Scenarios for lower electricity system emissions to inform the development of the 2017 LTEP

Prepared for Discussion with Ministry of Energy

August 14, 2017

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Overview

- The Ministry of Energy asked the IESO for updated analysis on reducing electricity system emissions further to help inform decisions on electricity system outlooks in the upcoming Long-Term Energy Plan
  - The analysis focused on potential actions that could, on paper, achieve several GHG emission levels
  - The IESO has not fully explored the feasibility of these scenarios , both from the perspective of acquiring and building these facilities nor from operating the system reliably. It is expected that these considerations would lead to even higher costs
- Scenarios considered in the IESO's updated analysis include:
  - emissions under the reference case "business as usual" outlook;
  - maintaining emissions "flat" at 2017 levels;
  - minimizing emissions while recognizing the need to maintain a minimum amount of gas facilities to meet system operability requirements; and,
  - reducing electricity system emissions to zero through a phase out of the gas-fired generation fleet
- The IESO's analysis concludes that further reductions in emissions would be very difficult to achieve cost effectively and would require significant investments in new resources and associated infrastructure
- Additionally, it is expected that the scale and cost of deploying these new resources will pose many challenges with respect to land use, siting, lead time for procuring resources and building transmission, and cost equity

Key Messages

- Electricity sector emissions in Ontario are already significantly lower than the other sectors of the economy; Ontario's electricity system today contributes to about 2% of Ontario's overall economy-wide emissions
- Ontario's natural gas-fired generation is the cornerstone of the intermediate and peaking generation; it provides operational flexibility and is a key component to maintaining reliability
- Further reductions in emissions through additions of non-carbon emitting resources would be very difficult to achieve and would require significant investments in new resources and accompanying transmission
- Deploying these new resources will pose significant challenges with respect to land use, siting, lead time for procuring resources and building transmission, and cost equity
- When adding additional non-carbon emitting resources, it is expected that additional flexible resources (i.e. fast start units) would also be required from a reliability perspective; this would be achieved either through (1) conversion of the existing gas fleet to simple cycle; and/or (2) building new simple cycle facilities
- Opportunities to lower emissions could exist throughout the 2020s, enabled through expiration of gas-fired generation contracts, improvements in technology cost and performance, and market mechanisms for acquiring resources competitively and cost-effectively (such as IESO's future capacity auction)
- Market Renewal can help identify transparent and competitive mechanisms to help deliver these objectives; however, the projected savings of up to $5 billion may not be realized

Summary of the IESO's assessment of scenarios for reduced emissions

By 2035					
Scenario	**Wind/Storage Resources Added and Natural Gas Resources Removed (MW/TWh)**	**Greenhouse Gas Emissions (MT CO_2)**	**Total Cost of Electricity Service (2017 $ Billion)**	**Wind Surplus Energy (TWh)**	**Cost of Carbon Reduction (2017 $/tonne)***
Reference Case	--	8.5 MT CO_2	$19.1 B	Negligible	$38/tonne
Emissions at 2017 levels	Wind & Storage added: 8.5 GW / 21 TWh Gas removed: 0 GW / 12 TWh	4.0 MT CO_2	$20.0 B	9 TWh	$215/tonne
Minimum gas for operability	Wind & Storage added: 42 GW /90 TWh Gas removed: 6 GW / 19 TWh	1.4 MT CO_2	$28.2 B	70 TWh	$1,290/tonne
Gas Phase Out	Wind & Storage added: 54 GW /114 TWh Gas removed: 9 GW / 22 TWh	0 MT CO_2	$31.0 B	90 TWh	$1,408/tonne

*Figures do not include additional costs for transmission investments, or cost of additional flexible resources that may be required for system reliability.

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Scenarios considered for lower emissions

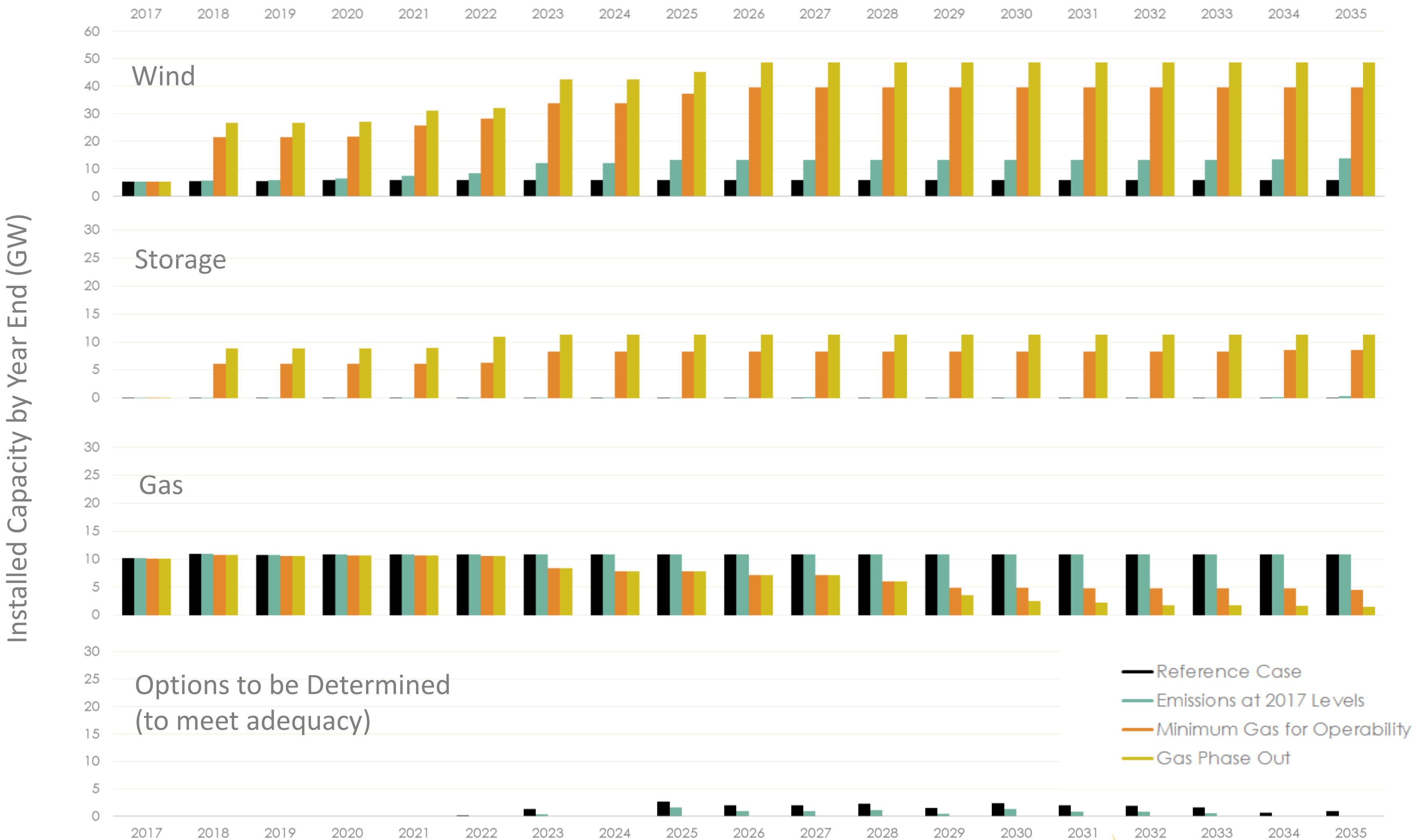
The IESO assessed a number of scenarios that consider even lower emissions relative to the reference case outlookThese lower emissions scenarios are enabled through investments in additional non-carbon emitting resources over and above the reference case outlook.

- Scenarios considered:

Emissions at 2017 Levels	Minimum Gas for Operability	Gas Phase Out
Objective is to maintain emissions at 2017 levels. Non-emitting resources were assumed to replace gas production over and above 2017 levels.	Objective is to maintain a minimum amount of gas generation required to meet system operability requirements. Non-emitting resources were assumed to replace gas production not needed for operability.	Objective is to achieve zero emissions. Non-emitting resources were assumed to replace gas energy production beginning in 2018 and gas-fired capacity following contract expiration. Operability requirements are assumed to be met by the non-emitting resources added.

- A combination of additional wind and storage were assumed for the non-emitting resource required to displace the respective amount of gas-fired generation in each scenario (see Appendix II for cost assumptions).
- For the "Minimum Gas for Operability" scenario, about 3,800 MW of gas with a capacity factor of 10% is the minimum level of gas required for operability (see Appendix II for additional details).
- For the purpose of analysis, it was assumed that replacement resources would be available when needed (i.e. excluding lead time considerations), the technology performance is equivalent to gas, technology cost reflects current cost outlooks, and additional transmission costs were not included.

Resource additions across scenarios: The amount of non-emitting resources added in each scenario relative to the reference case outlook is dependent on the amount of gas generation displaced. Additional non-emitting resources – wind/storage – is added to replace the energy produced by the gas-fleet and replace capacity provided by the gas-fleet to meet adequacy requirements.



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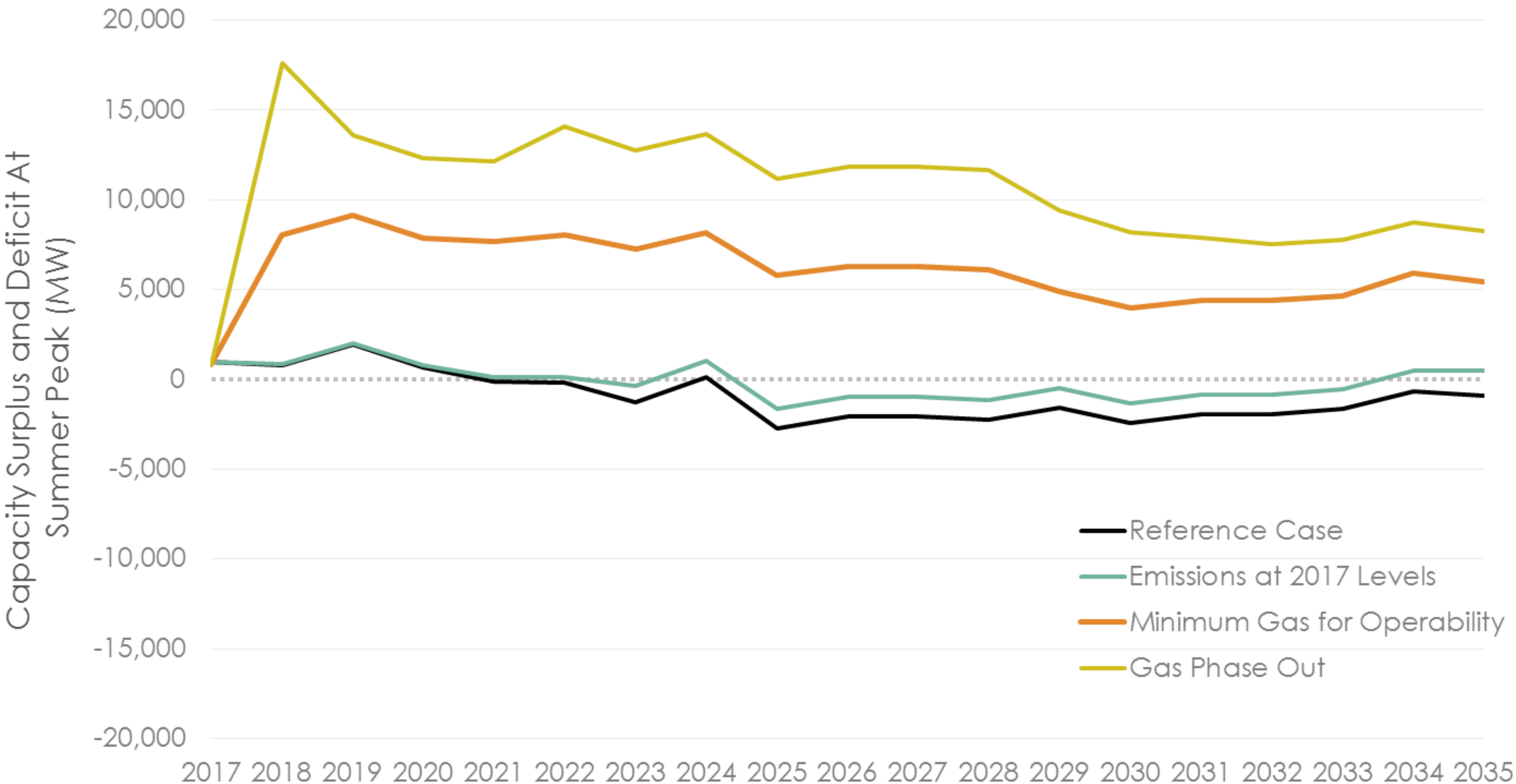
Impact on capacity adequacy: In scenarios where emissions are reduced below 2017 levels, Ontario transforms from having capacity shortfalls throughout the 2020s to having significant capacity surpluses – which increases as more energy from gas-fired generation is displaced.



