Annual Planning Outlook

Supply, Adequacy and Energy Outlook Module

April 2025

Connecting Today.
Powering Tomorrow.

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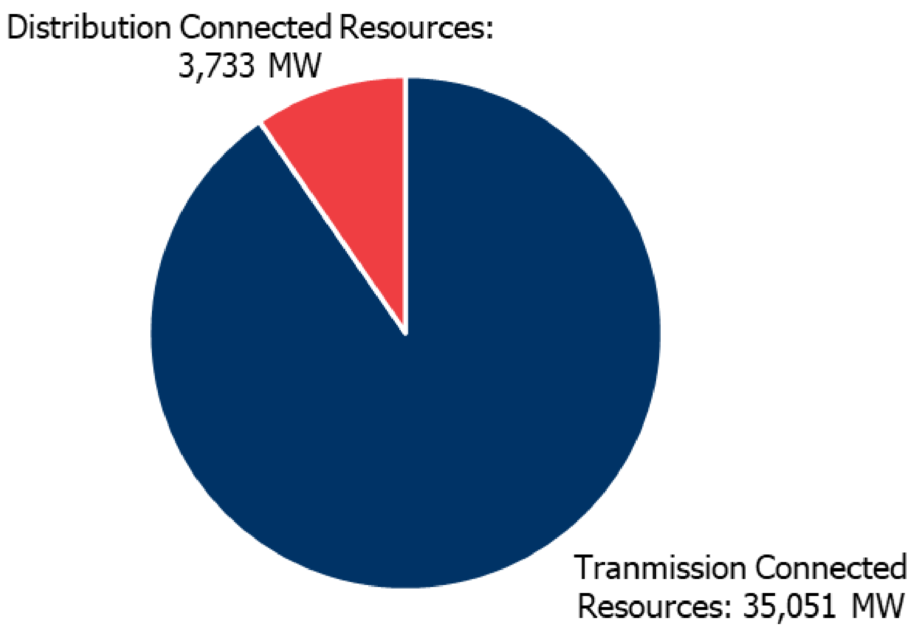
1. Supply Outlook

1.1 2025 Transmission and Distribution Connected Installed Capacity

Of the 38,784 MW of installed capacity that exists in the system today, about 90% is connected to the transmission system whereas the remaining 10% is connected to the distribution system. The transmission-connected resources are generally connected to the IESO controlled grid and are mostly market participants. However, the distribution-connected resources tend to be embedded resources consisting of either contracted or rate-regulated resources, and are mostly non-market participants. The distribution-connected resources exclude behind the meter resources that do not have a contract with the IESO, as the IESO has limited visibility of these resources. In 2025, there are about 35,051 MW installed capacity of transmission-connected resources and about 3,733 MW installed capacity of distribution-connected resources.

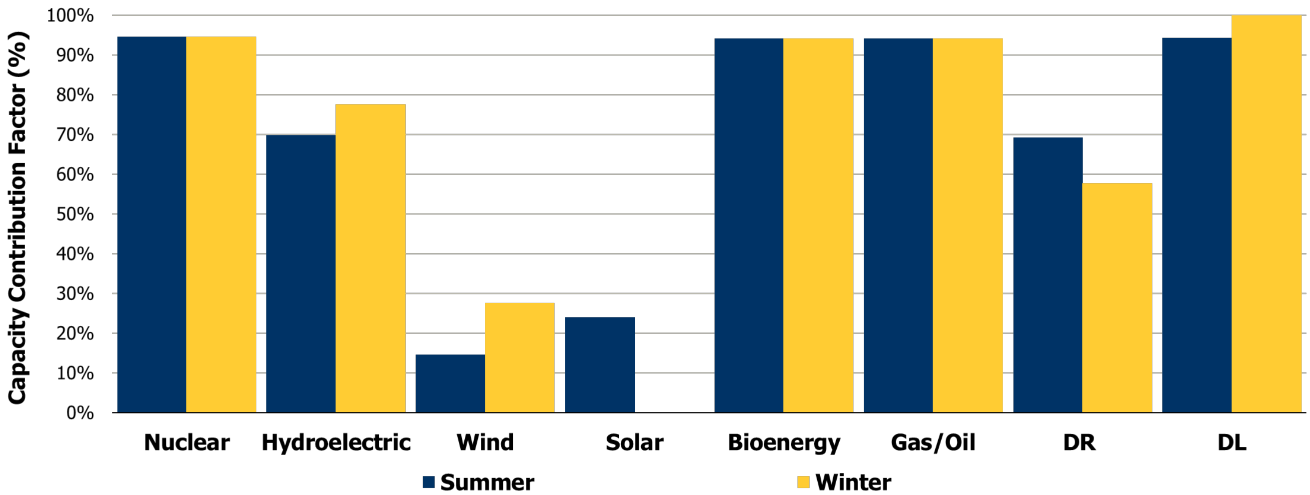
Figure 1 | 2025 Installed Capacity



1.2 Summer and Winter Capacity Contribution

Figure 2 represents the summer and winter peak capacity contribution by fuel type. As shown below, these values are generally higher in the winter than summer except for solar.

Figure 2| 2025 Summer and Winter Peak Capacity Contribution



Capacity contribution factors reflect forced outages as well as reductions due to ambient conditions. The reasons for the differences in contribution by season are as follows:

- Nuclear units, Bioenergy, and Gas/Oil resources do not exhibit much variation between summer and winter capacity contributions.
- Hydroelectric capacity contribution factors are higher in the winter due to increased water availability.
- Wind capacity contribution factors vary throughout the year because of seasonal wind patterns. Wind speeds are typically higher in winter causing increased average production compared to summer resulting in higher contribution factors in winter.
- Solar contribution factors vary throughout the day, with the highest from noon to mid-afternoon. Since demand peaks are later in the evening in the winter, solar factors are negligible in the winter and higher in the summer.
- Demand response and dispatchable loads peak capacity contribution varies as it depends on their bid values by season.

