



Annual Planning Outlook

Capacity Expansion Scenario and Outcomes

September 2026

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1. Executive Summary

Capacity Expansion Scenario and Outcomes is a module that assesses theoretical resource portfolios that could meet future electricity system needs across the three forecast scenarios presented in the *2026 Annual Planning Outlook (APO)*, along with projected system costs and greenhouse gas (GHG) emissions for the different scenarios. The information presented in this module does not represent a plan or actions that will be taken in the different forecast scenarios; instead, it provides perspectives on several illustrative, least-cost pathways to meet Ontario's electricity system needs. With this in mind, resource portfolios were developed under a set of technical assumptions and do not reflect real world policy decisions or economic development. Actual outcomes depend on many factors, including electricity procurement decisions yet to be made, the trajectory of economic growth, geopolitical developments, government policies and technological evolution.

Investments in Ontario's electricity system are critical to supporting population growth, economic development, and electrification. Without investments in new infrastructure, the reliability of the province's electricity system and opportunity for economic growth will be at risk. Building a system that can enable growth will result in additional costs, but this module shows that tapping into all available resources and managing the timing of investments will help mitigate increases and keep those costs stable over the long-term, only slightly above inflation.

The module builds on the demand forecast scenarios and supply outlook¹ from the 2026 APO, where the reference scenario indicated growing supply gaps in the 2030s; in the high-demand scenario the gap is larger and emerges earlier. While the supply gap identified in the reference scenario of the APO informs procurement targets and provides a signal to the market that will drive future investment decisions, this module goes a step further and "solves" the supply-demand gap to provide a conceptual understanding of the types of resources that could meet future electricity needs, along with future costs and emissions. This assessment is also performed on the high- and low-demand forecast scenarios.

Reference scenario modelling of a future supply mix indicates a total installed capacity of 92 gigawatts (GW) in 2050; of this, 27 GW is existing and committed supply (mostly made up of nuclear and hydroelectric resources), and 65 GW is from net new resources selected to meet remaining needs. While the reference scenario build-out is led by intermittent generation, new nuclear and storage add significant capacity to the portfolio, resulting in a diverse mix of resources in 2050. The build-out considers factors such as the rate of demand growth, timelines for the construction and deployment of infrastructure, expected asset replacement and retirement needs, as well as system adequacy requirements. Under this scenario, the resource portfolio would be capable of meeting Ontario's electricity needs and the province would continue to be a net electricity exporter.

In the high-demand scenario, the total installed capacity of 124 GW in 2050 includes 97 GW of net new resources, supported by increased build-outs of nuclear, intermittent generation, gas, storage,

¹ The 2026 APO supply outlook consists of existing and committed resources – including resources committed through actions undertaken by the IESO and/or informed by government policy – until their contract or commitment period ends.

and demand response. In the low-demand scenario, the total installed capacity of 74 GW in 2050 includes 48 GW of net new resources.

Leveraging existing assets will be critical to keeping the system reliable and affordable over the long term, and policy decisions on how existing assets such as natural gas-fired generation can be used will have an impact on future system costs. Canada's Clean Electricity Regulations, which are currently under review, were not modelled in this assessment, though the IESO's analysis has indicated that the current regulations would increase electricity system costs beyond what is represented here. To accommodate for uncertainty in future regulations, gas production in the 2026 APO was modelled within an envelope reflecting the emissions profile of the 2025 APO. This approach mitigates reliability and cost risks by delaying the implementation of emissions reductions, while still resulting in near-zero emissions by 2050.

Nuclear generation continues to play a key role as a reliable baseload resource in the modelled scenarios, with new nuclear selected in all scenarios. In the reference scenario, 46% (71 TWh) of total generation in 2026 is provided by nuclear resources and increases to 62% (191 TWh) of total generation in 2050. Moreover, with new nuclear capacity coming online, particularly in the mid-2040s onwards, nuclear generation is projected to gradually displace generation from gas-fired resources that initially rises in the late-2020s and early-2030s during refurbishments of nuclear assets. Wind and solar resources show steady growth in the coming decades, and hydroelectric generation remains stable across the planning horizon, continuing to provide reliable baseload capacity.

The primary driver of the cost outlook is the significant rate and magnitude of demand growth and the corresponding need to build-out generation resources and transmission infrastructure to meet that demand. In the reference scenario, total annual system costs² are projected to increase from \$26.4 billion in 2026 to \$54.3 billion in 2050, reflecting the scale of the infrastructure build-out required to meet future demand. Strong demand growth moderates system-average unit costs by spreading system costs over a larger volume of electricity consumption. With this moderation of costs, system-average unit costs are projected to increase by approximately 1.0 per cent above inflation annually in the near term, remain relatively flat through the 2030s, and then rise at an annual rate of approximately 2.2 per cent above inflation during the 2040s. The projected unit costs are partly dependent on the realization of assumed export revenues. These system-average unit costs are planning estimates and are not forecasts of retail electricity rates or customer bills.

This module also includes a marginal cost forecast, which shows an increase in the near-term while nuclear refurbishments are underway and gas-fired generation is relied on in the interim followed by a reduction as new generation comes online. In general, marginal costs indicate the trajectory of market prices and, while indicative, are not a price forecast. Actual marginal costs can differ widely due to market participant behaviour, congestion, the resource mix, the variable input cost for fuel, and other factors or uncertainties.

With an increasing population, an economy that is poised for long-term growth, and electrification of home heating, transportation and industrial processes, Ontario's electricity system needs to evolve to keep pace with rapid change, with new, prudently sequenced investments needed across the sector.

² All dollar values are expressed in 2025 Canadian dollars, unless otherwise stated.

The significant lead times associated with components of the resource portfolios and their corresponding outcomes presented in this module reinforce the importance of long-term planning in informing investment decisions, allowing for adjustment of planned actions and sequencing of investments to align with demand growth and to reflect evolving system conditions. Along with coordinated policy action, the IESO's iterative planning process can help manage electricity costs while delivering the necessary system build-out to meet growing demand and support economic growth. Broader electrification also reflects a recalibration of energy costs, with a greater share of total energy needs being met by Ontario's electricity system. While system costs must increase to sustain the growth Ontario is experiencing, investments in the system will support electrification, which may displace expenditures on other energy sources and reduce overall energy costs for some residents and businesses, depending on factors such as electricity and fuel prices, equipment costs and individual consumption patterns. These potential savings are not assessed in this module.

2. Capacity Expansion and Resource Build-Out

2.1 Capacity Expansion Modelling

Capacity expansion (CapEx) modelling is a mathematical modelling tool used to determine a cost-optimal build-out of resources and transmission, based on current assumptions, to meet future electricity demand. A capacity expansion model was used to assist in establishing the expanded resource portfolios for the three forecast scenarios presented in the 2026 APO. The resource portfolios and outcomes of the model should not be interpreted as a plan; but rather, as providing perspectives on several illustrative, least-cost pathways to meet Ontario's electricity system needs.

2.1.1 Methodology

At a high level, the overall approach is as follows:

1. Based on the existing system, determine the least-cost resource build-out based on the resource and reliability constraints using the capacity expansion modelling simulation software³.
2. Assess the full resource mix in a production cost model to ensure that energy adequacy is met and unserved energy is reduced to zero.
3. If the resource mix is deemed insufficient, restart the process at Step 1.
4. When a resource mix is deemed sufficient, it is then post-processed for reporting on metrics such as cost and emissions.

This approach to resource adequacy assessments is consistent with the IESO's system planning processes. Further information can be found in the [2026 APO Resource Adequacy and Energy Assessment Methodology](#).

2.1.2 Candidate Resources

Candidate resources representing options for the CapEx model to select from were comprised of:

- Existing natural gas generators, allowed to continue operating until end of service life;
- New-build natural gas generation, such as combined cycle gas turbines or simple cycle gas turbines;
- New battery energy storage systems (four-hour duration);
- New onshore wind;
- New solar;
- New hydroelectric resources;
- New nuclear (large-scale and small modular reactors); and

³ Modelling was performed using the LT Expansion tool in Energy Exemplar's PLEXOS simulation software.

- Demand response, which provides flexible load management options.

Effective load carrying capacity (ELCC) was applied for wind, solar and storage resources to account for the marginal capacity contributions of these resources.

Resources that were excluded from this modelling⁴ due to feasibility constraints such as economic competitiveness, regulatory barriers or policy include:

- Offshore wind;
- Hydrogen used for direct-fired electricity generation;
- Biomass;
- Pumped storage; and
- Firm imports.

2.1.3 Transmission Considerations

The capacity expansion analysis includes transmission interface constraints and potential economic transmission expansion that would be needed to enable the resource build-out. Interface upgrades were enabled within the capacity expansion model, allowing transmission upgrades to be selected alongside the resource candidate options discussed above.

2.1.4 Cost & Performance Considerations

Cost and performance data for candidate resources are based on the 2024 National Laboratory of the Rockies⁵ Annual Technology Baseline, ensuring alignment with the most comprehensive and reliable publicly available information. Nuclear cost inputs were based on Ontario Power Generation's cost estimates for the Darlington New Nuclear Project.

