NPCC 2021 Ontario Comprehensive Review of Resource Adequacy

For the period from 2022 to 2026

Approved by the RCC on November 30, 2021

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Powering Tomorrow.

Executive Summary

The Independent Electricity System Operator (IESO) submits this assessment of resource adequacy for the Ontario Area to comply with the Reliability Assessment Program established by the Northeast Power Coordinating Council (NPCC). The 2021 Comprehensive Review of Resource Adequacy covers the study period from 2022 through 2026 and supersedes previous reviews.

Since the last Comprehensive Review conducted in 2018, 1,701 megawatts (MW) of new generation capacity has been installed in Ontario. The installed capacity additions include 994 MW of gas, 573 MW of wind, 98 MW of solar and 36 MW of hydroelectric generation. Another 160 MW of generating resource capacity is planned to come into service, while 3,094 MW of capacity is expected to retire over the horizon of this study.

In December 2020, the IESO held its first capacity auction, securing 992 MW of capacity from resources including generation, imports, storage, and DR. Annual capacity auctions will be held to procure resources to meet short-term capacity needs.

The IESO determines Ontario's level of resource adequacy using the General Electric Multi-Area Reliability Simulation (GE-MARS) program and applies the NPCC criterion that requires a loss of load expectation (LOLE) value of no more than 0.1 days/year.

The results presented in the tables below show that the NPCC LOLE criterion is satisfied for the Median Demand Growth scenario. To satisfy the NPCC criterion, the use of 70 MW of tie benefits will be required for 2022. The NPCC criterion is satisfied for 2023 to 2025 with existing and planned resources. For 2026, the use of 1,400 MW of tie benefits will be required to satisfy the criterion.

For the High Demand Growth scenario, the NPCC criterion is satisfied for 2023 and 2024 with existing and planned resources. For 2022, 2025 and 2026 tie benefits of up to 70, 1,400 and 3,400 MW respectively are required to meet the LOLE criterion.

The IESO's Resource Adequacy Framework comprises a suite of mechanisms to procure a portfolio of reliable, competitive and cost-effective supply. The annual capacity auction held in December fulfills the short-term operational planning timeframe (one-year) capacity needs. The IESO will evolve and expand the capacity auction by launching a series of competitive procurements to secure resources to meet adequacy need over the longer term.

Annual LOLE Values for Median Demand Forecast

	2022	2023	2024	2025	2026
Median Demand Forecast (MW)	22,580	22,110	21,772	22,033	22,348
Available Resources (MW)	27,772	26,884	26,396	26,768	24,664
Tie Benefits (MW)	70	0	0	0	1,400
LOLE (days/year)	0.10	0.07	0.06	0.07	0.10

Annual LOLE Values for High Demand Forecast

	2022	2023	2024	2025	2026
High Demand Forecast (MW)	22,580	22,454	22,459	22,686	22,934
Available Resources (MW)	27,772	26,884	26,396	26,768	24,664
Tie Benefits (MW)	70	0	0	1,400	3,400
LOLE (days/year)	0.10	0.08	0.03	0.10	0.10

Major assumptions used in the assessment are summarized below.

Major Assumptions

Assumption	Description
Adequacy Criterion	NPCC LOLE requirement of not more than 0.1 days/year
Study Period	January 1, 2022 to December 31, 2026
Reliability Model	GE's MARS program
Load Model	Hourly loads with monthly forecast uncertainty
Median Demand Growth Rate	-0.26% per annum (average)
High Demand Growth Rate	+1.05% per annum (average)
Capacity Additions	160 MW by end of 2021