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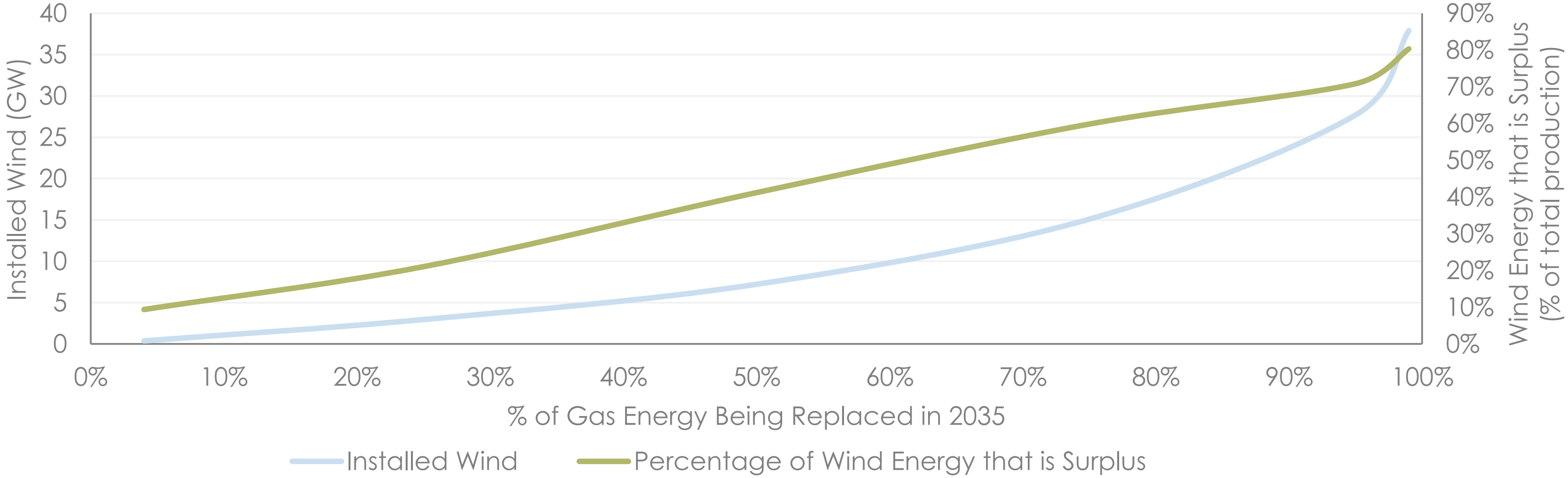
Impact on surplus energy: As more gas-fired energy production is displaced to achieve lower emissions, more wind/storage needs to be added and the amount of over building of these resources increases significantly. The overbuild is required to ensure that wind and storage can displace the gas production every hour of the year – which is the inherent difficulty of shaping a lowest cost wind-storage resource to be as dispatchable as a gas unit. There is a trade-off between wind capacity overbuild and installed storage. In each case the minimum cost combination was selected. It was found that to replace all gas energy with non-emitting renewables like wind and storage, the minimum cost combination would include a wind overbuild with about 80% of the total wind production going to surplus .



Scenario	Increase in Wind Installed Capacity by 2035 (MW)	Increase in Wind Energy Production by 2035 (TWh)	Amount of Increase in Wind Energy Production that is Surplus by 2035* (TWh)
Emissions at 2017 Levels	8,010	21	9
Minimum Gas for Operability	33,800	88	70
Gas Phase Out	42,900	112	90

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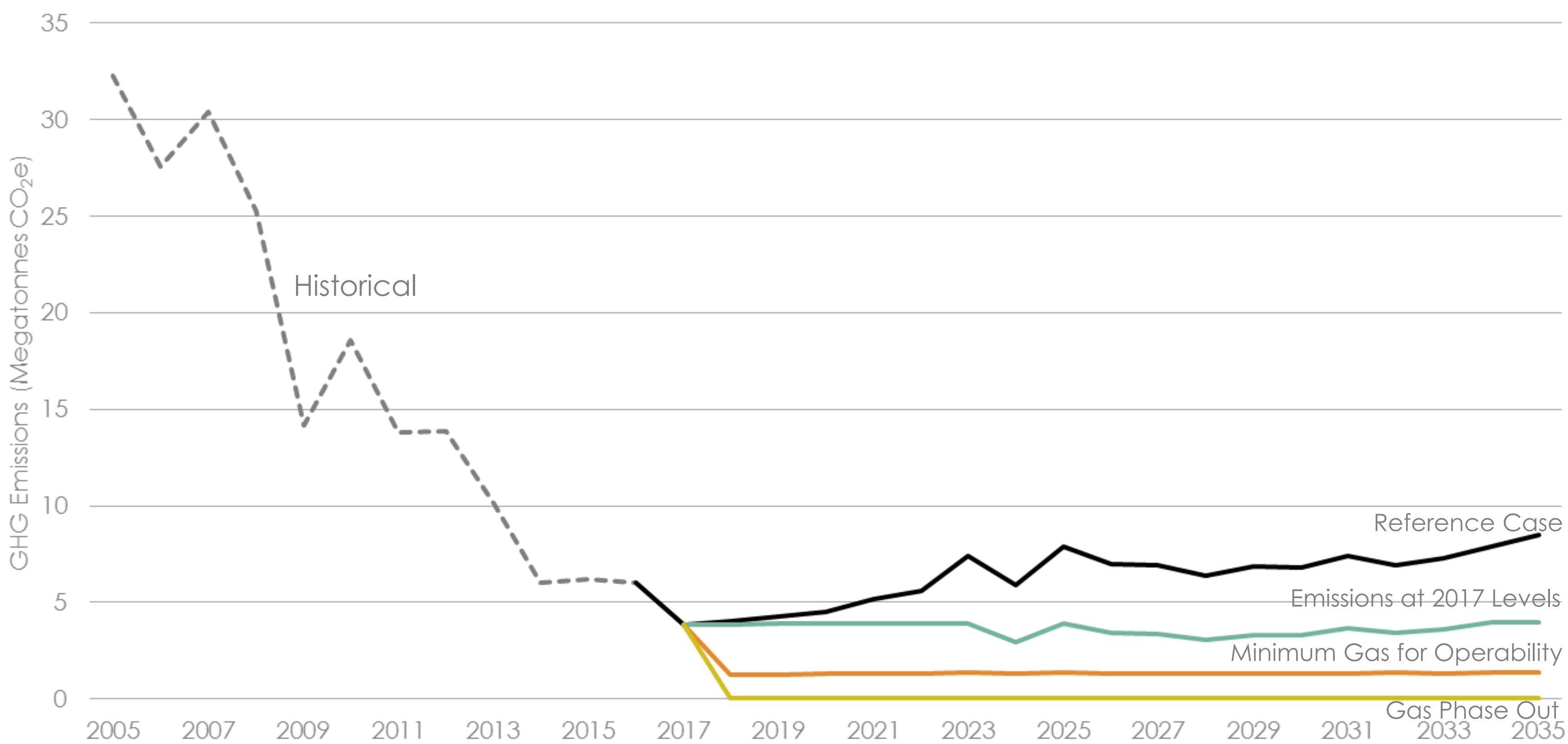
* Curtailment of nuclear and wind is expected, as not all surplus energy will be exported

Outlook for emissions: Emissions are reduced by between 4.5 MT to 8.5 MT per year by 2035 across the lower emissions scenarios considered



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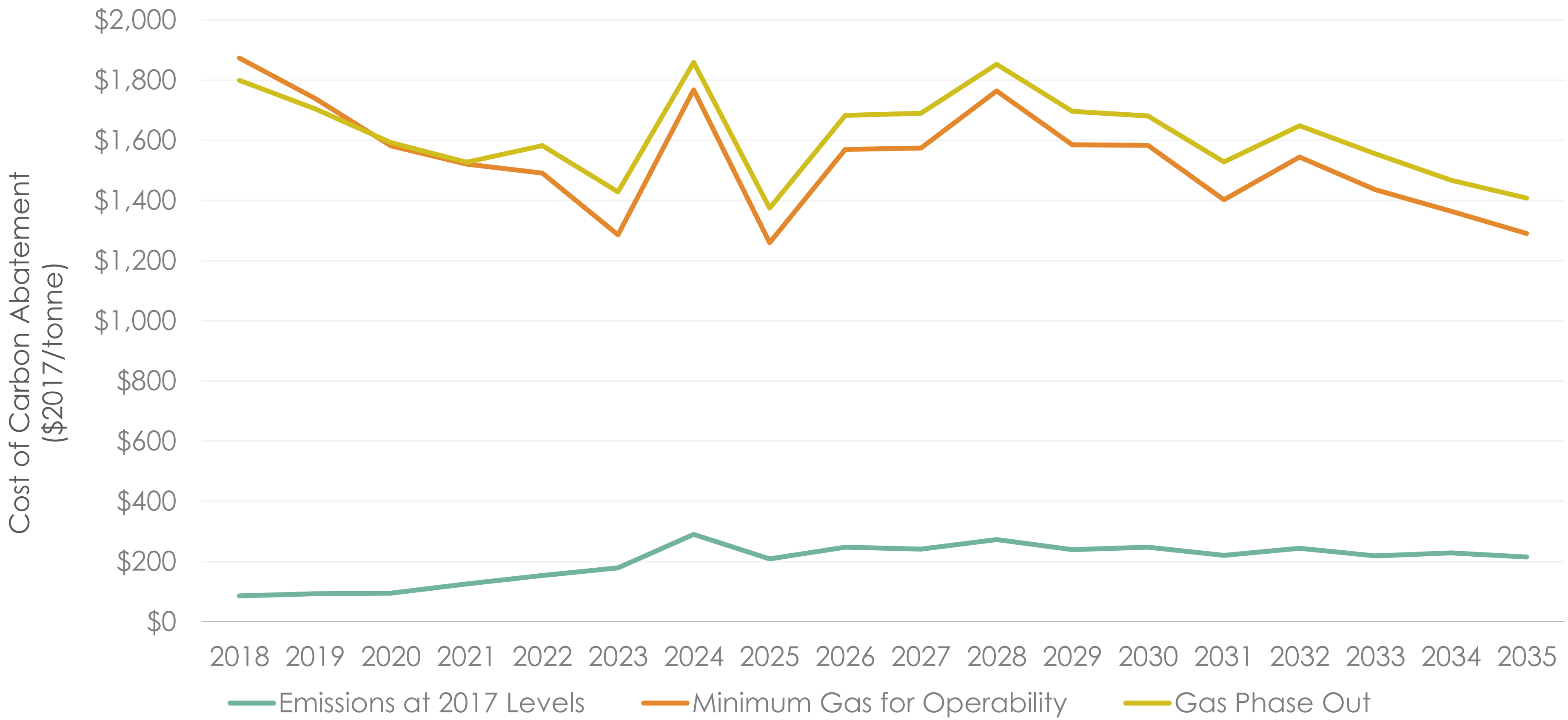
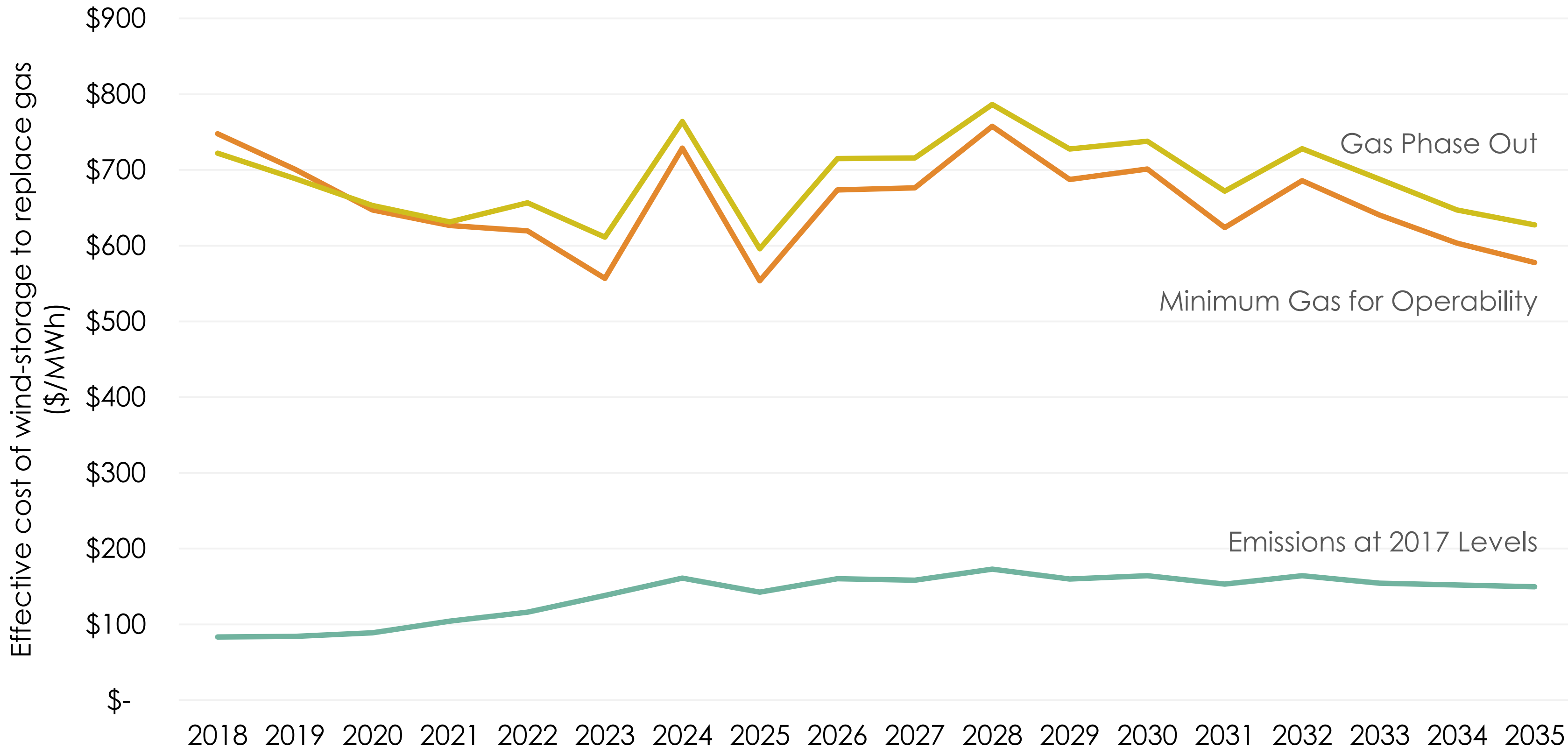
Cost of carbon abatement: The cost of carbon abatement to maintain emissions at 2017 levels ranges from about $86/tonne to $290/tonne. However, in scenarios where emissions are reduced below 2017 levels, as increasing amounts of gas production is replaced with wind/storage, the abatement cost rises significantly – ranging between $1,259/tonne to $1,874/tonne across the scenarios where gas is maintained for operability and where emissions is reduced to zero. As context, the current cap and trade floor price is about $18/tonne rising to about $40/tonne (2017 $ CDN) by 2035.



