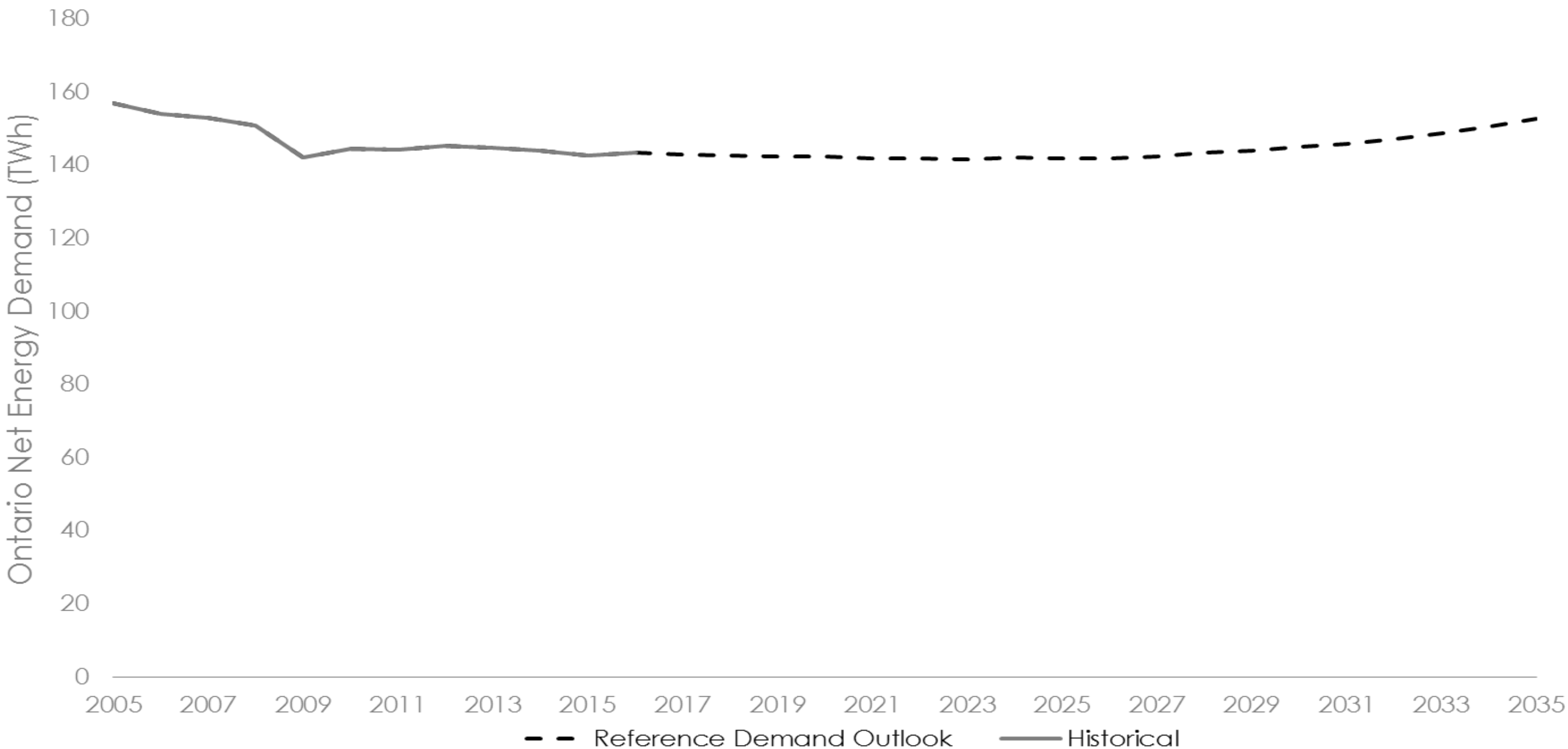
* Off-ramp of last two Bruce units cannot be exercised until 2027 and so an agreement cannot be made today.

** Bridge resources are included when the amount of supply removed is greater than the amount of import added in. Two cases are examined: one where gas is the bridge resource and another where a non-emitting resource (wind/storage) is the bridge.

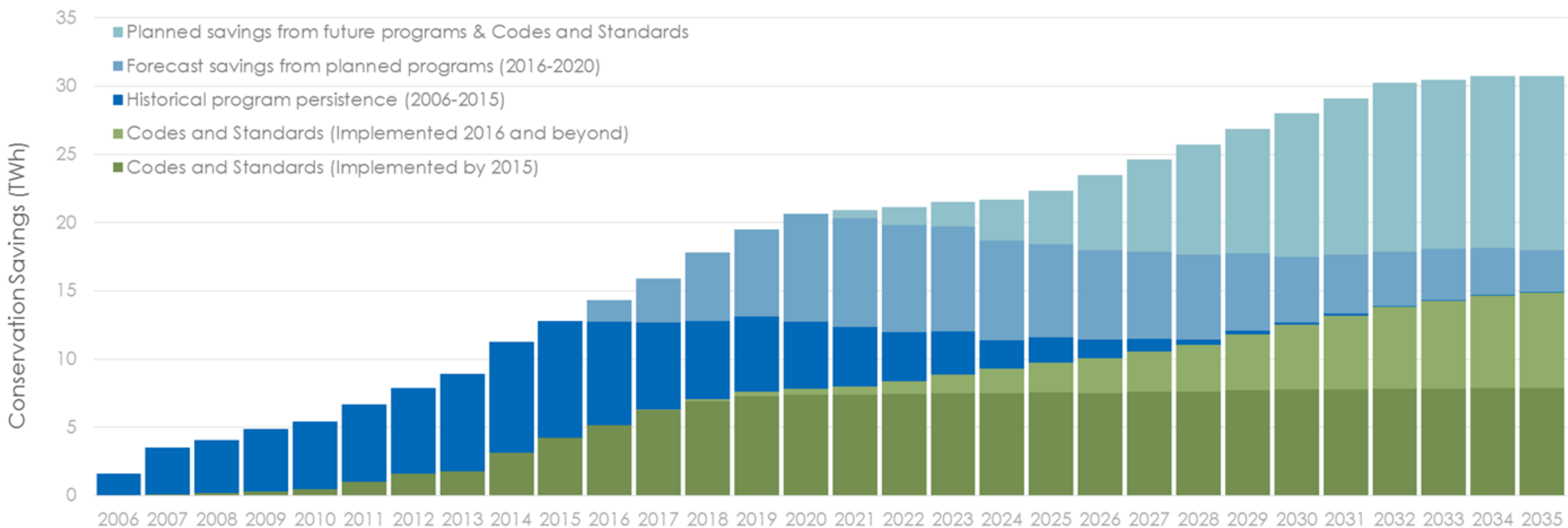
*** Positive (+) values denote increase in emissions, negative (-) values denote decrease in emissions.

1. Overview of the current electricity system outlook as context for assessing electricity import options from Quebec

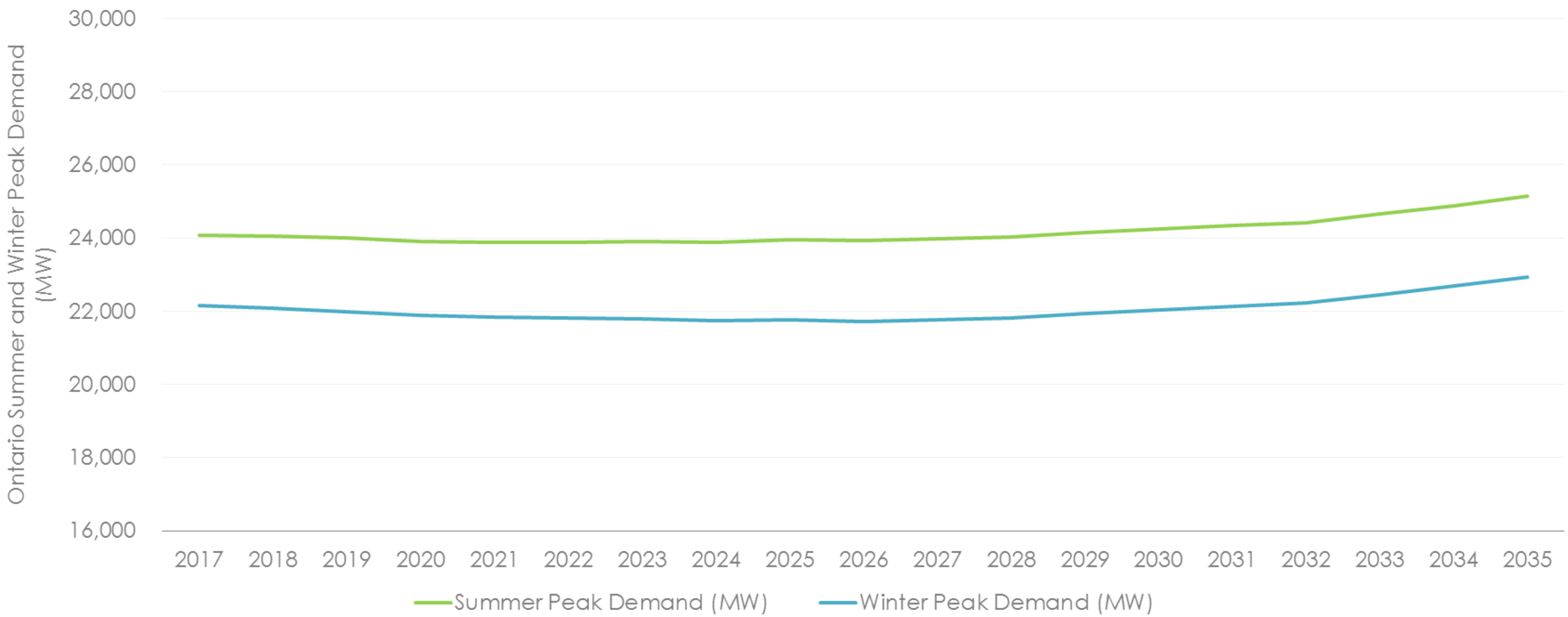
Ontario's demand for electricity is now about ten percent lower than it was a decade ago. Key drivers of demand reductions over the past decade include economic restructuring, conservation and price effects. Demand under the reference or "Status Quo" outlook is expected to remain relatively flat over the next decade, but is expected to grow somewhat by 2035 due to rising adoption of electric technologies such as electric vehicles in the province.



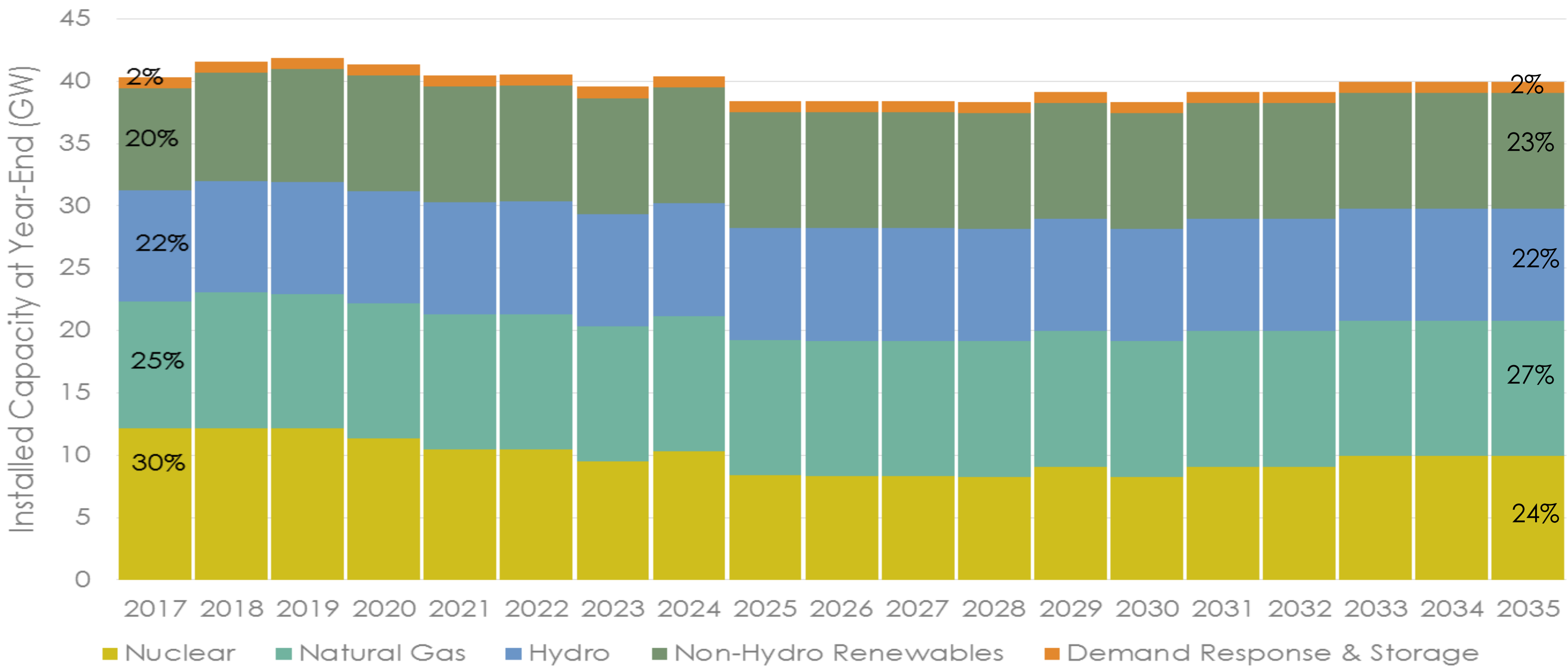
## The electricity demand outlook reflects the achievement of the conservation savings targets outlined in the 2013 Long Term Energy Plan: 30 TWh of energy efficiency savings by 2032. These savings are expected to effectively offset all economy-driven growth in demand.



The demand outlook continues to anticipate that Ontario's summer peak demands will be greater than peak demands in the winter. The capability of Ontario's electricity resource and delivery system is generally more constrained in summer months than in winter months.

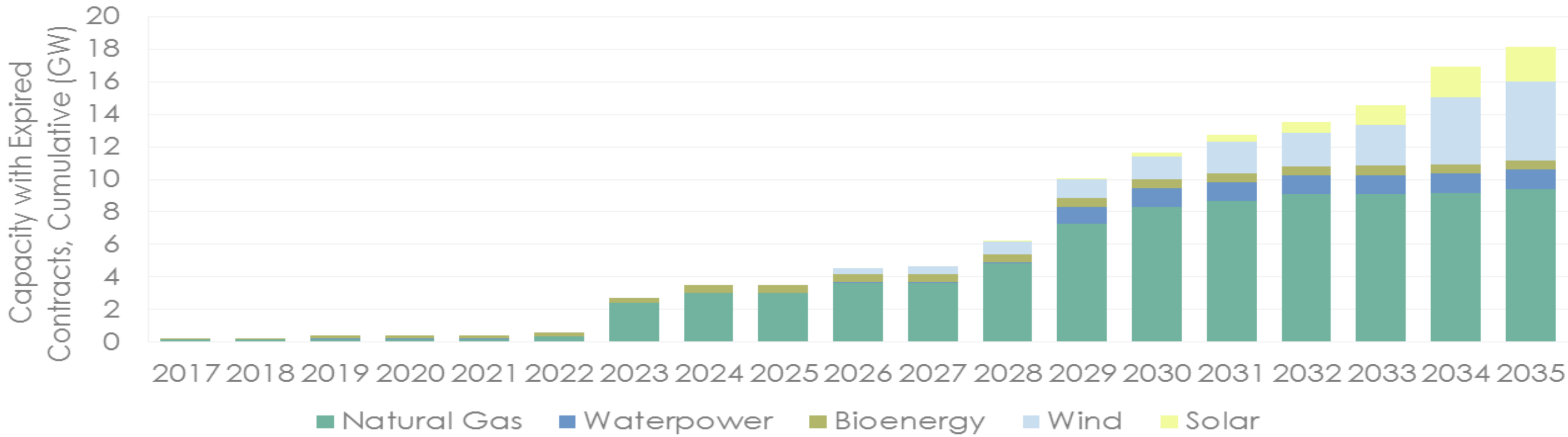


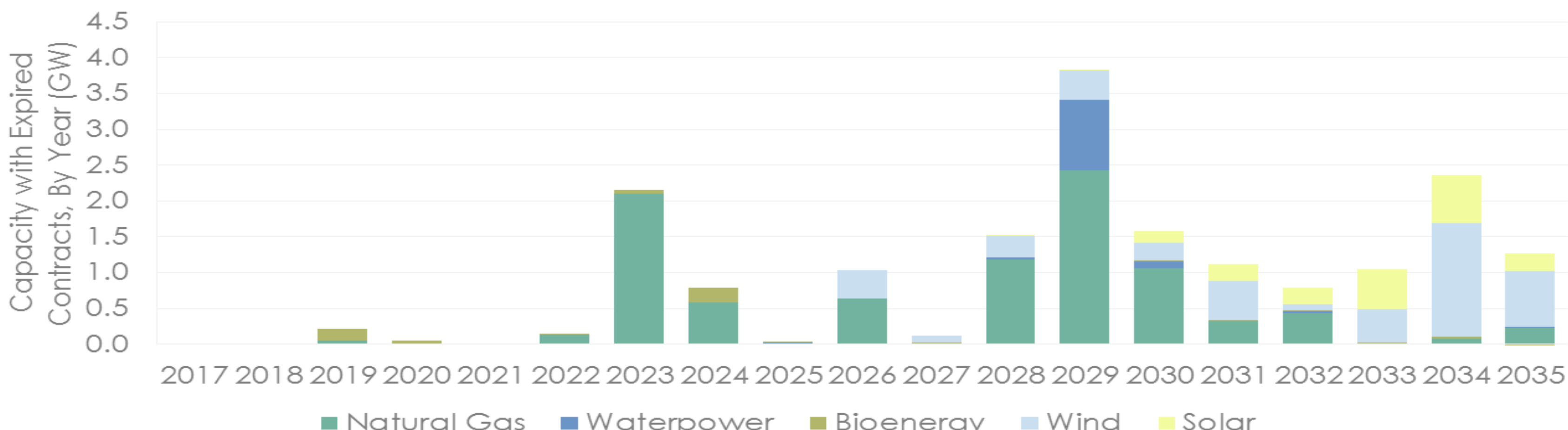
## Taken together, existing resources combined with resources anticipated over the foreseeable future would maintain a total long-term installed capacity of about 40 GW in Ontario. In general, the share of nuclear would decline following Pickering retirement, while the share of renewables would increase. Natural gas-fired generation would continue to play a vital role in supporting the operability of Ontario's power system.




May not sum to 100% due to rounding.

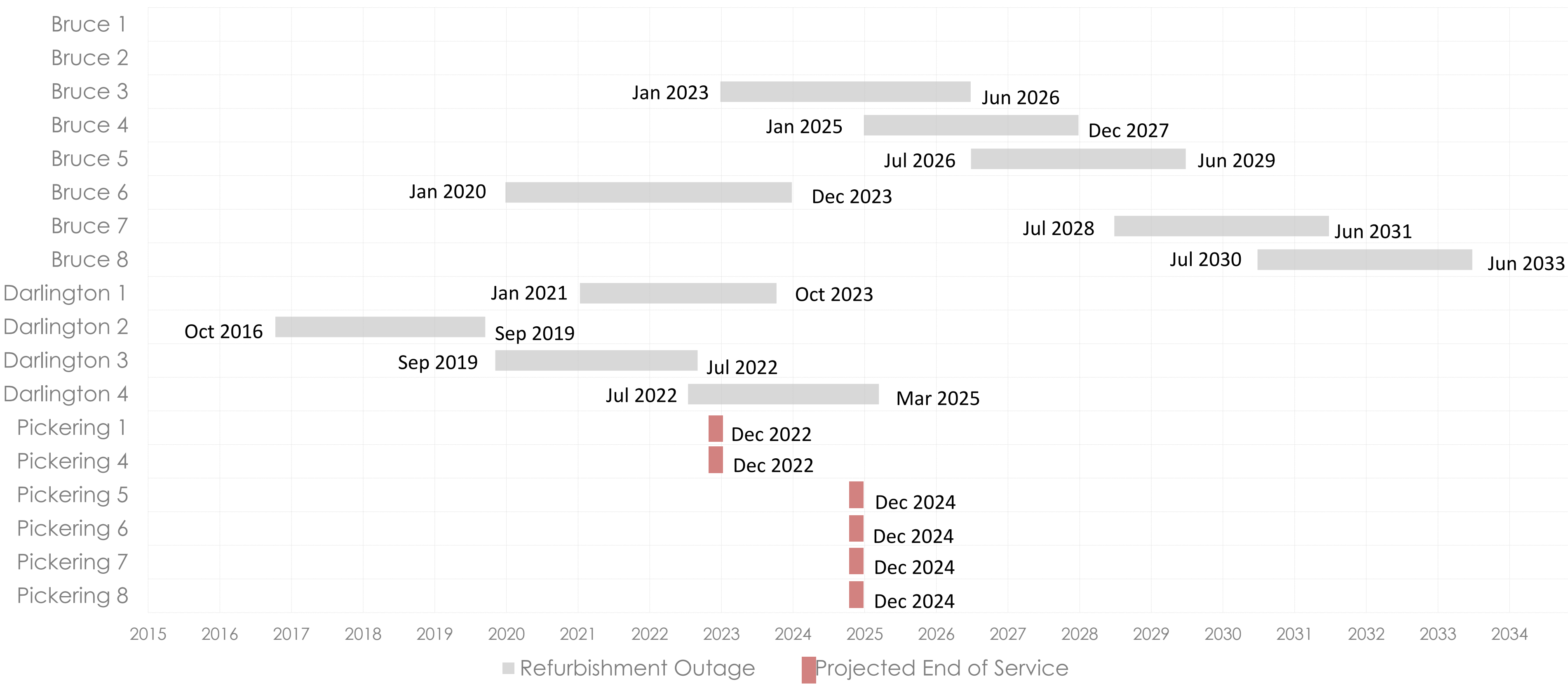
While the outlook for total installed capacity appears to remain relatively stable over the planning outlook, the potential for sizeable resource turnover is anticipated beneath the surface. For example, approximately 18 GW of existing supply resources will reach the end of their contractual term by 2035. These resources provide opportunities for adaptation should, for example, demand trend lower or better opportunities arise.



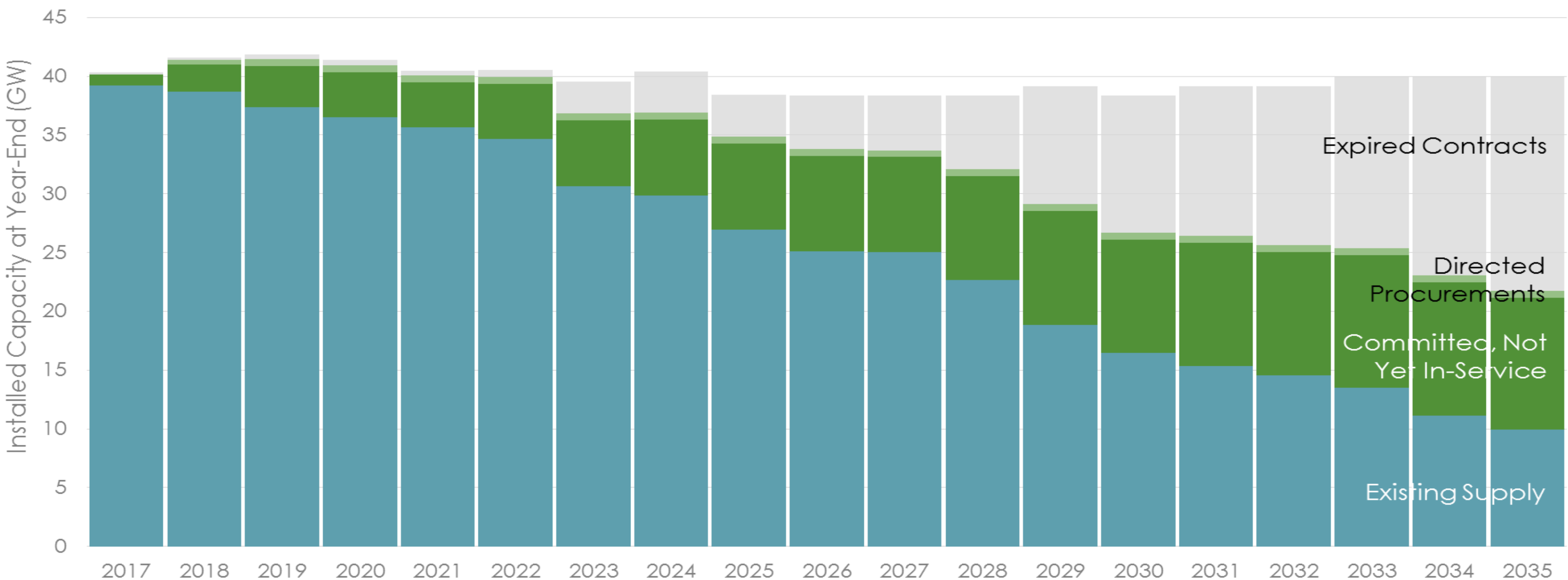

Capacity shown is at year-end.

Nuclear refurbishments and retirements will also contribute to significant turnover in the Ontario electricity supply system over coming years. The figure below outlines refurbishment outage timing and duration at Darlington and Bruce, and identifies planned retirement dates for units at Pickering. Current plans would see the refurbishment of up to 8.5 GW at Darlington and Bruce and the retirement of 3 GW at Pickering.



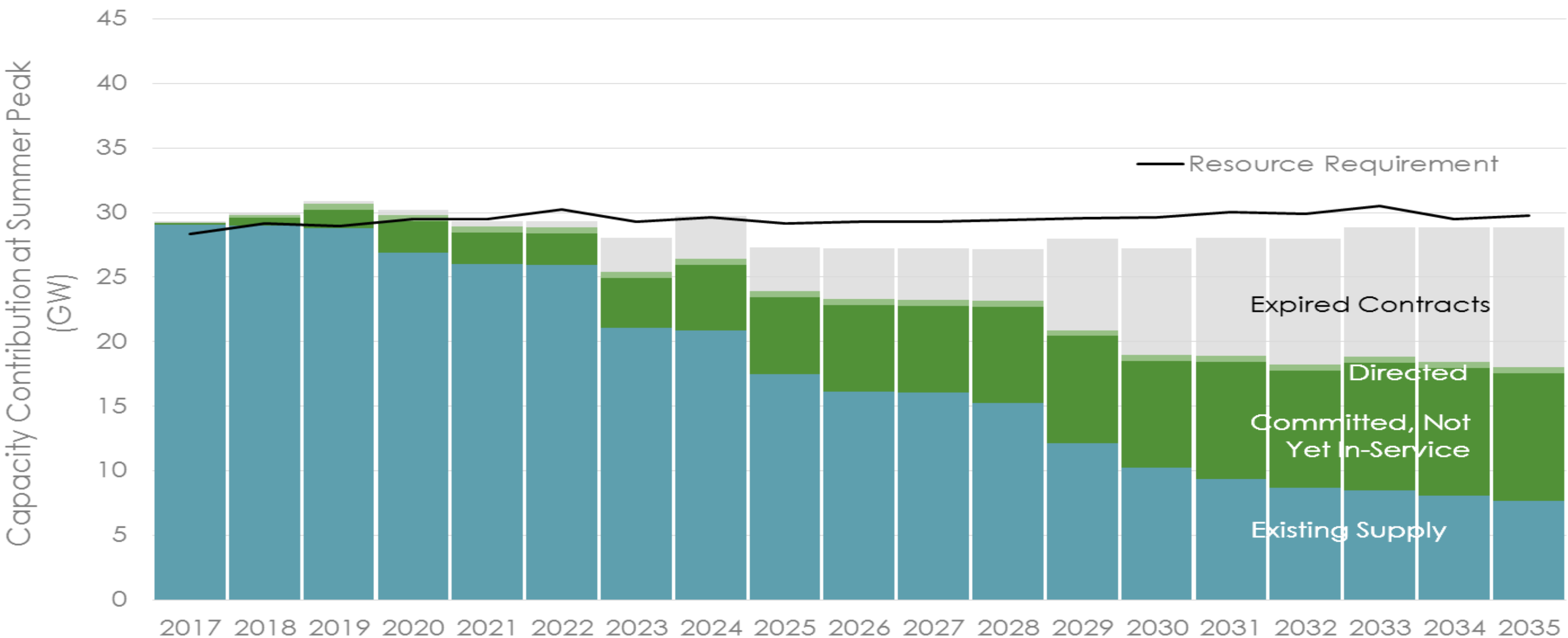

Bruce refurbishment per 2016 OPO. Darlington refurbishment per OPG June 19, 2017 data.
Pickering retirement dates per 2016 OPO.

As described in the previous slides, resources which exist today will decline over time as nuclear units at Pickering are retired and nuclear units at Darlington and Bruce are temporarily removed from service for refurbishment. Further reductions might occur as existing resource contracts reach term. In addition to existing resources, there are others on the way: these have been committed to under various procurement processes and are now at differing stages of implementation. The figure below shows the potential contribution of existing resources, committed resources and nuclear refurbishments, and expired contracts towards Ontario's long-term installed total.

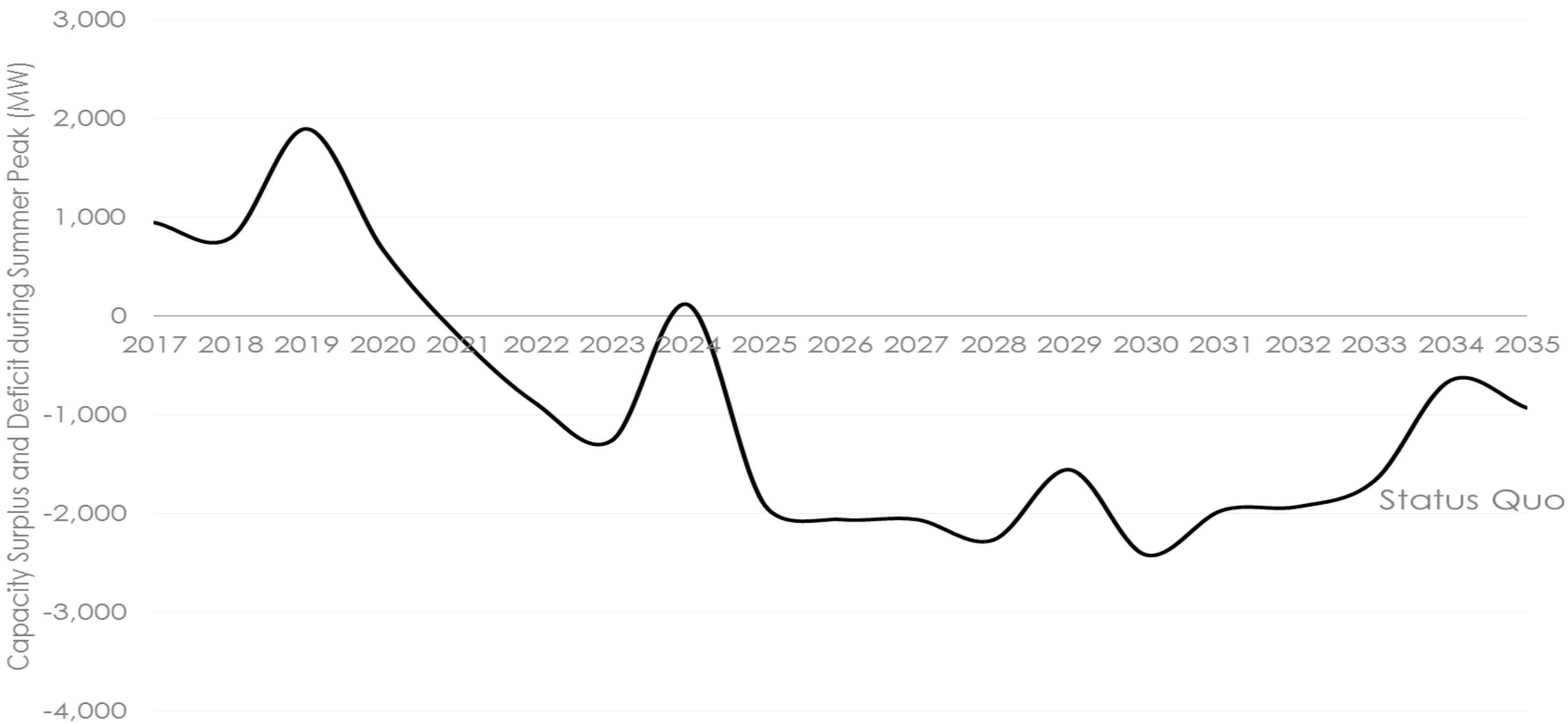



Status Quo includes 500 MW firm capacity in the summer from the original capacity swap with HQ, assumed to enter service in 2023, updated Darlington refurbishment schedule, and reserve margin requirements

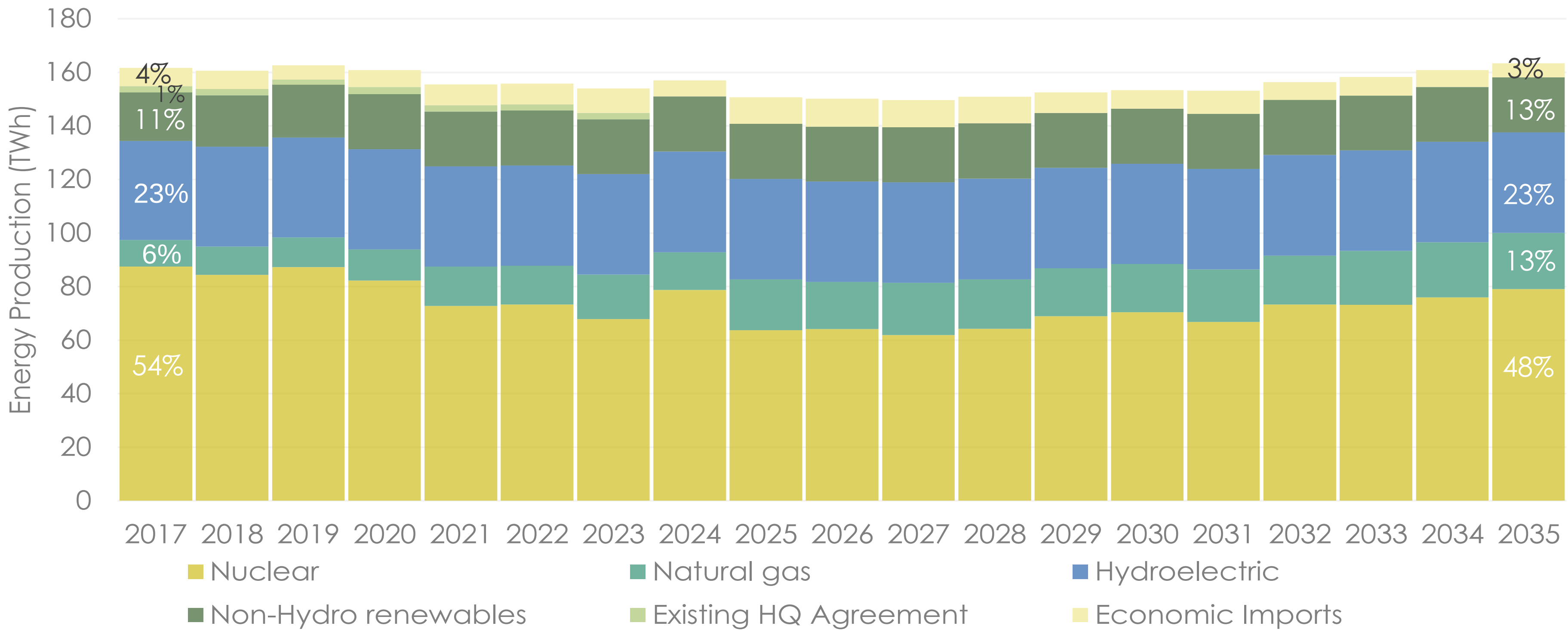
Projected resource capacity contributions at the time of Ontario's summer peak demand are compared to Ontario's projected resource adequacy requirement in the figure below. Ontario will remain adequately supplied for the next several years if all resources which exist today continued to remain available and if all committed resources currently in the pipe are implemented. Ontario will require additional resources starting in the early-to-mid 2020s.



Assuming existing resources continue to operate and those resources whose contracts expire continue to remain in the market post contract expiration, Ontario would see surplus capacity for the next few years before requiring between approximately 1 GW - 2 GW of additional electricity resources starting in about 2022/2023. While the precise amount is a moving target, the need for additional resources is expected to be sustained throughout the 2020s and to be well correlated with periods of nuclear unavailability due to refurbishment outage. New capacity opportunities can be addressed in a variety of ways, including new generation, increased demand response, increased conservation, and firm imports.

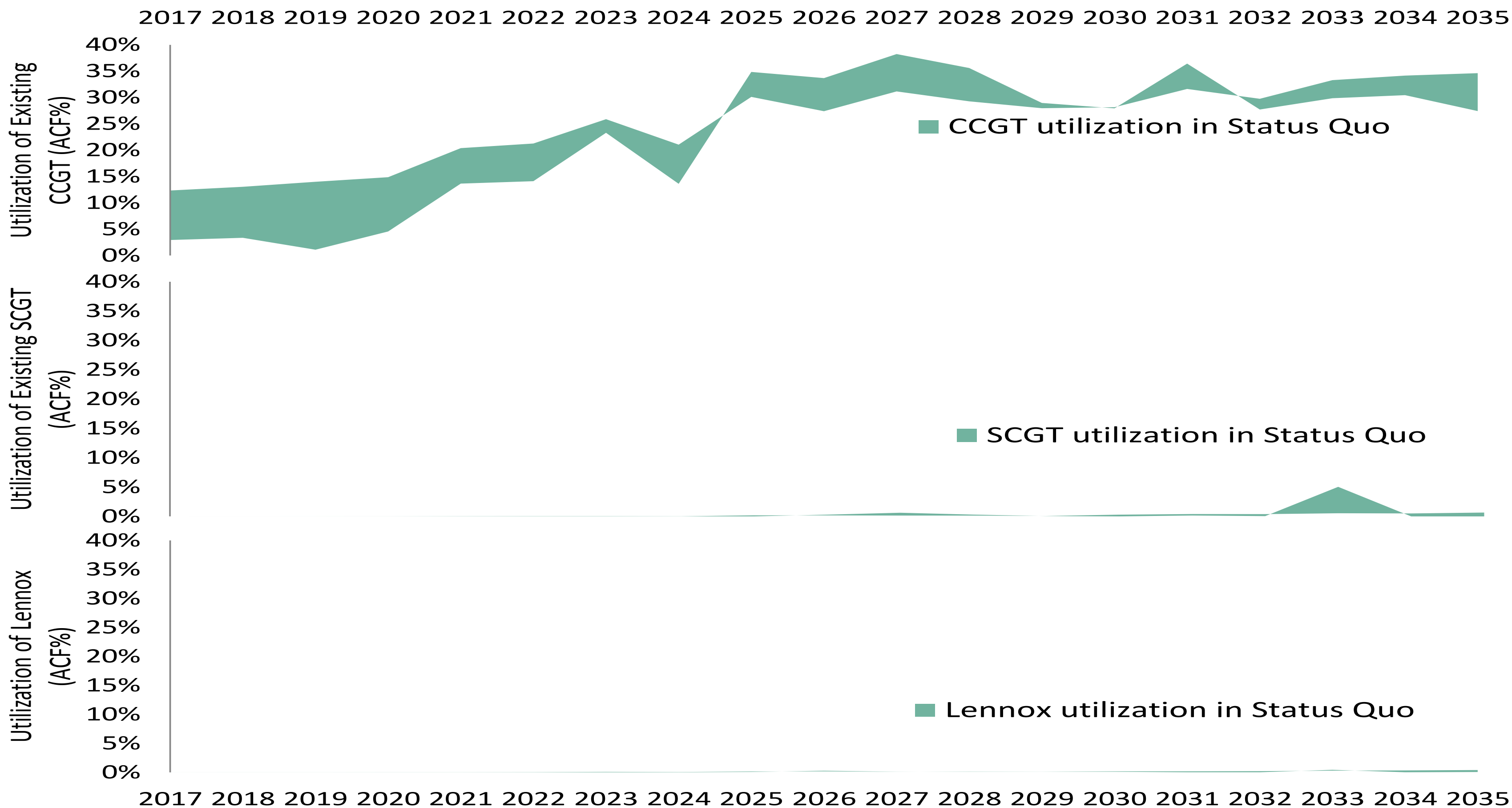


Ontario has a low carbon-emitting electricity system. Approximately 90% of the electricity produced in Ontario comes from non-fossil emitting sources (renewables and nuclear). Electricity production from nuclear resources in Ontario is expected to decline over coming years while renewable energy production is expected to increase. Production from natural gas-fired resources is expected to pick up the balance when output from other sources is lower or when demand rises.




Totals may not add up due to rounding

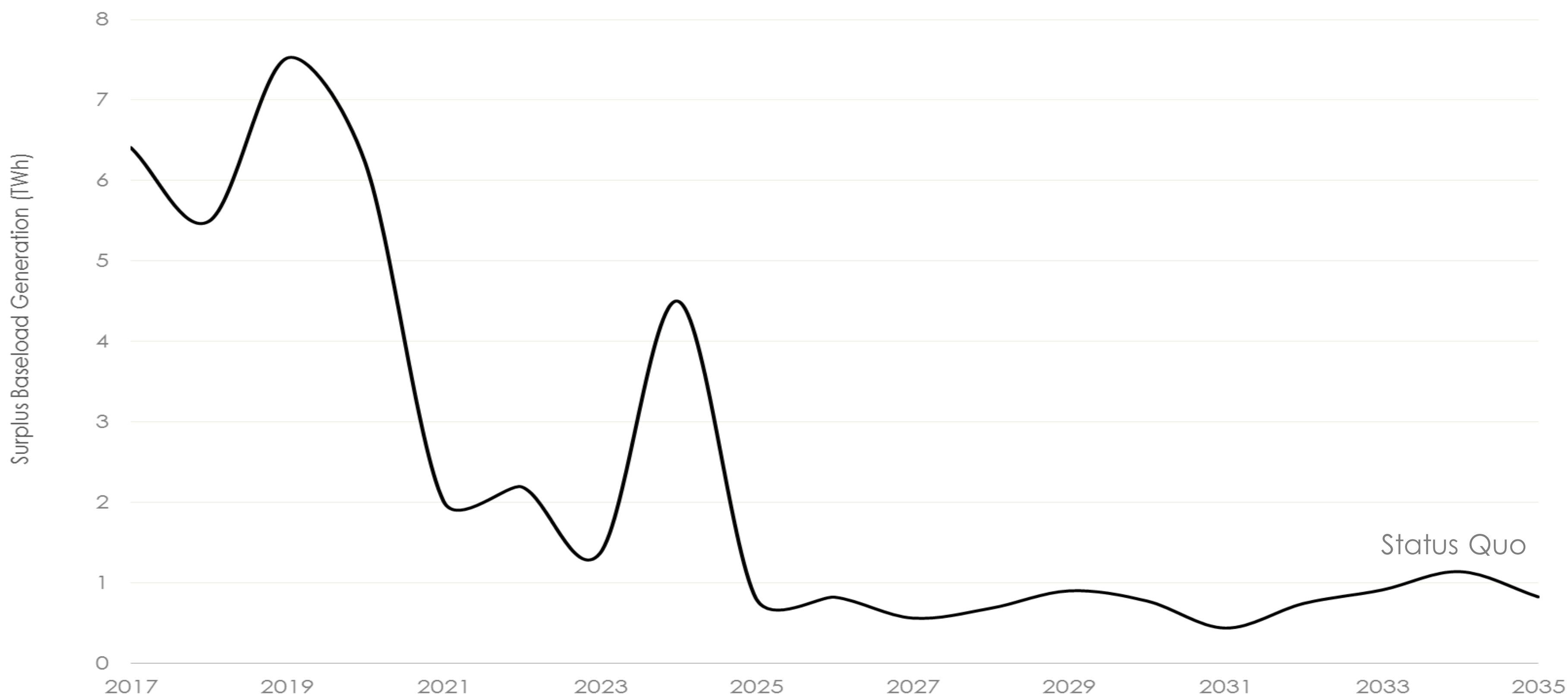
Assuming existing resources continue to operate throughout the planning outlook, Ontario is expected to have sufficient energy to meet its electricity needs throughout the planning period, unlike capacity. The utilization of Ontario's existing CCGT fleet is generally expected to be less than 25% up to the early 2020s. After Pickering retires in 2022/2024, utilization of the existing CCGT fleet is expected to increase to about 40%, lower than the average utilization of CCGT fleet across NERC jurisdictions, which is generally between 50% to 60%*. Although the gas fleet is expected to have relatively low utilization under the Status Quo outlook, opportunity exists, particularly in the longer term, to displace some of this production.




The range represents utilization with and without reliance on economic imports for energy.

*Source: NERC, Accommodating an Increased Dependence on Natural Gas for Electric Power (May 2013)

The amount of surplus energy ("surplus baseload generation" or "SBG") is expected to average about 4.5 TWh per year over the next few years. Projected declines in surplus energy over the longer-term will be driven by nuclear unit retirements and refurbishments. Surplus energy is expected to average about 1 TWh per year in the period beyond 2025; an 85% reduction from today's levels.