Assumption	Description
Confirmed Generating Capacity Retirements	1,030 MW by end of 2024 and 2,064 MW by end of 2025
Internal Transmission Constraints	10-zone transmission model with IESO's normal system operating security limits applied on interfaces between zones
Firm Export Contracts	500 MW to Quebec in winter months, December to March, until 2023
Non-firm Imports	250 MW
Tie Benefits (i.e. non-firm imports)	As needed, in addition to 250 MW
Emergency Operating Procedures	Aggregated net impact of 2.94% of demand
Unit Availability	Planned outages are based on outage submissions from market participants. Nuclear refurbishment schedule is based on information provided by nuclear operators. Equivalent Forced Outage Rates on Demand (EFORd) are derived from a rolling five-year history of actual forced outages and forced derates.
Energy Efficiency and Embedded Generation	Used as load modifiers and reflected in the demand forecast
Demand Management	Used as resources

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1. Introduction

The 2021 Comprehensive Review of Resource Adequacy for Ontario is submitted to the Northeast Power Coordinating Council (NPCC) in accordance with Appendix D of the 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 capacity as the Planning Coordinator for Ontario.

The 2021 Comprehensive Review of Resource Adequacy covers the study period from 2022 through 2026 and supersedes previous reviews. The previous Comprehensive Review was approved by the NPCC Reliability Coordinating Committee in December 2018 and covered the 2019 to 2023 period. Interim Reviews were completed in 2019 and 2020.

This review is based on the 2020 Annual Planning Outlook published in December 2020.

1.1 Comparison of 2021 vs. 2018 Comprehensive Review

1.1.1 Demand Forecast

Table 1-1, 1-2, 1-3 and 1-4 show a comparison between the peak demand forecasts for the 2018 Comprehensive Review and the 2021 Comprehensive Review under Median and High Demand Growth scenarios for the overlapping years. These tables also present peak demand forecasts for the years 2022 to 2026.

Table 1-1 | Comparison of Demand Forecasts: Normal Weather Summer Peak (MW) for Median Demand Growth

Year	2018 Review	2021 Review	Difference
2022	22,098	22,580	482
2023	22,139	22,110	-29
2024		21,772	
2025		22,033	
2026		22,348	
Annual Growth Rate	0.19%	-0.26%	

Table 1-2 | Comparison of Demand Forecasts: Normal Weather Summer Peak (MW) for High Demand Growth

Year	2018 Review	2021 Review	Difference
2022	24,308	22,580	-1,728
2023	24,796	22,454	-2,342
2024		22,459	
2025		22,686	
2026		22,934	
Annual Growth Rate	2.01%	1.05%	

Table 1-3 | Comparison of Demand Forecasts: Normal Weather Winter Peak (MW) for Median Demand Growth

Year	2018 Review	2021 Review	Difference
2022	21,165	21,033	-132
2023	21,273	21,357	84
2024		21,681	
2025		21,972	
2026		22,348	
Annual Growth Rate	0.51%	1.53%	

Table 1-4 | Comparison of Demand Forecasts: Normal Weather Winter Peak (MW) for High Demand Growth

Year	2018 Review	2021 Review	Difference
2022	23,282	21,361	-1,921
2023	23,826	21,759	-2,067
2024		22,485	
2025		22,697	
2026		22,950	
Annual Growth Rate	2.34%	1.03%	

Over the forecast period, Ontario peak demand is expected to decrease by about 0.26% annually under the median demand forecast, and increase by about 1.05% annually under the high demand forecast.

The peak demands are shaped by two competing factors: those that increase the demand for electricity and those that act to reduce the requirement for grid supplied electricity. The increased demand for electricity is being driven by population growth, economic expansion and increased penetration of electric devices. Offsetting the growth are reductions from conservation energy efficiency and codes and standards (C&S) savings, electricity price responsiveness, and increased output by embedded generation[1].

Recent policy changes have led to lower committed energy efficiency savings and when combined with the lower growth rates of renewable embedded generation, lessening much of the downward pressure on forecast peak demands going forward. Going forward increased adoption of electric vehicles and trends to decarbonize should provide long term growth to Ontario's electricity sector.