2.2 Build Capability

2.2.1 Introduction

Build capability is the feasible amount of annual installed capacity of a particular resource type that may be constructed. Assumptions of build capability in the IESO's previous planning publications were informed by actual procurement experience or sourced from technical bodies or associations such as the National Laboratory of the Rockies. While this approach provided a view of resources that have previously been built and an indication of what resource builds may be achievable, other factors such as underlying macroeconomic conditions could influence the feasibility of construction of new resources, thus impacting future build capability⁶.

⁴ While these resources were excluded for the purpose of capacity expansion modelling, it does not exclude them from consideration in Ontario's future resource mix.

⁵ Formerly known as the National Renewable Energy Laboratory.

⁶ Modelling of build capability is independent of, and does not inform, procurement activities or setting of targets.

This section provides an overview of the approach and assumptions used to incorporate build capability⁷ into the 2026 APO capacity expansion modelling.

2.2.2 Considerations and Inputs

Build capability for each forecast scenario was estimated for the candidate resources considered by the capacity expansion model for the outlook period. More than 70 input variables were used to estimate build capability, with the majority related to manufacturing considerations and labour requirements for facility construction (e.g., workforce availability and employment metrics in Ontario). Manufacturing considerations are influenced by material and equipment availability across various resource technologies (e.g., turbine manufacturing capacity); Ontario's share of material and equipment used in the construction of new power generation equipment from the global import market; and trends of economic growth rates and production timing. To estimate build limits for capacity expansion modelling, a conservative but realistic set of assumptions was used for each variable input.

Limitations due to land availability were considered within the model, but as land limitations were typically less restrictive to building new resources than labour and manufacturing constraints, these were non-binding constraints. Policy considerations were also imposed on land availability; however, the model's granularity was unable to capture unique considerations at some local levels. For example, community support requirements will further limit the potential for resource development across the province, which is not captured in this study.

Inputs to the model were based primarily on the best available data in 2024 and results are reflective of a single point in time. While constraints predicted by the model are expected to be solved by market forces, they help to highlight challenges in system planning and may provide insights into where policy or investment focus is needed. Evolving government policies, supply chain constraints and broader trends in power generation will continue to reshape the underlying input variables.

2.2.3 Methodology

The overall approach to align the capacity expansion build-out (i.e., what is cost optimal) with build capability (i.e., what is feasible) is described below, and is integrated with the high-level CapEx methodology described in Section 2.1.1.

1. Determine the least-cost resource mix using the CapEx tool, using historical build constraints (i.e., Step 1 of CapEx methodology).
2. Determine the relative labour allocation for each resource type based on the percentage of each resource build-out from CapEx, to provide the build capability model with insight into where finite resources should be allocated.
3. Run the build capability model to determine the annual build capability for each resource type; the binding constraint for each resource type is identified as the lower value between manufacturing and labour limits.

⁷ The IESO retained Deloitte in 2024 to develop a build capability model and conduct an evaluation of annual build capability for key resource technologies in Ontario.

4. Repeat Step 1 with annual resource build constraints now informed by the build capability model.
5. Iterate until the CapEx and build capability models converge with equivalent build capability values⁸, the system is solved (i.e., supply meets demand) and build capability is optimized based on allocation of finite labour and manufacturing resources.
6. Perform Step 2 of CapEx methodology in Section 2.1.1.

2.2.4 Modelling Assumptions and Limitations

Assumptions and limitations with the build capability model are discussed below.

- Build capability values used for the purpose of this assessment are reflective of global macroeconomic trends and conditions. While the model is aligned with 2026 APO demand forecast scenario assumptions, it is independent of any demand forecasts until integrated with CapEx.
- Proxy data were applied where information was not available, e.g., representation of export percentages of a resource or component type by a single country's export amounts, in absence of resource-specific values.
- Granularity of modelling assumptions was limited. Manufacturing considerations were based on literature, with the underlying assumption that raw materials or components (raw minerals, transformers) were implicitly considered within the broader manufacturing landscape. There was also no consideration for specialized transport methods such as boats or trucks for wind turbine blades.
- Interpolation of data supporting the model was required where data was from single sources or ranges of data spanned multiple years; in cases where variables used to predict future growth trends had no supporting information or data source to rely on, conservative assumptions were made to determine the lowest reasonable limits that might be achieved.
- The capability to build many resource types was limited by availability of labour when solving for Ontario specific demand, making the model highly sensitive to the assumptions around labour distribution. The model assumes labour can shift between roles (e.g., to manufacturing), without accounting for the need to backfill the vacancies that were created.
- In certain cases, the model indicated that there were insufficient components to build certain resource types (e.g., gas and hydroelectric turbines). To allow the CapEx model to solve, annual resource build capability values were over-ridden, with the underlying assumption that in practice, market forces would resolve this mismatch.
- Build capability was considered on a decade-level basis instead of annual-level, for simplification.

⁸ Ideally, build capability assumptions will not be so restrictive to prevent the CapEx model from solving. In certain instances, build capability values were exceeded to allow the model to solve, as indicated in Section 2.2.4.

2.3 Resource Build-Outs and Resulting Portfolios

Building on the 2026 APO demand forecast scenarios and supply outlook⁹ and given the key assumptions and approach described in Section 2.1, the resulting resource portfolio determined for each scenario incorporates incremental resources¹⁰ required to meet system needs, as well as assumed retirements of existing and committed resources. The analysis covers net changes in resource availability over time, considering both new additions and retirements.

Illustrative portfolios for 2035 and 2050 are provided below and in the accompanying [2026 APO Capacity Expansion Scenario and Outcomes Data](#) and [2026 APO Marginal Energy Costs and Capacity Costs](#) and reflect the integration of new resources and anticipated changes in the fleet. The resulting portfolios balance new non-emitting resources with the strategic phase-out of aging infrastructure, resulting in a resilient, low-emissions electricity system capable of meeting Ontario's future needs.

In order to enable the most cost-optimal resource build-out, the East-West Transfer East (EWTE) interface was expanded in the reference and high-demand scenarios. The interface, which comprises the circuits that connect the northeast and northwest zones, was expanded by approximately 210 MW in the reference scenario and 60 MW in the high-demand scenario.

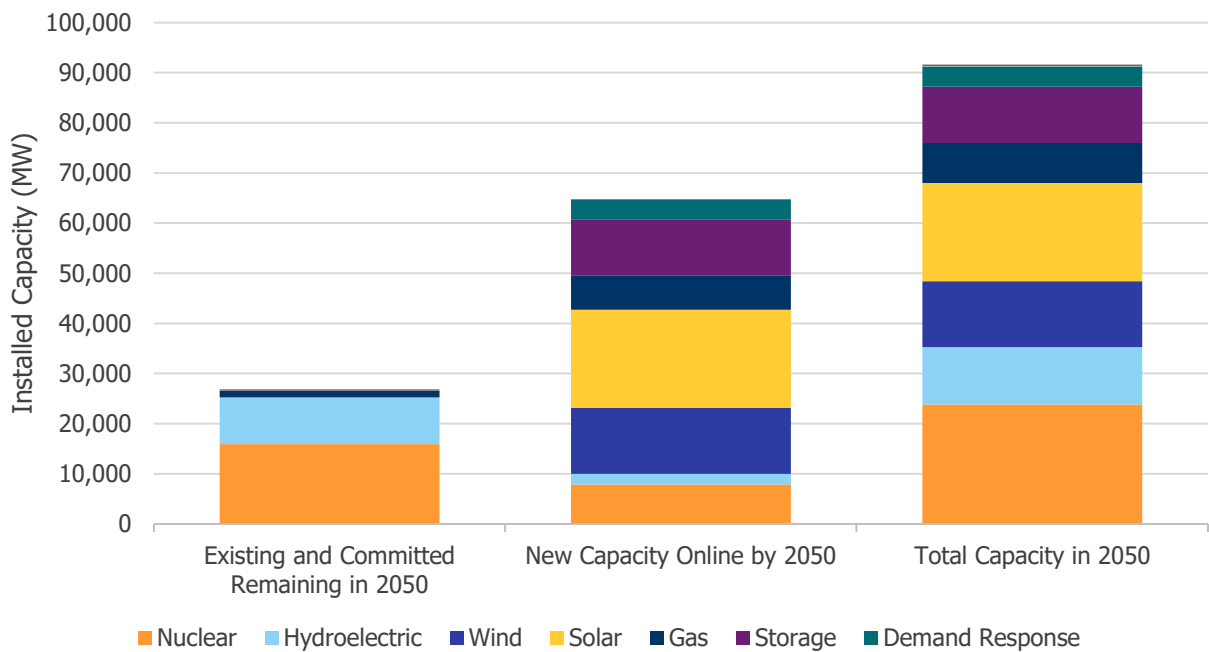
2.3.1 Reference Scenario

Reference scenario modelling of a future resource mix indicates a total installed capacity of 92 GW in 2050 (shown in Figure 1); of this, 27 GW is existing and committed supply (mostly made up of nuclear and hydroelectric resources), and 65 GW is from new capacity selected to meet remaining needs. For the purposes of this modelling exercise, the reference scenario build-out is led by wind and solar; new nuclear and storage add significant capacity to the portfolio, resulting in a diverse mix of resources in 2050.

