# Annual Planning Outlook

## Capacity Expansion Scenario, Costs, and Emissions

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# Table of Contents

# List of Figures

# List of Tables

# 1. Executive Summary

Capacity Expansion Scenario, Costs, and Emissions is a module that assesses a theoretical supply mix that could meet future electricity system needs, along with its projected system costs and greenhouse gas (GHG) emissions. While actual outcomes will be determined by results of future competitive procurements and government policies, this module estimates outcomes based on selecting the lowest-cost supply mix that could meet future reliability needs. The module builds on *2025 Annual Planning Outlook* demand forecast and supply outlook, which identify a growing supply gap in the years ahead.

While the supply gap identified in the APO provides a signal to the market that will drive future investment decisions, this module goes a step further and "solves" the supply gap to provide a conceptual understanding of the types of resources that could meet future electricity needs, along with future costs and emissions.

In modelling a future supply mix that maintains reliability, the IESO assumes that 26,214 megawatts (MW) of existing and committed supply will remain in-service in 2050, and then considered a range of new candidate resources. The resulting 40,070 MW of new supply is a mix of resources considering factors such as the rate of demand growth, regulatory lead times, construction and deployment of infrastructure timelines, expected asset replacement and retirement needs, as well as system adequacy requirements.

By 2050, under this scenario, Ontario would have total system capacity of 66,285 MW that is capable of meeting Ontario's electricity needs while continuing to be a net electricity exporter. With cost and reliability criteria as key drivers, the supply mix that was chosen in the IESO's modelling reaffirmed the importance of a diverse supply mix.

The IESO's modelling also forecasts grid emissions to reach near zero by 2050 as gas generation is almost entirely displaced by lower cost, non-emitting supply. This reflects the significant amount of storage, new and refurbished nuclear, other non-emitting supply expected to be built, as well as the strategic phase-out of aging infrastructure and economic inefficiency of older gas plants' limited remaining service life. In the near term, grid emissions are expected to increase as gas-fired generation is required to meet periods of increasing demand and temporarily replace nuclear production while refurbishments are underway.

However, the electricity grid can reduce more emissions than it produces as it supports the electrification of more emissions-intensive industries. Ensuring the electricity system remains reliable and affordable will be critical to achieving these emissions reductions. In addition, as increasing demand is met with an increasing amount of non-emitting supply, each unit of electricity consumed becomes less emissions-intensive over time. Electricity with low emissions-intensity may attract businesses interested in building new or expanded facilities in jurisdictions with non-emitting electricity resources.

Based on analysis conducted in January 2025, total system costs (in $2024) are expected to increase from $25.6 billion in 2025 to $46.4 billion by 2050. While overall costs increase, the per-unit cost of electricity to the consumer is expected to decline in the near term, remain flat through the 2030s, before increasing slightly in the 2040s.

Under this scenario in real-terms (2024 dollars), costs are anticipated to decrease about 10 per cent by 2039 and rise four per cent by 2050 compared to today, beginning at $170 per megawatt-hour (MWh) in 2025, dipping to $155 per MWh in 2039, before reaching $177 per MWh in 2050. Electricity costs remaining affordable over the long term — despite a significant expansion of the system — reinforces how Ontario's electricity system is prepared to support the electrification of industrial processes, transportation, and home heating. By relying on the province's electricity system, customers will also be able to reduce their carbon footprint.

Overall, this module is designed to analyze the financial and environmental outcomes of a potential supply mix that could meet forecasted demand and adequacy requirements over the next 25 years. Under this scenario, Ontario is well-positioned to keep electricity reliable, affordable, and sustainable during an era of significant growth and expansion of the electricity grid.

# 2. Capacity Expansion and Resource Build-Out

## 2.1 Capacity Expansion Modelling

To build an adequate supply mix, a variety of tools and data are needed alongside professional judgement. A capacity expansion model (CapEx) was used to assist in the design of an expanded supply mix. This mix is subjected to several assessments to determine that it is capacity- and energy-adequate[1]. At a high level, the overall approach is as follows:

1. Determine the least-cost supply mix based on the demand forecast, resource inputs, and constraints using the CapEx tool within PLEXOS by Energy Exemplar.
2. Assess the supply mix to ensure that resource capacity adequacy is met. This determines if the least-cost supply mix satisfies Northeast Power Coordinating Council (NPCC) resource adequacy requirements[2].
3. Assess the supply mix in a production cost model to ensure that resource energy adequacy is met.
4. If the supply mix is deemed insufficient, restart the process at Step 1.
5. When a supply 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 IESO system planning processes. Further information can be found in the APO Resource Adequacy and Energy Assessment Methodology.