Since the 2018 Comprehensive Review, the economy's trajectory has been impacted by the global pandemic. Over the first half of 2020, the economy was in turmoil as supply disruptions and public policy measures in response to the pandemic (shut downs) caused demand to fall dramatically. As we moved to the latter half of 2020 the economy settled into a pattern that has held throughout 2021, with the industrial and other primary sectors returning to pre-COVID levels. The economic impacts of the pandemic have remained in the service sectors – particularly hospitality, accomodations and restaurants – which have a very small electricity impact. Although the economy remains in flux as the pandemic continues, electricity demand has increased throughout 2021 and is expected to increase over the forecast horizon. This is due to post pandemic pent-up demand and increased electrification in an effort to reduce carbon emissions.

The system remains weather sensitive as a large portion of the workforce continues to work from home. There is an expectation that work from home or remote working will persist post-pandemic, albeit to a lesser extent, leaving the system more weather sensitive. This has a significant impact on the summer peak due to residential air conditioning load. The winter peak is less impacted as changes in residential loads have less of an influence on winter peak demand.

Over the forecast horizon, the annual peaks are expected to fall in the near term before increasing in the latter half of the forecast under the Median Demand Growth scenario. This is partly due to the workforce migrating back to the office and peaks declining. Later in the forecast peaks will increase due to broader electrification as an effort to reduce carbon emissions.

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[1] *Contracted Embedded Generation (or Embedded Generation* for short) refers to generators that supply electricity to local distribution systems, and have power purchase agreements (contracts) with the IESO. They do not participate in the IESO-administered market, but rather reduce demand on the transmission grid. Since these generators have contracts with the IESO, the IESO can track their existing and future capacities.

Under the High Demand Growth scenario the winter and summer peaks follow a similar pattern to the Median Growth, as they are flat or declining in the near term before accelerating over the remainder of the forecast horizon.
The High Growth scenario is propelled by increased penetration of electric vehicles and strong growth in the mining sector.

In both the Median and High Growth forecasts, the effect of price-responsive loads reducing consumption on their own under the Industrial Conservation Initiative (ICI) [2] are included. An estimate of an additional 1,300 MW of price-responsive demand is incorporated in the demand forecast. This is a result of price-responsive loads reducing on their own under the ICI.

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.

1.1.2 Resources Forecast

Tables 1-5 and 1-6 compare the capacity of supply resources at the time of the summer and winter peak respectively for the current 2021 Comprehensive Review with the 2018 Comprehensive Review. This 2021 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.

Table 1-5 | Comparison of Available Resources Forecasts (MW) at Summer Peak

Year	2018 Review	2021 Review	Difference
2022	26,076	27,722	1,696
2023	25,638	26,884	1,246
2024		26,396	
2025		26,728	
2026		24,664	

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 (i.e., peak demand factor) over a 12-month base period.

Table 1-6 | Comparison of Available Resources Forecasts (MW) at Winter Peak

Year	2018 Review	2021 Review	Difference
2022	29,191	28,402	-789
2023	27,846	27,387	-459
2024		29,113	
2025		28,591	
2026		29,686	

The differences in available resources between the 2021 Comprehensive Review and the 2018 Comprehensive Review, for overlapping periods, are primarily due to the factors below.

- Changes to nuclear outages and refurbishment schedules
- Pickering A NGS (1,030 MW) retirement delayed from 2022 to 2024
- Small changes to hydroelectric and demand response available capacity values at peak

2. Resource Adequacy Criterion

2.1 Criterion Statement and Application

The IESO uses the NPCC resource adequacy criterion from Directory #1 to assess the adequacy of resources in the Ontario Planning Coordinator Area:

> "R4 Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.
>
> R4.1 Make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

The IESO uses the Load Forecast Uncertainty (LFU) associated with the normal weather demand forecast for this assessment, which captures the variability of the weather scenario. The LFU is modelled through the use of probability distribution.
Scheduled and forced outages/deratings to Ontario generators are assessed by considering submissions by generator owners, actual historic outage observations and more generalized outage factors.

