Annual Planning Outlook

Supply, Adequacy and Energy Outlook Module

December 2022

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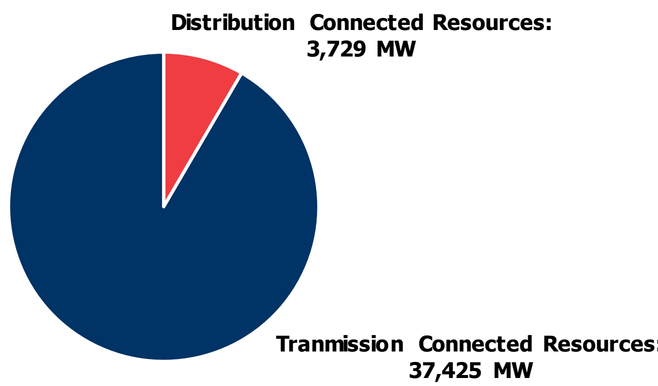
1. Supply Outlook

1.1 2023 Transmission and Distribution Connected Installed Capacity

Of the 41,154 MW of installed capacity that exists in the system today, about 91% is connected to the transmission system whereas the remaining 9% 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 2023, there is about 37,400 MW of installed capacity of transmission connected resources and about 3,700 MW of installed capacity of distribution connected resources.

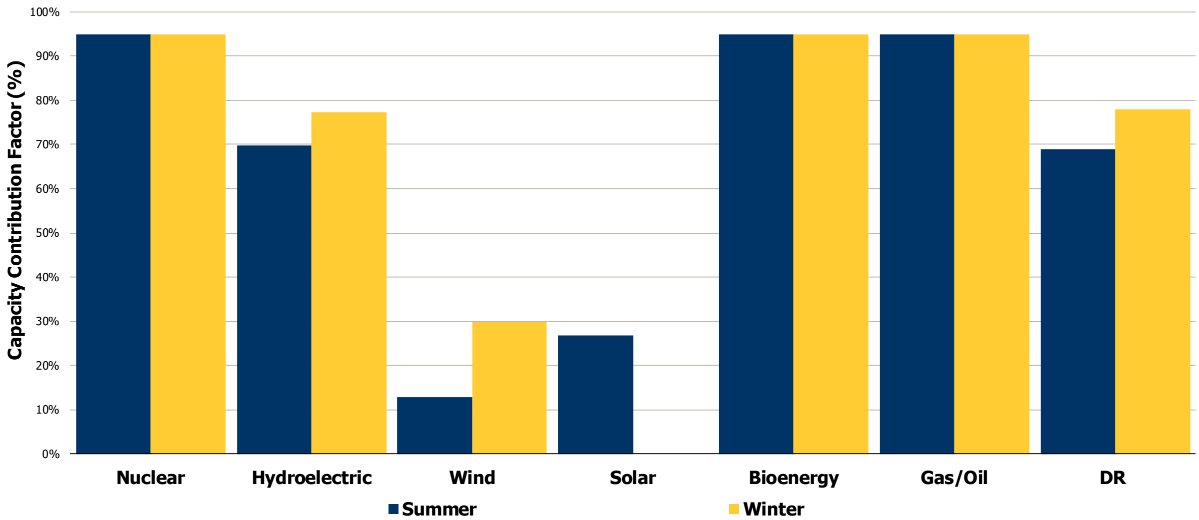
Figure 1 | 2023 Installed Capacity



1.2 Summer and Winter Capacity Contribution

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

Figure 2 | Summer and Winter Capacity Contribution



Capacity contribution factors reflect forced outages as well as reductions due to ambient conditions. 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 varies throughout the year as a result of seasonal wind patterns. Wind speeds are typically higher in the winter, which cause a higher average production in winter 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 and during the day in the summer, solar factors are negligible in the winter and higher in the summer.
- Demand Response (DR) capacity contribution factors are based on the DR historical performance from past DR activations and DR test results. Historically, higher contribution factors have been recorded in winter compared to summer.