2. Capacity Adequacy Outlook

2.1 Nuclear Refurbishment Reserve

Resource adequacy assessments reflect additional planning reserve to manage the risk of nuclear refurbishment and new nuclear project delays. This year's reserve has higher values in the future due to new planned nuclear resources from Powering Ontario's Growth. The contribution of this additional planning reserve on summer and winter adequacy needs is shown in Figure 3 and Figure 4 respectively.

Figure 3 | Planning Reserve for Nuclear Refurbishment, Summer

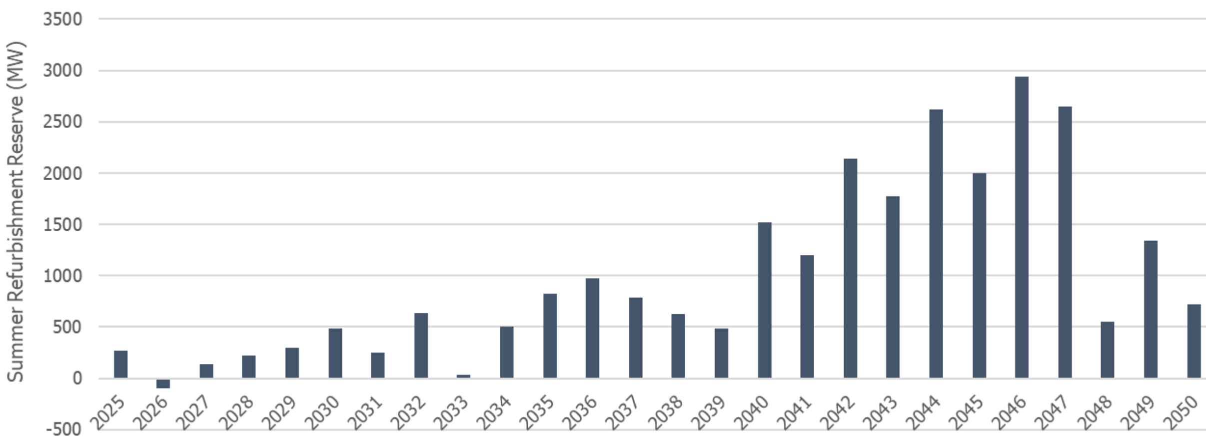
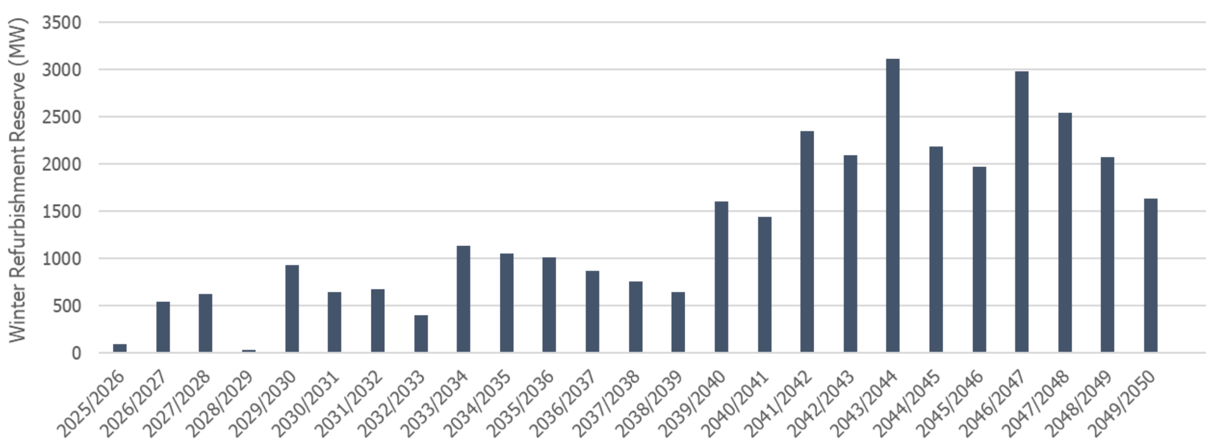


Figure 4 | Planning Reserve for Nuclear Refurbishment, Winter



2.2 Seasonal LOLE Allocation

The IESO's resource adequacy criteria require an annual loss-of-load expectation (LOLE) of 0.1 days/year. The criteria do not provide guidance on how the LOLE should be allocated across seasons. The IESO allocates LOLE across seasons to minimize capacity needs, based on the prevailing supply and demand conditions within a given year.

In the long-run, internal studies have shown that annual average resource requirements are minimized when the LOLE is split 0.06 days/year in summer and 0.04 days/year in winter. In the near-term, different allocations minimize the resource requirements. The 2025 APO LOLE allocation is shown in Table 1 and Table 2.

Table 1 | Summer LOLE Allocation

Season	2025	2026	2027-2050
Target LOLE (days/year)	0.09	0.09	0.06

Table 2 | Winter LOLE Allocation

Season	2025/26	2026/27	2027/28-2049/50
Target LOLE (days/year)	0.01	0.01	0.04

The impact of the 2025 APO LOLE allocation, described in the previous paragraph, compared to the long-run 60/40 assumption is shown in Figure 5 and Figure 6 for summer and winter, respectively. This LOLE allocation has the effect of reducing summer and winter needs.