Figure 1 | Installed Capacity in 2050 – Reference Scenario

⁹ The 2026 APO supply outlook consists of existing and committed resources – including resources committed through actions undertaken by the IESO and/or informed by government policy – until their contract or commitment period ends.

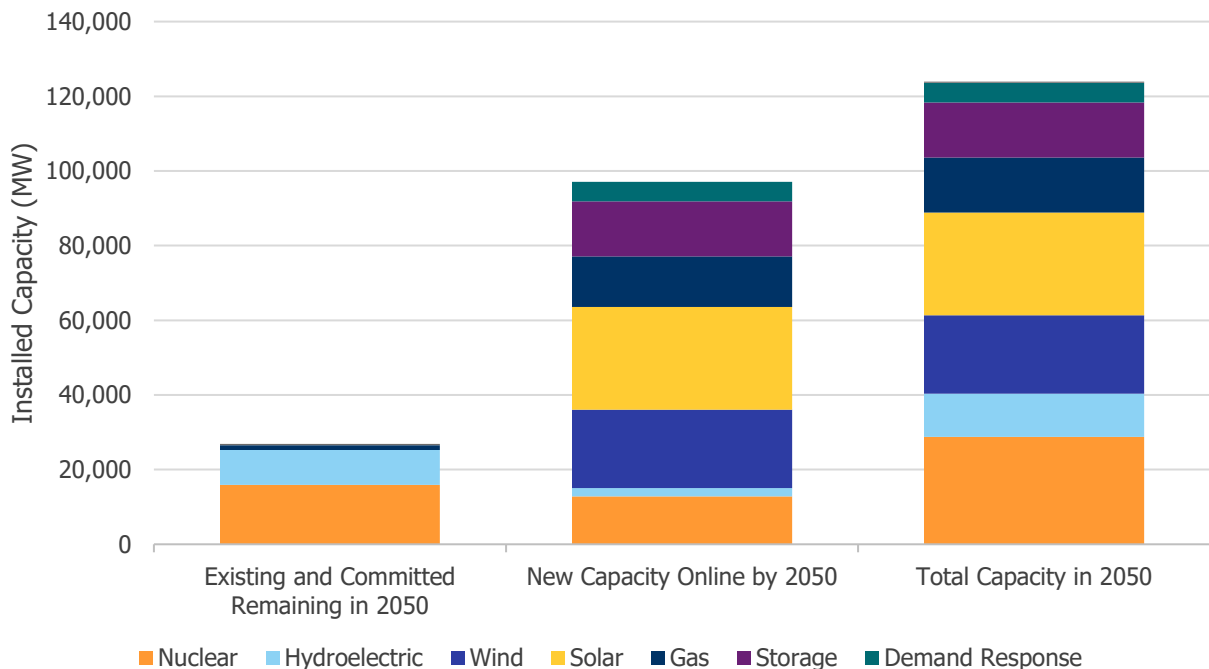
¹⁰ “Incremental” refers to the additions required beyond the existing and committed resources.



2.3.2 High-Demand Scenario

In 2050, modelling for the high-demand scenario indicates a diverse net-new resource portfolio of approximately 97 GW, led by wind and solar, and supported by increased build-outs of gas, storage, nuclear, demand response and hydroelectric resources, compared to the reference scenario. Total installed capacity for this scenario is approximately 124 GW in 2050 and is shown in Figure 2.

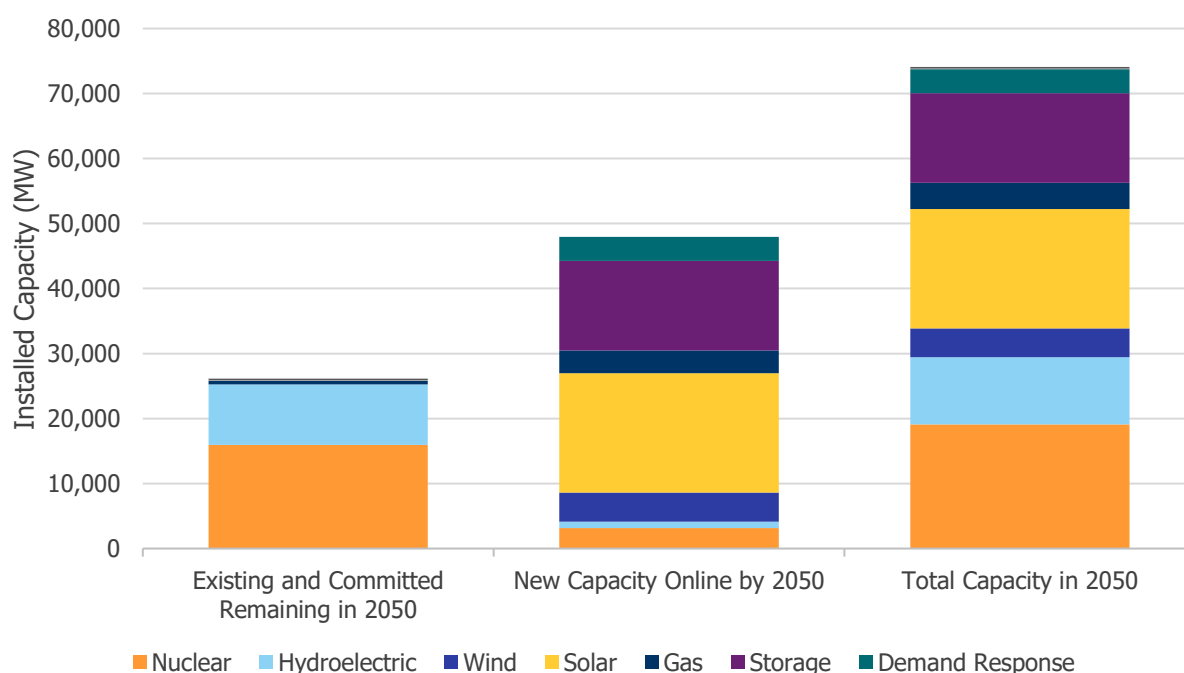
Figure 2 | Installed Capacity in 2050 – High-Demand Scenario



2.3.3 Low-Demand Scenario

In 2050, modelling for the low-demand scenario indicates a diverse net-new resource portfolio of approximately 48 GW, led by solar and storage, with support from wind, gas, demand response, nuclear and hydroelectric resources. Total installed capacity for this scenario is approximately 74 GW in 2050 and is shown in Figure 3.

Figure 3 | Installed Capacity in 2050 – Low-Demand Scenario



2.3.4 Retirement of Existing and Committed Resources

The retirements shown in Table 2 are common to all three scenarios¹¹ and total approximately 17,805 MW by 2035 and 22,887 MW by 2050, measured as the cumulative decline from each fuel's highest installed level. No nuclear retirements occur over the outlook period; nuclear capacity reduced due to refurbishment outages returns to service, and existing and committed nuclear capacity ends the outlook period at its maximum level. While a significant amount of existing wind and solar capacity retires by 2050, it is replaced by the addition of new or repowered capacity from renewable generation, in particular solar resources.

Table 1 | Retirement of Existing and Committed Resources

Resource Type	Retirements by 2035 (MW)	Retirements by 2050 (MW)
Hydroelectric	-	-
Solar	2,134	2,649
Wind	4,368	5,533

¹¹ The exception is retirements of natural gas resources by 2050, where the amount shown in the table represents retirements for the reference and high scenarios (natural gas retirements for the low scenario are 10,867 MW). The difference in retirements is due to different levels of natural gas being re-contracted in CapEx.

Nuclear	-	-
Bioenergy	393	402
Demand Response	1,716	1,716
Natural Gas	9,194	10,136
Storage	-	1,204
Total	17,805	22,887

3. Outcomes and Other Considerations

3.1 Provincial Energy Production

The provincial energy production outlook presented in this analysis reflects multi-area simulation results derived from the production cost model. This model simulates hourly dispatch of Ontario's resources and trade with neighbouring jurisdictions to meet provincial electricity demand, accounting for the availability and economics of nuclear, natural gas, hydroelectric resources, non-hydroelectric renewables, and storage, as well as demand response resources.

Figures 4 to 6 illustrate Ontario's forecasted annual energy production by resource type for each scenario, to meet the annual energy demand forecasted in the 2026 APO and the annual demand associated with charging existing and new storage resources. Nuclear generation remains a key baseload resource, with its contribution increasing notably as new nuclear capacity comes online, particularly from the mid-2040s onwards. Intermittent resources – wind and solar – show steady growth. Hydroelectric generation remains stable across the planning horizon, continuing to provide reliable baseload supply.

Gas-fired generation initially increases during the late-2020s and early-2030s due to nuclear refurbishments and growing electricity demand but subsequently decreases as additional renewable and nuclear resources become operational. By the mid-2040s, natural gas generation significantly declines as supply from new nuclear and other resources displace fossil generation, reducing emissions and marginal costs.

The analysis indicates that under normal weather conditions, the forecasted resource additions ensure there is no unserved energy needs throughout the planning horizon. However, the modelled resource mix and the system's ongoing adequacy are contingent on timely resource deployment and infrastructure enhancements. Delays or constraints in resource availability could impact reliability and necessitate adjustments to the resource build-out.