2. Capacity Adequacy Outlook

2.1 Nuclear Refurbishment Reserve

Resource adequacy assessments reflect additional planning reserve to manage the risk of nuclear refurbishment project delays. The planning reserve for nuclear refurbishment has been updated to reflect updates to the nuclear refurbishment schedule for Darlington NGS and Bruce NGS. The planning reserve has not been updated to reflect the announcement regarding Pickering NGS. 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

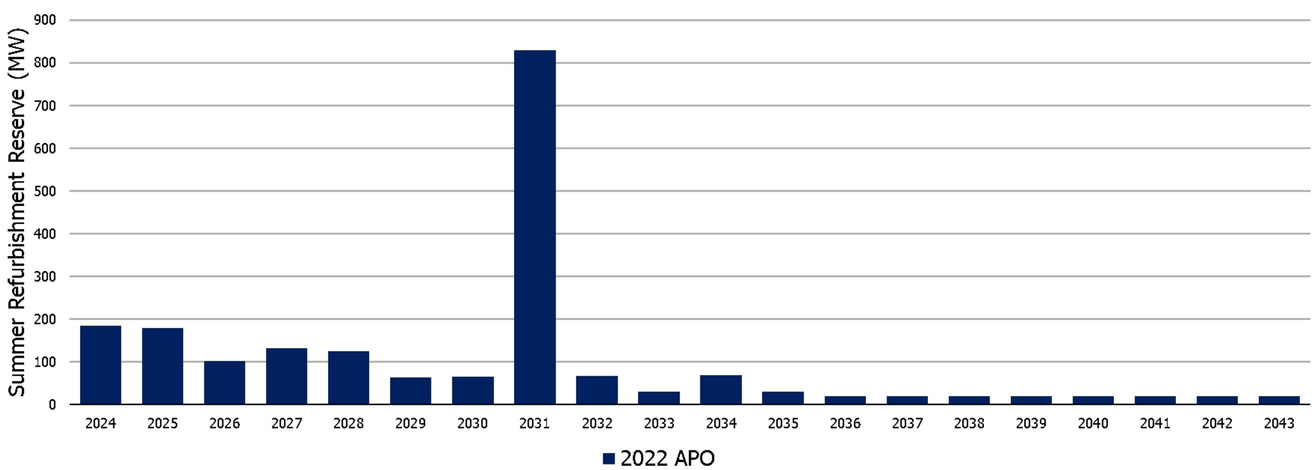
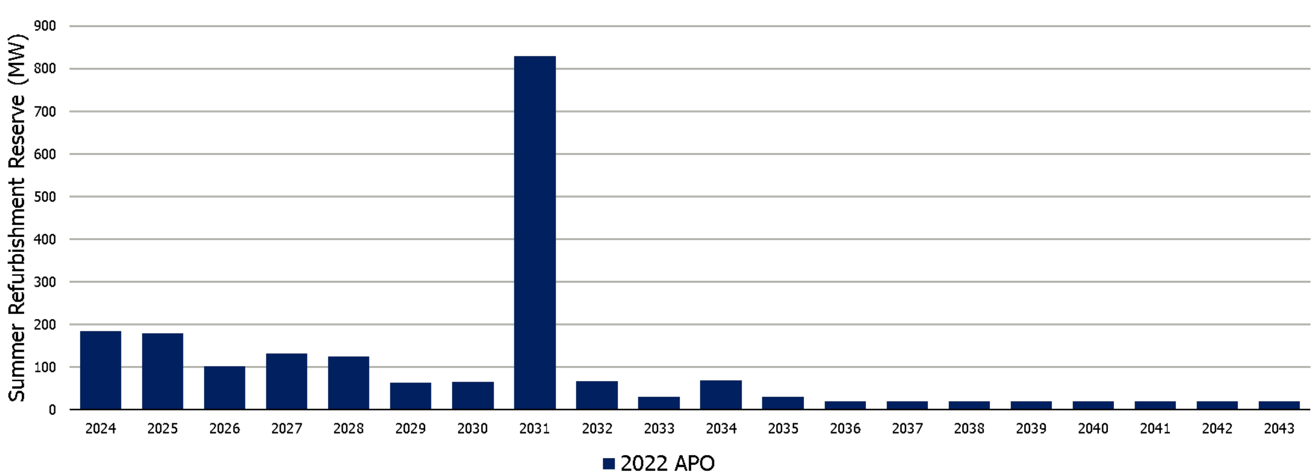