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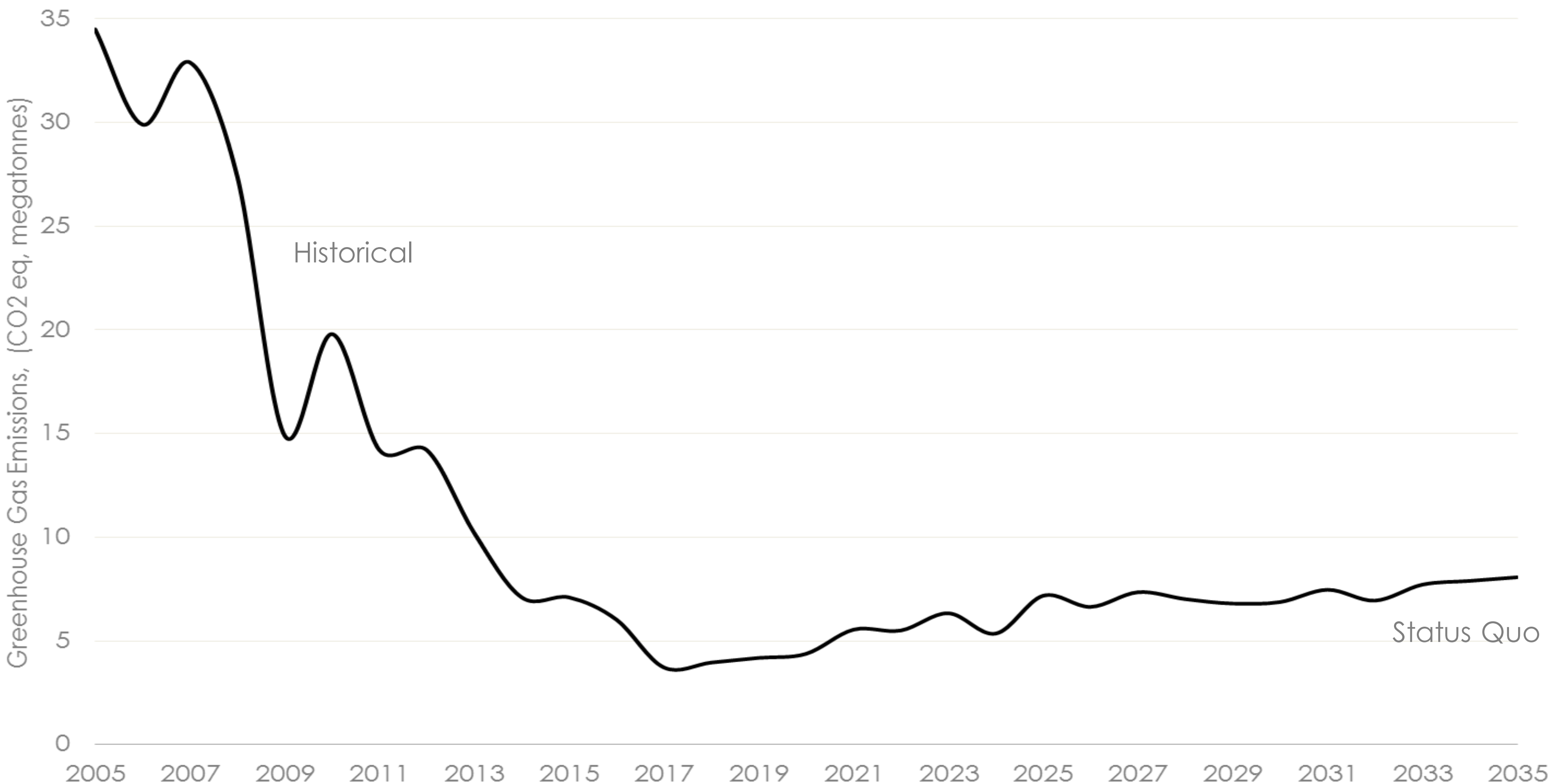
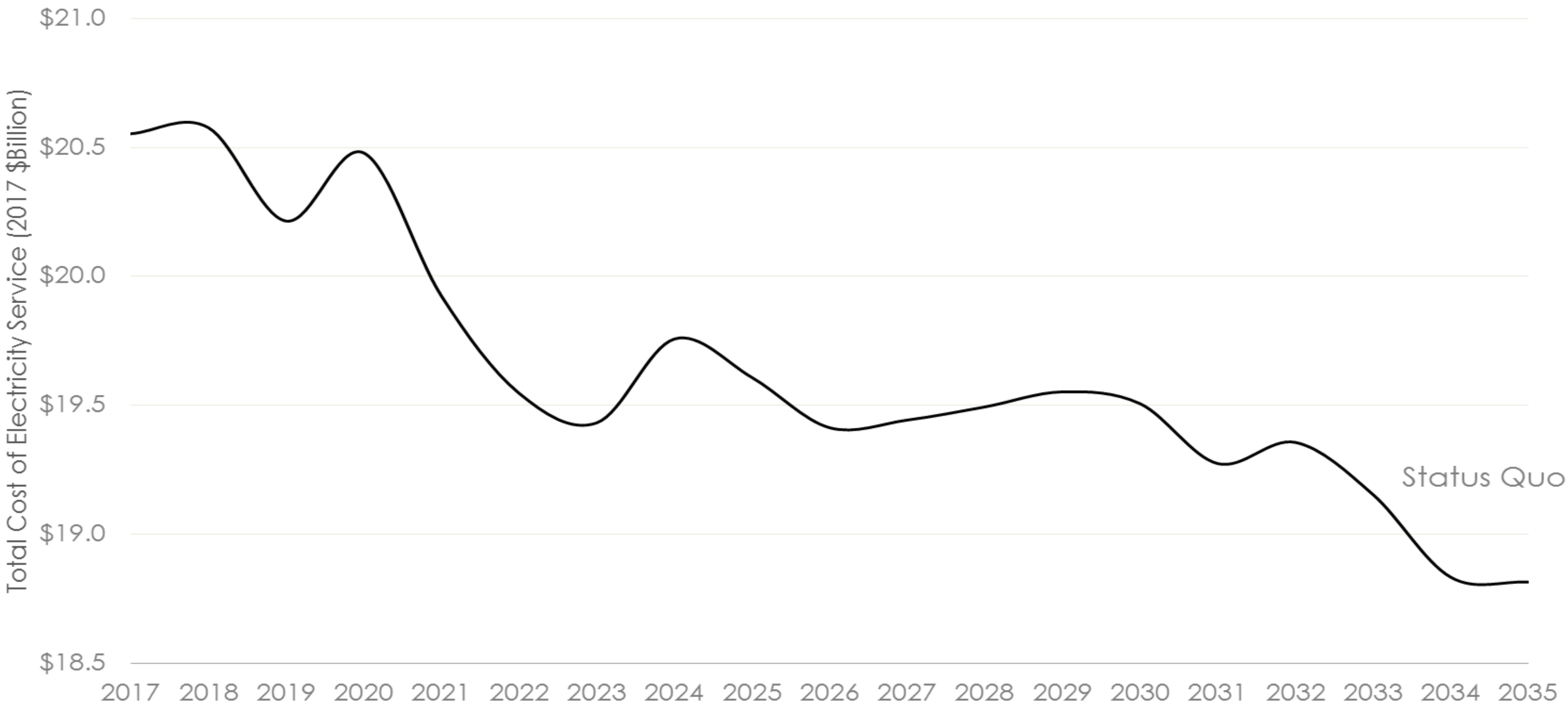
## Greenhouse gas emissions from the Ontario electricity sector declined by more than 80% over the past decade. Today, the Ontario electricity sector represents about 2% of Ontario's economy-wide greenhouse gas emissions. Electricity sector greenhouse gas emissions are expected to remain well below historic levels over the next two decades.



Ontario's total cost of electricity service represents the annual amount that must be recovered from all electricity consumers in the province to cover the cost of investing in and operating the electricity system. The total cost of electricity service is expected to average about $19.6B per year over the planning period and to decline in real terms from about $21B today to $18.8B by 2035 (figures in 2017 $).

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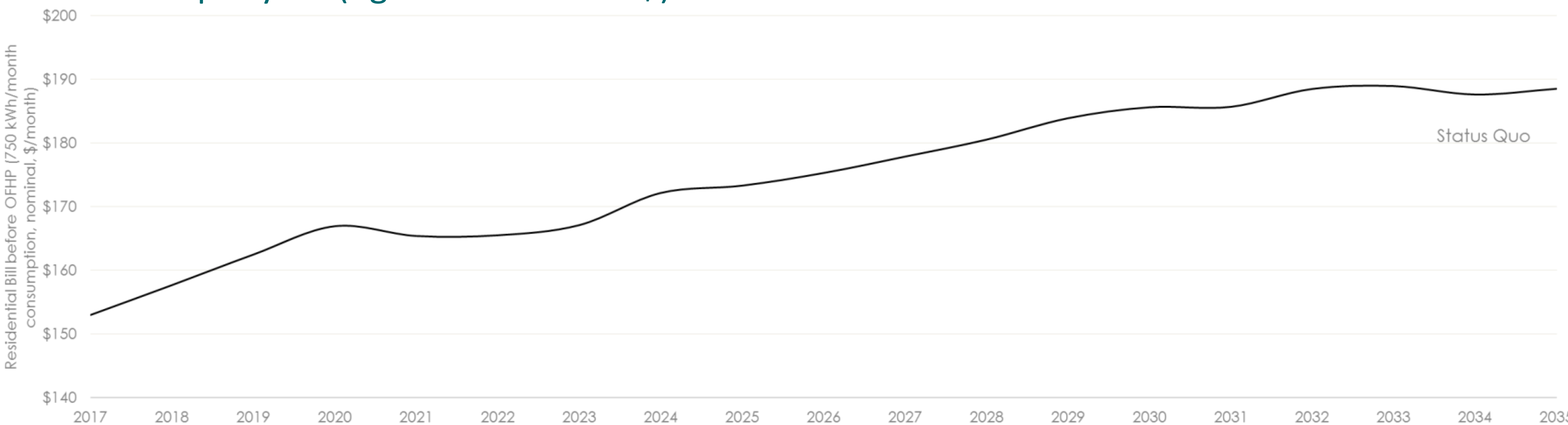
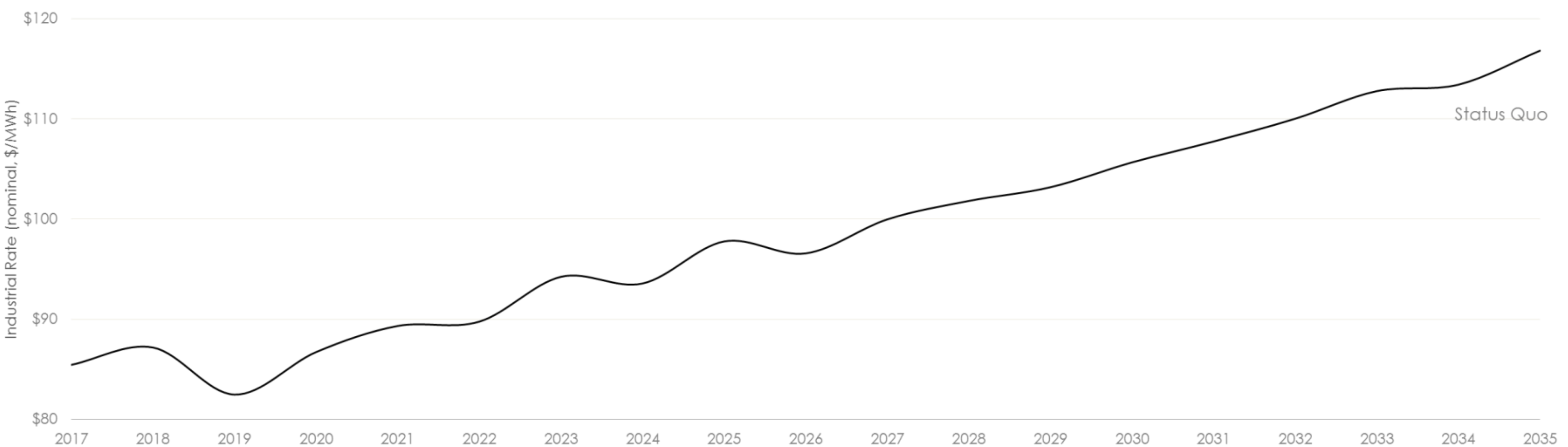
The previous slide illustrated total electricity costs for Ontario (in Real $2017). Total costs are allocated to electricity consumers. In the Status Quo outlook, residential electricity bills increase from $153/month today to $189/month by 2035 (pre-OFHP), with an annual average increase of about 1.1% per year. Industrial electricity rates increase from $85/MWh today to $120/MWh by 2035, with an annual average increase of 1.8% per year (figures in nominal $).

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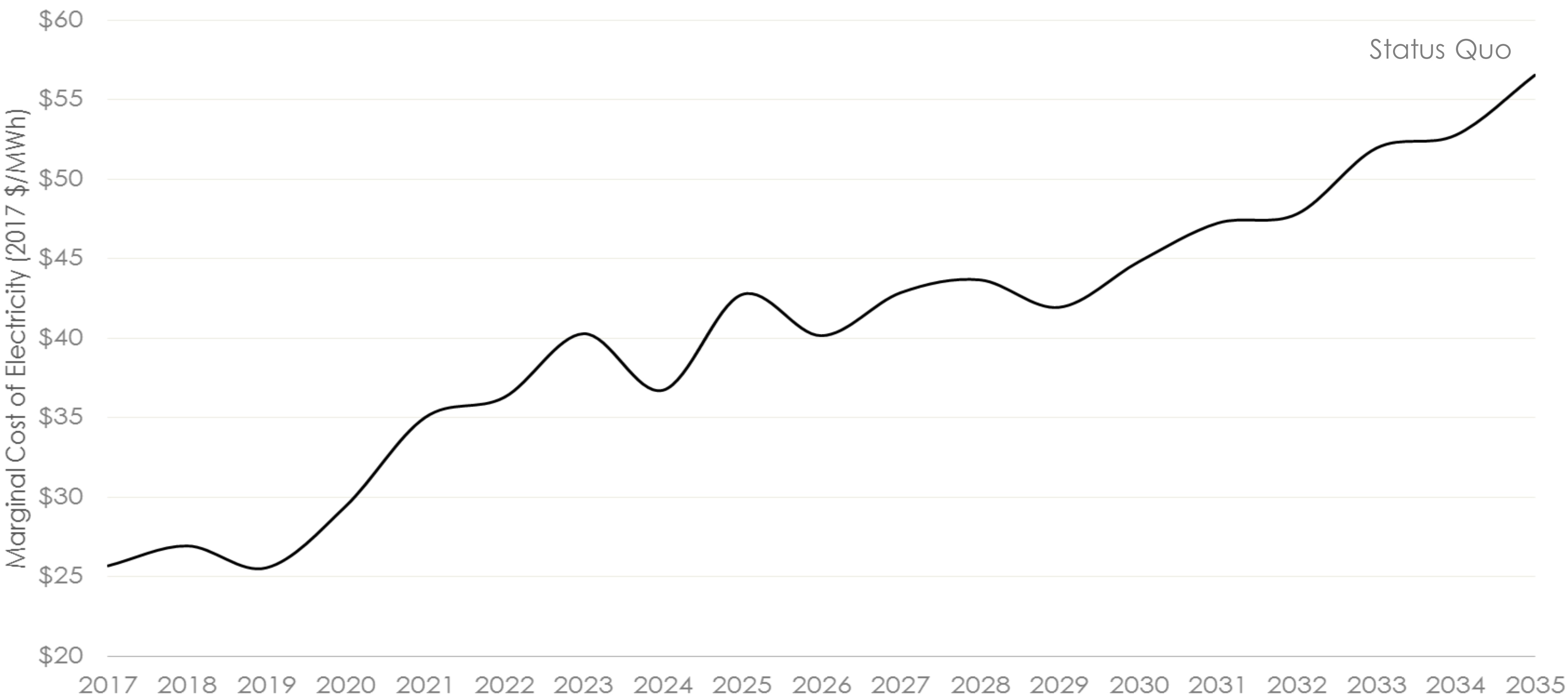
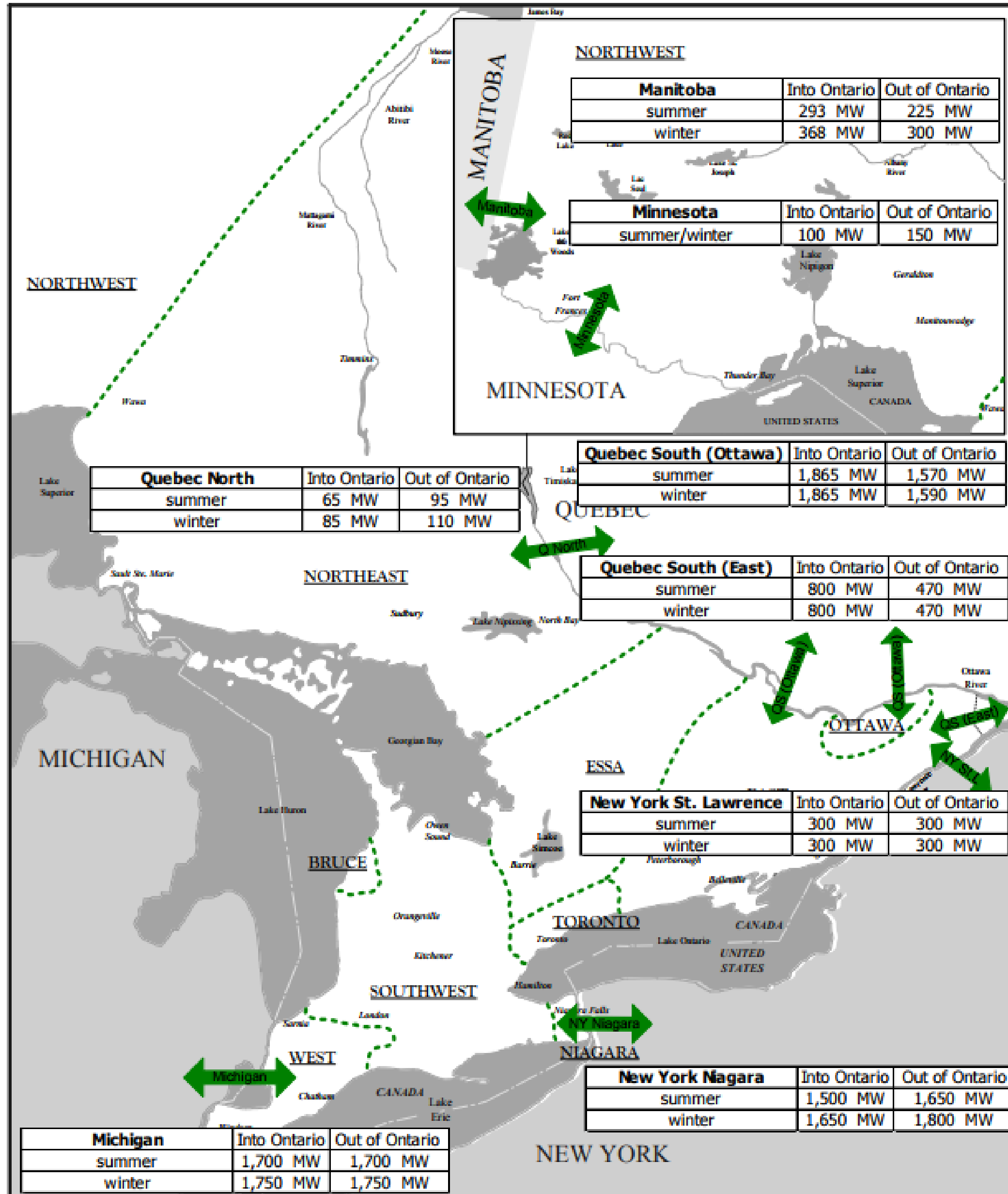
The marginal cost of power in the electricity market (representative of HOEP) is projected to average about $27/MWh prior to the 2020s and rise to about $57/MWh by the end of the outlook horizon. As marginal costs rise, the share of global adjustment allocated to residential customers declines (and rises for non-residential customers).



Ontario’s interties provide reliability and economic benefits. Ontario currently has interconnections with five jurisdictions which facilitate economic transactions between Ontario and its neighbours. Ontario’s ability to receive electricity imports from its neighbours is determined by the availability and price of electricity in neighbouring jurisdictions, the capability of the interties to deliver electricity across the border, and the transmission capability to deliver electricity from the border to load centres in Ontario.




| Manitoba | Into Ontario | Out of Ontario |
|---|---|---|
| summer | 293 MW | 225 MW |
| winter | 368 MW | 300 MW |

| Minnesota | Into Ontario | Out of Ontario |
|---|---|---|
| summer/winter | 100 MW | 150 MW |

| Quebec North | Into Ontario | Out of Ontario |
|---|---|---|
| summer | 65 MW | 95 MW |
| winter | 85 MW | 110 MW |

| Quebec South (Ottawa) | Into Ontario | Out of Ontario |
|---|---|---|
| summer | 1,865 MW | 1,570 MW |
| winter | 1,865 MW | 1,590 MW |

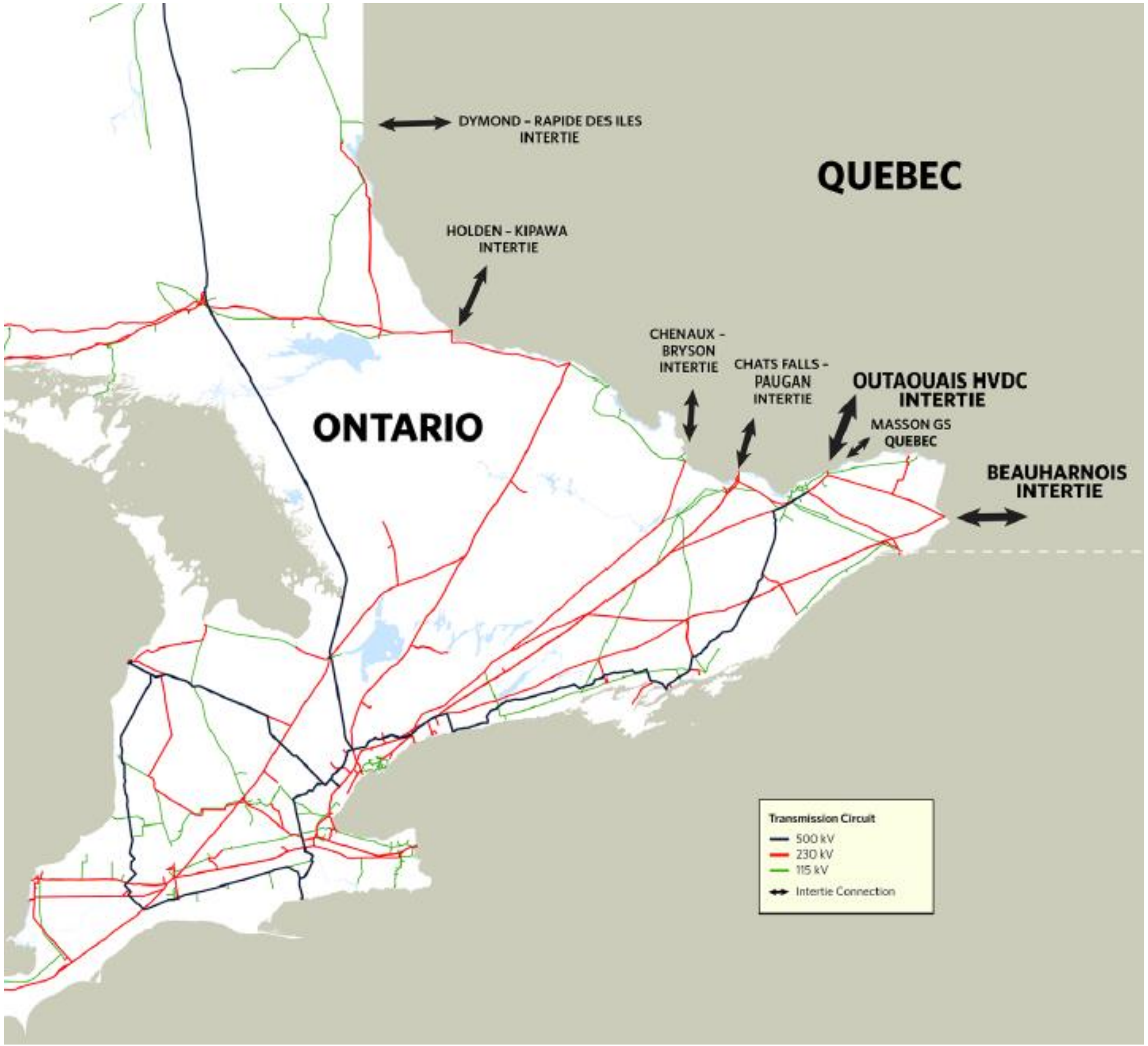
| Quebec South (East) | Into Ontario | Out of Ontario |
|---|---|---|
| summer | 800 MW | 470 MW |
| winter | 800 MW | 470 MW |

| New York St. Lawrence | Into Ontario | Out of Ontario |
|---|---|---|
| summer | 300 MW | 300 MW |
| winter | 300 MW | 300 MW |

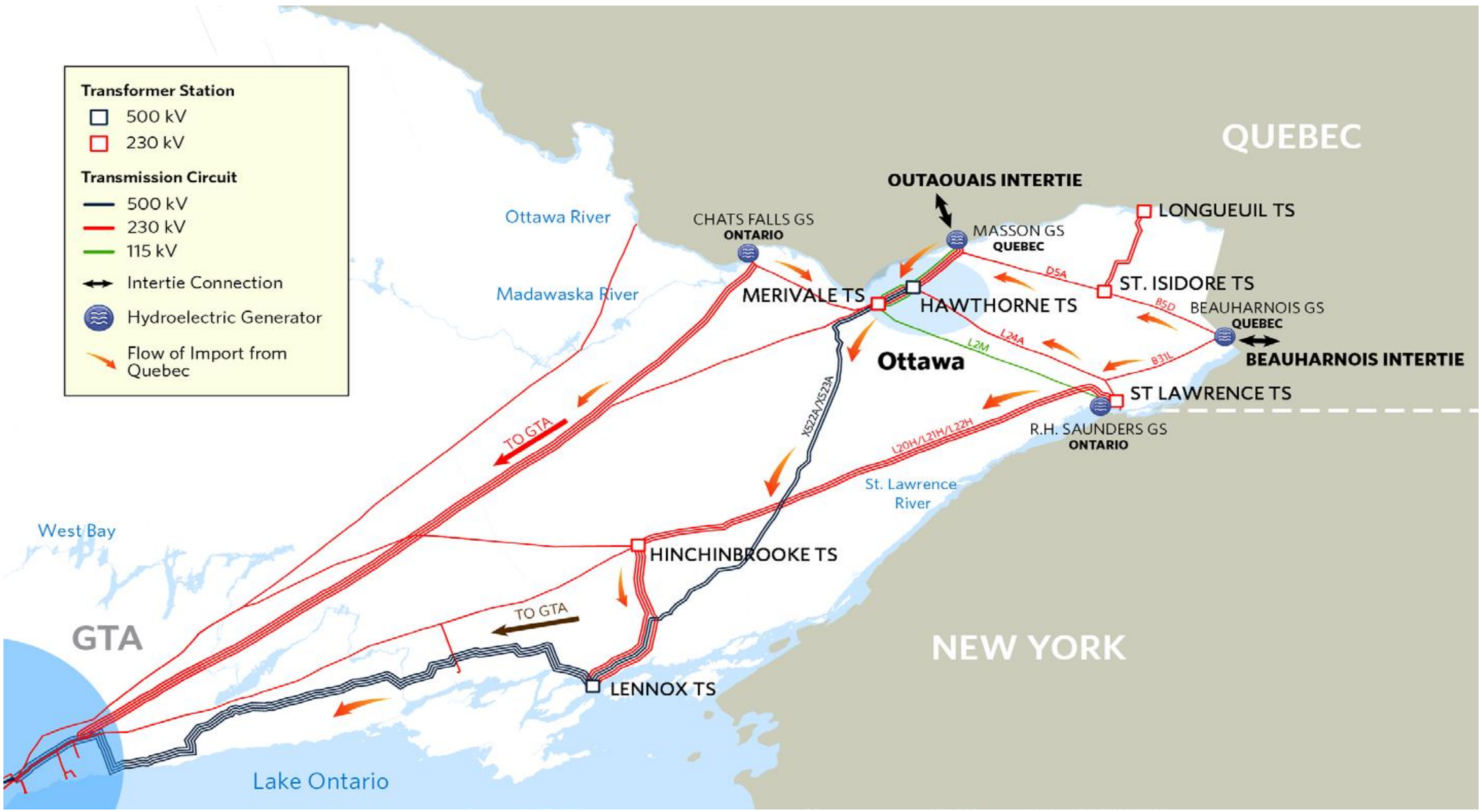
| New York Niagara | Into Ontario | Out of Ontario |
|---|---|---|
| summer | 1,500 MW | 1,650 MW |
| winter | 1,650 MW | 1,800 MW |

| Michigan | Into Ontario | Out of Ontario |
|---|---|---|
| summer | 1,700 MW | 1,700 MW |
| winter | 1,750 MW | 1,750 MW |

Ontario currently has seven interconnections with Quebec. Most of the trade with Quebec is through the Outaouais HVDC intertie, which is capable of transferring up to 1,250 MW.



Existing internal transmission constraints within Ontario can limit the amount of imports that can be relied upon. There are currently transmission constraints in the Ottawa and St. Lawrence areas which limit full use of firm import capability from HQ.

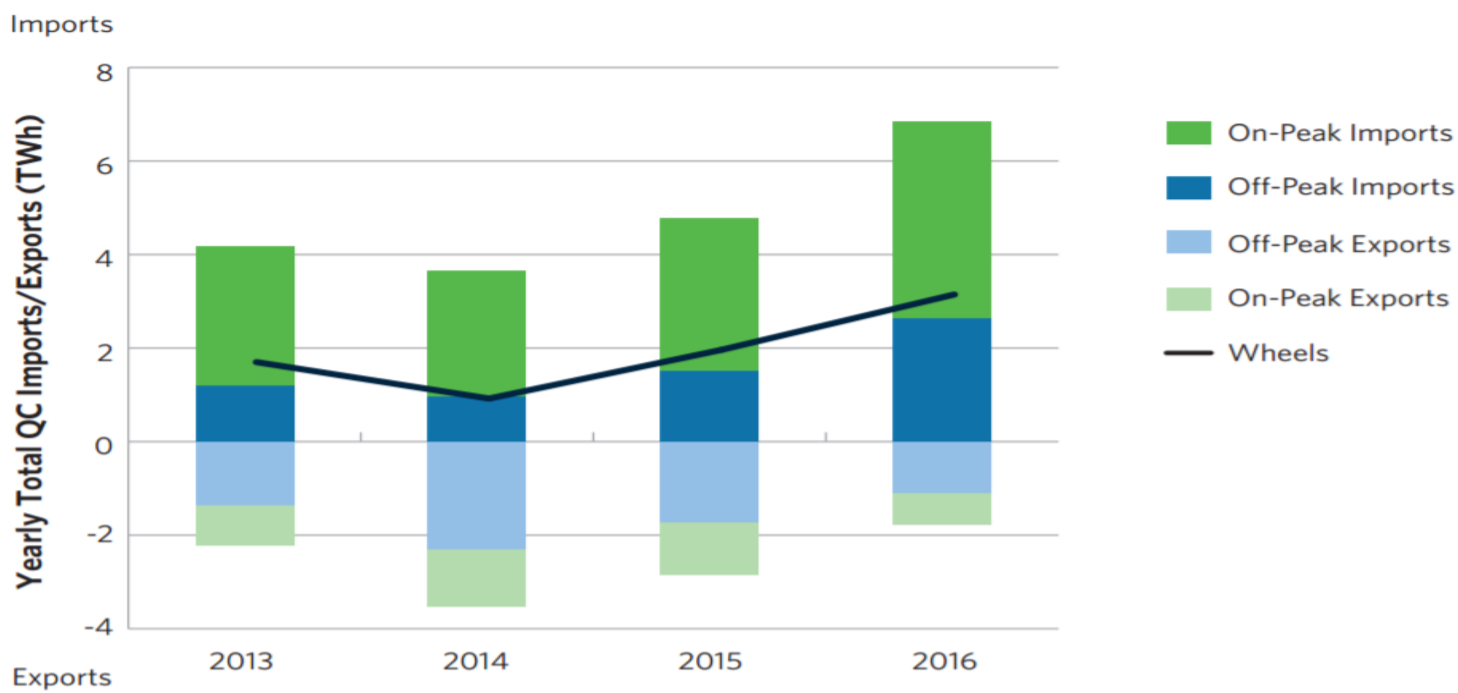


# The 2017 "Ontario-Quebec Interconnection Capability" report identified options for addressing transmission constraints and their estimated costs and lead times (see the table below). An investment of $20M between Hawthorne TS and Merivale TS would allow Ontario to make full use of the existing HVDC intertie. Development work on this option continues.

| Case | System Change | Total Transmission Cost and Timing Requirements | Total Resulting Firm Import Capability (MW) |
|---|---|---|---|
| 1 | Existing System | | **0 MW firm import**<br>• Non-firm energy imports are feasible, depending on system conditions, such as demand, and eastern Ontario hydroelectric generation levels. |
| 2 | After replacing two 230 kV line disconnect switches at Hawthorne TS | Approx. $ 500 000;<br><br>1-2 years of lead time | **500 MW firm import on HVDC intertie**<br>• In conjunction with Ottawa demand growth up to mid-2020s<br>• Energy import may be able to exceed 500 MW for some hours |
| 3 | After replacing two 230 kV line disconnect switches <u>and</u> reconductoring two 230 kV circuits between Hawthorne TS and Merivale TS (approx. 12 km) | Approx. $20 M<br><br>3 years of lead time<br>Note: scheduling outages for this work will require significant timing coordination | **1,250 MW firm import - Full capability of HVDC intertie**<br>• Energy import would be limited to approximately 1250 MW at any given time<br>• In addition to enabling increased use of the intertie capability, reconductoring the Hawthorne-Merivale circuits would allow Ontario to further optimize the targeting of the 2.3 TWh import agreement. |
| Cases 4 and 5 are alternative options that build on Case 3 to enable two levels of incremental import capability from the dedicated generators at the Beauharnois intertie | | | |
| 4 | Operating the Beauharnois intertie in bus-split mode – directing 400 MW of intertie capability to the Hawthorne TS hub | Operational change – no significant incremental cost or timing requirements above the $20 M required for Case 3 | **1,650 MW firm import (1,250 MW from HVDC + 400 MW from Beauharnois)**<br>• Energy import would be limited to approximately 1,650 MW at any given time, also dependent on availability of specific Quebec generators<br>• Change of configuration would result in a lower level of supply reliability for some eastern Ontario customers. |
| 5 | After reinforcing the eastern Ontario network by rebuilding 115 kV circuit L2M between St. Lawrence and Merivale TS as a double-circuit 230 kV transmission line (approx. 86 km) | Approx. $220 M<br>Plus the cost of additional upgrades in the Ottawa area that may be required.<br><br>5-7 years of lead time | **2,050 MW firm import (1,250 MW from HVDC + 800 MW from Beauharnois)**<br>• Energy import would be limited to approximately 2,050 MW at any given time, also dependent on availability of specific Quebec generators |

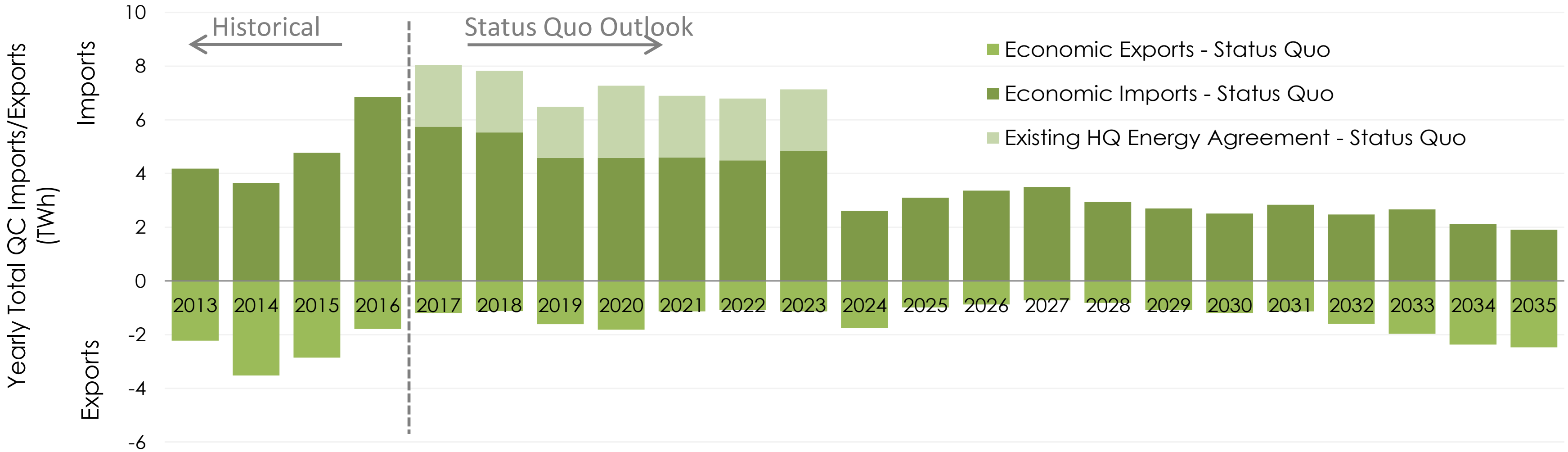
Note: cases are organized based on system upgrade requirements

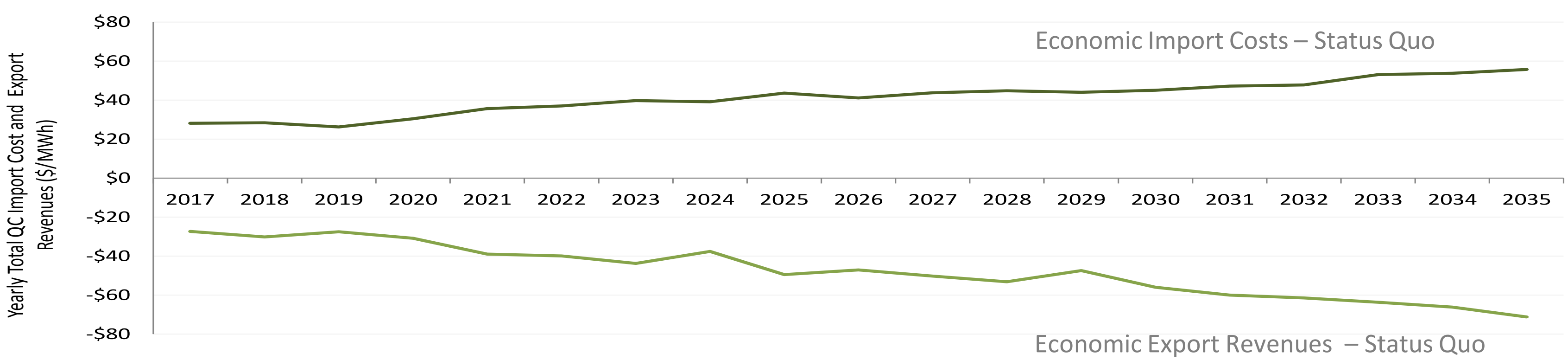
Despite existing transmission constraints, Ontario regularly trades electricity with Quebec in the real-time electricity market when economic, limited by the intertie capability in real-time. Electricity exports from Ontario to Quebec have been declining in recent years, from a maximum of about 3.5 TWh to 1.8 TWh between 2013 and 2016. Imports from Quebec into Ontario have been increasing from about 2.5 TWh to 3.5 TWh over the same period, while total imports including wheel-throughs rose from 4 TWh to 7 TWh. As imports have increased, so have the wheel-throughs, which accounted for about half of Onatrio's electricity imports from Quebec in 2016.




A wheel-through is a type of energy transaction in which power is sent from one jurisdiction (QC), through another jurisdiction (ON), and on for consumption in a different regional market.

Economic import/export transactions with Quebec are expected to continue, even without firm agreements. In the Status Quo outlook, Ontario would annually import 2 TWh to 6 TWh from Quebec at a spot price averaging $41/MWh. Over the same time period, Ontario would annually export about 1.5 TWh at a spot price of $47/MWh.

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## In addition to the economic electricity import/export transactions with Quebec that are expected to take place over the Status Quo outlook, Ontario signed an energy sales and cycling agreement with Quebec in 2016, building upon the 2015 capacity swap agreement.

- The 2016 energy sales and cycling agreement consists of:
    1. Ongoing sale of 500 MW of firm capacity from Ontario to Quebec during the winter periods of 2016 – 2023
    2. Total 2.3 TWh of energy from Quebec to Ontario, to be offered into the IESO-administered market with the intention of displacing higher cost/higher emission gas generation
    3. Cycling energy from Ontario to Quebec, to be cycled to Quebec during periods of surplus, stored in Quebec and returned to Ontario with the intention of displacing higher cost/higher emission gas generation
    4. As a result of Ontario having provided 500 MW of capacity to Quebec in winter of 2015/16 as part of the original Capacity Swap Agreement, a commitment from Quebec to deliver 500 MW of firm capacity to Ontario for four months during summer period(s) of the IESO's choosing before 2030

- The 2016 agreement replaces the 2015 capacity swap agreement that saw Ontario provide 500 MW of firm capacity to Quebec during the winter periods of 2016 – 2023 while Quebec would provide 500 MW of firm capacity to Ontario during the summer periods of 2016 – 2023. This swap took advantage of the seasonal asymmetry of capacity surpluses between Ontario and Quebec.

# Additional details of the 2016 Ontario-HQ energy sale and energy cycling agreement.

| | |
|---|---|
| **Term** | 7 years from 2017-2023 |
| **Energy** | 2.3 TWh / year (2 TWh energy and 0.3 TWh returned cycled energy) |
| **Contract Price** | 2 TWh / year at $60/MWh and escalated at CPI (~= $61.20/MWh in 2018). 0.3 TWh of cycled/stored surplus energy at $0/MWh. |
| **Delivery Process** | Energy is offered into the Ontario market every hour at a formula price that targets natural gas production. Ontario market dispatches Quebec energy when Ontario price is higher than formula price (i.e. when gas is expected to run). |
| **Energy Impact** | Intended to target reduction in Ontario dispatchable natural gas and lower carbon emissions in Ontario with year-to-year flexibility, and a true up year at the end of contract, as required. The commitment to 2.3 TWh/year is based on the expected need for dispatchable gas production to meet domestic demand over the contract term. Formula price can be adjusted to ensure continued effective reduction in dispatchable gas and avoid surplus energy. |
| **Flexibility** | There is a recognition that not all the energy will be delivered in any particular year. There is provision to make that up in subsequent years and a true up provision in the 8th year. Any true-up of the energy portion of agreement is on a take or pay basis in 2023. The true up of the returned cycled energy in 2023 is on a no consequence to either side basis, therefore, Ontario takes the risk. |
| **Capacity** | There is no capacity component to this offer. Although there is an obligation to offer ~ 1,000 MW/hr, Quebec is relieved from ~40 hours (reliability constraint) with no penalties. After that Quebec pays $5/MWh in penalties. |
| **Other contracts as part of the value "bundle"** | No change to the other components as part of the "bundle" from the existing agreement:<br>a) Ongoing sale of 500 MW of firm capacity from Ontario to Quebec during the winter periods of 2016 – 2023<br>b) As a result of Ontario having provided 500 MW of capacity to Quebec in winter of 2015/16 as part of the original Capacity Swap Agreement, a commitment from Quebec to deliver 500 MW of firm capacity to Ontario for four months during summer period(s) at Ontario's discretion before 2030 |

2. Overview of the June 22, 2017 Hydro Quebec amended energy sales and cycling agreement ("The Updated HQ proposal")

# Compared to the current agreement between Ontario and Quebec, the updated Hydro Quebec proposal would see more energy imported into Ontario for a longer period of time, with less flexibility to target periods of higher value to Ontario

| Item | Existing Agreement (2016) | Updated Proposal (June 22, 2017) |
|---|---|---|
| Term | 7 years, from 2017 to 2023 | 20 years, from 2018-2038 |
| Firm Capacity | 0 MW | 0 MW |
| Energy Quantity | 2.3 TWh/year (2 TWh energy + 0.3 TWh returned cycled energy) | 8.3 TWh/year (potential for an additional up to 0.3 TWh returned cycled energy after the 8 TWh is delivered) |
| Price | \$61.20/MWh escalated at CPI | \$61.20/MWh escalated at CPI |
| Flexibility | Energy is targeted towards higher value periods (price/emissions avoidance) | Take or pay (no opportunity to target energy towards higher value periods) |

A complete comparison of the updated proposal and the existing 2016 agreement is available at the Appendix

# Additional details of HQ's June 22, 2017 amended and restated energy sales and energy cycling agreement

| | |
|---|---|
| **Term** | 20 years from 2018-2038 |
| **Energy** | 8 TWh / year energy. Potential for additional cycled energy up to 0.3 TWh after the 8 TWh is delivered. |
| **Contract Price** | 8 TWh / year energy at $61.21/MWh, and escalates at CPI. Up to 0.3 TWh of cycled/stored surplus energy at $0/MWh, only after 8 TWh is fulfilled. |
| **Delivery Process** | Energy is offered into the Ontario market every hour at a fixed -$15/MWh. Ontario market dispatches Quebec energy to flow whenever Ontario price is higher than -$15/MWh. |
| **Energy Impact** | Ontario must take 8 TWh of energy at the stated contract price every year, whether the energy is needed or not. |
| **Flexibility** | Ontario must pay for 8 TWh at the contract price every year, whether the energy is delivered or not. |
| **Capacity** | There is no capacity component to this offer. Although there is an obligation to offer ~ 1,000 MW/hr, Quebec is relieved from ~40 hours (reliability constraint) with no penalties. After that Quebec pays $5/MWh in penalties. |
| **Other contracts as part of the value "bundle"** | No change to the other components as part of the "bundle" from the existing agreement:<br>a) Ongoing sale of 500 MW of firm capacity from Ontario to Quebec during the winter periods of 2016 – 2023<br>b) As a result of Ontario having provided 500 MW of capacity to Quebec in winter of 2015/16 as part of the original Capacity Swap Agreement, a commitment from Quebec to deliver 500 MW of firm capacity to Ontario for four months during summer period(s) at Ontario's discretion before 2030 |

3. Assessment of the Updated Hydro Quebec proposal as submitted to the IESO, in the context of the current electricity system outlook

# The Status Quo electricity planning outlook described in previous slides is the starting point for assessing the updated Hydro Quebec import proposal as submitted to the IESO

- The updated Hydro Quebec proposal is analyzed as given, assuming no changes to the terms of the proposal (e.g., product offered, timing, quantity, duration, etc.)

- The outlook for demand and installed supply is unchanged from the Status Quo outlook. All existing resources are assumed to continue to be available throughout the planning outlook.

- The objective of this scenario is to assess how the current and future electricity system reacts or "adapts" to the insertion of imports per HQ's proposal. The impacts on the electricity system are examined from the perspective of:
  - Impact on the timing and size of capacity needs
  - Impact on energy production from electricity resources
  - Change in surplus baseload generation
  - Change in electricity sector emissions
  - The break-even import price for the HQ imports is the price in which the total cost of the Ontario electricity system remains unchanged relative to the Status Quo outlook.
  - Total cost of electricity service and cost of electricity for consumers, with the proposed HQ offer price of $61.20/MWh ($2017)

- Sensitivity analysis is performed to assess the impact of lower and higher natural gas and carbon prices (further information on assumptions can be found in the appendix)

**Capacity adequacy:** Ontario will require additional resources starting in the early-to-mid 2020s. The updated HQ proposal would not help meet projected capacity needs in Ontario, as it is proposal for energy only – capacity is not on offer.