This module considers a range of candidate resources to meet Ontario's electricity system needs to address the need for system flexibility and reliability. Resources considered in this module include:

- Existing natural gas generators, allowed to renew contracts until the end of their service life;
- New-build natural gas generation, such as combined cycle gas turbines or simple cycle gas turbines;
- New battery energy storage systems;
- New onshore wind;
- New solar;
- New nuclear (Large, and Small Modular Reactors); and
- Demand response, which provides flexible load management options.

[1] "Energy" in the APO refers to either electricity or electrical energy, measured in watt-hours.
[2] This module includes the reserve margin requirement and meets the LOLE standard of 0.1 days per year for firm disconnected load disconnections due to supply shortages, ensuring compliance with NPCC resource adequacy standards.

Resources excluded due to feasibility constraints such as economic competitiveness, or policy barriers include:

- Offshore wind, which faces challenges related to legality and community approval;
- Hydrogen used for direct-fired electricity generation;
- Biomass; and
- Firm imports.

Resource build limit assumptions and start dates generally align with those in the IESO's *Pathways to Decarbonization* report, with specific adjustments to reflect practical deployment constraints and historical capacity expansion trends:

- Small modular reactors (SMRs): Building new SMRs beyond the four planned units at Darlington (discussed in Section 3.1.2 of the 2025 APO main report) is unavailable until 2040, with a build limit of 300 MW per year thereafter.
- Large nuclear facilities: Unavailable until 2043, with a build limit of 600 MW per year thereafter. The nuclear lead time was a key consideration in setting this limit. Bruce C was used as a reference, supporting an estimated 1,200 MW per year maximum increase in nuclear capacity based on past construction timelines and deployment feasibility.
- New natural gas generation: Unavailable until 2029, with a build limit of 1,000 MW per year thereafter. This limit was aligned with the hydrogen capacity build limits from *Pathways to Decarbonization*, reflecting similar infrastructure development timelines and constraints.
- Demand response/dispatchable load: Limited to 12.5 per cent of annual peak system demand per year to ensure system flexibility while accounting for economic and technical feasibility.

These build limits were set based on historical data, regulatory lead times, and infrastructure constraints that affect the practical deployment rate of new generation technologies. The maximum annual increase in installed capacity observed in Ontario was used as a reference point.

## 2.2 Key Uncertainties

### 2.2.1 Transmission Considerations

The capacity expansion analysis in this module does not explicitly incorporate transmission constraints or future transmission expansion that would be needed to enable the resource build-out. While the current results provide a high-level view of resource adequacy and optimal capacity additions, they do not account for the geographical distribution of resources or existing and potential bottlenecks within Ontario's bulk transmission system.

Running the capacity expansion model without transmission constraints enables an unconstrained evaluation of energy, cost, and emissions. In contrast, the production cost model was simulated both with and without a limited set of existing transmission constraints. While the constrained case provides initial insights into potential transmission needs, its primary purpose was to inform energy, cost, and emissions analysis. For modeling simplicity, new gas resources were placed near load centres, meaning that the "with transmission constraints" simulation had a negligible impact on unserved energy. However, the transmission limitations that were modelled constrained renewable generation, leading to increased reliance on natural gas generation and storage dispatch.

The IESO plans to incorporate more fulsome transmission limitations, and to incorporate transmission expansion and resource siting in future capacity expansion modelling to better reflect real-world constraints and progress toward more optimized system planning. A more geographically granular approach, such as a zonal breakdown of capacity expansion results, would help identify areas where transmission reinforcements are required to support the evolving resource mix.

### 2.2.2 Cost & Performance Considerations

Cost and performance data for candidate resources are based on the U.S. National Renewable Energy Laboratory 2024 Annual Technology Baseline, ensuring alignment with the most comprehensive and reliable publicly available information. The reliance on U.S. data may not fully reflect Ontario market or unique Canadian conditions such as climate conditions, labour costs, and regulatory differences.

## 2.3 Resource Build-Out and Resulting Supply Mix

Given the key assumptions and approach described in Section 2.1, the resulting supply mix incorporates incremental resources required to meet system needs, as well as assumed retirements of existing and committed resources[3]. The analysis covers net changes in resource availability over time, considering both new additions and retirements. The illustrative supply mix for 2035 and 2050 are detailed below, reflecting the integration of new resources and anticipated changes in the fleet.

