NPCC 2020 Ontario Interim Review of Resource Adequacy

FOR THE PERIOD FROM 2021 TO 2023

APPROVED BY THE RCC
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Document Change History

Issue	Reason for Issue	Date
1.0	For submission to CP-8	October 14, 2020
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1 EXECUTIVE SUMMARY

The Independent Electricity System Operator (IESO) submits this assessment of resource adequacy for the Ontario Area in accordance with the Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory #1, "Design and Operation of the Bulk Power System."

The 2020 Interim Review of Resource Adequacy covers the study period from 2021 through 2023 and identifies changes in assumptions from the 2018 Comprehensive Review, including changes to facilities and system conditions, generation resources' availability, demand forecast and the impact of these changes on the overall reliability of the Ontario electricity system.

The results presented in Table 1 conclude that Ontario will be able to meet the NPCC resource adequacy criterion that limits the loss of load expectation (LOLE) to no more than 0.1 days/year for all years within the study period (2021 to 2023) for both demand scenarios.

For the median demand growth scenario, the NPCC criterion is satisfied for 2021 and 2022 forecast years with existing and planned resources. For the 2023 forecast year, existing and planned resources are not sufficient to satisfy the adequacy criterion absent the use of Emergency Operating Procedures (EOP). The IESO has identified a resource adequacy need for this year and expects to acquire resources to meet this need.

For the high demand growth scenario, the NPCC criterion is met for 2021 forecast year with existing and planned resources. For 2022, the invoking of EOP would be required to meet the LOLE criterion. For 2023, existing and planned resources are not sufficient to satisfy the adequacy criterion absent the use of EOP and tie benefits..

Table 1 Annual LOLE Values - Median and High Demand Forecast

Scenario	EOPs	Tie Benefits (MW)	LOLE [days/year]		
			2021	2022	2023
Median	No	0	0.018	0.058	0.226
	Yes	0	-	-	0.093
High	No	0	0.039	0.128	0.434
	Yes	0	-	0.042	0.172
	Yes	400	-	-	0.101

In all cases, the need can also be addressed in whole or in part through tie benefits. The IESO's Reliability Standards Review initiative is currently looking at the use of non-firm imports to meet future adequacy requirements.

2 TABLE OF CONTENTS

2.1 List of Tables

3 CHANGES IN ASSUMPTION FROM 2018 COMPREHENSIVE REVIEW

3.1 Demand Forecast

Table 3.1 compares the summer peak demand forecasts for the 2020 Interim Review with the 2018 Comprehensive Review under median and high demand growth scenarios for the forecast period of January 1, 2021 to December 31, 2023. Although point forecasts are presented for both the median and high demand growth scenarios, each scenario has an associated "uncertainty" distribution which recognizes the variability of demand due to weather volatility.

Table 3.1 Comparison of Demand Forecasts

Year	Normal Weather Summer Peak					
	Median Demand Growth			High Demand Growth		
	2018 Review	2020 Review	Difference	2018 Review	2020 Review	Difference
2021	22,155	22,281	126	23,750	22,673	-1,077
2022	22,098	22,503	405	24,308	23,051	-1,257
2023	22,139	22,733	594	24,796	23,248	-1,548
Annual Growth Rate	-0.04%	1.01%		2.18%	1.26%	

Since the 2018 Comprehensive Review the onset of the COVID-19 global pandemic has caused sudden and unprecedented levels of uncertainty in virtually all facets of society but especially in economic terms and consequently electricity demand. Market sectors have been structurally affected and the levels of permanency have yet to be determined. Residential electricity demand has increased due to higher levels of daily occupancy from working-from-home, sheltering-in-place/social-distancing/quarantining, and/or illness recovery; impacting most end-uses including HVAC, food preparation and computers, televisions and electronics. The commercial sector has been impacted by social distancing especially in the retail, restaurants, offices, hospitality and educational sub-sectors. Industrial sector output has been disrupted on some levels. Electric vehicle electricity demand has decreased due to a combination of lower sales and less distance travelled. Rail transit electrification project completion timelines have been extended. In terms of the 2020 Review Growth Scenarios, the median growth scenario reflects assumptions of a deep economic recession in year 2020-2021 and a slow, multi-year recovery, electricity demand returning to pre-pandemic year 2019 levels by the end of 2025, and the high growth scenario reflects assumptions of a shallow economic recession in year 2020 and a relatively rapid recovery, with electricity demand returning to pre-pandemic year 2019 levels by the end of 2022. These forecasts were developed in the April-May 2020 time-frame based on limited empirical data of pandemic affects, magnitude and persistence, economic assessments and effects on electricity demand.