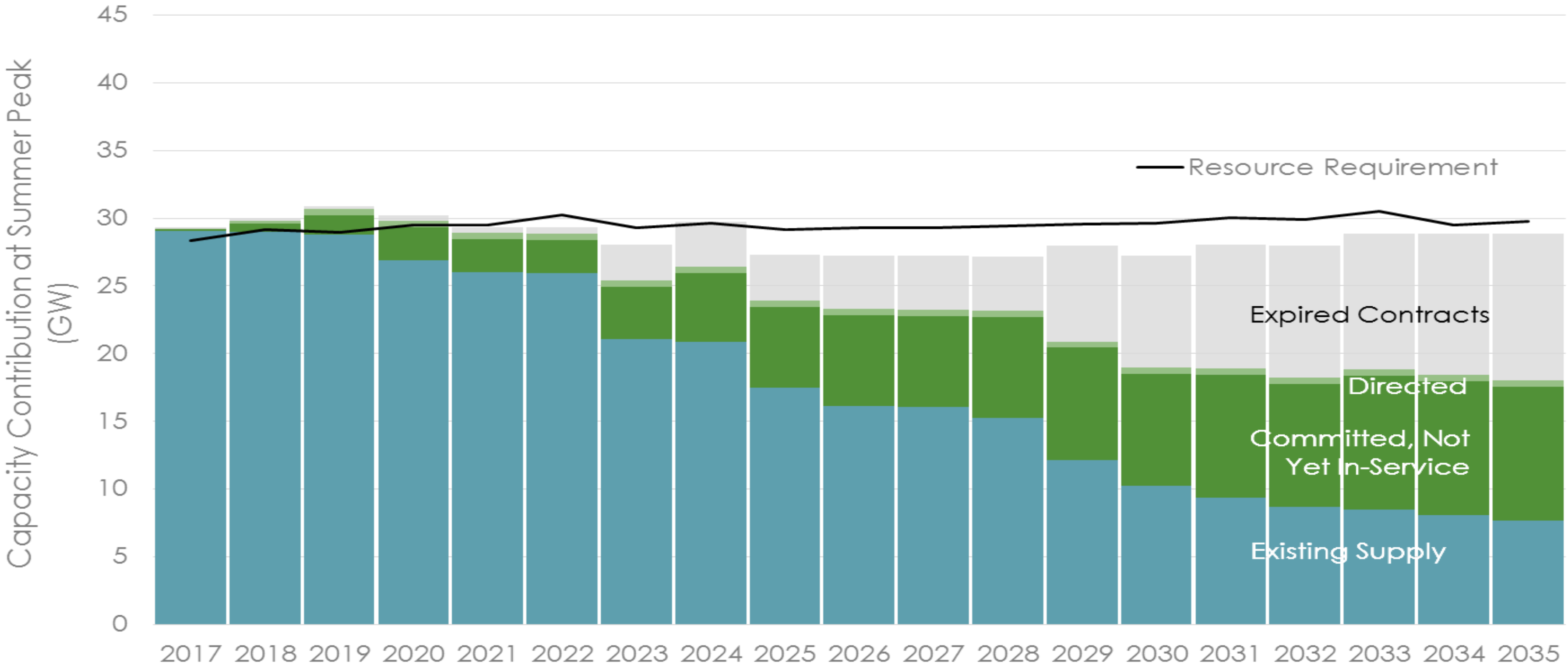


Figure includes 500 MW firm capacity in the summer of 2023 from the original HQ capacity swap agreement.

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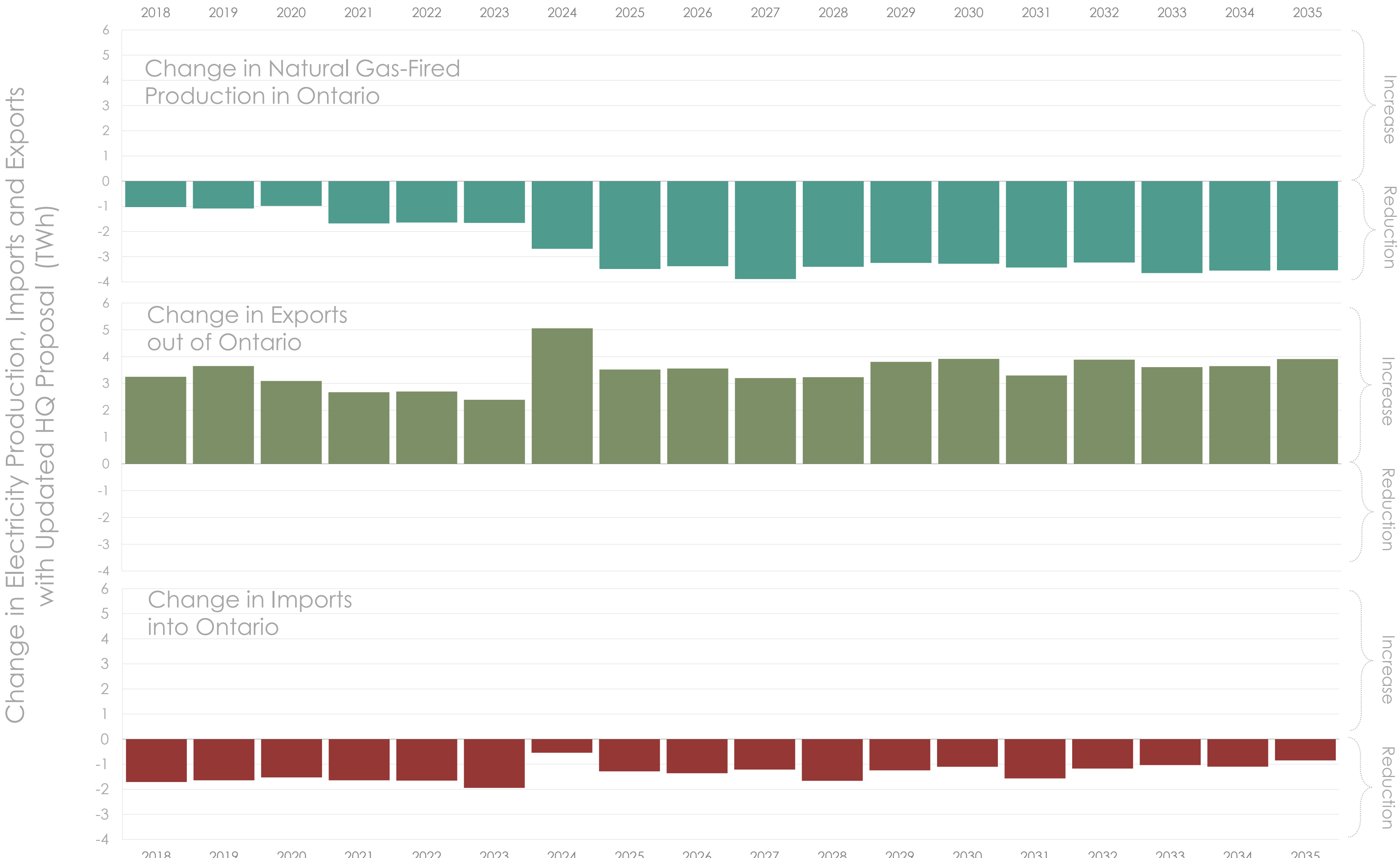
**Energy production:** 46% of the 8 TWh that would be sold to Ontario each year under the updated HQ proposal would be effectively exported out of Ontario, about 35% would reduce production from gas-fired resources in Ontario, about 19% would reduce other imports into Ontario



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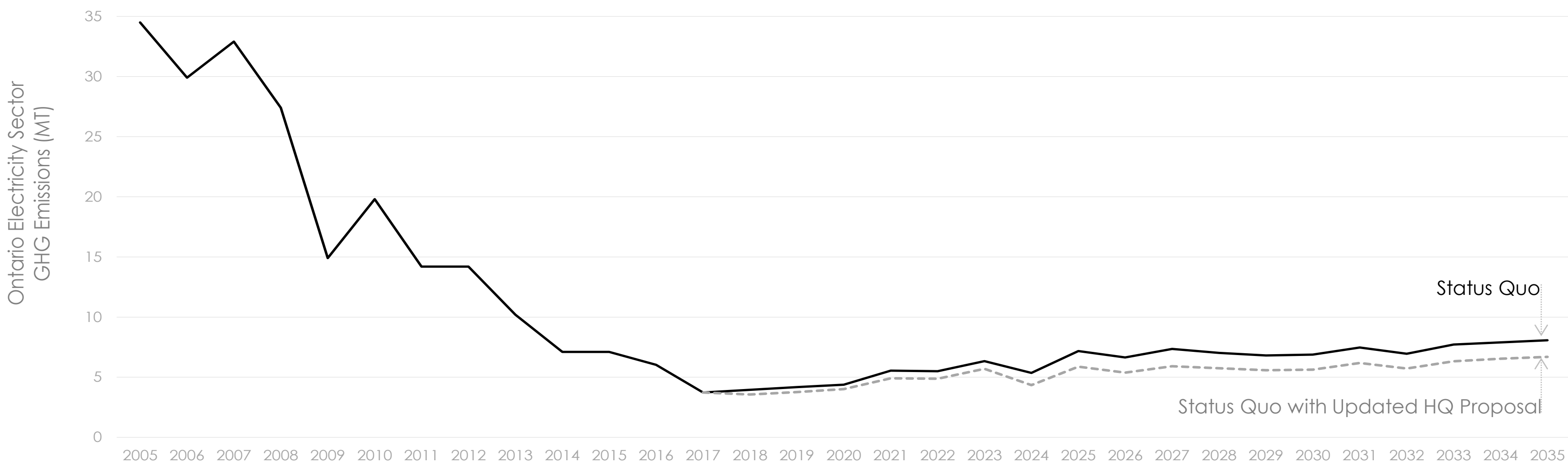
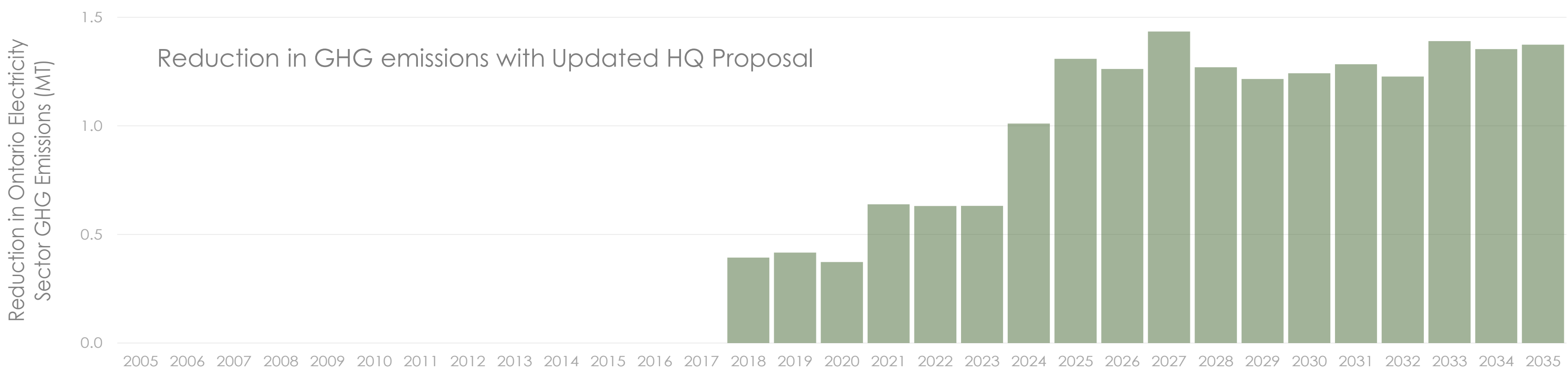
**GHG emissions:** the HQ proposal would reduce carbon emissions in Ontario's electricity sector by about 1 MT per year, on average. The effect would be less pronounced in the nearer-term (about 0.4 MT CO2 reduction each year between 2018 and 2023), and more pronounced in the longer-term (about 1.4 MT CO2 reduction each year beyond 2024 ).

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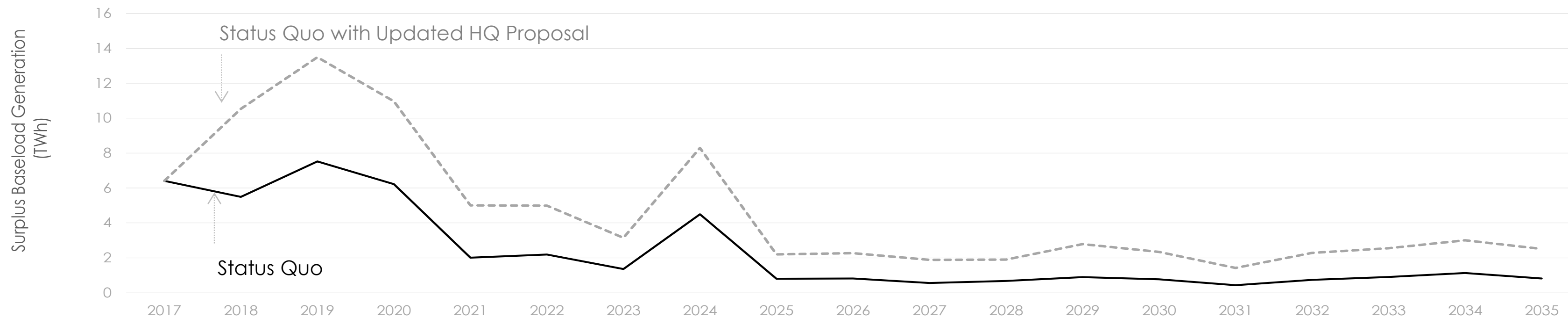
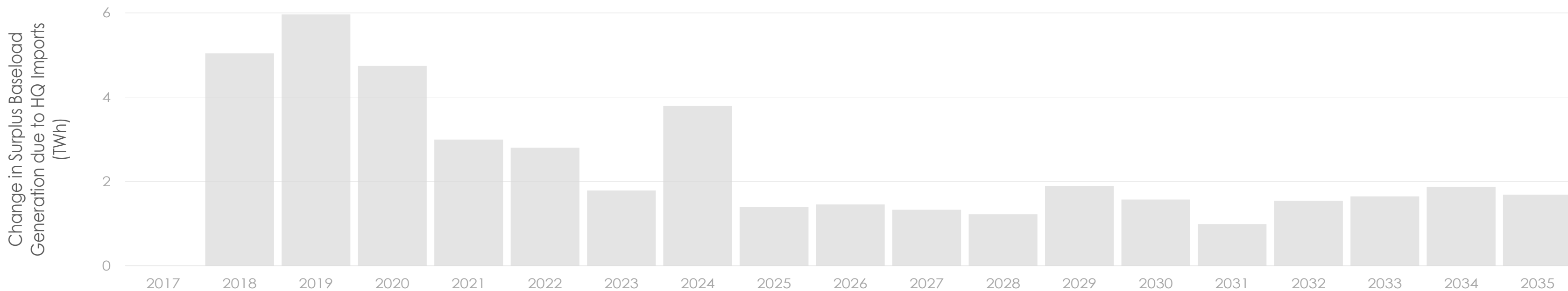
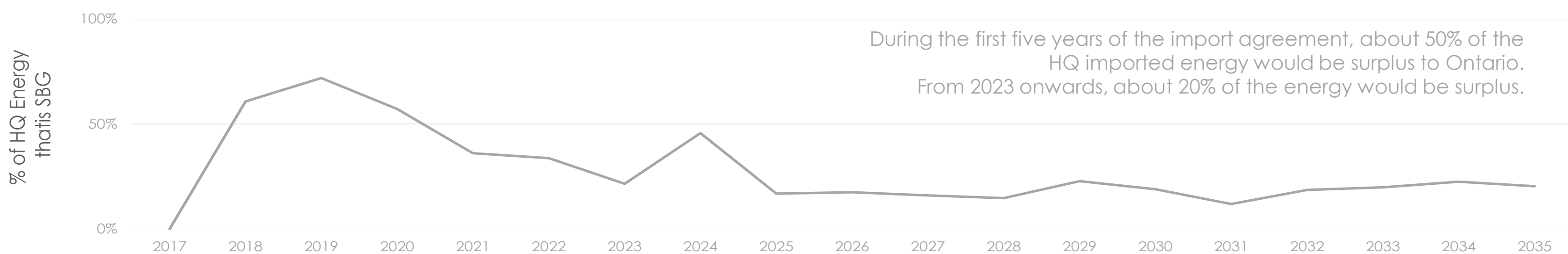
**Implied cost of carbon reduction:** As described on the previous slide, the HQ proposal would reduce carbon emissions in Ontario's electricity sector by about 1 MT per year, on average. The incremental cost of achieving this reduction would peak at about $850/tonne in 2020, and then decline to an average of $140/tonne beyond 2025. It would average about $300/tonne over the planning period. For comparison, the current cap and trade floor price is about $18/tonne rising to about $40/tonne (2017 $ CDN) by the end of the planning outlook.

**Surplus baseload generation (SBG):** the updated HQ proposal would increase surplus baseload generation in Ontario. The effects of the updated proposal on Ontario SBG would be more pronounced in the nearer-term, less pronounced in the longer-term. For example, SBG in Ontario would increase by about 5 TWh starting in 2018, but would decline to about 2 TWh starting in the mid-2020's. Altogether, about 30% of the 8 TWh imported from HQ each year would be surplus over the planning period. Surpluses in this context mean paying more than necessary.

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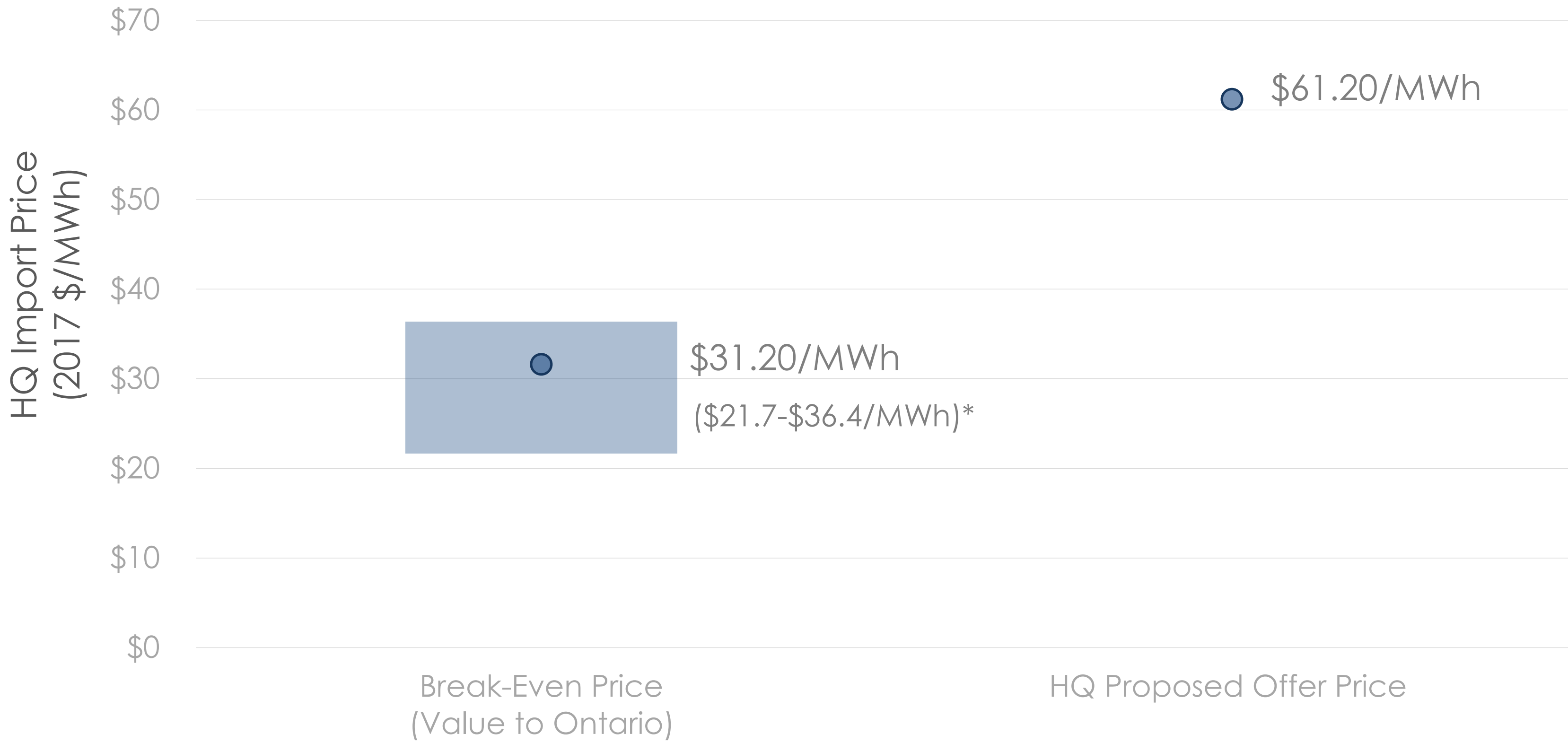
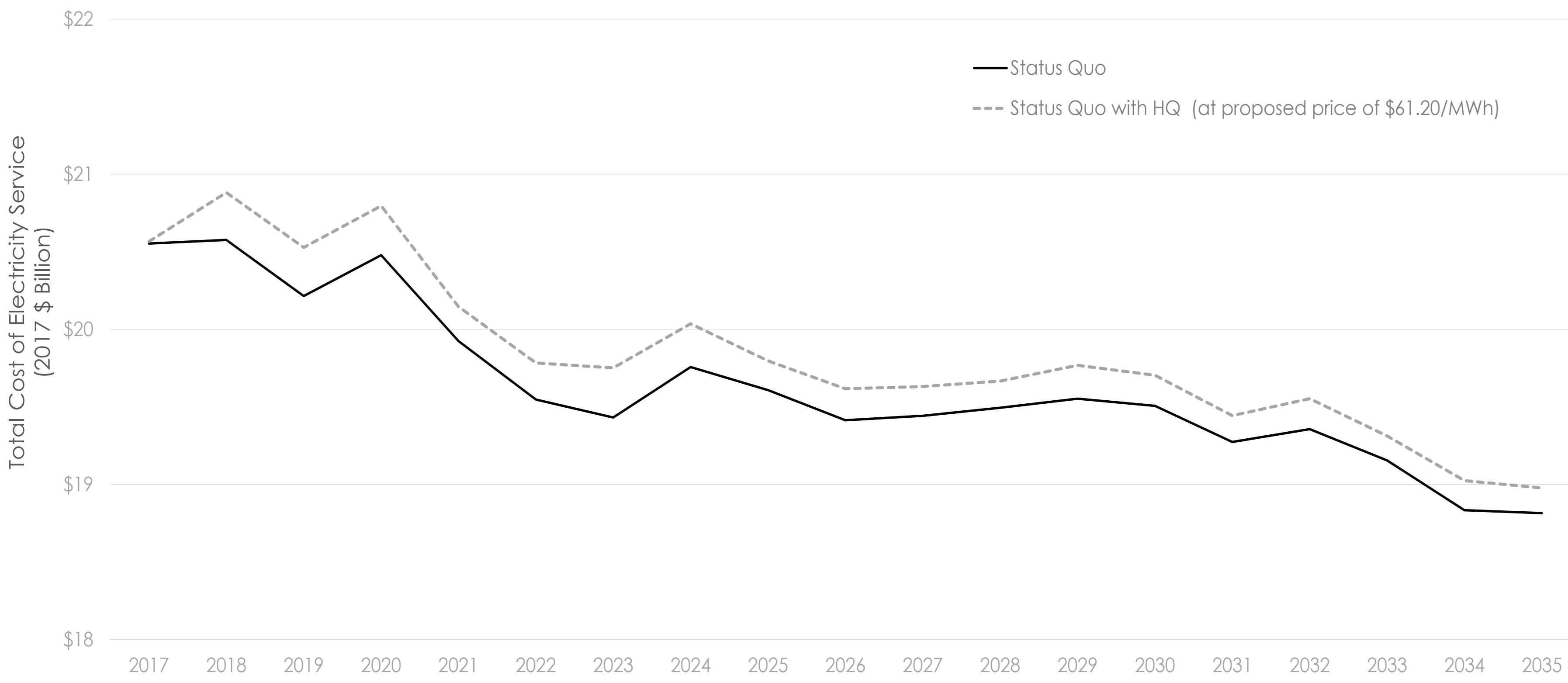
**Value of HQ proposal as submitted:** As illustrated in the previous slides, the updated energy import proposal from HQ would have the effect of, among other things, reducing energy production from gas-fired resources in Ontario. After accounting for cost savings from reduced gas-fired energy production, the price of HQ imports at which the cost of electricity in Ontario would remain unchanged ("break-even") would be about $32/MWh, but could range between $22-$36/MWh under lower/higher gas/carbon prices. This is less than HQ's proposed offer price of $61.20/MWh (all figures are in 2017$). Paying a price that is higher than the break-even price would result in higher electricity costs.

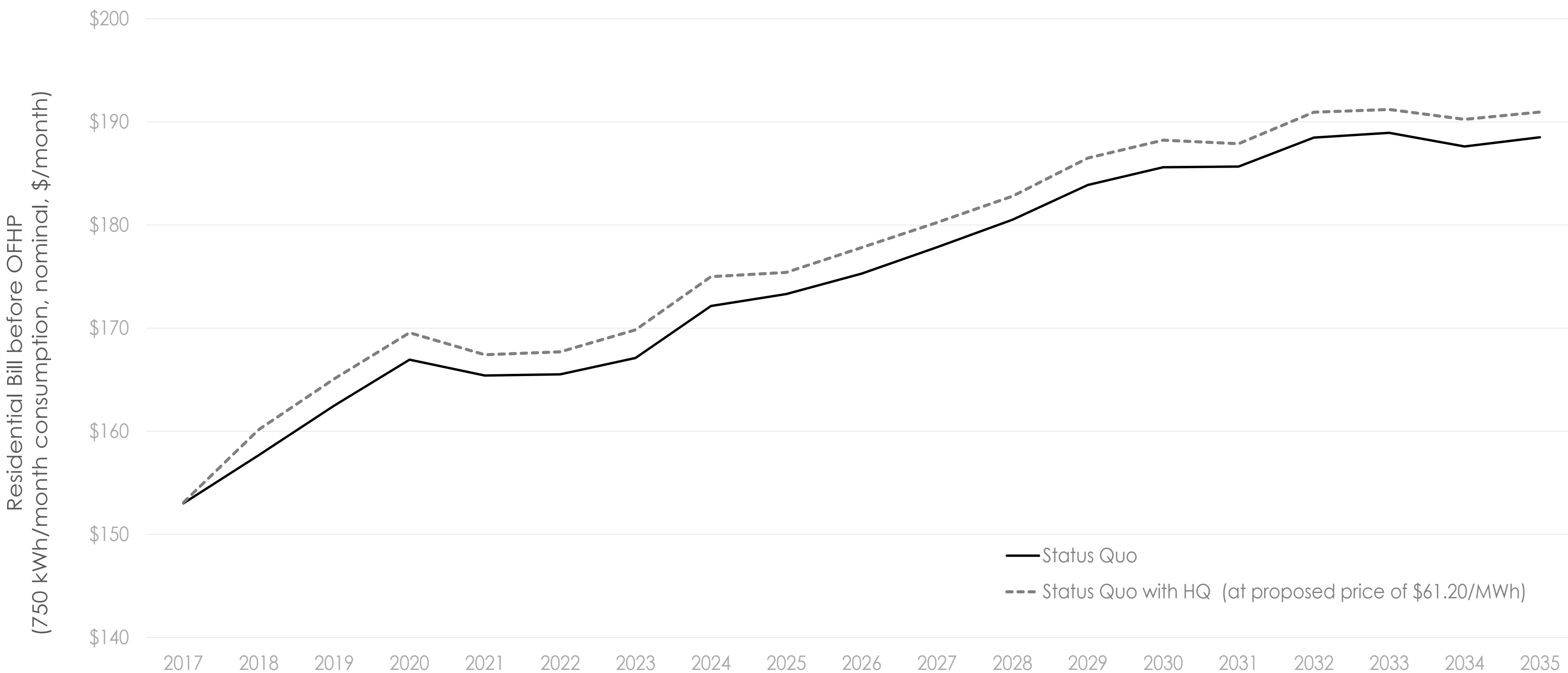



*Range reflects lower/higher gas/carbon price assumptions. The base outlook assumes a gas price of $3.81/MMBtu (Dawn, 2017 $ US) and a carbon price of $14/tonne in 2017 rising to $32/tonne in 2032 (2017 $ US). The lower range assumes $2.31/MMBtu (Dawn, 2017 $ US) gas price and the same carbon price as the base outlook. The higher range assumes the same gas price as the base outlook but a carbon price of $59/tonne by 2035 (2017 $ US).

**Total cost of electricity service:** Ontario's total cost of electricity service would increase by an average of $200M per year under the updated HQ import proposal of $61.20/MWh (figures in 2017 real dollars)



**Residential bill:** Ontario residential bills would increase by an average $2.4/month (nominal dollars) under the updated HQ import proposal. This is the net effect of higher GA costs partly offset by lower HOEP costs.

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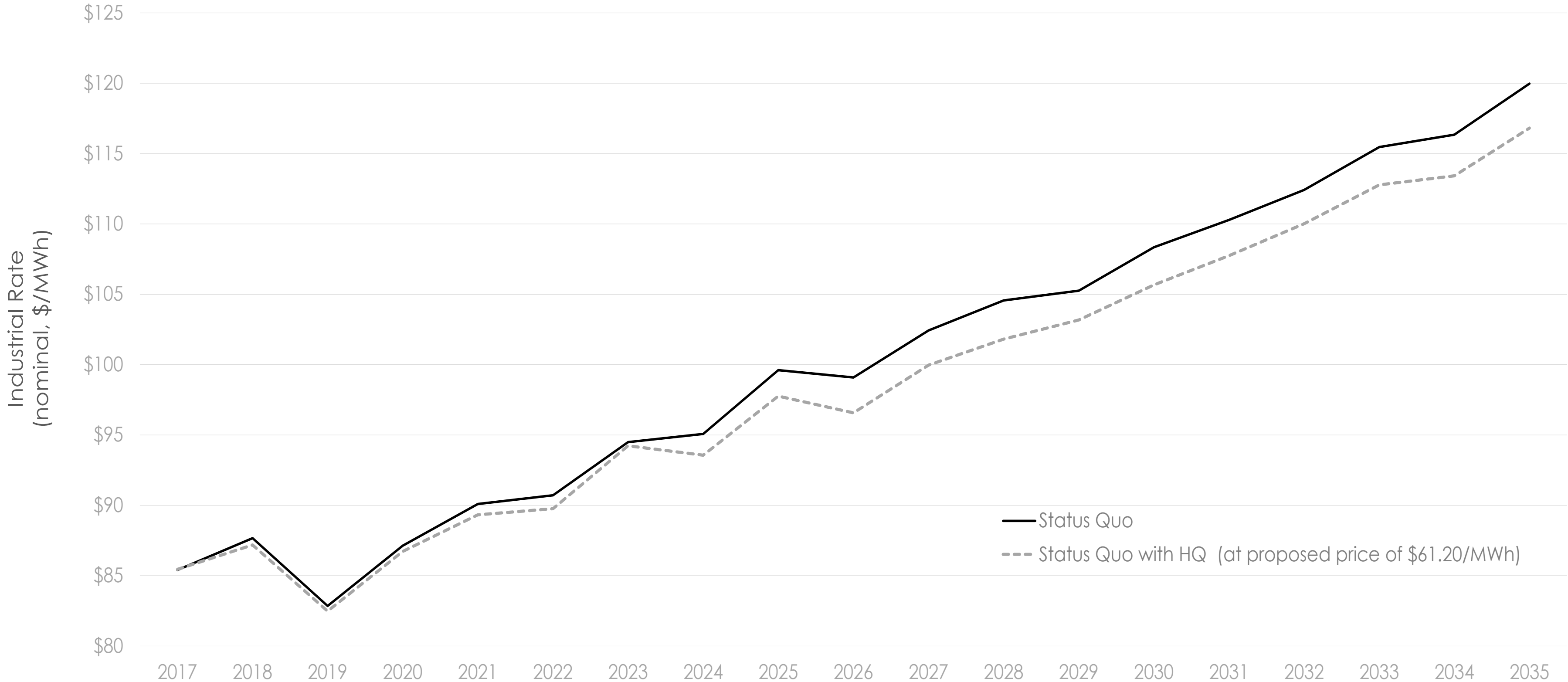
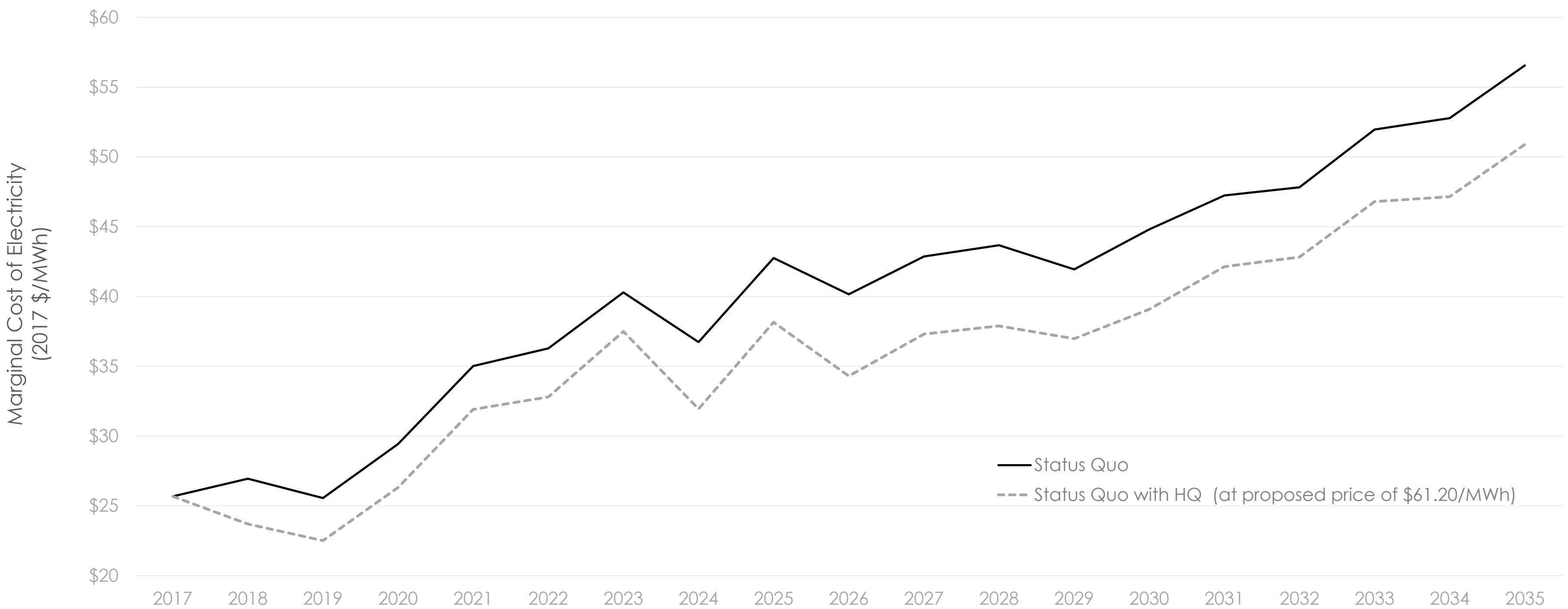
**Industrial rate:** Industrial rates reflect the average for the Class A direct connected customers. Impacts on individual industrial customers can vary significantly depending on their ability to take advantage of the ICI program. On average, Ontario industrial rates would decrease by $1.8/MWh (nominal dollars) under the updated HQ import proposal. In practice, rates would decrease for some, increase for others.



**Marginal cost of electricity:** Ontario's hourly marginal cost of electricity (estimate of HOEP) would decrease by an average $4.6/MWh (figures in 2017 real dollars) under the updated HQ import proposal price of $61.2/MWh. Lower marginal costs would lead to higher residential bills and lower industrial rates. These lower marginal costs added to the higher cost of the energy purchased from HQ would lead to higher global adjustment (GA) costs. The net effect of the lower HOEP and higher GA would lead to higher residential bills and a varied impact on average industrial rates depending on an industrial customer's ability to participate in the ICI program.



# Data tables for cost to customer results shown on slides 47 - 50

| Total Costs of Electricity Service (2017 $ billion) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | $20.6 | $20.6 | $20.2 | $20.5 | $19.9 | $19.5 | $19.4 | $19.8 | $19.6 | $19.4 | $19.4 | $19.5 | $19.6 | $19.5 | $19.3 | $19.4 | $19.2 | $18.8 | $18.8 |
| Status Quo with HQ (at proposed price of $61.2/MWh) | $20.6 | $20.9 | $20.5 | $20.8 | $20.1 | $19.8 | $19.8 | $20.0 | $19.8 | $19.6 | $19.6 | $19.7 | $19.8 | $19.7 | $19.4 | $19.6 | $19.3 | $19.0 | $19.0 |
| Delta "SQ with HQ" vs "SQ" | $0.0 | $0.3 | $0.3 | $0.3 | $0.2 | $0.2 | $0.3 | $0.3 | $0.2 | $0.2 | $0.2 | $0.2 | $0.2 | $0.2 | $0.2 | $0.2 | $0.2 | $0.2 | $0.2 |

| Residential Bill Prior to OFHP (assuming 750 KWh/month consumption, nominal $ per month) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | $153 | $158 | $162 | $167 | $165 | $166 | $167 | $172 | $173 | $175 | $178 | $181 | $184 | $186 | $186 | $188 | $189 | $188 | $189 |
| Status Quo with HQ (at proposed price of $61.2/MWh) | $153 | $160 | $165 | $170 | $167 | $168 | $170 | $175 | $175 | $178 | $180 | $183 | $186 | $188 | $188 | $191 | $191 | $190 | $191 |
| Delta "SQ with HQ" vs "SQ" | $0.1 | $2.5 | $2.6 | $2.6 | $2.0 | $2.2 | $2.7 | $2.8 | $2.1 | $2.5 | $2.4 | $2.3 | $2.6 | $2.6 | $2.2 | $2.5 | $2.3 | $2.6 | $2.4 |

| Industrial Rate (nominal $/month) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | $85 | $88 | $83 | $87 | $90 | $91 | $94 | $95 | $100 | $99 | $102 | $105 | $105 | $108 | $110 | $112 | $115 | $116 | $120 |
| Status Quo with HQ (at proposed price of $61.2/MWh) | $85 | $87 | $82 | $87 | $89 | $90 | $94 | $94 | $98 | $97 | $100 | $102 | $103 | $106 | $108 | $110 | $113 | $113 | $117 |
| Delta "SQ with HQ" vs "SQ" | $0.0 | -$0.5 | -$0.4 | -$0.4 | -$0.8 | -$1.0 | -$0.3 | -$1.5 | -$1.8 | -$2.5 | -$2.5 | -$2.8 | -$2.1 | -$2.7 | -$2.5 | -$2.4 | -$2.7 | -$2.9 | -$3.2 |

| Marginal Costs (2017 $/MWh) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | $26 | $27 | $26 | $29 | $35 | $36 | $40 | $37 | $43 | $40 | $43 | $44 | $42 | $45 | $47 | $48 | $52 | $53 | $57 |
| Status Quo with HQ (at proposed price of $61.2/MWh) | $26 | $24 | $23 | $26 | $32 | $33 | $37 | $32 | $38 | $34 | $37 | $38 | $37 | $39 | $42 | $43 | $47 | $47 | $51 |
| Delta "SQ with HQ" vs "SQ" | $0.0 | -$3.2 | -$3.1 | -$3.1 | -$3.1 | -$3.5 | -$2.8 | -$4.8 | -$4.6 | -$5.9 | -$5.6 | -$5.8 | -$5.0 | -$5.7 | -$5.1 | -$5.0 | -$5.2 | -$5.6 | -$5.7 |

4. Assessment of indicative options for enhancing the value of the Updated Hydro Quebec proposal to Ontario Ratepayers; as an alternative or complement to existing electricity resources in Ontario

## Opportunities may exist to enhance the value of Hydro Quebec's updated import proposal by better aligning it with Ontario's needs, either as an alternative or complement to existing electricity resources in Ontario

- The previous section assessed the updated HQ proposal in the context of the Status Quo electricity system outlook

- HQ imports could be an alternative to existing resources and commitments in Ontario:
  - 18,000 MW of installed supply reaches end of contract term throughout the planning outlook including about 9,000 MW of gas-fired generation beginning in the 2020s
  - Further opportunities to adapt the supply mix exist through the off-ramps enshrined in the Darlington and Bruce nuclear refurbishment agreements. These off-ramps can be exercised in response to sustained reductions in electricity demand and/or better alternatives that could emerge over the planning horizon

- Further to being an alternative to existing resource in Ontario, HQ imports could provide greater value if firm capacity were provided, timed to begin later in the planning horizon when needs emerge, and provided in quantities better aligned with Ontario's needs

## The IESO analyzed a range of scenarios that consider different supply mix adaptations to integrate HQ imports. Five additional scenarios were considered.

- **Scenario A** examines the implications of HQ imports being an alternative to reacquiring some gas-fired generation facilities at the end of contract term
- **Scenario B** examines the implications of HQ imports being an alternative to refurbishing two Darlington units
- **Scenario C** examines the implications of HQ imports being an alternative to refurbishing two Bruce units
- **Scenario D** examines the implications of HQ imports being an alternative to refurbishing one Darlington unit and not reacquiring some gas-fired generation facilities at the end of contract term
- **Scenario E** examines opportunities for HQ imports to meet projected capacity needs observed in the Status Quo outlook while displacing some energy production from gas-fired generation

## As a complement to the five scenarios, different import product arrangements were assessed under each scenario – focusing on better shaping the import product, inclusion of firm capacity, aligning timing with resource decisions/needs. These can be thought of as "sub-scenarios" or "cases"

- **Case 0** examines the implications of importing 8 TWh energy and 1 GW firm capacity, for 20 years, beginning in 2023 (align with when Pickering nuclear units begin to retire)

- **Case 1** examines the implications of importing 8 TWh energy and 1 GW firm capacity, for 20 years, beginning where aligned with the timing of when gas-fired generation facilities are no longer reacquired at contract expiry or when those nuclear units that were to be refurbished are retired per scenarios A through E.

- **Case 2** examines the implications of importing up to 8 TWh energy and up to 1 GW firm capacity, for 20 years, beginning where aligned with resource needs

# Summary of scenarios/cases assessed

| Scenario | Case | HQ Capacity | HQ Energy | HQ Timing | Gas | Nuclear |
|---|---|---|---|---|---|---|
| Status Quo | SQ | N/A | | | Status Quo | Status Quo |
| **Scenario** | **Case** | **HQ Capacity** | **HQ Energy** | **HQ Timing** | **Gas** | **Nuclear** |
| HQ imports as an alternative to reacquiring some gas-fired generation facilities at end of contract term | A0 | 1 GW | 8 TWh | January 2023, to align when Pickering is expected to reach end of life in 2022/2024 | Remove ~1 GW gas resources as contracts expire | Per Status Quo |
| | A1 | | | July 2024, following the shutdown of natural gas units in July 2024 and December 2025 | | |
| | A2 | Up to 1 GW as needed to meet reliability | Up to 8 TWh to meet energy requirements | January 2023, when a capacity need emerges | | |
| HQ imports as an alterative to refurbishing two Darlington units | B0 | 1 GW | 8 TWh | January 2023, to align when Pickering is expected to reach end of life in 2022/2024 | Per Status Quo | Retire Darlington unit 1 and 4 |
| | B1 | | | January 2025, following the shutdown of two nuclear units in September 2022 and December 2023 | | |
| | B2 | Up to 1 GW as needed to meet reliability | Up to 8 TWh to meet energy requirements | January 2023, when a capacity need emerges | | |
| HQ imports as an alternative to refurbishing two Bruce units | C0 | 1 GW | 8 TWh | January 2023, to align when Pickering is expected to reach end of life in 2022/2024 | Per Status Quo | Retire Bruce unit 7 and 8 |
| | C1 | | | January 2029, tied to the shutdown of two nuclear units in December 2028 and December 2030 | | |
| | C2 | Up to 1 GW as needed to meet reliability | Up to 8 TWh to meet energy requirements | January 2023, when a capacity need emerges | | |
| HQ imports as an alternative to refurbishing one Darlington unit and not reacquiring some gas-fired generation facilities at the end of contract term | D0 | 1 GW | 8 TWh | January 2023, to align when Pickering is expected to reach end of life in 2022/2024 | Remove 1 GW less one unit at Darlington of gas resource | Retire Darlington unit 4 |
| | D1 | | | January 2025, following the shutdown of one nuclear unit in December 2023 and a natural gas unit expiring in December 2023 | | |
| | D2 | Up to 1 GW as needed to meet reliability | Up to 8 TWh to meet energy requirements | January 2023, when a capacity need emerges | | |
| HQ imports to meet projected capacity needs observed in the Status Quo outlook while displacing some energy production from gas-fired generation | E0 | 1 GW | 8 TWh | January 2023, to align when Pickering is expected to reach end of life in 2022/2024 | Per Status Quo | Per Status Quo |
| | E1 | | | January 2025, when a long term capacity need is observed from the Status Quo | | |
| | E2 | Up to 1 GW as needed to meet reliability | Up to 8 TWh to meet energy requirements | January 2023, when a capacity need emerges | | |

## Each scenario was assessed from a number of perspectives and compared to the Status Quo outlook. Sensitivities were also performed on select cases.

- The impacts on the electricity system were examined from a number of perspectives including:
  - Impact on the timing of capacity needs
  - Impact on energy production from the generation fleet
  - Change in surplus baseload generation
  - Change in electricity sector emissions
  - Price of HQ imports at which the total cost of the electricity system remains unchanged relative to the Status Quo outlook. This is the break-even import price.
  - Total cost of electricity service and cost of electricity for consumers with the break-even import price.