**Table 1 | Illustrative Incremental Resource Portfolio Build-Out Beyond Existing and Committed Resources**

| Fuel Type | Resource Build-Out 2035 (MW) | Resource Build-Out 2050 (MW) |
|---|---:|---:|
| Hydro | 2,219 | 2,219 |
| Solar | 4,200 | 4,800 |
| Onshore Wind | 8,000 | 10,399 |
| Nuclear | - | 8,100 |
| Demand Response | 3,327 | 4,191 |
| Gas | 5,865 | 7,361 |
| Battery Storage | 3,000 | 3,000 |
| **Total** | **26,611** | **40,070** |

[3] "Incremental" refers to the additions required beyond the existing and committed resources.

**Table 2 | Retirement of Existing and Committed Resources**

| Fuel Type | Retirements by 2035 (MW) | Retirements by 2050 (MW) |
|---|---:|---:|
| Hydro | - | - |
| Solar | 2,135 | 2,650 |
| Wind | 4,368 | 5,533 |
| Nuclear | 6,518 | 10,850 |
| Bioenergy | 398 | 407 |
| Demand Response | - | - |
| Gas | 9,464 | 11,244 |
| Battery Storage | 940 | 2,111 |
| **Total** | **23,824** | **32,797** |

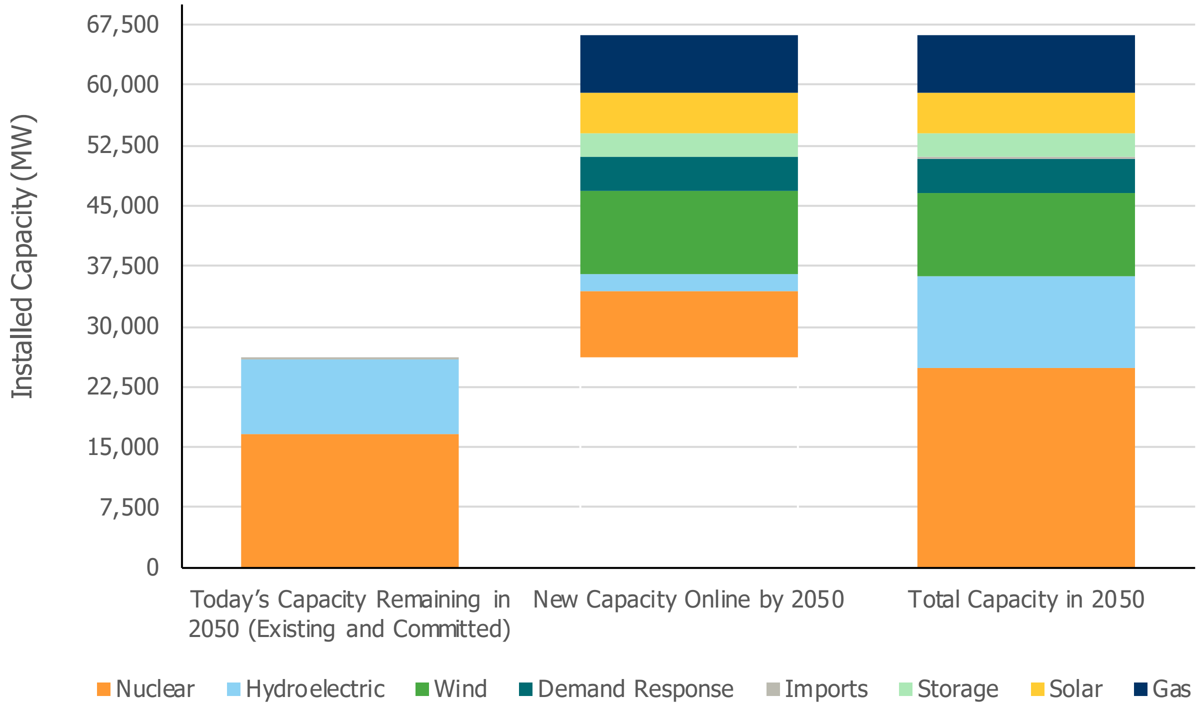
In addition to the new resource additions, the analysis assumes the retirement of older, less efficient gas-fired generation units over time. These retirements result in a net reduction in gas capacity of approximately 3,599 MW by 2035 and 3,883 MW by 2050.