Notwithstanding pandemic impacts, pre-pandemic electricity sector outlooks forecasted very slow demand growth over the forecast period. Major updates since the 2018 Comprehensive Review include:

- electricity conservation program framework savings projections have been updated to reflect policy changes in Ontario, specifically applying to the period beyond 2020 in which projected savings have been significantly reduced. Since the completion of the forecast, the IESO has received committed energy efficiency framework policy for the 2021-2024 period. The demand reduction effects of the updated policy were not incorporated into this demand forecast.
- growth in embedded[1] generation has plateaued and a number of projects have been terminated by government directive. Further, Ontario has no policy framework for contracting embedded generation moving forward.
- when 2019 actual historical demand data was included as a baseline for in the updated electricity demand forecast for the 2020 Review, this resulted in resetting the starting point of the forecast thus having an impact on the ensuing years' demand levels. The resetting of the starting point resulted in higher energy demand compared to that of the 2018 Comprehensive Review.

Drivers impact on grid demand

In the median growth scenario, summer peak demand is expected to increase over the forecast period compared to the 2018 Review. This growth is attributable to:

- new agricultural sector greenhouse load growth in the West Zone;
- recovery in the state of the economy and electricity demand in years 2021 to 2023 covered in this Interim Review, given the impact of COVID-19 pandemic and resulting economic downturn in years 2020-2021 which was not included in the 2018 Comprehensive Review, primarily in commercial sector deeply affected by social-distancing practices and electric vehicle electricity demand; and
- elimination in the growth of load modifiers such as conservation program framework electricity savings, Industrial Conservation Initiative[2] and embedded generation.

The load modifiers which act to decrease grid-demand were included in the 2018 Review Median Growth Scenario.

[1] Embedded Generation refers to distributed generation that does not participate in the IESO-Administered Market. Outputs from these resources are estimated using metered data from generators greater than 5 MW, monthly energy estimates from local distribution companies and contract data for those that have contracts with the IESO. The output is then netted from the demand forecast used in this study.

[2] Industrial Conservation Initiative (ICI) is a form of demand response that incents participating customers to reduce demand during peak periods. Customers who participate in the ICI, referred to as Class A, pay global adjustment costs based on their percentage contribution to the top five peak Ontario demand hours over a 12-month base period.

In the 2020 Review, High Growth Scenario summer peak demands are slightly higher than the Median Growth Scenario due to:

- higher baseline levels (as of December 31, 2020); and
- higher absolute electricity demand growth and electricity demand growth rates compared to the Median Growth Scenario, generally in all sectors, but especially due to the commercial sector rebounding significantly stronger in the first year of the forecast period of year 2021;

Summer peak demands in the 2020 Review High Growth Scenario are lower than the corresponding peak demands in the 2018 Review High Growth Scenario due to persisting pandemic impacts since year 2020.

3.2 Resource Forecast

Table 3.2 compares the capacity of supply resources at the time of the summer peak for the current 2020 Interim Review with the 2018 Comprehensive Review. This 2020 review assumes resource availability based on the available information for existing and planned resources. These values do not include distributed energy resources (DERs), except for those that participate in the IESO-administered markets.

Available resources are determined based on the following:

1) Historical median contribution of hydroelectric resources during peak demand hours;
2) Total capacity available from thermal units (nuclear, gas, oil and biofuel) after discounting for planned outages and seasonal derating;
3) Historical median contribution of wind and solar resources during the peak demand hours; and
4) Projected effective capacity of the following demand-side resources: Demand Response (DR) and Dispatchable Loads.

Table 3.2 shows how the available capacity of supply resources has changed compared to the 2018 Comprehensive Review.

Table 3.2 Comparison of Available Resource Forecasts (MW)

Year	Available Resources at Summer Peak		
	2018 Review	2020 Review	Difference
2021	25,362	26,834	1,472
2022	26,076	27,236	1,160
2023	25,638	25,650	12

The differences in available resources between the 2020 Interim Review and the 2018 Comprehensive Review are primarily due to:

- Changes to nuclear outages and refurbishment schedule.
- Pickering retirement delayed to 2024-25 from 2022-24.

- Changes to hydroelectric and demand response capacity value calculation methodologies.

Table 3.3 lists the major projects expected over the study period.

Table 3.3 Major Projects

Project Name	Fuel Type	Capacity (MW)
Henvey Inlet Wind Farm	Wind	300
Romney Wind Energy Centre	Wind	60

3.3 Transfer Capabilities and Fuel Supply

Northwestern Ontario is connected to the rest of the province by the double-circuit, 230 kV East–West Tie. Additional capacity is required to maintain reliable supply to this area under the wide range of possible system conditions. A new 450 km long 230 kV double-circuit transmission line is planned to come into service in 2022 to reinforce the connection of Northwestern Ontario to the rest of the provincial grid, providing reliable and cost-effective long-term supply to this area.