Strategic and timely investments in new nuclear, intermittent resources, storage, and targeted transmission infrastructure will remain critical to effectively integrating new resources and maintaining the reliability of Ontario's electricity system. These findings underscore the importance of ongoing alignment between resource planning and transmission expansion.

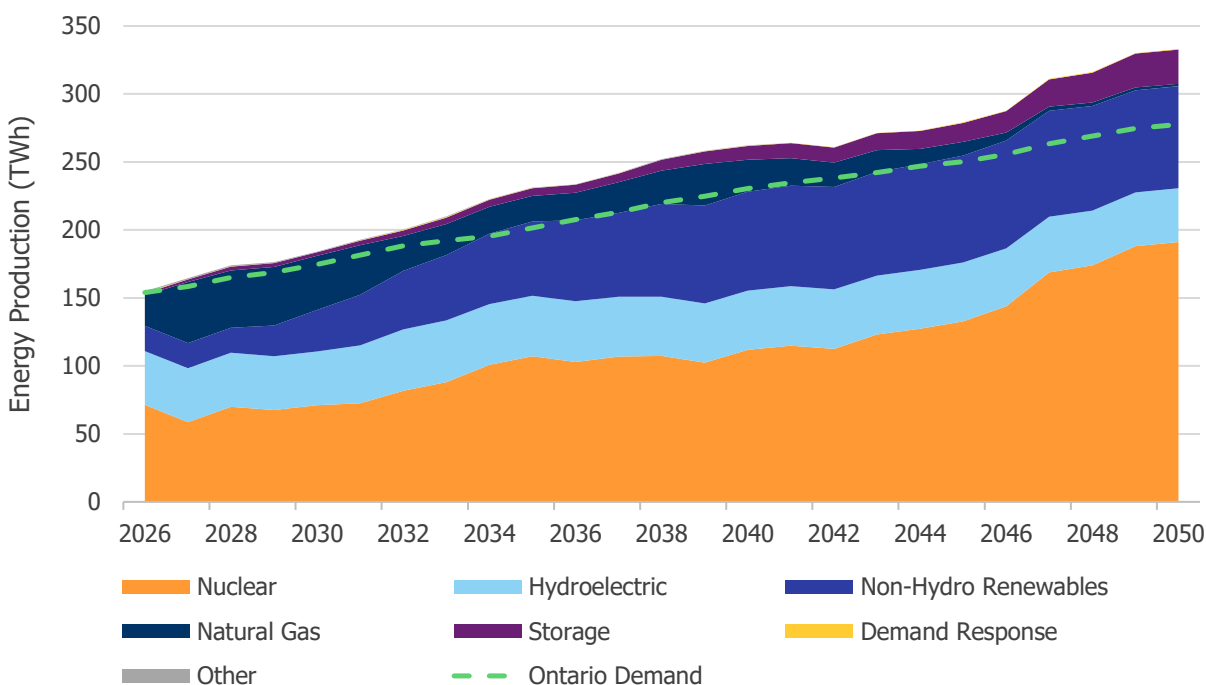
Surplus baseload generation, which arises in all three scenarios, presents opportunities for domestic load growth and beneficial electricity exports to neighbouring jurisdictions, leveraging Ontario's non-emitting supply and the ability to build new non-emitting resources such as nuclear, wind and solar. This can help mitigate the risk of overbuilding the system if development of domestic demand trends towards the low-demand forecast scenario. Where surplus export opportunities are available, securing firm commitments in advance of new resource construction can help ensure cost recovery. Export load from any firm commitments that are established would be reflected in future APOs.

3.1.1 Reference Scenario

Energy production for the reference scenario is shown in Figure 4. Total annual generation of 154 TWh in 2026 grows to 226 TWh in 2035 and 308 TWh in 2050. Nuclear generation of 71 TWh in 2026 increases to 191 TWh in 2050 and makes up 62 per cent of total generation, as refurbished units return to service and new nuclear capacity comes online.

Gas-fired generation peaks at 45 TWh in 2027 during the nuclear refurbishment period, declines to 19 TWh in 2035, increases temporarily to 31 TWh in 2039 as gas output bridges new large-scale nuclear developments in the 2040s, and falls to under 2 TWh in 2050. Generation from intermittent resources grows from approximately 19 TWh in 2026 to 75 TWh in 2050, while hydroelectric production remains steady around 40 to 45 TWh per year. Energy production from storage resources represents the total annual generation from existing and new storage resources while discharging and supplying energy to the grid.

Figure 4 | Annual Energy Production — Reference Scenario¹²



3.1.1.1 Surplus Baseload Generation

The reference scenario indicates periods of surplus baseload generation (SBG) in years where the combined output of nuclear, hydroelectric and intermittent generation exceeds demand¹³, particularly during low-demand periods such as the spring shoulder season and overnight hours. The analysis assumes all hydroelectric output is baseload; however, considering only minimum hydroelectric output as must-run reduces the SBG hours indicated below by 25 to 35 per cent.

¹² The "Other" category shown in Figures 4, 5 and 6 represents embedded combined heat and power resources.

¹³ The assessment of SBG takes into consideration the net hourly energy demand presented in the 2026 APO, and the hourly demand associated with charging existing and new storage resources.

Between 2027 and 2030, SBG conditions are limited to approximately 120 to 240 hours per year; however, as new non-emitting supply is added to the system, in 2035, SBG reaches approximately 5,000 hours per year. In 2050, SBG reaches 7,700 hours per year, with an hourly surplus peak of approximately 8,000 MW in the later years of the horizon. This reflects the scale of the build-out required to meet energy needs with a non-emitting resource mix, and the limited ability to dispatch a resource portfolio made up of a significant amount of nuclear, wind and solar resources.

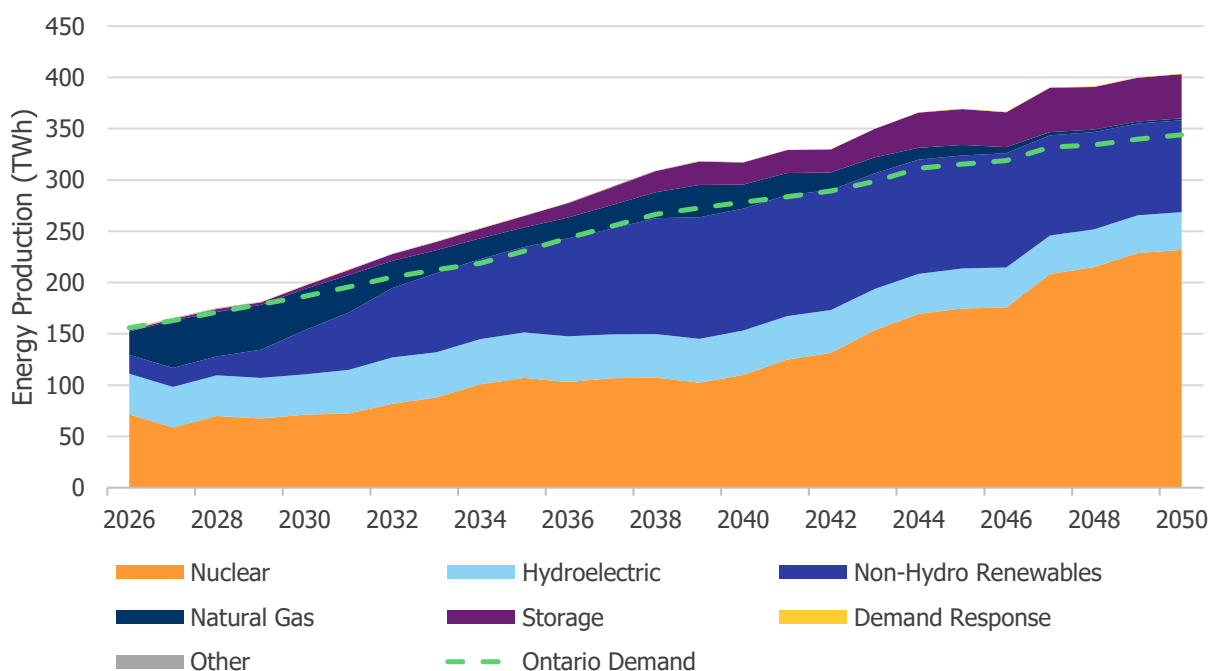
Exports are expected to absorb most of the surplus in 2050, reaching approximately 52 TWh during SBG hours. While materialization of non-firm exports is dependent on market demand in neighbouring jurisdictions and sufficient intertie capability, firm export agreements can provide more certainty for resource planning and cost recovery. Curtailment of intermittent generation output is not needed through 2030 to manage the surplus but grows to 9 TWh per year in 2050.

3.1.2 High-Demand Scenario

Energy production for the high-demand scenario is shown in Figure 5. Total annual generation is higher across the entire planning horizon compared to the reference scenario, reflecting the expanded resource fleet required to meet elevated demand. Total annual generation of 154 TWh in 2026 grows to 254 TWh in 2035 and 361 TWh in 2050, which is approximately 17 per cent higher than the reference scenario at the end of the planning horizon.