Although the capacity expansion model has the ability to recontract existing gas plants after their contracts expire, it chooses not to do so. This decision is driven by the economic inefficiency of older units and their limited remaining service life. This approach ensures that gas generation continues to provide critical system flexibility while aligning with cost-effectiveness and long-term reliability objectives.

Nuclear retirements are offset by the addition of SMRs, which ensure continued contribution to baseload capacity. Similarly, the addition of new solar and wind capacity exceeds retirements in these categories, reflecting Ontario's strategic focus on expanding renewable energy generation.

The resulting capacity mix balances new non-emitting resources with the strategic phase-out of aging infrastructure, creating a resilient, low-emissions electricity system capable of meeting Ontario’s future energy needs.

**Figure 1 | Capacity Expansion Scenario – Installed Capacity in 2050**



# 3. Outcomes and Other Considerations

## 3.1 Provincial Energy Production

The provincial energy production outlook presented in this analysis reflects Ontario-only generation results derived from the production cost model. This model simulates hourly dispatch of Ontario's resources 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.

Figure 2, shown later in Section 3.2, illustrates Ontario’s forecasted annual energy production by resource type. Nuclear generation remains a key baseload resource, with its contribution increasing notably as new nuclear capacity comes online, particularly from the mid-2040s onwards. Renewable resources—primarily wind and solar—show steady growth, reflecting policy-driven additions. Hydroelectric generation remains stable across the planning horizon, continuing to provide reliable baseload capacity.

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

The analysis indicates that, under normal weather conditions and in the absence of transmission constraints, the forecasted resource additions ensure there is no unserved energy throughout the planning horizon. However, the modeled supply 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 investments in new nuclear, renewables, storage, and targeted transmission infrastructure will remain critical to effectively integrating new resources and maintaining Ontario’s reliability standards. These findings underscore the importance of ongoing alignment between resource planning, transmission expansion, and evolving provincial and federal decarbonization policies, such as the Clean Electricity Regulations (CER).

## 3.2 Fleet Utilization and Marginal Resources

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 (operating essentially constantly – e.g., nuclear), dispatchable (operating as needed – e.g., gas), or intermittent (operating when fuel is available – e.g., solar or wind). 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; overnight during autumn, 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, and the marginal cost in each hour in the planning horizon is identified. In general, the marginal costs indicate the trajectory of market prices, which can differ widely due to market participant behaviour, congestion, the supply mix, the variable input cost for fuel, and other factors.