Figure 5 | Impact of 2025 APO LOLE Allocation vs. Long-Run Assumption, Summer

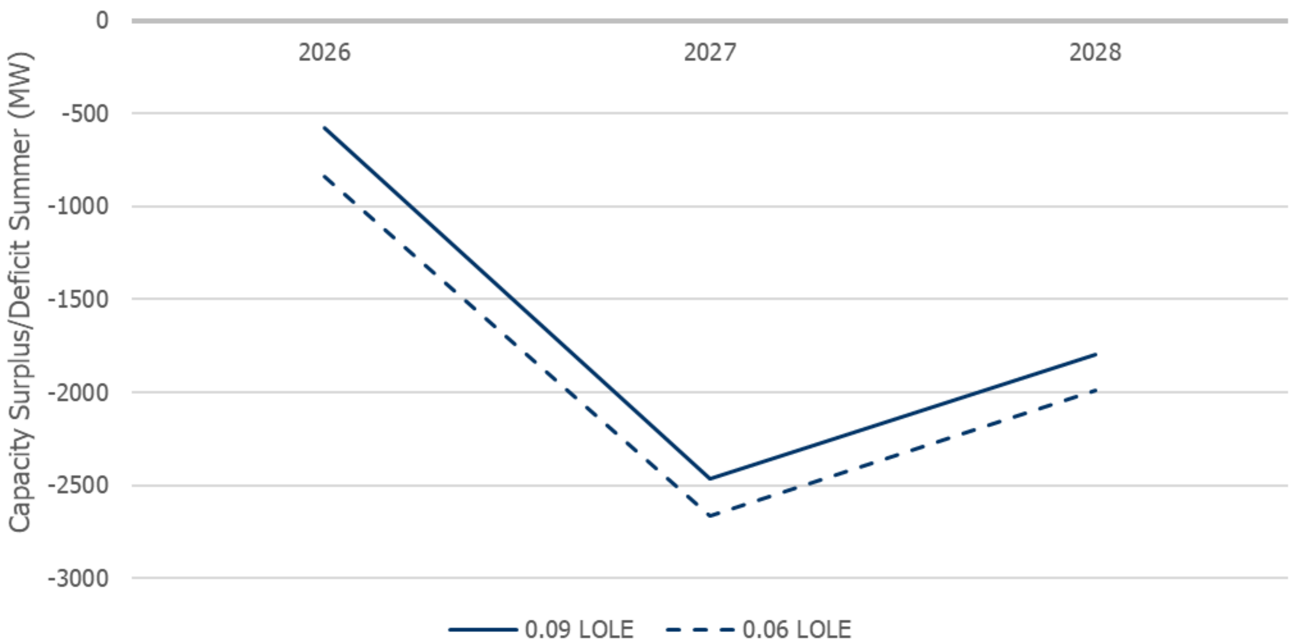
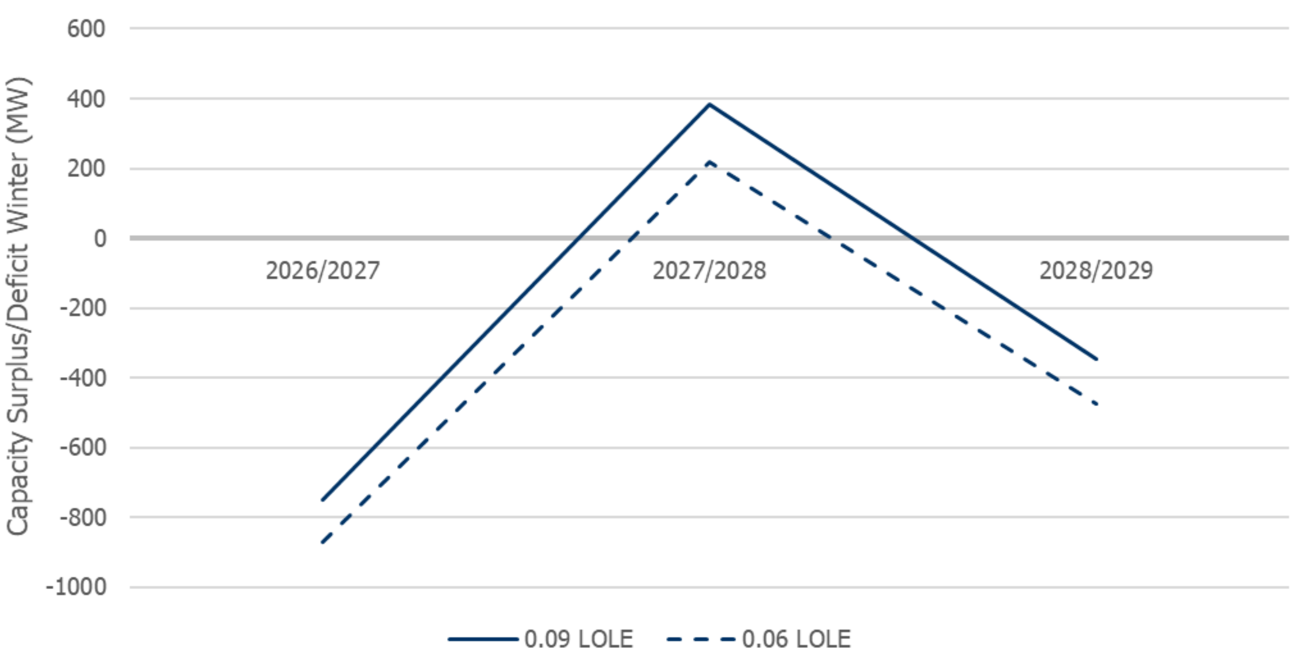


Figure 6 | Impact of 2025 APO LOLE Allocation vs. Long-Run Assumption, Winter



2.3 Ontario’s Trading with Quebec

The 2015/2016 capacity sharing agreement saw Ontario provide 500 MW of capacity to Hydro-Québec (HQ) during Quebec’s winter peak periods. This agreement was in place until winter 2022/23.