Effective cost of replacement resources: As more energy from gas-fired generation is replaced, the effective cost of each MWh increases. In the first few years of the scenario where emissions are maintained at 2017 levels, the effective cost of resources added is close to the cost per MWh of wind since the incremental gas energy production being replaced is quite small and most of the wind added is replacing gas directly with no need for storage. In scenarios where emissions are reduced below 2017 levels, a significant overbuild of wind and storage is required to fully displace gas production. As a higher percentage of the energy from wind/storage becomes surplus relative to the gas displaced, the effective cost of wind/storage rises considerably.



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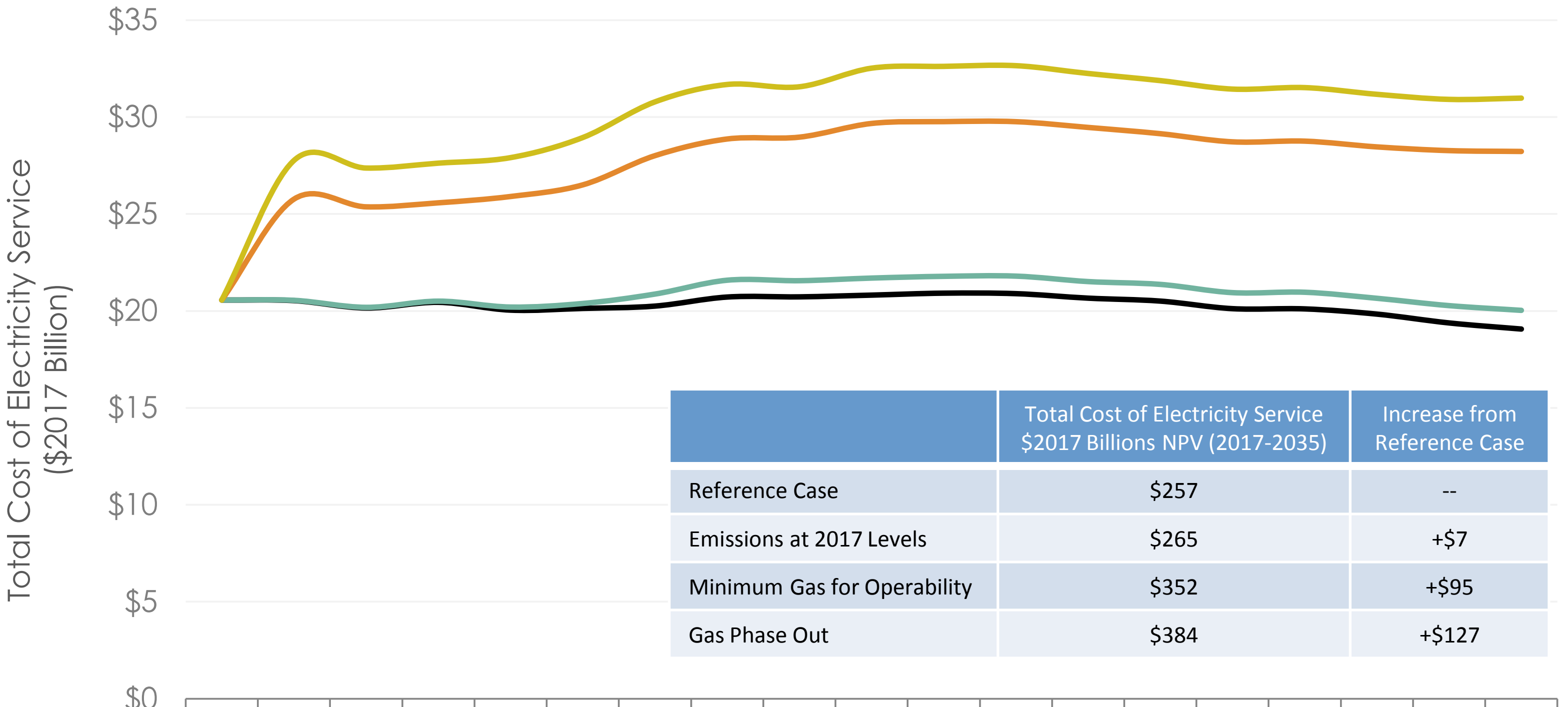
Total cost of electricity service: By 2035, relative to the reference case outlook the total cost of electricity service rises between $0.9B in the flat emissions scenario and $9.1B to $11.9B in scenarios where emissions are even lower. On an NPV basis between 2017 and 2035, in the scenario where emissions are maintained at 2017 levels, the total cost of electricity service is about $7B higher relative to the reference case outlook and where even lower emissions are sought is about $95B to $127B higher relative to reference case outlook. This reflects the additional cost of wind/storage added and the savings from displaced gas generation. **Additional costs for transmission have not been reflected.**



	Total Cost of Electricity Service $2017 Billions NPV (2017-2035)	Increase from Reference Case
Reference Case	$257	--
Emissions at 2017 Levels	$265	+$7
Minimum Gas for Operability	$352	+$95
Gas Phase Out	$384	+$127

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reference Case	20.6	20.5	20.2	20.4	20.0	20.1	20.2	20.7	20.7	20.8	20.9	20.9	20.7	20.5	20.1	20.1	19.8	19.4	19.1
Emissions at 2017 Levels	20.6	20.5	20.2	20.5	20.2	20.4	20.9	21.6	21.6	21.7	21.8	21.8	21.5	21.4	20.9	21.0	20.7	20.3	20.0
Minimum Gas for Operability	20.6	25.8	25.4	25.6	25.9	26.5	28.0	28.9	29.0	29.7	29.8	29.8	29.5	29.1	28.7	28.8	28.5	28.3	28.2
Gas Phase Out	20.6	27.8	27.4	27.6	27.9	28.9	30.8	31.7	31.6	32.5	32.6	32.6	32.2	31.9	31.4	31.5	31.2	30.9	31.0

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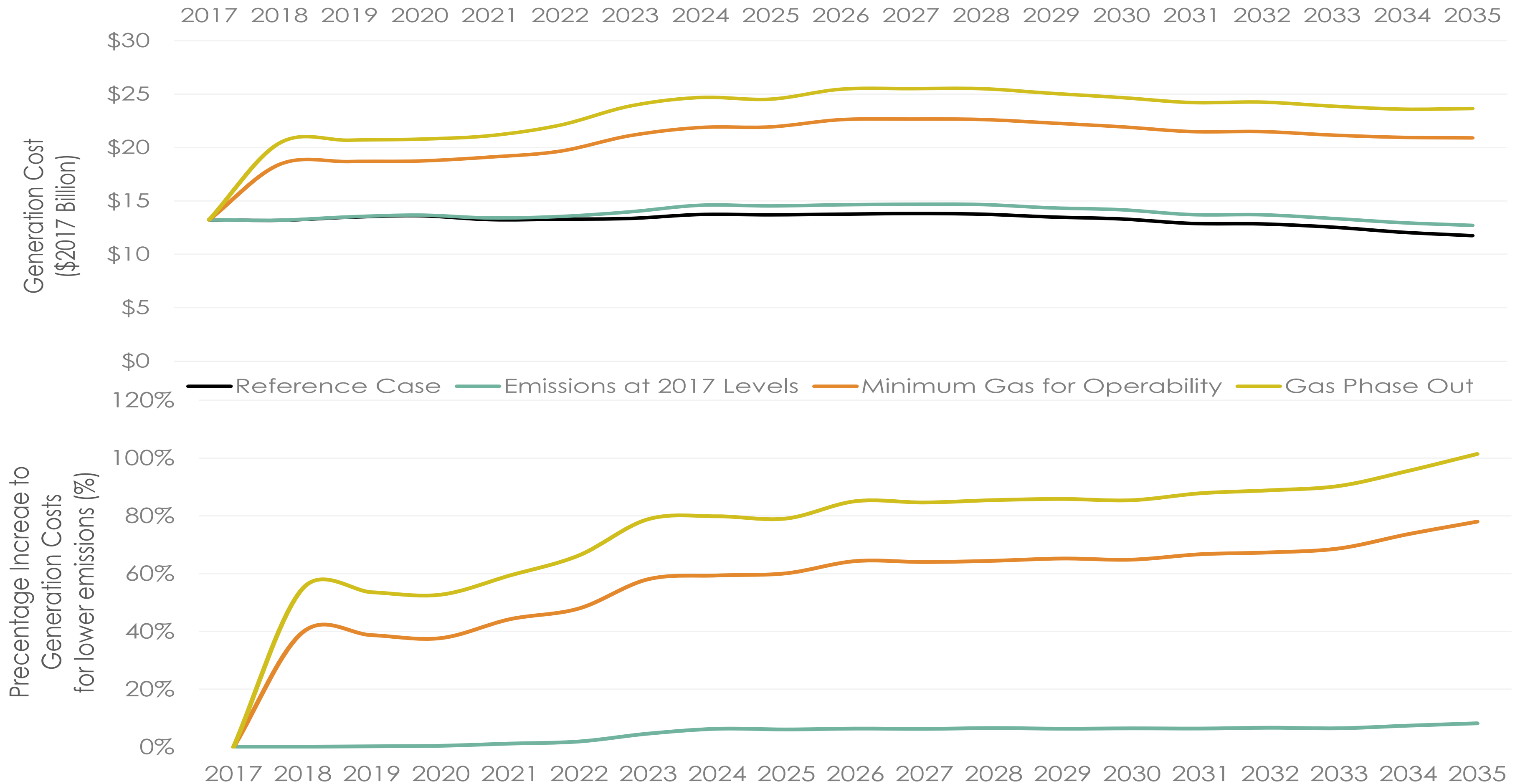
Cost of electricity generation: The analysis reflects changes in generation costs only – i.e. capital cost of investing in wind and storage and savings from displacing gas-fired capacity and energy production. The increase in generation cost for the scenario where emissions are reduced to zero can be greater than 100% by 2035 relative to the reference case outlook. Changes in transmission costs were not considered in this analysis. Transmission costs are expected to be higher across the emissions scenarios as additional transmission would be required to accommodate higher levels of wind and storage and to address local supply reliability in areas where gas-fired generation had once provided that reliability.