**Figure 2 | Annual Energy Production**

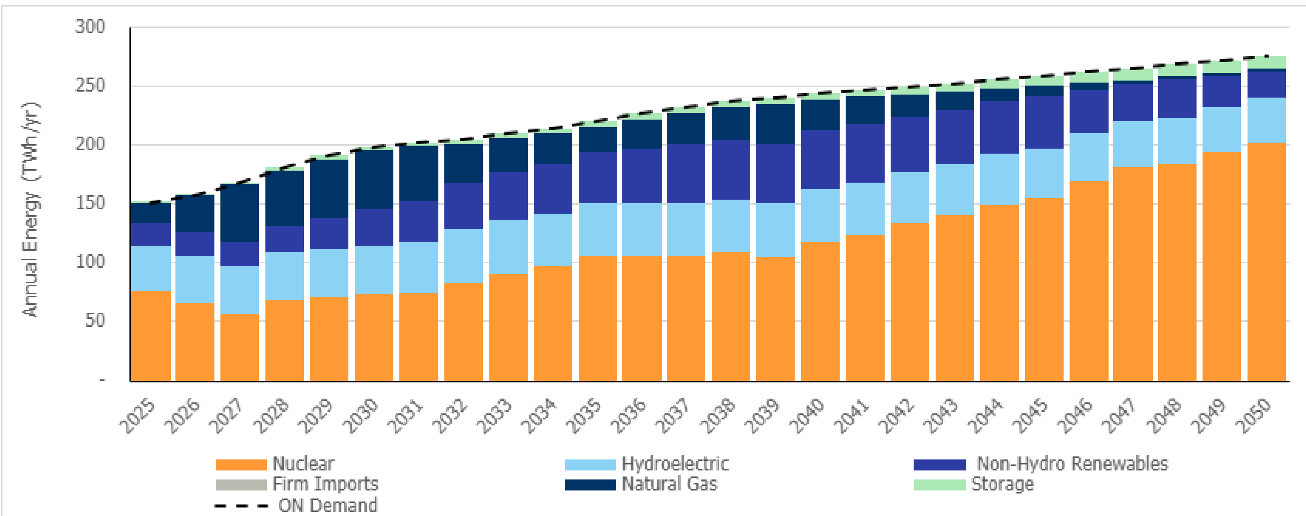
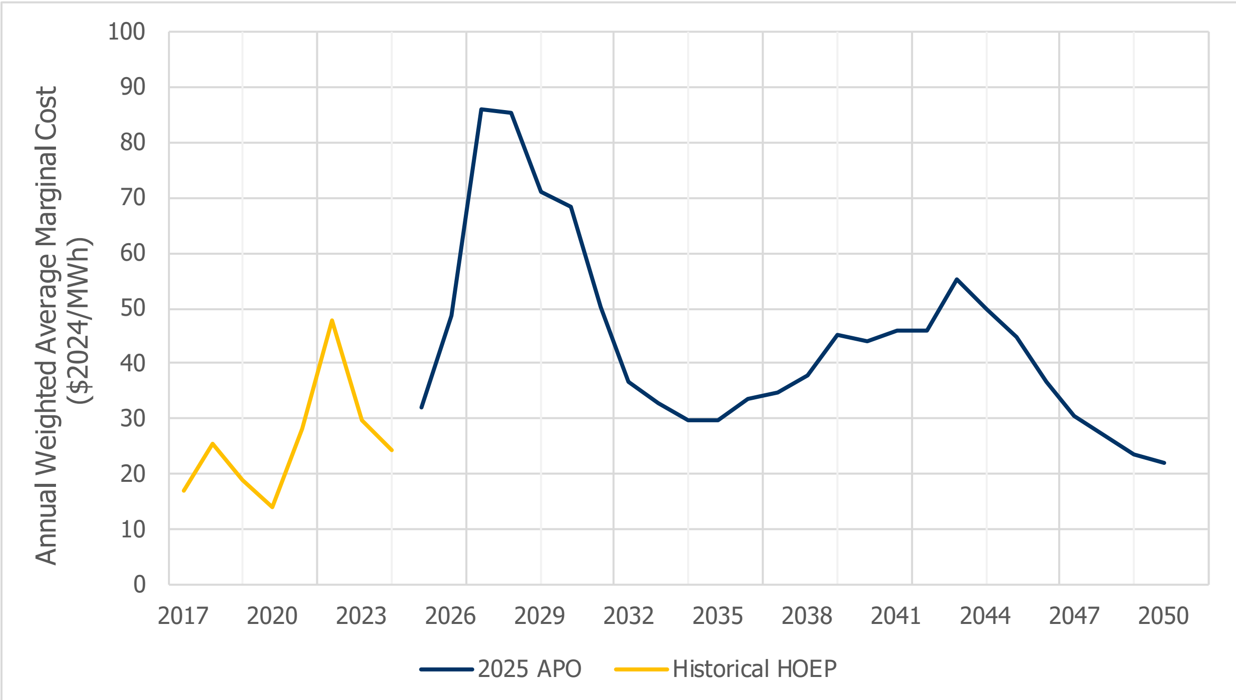



Figure 3 illustrates the forecasted weighted average marginal costs alongside the historical Hourly Ontario Energy Prices (HOEP). Marginal costs rise in the late 2020s due to increased reliance on gas-fired generation, primarily to manage nuclear refurbishments and growing electricity demand. These costs temporarily decline in the early 2030s as new renewable and nuclear resources begin to enter the system. Marginal costs increase again after 2035, primarily due to continued reliance on gas generation for system flexibility. However, this reliance decreases significantly by the mid-2040s as substantial new nuclear capacity enters the system, lowering marginal costs toward 2050.