The IESO has the option to call on 500 MW of import capacity from HQ to contribute towards resource adequacy. This option is available in any summer prior to September 2030. It would reduce the need to acquire capacity in the period it is exercised. Ontario expects to call on that option in the summer 2027. This is considered in the Integrated Reliability Needs assessment of the 2025 APO.

In 2024, the IESO entered into a capacity sharing agreement with HQ, for provision of IESO providing HQ a minimum of 600 MW in the winter period, and HQ providing IESO up to 600 MW in the summer period . This is considered in the Integrated Reliability Needs assessment of the 2025 APO.

2.4 Zonal Constraints

Locational requirements exist due to limitations on the transmission system, typically specified through “transmission transfer capability limits” over transmission interfaces.

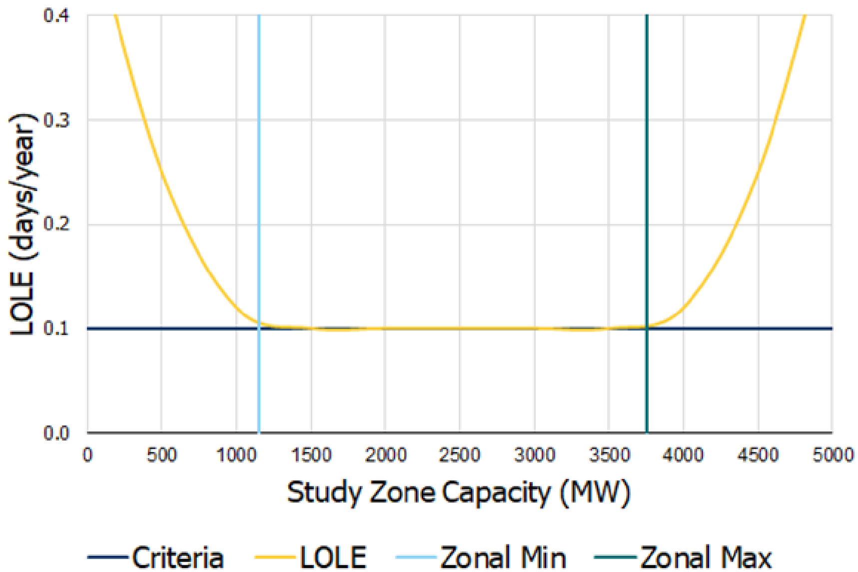
To account for transmission transfer capabilities across Ontario’s interfaces, the IESO specifies the minimum and maximum incremental capacity amounts required in certain regions of the province. These minima and maxima are typically presented at the zonal level, and in some cases are reported for groups of zones that share a common limiting interface. The zonal constraints calculation methodology described in this section is used to inform the annual Capacity Auction targets.

A zonal minimum represents the minimum required capacity necessary to meet the provincial resource adequacy criterion. A zonal maximum represents the maximum amount of capacity in a zone that can contribute to provincial resource adequacy. In other words, the zonal minimum is a capacity requirement; capacity exceeding the zonal maximum does not provide further value from a resource adequacy perspective (e.g. transmission deliverability assessments may further reduce the maximum in some areas).

The methodology for establishing the transmission transfer capabilities is provided in the Ontario Transmission Interfaces and Interties Overview. These capabilities can have an impact on the extent to which a resource can contribute towards adequacy. The 0.1 days/year LOLE criterion is not set at a zonal level – it is an adequacy target for the province as a whole. The same LOLE can be achieved by placing resources in different locations. However, some locations may be better than others as a result of interface limits.

Zonal minimum and maximum capacity values are calculated using zonal constraint curves. Zonal constraint curves are developed by adding or removing capacity in a zone and removing or adding a corresponding amount of capacity in the rest of the system, such that the total incremental capacity is constant. The zonal constraint curve is developed using a “two-zone” representation of the transmission system. The only interfaces that are represented in the capacity adequacy tool should be those that are connected to the study zone; the remainder are removed or set to a non-limiting value. The resulting system LOLE across a range of study zone capacities creates the zonal constraint curve, as shown in Figure 7.

Figure 7| General Shape of Zonal Constraint Curve



The flat portion of the curve represents the range of study zone capacity where the system LOLE will remain approximately unchanged for an equal and offsetting amount of capacity in the rest of the system. Where the curve slopes upwards to the right, LOLE is increasing as study zone MWs are added and an equal amount of MWs are removed from the rest of the system. This indicates that additional MWs in the study zone cannot be fully utilized to offset capacity in the rest of the system and a zonal maximum can be established where the LOLE is greater than the LOLE threshold[1].

Similarly, where the curve slopes upward to the left, LOLE is increasing as study zone incremental capacity is reduced and an equal amount of MWs are added in the rest of the system. This indicates that additional MWs in the rest of the system cannot be fully utilized to offset capacity in the study zone and a zonal minimum can be established where the LOLE is greater than the LOLE threshold.

Zonal adequacy constraints help identify where adequacy needs exist across the system and where they can most effectively contribute towards meeting resource adequacy needs. The zonal constraint curves described only reflect adequacy needs and not security needs. Security needs are considered as part of a transmission assessment and may lead to additional constraints on the amount of capacity acquired in a zone.

For the zones without minimums, the assumption is the zone's adequacy needs would be satisfied by acquiring the system's capacity need while not violating the zonal maximums. For zones without maximums, it implies that the true maximum is outside the scope/upper bound of the model and any capacity acquired would be capped at the provincial capacity need. Although zonal maximums limit

[1] LOLE threshold = System LOLE using target capacity requirement (per seasonal allocation) + 0.001 days/year

the amount of capacity that can be added to a zone, the total amount of capacity added to all zones is limited by the global resource adequacy (capacity) need.