- Sensitivity analysis was performed for select cases to assess the impact of:
  - Lower and higher natural gas and carbon prices
  - Higher nuclear costs
  - To the extent more energy is removed from a resources decision relative to the energy provided by imports, it is assumed the replacement energy could be provided by a range of resource types. Two book ends are examined: n one case the replacement energy is from gas-fired production, in the other case from a combination of wind and storage resources
  - Further information on sensitivity assumptions can be found in the appendix

# Scenario A: Overview
## HQ imports as an alternative to reacquiring some gas-fired generation facilities at the end of contract term

- Scenario A examines the implications of HQ imports being an alternative to reacquiring some gas-fired generation facilities at the end of contract term

- 1,090 MW of installed (940 MW effective) gas-fired generation capacity is removed to accommodate 1,000 MW of firm HQ import capacity
  - For modelling purposes, it is assumed that Brighton Beach GS which reaches its end of contract term July 2024 and Sarnia GS which reaches its end of contract term December 2025 are not to be reacquired at contract expiry. These facilities are otherwise assumed to continue to operate in the Status Quo outlook.
  - Nuclear fleet and remaining installed supply resources remain unchanged

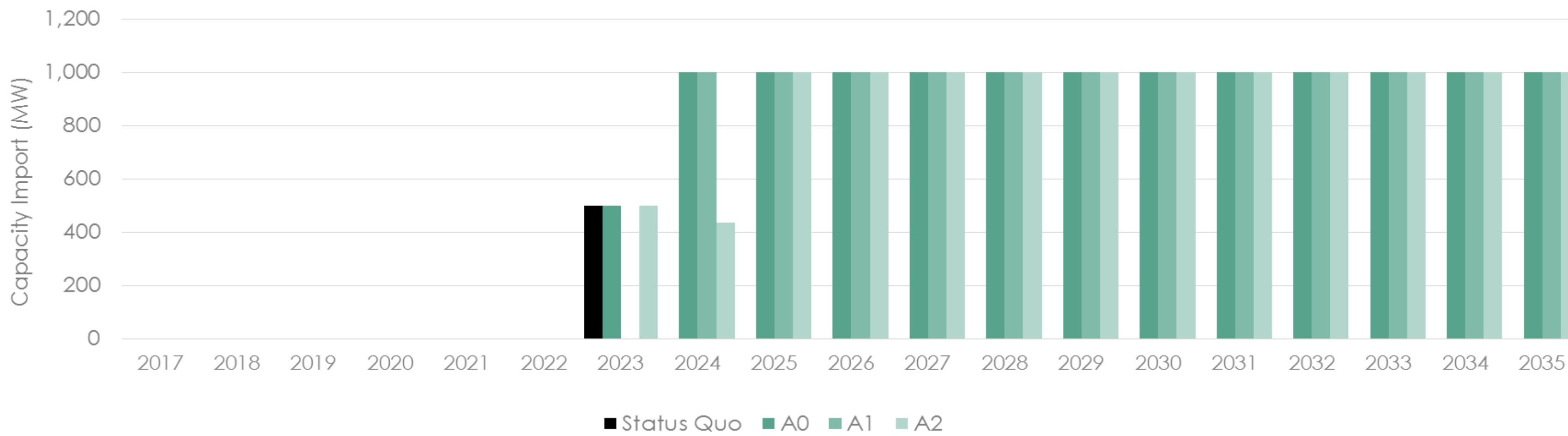
- With respect to HQ imports:
  - Case 0: Reflects 8 TWh energy and 1 GW firm capacity beginning in January 2023, following retirement of Pickering units, for a 20 year term
  - Case 1: Reflects 8 TWh energy and 1 GW firm capacity beginning in July 2024 for a 20 year term, immediately following the retirement of the first non-reacquired gas-fired facility
  - Case 2: Capacity import is limited to up to 1 GW to align with capacity needs. Energy import is limited to up to 8 TWh, in quantities proportional to the capacity import. Imports begin in January 2023 for a 20 year term.

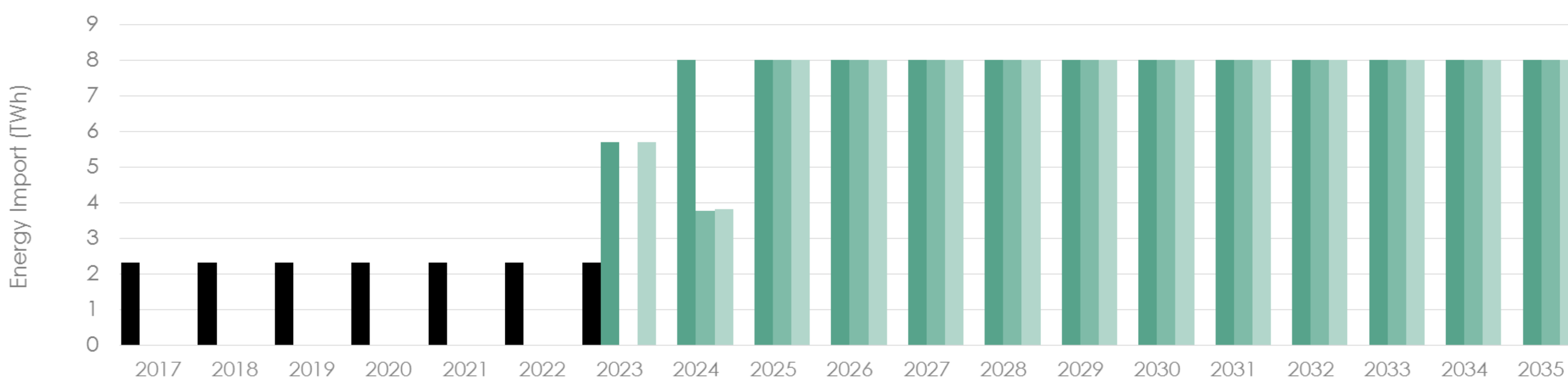
- In all Cases, the existing HQ agreement remains unchanged for the period 2017 to 2023. Where overlap exists with the proposed agreement, in 2023 in particular, the maximum HQ import quantity is limited to 8 TWh and 1 GW.

- To the extent there are additional capacity needs over and above existing resources which continue to operate post contract expiry and after accounting for HQ imports and resources removals (as described above), these needs are assumed to be met by a capacity based resources (modelled as an SCGT which is assumed to be the benchmark resource for capacity).

**Scenario A:** HQ import capacity and energy product evaluated

The new Quebec import product begins in 2023 in A0 (following retirement of the first two Pickering units), 2024 in A1 (when gas-facilities being replaced see their contracts expire), and 2023 in A2 (aligned with capacity needs).

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## **Scenario A:** Capacity adequacy outlook

The adequacy picture remains unchanged relative to the Status Quo outlook with the new Quebec import product. The capacity needs that exist in the Status Quo outlook are not addressed as the import product replaces gas-facilities that would otherwise be operating.


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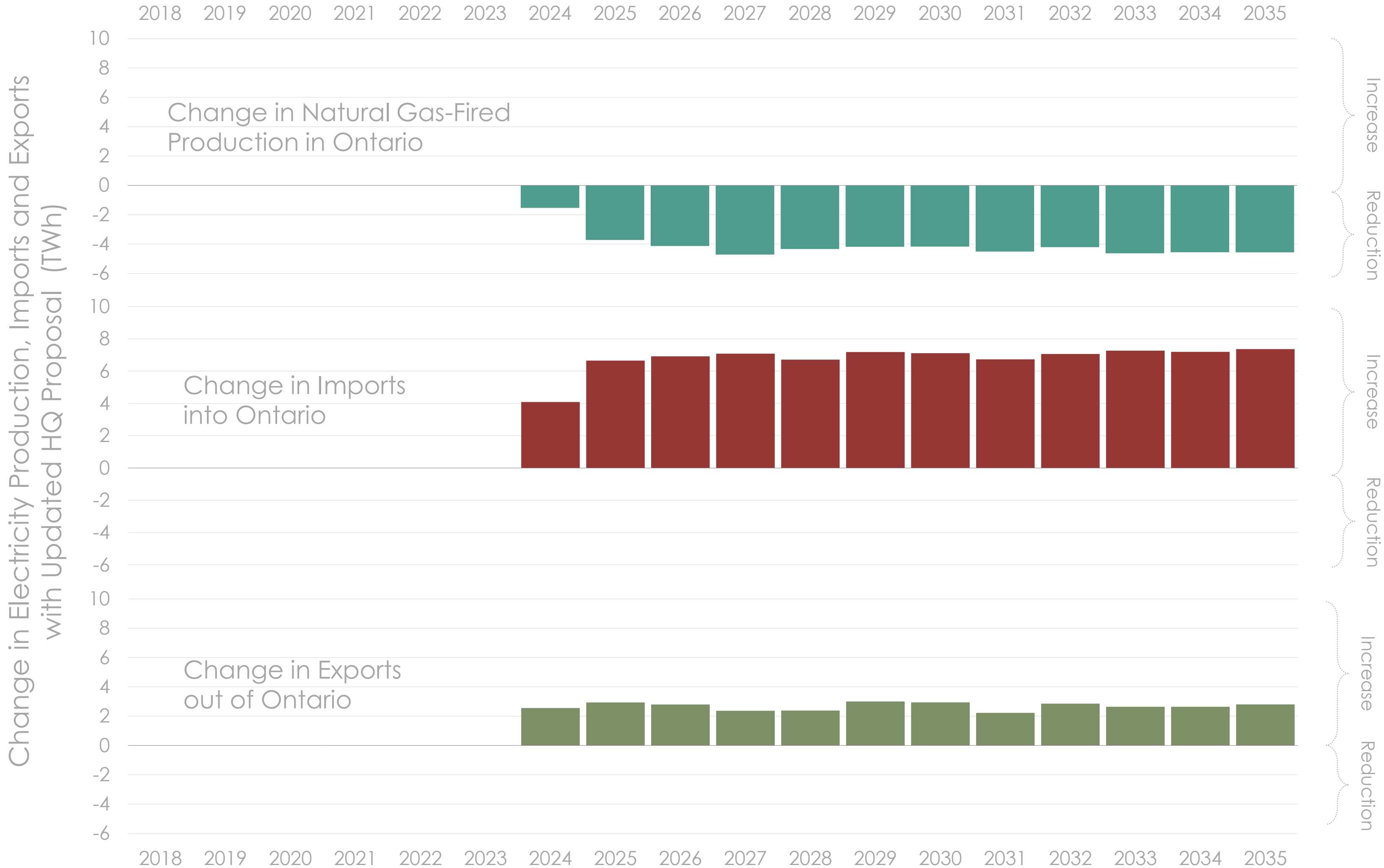
## **Scenario A:** Change in energy mix

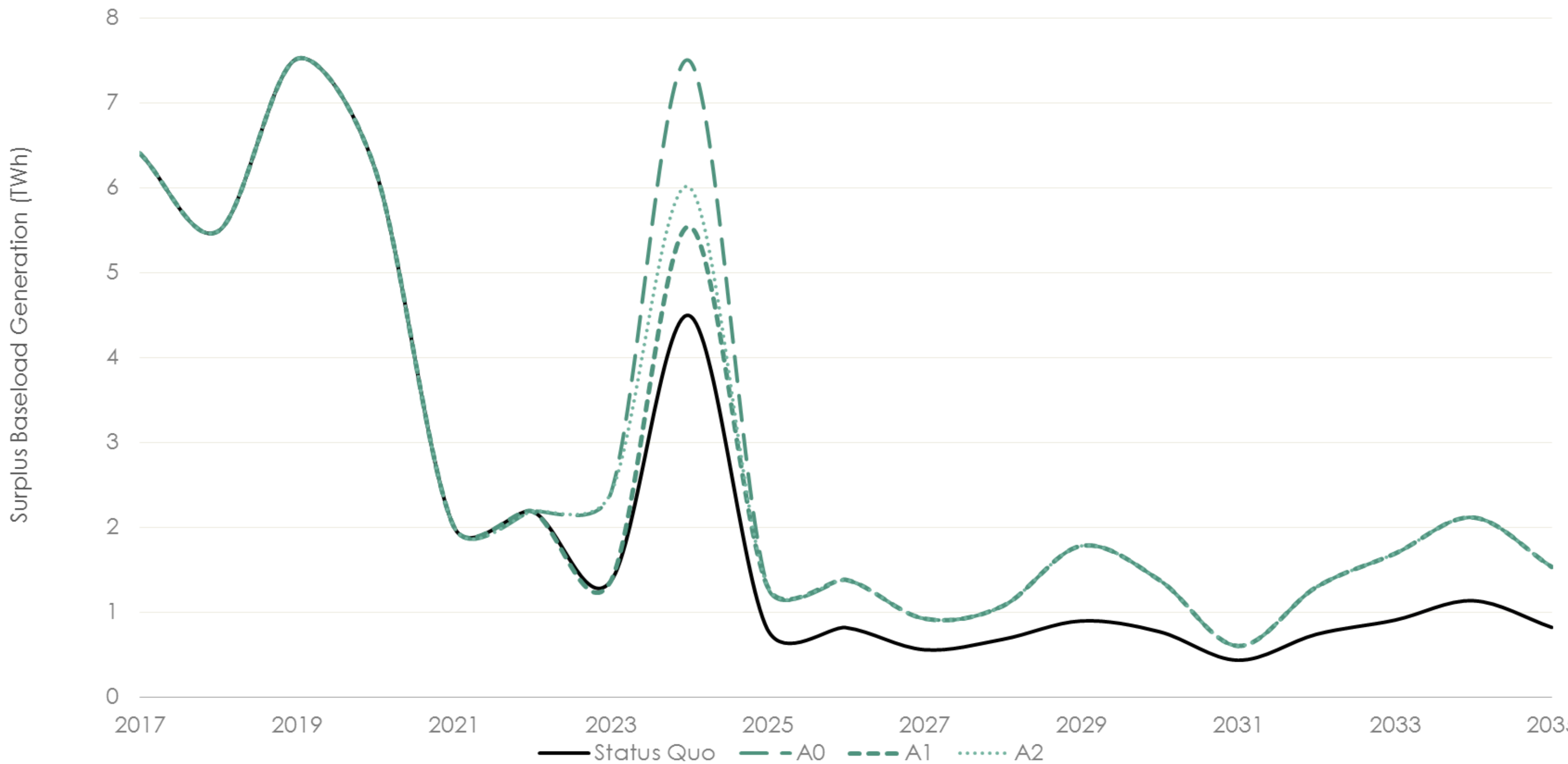
Relative to the Status Quo outlook, to accommodate 8 TWh of annual import from HQ, energy from gas-fired generation decreases by about 4 TWh/year while electricity exports increase by about 3 TWh/year




Note: Based on Case A1

## **Scenario A:** Surplus Baseload Generation

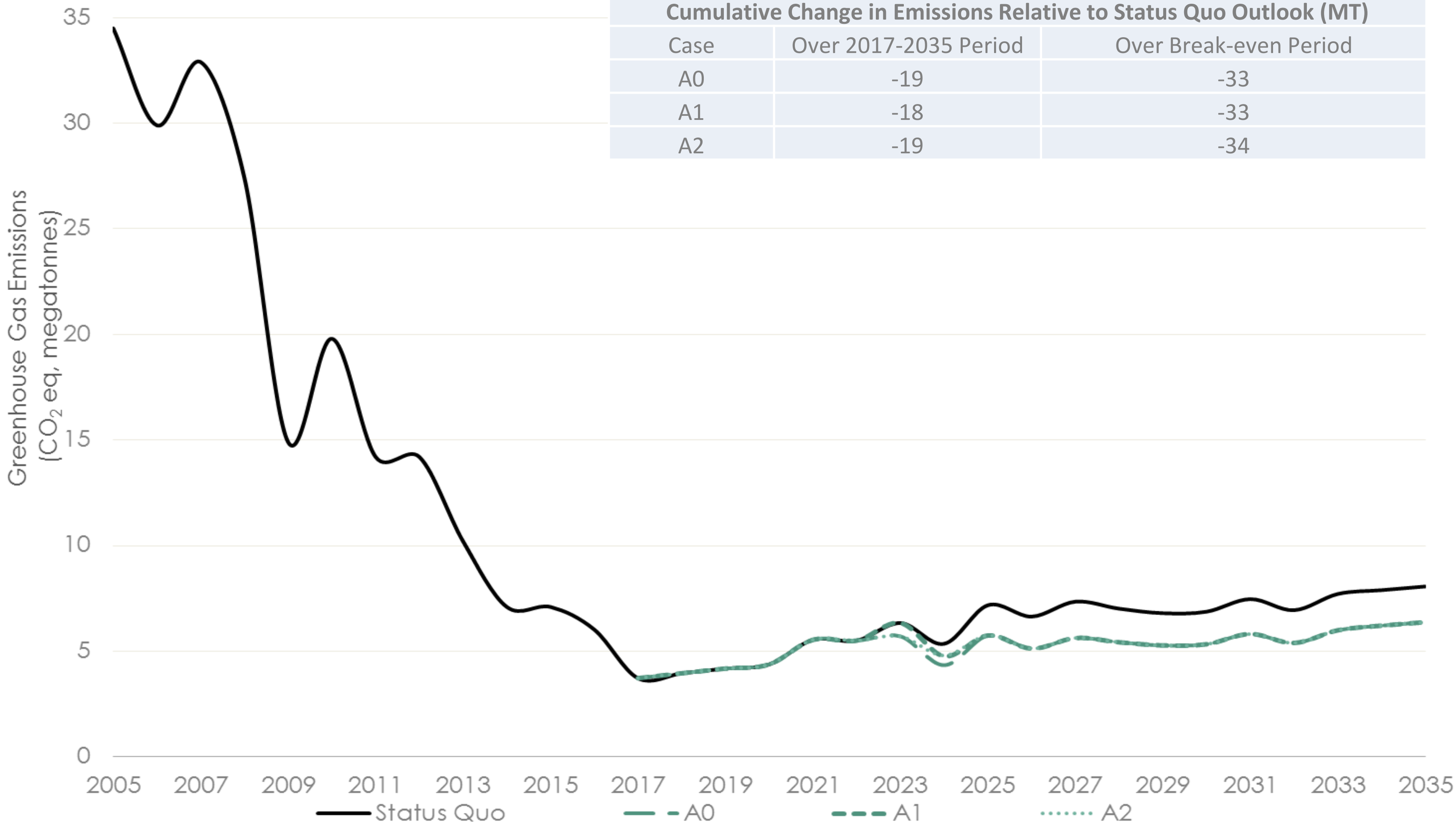
Relative to the Status Quo outlook, SBG increases by 1-2 TWh as the energy from the HQ import product is greater than the amount of gas-fired generation displaced



**Scenario A:** Greenhouse gas emissions

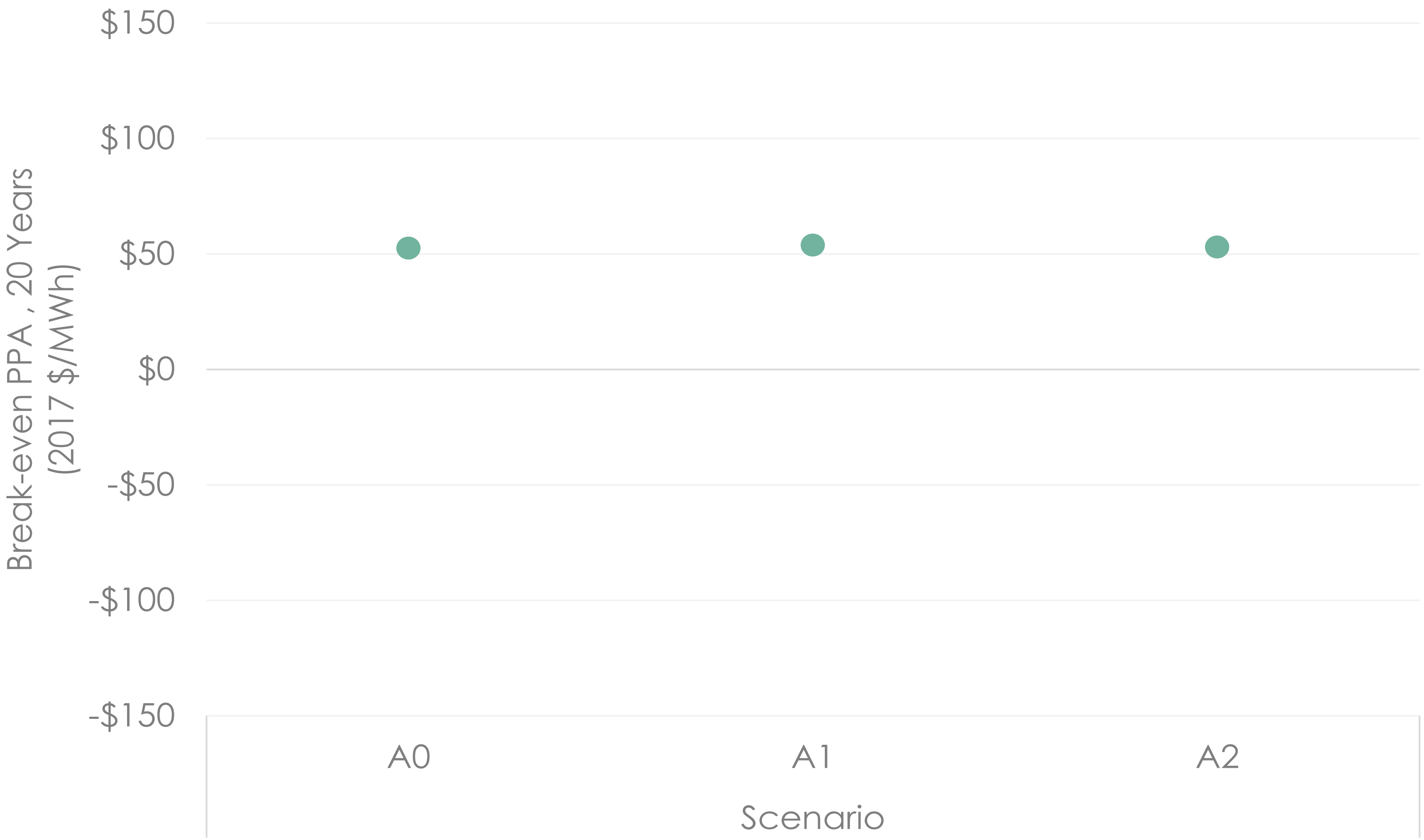
GHG emissions decline relative to the Status Quo outlook as the HQ import product displaces gas-fired generation

| Cumulative Change in Emissions Relative to Status Quo Outlook (MT) | | |
|---|---|---|
| Case | Over 2017-2035 Period | Over Break-even Period |
| A0 | -19 | -33 |
| A1 | -18 | -33 |
| A2 | -19 | -34 |



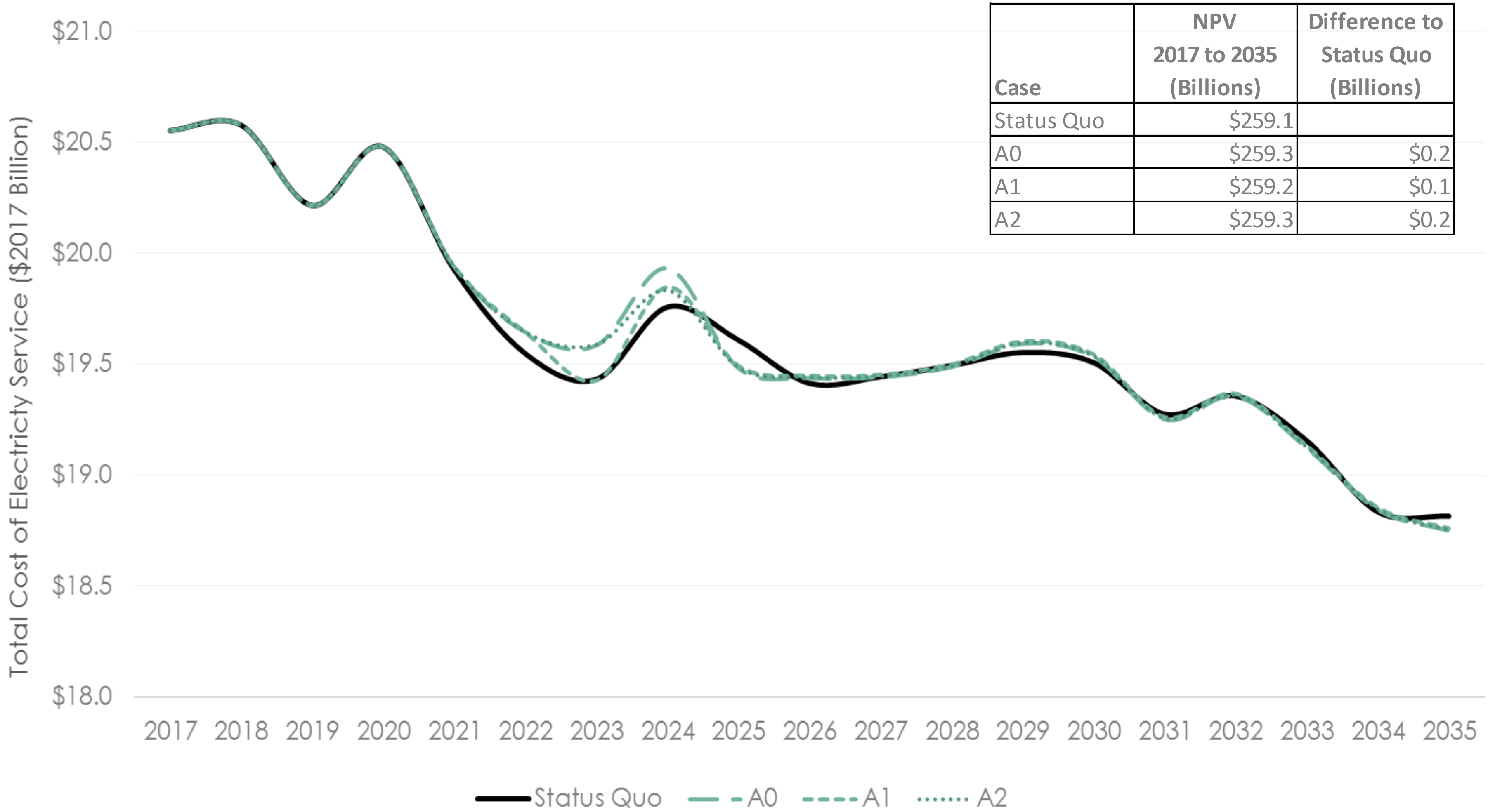
## **Scenario A:** Break-even price

The price of the HQ import product at which the total system cost is break-even with the Status Quo outlook, after accounting for reduced gas capacity/energy production, ranges between $53-$54/MWh.



# **Scenario A**: Total cost of electricity service

The total cost of electricity service at the Scenario A break-even price is higher than the Status Quo outlook, with the exception of the years 2024, 2025, and 2031. The NPV of the total cost of electricity service between 2017-2035 across the Scenario A cases is higher than the Status Quo outlook by $0.1-$0.2 billion (2017$).

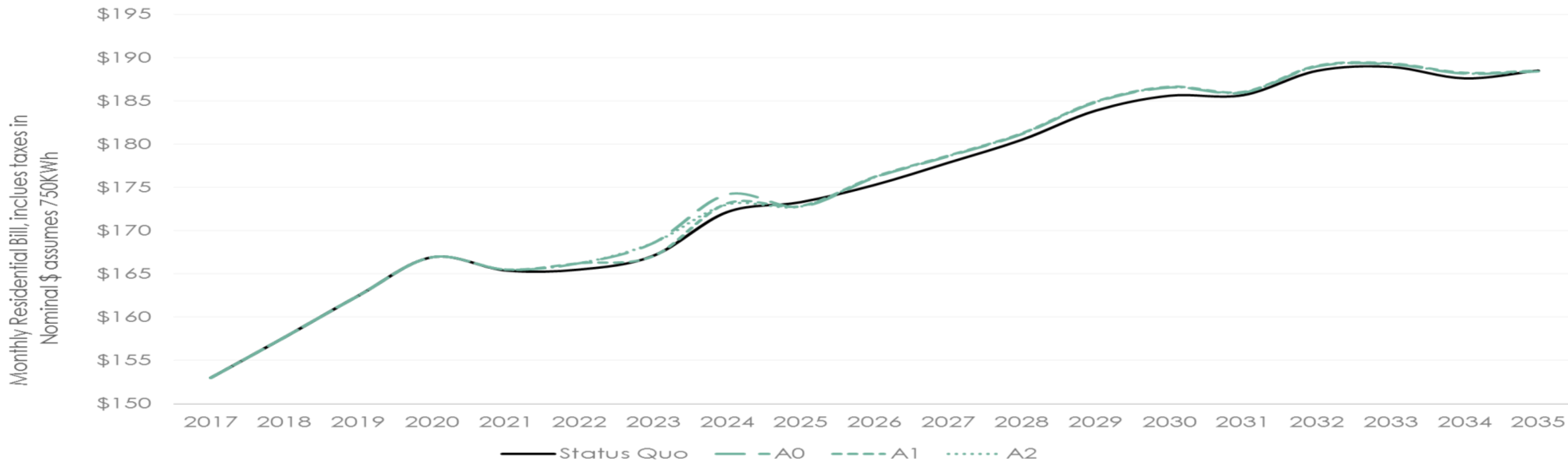


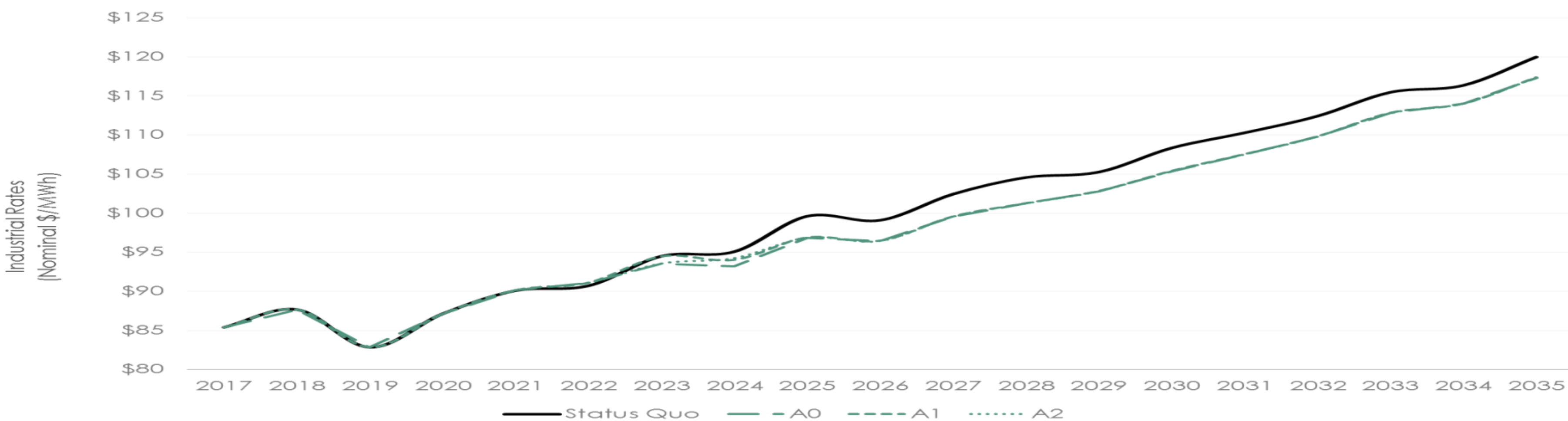

| Case | NPV 2017 to 2035 (Billions) | Difference to Status Quo (Billions) |
|---|---|---|
| Status Quo | $259.1 | |
| A0 | $259.3 | $0.2 |
| A1 | $259.2 | $0.1 |
| A2 | $259.3 | $0.2 |

Cases A0 through A2 reflect the HQ import product at its break-even price.

**Scenario A**: Residential monthly bills and industrial rates

Residential monthly bills (pre-OFHP) for Scenario A are generally above the Status Quo outlook with the exception of the year 2025. The highest difference in residential bills occurs in 2024, by about $2 per month. Industrial rates are lower for Scenario A compared to the Status Quo outlook due to the lower marginal costs resulting from the HQ imports replacing natural gas generation. Impacts on individual industrial customers can vary significantly depending on their ability to take advantage of the ICI program.



# Scenario B: Overview
## HQ imports as an alternative to refurbishing two Darlington units

- Scenario B examines the implications of HQ imports being an alternative to refurbishing the last two units at Darlington

- In this scenario, Darlington unit 1 and 4 are retired in September 2022 and December 2023, respectively, whereas in the Status Quo, unit 1 and 4 would have undergone refurbishment from January 2021 to October 2023, and July 2022 to March 2025, respectively, then assumed to operate for another 30 years
  - 1,762 MW of installed (1,756 MW effective) nuclear capacity is removed in this scenario

- With respect to HQ imports:
  - Case 0: Reflects 8 TWh energy and 1 GW firm capacity beginning in January 2023, following retirement of Pickering units, for a 20 year term
  - Case 1: Reflects 8 TWh energy and 1 GW firm capacity beginning in January 2025 for a 20 year term, following the shutdown of the first Darlington unit in September 2022 but when sustained adequacy needs begin to emerge.
  - Case 2: Capacity import is limited to up to 1 GW to align with capacity needs. Energy import is limited to up to 8 TWh, in quantities proportional to the capacity import. Imports begin in January 2023 for a 20 year term.

- In all Cases, the existing HQ agreement remains unchanged for the period 2017 to 2023. Where overlap exists with the proposed agreement, in 2023 in particular, the maximum HQ import quantity is limited to 8 TWh and 1 GW.

# Scenario B: Overview (continued…)
## HQ imports as an alternative to refurbishing two Darlington units

- Given the mismatch in capacity, energy, and operating timeframe associated with nuclear units removed and HQ imports added in, gas-fired generation is assumed to bridge the difference. Additional sensitivity analysis is performed to assess the implication of bridging the difference with non-emitting resources (see next bullet).

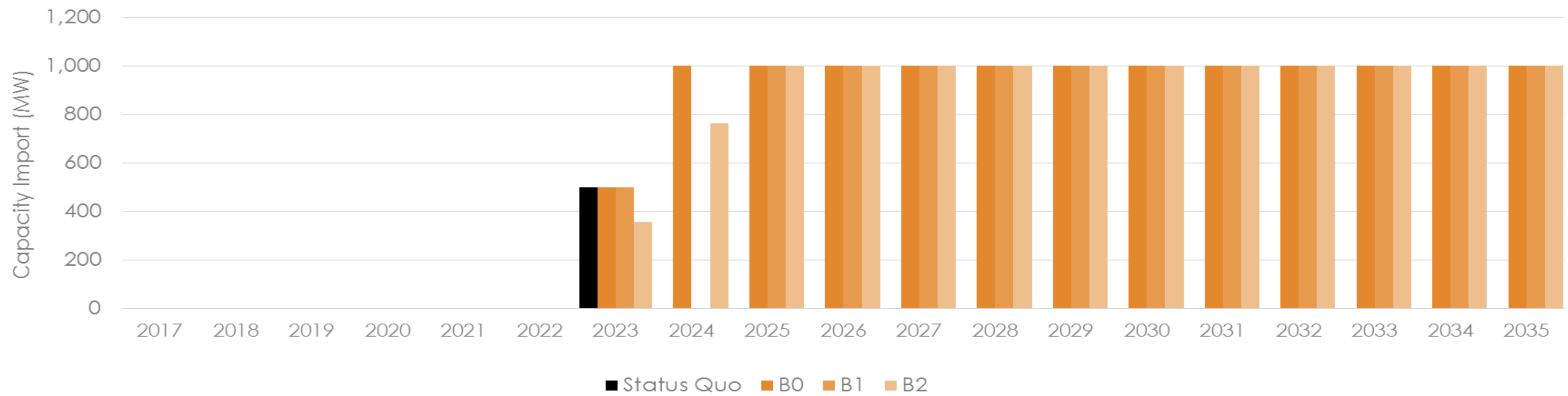
- Additional analysis is performed on Scenario B to assess the impact of the following on the value of HQ imports:
  - Higher cost of Darlington refurbishment and Darlington off-ramp
  - Lower and higher natural gas/carbon price
  - A combination of wind/storage resources as the bridge resource to account for the mismatch in capacity, energy, and operating timeframe associated with nuclear units removed and HQ imports added.

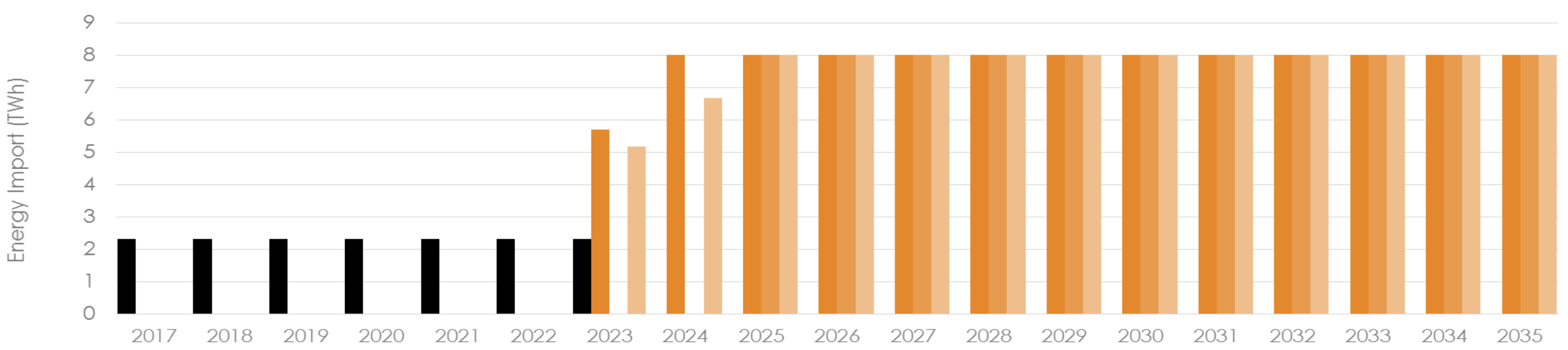
- Darlington availability and cost assumptions reflects data provided by OPG

- To the extent there are additional capacity needs over and above existing resources which continue to operate post contract expiry and after accounting for HQ imports added in and resources removed (as described above), these needs are assumed to be met by a capacity based resources (modelled as an SCGT which is assumed to be the benchmark resource for capacity).

## **Scenario B:** HQ import capacity and energy product evaluated

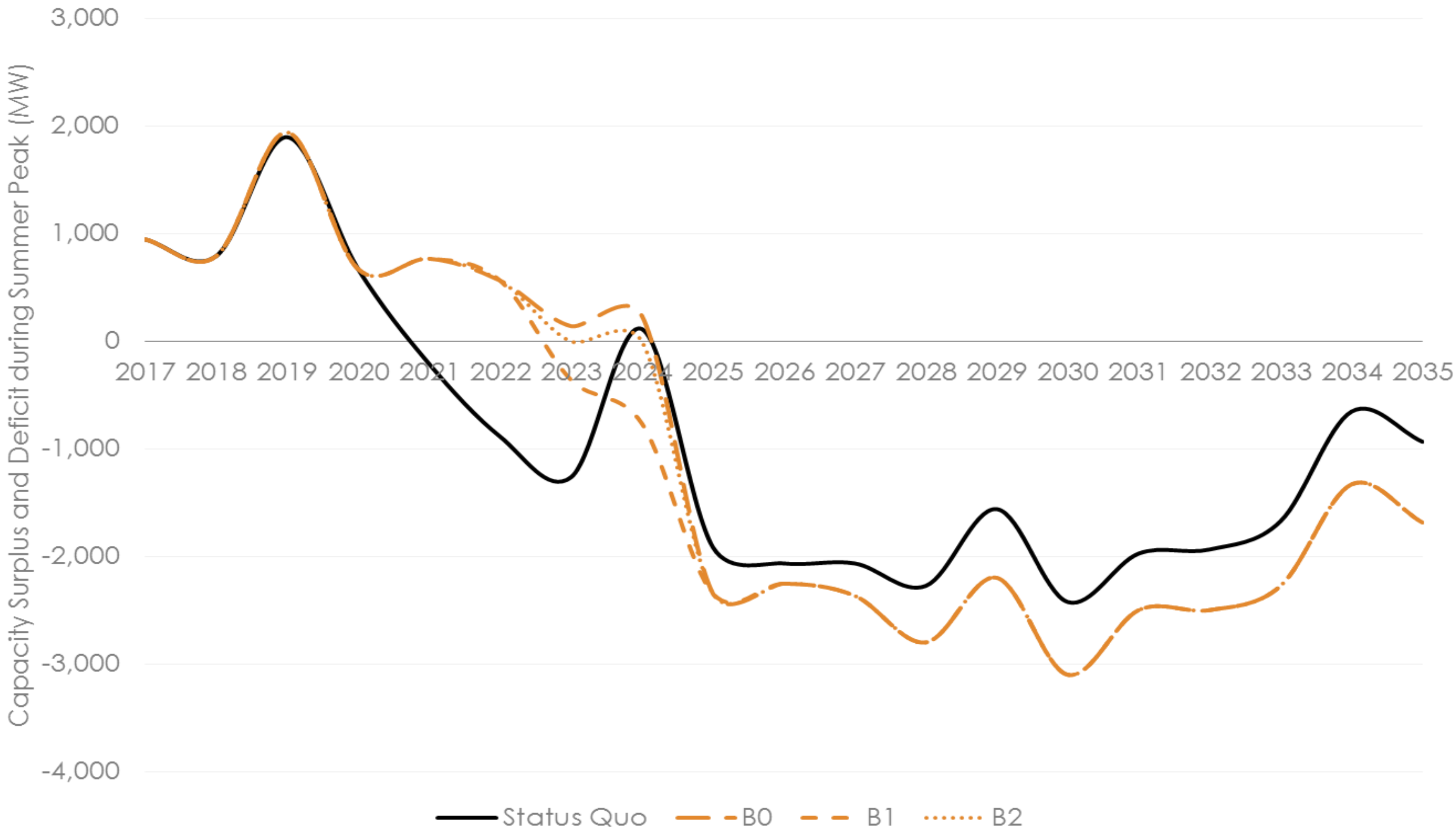
The new Quebec import product begins in 2023 in B0 (following retirement of the first two Pickering units) and 2025 in B1 (following when sustained adequacy needs begin to emerge). In B2, about 360 MW of the import product begins in 2023, ramping up to 1,000 MW by 2025 to align with capacity needs.



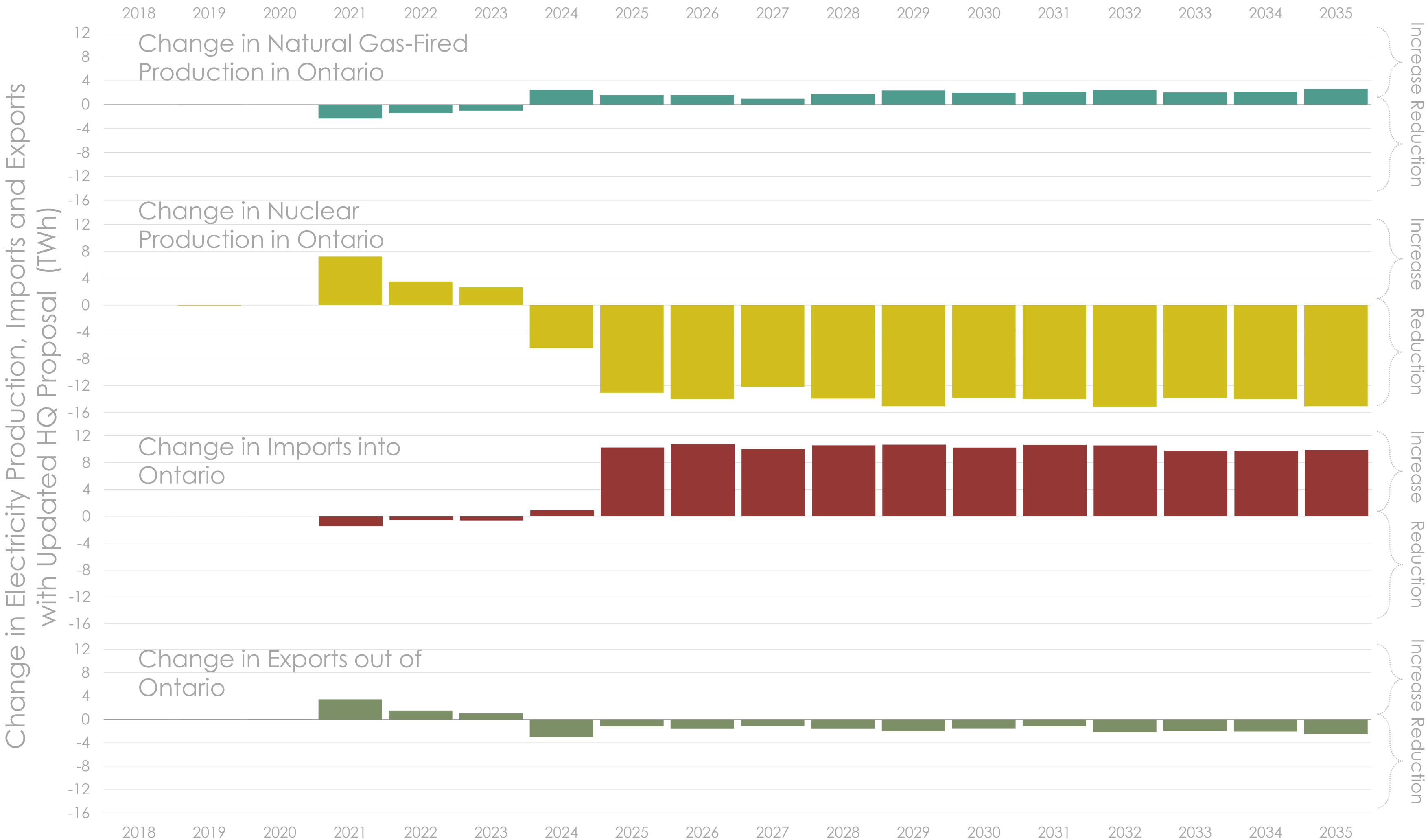
## **Scenario B:** Capacity adequacy outlook

Capacity needs increase relative to the Status Quo outlook as the capacity provided from the two off-ramped Darlington units is greater than the amount of capacity provided by the HQ import product.