**Figure 3 | Weighted Average Marginal Costs Forecast and Historical HOEP**



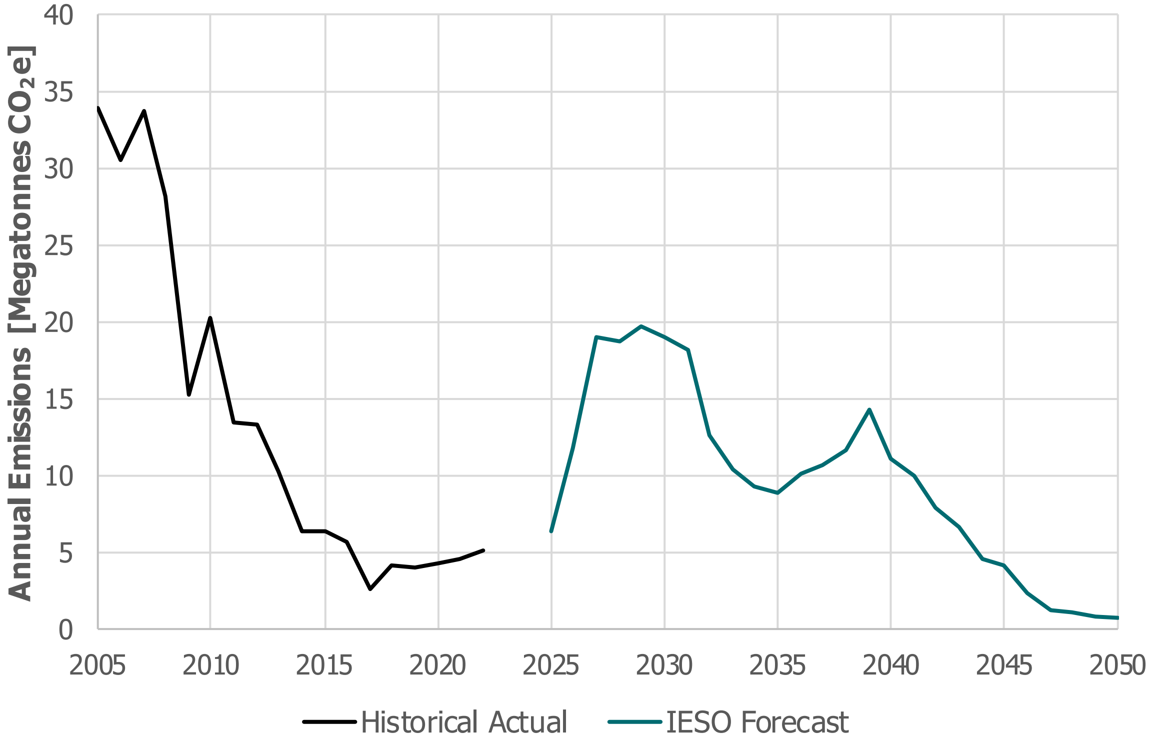

## 3.3 Greenhouse Gas Emissions

In the 2025 APO supply case (only existing and committed resources included), Ontario has energy needs from 2029 onwards[4]. Generation resources will need to be added to the electricity system to maintain adequacy, which could impact this emissions outlook. The CapEx model explores one potential way to acquire generation resources to fill this gap between electricity supply and demand. Actual emissions will depend on future procurement and program outcomes, with a diversity of supply expected to be procured. Planned actions to meet supply needs in the near to medium term are detailed in the 2025 APO.

Figure 4 shows both historical and forecast electricity system greenhouse gas emissions in Ontario. The historical actual emissions are taken from the Environment and Climate Change Canada's 2024 National Inventory Report. The forecast of future emissions is based on the IESO's analysis within this module's scenario, which does not model the federal CER (see Section 3.4). Rather, the analysis assumes resources discussed in Section 3.1 of the 2025 APO, as well as the additional resources identified from the CapEx modelling described in Section 2.3 of this module. A simulation dispatching the least-cost resources to meet electricity demand is performed on an hourly basis for every forecast year.

[4] This accounts for resources such as nuclear developments committed through the *Powering Ontario's Growth* plan. More details on what is included in the supply case can be found in Section 3.1 of the 2025 APO.