Table 3 and Table 4 provide a summary of the zones and their defining interfaces considered in the zonal adequacy assessment along with the assumed transmission transfer capability across each interface.

Table 3 | Zones and Defining Interfaces

Area	Interface
Bruce	FABC
Niagara	QFW
Northwest	E-W
West	BLIP
Toronto+Essa+East+Ottawa	FETT, FN/FS
Northeast+Northwest	E-W, FN/FS

Table 4 | Transmission Transfer Capabilities (2025-2050)

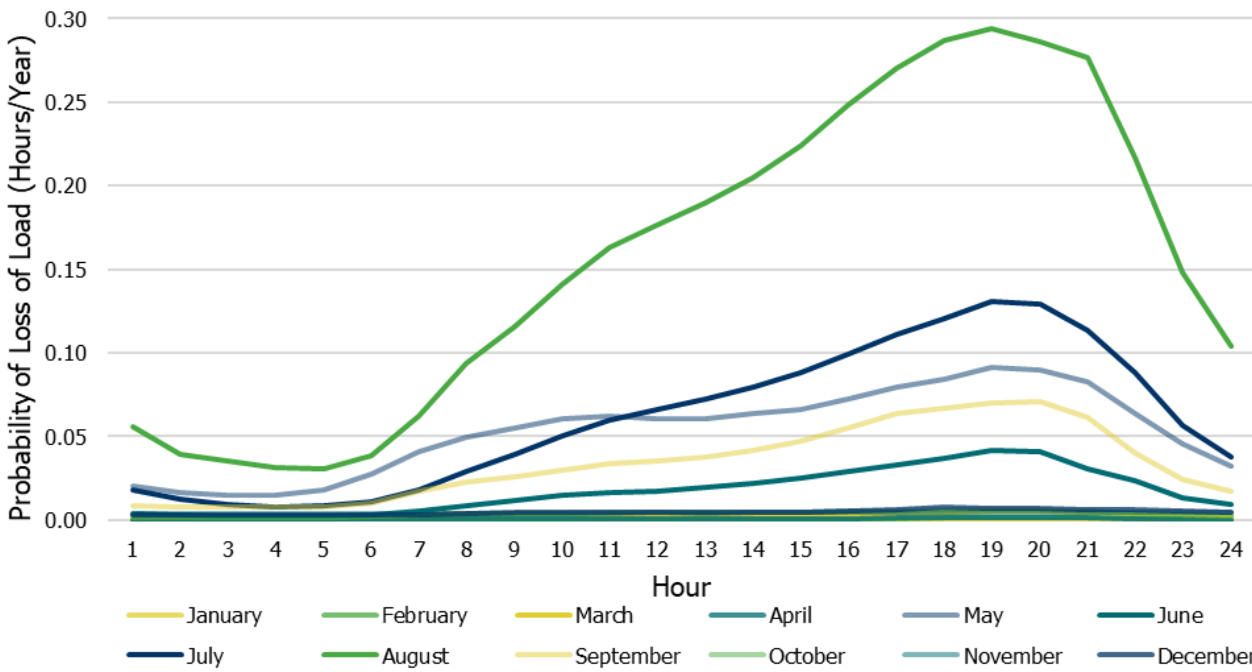
Interface	Positive Direction Interface Transfer Capability (MW)	Negative Direction Interface Transfer Capability (MW)
E-W	Ranges from 490 to 830	Ranges from 420 to 700
FABC	9,999	9,999
BLIP	Ranges from 2,460 to 3,775	Ranges from 1,510 to 1,625
QFW	Ranges from 2,025 to 2,110	9,999
FETT	Ranges from 4,700 to 7,350	9,999
TEC	9,999	9,999
FIO	2,950	9,999
FN/FS	Ranges from 1,865 to 1,979	Ranges from 1,750 to 2,270
CLAN	9,999	9,999

2.5 Hourly Probability of Loss of Load

To further understand the characteristics of system needs and the types of resources that can meet these needs, the hourly probability of loss of load was analyzed for the year 2029, against the resource adequacy outlook in Section 4 of the 2025 APO, and does not consider the previous and underway actions, and risks identified in Sections 7 and 8. Given the hourly load forecast and the available resources at each hour, the probability of loss of load is different for every hour. If the system's reserve margin falls below zero in a particular hour, then loss of load is certain.

In its probabilistic assessment, the IESO has analyzed hundreds of simulations at different load levels to determine a metric that best represents the probability of loss of load at every hour of the year. Figure 8 outlines the described metric at every hour of the day for each month in 2029 against the demand forecast and supply outlook. The contract expiry of the Lennox and Atikokan generating stations in 2029 cause a significant increase in need. Summer months such as July and August exhibit a higher probability of need during hours 16-22, while in winter, there is a small spike around hours 9-10 and then a larger need during hours 17-23. In Ontario, summer months constitute most of the hourly needs given that the system is currently summer peaking; however, the shape of the hourly profiles changes from year to year and is impacted by factors such as the demand forecast, load forecast uncertainty, supply forecast, outages and transmission constraints.