**Scenario B:** Change in energy mix

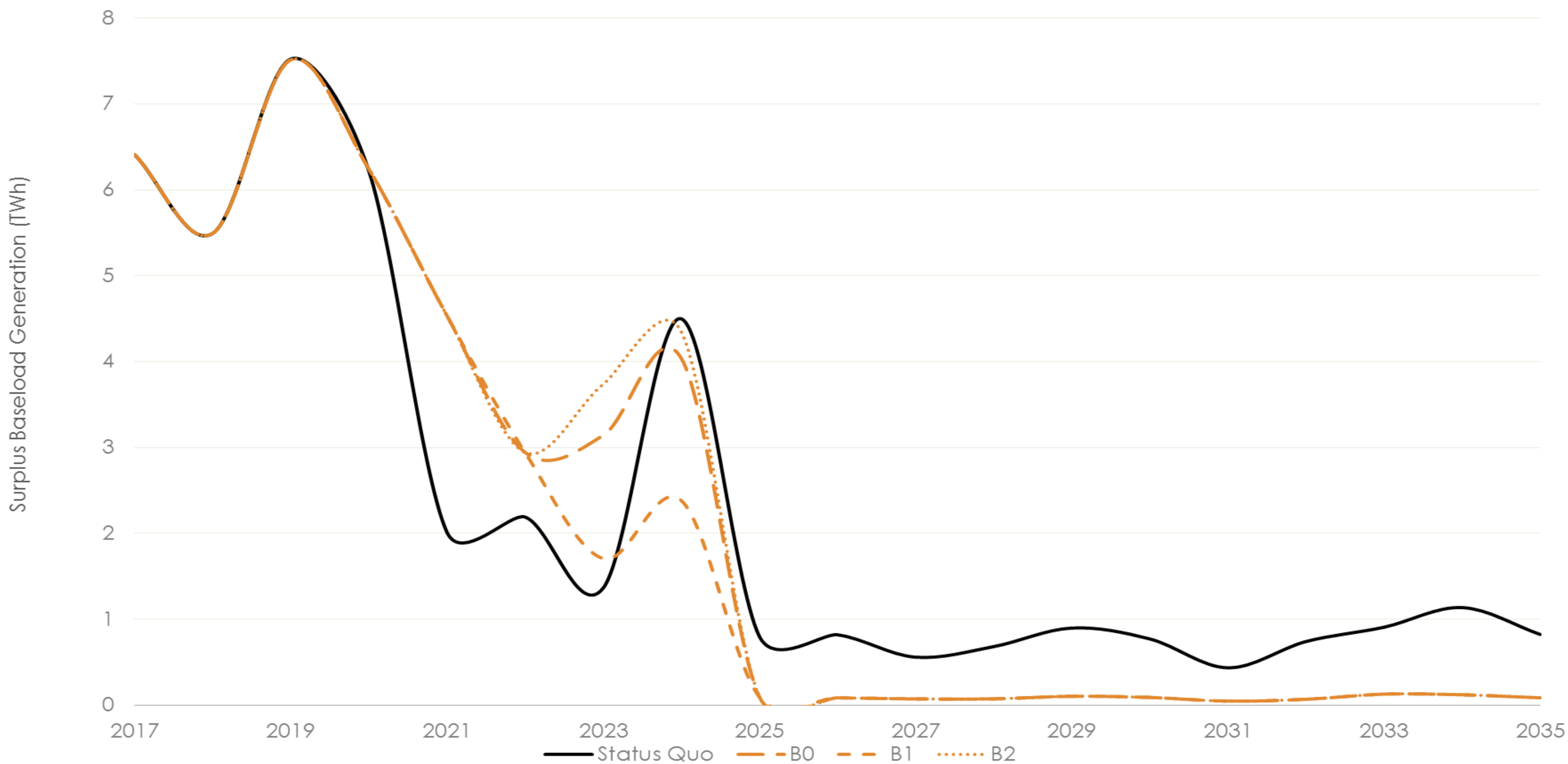
Relative to the Status Quo outlook, to accommodate 8 TWh of annual HQ imports, nuclear production declines by 12-15 TWh/year while production from gas-fired generation increases by 1-3 TWh/year. Exports decrease by 1-3 TWh/year.




Note: Based on Case B1

**Scenario B:** Surplus Baseload Generation

Relative to the Status Quo outlook, SBG declines to virtually zero as baseload nuclear units are retired while imported energy is added in quantities less than the nuclear energy removed.

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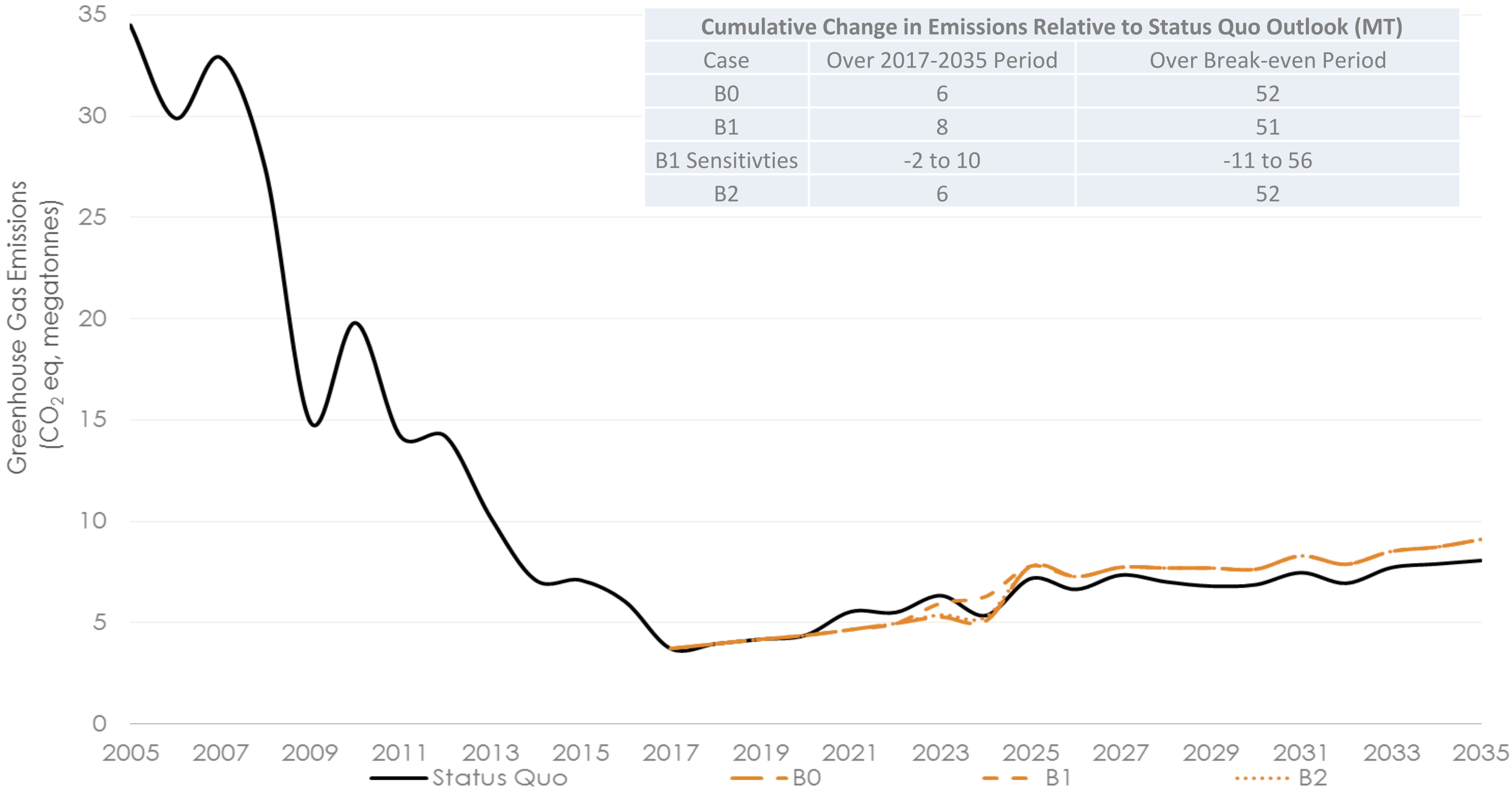
## **Scenario B:** Greenhouse gas emissions

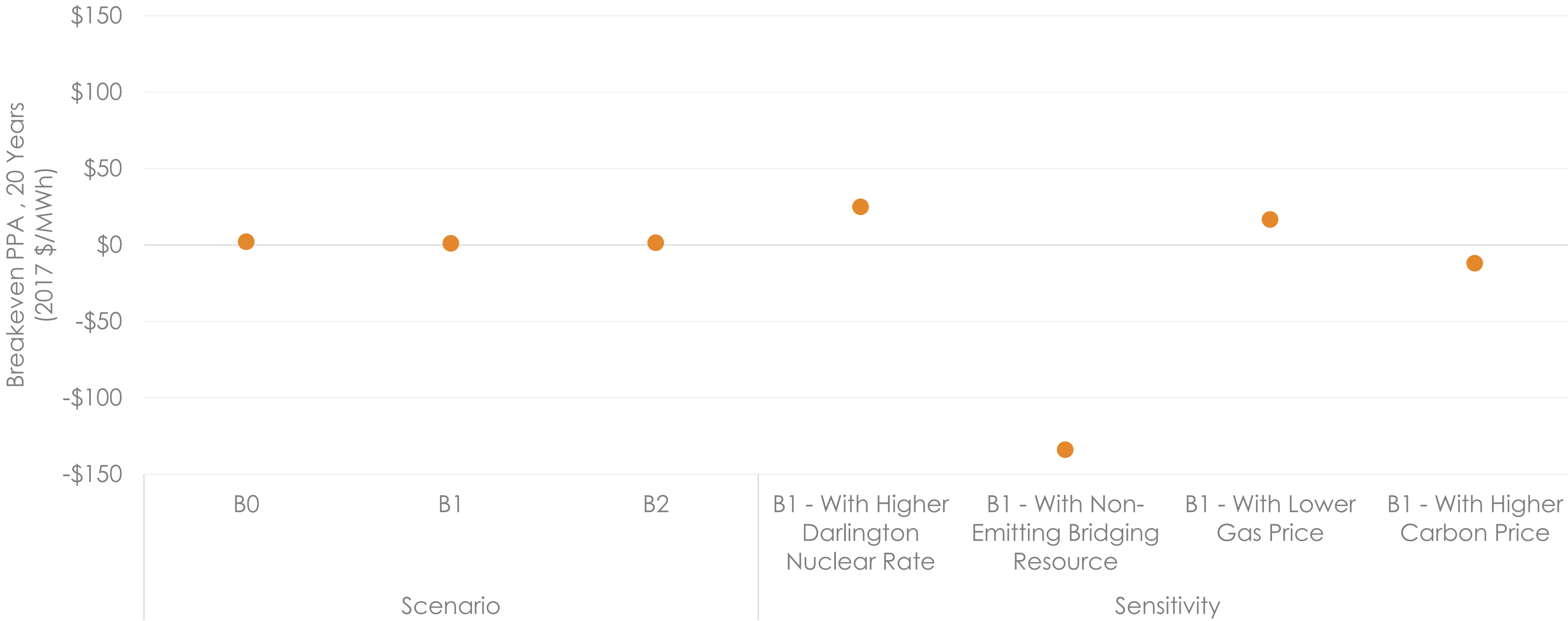
$CO_2$ emissions increase relative to the Status Quo outlook as Darlington units are retired and replaced with the Quebec energy import product. This is because gas-fired generation bridges the difference in energy available from the two Darlington units (which is more) relative to the imported energy that is added in (which is less).




| Cumulative Change in Emissions Relative to Status Quo Outlook (MT) | | |
|---|---|---|
| Case | Over 2017-2035 Period | Over Break-even Period |
| B0 | 6 | 52 |
| B1 | 8 | 51 |
| B1 Sensitivties | -2 to 10 | -11 to 56 |
| B2 | 6 | 52 |

**Scenario B:** Break-even price

## The price of the HQ import product at which the total system cost is break-even with the Status Quo outlook is about $0/MWh across the B cases but could range between minus $134/MWh and $25/MWh across the sensitivity cases.

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## **Scenario B:** Total cost of electricity service

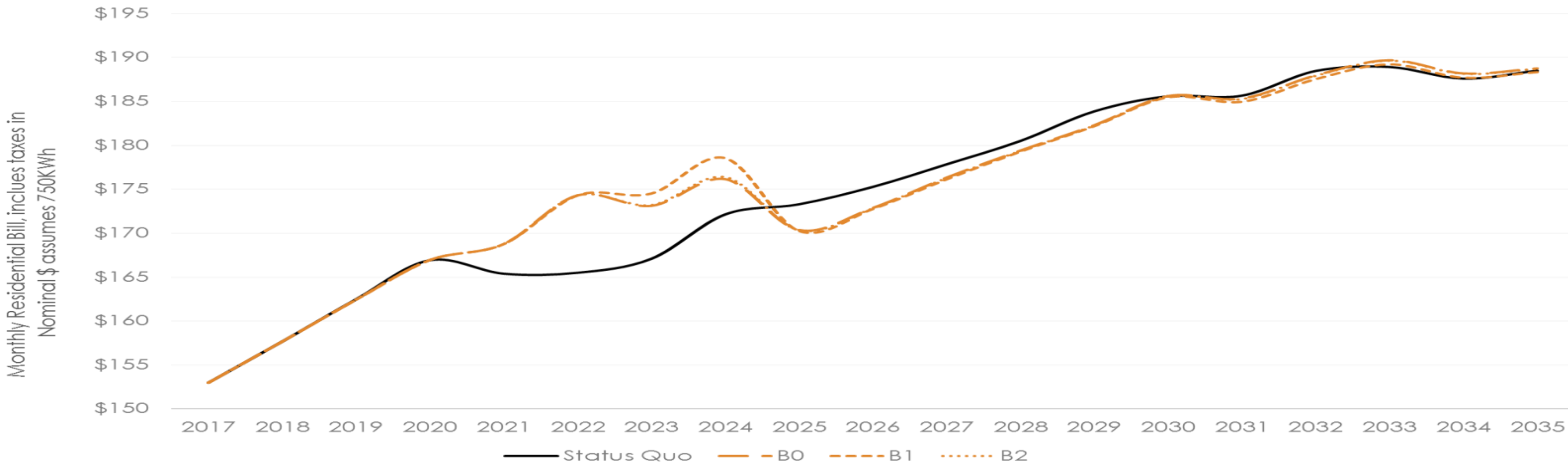
The total cost of electricity service at the Scenario B break-even price is higher than the Status Quo outlook with the exception of the years 2024 through 2032. The NPV of the total cost of electricity service between 2017-2035 across the Scenario B cases is higher than the Status Quo outlook by $1.6 - $1.9 billion (2017$).

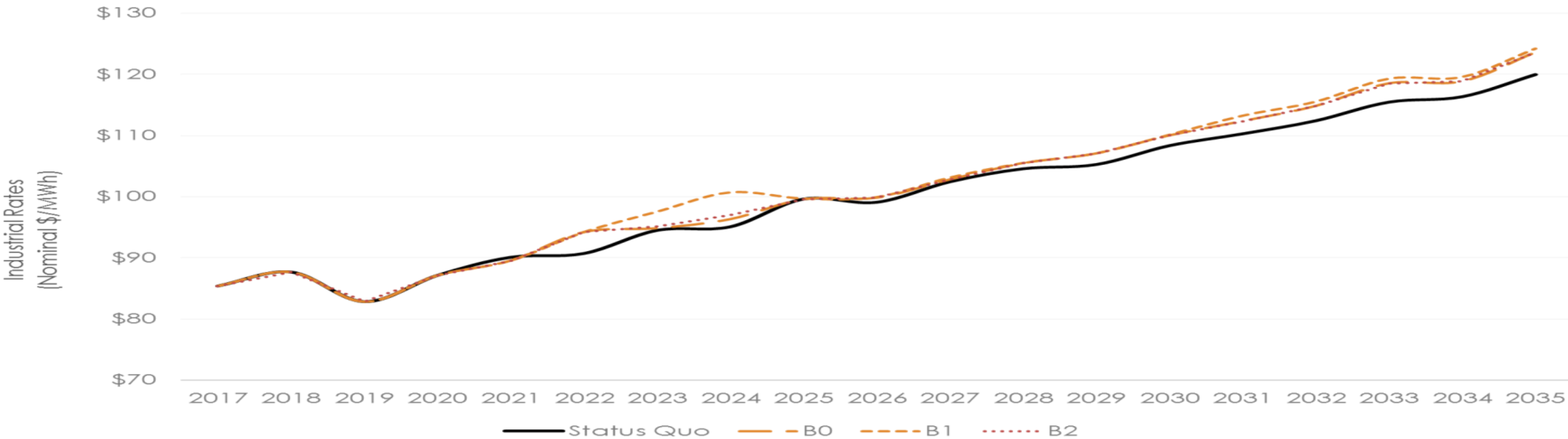
| Case | NPV 2017 to 2035 (Billions) | Difference to Status Quo (Billions) |
|---|---|---|
| Status Quo | $259.1 | |
| B0 | $260.7 | $1.6 |
| B1 | $261.0 | $1.9 |
| B2 | $260.7 | $1.6 |


Cases B0 through B2 reflect the HQ import product at its break-even price.

**Scenario B:** Residential monthly bills and industrial rates

Residential monthly bills (pre-OFHP) for Scenario B is above the Status Quo outlook in the 2020 to 2025 period and falling below in 2025 to 2030. Industrial rates, in general, are above the Status Quo outlook from 2022 to 2035.

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# Scenario C: Overview
## HQ imports as an alternative to refurbishing two Bruce units

- Scenario C examines the implications of not refurbishing the last two Bruce units

- In this scenario, Bruce units 7 and 8 are assumed to be retired in December 2028 and December 2030, respectively, where as in the Status Quo, unit 7 and 8 would have undergone refurbishment from July 2028 to June 2031, and July 2030 to June 2033, respectively, then assumed to operate for another 30 years.
  - 1,644 MW of installed (1,637 GW effective) nuclear capacity is removed in this scenario

- With respect to HQ imports:
  - Case 0: Reflects 8 TWh energy and 1 GW firm capacity beginning in January 2023, following retirement of Pickering units, for a 20 year term
  - Case 1: Reflects 8 TWh energy and 1 GW firm capacity beginning in January 2029 for a 20 year term, following the shutdown of the first Bruce unit in December 2028
  - Case 2: Capacity import is limited to up to 1 GW to align with capacity needs. Energy import is limited to up to 8 TWh, in quantities proportional to the capacity import. Imports begin in January 2025 for a 20 year term.

- In all Cases, the existing HQ agreement remains unchanged for the period 2017 to 2023. Where overlap exists with the proposed agreement, in 2023 in particular, the maximum HQ import quantity is limited to 8 TWh and 1 GW.

# **Scenario C:** Overview (continued…)
## HQ imports as an alternative to refurbishing two Bruce units

- Given the mismatch in capacity, energy, and operating timeframe associated with nuclear units removed and HQ imports added in, gas-fired generation is assumed to bridge the difference. Additional sensitivity analysis is performed to assess the implication of bridging the difference with non-emitting resources (see next bullet).

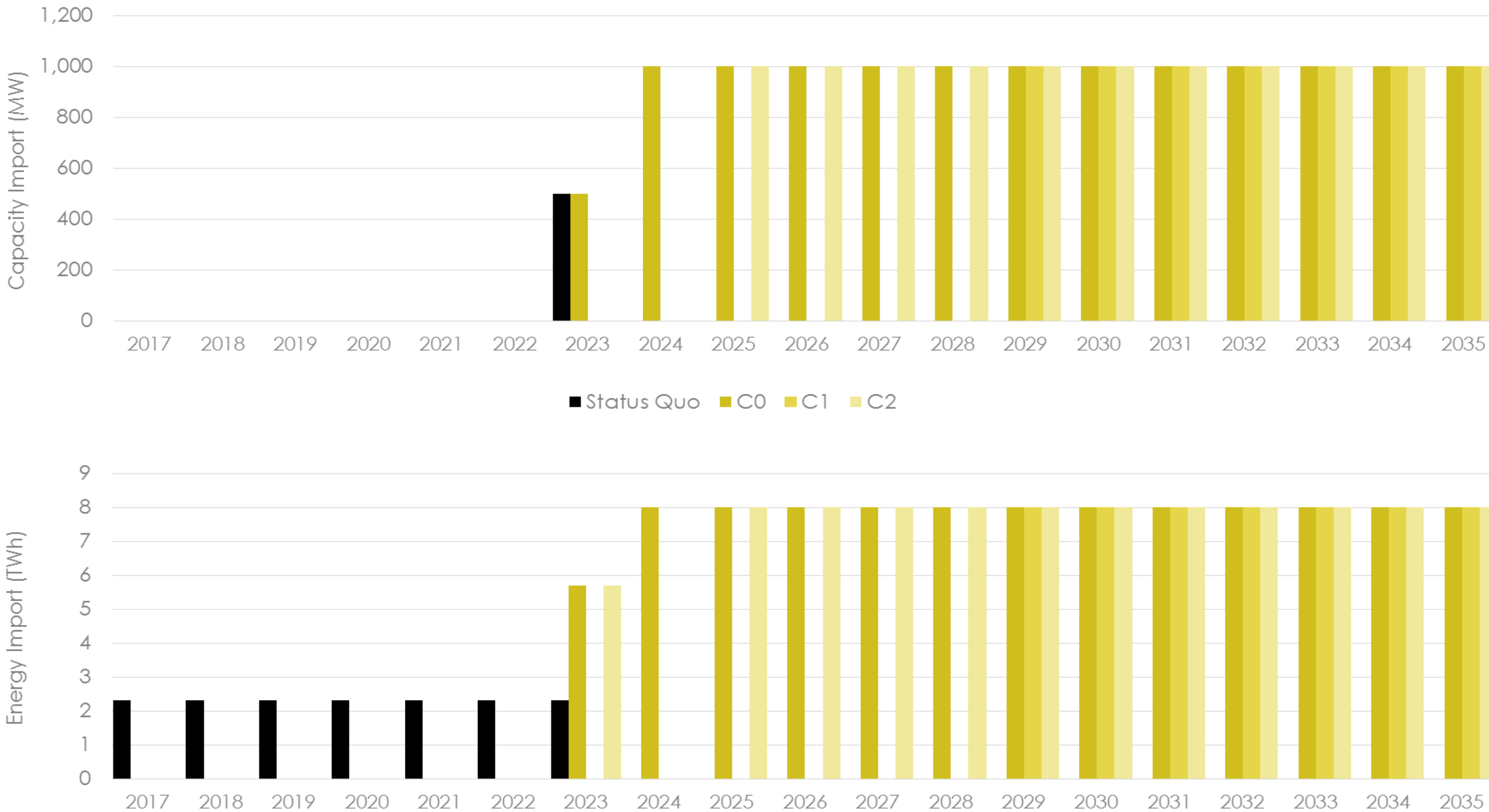
- Additional analysis is performed on Scenario C to assess the impact of the following on the value of HQ imports:
  - Higher cost of Bruce refurbishment and Bruce off-ramp
  - Lower and higher natural gas/carbon price
  - A combination of wind/storage resources as the bridge resource to account for the mismatch in capacity, energy, and operating timeframe associated with nuclear units removed and HQ imports added.

- Bruce availability and cost assumptions reflects data provided by Bruce Power and per the ABPRIA

- To the extent there are additional capacity needs over and above existing resources which continue to operate post contract expiry and after accounting for HQ imports added in and resources removed (as described above), these needs are assumed to be met by a capacity based resources (modelled as an SCGT which is assumed to be the benchmark resource for capacity).

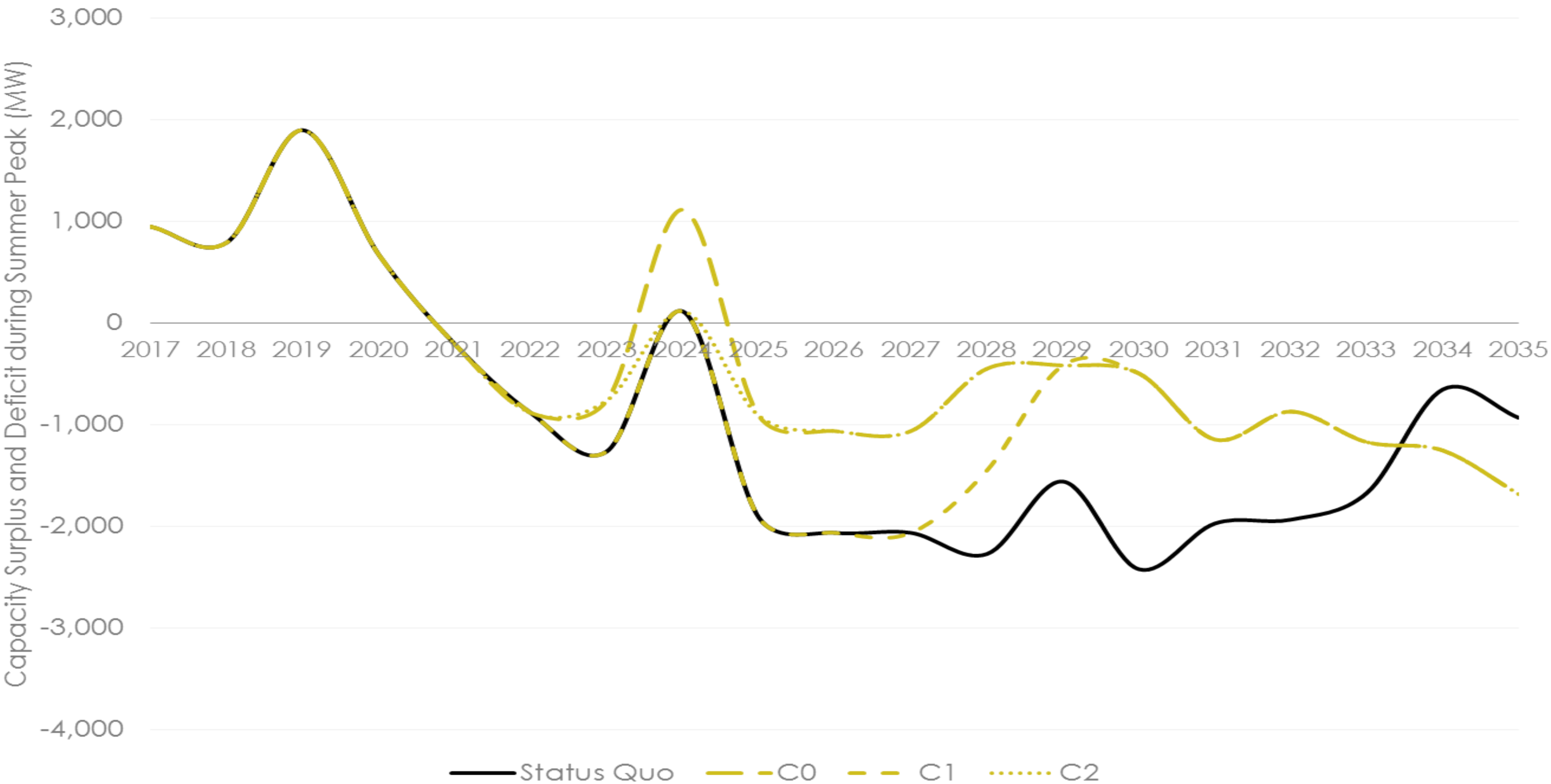
**Scenario C:** HQ import capacity and energy product evaluated

The new Quebec import product begins in 2023 in C0 (following retirement of the first two Pickering units), 2029 in C1 (coinciding with the retirement of the first Bruce unit), and 2025 in C2 (when sustained adequacy needs begin to emerge).



## **Scenario C:** Capacity adequacy outlook

Capacity needs decreases throughout the 2020s relative to the Status Quo outlook as the HQ import product addresses existing capacity needs while Bruce units that would otherwise be on refurbishment outage operate for an additional year. Beyond the 2030s, capacity needs increase relative to the Status Quo case as the capacity associated with Bruce units removed from service is greater than the capacity provided by the HQ import product.

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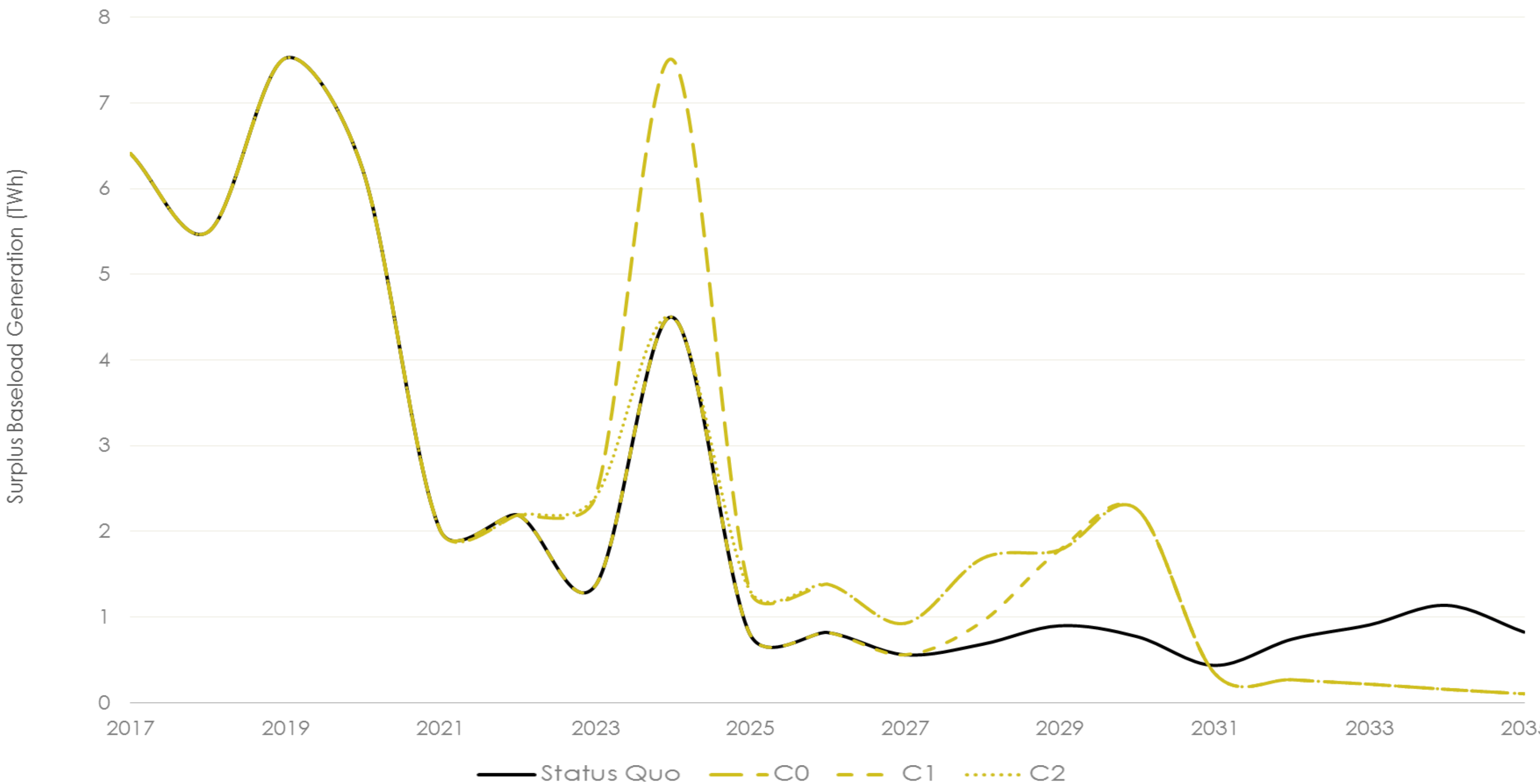
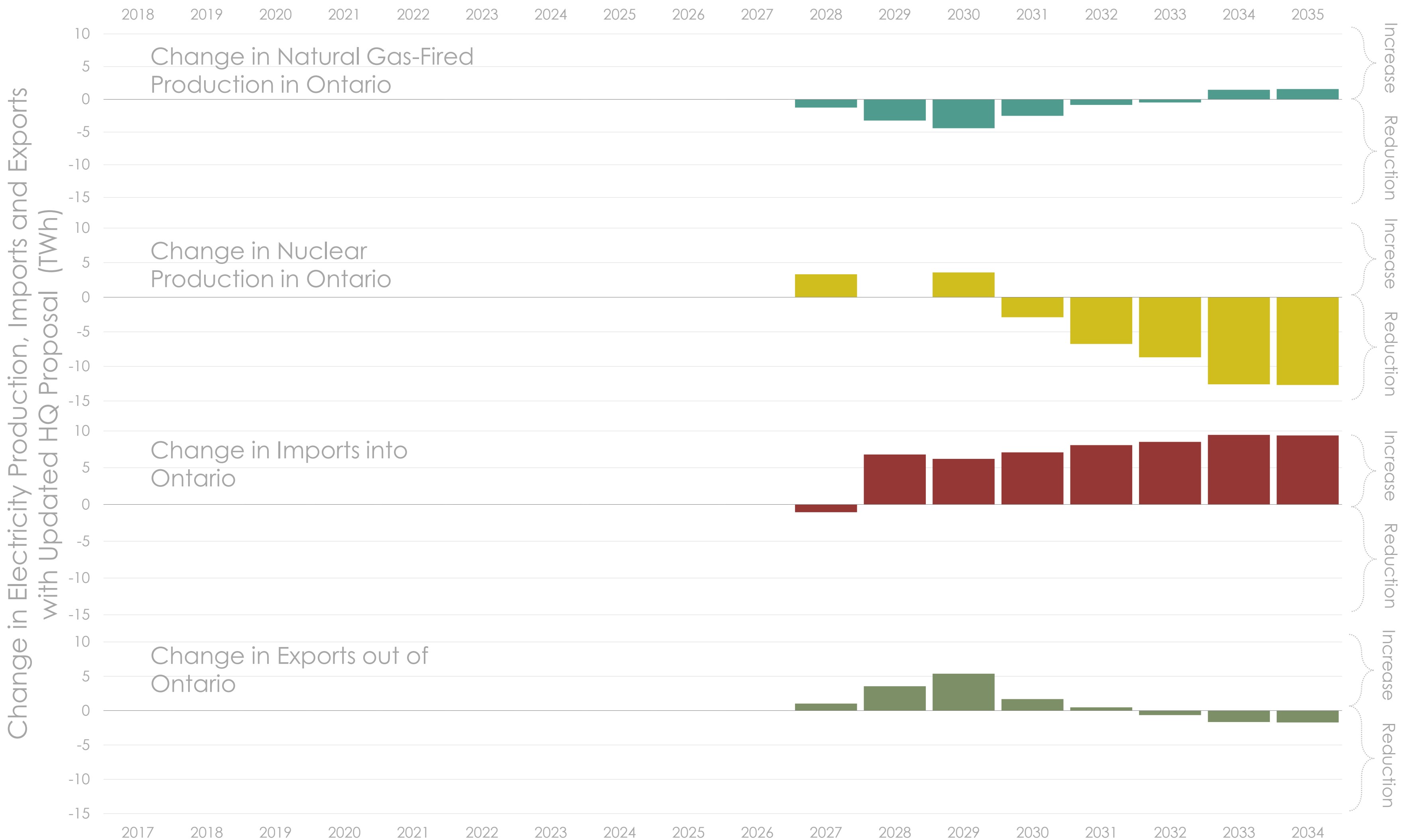
## **Scenario C:** Surplus Baseload Generation

Throughout the 2020s, SBG increases relative to the Status Quo outlook as the energy from the HQ import product added in is greater than the amount of energy from gas/nuclear displaced. Post 2030s, SBG declines relative to the Status Quo outlook as more nuclear production is removed relative to the energy added in from the HQ import product.



## **Scenario C:** Change in energy mix

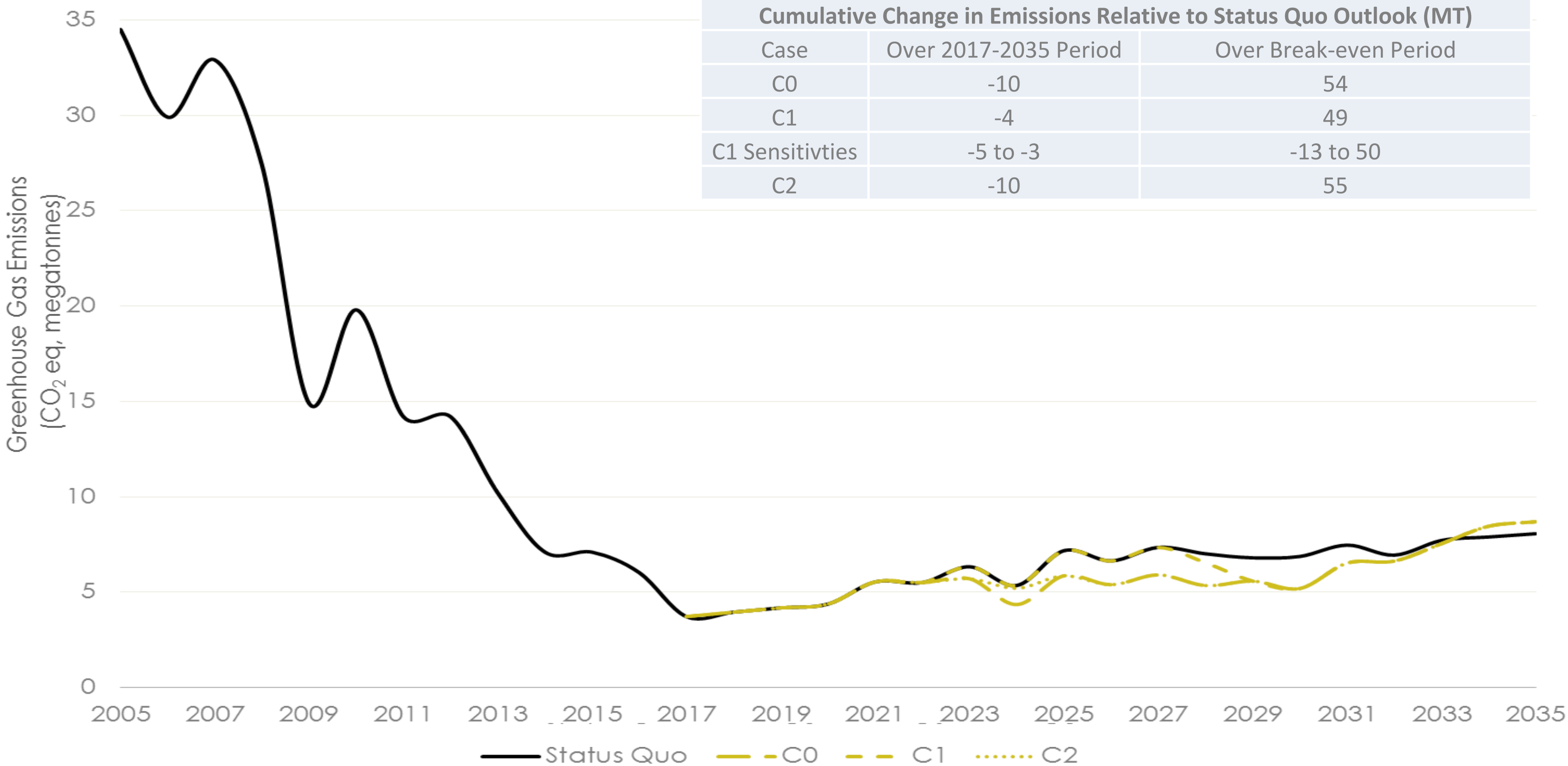
Relative to the Status Quo outlook, to accommodate 8 TWh of annual HQ imports, in the longer-term, nuclear production declines by about 12-13 TWh/year while production from gas-fired generation increases by 1-2 TWh/year. Exports decrease by 1-2 TWh/year.




Note: Based on Case C1

## **Scenario C:** Greenhouse gas emissions

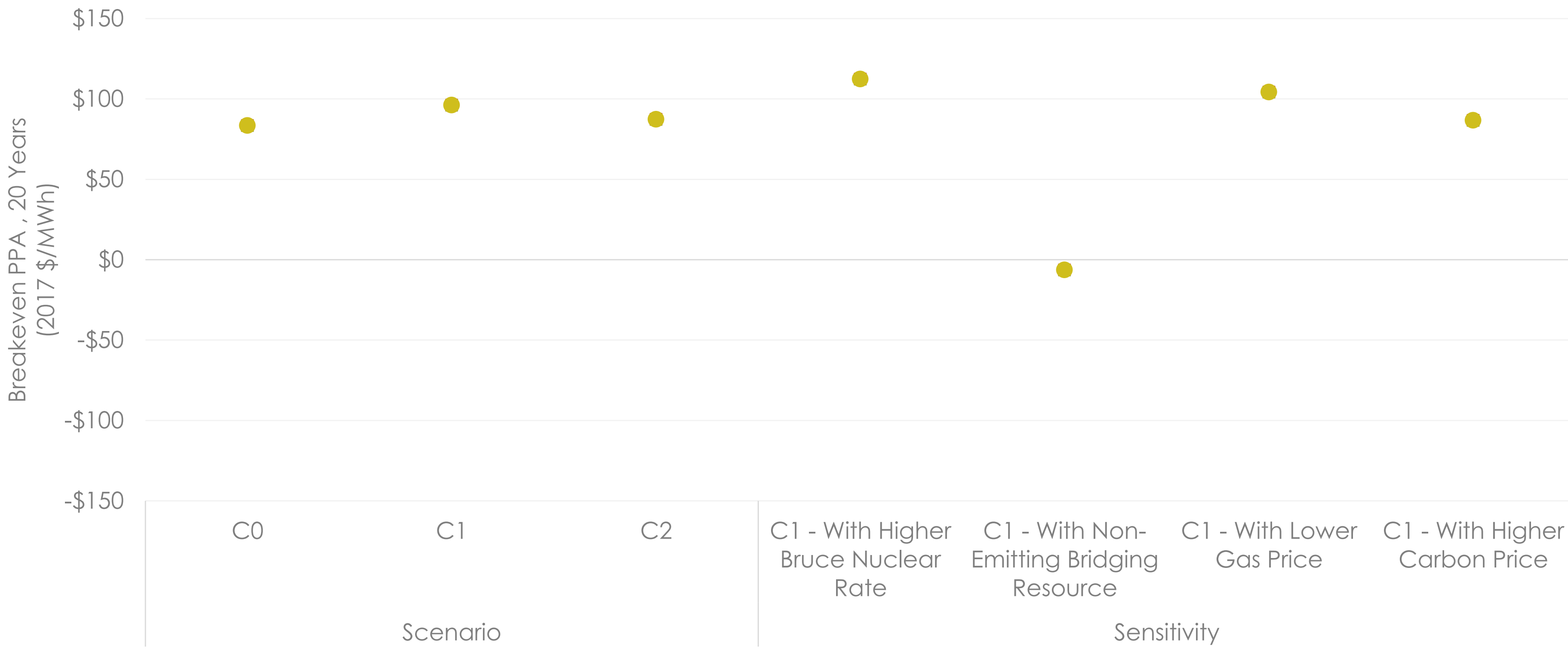
Relative to the Status Quo outlook, emissions decrease throughout the 2020s as the energy added in from the HQ import product displace gas-fired generation. Post 2030s, emissions increase relative to the Status Quo outlook as gas-fired energy production increases to bridge the difference in energy available from the two Bruce units removed (which is more) relative to the imported energy that is added in (which is less).




| Cumulative Change in Emissions Relative to Status Quo Outlook (MT) | | |
|---|---|---|
| Case | Over 2017-2035 Period | Over Break-even Period |
| C0 | -10 | 54 |
| C1 | -4 | 49 |
| C1 Sensitivties | -5 to -3 | -13 to 50 |
| C2 | -10 | 55 |

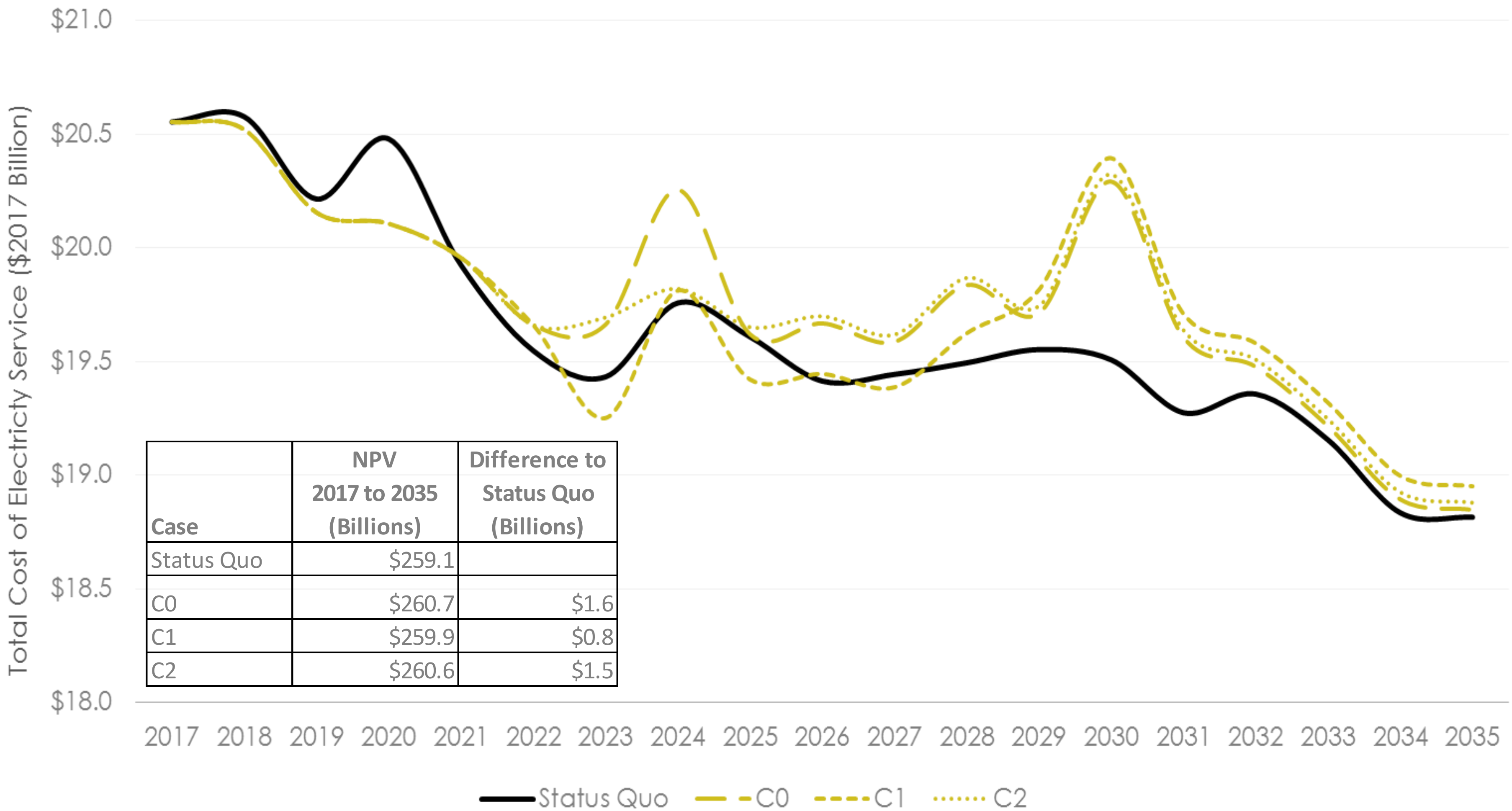
**Scenario C:** Break-even price

The price of the HQ import product at which the total system cost is break-even with the Status Quo outlook is between $83/MWh and $96/MWh across the C cases but could range between minus $6/MWh and $112/MWh across the sensitivity cases.



## **Scenario C:** Total cost of electricity service

The total cost of electricity service at the Scenario C break-even price is higher than the Status Quo outlook with the exception of the years 2017 through 2020. The NPV of the total cost of electricity service between 2017-2035 across the Scenario C cases is higher than the Status Quo outlook by $0.8 - $1.6 billion (2017 $).




| Case | NPV 2017 to 2035 (Billions) | Difference to Status Quo (Billions) |
|---|---|---|
| Status Quo | $259.1 | |
| C0 | $260.7 | $1.6 |
| C1 | $259.9 | $0.8 |
| C2 | $260.6 | $1.5 |

Cases C0 through C2 reflect the HQ import product at its break-even price.