Implementation challenges: Achieving electricity system emissions that are below 2017 levels will pose some practical challenges – in regards to land use, siting and lead time, and cost equity

- In the scenario where emissions are reduced to zero, about 43 GW installed wind and 11 GW installed storage is added by 2035 as compared to 6 GW of installed wind and 173 MW installed storage in the reference case outlook.
  - The geographic area required to accommodate this wind is 23 times the geographic area covered by the City of Toronto[1, 2]
  - The amount of storage is equivalent to about 65 Beck PGS reservoirs.
- There are lead time considerations with installing new, non-emitting resources. The analysis assumed that these resources would be available when needed and in-service as early as 2017. In practice, installation of new resources would be more gradual and over time.
- In addition to generation lead times, there is lead time associated with transmission. The transmission investments envisioned are those that have long lead times in the order of 7 to 10 years. This lead time was not considered in the IESO's analysis.
- Transmission investment would also be required to maintain bulk and local system reliability. The gas-fired capacity sited in the GTA such as in York Region and in Downtown Toronto were in lieu of transmission supply. If this supply is removed, alternative supply and/or transmission would be required to maintain local reliability.
- In addition, it is observed that much of the increase in emissions in the reference case outlook is being driven by gas-fired generation being dispatched to meet the export market and not meet Ontario demand. There would be cost equity issues regarding Ontario consumers paying to reduce emissions from resources being dispatched to meet demand outside of Ontario. Alternatively, increased tariffs on exports could reduce some of this gas dispatch and commensurately reduce emissions.

(1) National Renewable Energy Laboratory. Land-Use Requirements of Modern Wind Power Plants in the United States, August 2009. (2) City of Toronto, Toronto Facts, Geography, 2017.

Implications for system operability: To operate the power system and maintain reliability, resources that can be dispatched quickly are needed to manage changing demand patterns and intermittent resources. Currently, gas-fired generation cost-effectively provides these services. Opportunities exist for non-emitting resources to provide these services as technology performance and cost improves.

- 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 – driven by changing demand patterns and intermittent generation - 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.

- There is also a need to bring gas generation online today to provide operability services such as ramping and operating reserve. In the reference case outlook, about 3,800 MW supply is required for ramping and operating reserve. This is the "minimum" amount of gas reflected in the "minimum gas for operability scenario"

- Absent any gas facilities such as in the zero emissions case, the amount of flexible resources on the system to provide operating reserve and intra-hour dispatch in response to uncertainty will be inadequate.

- Although not considered in the IESO's analysis, adding additional amounts of non-emitting resources to the existing resource mix can also increase operability requirements

- Any reduction in gas-fired generation would need to ensure that resources capable of providing the above services are made available to the system. Ideal resources are those that can be scheduled more frequently, bid in such a manner as to be price responsive, and are capable of participating in the Operating Reserve market.

- With the addition of 8.5 GW to 54 GW of wind/storage, an additional 1.2 GW to 7.4 GW of flexibility will be required from new or existing resources. These additional flexible resources will be needed for system reliability.

Appendix I:
Overview of the reference case electricity system outlook

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Ministry of Energy's 2017 Long-Term Energy Plan Modelling Assumptions, April 6 2017 Document (1)

MINISTRY OF ENERGY'S 2017 LONG-TERM ENERGY PLAN MODELLING ASSUMPTIONS

This document summarizes the modelling assumptions for the reference outlook to inform the Ministry of Energy's 2017 Long-Term Energy Plan ("2017 LTEP").

The document reflects the IESO's understanding of the assumptions to be assumed for the 2017 LTEP based on IESO/ENERGY discussions between February and April 2017 and comments received from ENERGY staff on April 1, 2017.

In order to proceed with analytics, the IESO is seeking Ministry sign off on this document no later than Friday April 7, 2017

Section 1 – Assumptions

Outlook Timeframe

- The IESO will model the LTEP for the period 2017 to 2035 to align with the timeframe presented in the 2016 Ontario Planning Outlook (OPO).

Demand

- It is the IESO's understanding that ENERGY's preference is to consider a single demand outlook as the reference forecast. The reference demand forecast for the 2017 LTEP will be OPO Outlook B with the addition of electric vehicle (EV) demand assumptions per Outlook D (i.e., 2.4 million EVs by 2035).
- It is the IESO's understanding that ENERGY's preference is to consider a range of sensitivities around the reference demand forecast, with the range of sensitivity starting in 2026. Therefore, two sensitivities will be developed around the reference demand forecast to illustrate higher and lower ranges beginning in 2026:
  - The lower range will have similar assumptions to OPO Outlook A.
  - The higher range will assume higher household growth, higher new square footage growth in various commercial buildings, and greater growth in the industrial sector.
- Detailed energy/costing analysis will not be performed for the low and high demand sensitivities. Instead, their implications may be described qualitatively.

Conservation and Demand Response

- The 2013 LTEP targets 30 TWh of energy efficiency by 2032 and assumes that the near term target set in the Conservation First Framework and Industrial Accelerator Program of 8.7 TWh will be achieved by 2020.
- The IESO understands that ENERGY is seeking analysis on modeling a higher than 2013 LTEP conservation target within the OPO Outlook B. Based on discussions with the ADM and Michael Lyle, the IESO will perform analysis assuming 1) the 2013 LTEP conservation targets and 2) a higher conservation target.

- The 2013 LTEP included a Demand Response target which includes Time-of-Use (TOU), Industrial Conservation Initiative (ICI) and demand response (DR) auction combined to meet 10% of peak demand by 2025. It is the IESO's understanding that ENERGY requests to eliminate the demand response target that was established in 2013 LTEP for the 2017 LTEP base case. The IESO will assume for the 2017 LTEP base case that TOU and ICI will continue to persist throughout the planning horizon and any DR currently procured through the DR auction would continue to be available in future auctions. Should there be capacity needs moving forward, additional demand response could be procured through the capacity auction.

Supply

- The IESO will assume the nuclear schedule that is consistent with OPO, which reflects OPG's current business plan and the amended Bruce refurbishment agreement:
  - Bruce as per the schedule in the finalized ABPRIA;
  - Pickering continued operations to 2022/2024 (Note from ENERGY: In March 2017, OPG Board approved operation of all six units to 2024 subject to system needs and project economics. As such, the additional two years is considered a supply option/scenario rather than a base case);
  - Darlington as per the finalized refurbishment schedule.
- It is the IESO's understanding that ENERGY does not want to consider operation of all six Pickering units to 2024 as part of the analysis. The IESO will assume Pickering continued operations to 2022/2024 for the base case.
- The IESO will reflect the October 2016 Ontario-Quebec Electricity Trade Agreement.
  - Energy 2.3 TWh per year (2017 to 2022 inclusive) Quebec to Ontario;
  - 500 MW capacity per winter December to March (2016/17 to 2022/23 inclusive) Ontario to Quebec; and
  - 500 MW capacity Quebec to Ontario in return for delivery of 500 MW to Quebec in 2015/16 as part of original capacity swap.
- The IESO will reflect recently contracted new resources e.g. Chaudiere Falls Gatineau No.1 and Hull No.2 waterpower contracts.
- The IESO will assume the suspension of Large Renewable Procurement II and Energy From Waste Procurement as a result of the September 2016 direction.
- The IESO will assume FIT 5 and microFIT 2017 are the remaining renewable programs to be procured that are not yet online or contracted.
- The 2013 LTEP set renewable capacity targets of 10.7 GW for non-hydroelectric by 2021 and 9.3 GW for hydroelectric by 2025. The IESO will assume the elimination of hydro and non-hydro renewable targets and that there will be no further renewable procurements beyond FIT 5 and microFIT 2017 in the 2017 LTEP reference outlook.

Costs

Ministry of Energy's 2017 Long-Term Energy Plan Modelling Assumptions, April 6 2017 Document (2)

- The IESO will assume natural gas price forecast per the Sproule projection as of February 2017. Further updates to the gas price forecast will lengthen modelling timelines. The IESO will assess a lower and higher gas price forecast for sensitivity.
- The IESO will include new higher contracted price information for existing NUG contracts.
- The IESO will assume carbon cost as the reserve price (i.e., the floor price) projection in the 2017 LTEP base case, and the "updated CA-QC-ON Bloomberg Nov 2016" projection for the sensitivity.
  - Note that the reserve price projection is slightly different from the OPO forecast; it now includes the actual floor price for the March 2017 cap and trade allowance auction as notified in January 2017, and this value is inflated by 5% as per the cap and trade regulations and added an assumed inflation factor of 2%.
  - The "updated CA-QC-ON Bloomberg Nov 2016" projection has been provided to IESO via ENERGY.
  - See Appendix for the carbon price projection values.
- The IESO will assume OPG nuclear rates to be consistent with the revised OPG Rate Smooth received from Tim Christie on March 13, 2017. The IESO will use the OPG nuclear outage data received from Tim Christie on March 10, 2017, and the nuclear production data received from Tim Christie on March 13, 2017. No change to Bruce Power nuclear prices from OPO.
- The IESO will assume OPG hydro rates to be consistent with the data received from Tim Christie on March 23, 2017.
- Upon contract expiry, for modelling purposes, the IESO will assume the assets will continue to be available for the duration of the planning outlook (i.e. similar to Outlook B in OPO). This recognises that the system can benefit from a portion of ongoing value from these assets with some re-investment, rather than requiring complete new build to meet the demand. The results of the "Benefits Case Assessment of the Market Renewal Project" prepared by the Brattle Group indicates that the cost based methodology used in the 2016 OPO would generate slightly lower results than the market based methodology pricing for these assets after contract expiry. The capacity market will be the implementation mechanism that achieves these cost based values for these assets after contract expiry.

  For the 2017 LTEP, the following assumptions will be used for costing expired contracts:

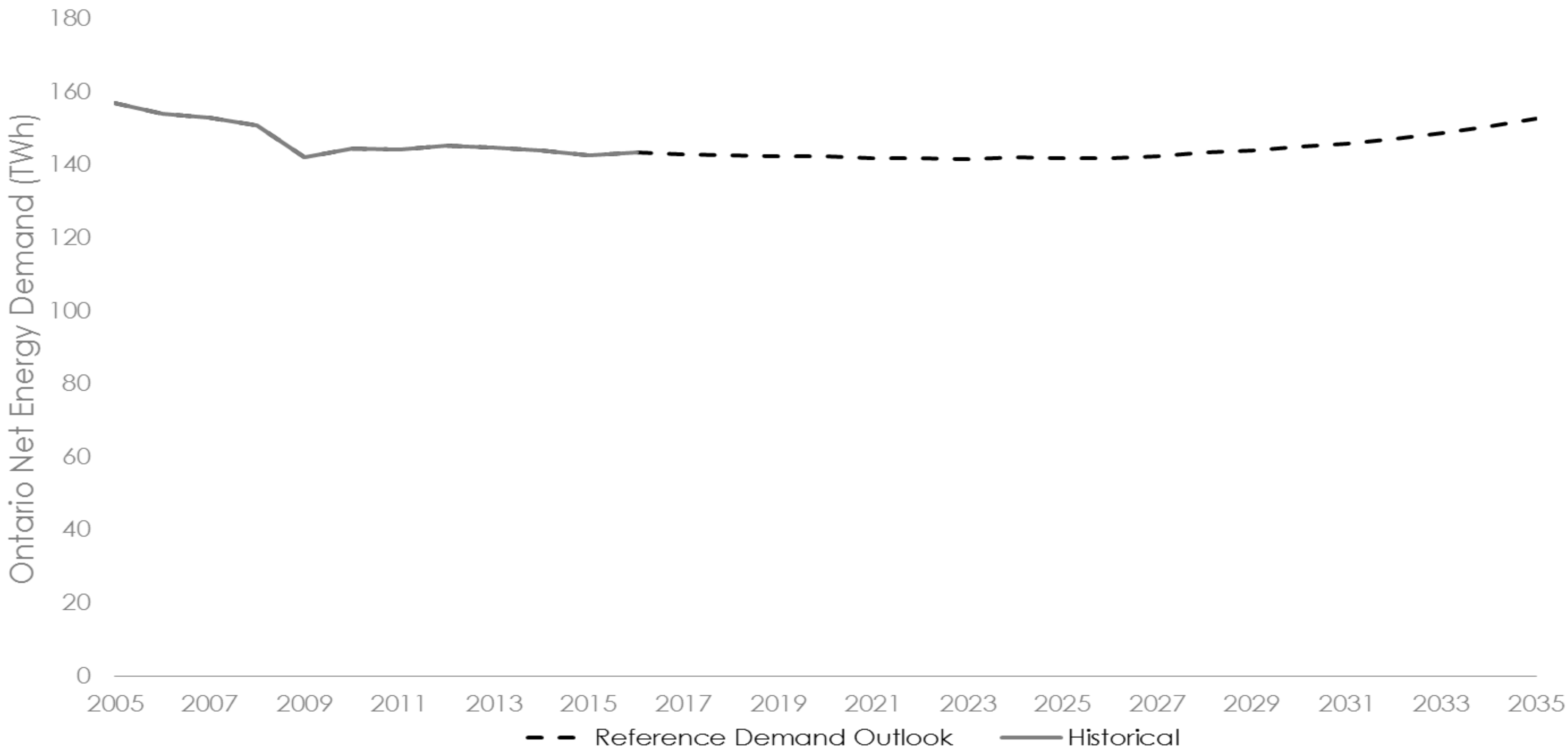
	Contract Expiry Cost Assumptions
Natural Gas	The contract information converted to a generic gas plant with re-investment proportions assumptions per Hatch Report.
Wind	Based on LRP I, with a discounted capital cost re-investment assumption for end of life components and accounting for on-going value from the balance of the asset. This cost assumption is lower than that used in 2016 OPO.
Solar	Based on LRP I, except that future investments for end of life components that need to be replaced decline in cost to recognise technological improvements. This cost assumption is lower than that used in 2016 OPO.