**Figure 4 | Ontario Electricity System Greenhouse Gas Emissions, Historical and Forecast**

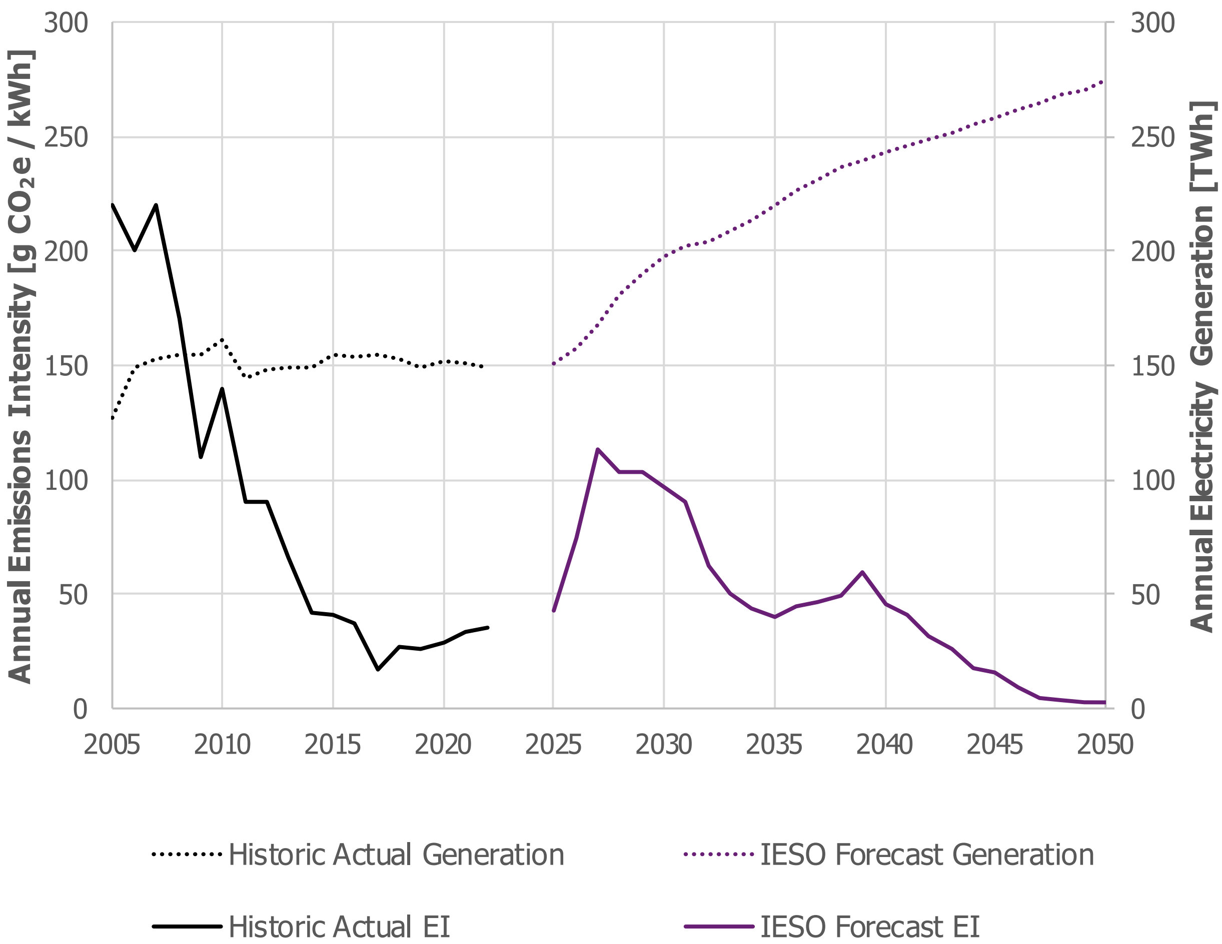



Electricity system emissions are forecast to increase in the 2020s and early-2030s due to growing demand and reduced nuclear production during planned refurbishment outages, which result in increased electricity production from gas-fired generation. This is shown in Figure 4. Electricity system emissions are then forecast to level out in the 2030s as new generation capacity is built to meet increasing demand. Electricity produced from gas generation later decreases in the 2040s as new supply comes online, including the four new Bruce C nuclear generation units. Electricity system emissions reach nearly zero (0.7 $MtCO_2e$) by 2050.

An increase in electricity system emissions due to utilizing natural gas generation does not necessarily mean an increase in economy-wide emissions. The emissions intensity of electricity remains far below that of other fuels, such as gasoline or diesel for automotive transportation or fuel oil for space heating. Switching from higher-emission fuels to low-carbon electricity (electrification) could increase electricity system emissions due to increased overall electricity consumption, while reducing provincial economy-wide emissions through emission reductions in other sectors. In addition, as electricity consumption increases due to electrification and growing demand, the attendant rise in electricity system emissions could be reduced through various means. These include increased energy efficiency, improved management of peak demand, or the entry of non-emitting resources to the Ontario market.

Electrification throughout the province will reduce economy-wide greenhouse gas emissions over time. For example, direct or indirect electrification of rail, individual industrial facilities, and home heating (forecast demand drivers that are discussed and considered in the 2025 APO Section 2), will all contribute to further greenhouse gas reductions in the greater economy, but actual reductions cannot be accurately quantified without more information. The simultaneous growth in electricity generation and decrease in carbon emissions intensity is shown in Figure 5 below. Even though Ontario is forecast to consume more electricity, each unit of that electricity is forecast to become less emissions intensive over time. The electricity emissions intensity (EI) follows a similar shape as the absolute emissions, with trends described above.