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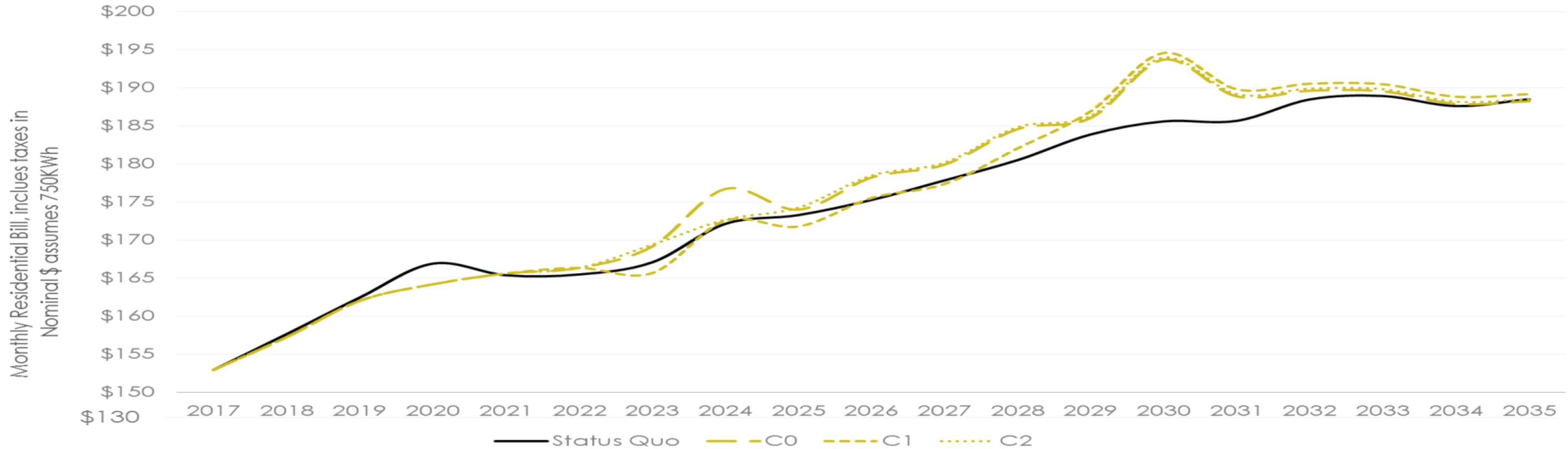
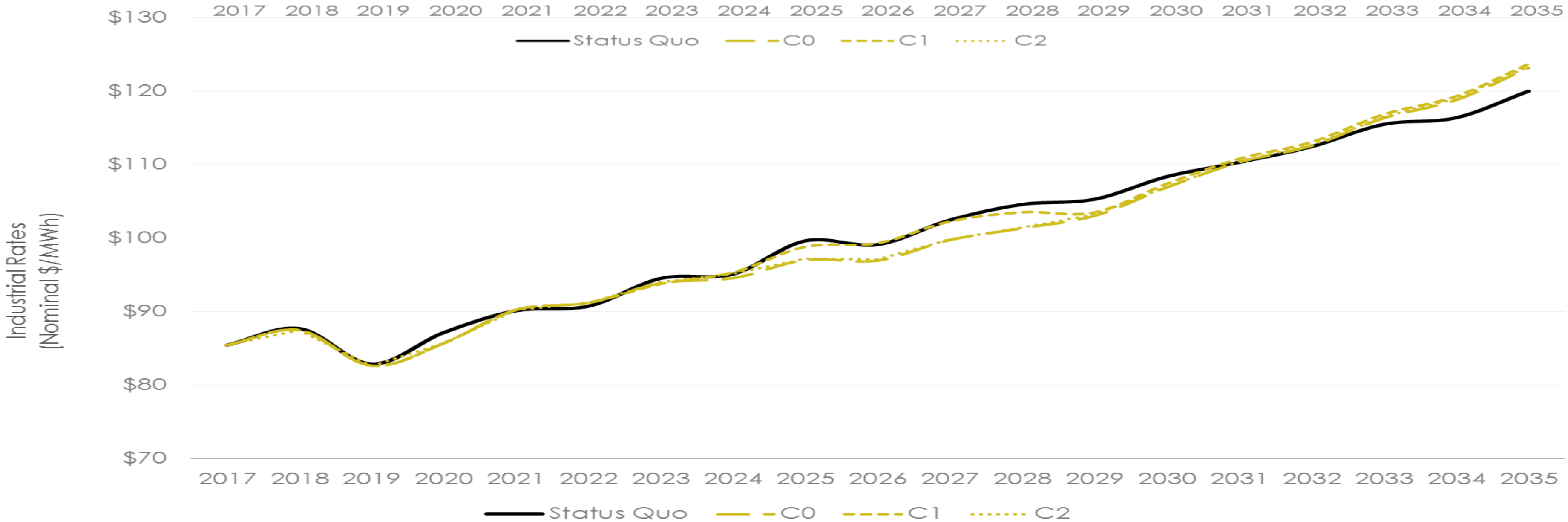
# **Scenario C:** Residential monthly bills and industrial rates

Residential monthly bills (pre-OFHP) in Scenario C are above the Status Quo outlook with exception of 2020. The industrial rates in Scenario C is lower in the mid-term but higher in the long-term relative to the Status Quo outlook.



# Scenario D: Overview

## HQ imports as an alternative to refurbishing one Darlington unit, while not reacquiring some gas-fired generation at contract expiry

- Scenario D examines the implications of not refurbishing the last unit at Darlington and not reacquiring some gas-fired generation at contract expiry

- In this scenario, Darlington unit 4 and Iroquois Falls NUG is assumed to be retired in December 2023. In the Status Quo, Darlington unit 4 would have undergone refurbishment from July 2022 to March 2025 then assumed to operate for another 30 years. Iroquois Falls NUG would have been available during the entire study period.
  - 1,009 MW of installed (962 MW effective) of capacity is removed in this scenario. This is comprised of 881 MW of installed Darlington capacity (878 MW effective) and 131 MW of installed (84 MW effective) of the Iroquois Falls NUG (for modelling purposes).

- With respect to HQ imports:
  - Case 0: Reflects 8 TWh energy and 1 GW firm capacity beginning in January 2023, following retirement of Pickering units, for a 20 year term
  - Case 1: Reflects 8 TWh energy and 1 GW firm capacity beginning in January 2025 for a 20 year term, following the shutdown of the first Darlington unit in September 2022
  - Case 2: Capacity import is limited to up to 1 GW to align with capacity needs. Energy import is limited to up to 8 TWh, in quantities proportional to the capacity import. Imports begin in January 2023 for a 20 year term.

## **Scenario D:** Overview (continued…)
## HQ imports as an alternative to refurbishing one Darlington unit and not reacquiring some gas-fired generation at contract expiry

- In all Cases, the existing HQ agreement remains unchanged for the period 2017 to 2023. Where overlap exists with the proposed agreement, in 2023 in particular, the maximum HQ import quantity is limited to 8 TWh and 1 GW.

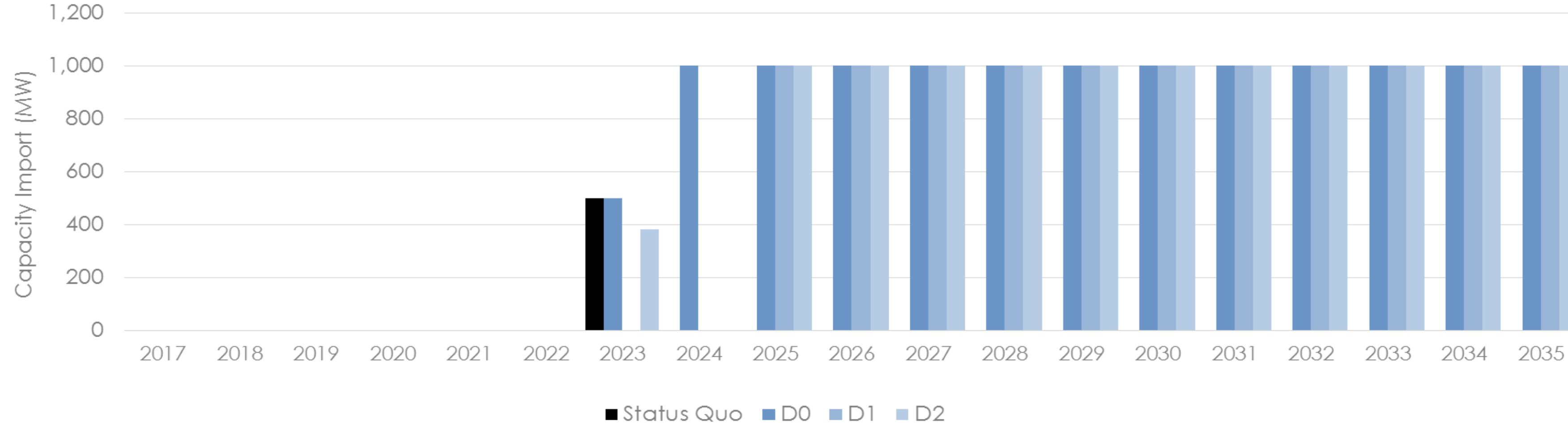
- Given the mismatch in capacity, energy, and operating timeframe associated with nuclear units removed and HQ imports added in, gas-fired generation is assumed to bridge the difference. Additional sensitivity analysis is performed to assess the implication of bridging the difference with non-emitting resources – namely a combination of wind/storage resources

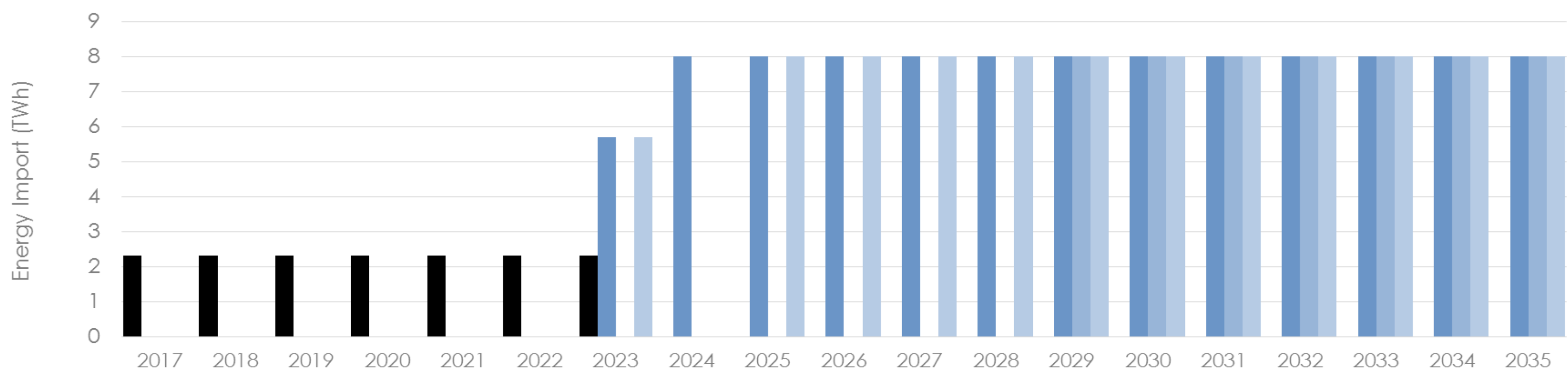
- Darlington availability and cost assumptions per data provided by OPG

- To the extent there are additional capacity needs over and above existing resources which continue to operate post contract expiry and after accounting for HQ imports added in and resources removed (as described above), these needs are assumed to be met by a capacity based resources (modelled as an SCGT which is assumed to be the benchmark resource for capacity).

**Scenario D:** HQ import capacity and energy product evaluated

The new Quebec import product begins in 2023 in D0 (following retirement of the first two Pickering units), 2025 in D1 (following retirement of a Darlington unit), and 2023 in D2 (following capacity needs).

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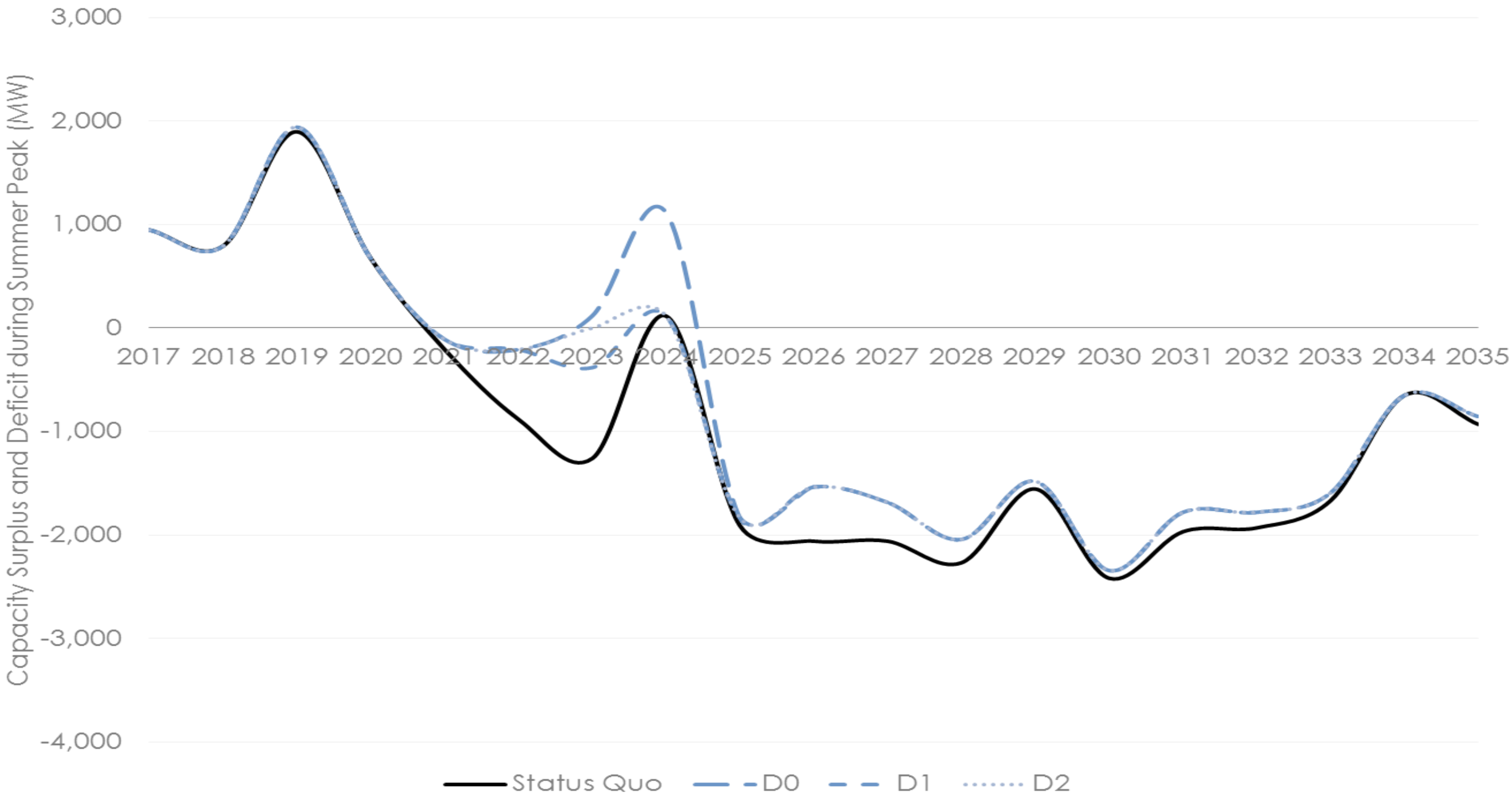
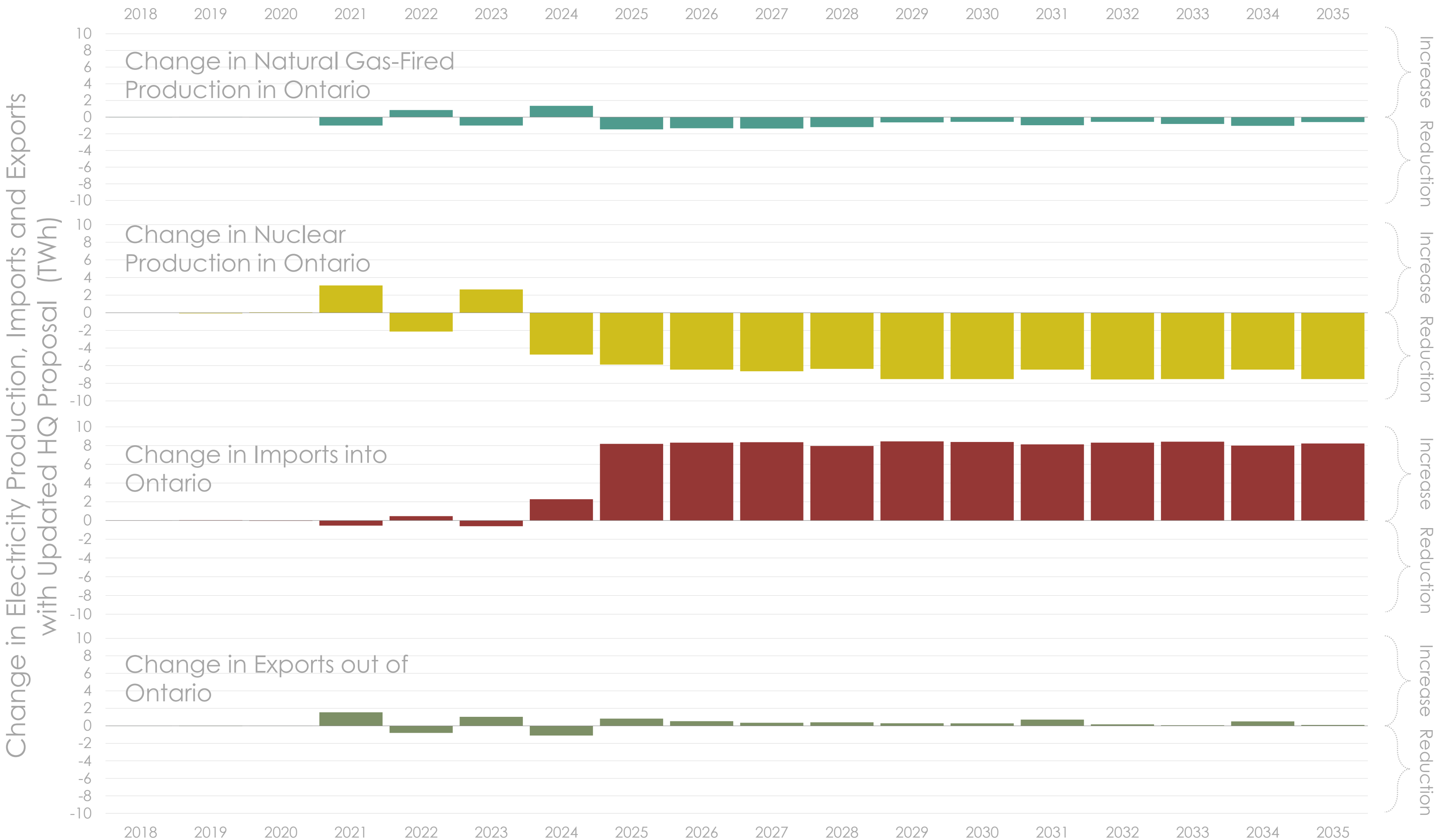
## **Scenario D:** Capacity adequacy outlook

Relative to the Status Quo outlook, although capacity needs are reduced in the early 2020s, they remain unchanged 2025 onwards.  This is because the capacity provided by the HQ import product replaces the capacity associated with the Darlington/gas unit removed and existing needs relative to the Status Quo outlook are not addressed.



## **Scenario D:** Change in energy mix

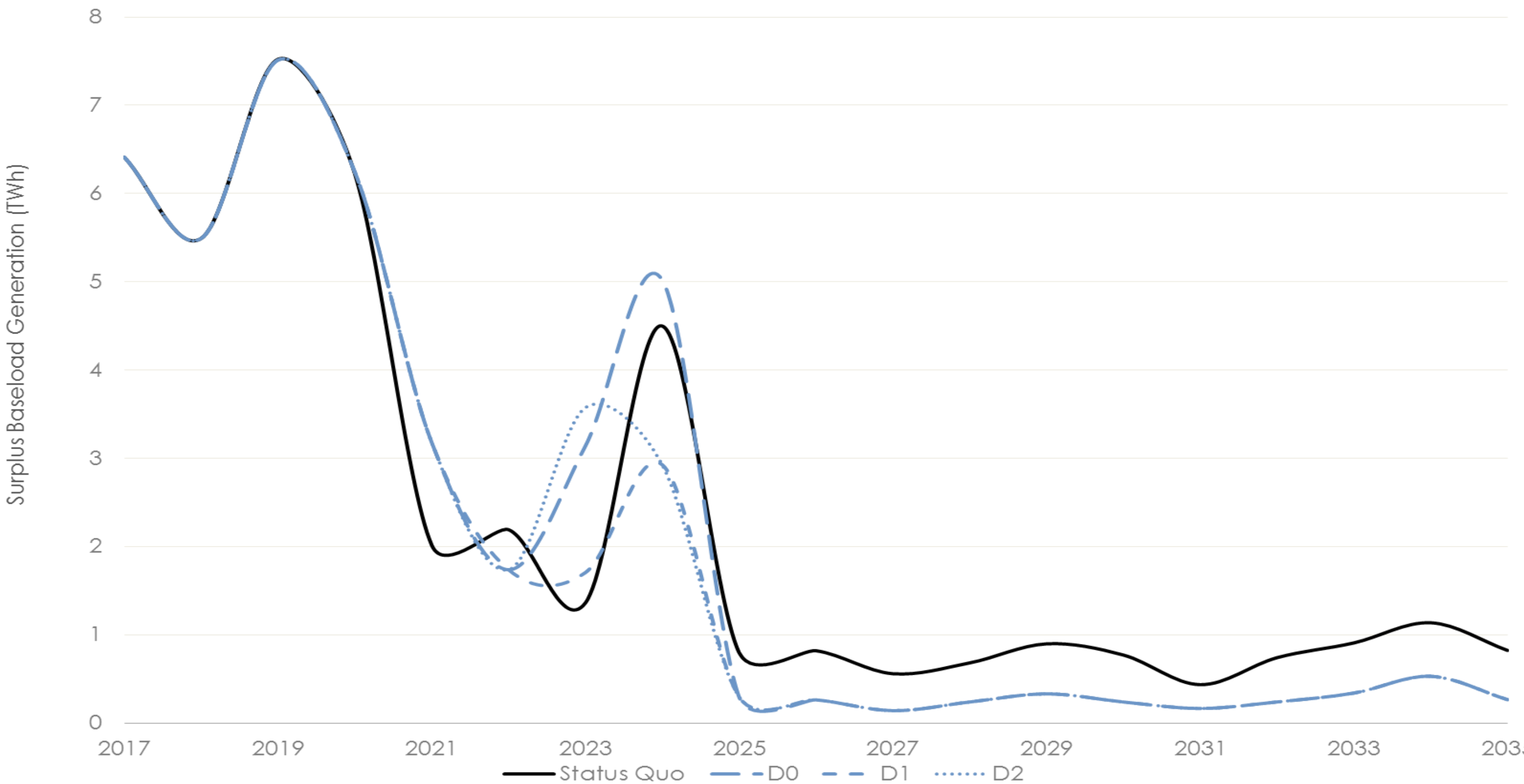
Relative to the Status Quo outlook, to accommodate 8 TWh of annual HQ imports, nuclear production declines by about 7 TWh/year while production from gas-fired generation declines by about 1 TWh/year. Exports are relatively unchanged.




Note: Based on Case D1

**Scenario D:** Surplus Baseload Generation

Throughout the early 2020s, SBG increases relative to the Status Quo outlook as the energy from the HQ import product added in is greater than the amount of energy from gas/nuclear displaced. Post 2025, SBG declines relative to the Status Quo outlook as more nuclear production is removed relative to the energy added in from the HQ import product.

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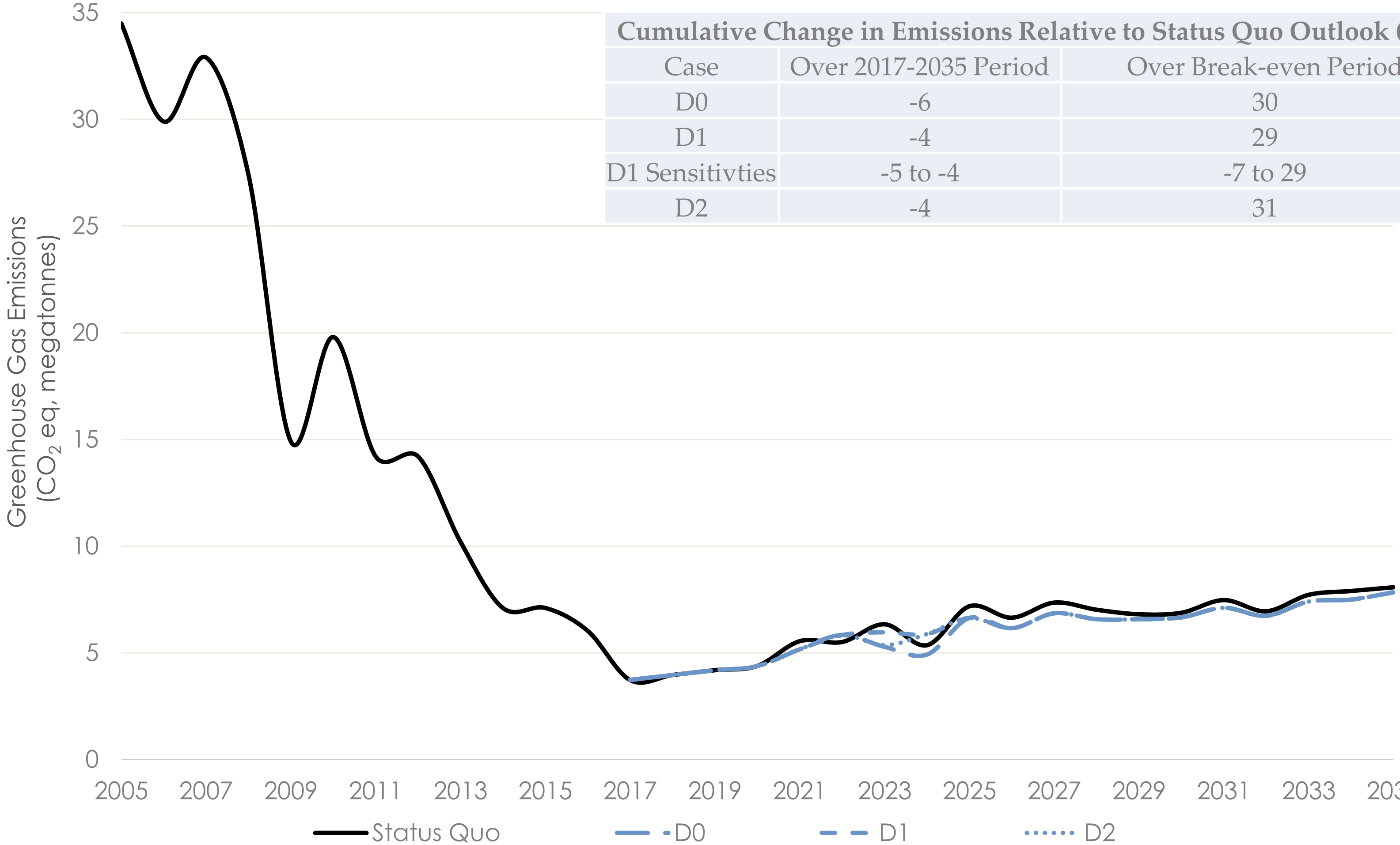
## **Scenario D:** Greenhouse gas emissions

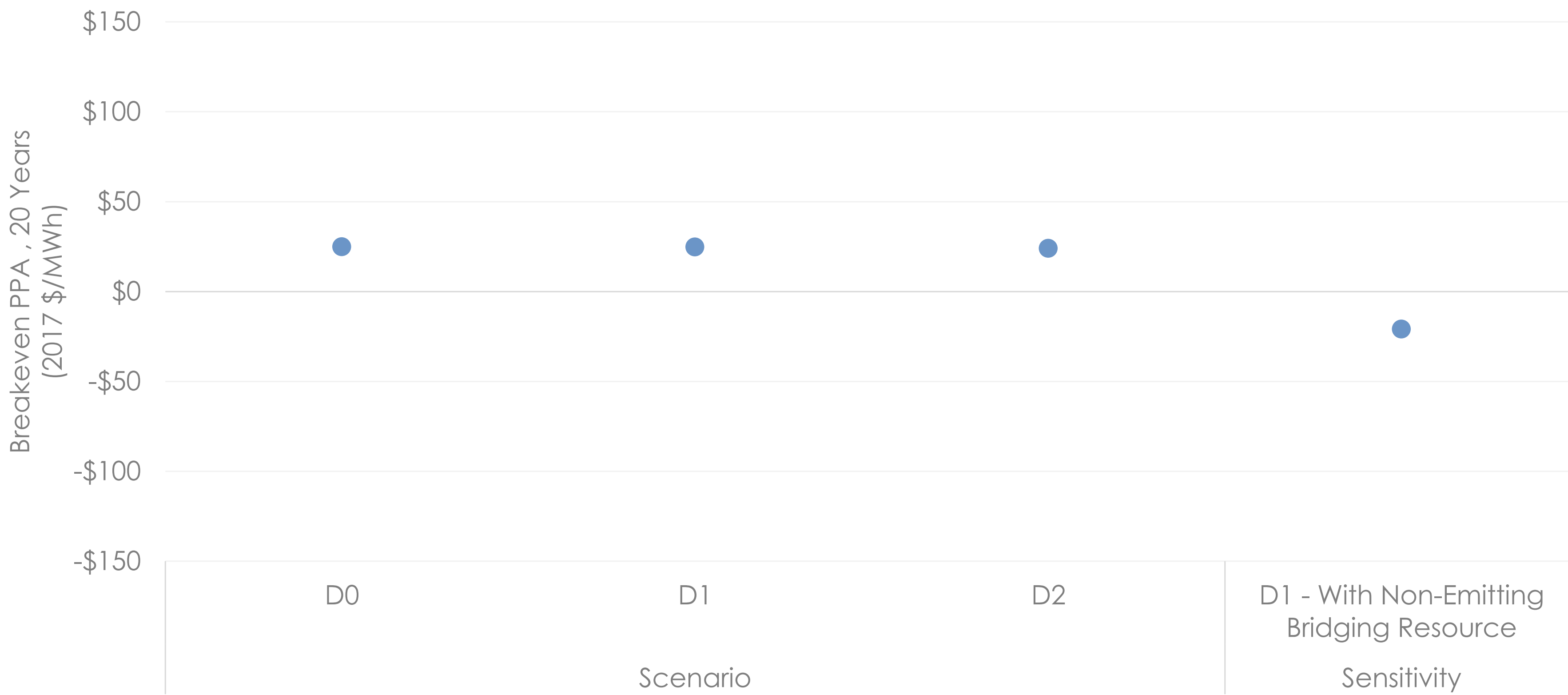
Relative to the Status Quo outlook, GHG emissions remain relatively unchanged between 2017 and 2035 as most of the energy from the HQ import product added replaces the energy that would have otherwise been provided from the Darlington unit removed. Over the break-even period, there is a net increase in emissions where gas is the bridge resource between the period when the 20 year HQ agreement ends and when the refurbished Darlington unit would have otherwise operated to.




| Cumulative Change in Emissions Relative to Status Quo Outlook (MT) | | |
|---|---|---|
| Case | Over 2017-2035 Period | Over Break-even Period |
| D0 | -6 | 30 |
| D1 | -4 | 29 |
| D1 Sensitivties | -5 to -4 | -7 to 29 |
| D2 | -4 | 31 |

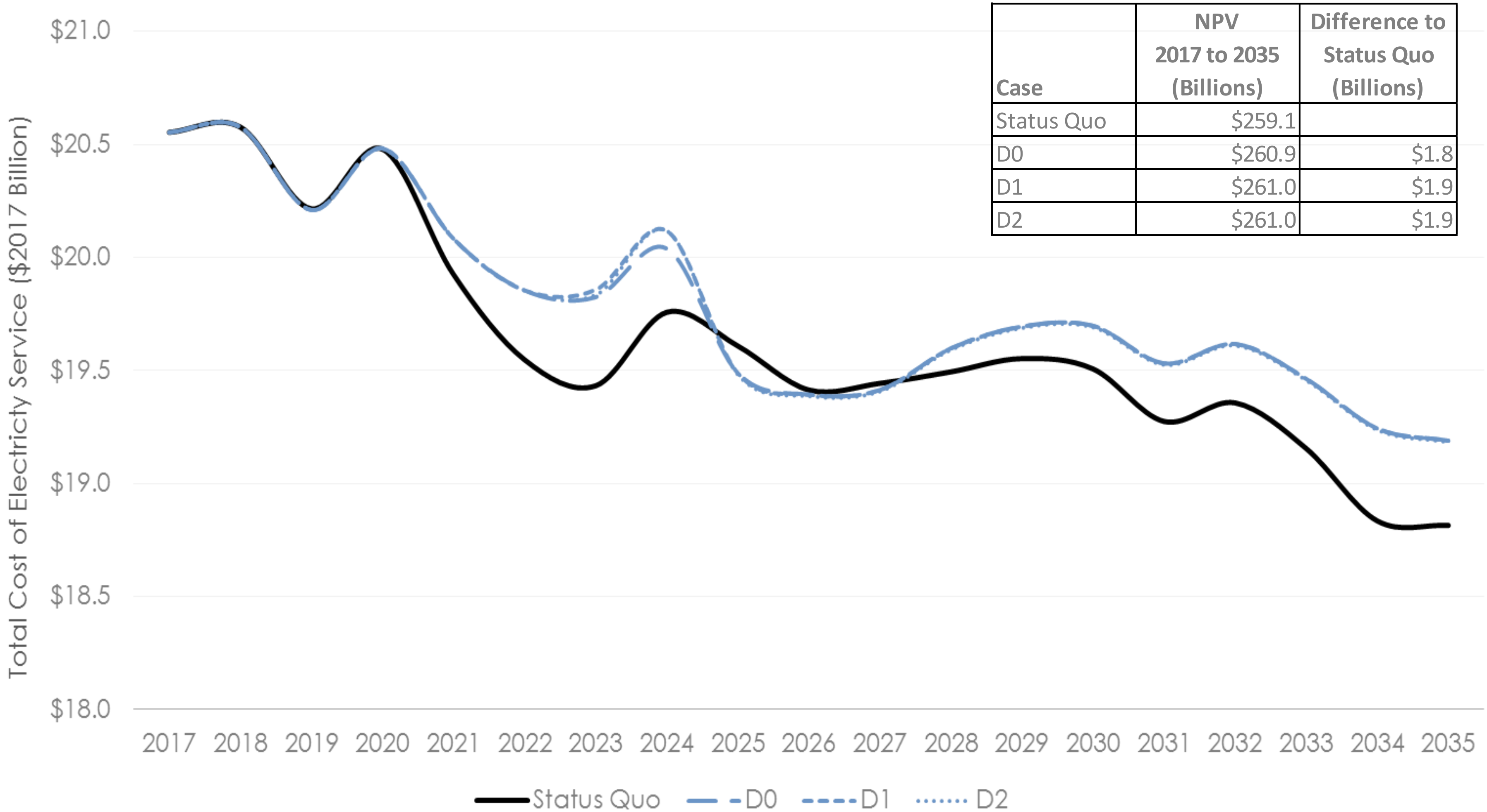
**Scenario D:** Break-even price

The price of the HQ import product at which the total system cost is break-even with the Status Quo outlook is between $24/MWh and $25/MWh across the D cases but could be as low as minus $21/MWh if the non-emitting resources bridge the difference in capacity, energy, and service life between the resources removed and HQ import product added in.



## **Scenario D:** Total cost of electricity service

The total cost of electricity service at the Scenario D break-even price is higher than the Status Quo outlook with the exception of the year 2025. The NPV of the total cost of electricity service between 2017-2035 across the Scenario D cases is higher than the Status Quo outlook by $1.8 -$1.9 billion (2017 $). The total cost of electricity service across the Scenario D are similar, with the exception of 2024.

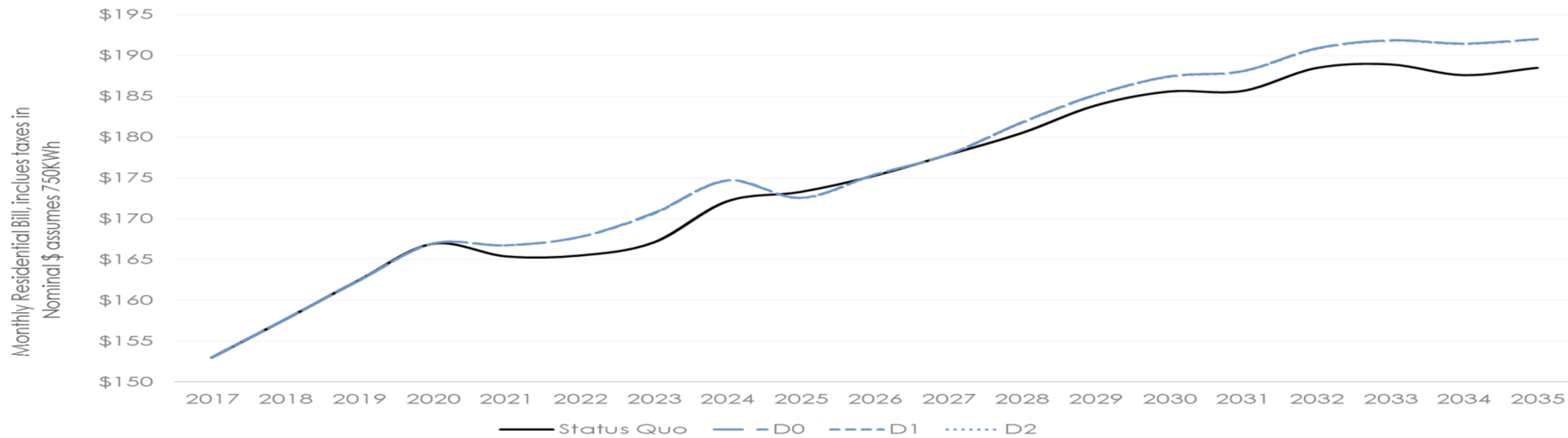


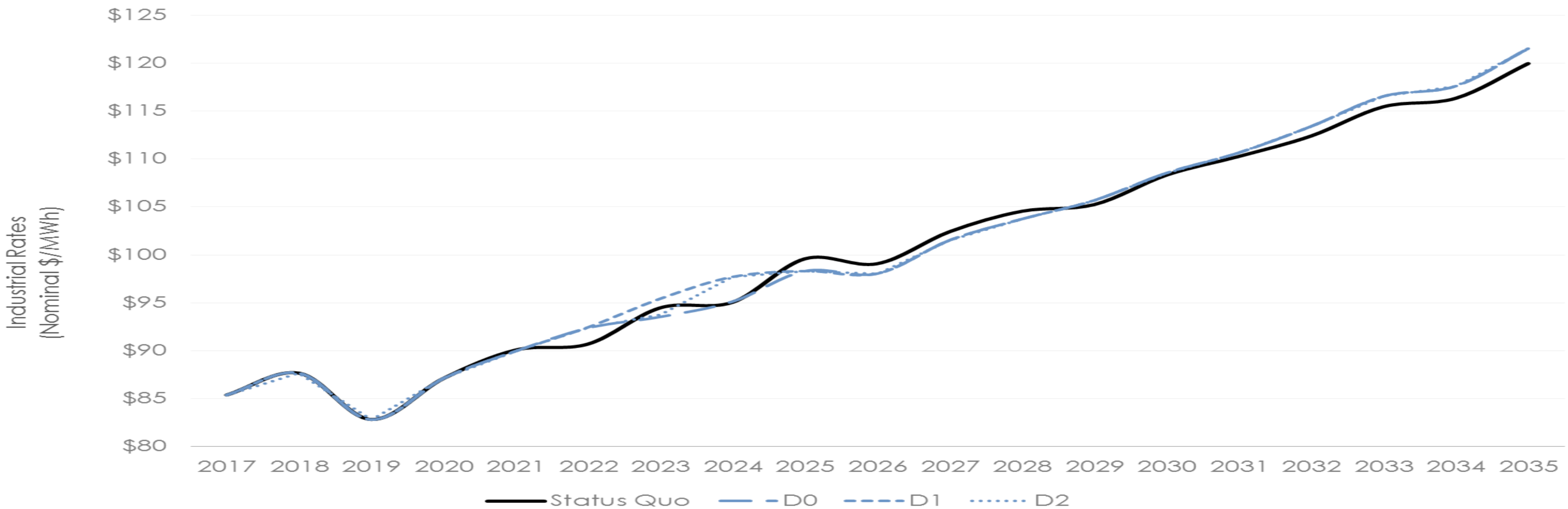

| Case | NPV 2017 to 2035 (Billions) | Difference to Status Quo (Billions) |
|---|---|---|
| Status Quo | $259.1 | |
| D0 | $260.9 | $1.8 |
| D1 | $261.0 | $1.9 |
| D2 | $261.0 | $1.9 |

Cases C0 through C2 reflect the HQ import product at its break-even price.

## **Scenario D:** Residential monthly bills and industrial rates

Residential monthly bills (pre-OFHP) in Scenario D is generally higher than the Status Quo outlook. Industrial rates in Scenario D are similar to the Status Quo outlook.

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## **Scenario E:** Overview

## Opportunities for HQ imports to help meet projected system needs and reduce energy production from gas-fired generation

- Scenario E examines opportunities for HQ imports to meet projected capacity needs observed in the Status Quo outlook while displacing some energy production from gas-fired generation

- In this scenario, HQ import is assumed to complement existing resources while meeting capacity needs that emerge in the Status Quo outlook. These needs would otherwise exist if HQ were an alternative to existing resources. In the previous scenarios, these existing needs are assumed to be met by a capacity resource (an SCGT is assumed for modelling purposes)
  - 1 GW of incremental installed new build capacity would be avoided in this scenario

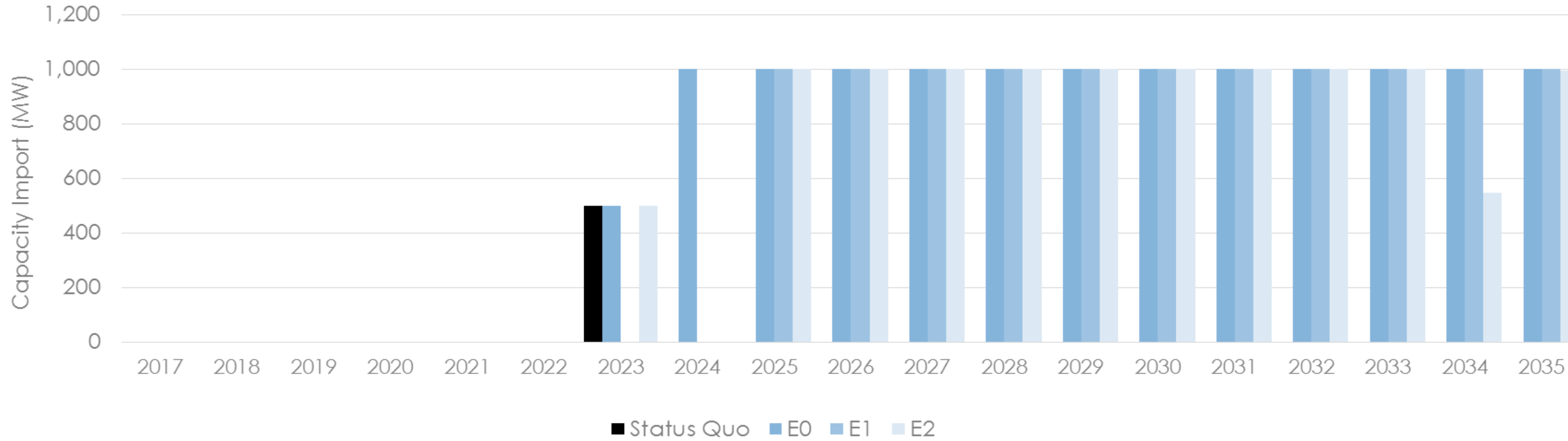
- With respect to HQ imports:
  - Case 0: Reflects 8 TWh energy and 1 GW firm capacity beginning in January 2023, following retirement of Pickering units, for a 20 year term
  - Case 1: Reflects 8 TWh and 1 GW firm capacity beginning in January 2025 for a 20 year term, to align with the sustained capacity need that emerges in the Status Quo outlook
  - Case 2: Capacity import is limited to up to 1 GW to align with capacity needs. Energy import is limited to up to 8 TWh, in quantities proportional to the capacity import. Imports begin in January 2023 for a 20 year term.

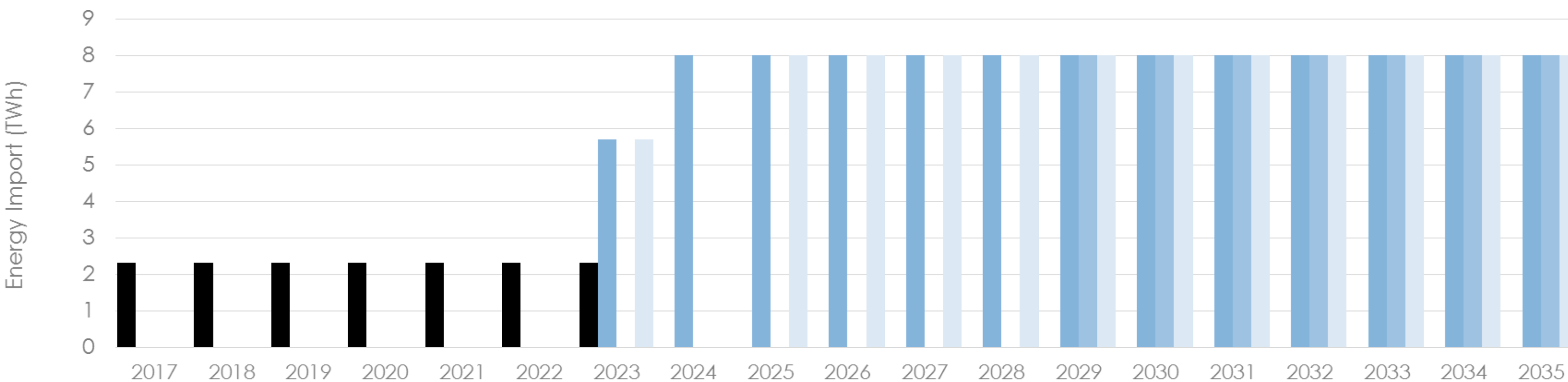
- In all Cases, the existing HQ agreement remains unchanged for the period 2017 to 2023. Where overlap exists with the proposed agreement, in 2023 in particular, the maximum HQ import quantity is limited to 8 TWh and 1 GW.