Industrial Rates and Residential Bills

CONFIDENTIAL April 6, 2017

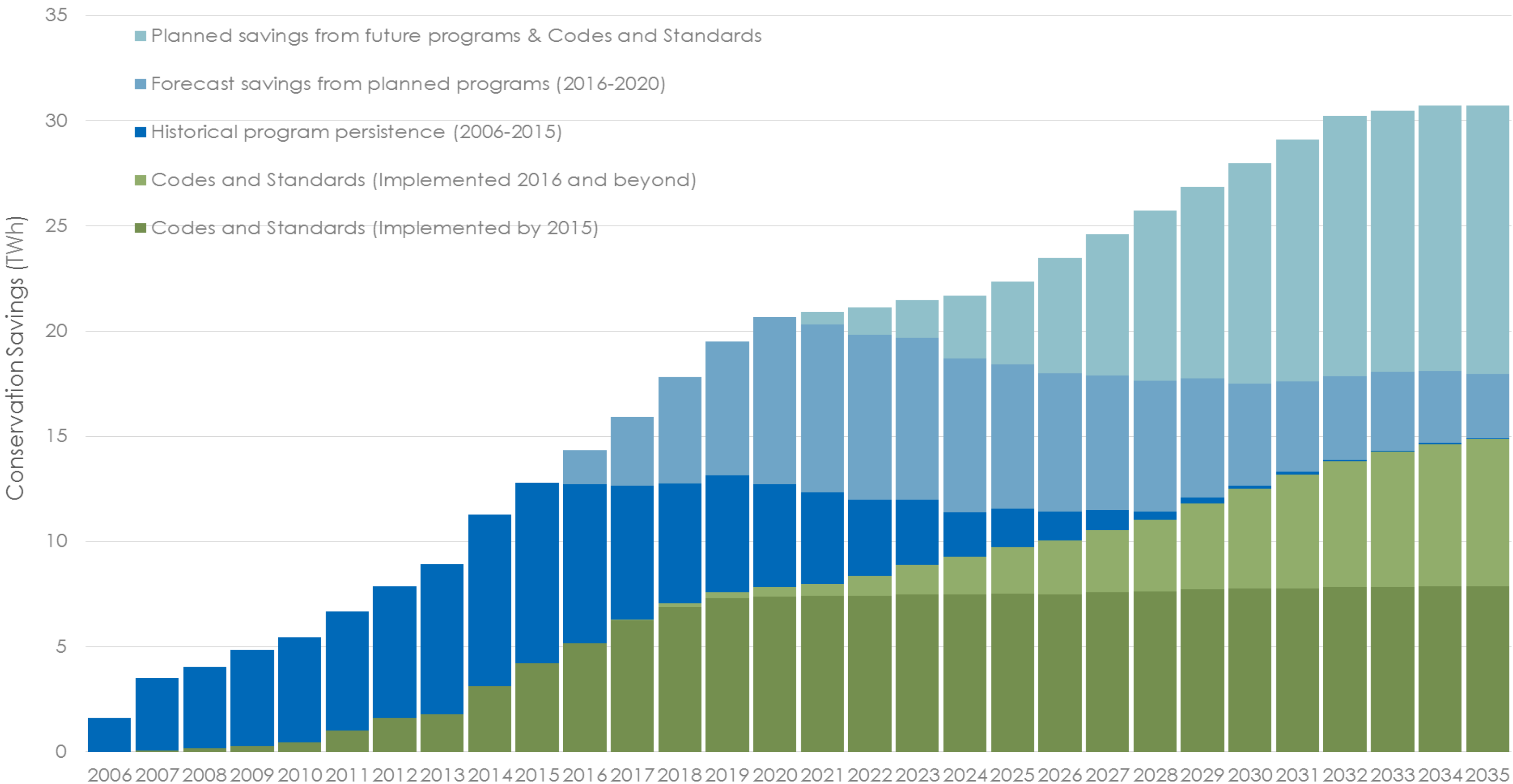
- The industrial rates and residential bill impacts will not reflect recycling of proceeds from the Cap and Trade program.
- The residential bills will be the base bills, prior to the application of the Ontario's Fair Hydro Plan.
- Application of the Ontario's Fair Hydro Plan to the residential bills will require specific guidance and direction from ENERGY.

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 case outlook is remains relatively flat over the next decade, but grows somewhat by 2035 due to the rising adoption of electric vehicles in the province.



Demand is consistent with Outlook B of the OPO plus higher levels of electric vehicles per OPO Outlook C/D.

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, achieved through conservation programs and building codes and equipment standards. These savings are expected to effectively offset all economy-driven growth in demand.



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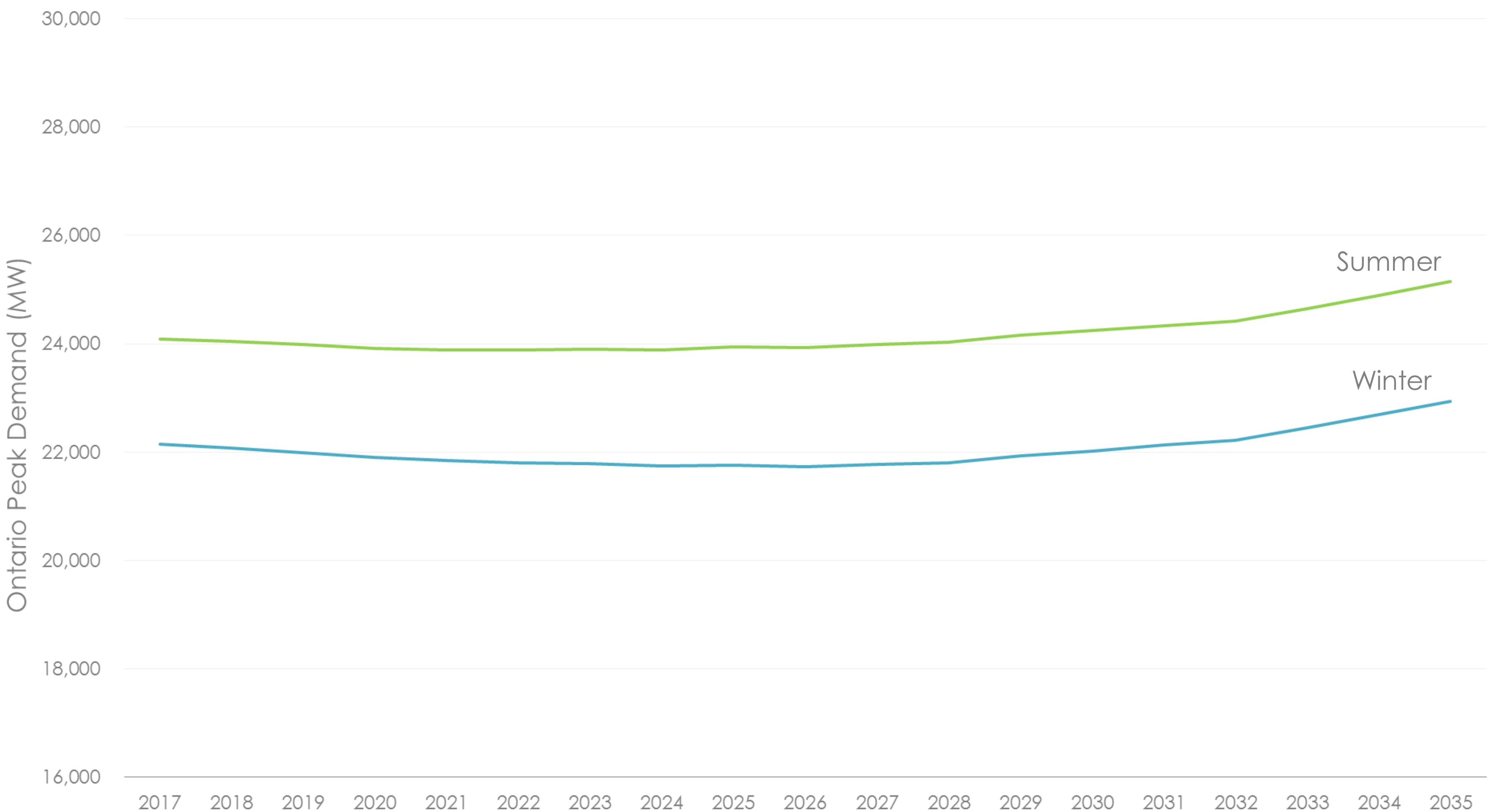
The demand outlook continues to anticipate that Ontario's summer peak demands will be greater than peak demands in the winter. The capability of Ontario's electricity resource and delivery system is generally more constrained in summer months than in winter months.



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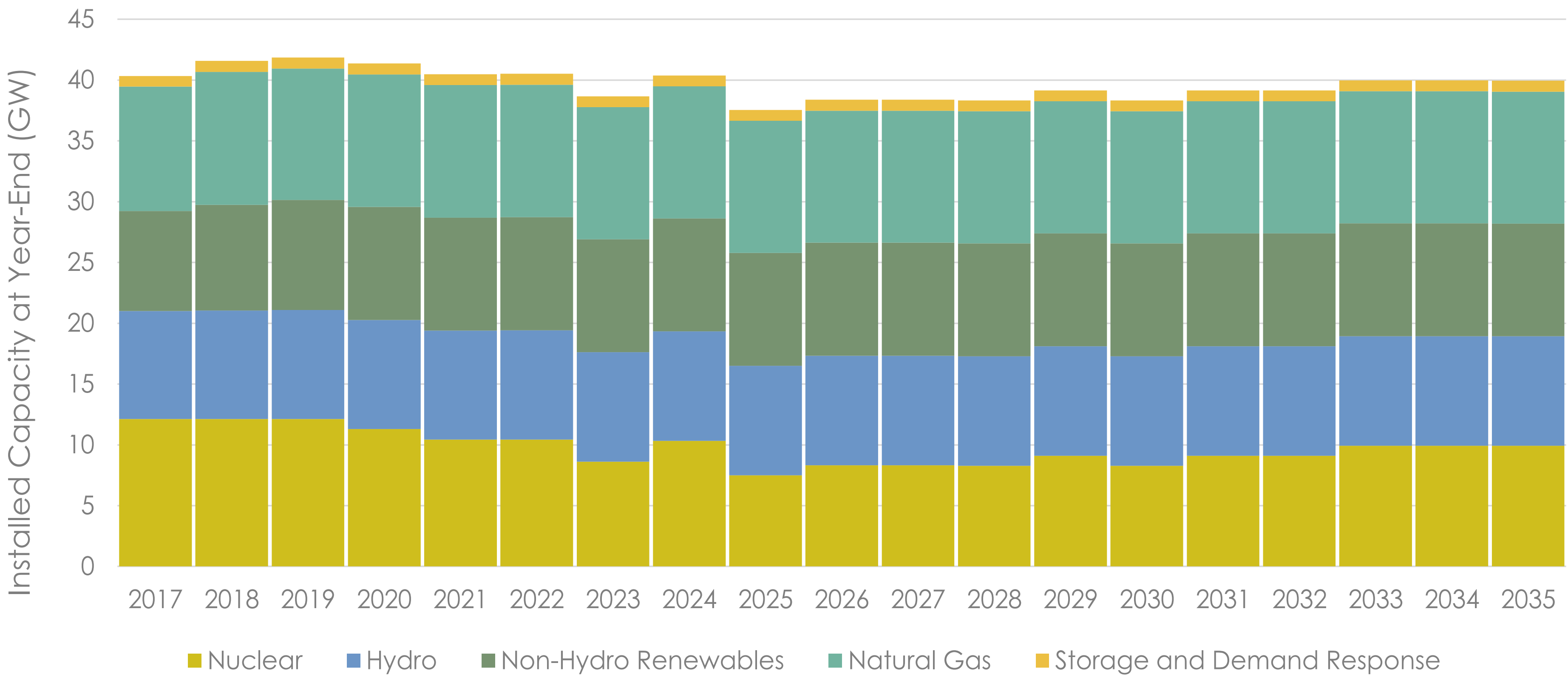
Taken together, existing resources combined with resources anticipated over the foreseeable future would maintain a total long-term installed capacity of about 40 GW in Ontario. In general, the share of nuclear would decline following Pickering retirement, while the share of renewables would increase.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