**Figure 5 | Carbon Emissions Intensity**




## 3.4 Carbon Policy

Currently, the electricity sector in Ontario and in 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, which assume that the price of carbon in Canada will rise to \$170/t$CO_2$e by 2030, in nominal dollars, and remain at that level for the duration of the planning period. See Minimum National Carbon Pollution Price Schedule (2023-2030) on Government of Canada's Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030.

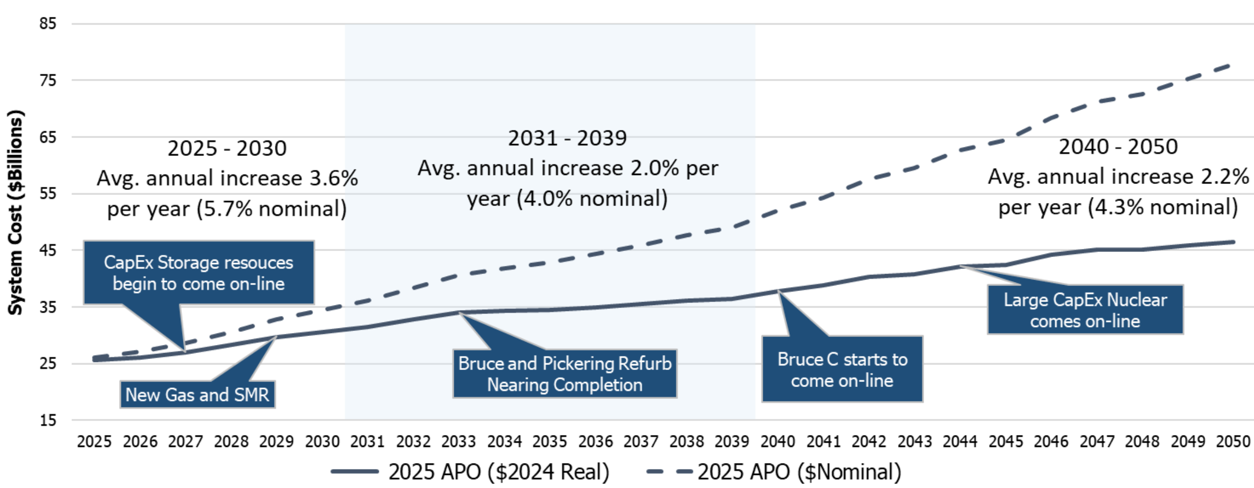
The federal government released Canada Gazette II on December 18, 2024 that finalized the Clean Electricity Regulations. The impacts of these regulations have not been included within the 2025 APO modelling nor this module. The IESO's modelling indicated more cost-effective pathways to reach a near net-zero grid by 2050 without the CER.

## 3.5 System Costs

Total system costs (in $2024) are expected to increase from $25.6 billion in 2025 to $46.5 billion by 2050, with the steepest increases in the first five years of the forecast as rising demand for electricity is greatest during this period. Costs of new CapEx resources begin to arise in the late 2020s with new storage coming online in 2027, followed by wind, gas, and solar in 2030, hydro in 2031, and nuclear in 2040. Additionally, investments in new transmission infrastructure will be needed to enable CapEx-modelled new resources. This is assumed to increase the overnight capital cost of the CapEx resources by 15 per cent as they come into service — consistent with the transmission cost assumptions used for CapEx resources from *Pathways to Decarbonization*. Distribution costs are assumed to increase due to housing stock increases, plus an annual capital investment of $1.7 billion per year commencing in 2031 to enable decarbonization and electrification.

Figure 6 shows the total cost forecast for the 2025 APO in both real ($2024) and nominal dollars.

**Figure 6 | Long-Term Total Cost of Electricity**




On a real, per unit (i.e., $/MWh) basis, electricity costs are expected to decline by 1 per cent per year in the near term, remain flat through the 2030s, and begin increasing in the 2040s by 1.2 per cent per year above inflation. Although the total cost increase is the steepest in the first five years, the unit costs decrease, in real dollars, due to the steep demand growth (electricity demand increases by 4.6 per cent per year, which is higher than the total costs increase of 3.6 per cent per year; resulting in a decline in unit costs). The 2.2 per cent per year total cost increase in 2040s is driven down to 1.2 per cent per year on a unit cost basis due to increasing demand at a rate of 1 per cent per year. Figure 7 shows the per unit cost forecast for the 2025 APO in both real ($2024) and nominal dollars.

## Figure 7 | Long-Term Unit Cost of Electricity