- To the extent there are additional capacity needs over and above existing resources which continue to operate post contract expiry and after accounting for HQ imports and resources removals (as described above), these needs are assumed to be met by a capacity based resources (modelled as an SCGT which is assumed to be the benchmark resource for capacity).

**Scenario E:** HQ import capacity and energy product evaluated

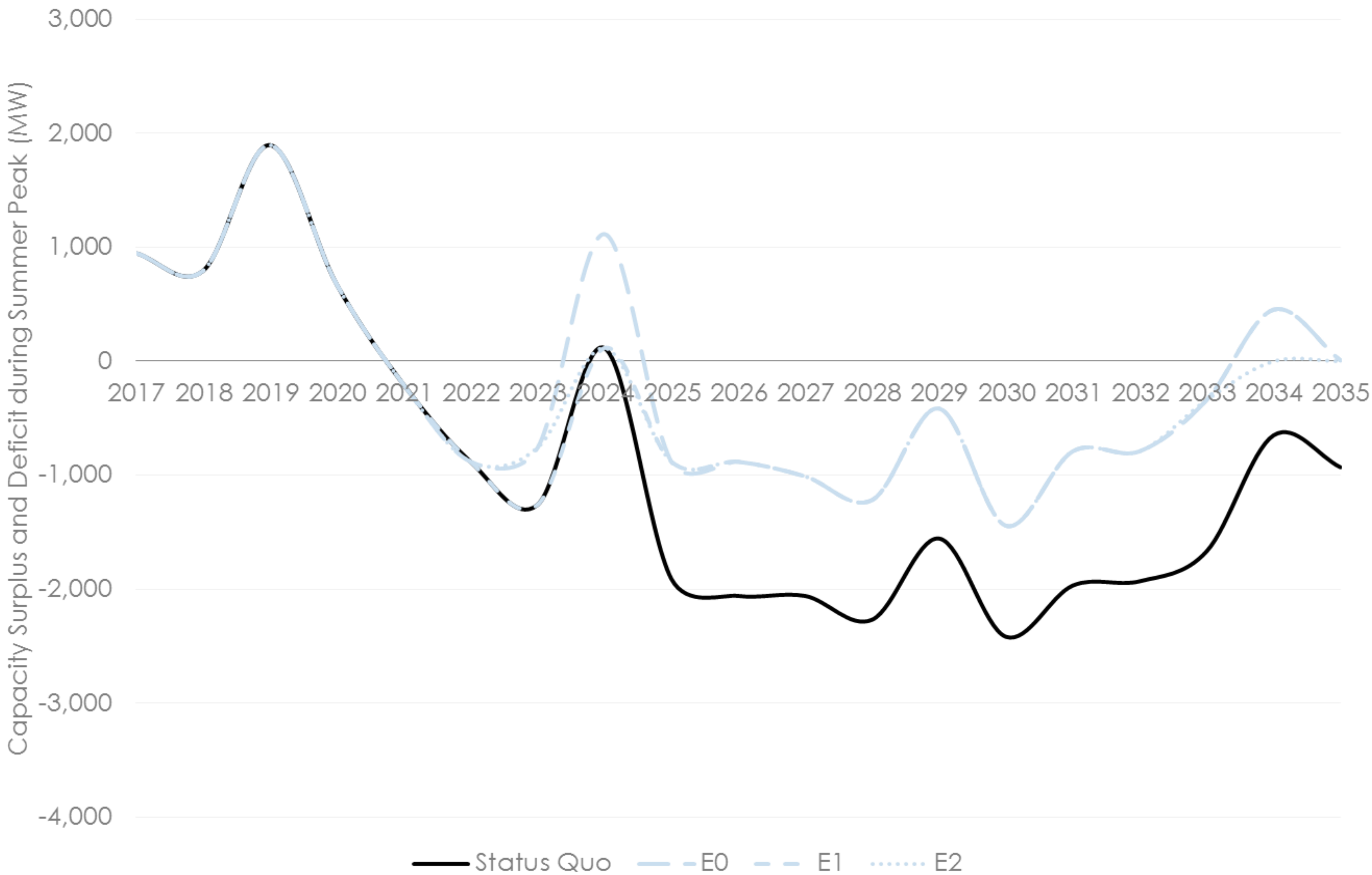
The new Quebec import product begins in 2023 in E0 (following retirement of the first two Pickering units), 2025 in E1 (when sustained capacity needs begin to emerge), and 2023 in E2 (shaped to aligned with capacity needs).



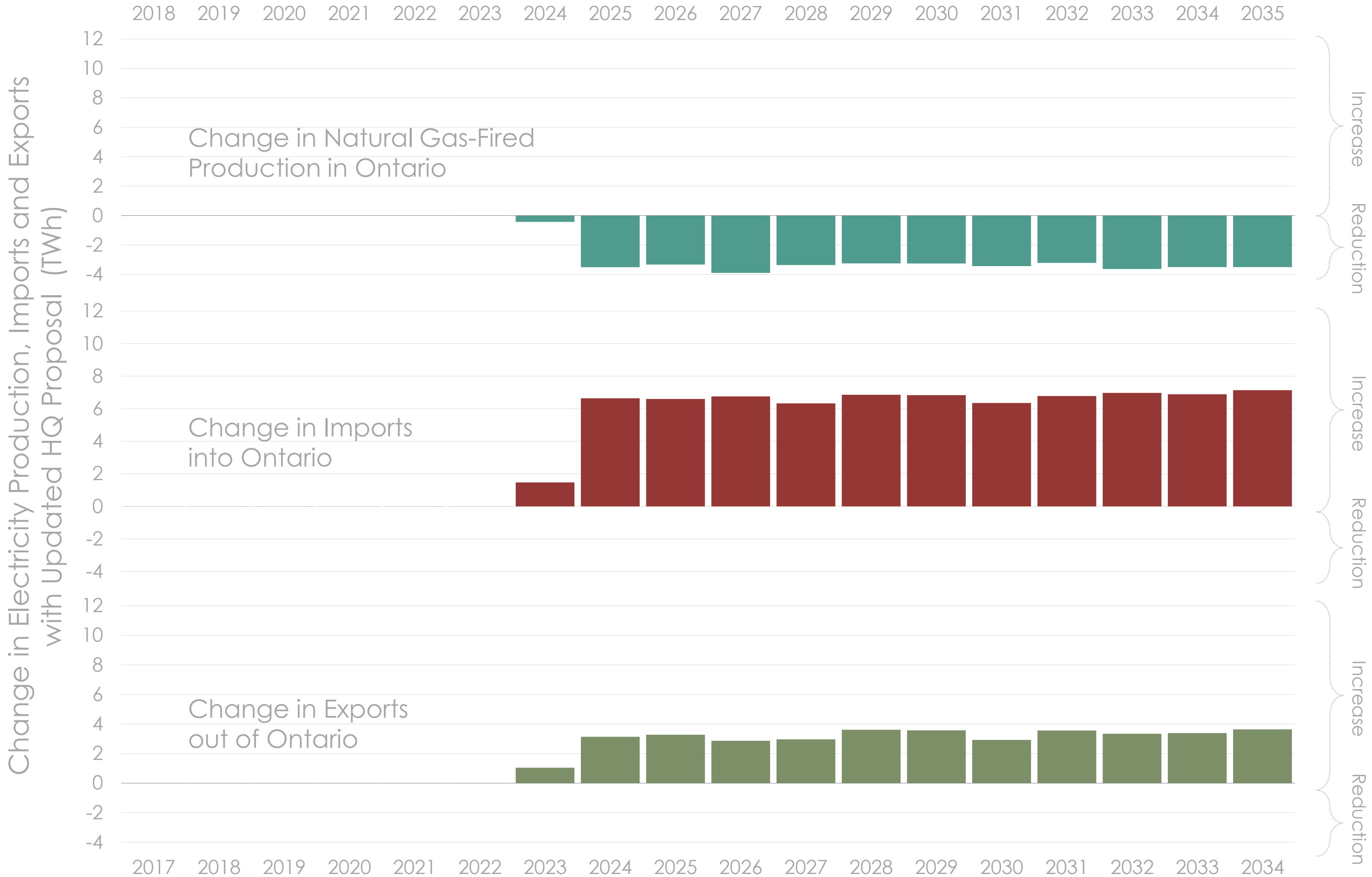
## **Scenario E:** Capacity adequacy outlook

Capacity needs decrease relative to the Status Quo outlook as the HQ import product helps address projected capacity needs.



**Scenario E:** Change in energy mix

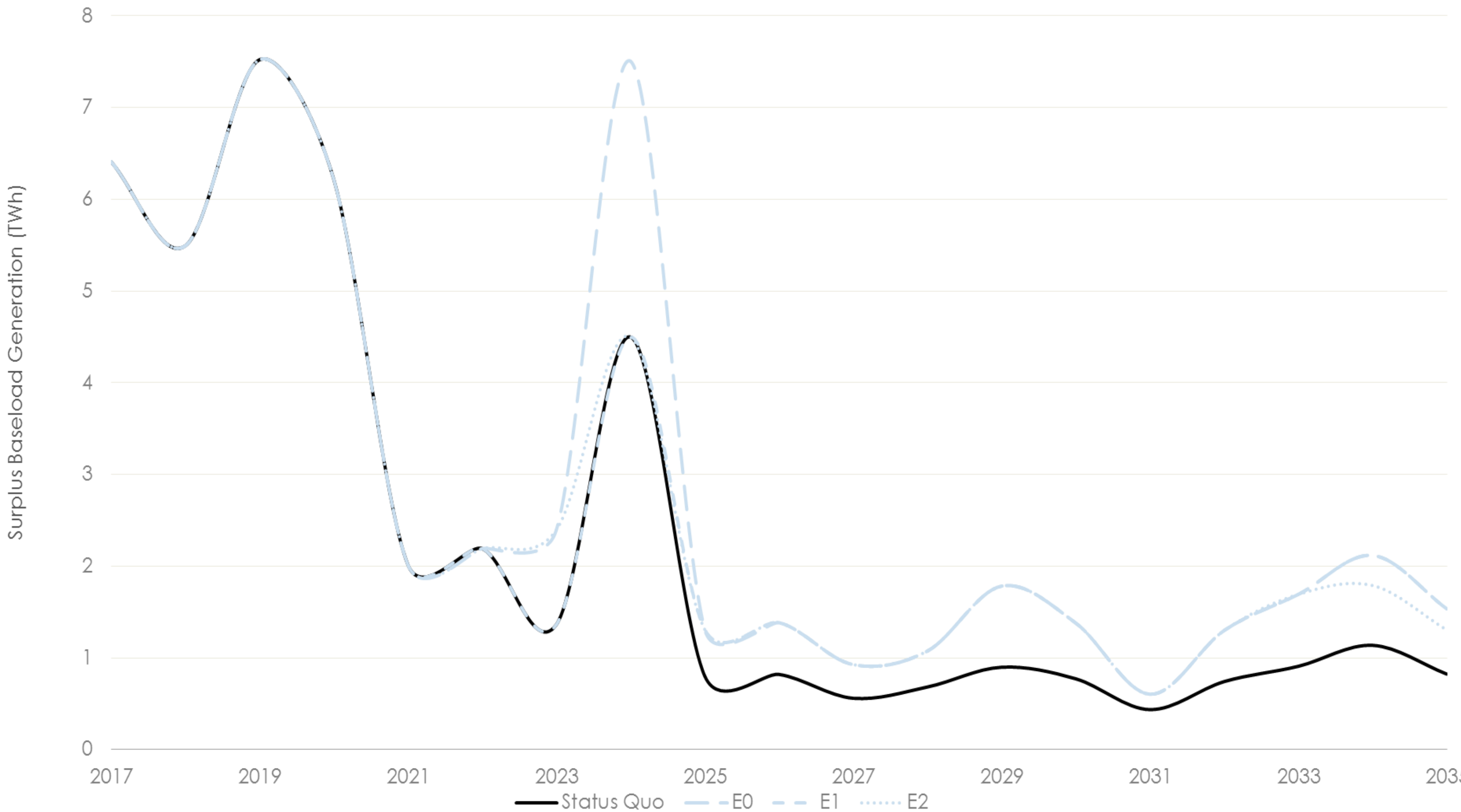
Relative to the Status Quo outlook, to accommodate 8 TWh of annual HQ energy imports, production from gas-fired generation decreases by 3-4 TWh/year while exports increase by 3-4 TWh/year.




Note: Based on Case E1

## **Scenario E:** Surplus Baseload Generation

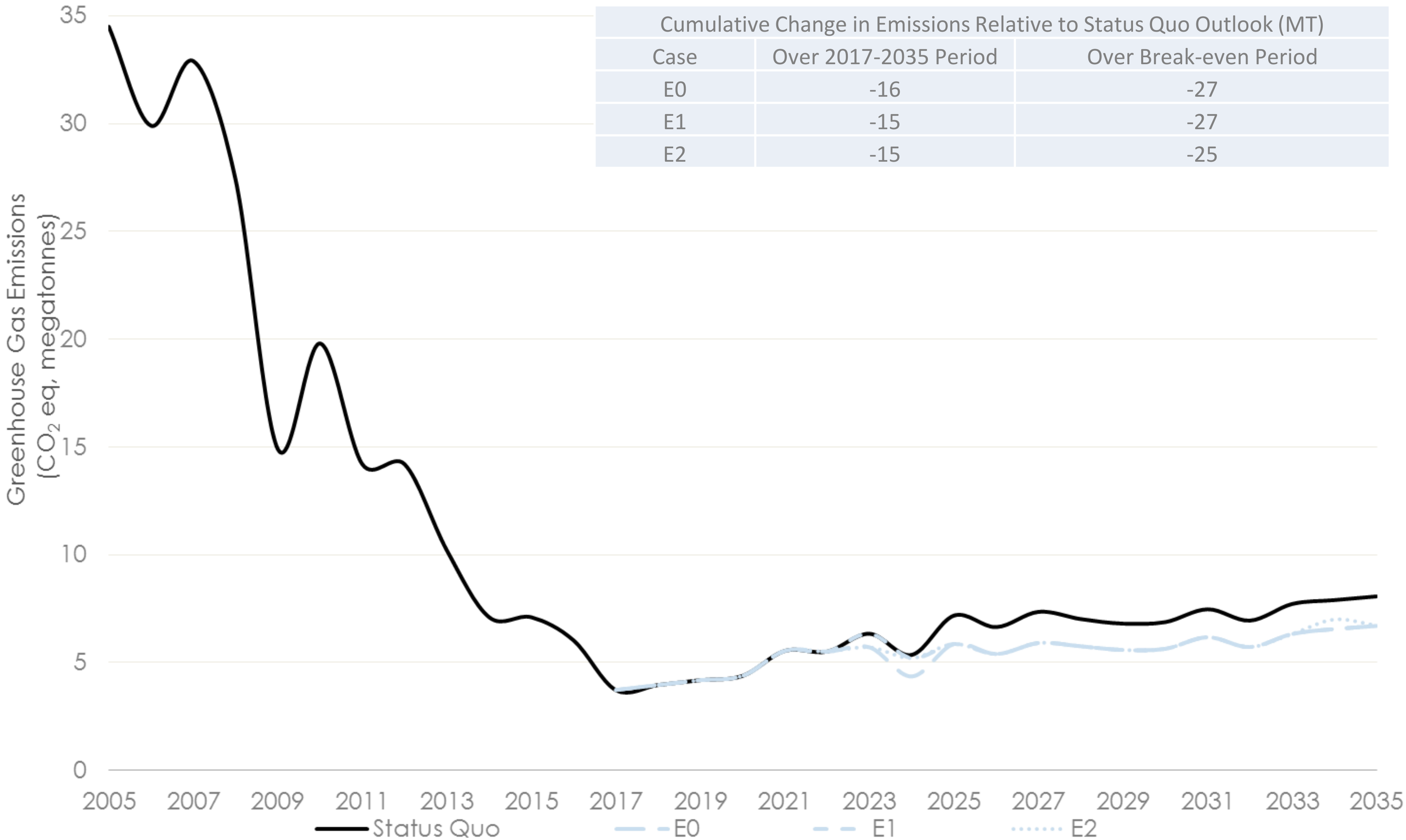
Relative to the Status Quo outlook, SBG increases by 1-2 TWh as the energy from the HQ import product is greater than the amount of gas-fired generation displaced.



## **Scenario E:** Greenhouse gas emissions

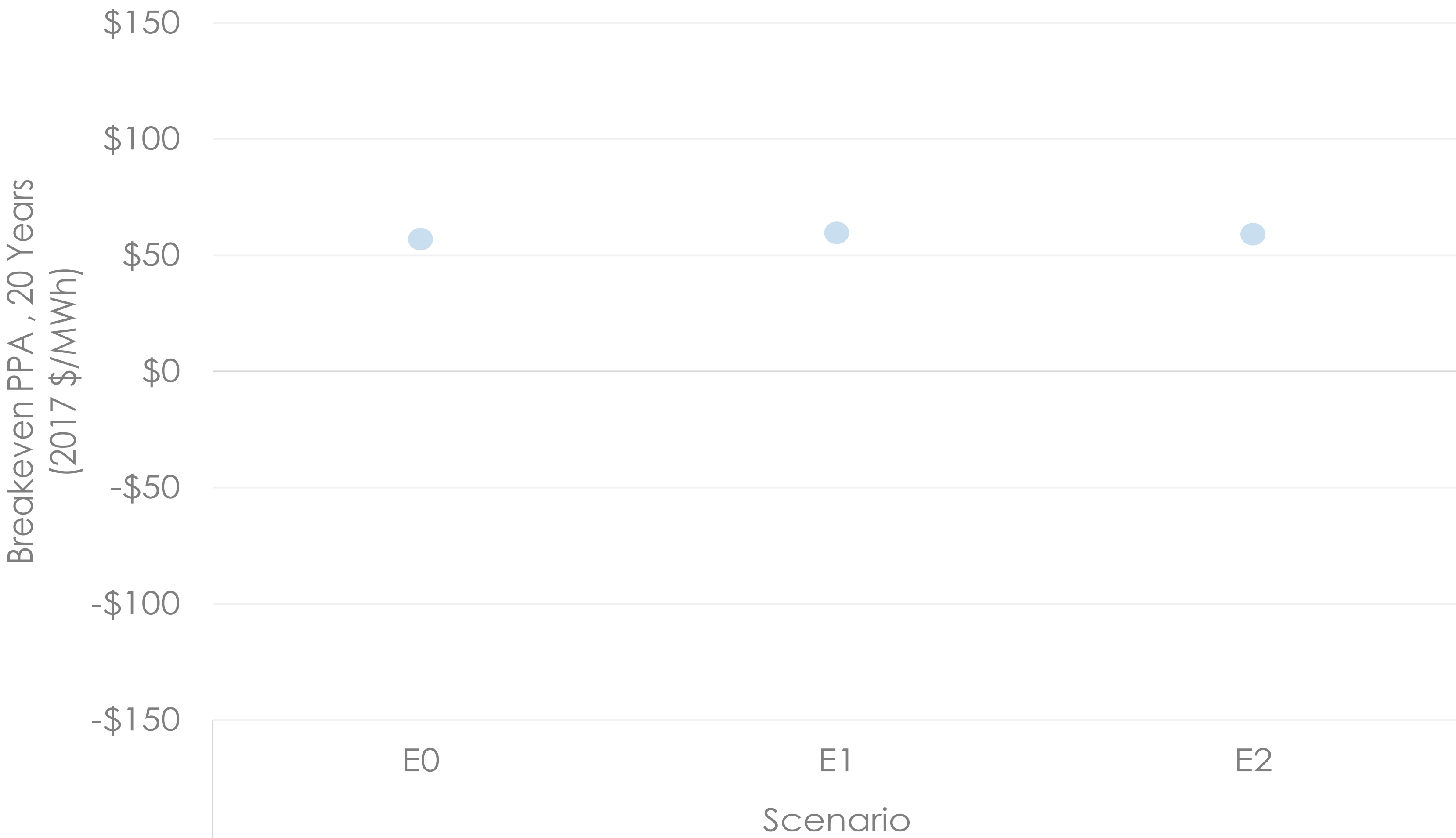
GHG emissions decline relative to the Status Quo outlook as the HQ import product displaces gas-fired generation.

| Cumulative Change in Emissions Relative to Status Quo Outlook (MT) | | |
|---|---|---|
| Case | Over 2017-2035 Period | Over Break-even Period |
| E0 | -16 | -27 |
| E1 | -15 | -27 |
| E2 | -15 | -25 |



**Scenario E:** Break-even price

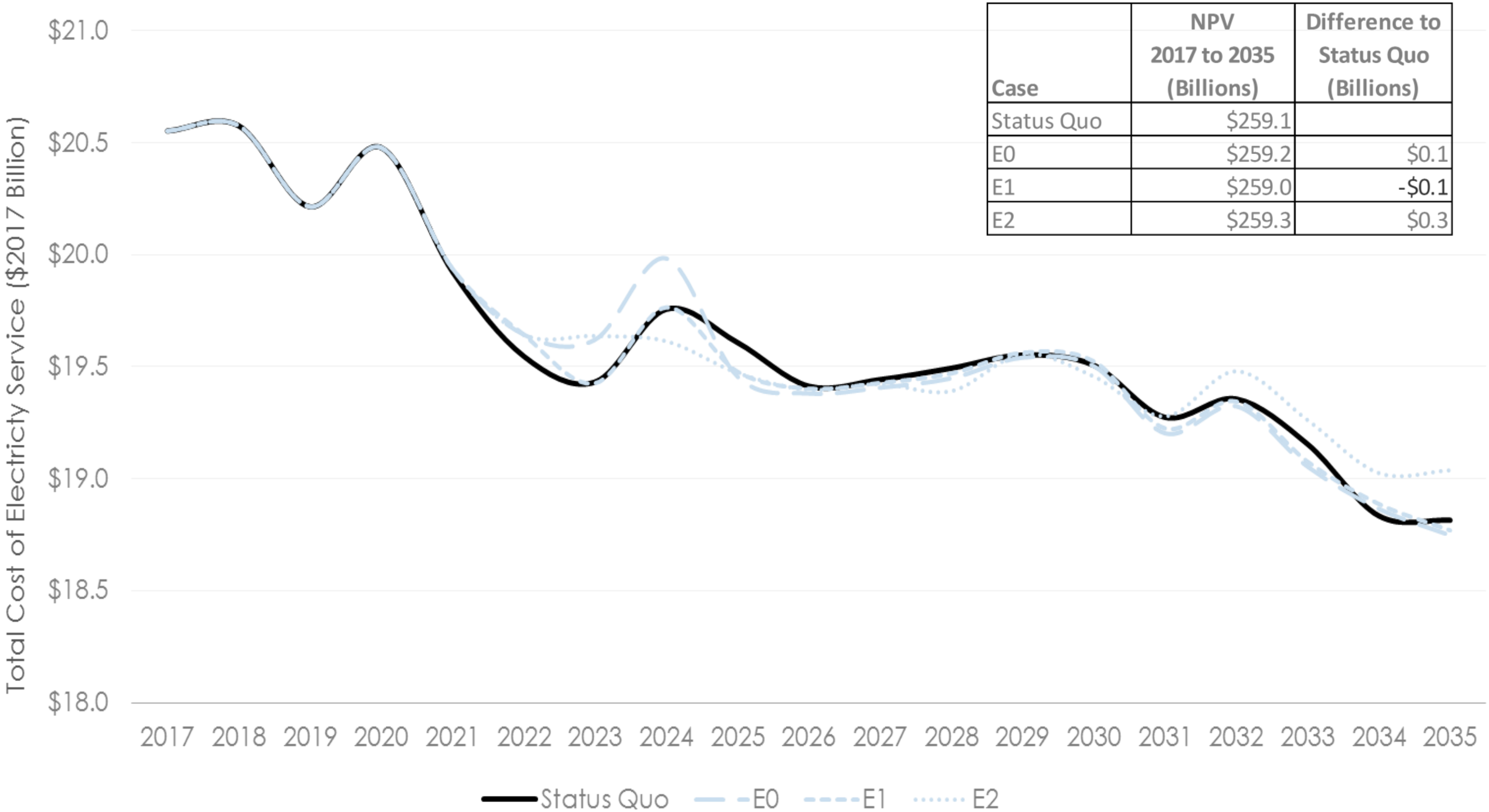
The price of the HQ import product at which the total system cost is break-even with the Status Quo outlook, after accounting for reduced gas capacity/energy production, ranges between $57-$60/MWh.



## **Scenario E:** Total cost of electricity service

The total cost of electricity service at the Scenario E break-even price is similar to the Status Quo outlook with the exception of the years 2022 through 2024. The NPV of the total cost of electricity service between 2017-2035 across the Scenario E cases is similar to the Status Quo outlook, differing by between -$0.1 billion and $0.3 billion relative to the Status Quo outlook (2017 $).

| Case | NPV 2017 to 2035 (Billions) | Difference to Status Quo (Billions) |
|---|---|---|
| Status Quo | $259.1 | |
| E0 | $259.2 | $0.1 |
| E1 | $259.0 | -$0.1 |
| E2 | $259.3 | $0.3 |

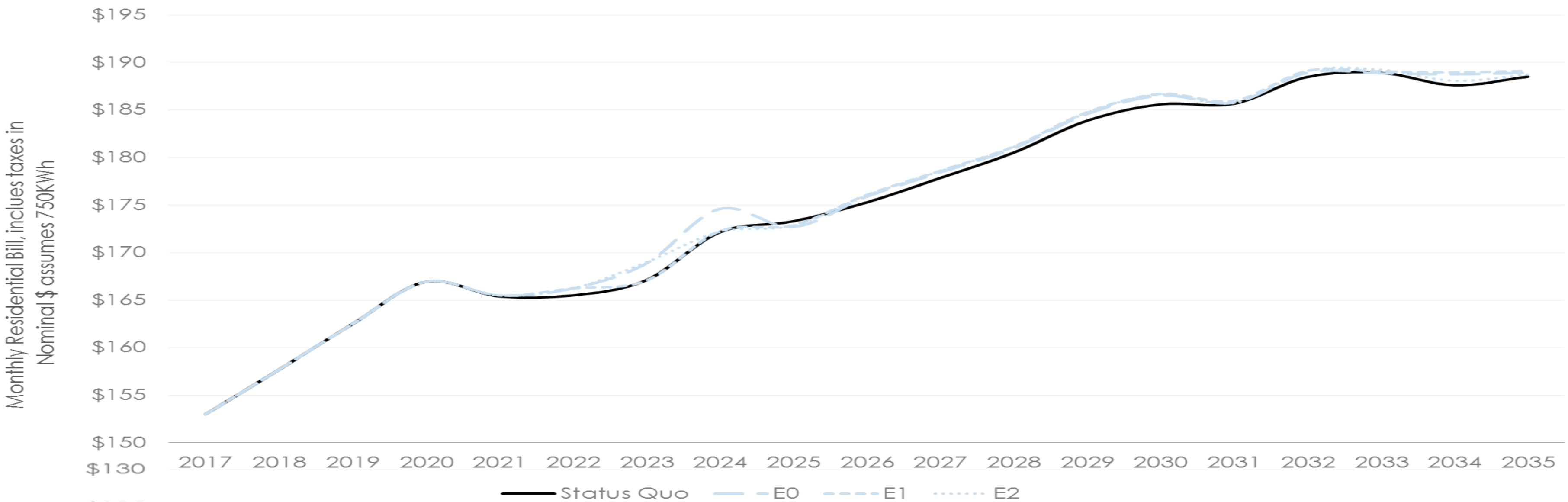


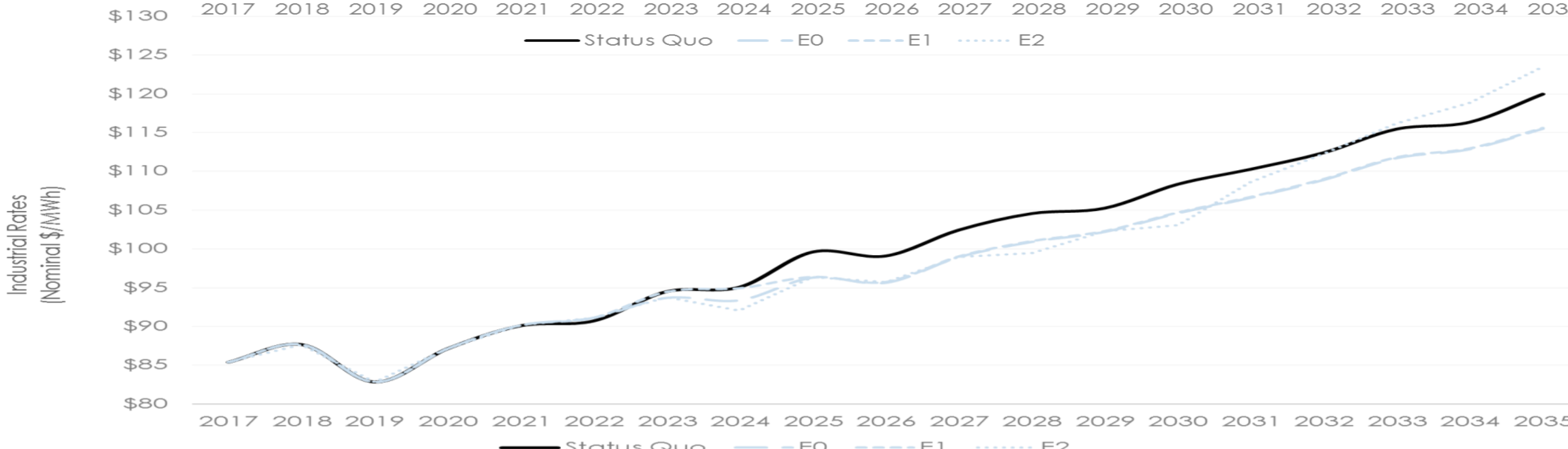



Cases E0 through E2 reflect the HQ import product at its break-even price.

# **Scenario E:** Residential monthly bills and industrial rates

Residential monthly bills (pre-OFHP) in Scenario E are similar to the Status Quo outlook with the exception of 2023-2024 where they are higher. Industrial rates in Scenario E are lower than the Status Quo outlook for some customers depending on their ability to take advantage of the ICI program.

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# Summary of scenarios assessed: break-even PPA & emissions

| Scenarios | | HQ Import Price at Which Total System Costs Remain Unchanged (Break-even) to Status Quo ($2017/MWh) | Net Change Cumulative Emissions over Break-even Period (MT $CO_2$) | HQ Import Start |
|---|---|---|---|---|
| Status Quo with HQ proposal as submitted to IESO, in context of current system outlook | With Base Gas Price | $32 | -23 | 2018 |
| | With Lower Gas Price | $22 | -29 | 2018 |
| | With Higher Carbon Price | $36 | -19 | 2018 |
| HQ imports as an alternative to reacquiring some gas-fired generation facilities at end of contract term | A0 | $52 | -33 | 2023 |
| | A1 | $54 | -33 | 2024 |
| | A2 | $53 | -34 | 2023 |
| HQ imports as an alterative to refurbishing two Darlington units | B0 | $2 | 31 | 2023 |
| | B1 | $1 | 33 | 2025 |
| | B2 | $1 | 31 | 2023 |
| | B1 - With Higher Darlington Nuclear Rate | $25 | 33 | 2025 |
| | B1 - With Non-Emitting Bridging Resource | -$134 | 4 | 2025 |
| | B1 - With Lower Gas Price | $17 | 37 | 2025 |
| | B1 - With Higher Carbon Price | -$12 | 30 | 2025 |
| HQ imports as an alternative to refurbishing two Bruce units | C0 | $83 | 22 | 2023 |
| | C1 | $96 | 25 | 2029 |
| | C2 | $87 | 23 | 2023 |
| | C1 - With Higher Bruce Nuclear Rate | $112 | 25 | 2029 |
| | C1 - With Non-Emitting Bridging Resource | -$6 | -3 | 2029 |
| | C1 - With Lower Gas Price | $104 | 26 | 2029 |
| | C1 - With Higher Carbon Price | $87 | 25 | 2029 |
| HQ imports as an alternative to refurbishing one Darlington unit and not reacquiring some gas-fired generation facilities at the end of contract term | D0 | $25 | 10 | 2023 |
| | D1 | $25 | 10 | 2025 |
| | D2 | $24 | 11 | 2023 |
| | D1 - With Non-Emitting Bridging Resource | -$21 | -6 | 2025 |
| HQ imports to meet projected capacity needs observed in the Status Quo while displacing some energy production from gas-fired generation | E0 | $57 | -27 | 2023 |
| | E1 | $60 | -27 | 2025 |
| | E2 | $59 | -25 | 2023 |

**Transmission impacts across scenarios:** Additional transmission investments would be required in the Ottawa area to enable firm capacity imports. Some additional transmission investments may be required across the province depending on which existing resources are removed to accommodate imports.

- Presently, Ontario is not importing any firm capacity from Quebec and is importing 2.3 TWh of energy
- To enable an up to 1,000 MW firm capacity import, upgrades to the Hawthorne x Merivale circuits would be required
- Depending on what generating units in Ontario are displaced as a result of an arrangement with HQ, additional low cost, low lead time upgrades may be required in eastern Ontario (e.g. voltage support may be required if Darlington units are retired).
- Other than the Hawthorne x Merivale upgrade in Ottawa, significant transmission reinforcements in eastern Ontario are not required to enable a capacity import. Additional reinforcements would also not be required to enable an energy import.
- However, a large (~1000 MW) import from HQ as part of an energy or capacity arrangement would materially increase loop flows through the St. Lawrence-New York intertie. This impact should be further investigated with New York.

# Additional transmission considerations with respect to scenarios where nuclear units are not refurbished

- In absence of Darlington units, in particular if only one unit is online, loss of dynamic voltage support will affect transfer limits, especially after Pickering nuclear generating station retires
- In addition, loss of inertia may affect system performance post-contingency, especially after Pickering retires and if all Darlington units are off-line (for example, due to a combination of planned and forced outages)
- In absence of Bruce units, loss of inertia may affect system performance post-contingency

## **System operability impacts across scenarios:** additional flexible resources are needed today to meet needs created by changing demand patterns and intermittent resources

- IESO has identified an emerging need for the ability to schedule resources capable of responding within a short time frame in order to manage forecast uncertainty in the real-time energy market

- Today, gas-fired resources are scheduled in the market to provide flexibility. For example, York Energy Center and East Windsor generating stations provide approximately 500 MW of flexibility. The overall flexibility requirement was recently revisited, identifying the need for an additional 740 MW of flexible capacity.

- Under today's system with the existing 2.3 TWh Energy Sales and Cycling Agreement, much of our domestic gas generation that used to provide that energy has been displaced. There continues to be a need to bring gas generation online to provide operability services such as ramping and operating reserve.

# Removal of existing flexible resources to accommodate imports would not address operability needs that exist. However, if imports can be made to be flexible, this could be of value to Ontario.

- Adding more imports and not renewing expiring gas contracts will not address the operability needs that exist today. Accommodating more imports (regardless of quantity) will require the need to schedule existing gas generating units more to provide flexibility, requiring some baseload facilities to be curtailed.

- In scenarios where 8 TWh HQ import displaces domestic gas (Scenario A and Scenario D), the amount of flexible resources on the system to provide operating reserve and intra-hour dispatch in response to uncertainty will be inadequate.

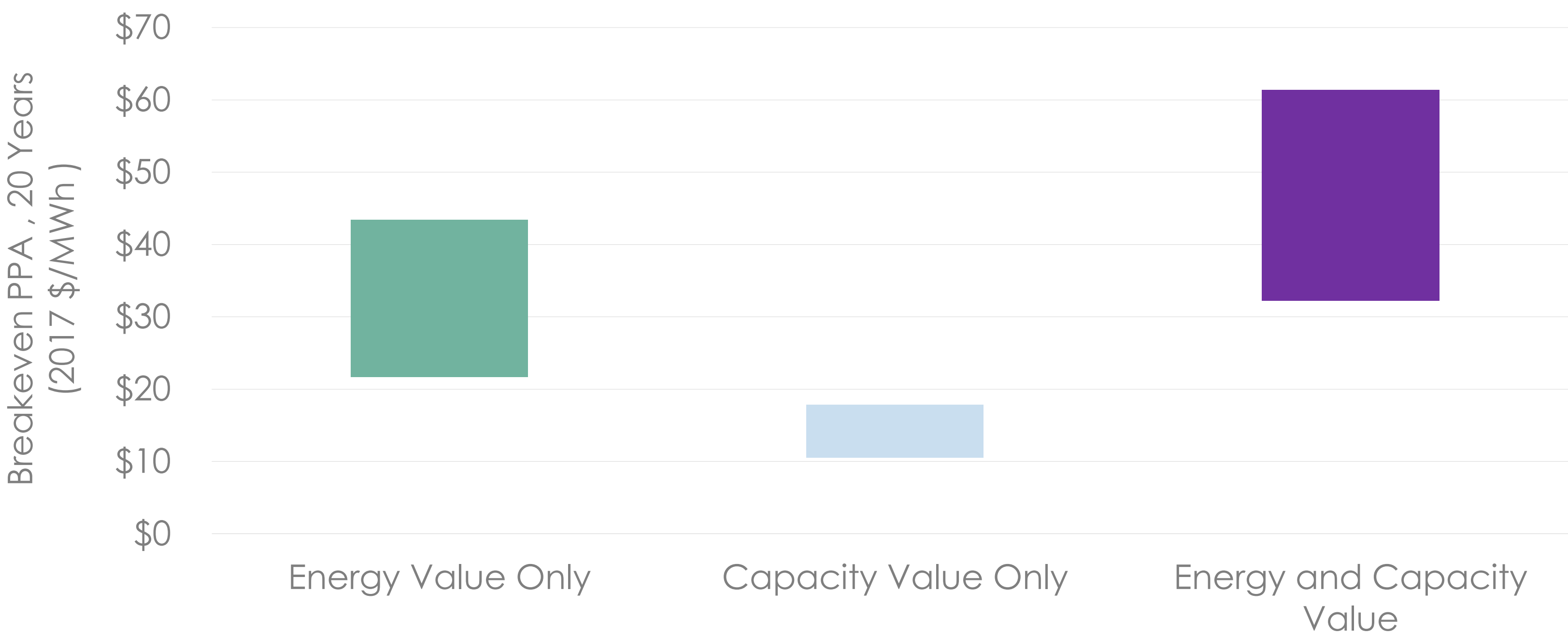
- Furthermore, some gas generators (eg. Portlands, York Energy Center, Kirkland Lake) were connected to the system in lieu of transmission upgrades – in absence of the gas generation, local reliability issues may be encountered.

- However, if imports can be scheduled more frequently (eg. every 5 or 15 mins), bid in such a manner as to be price responsive and require them to participate in the Operating Reserve market, that could provide flexibility benefits to Ontario

# 5. Observations and insights

# 1. Value of imports can be greater if it includes firm capacity in addition to energy

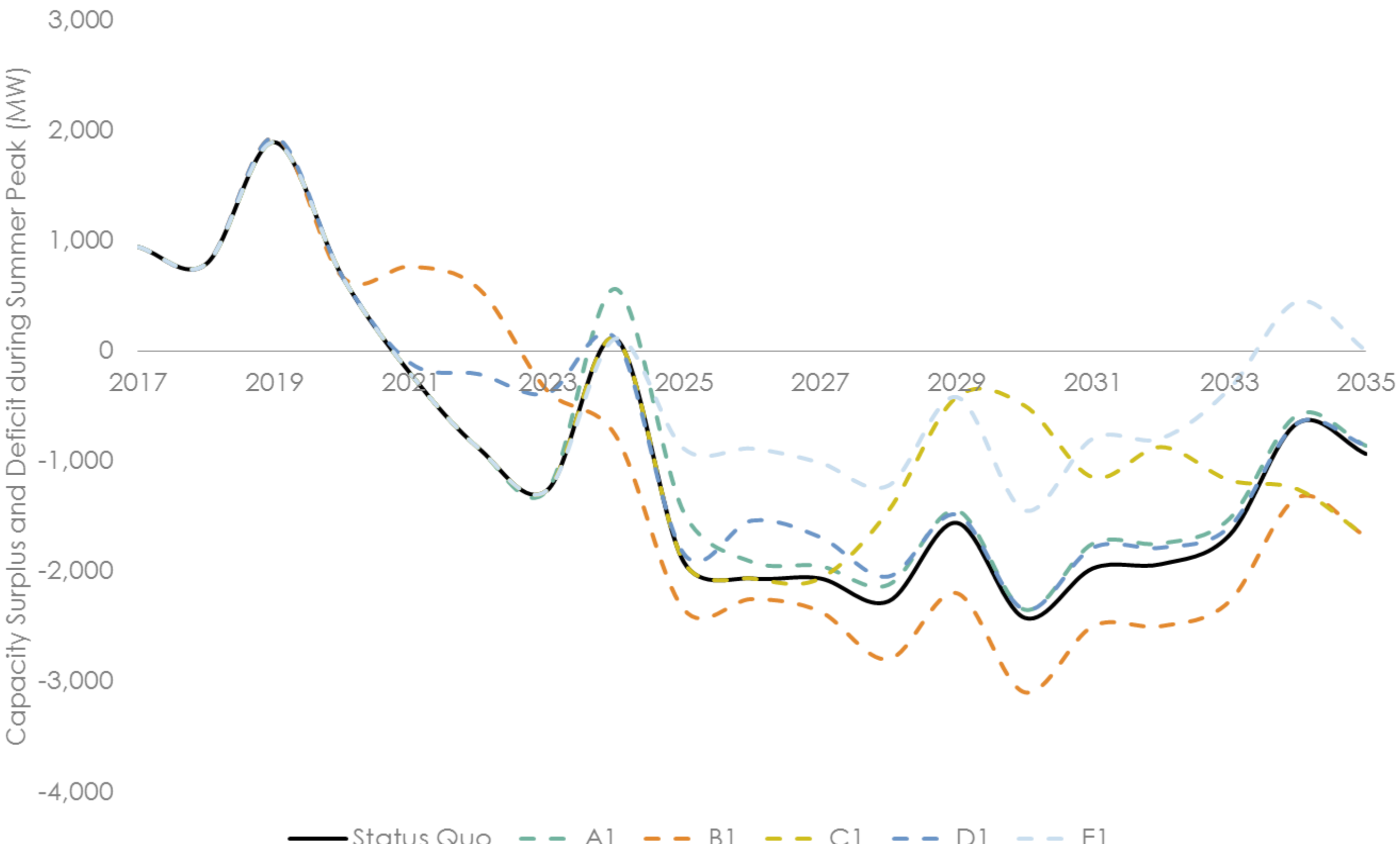
- Existing resources provide both capacity and energy. If existing resources are replaced with an energy only import product, the capacity will have to be sought elsewhere. The cost of this capacity would reduce the value imports provide. In other words, a capacity and energy product together provides greater value than an energy only product.




Range reflects scenarios: “Status Quo with HQ”, “A”, and “E”.

## 2. Imports that address projected incremental needs have greater value than those that target existing resources

- Assuming all existing /committed resources continue to be available throughout the planning outlook and resources continue to be available post contract expiry, Ontario would have a capacity shortfall of 1-2 GW, beginning in the early 2020s. Replacing existing resources would not necessarily address these additional needs and could worsen those needs if there is a mismatch in the amount of existing capacity removed and firm import capacity added in.
- In addition, the cost savings associated with replacing existing assets is less than avoiding new investments as most of the investment costs associated with existing assets are generally sunk and depreciated.




Scenarios A through D are those where HQ import capacity is an alternative to existing resources. In these scenarios, capacity needs are generally unchanged when the gas-fired/nuclear resources being replaced are retired.

However, where imports are brought in earlier than when the gas-fired/nuclear resource they replace are retired , or in Scenario E where projected incremental needs are addressed, capacity needs (and therefore need for new investments) are reduced relative to the Status Quo outlook.