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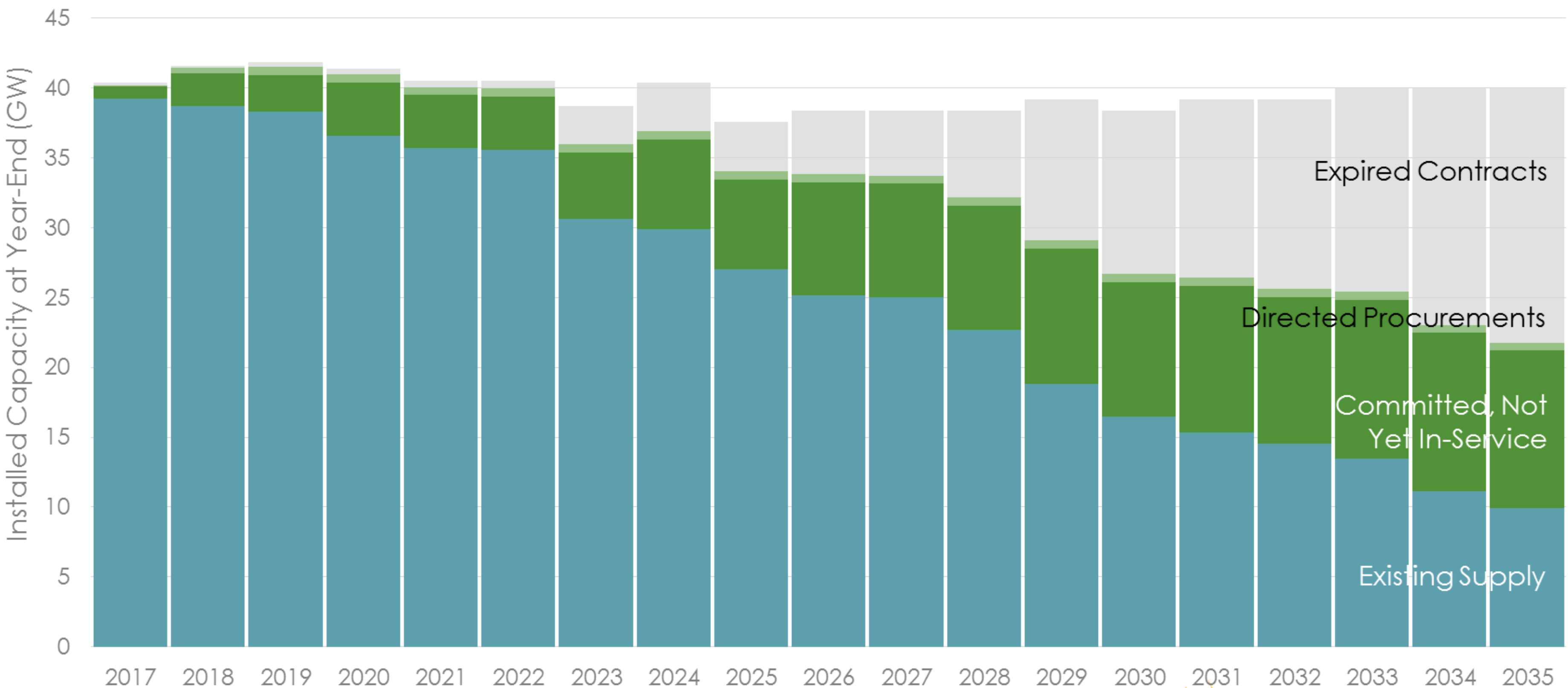
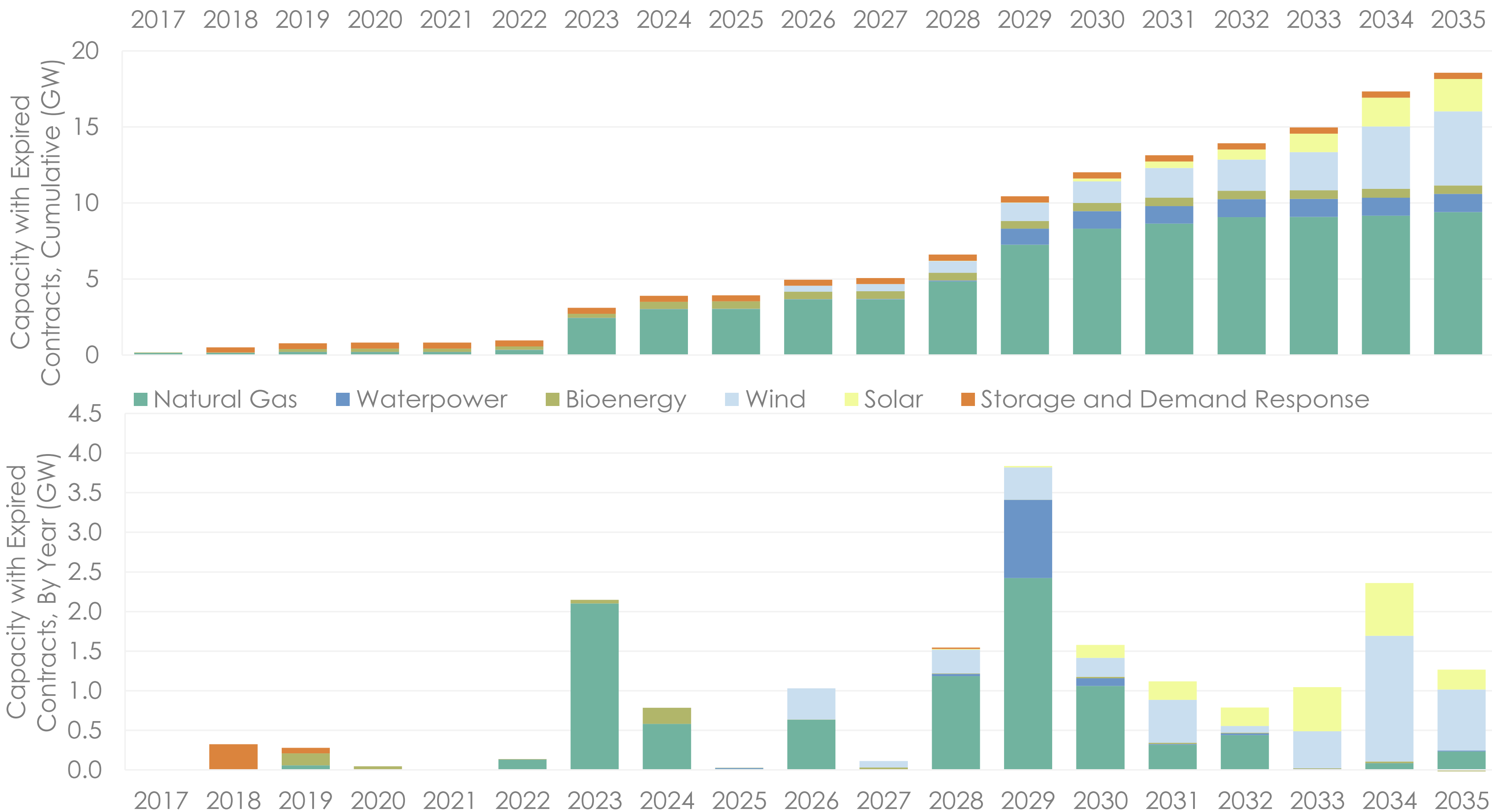
While the total installed capacity remains relatively unchanged, the supply mix undergoes a transition over the outlook. Resources which exist today will decline over time as nuclear units at Pickering are retired and nuclear units at Darlington and Bruce are temporarily removed from service for refurbishment. 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.



While the outlook for total installed capacity remains 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. Half of these resources are natural gas facilities, expected to reach contract expiry in the mid 2020s, while the other half represents renewable resources, expected to expire in around early 2030s. These resources provide opportunities for adaptation should, for example, demand trend lower or better opportunities arise.



Capacity shown is at year-end.