Ontario's interconnections with Manitoba, Minnesota, Quebec, New York and Michigan and the resultant tie-benefits are used as needed, within the constraints of the inter-tie transfer capabilities and the most recent NPCC Tie Benefits Study[3].

Emergency operating procedures (EOPs) are used in the resource adequacy assessment if the existing and planned resources are not sufficient to meet the LOLE criterion. Table 2-1 summarizes the assumptions regarding the load relief from EOPs used when required in this study. For this study, all EOPs are applied in one block.

[3] NPCC Review of Interconnection Assistance Reliability Benefits, December 2019

Table 2-1 | Emergency Operating Procedure Assumptions

EOP Measure	EOP Impact (% of Demand)
Public Appeals	1.00
No 30-minute OR (473 MW)	0*
No 10-minute OR (945 MW)	0*
Voltage Reductions	1.94
Aggregated Net Impact	**2.94**

*Although 30-minute and 10-minute operating reserve (OR) are included in this list of EOPs, the analysis does not impose a requirement to provide for OR since only loss of load events are being considered. Therefore, the net benefit of applying EOPs in the analysis excludes relaxation of OR requirements.

2.2 Resource Requirements to Meet the Criteria

The Ontario resource mix is well-balanced with a variety of fuel types. A diverse generation mix is important for resource adequacy and market efficiency, because it provides dispatch flexibility and reduced vulnerability to fuel supply contingencies.
The expected installed capacity mix at the time of the summer peak for each year of the study period is listed in Table 2-2. Tables 2-3 and 2-4 show installed capacity summer peaks and winter peaks for the study period. These values do not include generators that operate within local distribution service areas (embedded generation), except for those that participate in the IESO-administered market. The resource forecast is based on information from the 2020 Annual Planning Outlook and the consideration of 250 MW of non-firm imports.

Table 2-2 | Ontario Expected Installed Capacity Mix by Fuel Type (%) at Peak Day

Fuel Type	2022	2023	2024	2025	2026
Nuclear	33.0%	33.0%	33.0%	31.2%	27.3%
Gas / Oil	26.5%	26.5%	26.5%	27.2%	28.8%
Hydroelectric	22.5%	22.5%	22.5%	23.1%	24.4%
Wind	12.5%	12.5%	12.5%	12.8%	13.5%
Biofuel	0.7%	0.7%	0.7%	0.8%	0.8%
Solar	1.2%	1.2%	1.2%	1.2%	1.3%
Demand Side Management	3.6%	3.6%	3.6%	3.7%	3.9%

Table 2-3 | Installed Capacity at Summer Peak (MW)

Fuel Type	2022	2023	2024	2025	2026
Nuclear	13,089	13,089	13,089	12,059	9,995
Gas / Oil	10,515	10,515	10,515	10,515	10,515
Hydroelectric	8,918	8,918	8,918	8,918	8,918
Wind	4,943	4,943	4,943	4,943	4,943
Biofuel	296	296	296	296	296
Solar	478	478	478	478	478
Demand Side Management	1,422	1,422	1,422	1,422	1,422
Total	**39,661**	**39,661**	**39,661**	**38,631**	**36,567**

Table 2-4 | Installed Capacity at Winter Peak (MW)

Fuel Type	2022	2023	2024	2025	2026
Nuclear	13,089	13,089	12,574	12,059	9,995
Gas / Oil	10,515	10,515	10,515	10,515	10,515
Hydroelectric	8,918	8,918	8,918	8,918	8,918
Wind	4,943	4,943	4,943	4,943	4,943
Biofuel	296	296	296	296	296
Solar	478	478	478	478	478
Demand Side Management	1,422	1,422	1,422	1,422	1,422
Total	**39,661**	**39,661**	**39,146**	**38,631**	**36,567**

2.2.1 Resource Availability Considerations

There are several modelling techniques employed to mitigate reliability impacts resulting from the proposed resource availability.