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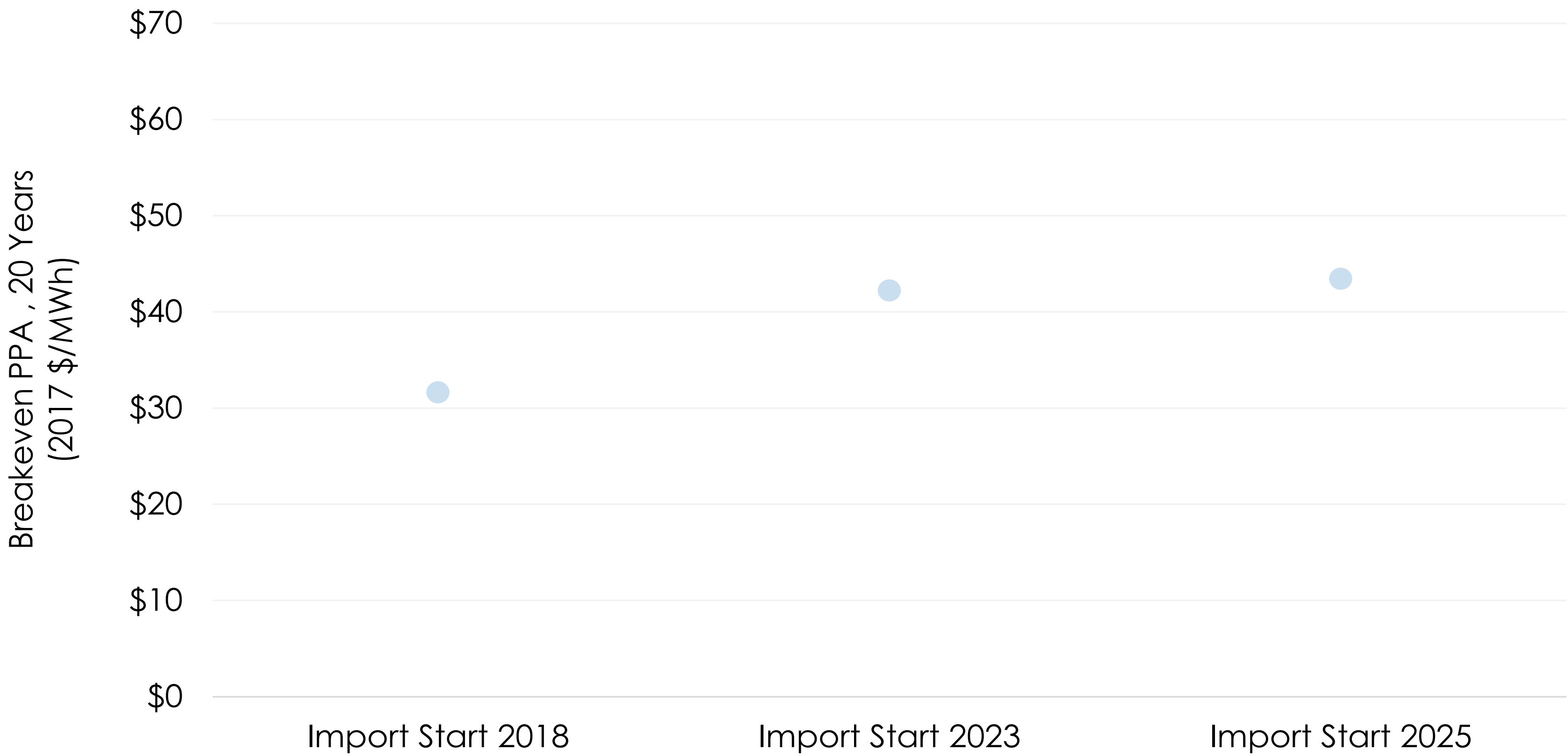
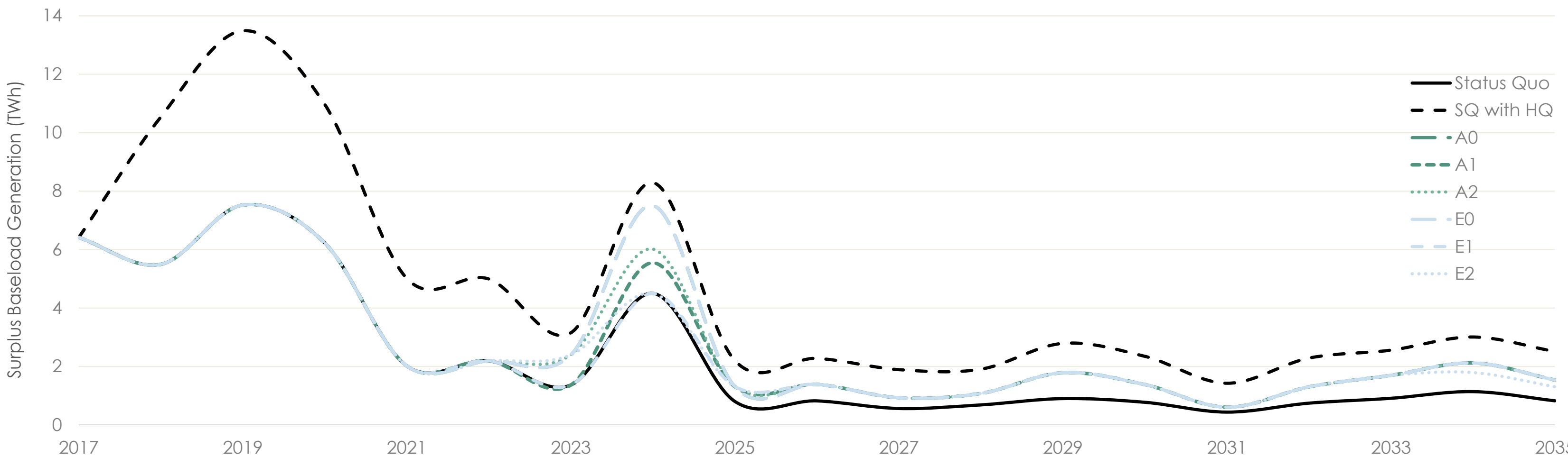
# 3. Aligning the timing of imports with needs/resource decisions would increase the value imports provide and avoid overpaying for resources in periods where they are not required

- The price of HQ imports at which the total system cost is break-even with the Status Quo outlook increases when imports start later in time – corresponding to periods where imports have higher value to the system

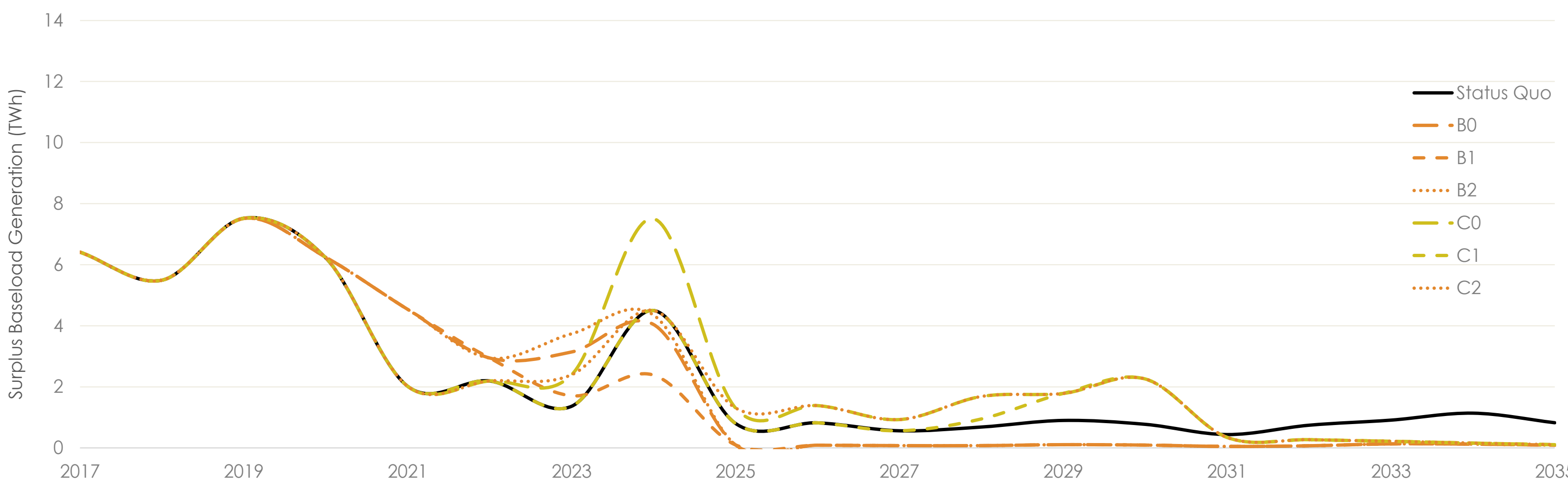



Note: 2018 break-even per "Status Quo with HQ" scenario. 2023 and 2025 break-even values are those associated with Scenarios A and E.

## 4. Where imported energy displace gas-fired generation, too much energy imported could increase SBG if more energy is imported than the gas-fired energy displaced. Imports that target energy production from nuclear could reduce SBG if imported energy is less than the amount of nuclear energy displaced.



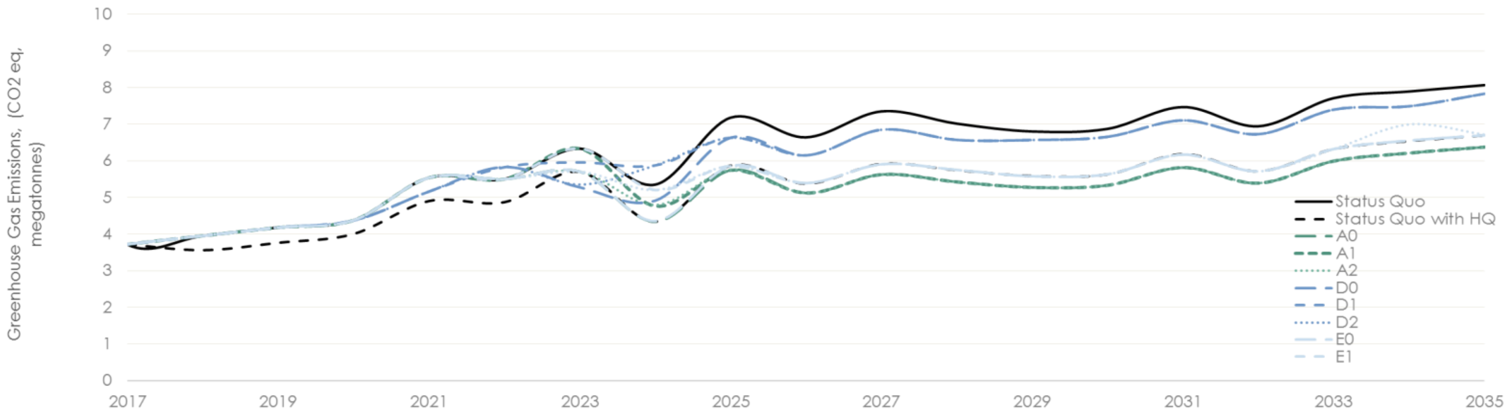

In "Status Quo with HQ" and Scenarios A and E, the amount of energy imported exceeds the amount of gas production displaced. As a result, SBG increases.



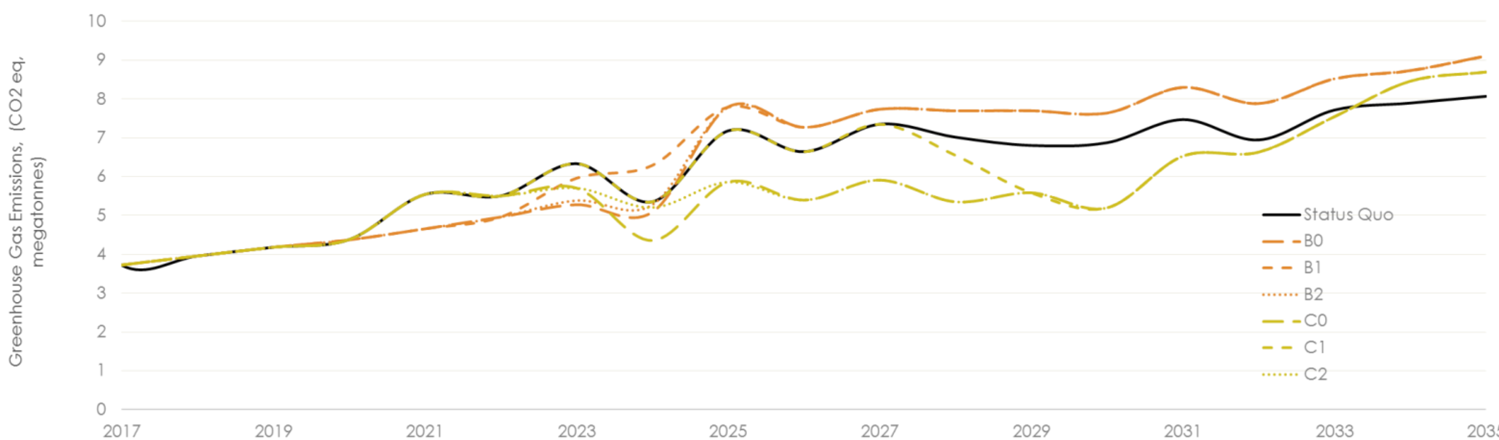

In scenarios B and C, SBG decreases as the imported energy is less than the amount of nuclear energy removed.

## 5. Replacing gas, to a certain degree, would yield lower emissions. Replacing nuclear could yield higher emissions.

- Where there is a mismatch in capacity, energy, and operating life of resources being removed and added-in, and where gas is the bridging resource, emissions would increase. This is the case where imports are an alternative to refurbishing nuclear units. The increase in emissions could be mitigated by adding in non-emitting resources to bridge the difference. However, if these non-emitting resources were higher cost relative to gas, the value of imports would be lower.



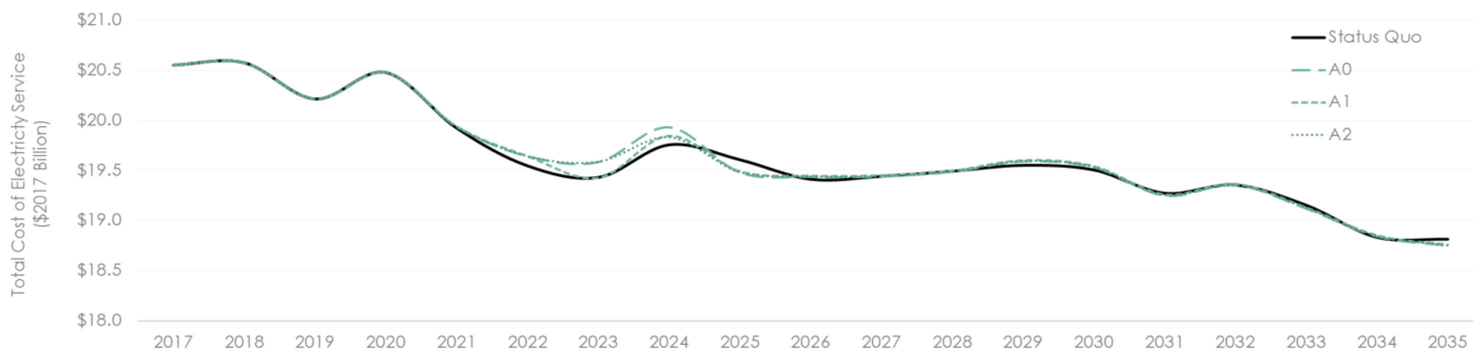

In scenarios A and E, imports displace gas-fired generation, thus emissions are lower relative to the Status Quo outlook.



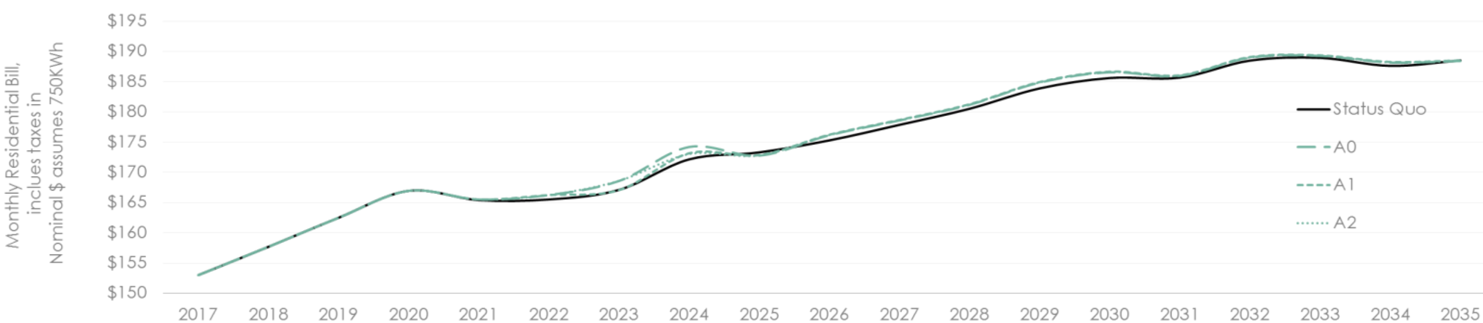

In scenarios B and C, imports replace refurbished nuclear units. In these scenarios, emissions increase relative to the Status Quo as production from existing gas-fired generation increases to bridge the difference between the amount of nuclear energy removed and energy import added in.

# 6. While total cost of service can be maintained unchanged at the right HQ price, residential bills generally increase while industrial rates decline for some consumers depending on their ability to take advantage of the ICI program

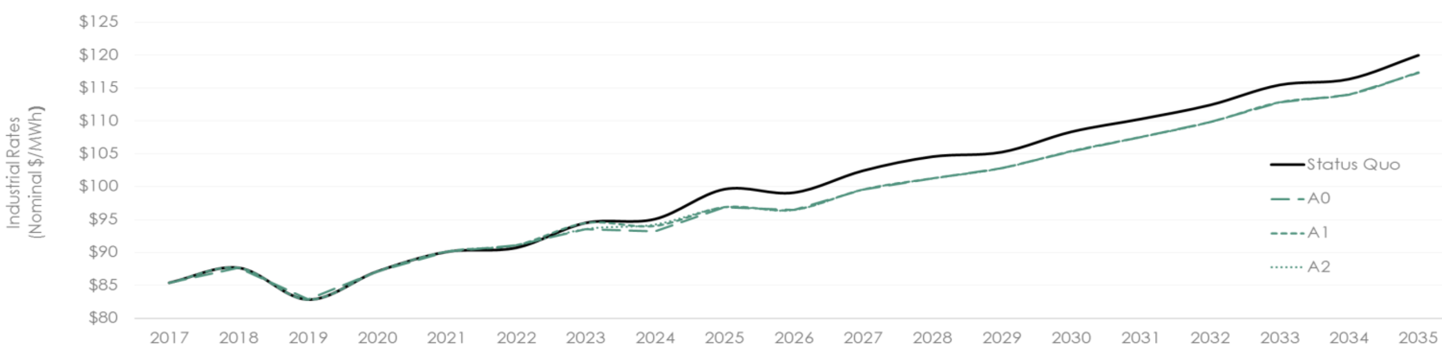
- Lower marginal costs result in a greater share of global adjustment allocated to residential consumers




Total cost of service remains unchanged relative to the Status Quo outlook in the longer-term.



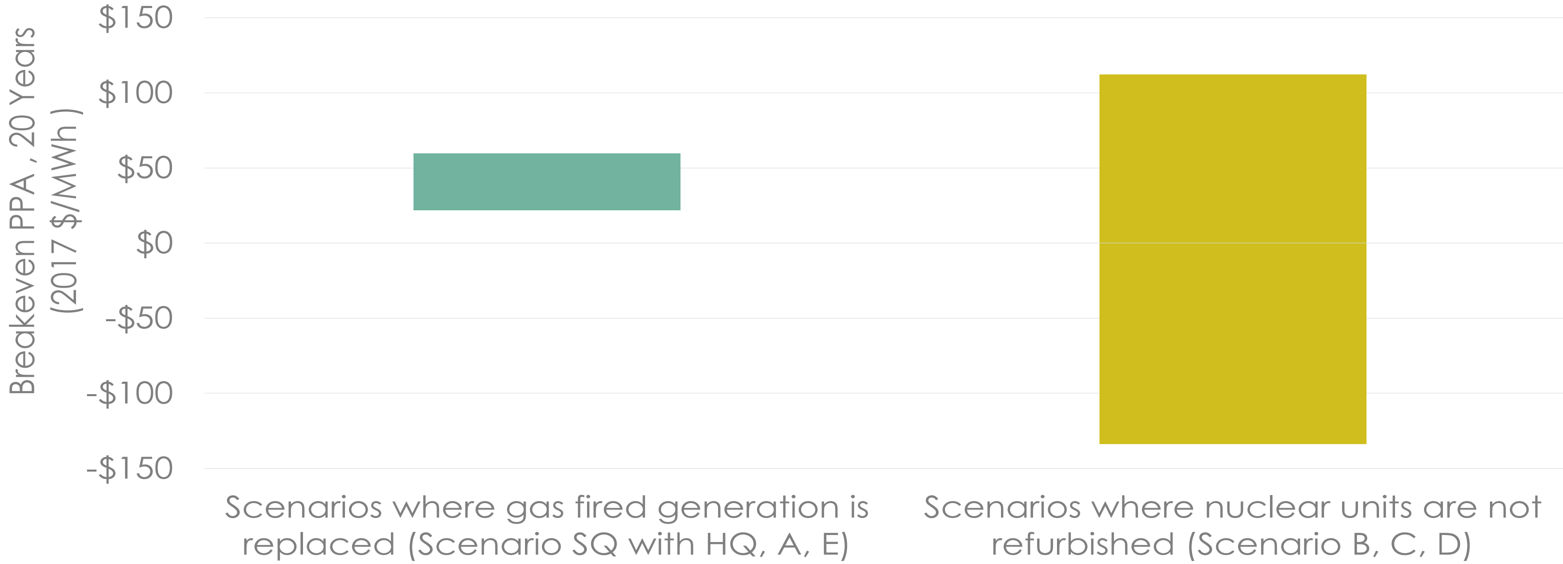

Residential bills increase relative to the Status Quo outlook.




Industrial rates for those customers that have the ability to participate in the ICI program decrease relative to the Status Quo outlook.

# 7. If existing resources are targeted for replacement with imports, imports as an alternative to existing gas-fired resources could provide greater value than as an alternative to existing nuclear resources

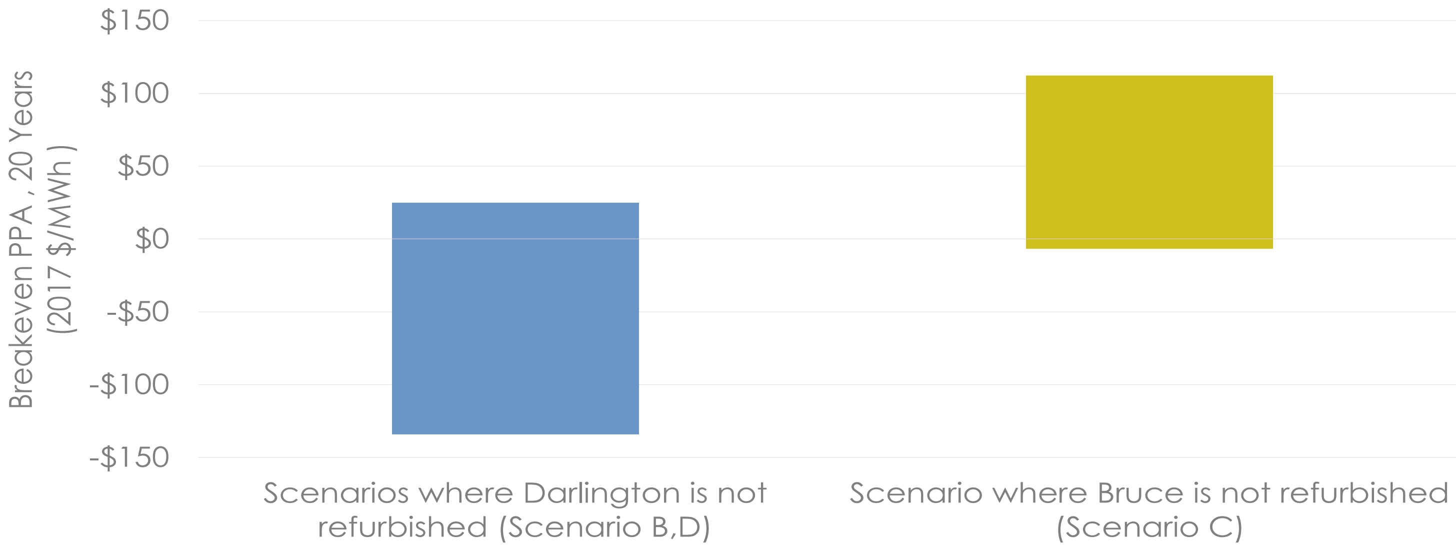
- Reducing energy production from existing gas-fired resources would reduce fuel costs and reduce GHG emissions. The cost of off-ramping nuclear units could reduce the cost savings achieved from pursuing alternative resources such as imports. The mismatch in capacity, energy, and operating life of refurbished nuclear units being removed and cost of off-ramping as compared to imports added in could result in higher costs overall as additional resources would have to be added in to bridge the difference. The higher cost of operating remaining nuclear units is another consideration which could see the value of imports decrease (see next slide).



## 8. Value of imports as compared to nuclear is a function of the cost of operating those nuclear units not forgone, costs incurred prior to off-ramp that must be recovered, timing of off-ramp, and other transaction costs that are related to exercising an off-ramp. These can lead to a varied price for nuclear refurbishment which would influence the price one ought to pay for imports for system costs to remain unchanged.

- Value of imports as an alternative to nuclear refurbishment could be higher where the cost of nuclear after off-ramping is lower than what it otherwise would be.

- In addition, different contractual arrangements across nuclear operators can limit the timing of when off-ramps can be exercised. In the case of Bruce, economic off-ramps in response to better alternatives can only be exercised 18 months prior to the refurbishment outage of the pairs of units being off-ramped. In the case of off-ramping the last two Bruce units, decision to off-ramp can only be made in 2027.



# 6. Appendix

# Overview of existing Hydro Quebec agreement and updated proposal (1)

**OVERVIEW OF EXISTING HYDRO QUEBEC AGREEMENT AND NEW OFFER**

July 10, 2017

| Item Comparison | Existing Energy Sales and Cycling Agreement | New Offer | Initial Comment |
|---|---|---|---|
| Term | 7 years from 2017 to 2023 | 20 Years from 2018 to 2038 | Longer commitment |
| Quantity | 2.3 TWh per year (= 2 TWh energy + 0.3 TWh returned cycled energy)<br>Note: Ontario sends 0.5 TWh of surplus energy to Quebec and receives 0.3 TWh back during peak hours. | 8 TWh per year of energy.<br>Potential for additional cycled energy, up to 0.3 TWh after the 8 TWh is delivered. | Roughly four times more energy, and approximately the same cycling amount. |
| Contract Price | 2 TWh of energy at 60 $/MWh and escalated at CPI (~= 61.20$/MWh in 2018)<br>0.3 TWh of cycled/stored energy at $0/MWh | 8 TWh of energy at 61.20 $/MWh and escalates at CPI<br>Up to 0.3 TWh of cycled/stored energy at $0/MWh, only after 8 TWh is fulfilled. | No change in contract price for energy, or cycled/stored energy. |
| Delivery Process | Energy is offered into the Ontario market every hour at a formula price that targets natural gas production:<br>Ontario market dispatches Quebec energy when Ontario price is higher than formula price (i.e. when gas is expected to run). | Energy is offered into the Ontario market every hour at a fixed -15 $/MWh. Ontario market dispatches Quebec energy to flow whenever Ontario price is higher than -15 $/MWh. | Both the formula price and the -15 $/MWh facilitates the flow of energy through the market; however, Ontario ratepayers will pay the contract price.<br>The new formula is a very low fixed price that will result in energy being delivered virtually at all hours.<br>To achieve the 8 TWh commitment, energy would need flow to Ontario at virtually all hours of the day due to limitations on the HVDC tie. As an example, 1,000 MW x 24hrs/day x 365 Days = 8.76 TWh. This level of commitment (i.e. 1,000 MW) would use approximately 80% of the HVDC tie line. |
| Energy Impact | Intended to target reduction in Ontario dispatchable natural gas and lower carbon emissions in Ontario with year-to-year flexibility, and a true up year at the end of contract, as required. The commitment to 2.3 TWh/year is based on the expected need for dispatchable gas production to meet domestic demand over the contract term. Formula price can be | Ontario must take 8 TWh of energy at the stated contract price every year, whether the energy is needed/delivered or not. | The existing contract provides the tools to effectively target and displace dispatchable gas .In the New Offer the commitment to the higher 8 TWh along with a fixed negative offer price would result in energy flowing even if and when surplus baseload generation is being experienced in Ontario. Water, wind, solar and nuclear would likely be curtailed/reduced before the energy from |

# Overview of existing Hydro Quebec agreement and updated proposal (2)

**OVERVIEW OF EXISTING HYDRO QUEBEC AGREEMENT AND NEW OFFER** July 10, 2017

| Item Comparison | Existing Energy Sales and Cycling Agreement | New Offer | Initial Comment |
|---|---|---|---|
| | adjusted to ensure continued effective reduction in dispatchable gas and avoid surplus energy. | | Quebec. |
| Flexibility | There is a recognition that not all the energy will be delivered in any particular year. There is a provision to make that up in subsequent years and a true up provision in the 8th year.<br>Any true-up of energy portion of agreement is on a take or pay basis in 2023.<br>The true up of the return cycled energy in 2023 is on a no consequence to either side basis therefore Ontario takes the risk. | Ontario must pay for 8 TWh at the contract price every year whether the energy is delivered to Ontario or not. | The contract no longer targets gas, and Ontario would be required to either take the energy from Quebec, or decline it and still pay the contract cost.<br>The proposed new contract considers cycling at the end of each year, while the current contract allows cycling to be considered first in alternating years. Coupled with the annual flexibility provisions, both the 2 TWh and the 0.3 TWh can be better utilised over the course of the contract to best achieve target objectives and avoid excess energy and costs. |
| Capacity | There is no capacity component to this offer.<br>- Although there is an obligation to offer ~ 1,000 MW/hr, Quebec is relieved from ~40 hours (reliability constraint) with no penalties<br>- After that Quebec pays $5/MWh in penalties | There is no capacity component to this offer.<br>- Although there is an obligation to offer ~ 1,000 MW/hr, Quebec is relieved from ~40 hours (reliability constraint) with no penalties.<br>- After that Quebec pays $5/MWh in penalties | The agreements are similar, and neither allows Ontario to count the energy from Quebec as firm capacity for reliability purposes. |
| Other Contracts as part of the value "bundle" | There are two other agreements as part of the "bundle" for:<br>a) Capacity Sale to Quebec for 500 winter capacity until winter 2022/23<br>b) Amended Capacity swap (one year of 500 MW summer capacity owed to Ontario to be delivered at Ontario's discretion before September 2030.) | - There appears to be no change to these agreements | No change to other existing contracts but in the current arrangement Ontario was willing to pay the price for the 2 TWh of energy in the context of the entire bundle and the built in flexibility.<br>Energy is de-coupled from the value bundle in the last 13 years. |

# Indicative process for performing planning studies with respect to resource options

Demand Forecast → Capacity Outlook → Resource Adequacy Assessment

→ Energy Production Simulation → Transmission/Operability Assessment → Break Even Assessment

→ Determine Cost to Customer → Iterate as required

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# Key assumptions for capacity, energy, and economic analyses

- The study period begins in 2017 and covers the maximum period affected by the investment decisions in each scenario. This is either 20 years from the start of the HQ import in the scenarios where gas-fired resources are displaced or the period to the end of when those nuclear units that are off-ramped would have otherwise been operating to.

- If a capacity deficit exists, it is assumed to be met by a capacity based resource. The price of this capacity resource is assumed to be $140/kW-yr (2017 $). This capacity based resource is modelled as an SCGT which is the proxy resource for capacity.

- Energy production from the installed fleet is simulated using an economic dispatch model, taking into account prospects for electricity trade in neighbouring jurisdictions.

- With respect to the HQ import product:
  - For the case where HQ proposal is assessed as given, the import profile is modelled as “take or pay”
  - In scenarios A through E, the imported energy is shaped as a baseload portion and a peaking portion that targets higher value periods

- Net-present value (NPV) analysis assumes a 4% real discount rate

- 2% CPI assumed for inflation

# Nuclear refurbishment outage and retirement dates for Status Quo outlook

| Unit | Refurbishment Outage Start | Refurbishment Outage End | Projected End-of-Service |
|---|---|---|---|
| Bruce 3 | January 01, 2023 | June 30, 2026 | |
| Bruce 4 | January 01, 2025 | December 31, 2027 | |
| Bruce 5 | July 01, 2026 | June 30, 2029 | |
| Bruce 6 | January 01, 2020 | December 31, 2023 | |
| Bruce 7 | July 01, 2028 | June 30, 2031 | |
| Bruce 8 | July 01, 2030 | June 30, 2033 | |
| Darlington 1 | January 15, 2021 | October 14, 2023 | |
| Darlington 2 | October 15, 2016 | September 20, 2019 | |
| Darlington 3 | September 21, 2019 | July 19, 2022 | |
| Darlington 4 | July 20, 2022 | March 19, 2025 | |
| Pickering 1 | | | December 31, 2022 |
| Pickering 4 | | | December 31, 2022 |
| Pickering 5 | | | December 31, 2024 |
| Pickering 6 | | | December 31, 2024 |
| Pickering 7 | | | December 31, 2024 |
| Pickering 8 | | | December 31, 2024 |

Bruce refurbishment per 2016 OPO. Darlington refurbishment per OPG June 19, 2017 data. Pickering retirement dates per 2016 OPO.

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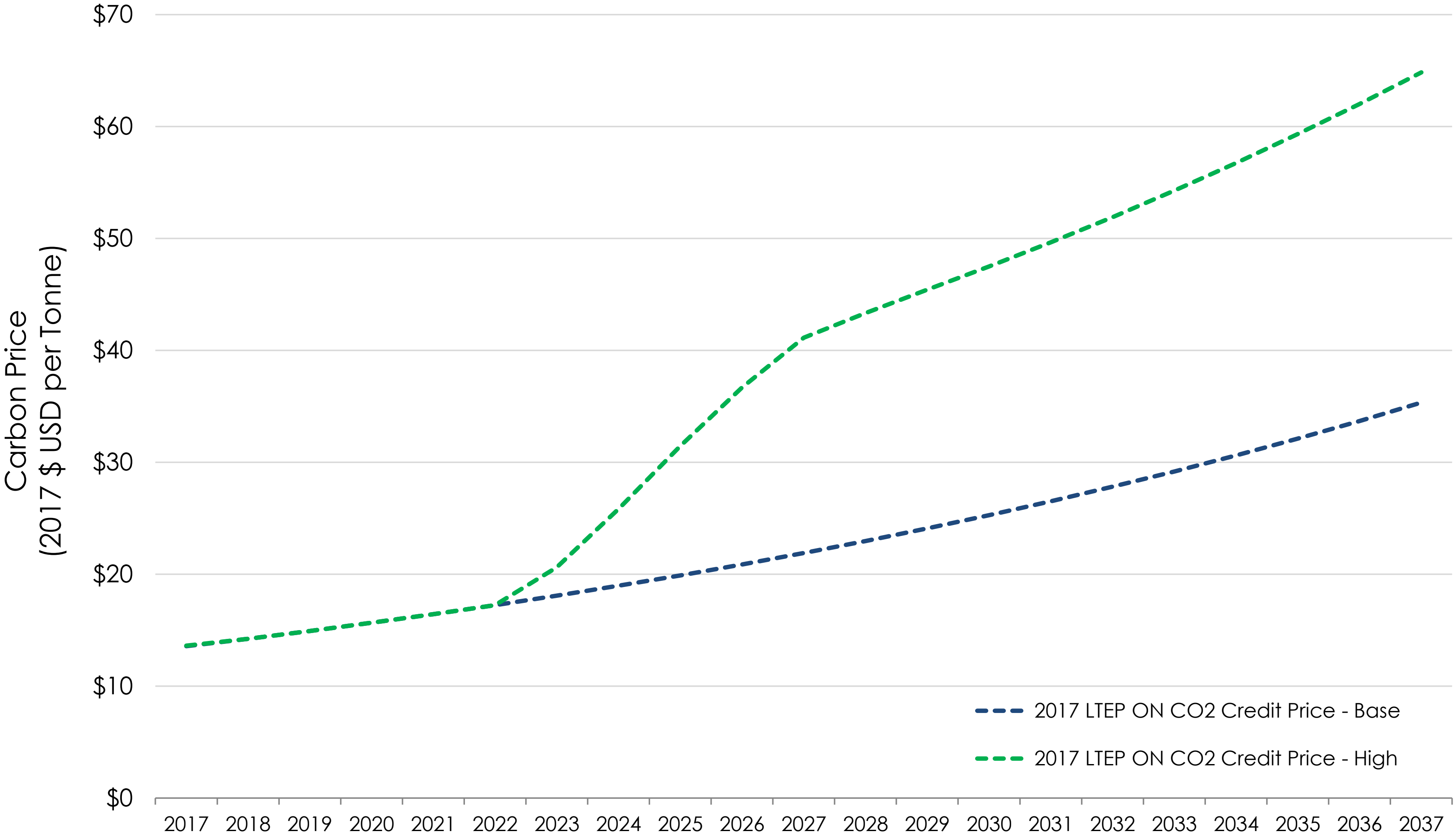
# Summary of assumptions for sensitivity analysis

| Sensitivities | Scenario | Assumptions |
|---|---|---|
| **Gas Price** | Low | Reference Gas Price minus $1.50 USD informed by industry outlooks/recent trends |
| | Base | Based on Feb 2017 Sproule |
| **Carbon Price** | Base | Reflects current floor prices |
| | High | Based on Bloomberg Outlook |
| **Bruce Rate** | Base | Per current contract price |
| | High | Threshold price which reflects 30% increase in refurbishment capital cost plus a doubling uranium prices after end of current fuel price agreement (from $4/MWh to $8/MWh 2031 onwards) |
| **Darlington Rate** | Base | Per rate provided by OPG |
| | High | 30% higher than rate provided by OPG. Based on upper bound of LUEC described in OPG's Darlington Refurbishment Business Plan filed with OPG |
| **Bridging Resource** | Base | Gas-fired generation is assumed to bridge any difference between resources removed and imports added in |
| | Non-Emitting | Non-carbon emitting resource assumed to bridge any difference between resources removed and imports added in. A combination of wind and storage resources is assumed as a proxy for a non-carbon emitting resource. |

# Gas price assumptions

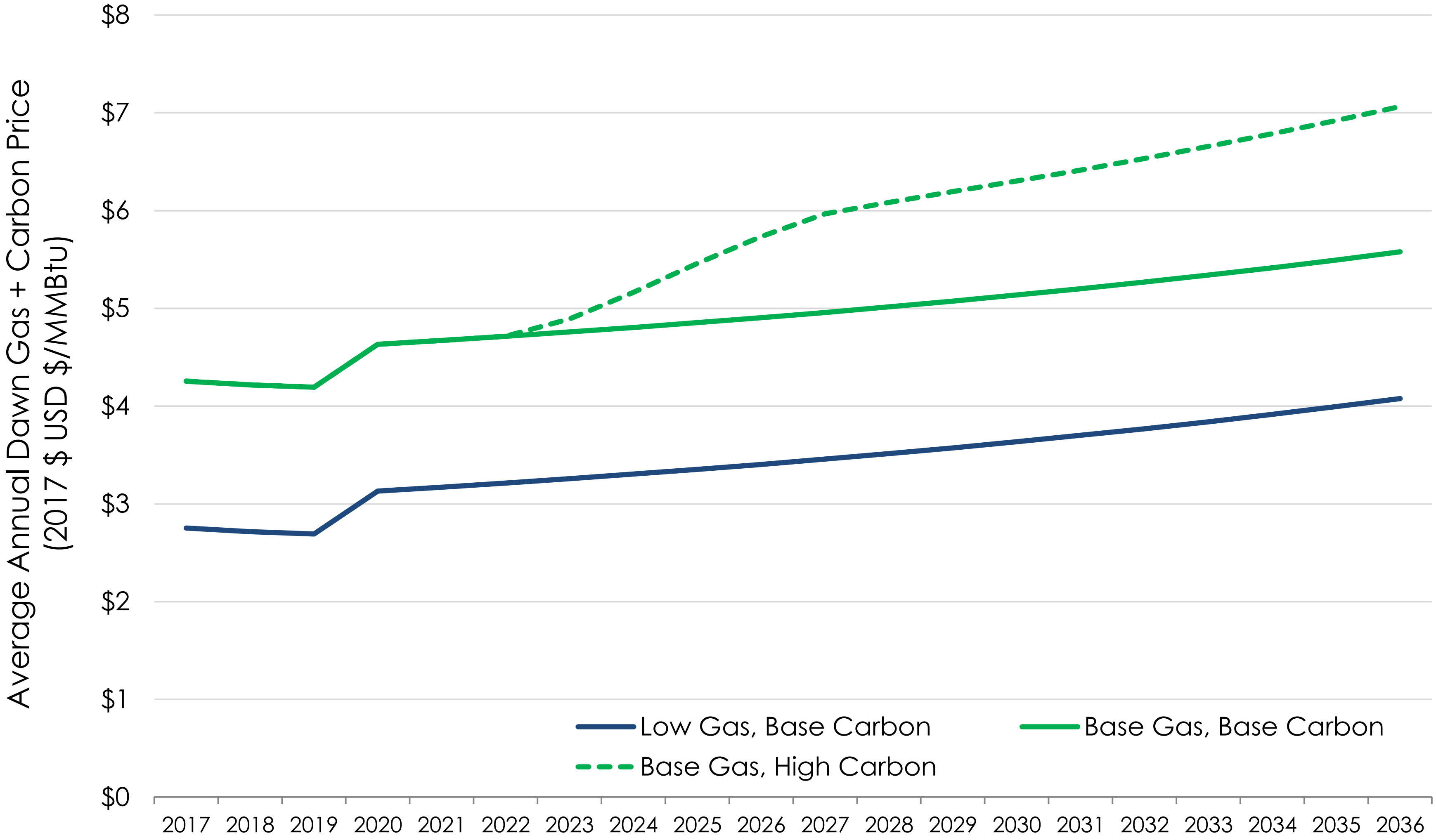

*"Base" reflects February 2017 Sproule outlook. "Low" assumes a $1.5/MMBtu US reduction from "Base" scenario informed by industry outlooks/recent trends.

# Carbon price assumptions




*"Base" reflects current floor price. "High" reflects Bloomberg carbon price outlook.

# Combined gas/carbon price scenarios for sensitivity analysis




*The carbon prices illustrated in the previous slide are converted to $/MMBtu and added to the gas prices illustrated in previously to create indicative effective gas/carbon prices. An emissions factor of 52.5 kg carbon per MMBtu is assumed.

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# Nuclear rate assumptions

*Excluded from this report as they are deemed confidential and commercially sensitive.

# Non-emitting bridging resource assumption: Overview

- For each scenario, a sensitivity was considered where the bridging resource was a combination of wind and storage

- To appropriately size a hybrid wind-storage resources for the bulk system, a detailed approach at the hourly level was considered to ensure the wind resource's daily and seasonal variations can be matched - with the help of storage - to match the profile of the desired energy delivery.

- Since the wind does not always blow when needed, the desired operational profile is a key parameter for sizing the hybrid resource to ensure that both the wind resource can produce enough energy over the entire year, and the storage is large enough to shape the delivery of that energy accordingly.

Inputs:
1. Wind Resource Profile
2. Desired Operational Profile
3. Physical Limitations
   (e.g. there may be physical limitations on how many MW of wind or MWh of storage can be installed)

→ Optimization →

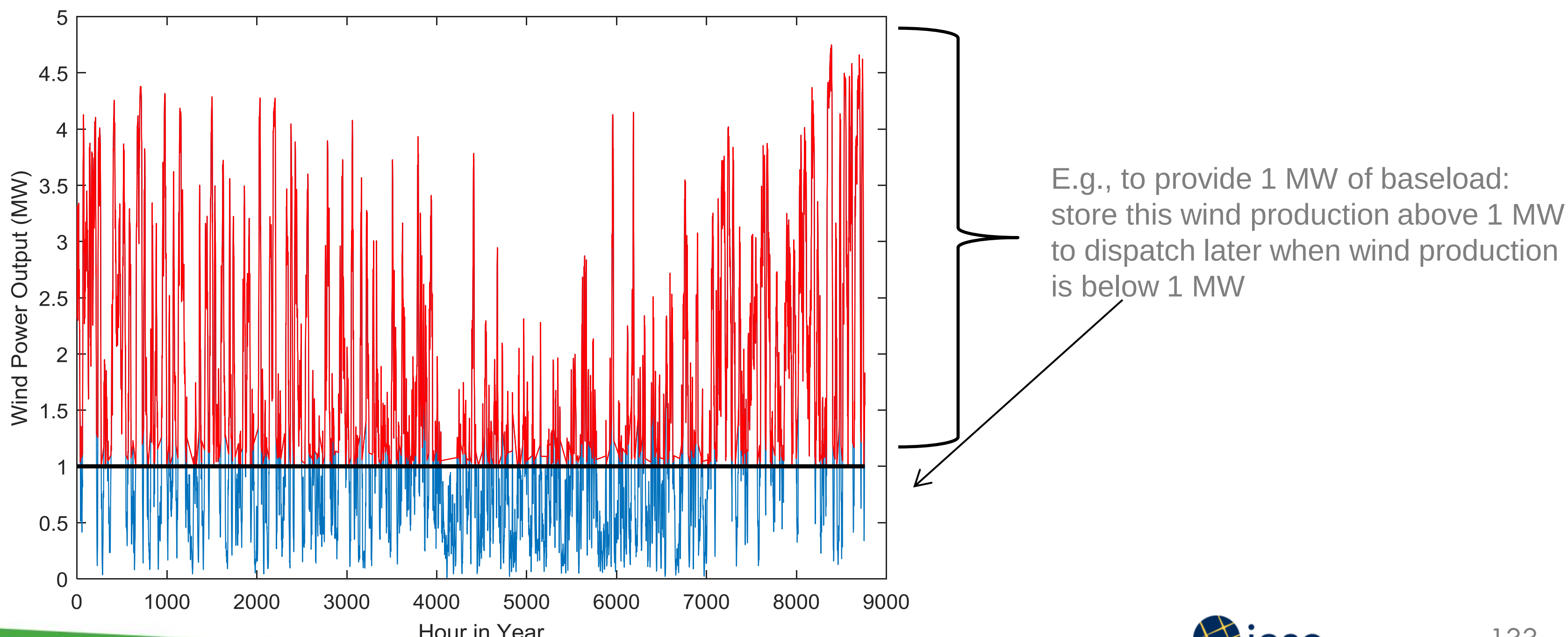
Outputs:
1. Installed Wind (MW)
2. Size of Storage (MW and MWh)

Generates the least cost hybrid wind-storage system that can satisfy the desired operational profile and the physical limitations

# Non-emitting bridging resource assumption: Operating profile

- The type of operating profile can have a big impact on how much energy is required of the hybrid system.  Typically, the larger energy required, the larger the hybrid resource needs to be, both in terms of installed wind capacity and energy storage power and energy capacity.

- For example, a baseload type application where each MW is providing energy 95% of the year, or 95% capacity factor. A MW of installed wind capacity might have a capacity factor of 30%, so the installed wind farm capacity must be larger than the baseload capacity requirement to be able to produce the required amount of energy over the year.  The system must also store the energy during periods where the wind farm is producing more than the required baseload capacity, for delivery during periods where the wind farm is producing less than the required capacity.



# Non-emitting bridging resource assumption: Applications considered

- The bridging resources were broken down into two different bulk system applications: a baseload type application and replacement of incremental gas resources for load-following and peaking application

- The resources were sized, considering three key parameters:
  1. Wind farm installed Capacity (MW)
  2. Storage Energy (MWh)
  3. Storage Power Capacity (MW)

- A least cost combination of the above was found that could meet the minimum requirements of each application

- The following table outlines the optimized wind-storage sizing, which provides 1 MW for each application studied:

| Application | Capacity Factor | Wind installed Capacity (MW) | Storage Energy Capacity (MWh) | Storage Power Capacity (MW) |
|---|---|---|---|---|
| Baseload Capacity | 91% | 6 | 8 | 1 |
| Incremental Gas Capacity | 40% | 5 | 4 | 1 |

# Non-emitting bridging resource assumption: Costs

- Wind:
  - The wind was assumed to have similar costs to existing wind projects in Ontario. Based on the LRP 1 results
  - The assumed cost is a PPA cost of $83/MWh

- Storage:
  - The storage capability was assumed to be provided equally by Compressed Air Energy Storage (CAES), Pumped Hydro and Li-Ion batteries.
  - These scenarios would require large amounts of bulk storage. The most proven large-scale technologies are CAES and pumped hydro, and Ontario has potential large-scale CAES and pumped hydro sites within the province. Li-Ion are modular and can be sited almost anywhere, and are increasing being deployed for large-scale projects.
  - For costing purposes, it was assumed that an equal combination of CAES, Pumped Hydro and Li-Ion batteries could be used to satisfy the storage requirements. The assumed cost is:
    - Cost of storage for baseload portion of bridging resource need being addressed: $207/MWh
    - Cost of storage for peaking portion of bridging resource need being addressed: $299/MWh