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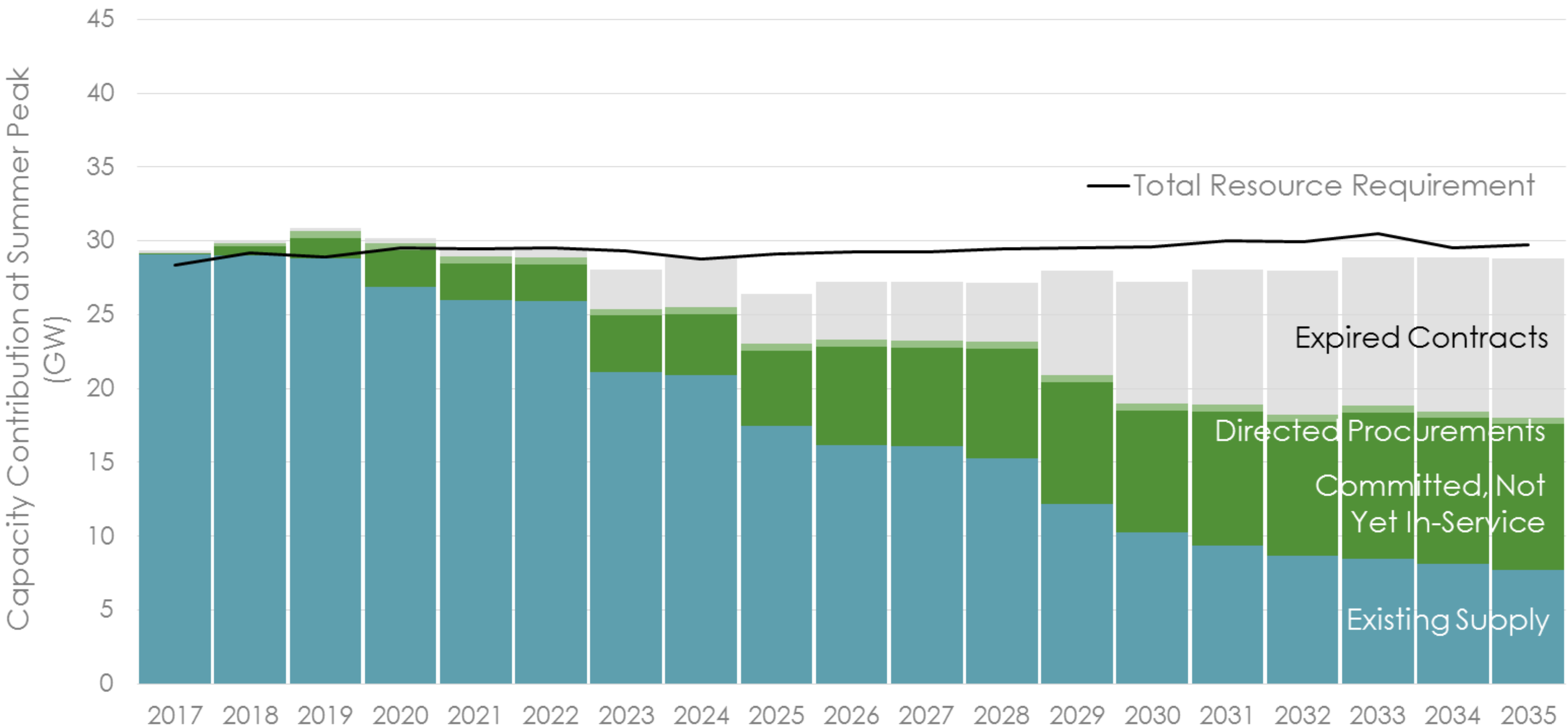
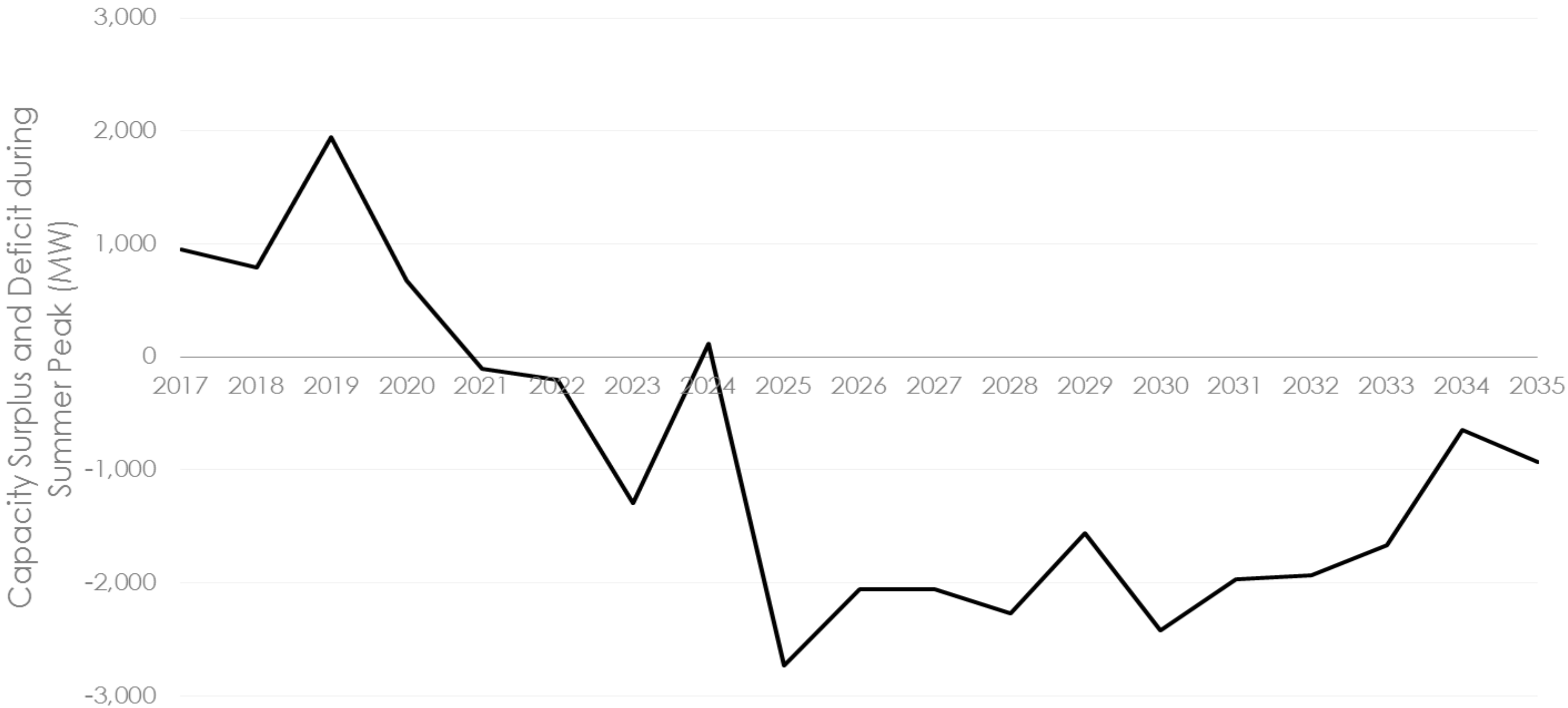
Projected resource capacity contributions at the time of Ontario's summer peak demand are compared to Ontario's projected resource adequacy requirement in the figure below. Ontario will remain adequately supplied for the next several years if all resources which exist today continued to remain available 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 and 2.5 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 is well correlated with periods of nuclear unavailability due to refurbishment outages. New capacity opportunities can be addressed in a variety of ways, including new generation, increased demand response, increased conservation, and firm imports.



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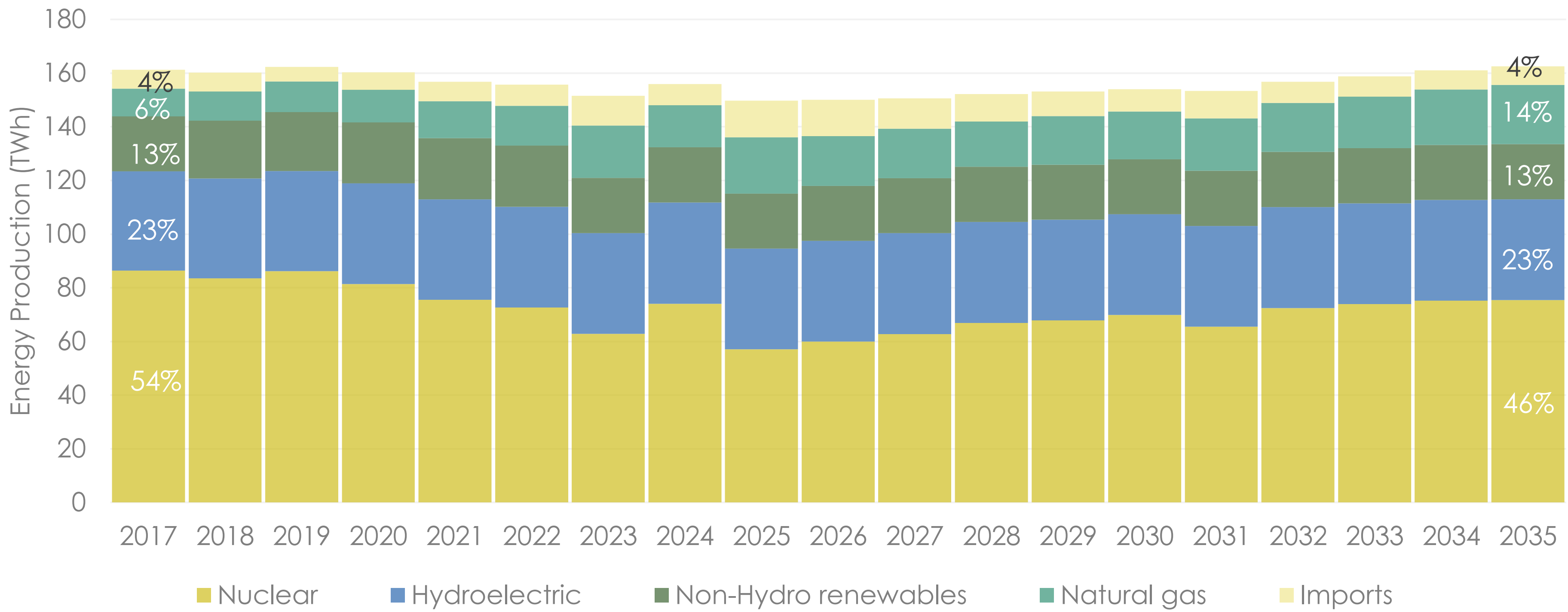
Ontario has a low carbon-emitting electricity system. Approximately 90% of the electricity produced in Ontario comes from non-fossil emitting sources. Electricity production from nuclear resources in Ontario is expected to decline over coming years while renewable energy production is expected to increase.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



Note: The energy production shown is energy produced from Ontario's generation fleet to meet both Ontario demand and exports driven by market demand. Imports reflect the 2.3 TWh/year (2017 to 2023) imports from Quebec per current Ontario-Quebec agreement and non-firm electricity imports that take place through the real time energy market.

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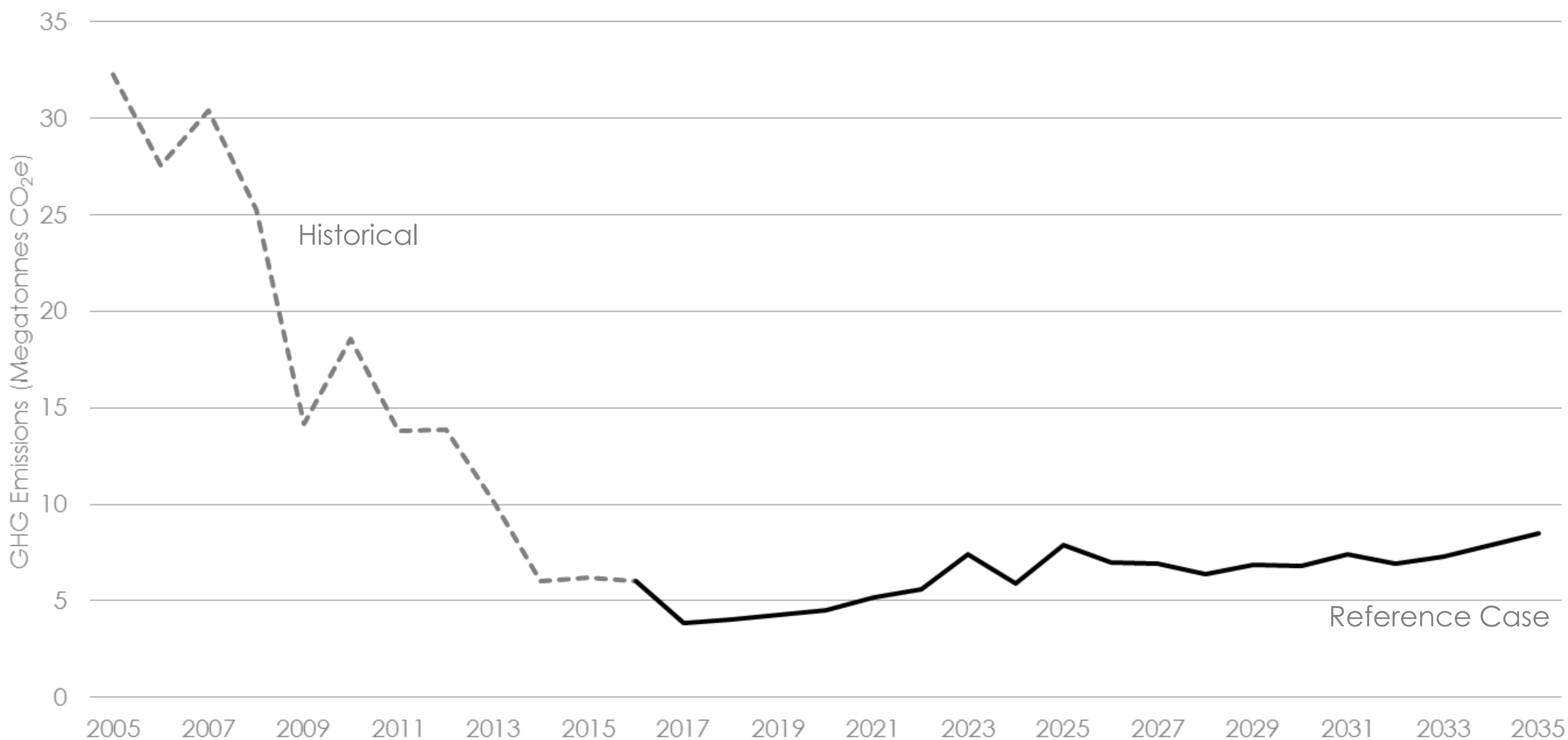
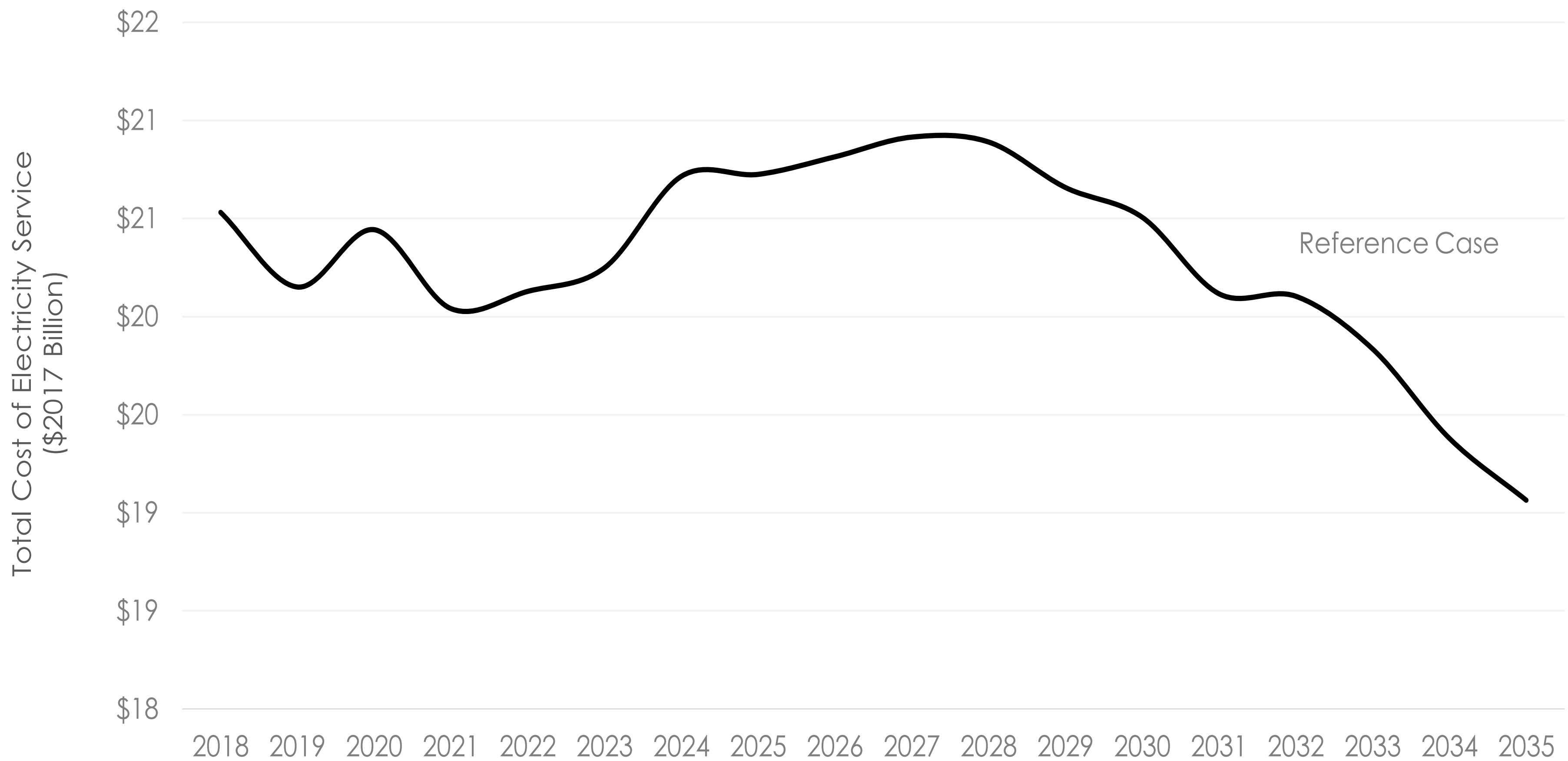
Greenhouse gas emissions from Ontario's electricity sector declined by more than 80% over the past decade. Today, Ontario electricity sector emissions contribute to about 2% of Ontario's economy-wide greenhouse gas emissions. Electricity sector greenhouse gas emissions are expected to remain well below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