Figure 8 | Hourly Probability of Loss of Load, 2029



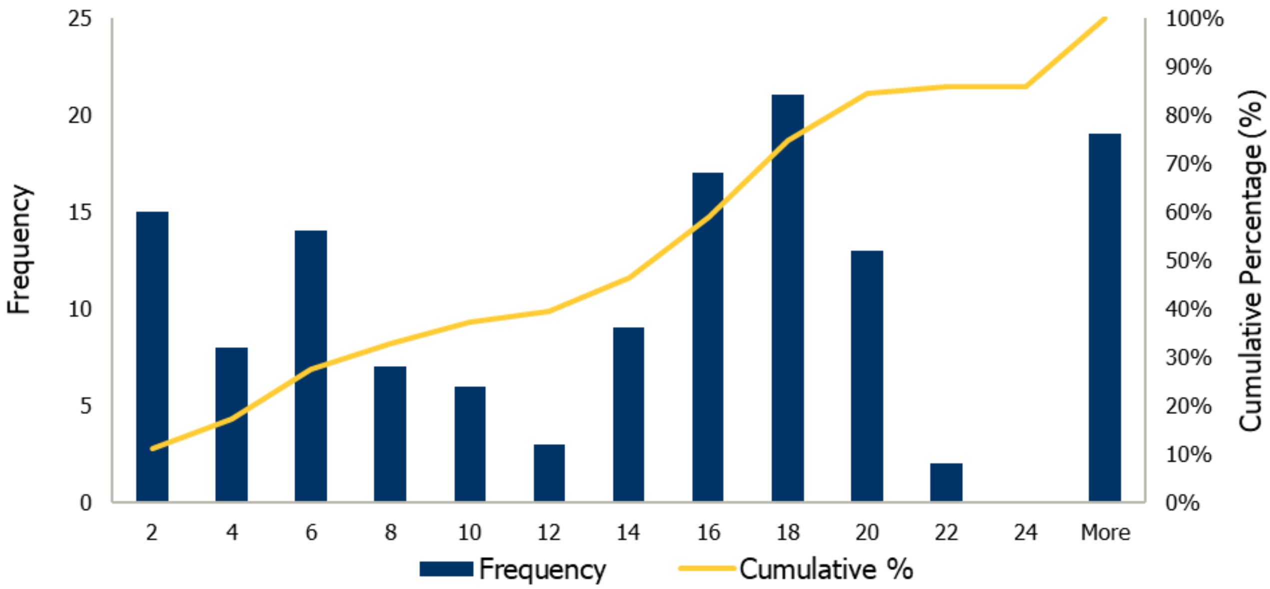
2.6 Duration of Loss of Load

The periods of resource adequacy risk identified in this report tend to be sustained for multiple, consecutive hours. Figure 9 shows the duration of risk periods in 2029. This assessment shows that the length of risk periods can vary greatly.

Looking at the entire range of outcomes observed in the IESO's probabilistic assessments can inform future procurements on the value of resources that are capable of providing energy for a sustained period of time, particularly in preparation for the potential for severe weather conditions, where about:

- 15 per cent of events persist for up to four hours;
- 20 per cent of events persist for more than 4 and up to 8 hours;
- 25 per cent of events persist for more than 8 and up to 16 hours; and
- 40 per cent of events persist for more than 16 hours.

Figure 9| Duration of Resource Adequacy Risk Periods, 2029



3. Energy Adequacy Outlook

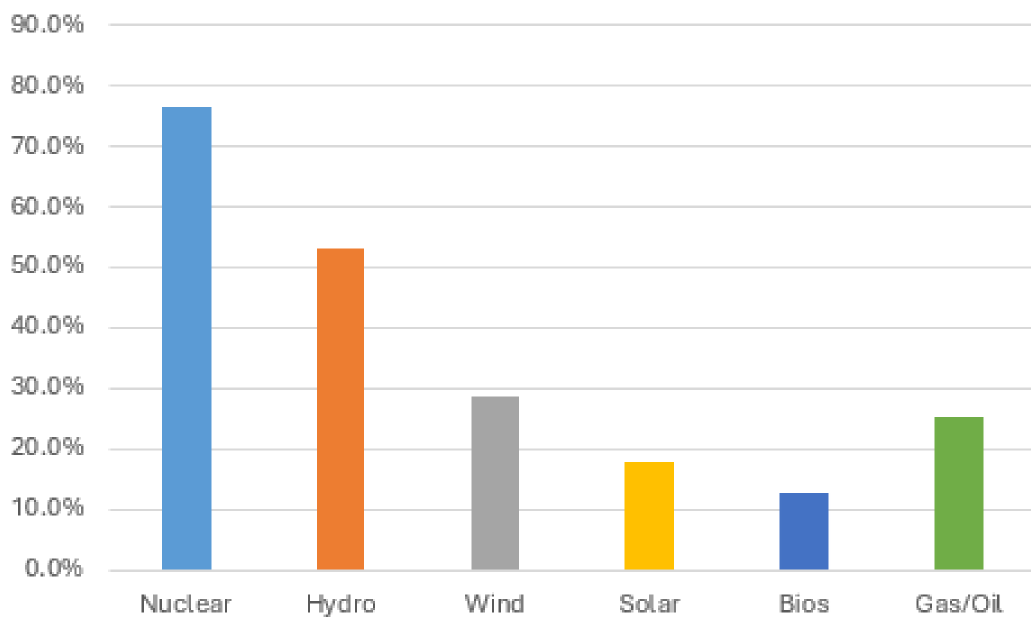
3.1 Exchange Rate and Ontario Natural Gas Price Forecast

The natural gas fuel forecast assumption is from the Sproule Price Outlook. These assumptions can be found in Table 2: Sproule Forecast – Henry Hub, Dawn, in the APO Fuel Cost Data Table.

3.2 Annual Energy Contribution Factors

Figure 10 represents the annual energy contribution factors by fuel type, based on average hourly production for the year 2025.