Nuclear output reaches 232 TWh in 2050, the largest absolute contribution in any scenario, reflecting the 12,822 MW of new nuclear capacity added by 2050. Annual energy production from non-hydroelectric renewables peaks near 119 TWh in the late 2030s before declining to approximately 90 TWh in 2050 as surplus conditions result in increased curtailments, and storage discharge grows to approximately 43 TWh in 2050.

Figure 5 | Annual Energy Production — High-Demand Scenario



3.1.2.1 Surplus Baseload Generation

In the high-demand scenario, SBG conditions are less likely to occur in the earlier years of the planning horizon due to increased demand and limited capacity from new baseload generation resources.

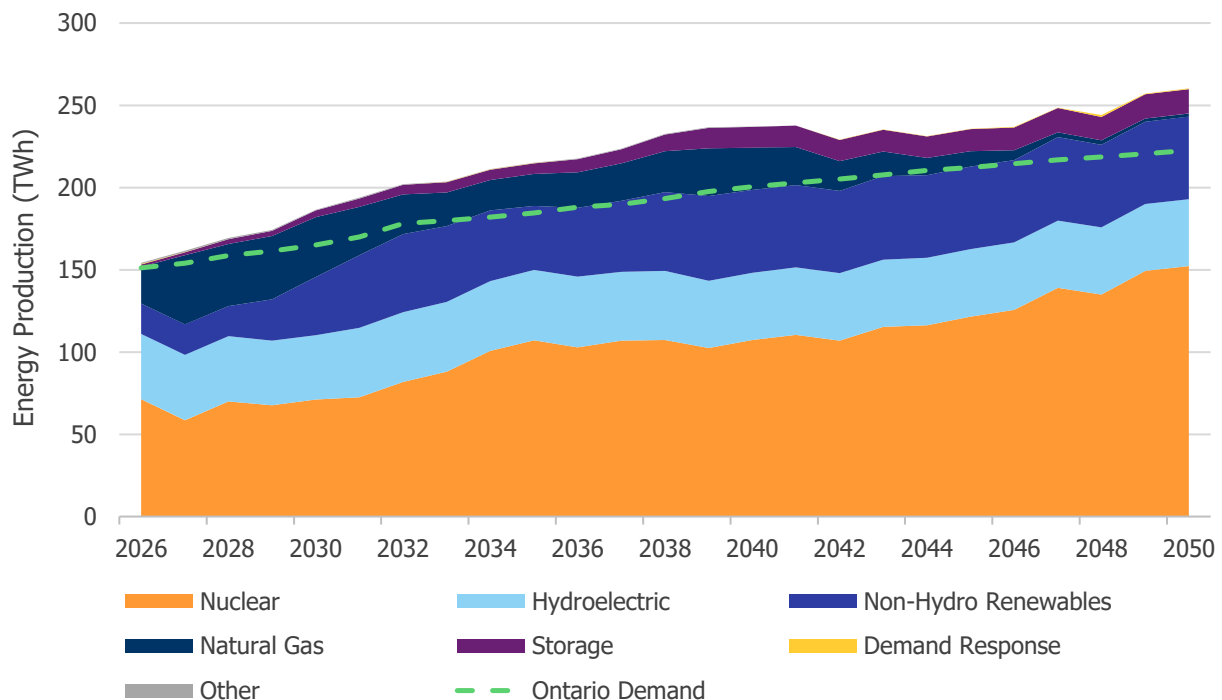
Between 2027 and 2029, SBG conditions are limited to 50 hours per year; however, as new non-emitting baseload supply comes online, SBG reaches approximately 5,000 hours per year by the mid-2030s. In 2050, SBG reaches 6,250 hours per year, less than that observed in the reference scenario as the expanded build-out is offset by higher demand. Exports are expected to absorb most of the surplus in 2050, reaching approximately 44 TWh during SBG hours.

3.1.3 Low-Demand Scenario

Energy production for the low-demand scenario is shown in Figure 6. Total annual generation of 154 TWh in 2026 grows to 209 TWh in 2035 and 246 TWh in 2050, approximately 20 per cent below the reference scenario at the end of the horizon. Nuclear generation reaches 152 TWh in 2050, making up 62 per cent of total generation, a similar share to the reference scenario.

Output from intermittent resources peaks at 52 TWh in 2039 and remains near 50 TWh through 2050, with solar becoming the dominant renewable contributor late in the horizon as the onshore wind build-out reaches a plateau at 4,465 MW. Gas-fired generation peaks at 42 TWh in 2027 and falls to under 2 TWh in 2050. Exports are expected to absorb most of the surplus in 2050, reaching approximately 44 TWh during SBG hours.

Figure 6 | Annual Energy Production — Low-Demand Scenario



3.1.3.1 Surplus Baseload Generation

In the low-demand scenario, the potential for SBG arises from both the modelled build-out and from the possibility that the system is built to meet reference scenario needs while demand materializes at low-demand scenario levels; in the latter case, the resulting surplus is expected to be considerably larger and presents opportunities for domestic load growth and firm export arrangements. Surplus conditions that arise on the system in real-time can be managed by shifting consumption of storage resources to periods of SBG and market exports.

The scenario indicates limited SBG conditions – approximately 200 hours per year – in this decade during the nuclear refurbishment period but grows to approximately 5,000 hours per year by the mid-2030s and 6,700 hours in 2050. During SBG hours, exports reach 34 TWh in 2050, with curtailment of wind and solar output remaining modest, at or below 1 TWh per year. The level of SBG hours in the low-demand scenario remains below the reference scenario level in 2050, as the smaller build-out partially offsets the lower demand.

3.2 Fleet Utilization and Marginal Resources

To support the affordability of Ontario's electricity supply, long-term power system plans use a production cost model that schedules resources to meet system needs based on the lowest cost. This model considers each resource's production and variable costs, which typically include fuel and variable operation and maintenance costs.

Supply resources are categorized as baseload, which operate essentially constantly (e.g., nuclear); dispatchable, which operate as needed (e.g., gas); or intermittent, which operate when fuel is available (e.g., wind or solar). Usually, baseload and intermittent resources have lower marginal energy costs than dispatchable resources.

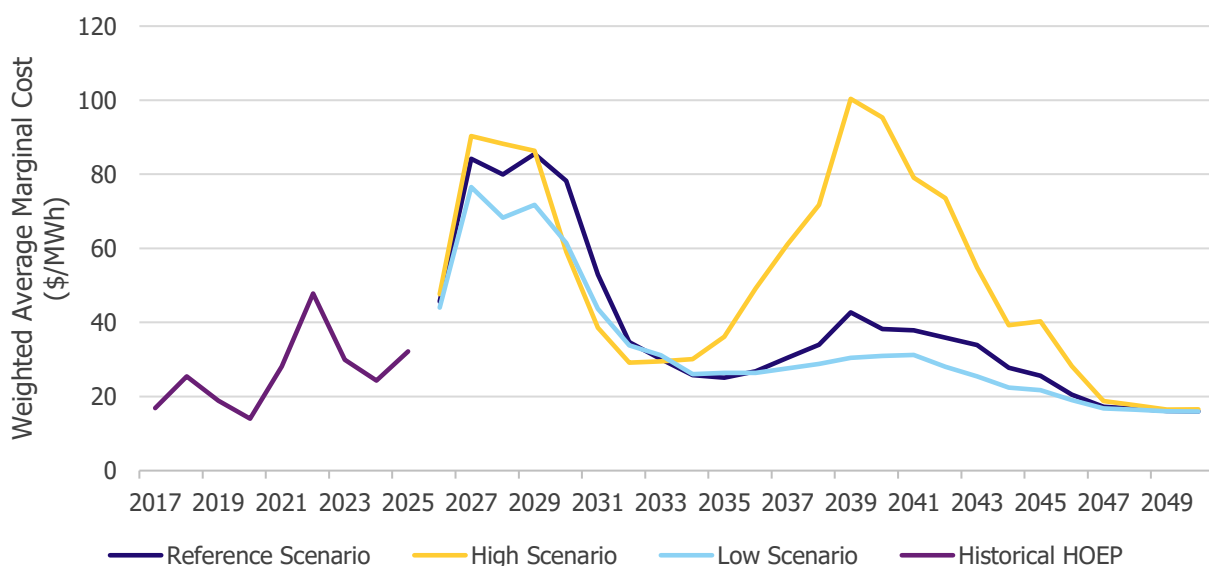
Resources are generally dispatched from lowest production cost baseload to higher production cost dispatchable. The marginal resource is the resource with the highest variable cost that provides the last unit of energy needed on the system. During the peak demand hours of hot summer days, the marginal resource is typically a natural gas-fired generator; during overnight autumn periods, gas-fired generation is less likely to be the marginal resource.

The data underpinning this outlook are based on the production cost model that simulates each hour of the outlook period. This model dispatches units in order of their production costs. The weighted average marginal costs presented in this module are derived from the hourly dispatch of gas-fired generation, using a methodology consistent with the historical relationship between gas dispatch and the Hourly Ontario Energy Price (HOEP)¹⁴. In general, the marginal costs indicate the trajectory of market prices and, while indicative, are not a price forecast. Actual marginal costs can differ widely due to market participant behaviour, congestion, the resource mix, the variable input cost for fuel, and other factors or uncertainties.

¹⁴ Historical values for 2025 include the Ontario Electricity Market Price (OEMP).