Figure 4 | Planning Reserve for Nuclear Refurbishment, Winter



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 2022 APO LOLE allocation is shown in Table 1 and Table 2

Table 1 | Summer LOLE Allocation

Season	2024	2025	2026	2027-2043
Target LOLE (days/year)	0.09	0.09	0.09	0.06

Table 2| Winter LOLE Allocation

Season	2024/25	2025/26	2026/27	2027/28-2043
Target LOLE (days/year)	0.01	0.01	0.01	0.04

The impact of the 2022 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. The capacity surplus/deficit values are shown assuming the continued availability of existing resources. This LOLE allocation has the effect of reducing winter surpluses and lowering summer needs.

Figure 5| Impact of 2022 APO LOLE Allocation vs. Long-Run Assumption, Summer

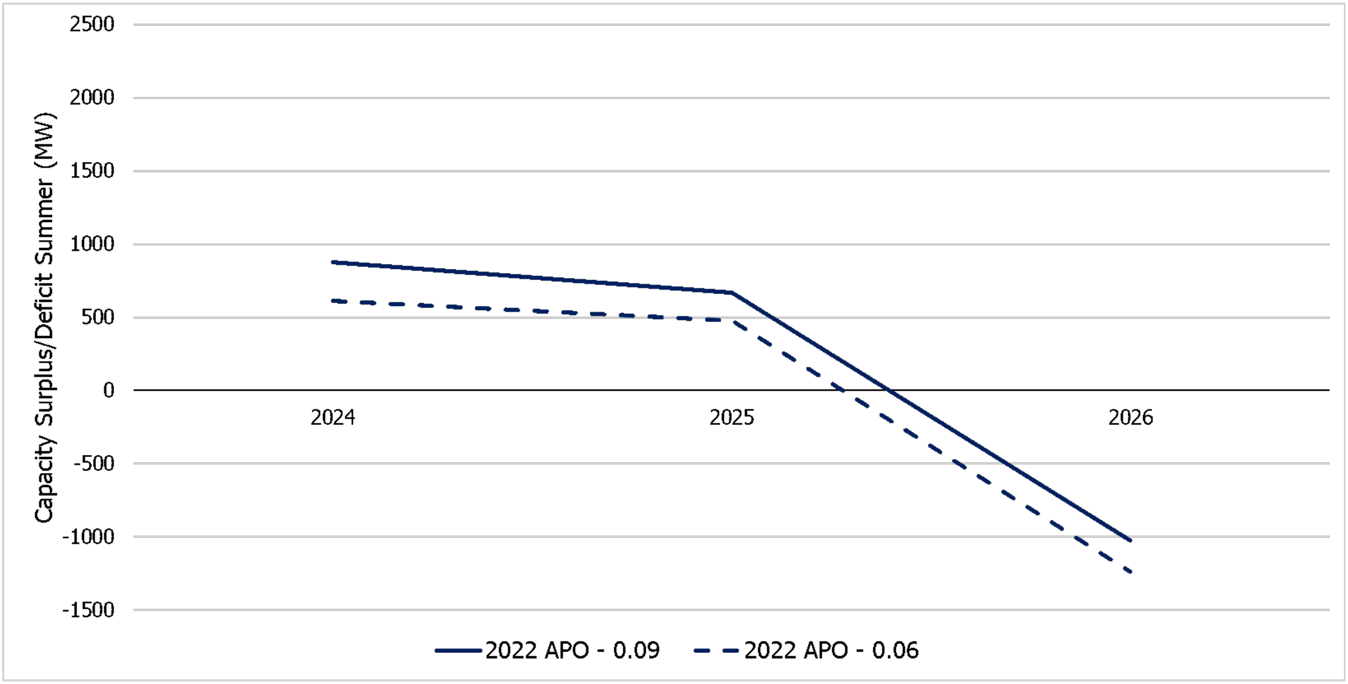
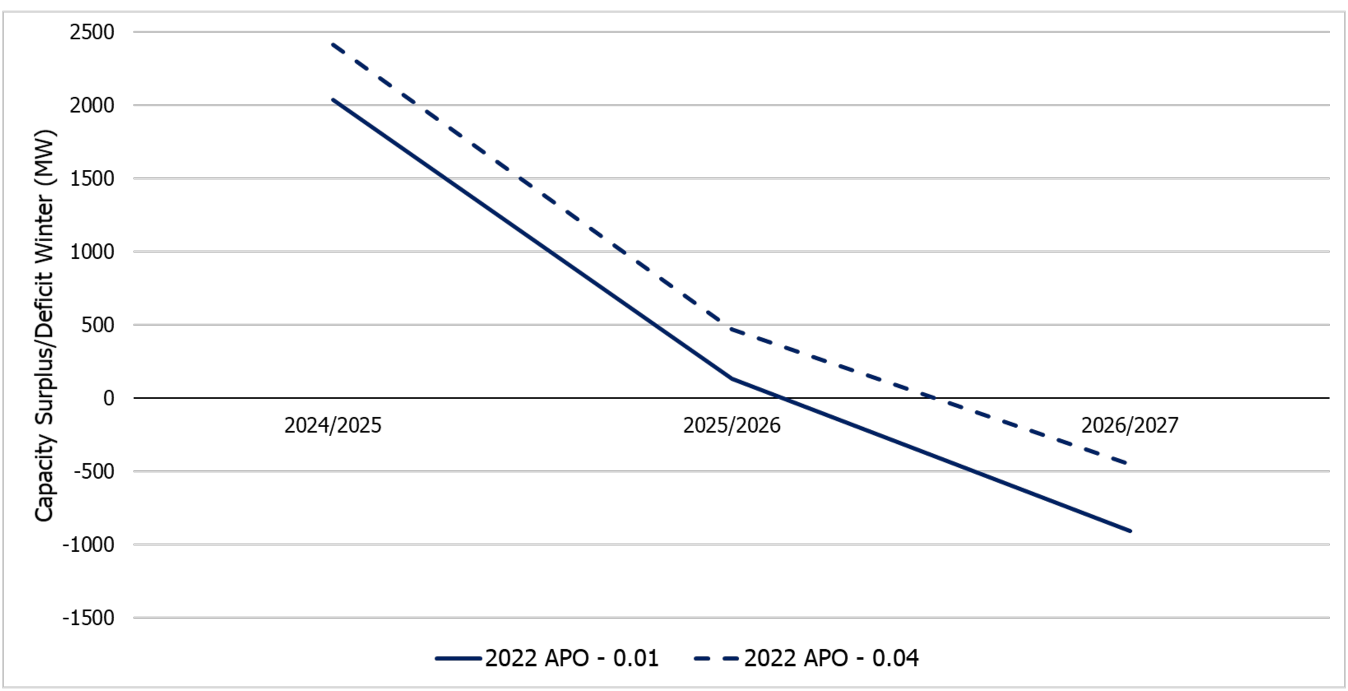