For existing thermal units EFORd for existing units are derived using a rolling five-year history of actual forced outages and derates. This ensures that nuclear, gas/oil and biofuel units' random derates and forced unavailability are represented in the MARS model.

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are based on historical production and contribution values.

By the end of 2023, about 4,947 MW of grid-connected wind-powered generation is expected to be in-service in Ontario. The wind generation capacity contribution is discounted from the nameplate value and represented in the MARS study as a probabilistic model developed on a zonal basis.

There are two main demand management mechanisms in Ontario: Demand Response (DR) and Dispatchable Loads. In order to reflect reality of demand management programs, the IESO uses effective demand management values instead of gross values. The effective values are based on historical behaviours.

Further details of capacity mix modelling and DR are provided in section 3.3 and Appendix A.3 and A.4.

Table 2-5 and Table 2-6 show expected available capacity at summer and winter peak for the study period. These values do not include generators that operate within local distribution service areas (embedded generation), except for those that participate in the IESO-administered market.

Resources considered in this review include all existing and planned resources expected to be in service during the review period. Planned resources include all committed projects under contract with the IESO.

Available resources are determined based on the following:

1. Historical median contribution of hydro resources during peak demand hours;
2. Total capacity available from thermal units (nuclear, gas, oil and biofuel) after discounting for seasonal derating;
3. Historical median contribution of wind and solar resources during the peak demand hours; and
4. Effective capacity of projected demand measure resources: DR and Dispatchable Loads
5. Outage schedules, including potential outages over the seasonal peak. The majority of outages that occur over the peak period are due to the refurbishment of nuclear generators, whose outages last two to three years per generator. The nuclear refurbishment schedule is shown in the Figure 2-1.

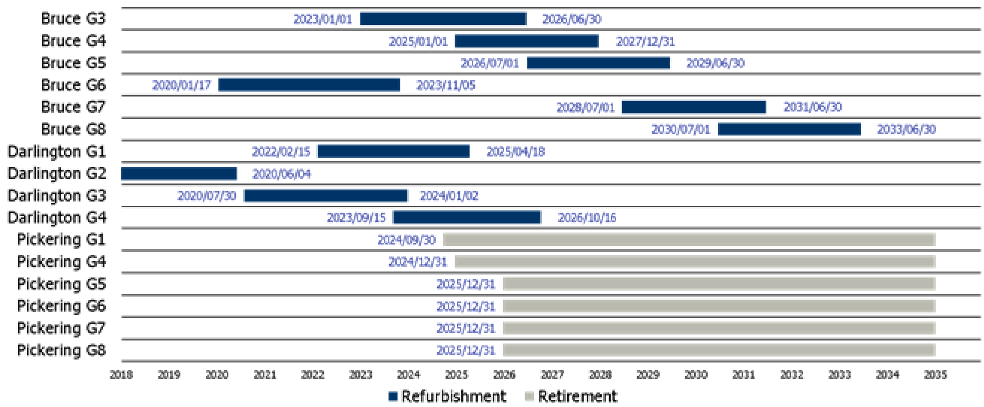
Table 2-5 | Available Capacity at Summer Peak (MW)

Fuel Type	2022	2023	2024	2025	2026
Nuclear	10,404	9,626	9,138	9,510	7,406
Gas / Oil*	9,440	9,440	9,440	9,440	9,440
Hydroelectric	6,202	6,202	6,202	6,202	6,202
Wind	751	751	751	751	751
Biofuel	288	288	288	288	288
Solar	66	66	66	66	66
DR	621	511	511	511	511
Firm Imports (+)/Exports (-)	0	0	0	0	0
Total	**27,722**	**26,884**	**26,396**	**26,768**	**24,664**

Table 2-6 | Available Capacity at Winter Peak (MW)