Figure 7 illustrates the forecasted weighted average marginal costs for the three scenarios. Marginal costs temporarily rise in the late 2020s as gas-fired generation is increasingly relied upon to manage nuclear refurbishments and growing electricity demand, peaking between \$77 and \$90 per MWh in the 2027 to 2029 period. Costs then decline through the early 2030s as new renewable and nuclear resources enter the system. In the high-demand scenario, marginal costs rise again through the late 2030s as gas bridges to nuclear developments in the 2040s, peaking at \$100 per MWh in 2039. In 2050, marginal costs in all three scenarios decline significantly to \$16 or \$17 per MWh, reflecting a supply mix dominated by low-variable-cost, non-emitting supply.

Figure 7 | Weighted Average Marginal Costs Forecast and Historical HOEP



3.2.1 Reference Scenario

In the reference scenario, near-term marginal costs rise temporarily as gas-fired generation — operating at higher utilization to compensate for reduced nuclear output during refurbishments — sets the price in an increasing share of hours. The weighted average marginal cost reaches \$80 to \$85 per MWh over the 2027 to 2029 period and is \$78 per MWh in 2030, before declining significantly through the early 2030s to \$25 per MWh in 2035 as new renewable and nuclear resources enter the system. A modest secondary rise to \$43 per MWh in 2039 reflects an increased reliance on gas resources as a bridge to nuclear developments in the 2040s, after which marginal costs decline steadily to \$16 per MWh in 2050 as non-emitting supply dominates the supply mix.

Gas fleet utilization follows the same pattern: the gas capacity factor peaks at 46 per cent in 2027, declines to a trough in the mid-2030s, temporarily rises again to 41 per cent in the 2036 to 2039 period as gas bridges to new nuclear developments in the 2040s, and declines again after 2041 to around three per cent in 2050.

3.2.2 High-Demand Scenario

In the high-demand scenario, marginal costs are higher than the reference scenario in the late 2020s — \$90 per MWh in 2027 versus \$84 per MWh in the reference scenario — but fall below reference scenario costs in 2030, at \$59 versus \$78 per MWh, as the larger build-out comes online earlier in the high-demand scenario. Marginal costs then climb through the late 2030s to a peak of \$100 per MWh in 2039 as increased production from gas-fired generation is needed to meet the elevated demand and bridges nuclear developments coming online in the 2040s. Marginal costs decline to \$17 per MWh in 2050. Gas fleet utilization peaks at 47 per cent in 2027 and declines through the 2040s to around 1.5 per cent in 2050.

3.2.3 Low-Demand Scenario

In the low-demand scenario, marginal costs are the lowest of the three scenarios for most of the outlook period — \$61 per MWh in 2030 versus \$78 per MWh in the reference scenario. Marginal costs in the low-demand scenario are close to the reference scenario through the mid-2030s — \$26 per MWh in 2035 — and are consistently below the reference and high-demand scenarios from the late 2030s onward, declining to \$16 per MWh in 2050.

Gas fleet utilization peaks at 43 per cent in 2027, falls to 18 per cent in 2034, rebounds to 63 per cent in 2039 and 75 per cent in 2041 — the highest gas utilization in any scenario — and declines from the mid-2040s to 6 per cent in 2050. This reflects the smaller system build-out rather than a supply shortfall — there is no unserved energy in any scenario, with higher utilization of the remaining gas fleet bridging to nuclear developments coming online in the 2040s.

3.3 Carbon Policy and Greenhouse Gas Emissions

3.3.1 Carbon Policy

Currently, the electricity sector in Ontario and other Canadian jurisdictions are subject to some form of carbon pricing. The carbon pricing assumptions used in this outlook are based on the provincial Emissions Performance Standards program and assume carbon price increases¹⁵ prior to the federal government's May 15, 2026, update to the headline price trajectory for industrial carbon pricing systems in Canada.

The federal government released Canada Gazette II on December 18, 2024 that finalized the [Clean Electricity Regulations](#). The impacts of these regulations were not included in this module; instead, gas production was limited within the electricity system emissions levels forecast in the 2025 APO, to support maintaining an emissions trajectory to achieve a near-zero system by 2050.

3.3.2 Greenhouse Gas Emissions

¹⁵ Based on the [Minimum National Carbon Pollution Price Schedule \(2023-2030\)](#), with the price of carbon in Canada rising to \$170/tCO₂e by 2030, in nominal dollars, and remaining at that level for the duration of the planning period.

This section presents the electricity system greenhouse gas emissions outlook under each of the three capacity expansion scenarios. Emissions are reported in megatonnes of carbon dioxide equivalent (MtCO₂e) and represent direct emissions from electricity generation within Ontario's grid, primarily from natural gas-fired generation. The forecast is derived from the production cost model, which dispatches the least-cost resource fleet on an hourly basis.

With production from gas-fired generation limited to within the electricity system emissions levels forecast in the 2025 APO, emissions across all three scenarios follow a similar trajectory. Emissions rise in the late 2020s as gas generation increases to compensate for reduced nuclear output during refurbishments, declines through the early 2030s as new renewable and nuclear capacity comes online, increases again in the late 2030s and falls sharply through the 2040s as a substantial amount of new nuclear comes online.

The scenario comparison isolates how different demand trajectories affect the magnitude and timing of emissions during the transition rather than the long-term endpoint, which converges across all three scenarios at approximately 0.7 MtCO₂e in 2050. Annual greenhouse gas emissions and greenhouse gas emissions intensity are provided in Figures 8 and 9.

Figure 8 | Ontario Electricity System Annual Greenhouse Gas Emissions, Historical and Forecast

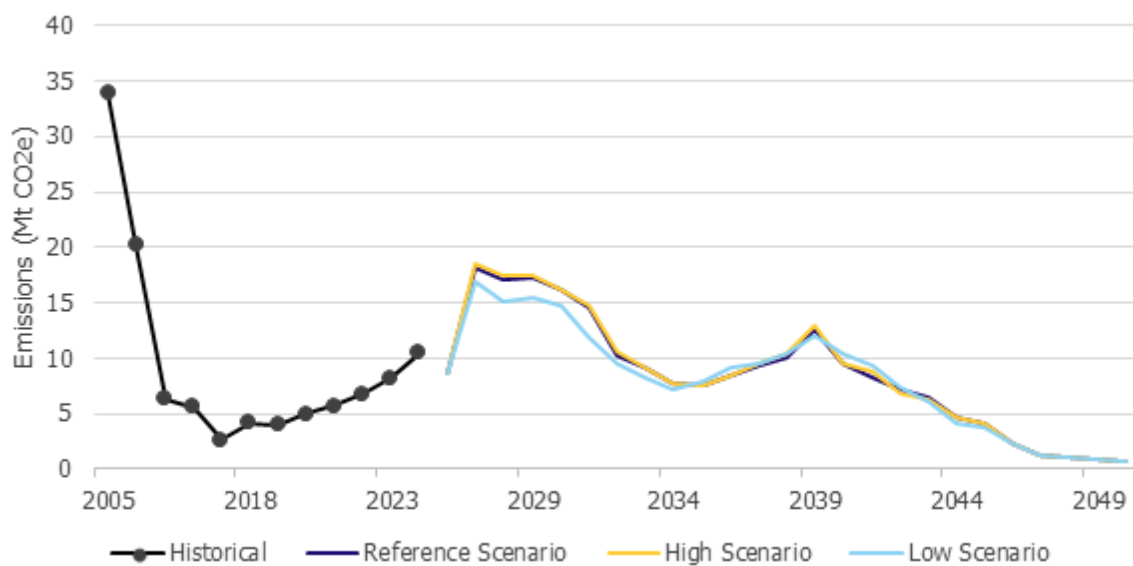
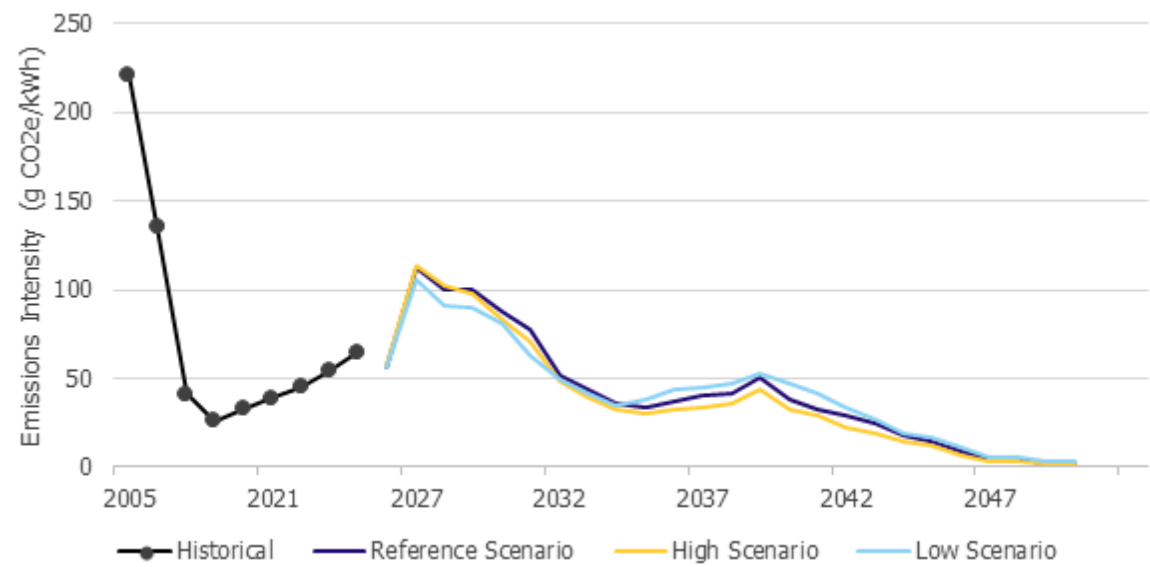


Figure 9 | Greenhouse Gas Emissions Intensity, Historical and Forecast



3.4 System Costs

As noted in the Executive Summary, the information presented in this module does not represent a plan, but rather a modelling exercise on least-cost pathways available to meet Ontario's electricity system needs in the different forecast scenarios. Resource portfolios do not reflect real world policy decisions or economic development, and actual outcomes will depend on electricity procurement and other policy decisions yet to be made, as well as the trajectory of economic growth, geopolitical developments, government and technological evolution.