Figure 6 | Impact of 2022 APO LOLE Allocation vs. Long-Run Assumption, Winter



2.3 Capacity from Hydro Quebec per Ontario-Hydro Quebec Trade Agreement

Ontario currently provides 500 MW of capacity to Hydro Quebec (HQ) during Quebec's winter peak periods. This agreement is in place until winter 2022/23. The winter capacity adequacy assessments shown in the APO no longer reflects this amount as the start of the study year is 2024.

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 2030. It would reduce the need to acquire capacity in the amount/year exercised. Ontario expects to call on that option in the summer of 2026 or 2027.

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 minima and maxima for select future years are shown for the summer season demand in Table 3 and for winter in Table 4. 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).

Table 3 | Incremental Summer Zonal Constraints, Scenario 1 without the 2022 AAR forward guidance CA targets (MW)

Zone	2024 Min	2024 Max	2025 Min	2025 Max	2026 Min	2026 Max
Bruce	0	N/A	0	N/A	0	N/A
East	0	N/A	0	N/A	0	N/A
Essa	0	N/A	0	N/A	0	N/A
Niagara	0	1,000	0	1,050	0	1,100
Northeast	0	50	0	50	0	50
Northwest	0	50	0	50	0	50
Ottawa	0	N/A	0	N/A	0	N/A
Southwest	0	N/A	0	2,300	0	1,800
Toronto	0	N/A	0	N/A	0	N/A
West	0	600	0	750	0	450
Toronto+Essa+East+Ottawa	0	N/A	0	N/A	0	N/A
Northeast+Northwest	0	50	0	50	0	50