Fuel Type	2022	2023	2024	2025	2026
Nuclear	8,943	7,428	9,154	8,632	9,727
Gas / Oil	10,180	10,180	10,180	10,180	10,180
Hydroelectric	6,774	6,774	6,774	6,774	6,774
Wind	1,948	1,948	1,948	1,948	1,948
Biofuel	288	288	288	288	288
Solar	0	0	0	0	0
DR	770	770	770	770	770
Firm Imports (+)/Exports (-)	-500	0	0	0	0
Total	**28,402**	**27,387**	**29,113**	**28,591**	**29,686**

Figure 2-1 | Nuclear Refurbishment and Projected End of Life Schedule



2.2.2 Firm Sales and Purchases

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 and Quebec will provide Ontario a total of 500 MW of capacity in the summer months (June to September) to be exercised, when needed, any time before September 30, 2030. This summer capacity was not relied upon in this Comprehensive Review.

2.2.3 Non-firm Imports

The IESO is including non-firm imports in resource adequacy assessments starting in 2021. The decision to use non-firm imports resulted from our Reliability Standards Review Engagement concluded in April 2021. This review includes about 250 MW of non-firm imports in the summer and about 240 MW in the winter, as compared to zero in the previous reviews. Moving forward, the IESO plans to update the non-firm import capacity assumption using the most recent four years of data.

2.3 Requirements to Determine Resource Adequacy Needs

The IESO's resource adequacy criterion is defined in the Ontario Resource and Transmission Assessment Criteria and confirms that "to assess the adequacy of resources in Ontario, the IESO uses the NPCC resource adequacy design criterion."

3. Resource Adequacy Assessment

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

- Median and high demand growth forecast and associated (LFU);
- Forecast of available resources and existing EOPs;
- Planned outage schedules submitted by market participants;
- EFORd for thermal units derived using historical generator performance data; and
- Transmission limits of major interfaces connecting different zones.

The above inputs are described in greater detail in Appendix A of this report.

3.1 Assessment Results

The results for the Median and High Demand Growth scenarios are presented in Tables 3.1 and 3.2 and show that the NPCC LOLE criterion is satisfied.

To satisfy the NPCC criterion, the use of 70 MW of tie benefits will be required for 2022. The NPCC criterion is satisfied for 2023 to 2025 with existing and planned resources. For 2026, the use of 1,400 MW of tie benefits will be required to satisfy the criterion.

For the High Demand Growth scenario, the NPCC criterion is satisfied for 2023 and 2024 with existing and planned resources. For 2022, 2025 and 2026 tie benefits of up to 70, 1,400 and 3,400 MW respectively are required to meet the LOLE criterion.

Table 3-1 | Annual LOLE Values for Median Demand Forecast

	2022	2023	2024	2025	2026
Median Demand Forecast (MW)	22,580	22,110	21,772	22,033	22,348
Available Resources	27,772	26,884	26,396	26,768	24,664
Tie Benefits (MW)	70	0	0	0	1,400
LOLE (days/year)	0.10	0.07	0.06	0.07	0.10

Table 3-2 | Annual LOLE Values for High Demand Forecast

	2022	2023	2024	2025	2026
High Demand Forecast (MW)	22,580	22,454	22,459	22,686	22,934
Available Resources	27,772	26,884	26,396	26,768	24,664
Tie Benefits (MW)	70	0	0	1,400	3,400
LOLE (days/year)	0.10	0.08	0.03	0.10	0.10

3.2 Demand and Resource Uncertainties

As in any system adequacy forecast, there are inherent uncertainties related to demand and resources, which include changes to demand forecast drivers, adjustments to generation resource availability, conservation or demand response, and import or tie benefits support. The IESO assesses system adequacy and uncertainities from near to long term, andhas various ways to mitigate these uncertainties and address needs.

Every quarter, looking out 18 months into the future, the IESO assesses the near term adequacy and reliability of Ontario's system integrating the generator and transmission outage plans of market participants. If resource needs arise, the IESO possesses a range of options to address the needs, including coordinating outages outside the peak load seasons or periods of potential capacity shortages, the reliance on non-firm imports, and through acquisition of short-term capacity via annual capacity auctions held in December of each year.