For this modelling exercise, the system cost outlook reflects cost recovery structures of existing system resources as well as capital investments required for projected new resources and infrastructure to meet the 2026 APO demand forecasts, including electricity demand-side management, generation and storage assets, and transmission and distribution infrastructure. The outlook also incorporates the costs associated with operating the system to ensure that supply reliably meets demand on an hourly basis, such as fuel expenditures, variable operating costs, wholesale and uplift charges and import and export costs and revenues. In short, the system cost outlook reflects the full range of costs associated with generation, storage, demand-side management, transmission and distribution infrastructure, as well as market operations and administration. The primary driver of the cost outlook is the significant rate and magnitude of demand growth and the corresponding need to build out generation and transmission resources in this CapEx model. Variations in demand growth across the three scenarios have material implications for total system costs and system-average unit costs, primarily because they result in different generation and storage resource requirements and, to a lesser extent, different transmission and distribution investment needs. These system-average unit costs are planning estimates expressed per unit of Ontario electricity demand; they are not forecasts of retail electricity rates or customer bills, which will also depend on cost allocation, rate design, consumption patterns and government electricity-support programs.

In the low-demand scenario, lower demand growth results in reduced incremental capacity requirements and lower investment in transmission and distribution infrastructure to integrate new resources and serve customers, compared to the reference scenario. Conversely, the high-demand scenario requires greater resource additions and expanded transmission and distribution infrastructure to meet increased system requirements, compared to the reference scenario.

System unit cost projections (i.e., dollars per megawatt hour), which more closely reflect customer cost impacts and affordability, are influenced by the interaction between the demand forecast, the pace of infrastructure investment and resource build capability assumptions within the CapEx model. To the extent that demand growth can be accommodated by existing infrastructure, unit costs are moderated or decline as fixed costs are recovered over a larger customer base, reflecting improved system utilization. Conversely, reduced system utilization and recovery of fixed costs over a smaller demand base results in higher unit costs, as seen in the near and medium-term of the low-demand scenario. However, the need for new investments in generation, storage, and network infrastructure

will have an impact on unit costs. This calculation uses the same net demand as from the main report, i.e. the denominator excludes electricity used to charge electricity storage.

In addition, under higher demand growth trajectories, resource-specific build capability assumptions within the CapEx model may constrain the deployment of lower-cost resources. As these lower-cost options are exhausted, the model increasingly selects higher-cost resources, contributing to unit costs, particularly over the long term.

3.4.1 Reference Scenario

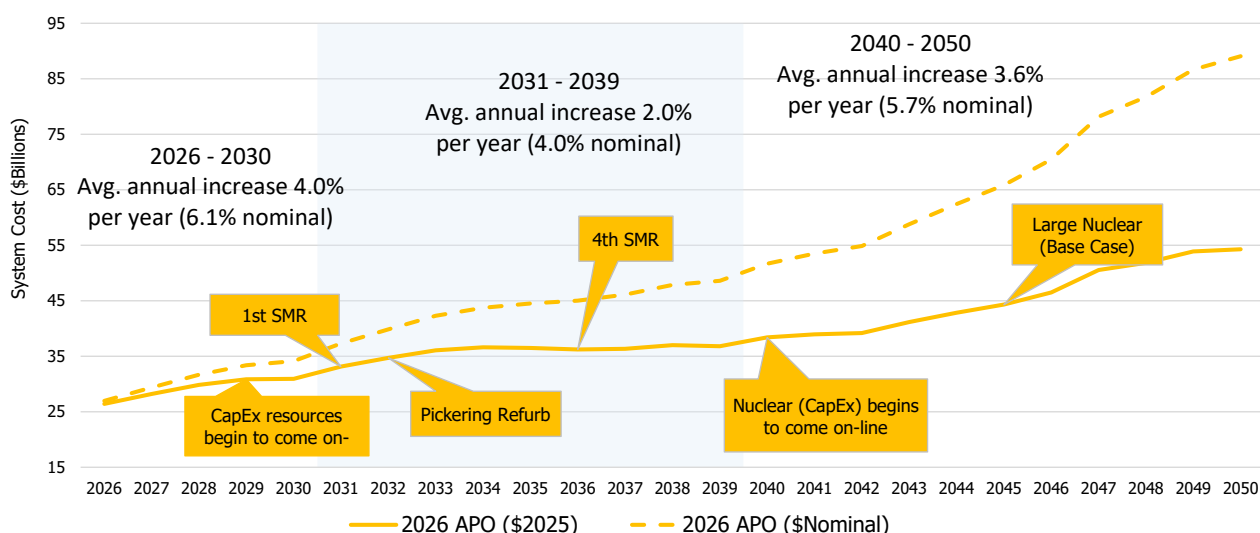
In the reference scenario, total system costs (in 2025 dollars) are shown in Figure 10 and are projected to increase from \$26.4 billion in 2026 to \$54.3 billion in 2050, reflecting the scale of the infrastructure build-out required to meet future demand and keep Ontario's grid reliable.

In the near term (2026–2030), per unit electricity costs are projected to increase by approximately 1.0 per cent annually, driven by nuclear rate increases and higher natural gas generation costs required to offset the temporary loss of capacity associated with the refurbishment of the Pickering B Nuclear Generating Station.

In the medium-term, overall costs remain relatively flat as Pickering B returns to service and the Darlington New Nuclear Project (i.e. the Darlington SMRs) begins operation, reducing reliance on gas generation. Moderation in nuclear rates further tempers cost growth over the 2031–2039 period. Over this same period, transmission and distribution costs will increase as new infrastructure is required to integrate new system resources and enable electrification.

In the long term, a substantial build-out of resources will have increased impacts on costs, while natural gas generation and associated costs decline through the 2040s.

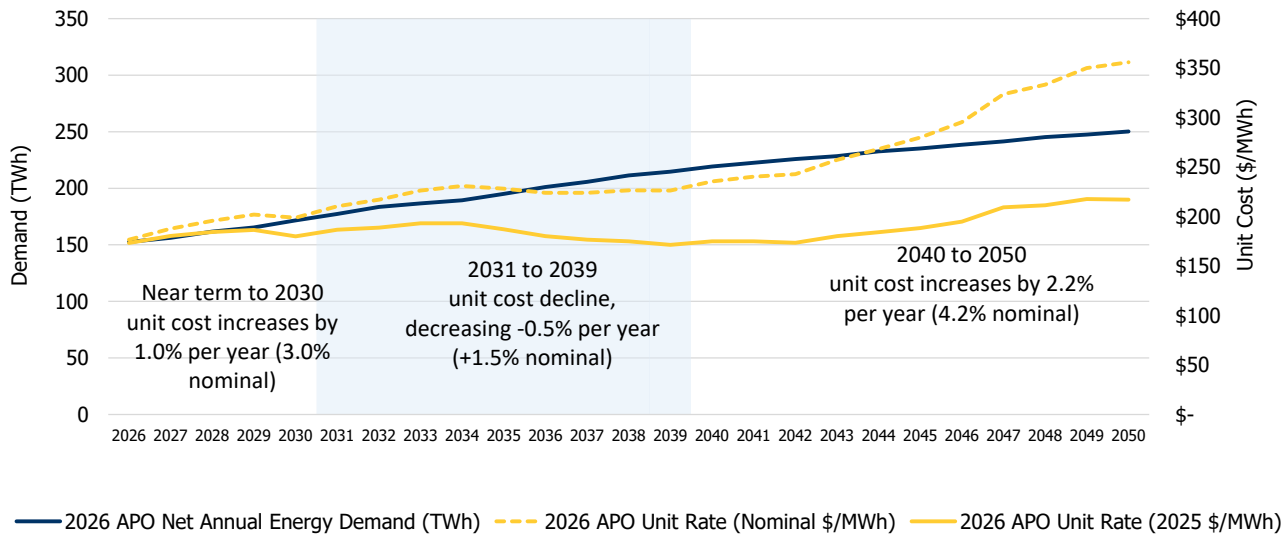
Figure 10 | Total Annual System Cost of Electricity – Reference Scenario



The per unit cost forecast for the reference scenario is shown in Figure 11 in both real (2025 dollars) and nominal terms. On a real, per unit basis (dollars per megawatt hour), electricity costs are

projected to increase by approximately 1 per cent annually in the near term, remain relatively flat through the 2030s and rise in the 2040s at an annual rate of approximately 2.2 per cent above inflation. Although total system costs increase over the planning horizon, strong demand growth moderates the increases in system-average unit costs by spreading system costs over a larger volume of electricity consumption. Export revenues also reduce the reported net system costs and system-average unit costs. Given the significant export volumes projected in later years, these results are sensitive to assumptions regarding export prices, export-market demand, intertie availability and curtailment.