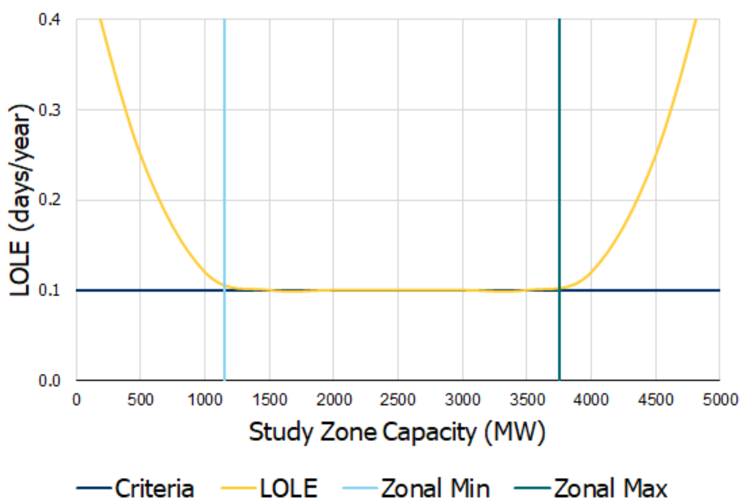
Table 4 | Incremental Winter Zonal Constraints, Scenario 1 without the 2022 AAR forward guidance CA targets (MW)

Zone	2024/2025 Min	2024/2025 Max	2025/2026 Min	2025/2026 Max
Bruce	0	N/A	0	N/A
East	0	N/A	0	N/A
Essa	0	N/A	0	N/A
Niagara	0	900	0	850
Northeast	0	250	0	100
Northwest	0	250	0	250
Ottawa	0	N/A	0	N/A
Southwest	0	500	0	N/A
Toronto	0	N/A	0	N/A
West	0	600	0	750
Toronto+Essa+East+Ottawa	0	N/A	0	N/A
Northeast+Northwest	0	250	0	100

The methodology for establishing the transmission transfer capabilities is provided in the Transmission Outlook Methodology. These capabilities can have an impact on the extent to which a resource can contribute towards adequacy. The 0.1 days/year LOLE criteria 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.

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

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 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.

Tables 5 and 6 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 5| Zones and Defining Interfaces[2]

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

[2] A description of the interfaces included is provided in the APO modules.

Table 6| Transmission Transfer Capabilities (2024-2043)

Interface	Positive Direction Interface Transfer Capability (MW)	Negative Direction Interface Transfer Capability (MW)
E-W	500	350
FABC	9,999	9,999
BLIP	Ranges from 2,020 to 3,700	Ranges from 570 to 1,550
QFW	2,400	9,999
FETT	Ranges from 4,700 to 7,350	9,999
TEC	9,999	9,999
FIO	2,950	9,999
FN/FS	1,850	1,750
CLAN	9,999	9,999

3. Energy Adequacy Outlook

3.1 Exchange Rate and Ontario Natural Gas Price Forecast

The annual exchange rate and natural gas fuel forecast assumption is from the Sproule Price Outlook released May 12, 2022.[3] Table 7 provides a summary of the forecast exchange rate and natural gas prices.

Table 7 | Henry Hub, Dawn Natural Gas Prices and Exchange Rate

Year	Henry Hub ($USD/MMBtu)	USD/CAD Exchange Rate	Dawn ($CAD/MMbtu)
2024 and onward	3.12	0.80	3.75

3.2 Discussion

Overall, the trends in the energy outlook in the 2022 APO are consistent with previous outlooks. While Pickering retirement drives year over year trends of declining surplus baseload generation (SBG), 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 due to lowered OPG hydroelectric production in line with 2022 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.

Fuel forecast changes are seen to have an impact on import and export flows. In addition to demand and supply drivers, fuel/carbon price differentials add uncertainties to the amount and direction of electricity trade and the extent to which Ontario's gas fleet is dispatched to meet Ontario's demand versus export demand.

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.

[3] More information on this report can be found on Sproule's website.

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