The total cost of electricity service represents the cost of electricity that must be recovered from all electricity consumers in the province to cover the cost of investing in and operating the electricity system. In the reference case outlook, the total cost of electricity service averages about $20.3 B per year over the outlook and declines in real dollars from about $21B today to $19.1B by 2035 (in 2017 $).



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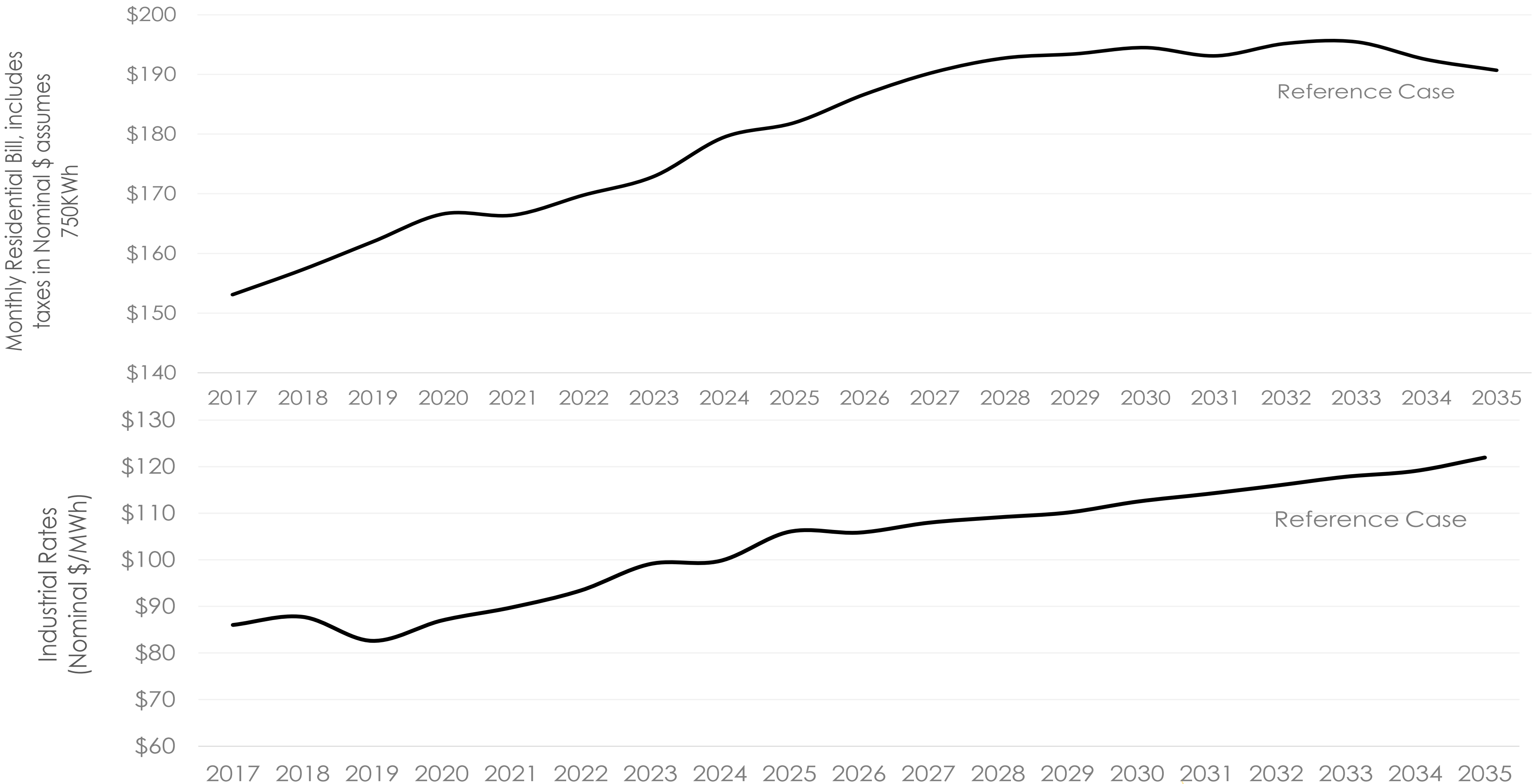
The previous slide illustrated the total cost of electricity service. These costs are allocated to electricity consumers. In the reference case outlook, residential electricity bills increase from $153/month to $190/month by 2035 (pre-OFHP), with an annual average increase of about 1.2% per year. Industrial electricity rates increase from $86/MWh today to $122/MWh by 2035, with an annual average increase of 1.9% per year (figures in nominal $).



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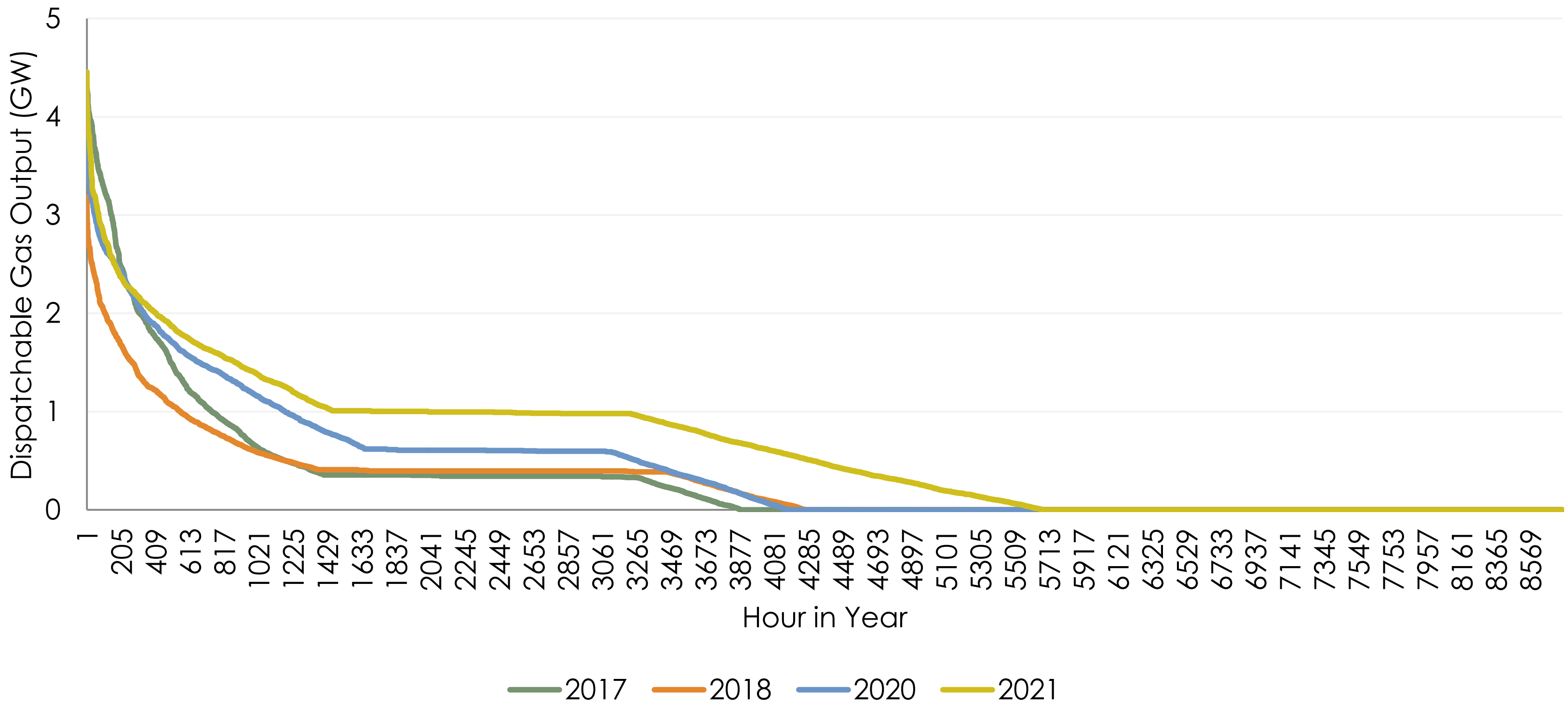
Appendix II:
Additional assumptions for scenarios with lower emissions

Minimum gas dispatch for operability

- To estimate the minimum gas dispatch for operability, the IESO simulated an Ontario-only system. The years in which there was surplus baseload generation in every hour was identified and it was assumed that all dispatchable gas units that were online in those years was purely for operability needs. Across the years 2017-2021[1], an average capacity of about 3,800 MW of gas with a capacity factor of 10% was the minimum level of gas needed for operability. This minimum level of gas was assumed for the Minimum Gas for Operability scenario.



- Capacity of 3,800 MW was based on the average of the maximum dispatchable gas output
- The 10% capacity factor was based on the average of the annual energy delivered

(1) 2019 was an outlier and was not used as part of the analysis for determining the minimum gas dispatch requirement for operability.

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Non-emitting resource cost assumptions

- 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; approximately $220/kW-yr

- Storage:
  - The storage capability was assumed to be provided equally by Compressed Air Energy Storage (CAES) and Pumped Hydro
  - These scenarios would require large amounts of bulk storage. The most mature large-scale technologies are CAES and pumped hydro, and Ontario has potential large-scale CAES and pumped hydro sites within the province. These technologies tend to have the lowest costs for bulk-scale applications, and given their maturity, costs are unlikely to change significantly over the planning horizon.
  - This represents a low range estimate of the outlook for the cost of storage
  - Cost of storage was assumed to be $395/kW-yr; with 8 hours of storage