Figure 10 | Annual Energy Contribution Factors



Energy contribution factors reflect outages as well as reductions due to ambient conditions. The reasons for the differences in contribution by fuel type are as follows:

- Nuclear units are must-run resources that have minimal weather and fuel limitations, so their production is high throughout the year. Their energy production is mainly limited by planned and forced outages.
- Hydroelectric energy contribution varies with season; it is highly dependent on the precipitation, and stochastic in nature. Therefore, the average production over the year is lower than the capacity contributions during peak hours in Figure 2.
- Wind energy production is dependent on seasonal wind patterns, which is also stochastic in nature. Wind energy generation is higher in the winter compared to the summer.

- Solar energy production is dependent on time of day and season. It is greatest during noon to mid-afternoon in the summer and lower in winter. Due to these varying hourly and seasonal contributions, solar exhibits a low energy contribution.
- Bioenergy is an energy-limited resource. Its energy contribution is limited by its fuel availability throughout the year.
- Gas/oil resources are only dispatched as needed by the system and hence their energy production is significantly lower compared to peak capacity factors in Figure 2.

3.3 Unserved Energy Description

Figure 12 to Figure 14 separate the annual unserved energy as described in Section 4 of the 2025 APO into winter, summer, and shoulder periods. These figures do not consider the previous and underway actions, and risks, identified in Section 8 of the 2025 APO.

Defining the characteristics of the unserved energy, for example, by the timing and magnitude, is important to better understand what resource can meet these needs and provide value. That is because different resource types provide differently across seasons (e.g. if the unserved energy is greater in the winter than in the summer, some resources such as solar and/or hydroelectric, may be less dependable as they produce less energy during the winter).

The heat maps below illustrate the total unserved energy, average unserved energy and maximum unserved energy during the winter, summer and shoulder seasons, over time of use (TOU) periods, across the study horizon. The time of use period definitions are described in Figure 11. It is important to note that the time of use periods are not of equal size in that they do not contain the same number of hours.

Figure 11 | Time-Of-Use Period Definitions

Winter			Summer			Shoulder	
On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak
December - March			June - September			April, May, October, November	
7 AM - 11 AM; 5 PM - 8 PM	11 AM - 5 PM; 8 PM - 11 PM	11 PM - 7 AM	11 AM - 5 PM	7 AM - 11 AM; 5 PM - 11 PM	11 PM - 7 AM	7 AM - 11 PM	11 PM - 7 AM

In the base case, the unserved energy begins to grow around 2030. It is observed across all seasons, with most of the time occurring in the winter.

Figure 12 | Total GWh Unserved Energy by TOU periods

	Winter			Summer			Shoulder		Annual
Year	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Total
2025	0	0	0	0	1	19	14	0	33
2030	366	360	770	505	642	1,047	388	466	4,544
2035	2,420	3,134	6,419	2,936	4,092	7,109	4,471	5,454	36,035
2040	5,911	7,708	15,079	4,621	6,841	12,158	11,433	13,471	77,222
2045	6,565	8,577	16,928	4,773	7,083	12,674	11,435	13,584	81,618
2050	7,113	9,240	16,835	5,748	8,642	12,784	12,146	12,308	84,816

Figure 13 | Average MWh Unserved Energy by TOU periods

	Winter			Summer			Shoulder		Annual
Year	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Average
2025	0	0	0	0	1	12	10	0	4
2030	608	466	504	967	738	681	279	303	519
2035	3,973	4,003	4,246	5,560	4,650	4,677	3,249	3,514	4,114
2040	9,596	9,733	9,920	8,751	7,774	7,999	8,309	8,680	8,791
2045	10,779	10,954	11,196	9,039	8,049	8,338	8,310	8,753	9,317
2050	11,679	11,800	11,134	10,886	9,820	8,411	8,827	7,930	9,682

Figure 14 | Max MWh Unserved Energy by TOU periods

	Winter			Summer			Shoulder		Annual
Year	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Max
2025	0	0	0	214	371	2,259	1,113	0	2,259
2030	5,281	5,179	4,545	7,252	7,062	7,403	4,199	4,256	7,403
2035	9,678	9,393	9,305	12,824	12,478	12,770	8,059	8,088	12,824
2040	16,036	15,226	15,965	16,690	16,552	16,364	13,512	15,084	16,690
2045	15,238	15,213	15,234	15,944	15,460	15,855	13,201	13,629	15,944
2050	15,769	16,009	15,802	18,181	18,338	19,009	13,926	15,891	19,009

Duration curves can also provide insights at the extremes (e.g. baseload and peaking requirements). Similar to the figures above, these duration curves represent the unserved energy described in Section 4 of the 2025 APO. They do not consider the previous and underway actions, and risks, identified in Section 8 of the 2025 APO.

Figure 15 separates the annual unserved energy by season and demonstrates that the unserved energy is greater in the winter than in the summer, illustrating that some resources (e.g. solar) may be less dependable as they produce less energy during the winter.

For this analysis, summer months are assumed to be May to October; winter months are November to April.