Supply to Ontario's gas fleet is robust and supported by significant firm supply and transportation contracts. Considering Ontario's gas-pipeline infrastructure and history of coordinated gas-electric operations, it is not expected that Onatrio's gas generators will experience any material fuel supply constraints within the study period.

3.4 Emergency Operating Procedures (EOP)

EOP are used in the resource adequacy assessment as described in NPCC Directory 1, if the existing and planned resources are not sufficient to meet the LOLE criterion. Table 3.4 summarizes the assumptions regarding the demand relief from EOP used when required in this study. For this study, all EOP are applied in one block.

Table 3.4 Emergency Operating Procedure Assumptions

EOP Measure	EOP Impact % of Demand
Public Appeals	1.00
Voltage Reductions	1.94
Aggregated Net Impact	**2.94**

The analysis does not impose a requirement to provide for Operating Reserve (OR) since only loss of load events are being considered. Therefore, the net impact of applying EOP in the analysis excludes relaxation of OR requirements.

3.5 Equivalent Forced Outage Rates (EFORd)

The IESO updated the EFORd in the 2020 Interim Review. EFORd for nuclear units and biofuel units are lower compared to 2018 Comprehensive Review.

Table 3.5 Ontario's EFORd

Fuel Type	EFORd Weighted Average	EFORd Range
Nuclear	4.8%	2.3 - 6.3 %
Gas/Oil	10.7%	0.1 - 29.1 %
Biofuel	6.6%	2.7 - 8.1 %

3.6 Firm Transactions: Purchase and Sale of Capacity

As part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter from December to March, until 2023.

Ontario can call on 500 MW of capacity during summer months from June to September before 2030, based on the province's need. The IESO did not make use of this firm import in the assessments.

4 RESOURCE ADEQUACY ASSESSMENT

The 2020 Interim Review of Resource Adequacy for Ontario is submitted to demonstrate compliance with the resource adequacy requirements of NPCC Regional Reliability Reference Directory #1, "*Design and Operation of the Bulk Power System.*" This report was prepared by the Independent Electricity System Operator (IESO) in its role as the Planning Coordinator for Ontario.

The 2020 Interim Review of Resource Adequacy covers the study period from 2021 through 2023. The assessment is based on information available to the IESO as of July 2020.

The probabilistic resource adequacy assessment is performed using GE-MARS. The following inputs are used:

- Median and high demand growth forecast and load forecast uncertainty (LFU);
- Forecast of available resources and EOP;
- Planned outage schedules submitted by market participants;
- Equivalent Forced Outage Rates on Demand (EFORd) for thermal units derived using historical generator performance data; and
- Transmission limits of major interfaces connecting different zones.

4.1 Assessment Results

The results for the median and high demand growth scenarios are presented in Table 4 and show that the NPCC LOLE criterion is satisfied for the forecasted scenarios.

For the median demand growth scenario, the NPCC criterion is satisfied for 2021 and 2022 forecast years with existing and planned resources. For the 2023 forecast year, existing and planned resources are not sufficient to satisfy the adequacy criterion absent the use of EOP. The IESO has identified a resource adequacy need for this year and expects to acquire resources to meet this need.

For the high demand growth scenario, the NPCC criterion is met for 2021 forecast year with existing and planned resources. For 2022, the invoking of EOP would be required to meet the LOLE criterion. For 2023, existing and planned resources are not sufficient to satisfy the adequacy criterion absent the use of EOP and tie benefits.

Ontario is interconnectied with Manitoba, Minnesota, Quebec, New York and Michigan and the tie-benefits are used as needed. The most recent NPCC Tie Benefits study[3] indicates a range of estimated tie benefit potential of 3,663 MW to 3,789 MW.

The Capacity Auction in December 2020 will have a target capacity of 700 MW for summer 2021. The resources that will compete in that auction are demand response, off-

[3] https://www.npcc.org/content/docs/public/library/publications/tie-benefits/rcc-approved-2019-december-16-tie-benefit-report.pdf

contract generators, system-backed capacity imports and storage facilities. The IESO intends to acquire future capacity through capacity auctions or other acquisition tools.

Table 4 Annual LOLE Values, Median and High Demand Forecast

Scenario	EOPs	Tie Benefits (MW)	LOLE [days/year]		
			2021	2022	2023
Median	No	0	0.018	0.058	0.226
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