Figure 11 | Unit Cost of Electricity – Reference Scenario

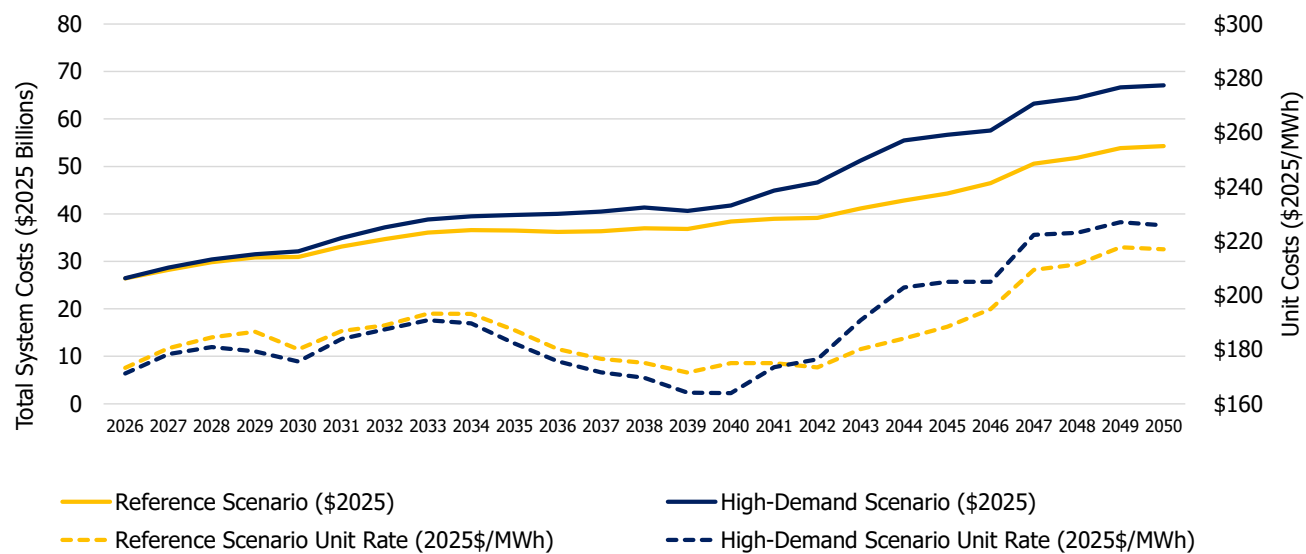


3.4.2 High-Demand Scenario

In the high-demand scenario, total system costs are higher over the planning horizon relative to the reference scenario, reflecting increased near-term demand and associated utilization of existing assets, as well as the need for more substantial investments in new system resources and network infrastructure over the medium to long-term.

Unit costs are lower in the near and medium-term due to improved system utilization and the recovery of fixed costs over a larger demand base. In the long term, however, unit costs exceed those in the reference scenario, reflecting increased reliance on higher cost resources required to meet elevated demand. Total system costs and unit costs for the high-demand scenario are shown in Figure 12.

Figure 12 | Total Annual System Costs and Unit Costs of Electricity – High-Demand Scenario

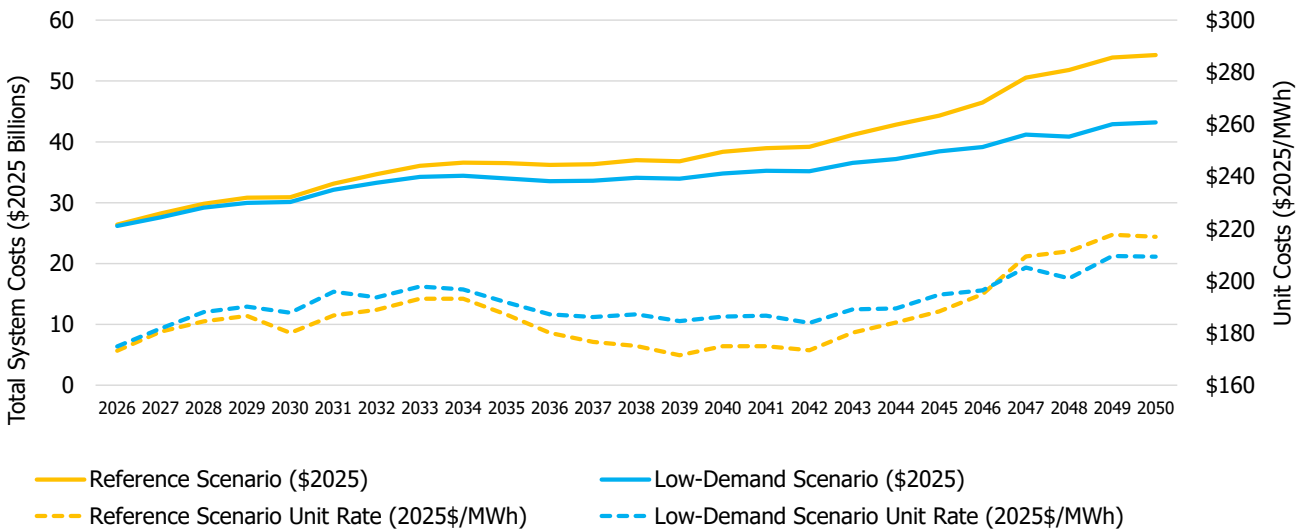


3.4.3 Low-Demand Scenario

In the low-demand scenario, total system costs are lower over the planning horizon relative to the reference scenario, reflecting reduced utilization of existing assets and lower investment requirements for new system resources and network infrastructure over the medium to long-term.

Unit costs in the near and medium-term are higher compared to the reference scenario, due to reduced system utilization and the recovery of fixed costs over a smaller demand base, while in the long-term, unit costs are lower, reflecting reduced investment requirements to meet lower demand. Total system costs and unit costs for the low-demand scenario are shown in Figure 13.

Figure 13 | Total Annual System Costs and Unit Costs of Electricity - Low-Demand Scenario



3.5 Operability Considerations

This section identifies high-level considerations for the reference scenario build-out described in Section 2.3.1, for selected essential reliability services assessed in the 2026 APO. Overall, the significant increase in capacity from intermittent generation, energy-limited storage resources and additional hydroelectric capacity in the reference scenario build-out highlights the importance of a system with resources that are flexible and dispatchable, to ensure system reliability is maintained while meeting energy and capacity needs.

3.5.1 Inertia

The substantial increase in capacity from baseload nuclear resources and the additional capacity from hydroelectric resources is expected to contribute a large amount of synchronous inertia to the system. This increase may be important in maintaining overall system inertia requirements if the broader Eastern Interconnection shifts increasingly towards inverter-based resources that do not inherently provide inertia. The increase in storage capacity could also be leveraged to provide synthetic inertia if required.

3.5.2 Primary Frequency Response

Ontario's frequency response capability may be significantly impacted by the shift of energy production away from natural gas-fired generation and towards intermittent generation under the CapEx build-out. Baseload hydroelectric resources are expected to continue providing the bulk of Ontario's frequency response, but contribution from other resource types may be required to meet future needs.

3.5.3 Regulation Service

Increases in intermittent capacity and continued electrification of Ontario's economy are expected to result in increased minute-to-minute variability and uncertainty leading to higher regulation service requirements over the outlook period. Enabling storage resources to provide regulation service will be key to meeting future increased regulation requirements.

3.5.4 Load Following

Load following requirements are expected to increase with a higher penetration of wind and solar resources, resulting in larger variations in net load¹⁶. With solar penetration representing over 20 per cent of capacity in 2050, extreme ramping events during sunrise and sunset will require an equivalent amount of fast ramping resources to offset the change in solar output on a day-to-day basis. Resource flexibility and dispatchability are also expected to be more critical as the installed capacity of baseload nuclear, hydroelectric resources, and variable generation begins to exceed forecasted minimum demand, potentially resulting in the need to manage surplus baseload generation conditions. With reductions in gas-fired generation offset by an increase in hydroelectric and storage resources, the system's load following capability will require further assessment as load-following from hydroelectric and storage resources may be restricted due to energy limitations.

3.5.5 Operating Reserve

Operating reserve requirements may increase over the forecast period if additional generation capacity results in a greater single largest contingency than the current largest nuclear unit in the province. New hydroelectric resources and storage capacity will increase operating reserve capability, though reduced gas will partially offset the increase.

¹⁶ Net load is the difference between Ontario demand and the output of wind and solar, which represents generation required from Ontario's other dispatchable resources.