Figure 15 | Unserved Energy by Season

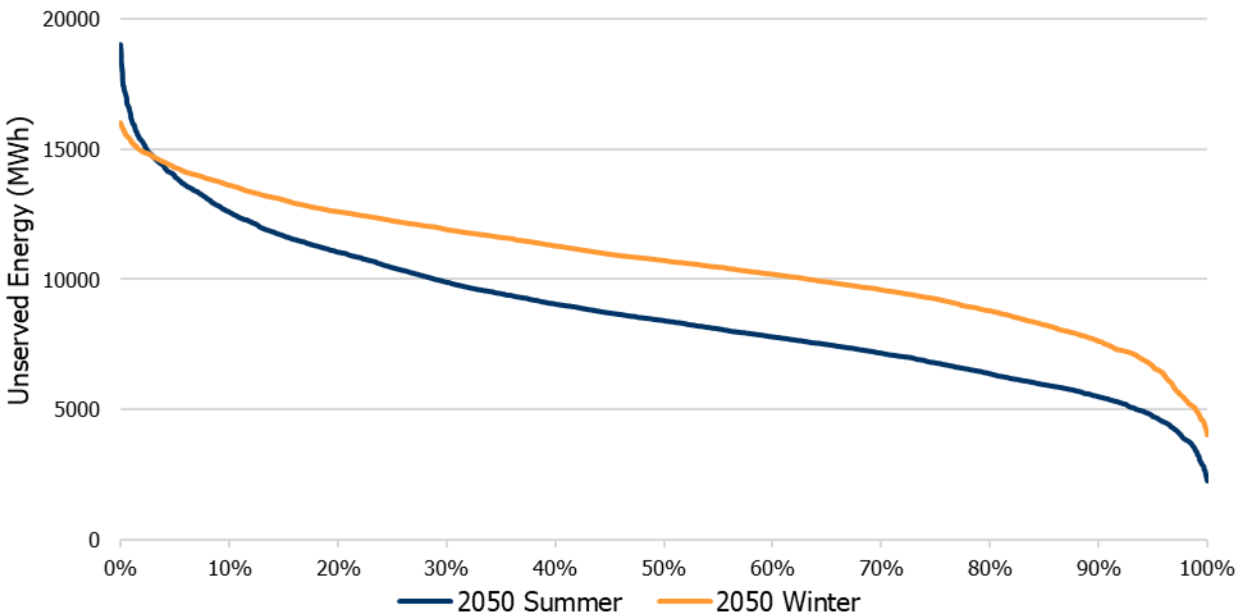
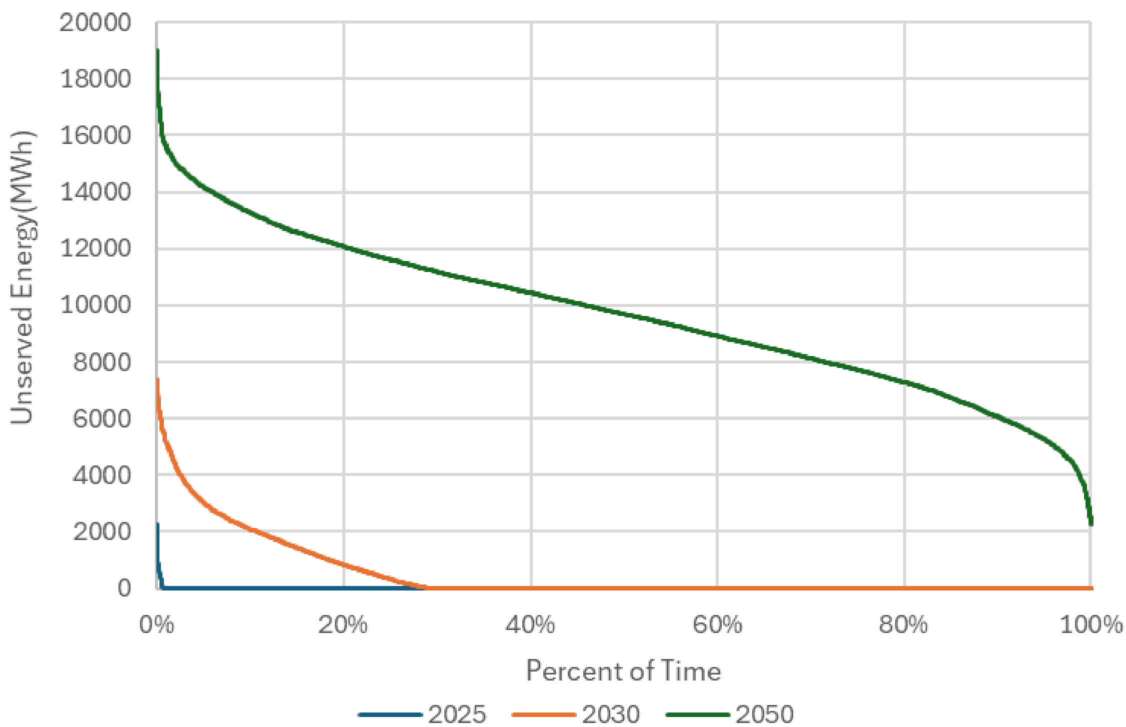


Figure 16 shows duration curves of the unserved energy need for years 2025, 2030 and 2050. These duration curves are used to illustrate the relationship between capacity requirement and utilization.

Figure 16 | Unserved Energy Duration Curve



In the base case, in 2030, a portion of the total energy need is not served (unserved energy) for about 30% of the year, as illustrated in Figure 16. By 2050, the energy not served occurs in all hours of the year; with a sizeable baseload amount that will be required at all times.

The need for baseload resources is not significant in the near term. However, it is expected to increase over the planning horizon. The peaking portion of the duration curve could be met by capacity products.

3.4 Discussion

Overall, the trends in the energy outlook in the 2025 APO are consistent with previous outlooks. Surplus baseload generation (SBG) is not an issue in 2025 APO. The growth in demand in the longer term increases capacity and energy requirements. Nuclear generation continues to be a major source of generation in Ontario. Energy from non-hydroelectric renewables has not changed materially while hydroelectric production is expected to be lower marginally due to lowered OPG hydroelectric production, in line with OPG 2023 Business Plan energy forecast. The extent to which existing resources remain in the market will dictate whether the need for future supply is primarily capacity or energy driven.

Energy results are shown for normal or median conditions. Weather conditions can have a substantial effect on energy demand and production from wind, hydroelectric, and solar resources. When interpreting energy outlooks, focus should be on trends, order of magnitude, and relative direction.

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