In December 2020, the IESO held its first capacity auction securing 992 MW of capacity from resources including generation, imports, storage, and DR. The target capacities for the December 2021 capacity auction will be 1,000 MW for the summer 2022 obligation period, and 500 MW for the winter 2022/2023 obligation period as announced in the IESO's 2021 Annual Acquisition Report.

Beyond the 18 month horizon, the IESO performs resource assessments and identifies resource shortfalls in its Annual Planning Outlook (APO) over a 20-year horizon. The Annual Acquisition Report (AAR) translates planning and operational information, such as the forecasts outlined in the APO and bulk and regional plans, into a series of procurement and market activities designed to meet the needs identified.

These activities include the evolution and expansion of the capacity auction, and a series of competitive procurements to secure resources to meet resource adequacy over all horizons. The IESO will initiate an RFP for up to 750 MW in late 2021 with a three-year commitment period beginning in 2026, to address adequacy needs. The IESO intends to launch an RFP for at least 1,000 MW in fall 2022 for a commitment period of at least seven years.

The most recent NPCC Tie Benefits study indicates a range of estimated tie benefit potential of 3,663 MW to 3,789 MW. For this review, 1,600 MW of tie benefits were used to meet the criterion for 2026 under Median Demand Growth scenario.

3.3 Resource Adequacy Studies Conducted Since Last Area Review

In addition to the Interim Revivews of Resource Adequacy that were submitted in 2019 and 2020, the IESO conducts several other studies of resource adequacy.

The 18-Month Outlook presents the IESO's assessment of the reliability of the Ontario electricity system over the short term. This quarterly publication identifies whether the existing and proposed generation and transmission facilities are adequate to meet Ontario's needs over the next 18-months.

The APO forecasts over a 20-year time horizon and includes outlooks for demand, resource adequacy, and transmission, and is published to guide investment decisions and market development. The outlook also includes reserve margin requirements to meet the NPCC reliability criterion of an annual loss of load expectation (LOLE) of 0.1 days/year.

3.4 Reliability Impacts Due to Environmental Regulations and Fuel Supply Issues

3.4.1 Environmental Regulations

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reduce GHG emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government's Paris Agreement commitments. In order to achieve this commitment, industry performance standards have been proposed to regulate large emitters.

Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program, which will regulate GHG emissions from large industrial facilities by setting thresholds that those facilities are required to meet. The EPS program sets a threshold allowance of 370 tonnes CO_2e/GWh for existing generators, and 0 tonnes CO_2e/GWh for any new-build generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently $40/tonne CO_2e, and set to increase linearly to $170/tonne CO_2e by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset emissions, or can be sold to other large emitters. Ontario's natural gas fleet currently has an average emissions factor of approximately 420 tonnes CO_2e/GWh, which means on average, and with a threshold allowance of 370 tonnes CO_2e/GWh, the Ontario fleet only pays for a fraction of what it is emitting (50 tonnes CO_2e/GWh, or about 12%). This threshold allowance was implemented to lessen carbon policy impacts on inter-jurisdictional electricity trade, but also with the consequence of lowering price driven consumption behaviour among ratepayers when these fractional costs are passed along. Since emissions deterents, for the most part, are price driven at this time, environmental regulation risk and the potential for gas generation on-peak capability reductions is deemed low.

For existing environmental regulations and issues, generators provide to the IESO their expected seasonal derates and these are modelled in MARS.

3.4.2 Fuel Supply and Transportation Considerations

Supply to Ontario's gas fleet is strong, with many gas generation suppliers holding 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.

- Over 30% of Ontario’s gas-fired power generation is located near the Dawn Storage Hub[4], which provides adequate storage capacity for Ontario’s winters with robust access to US NE gas supply. Many of Ontario’s gas generators have access to, and make use of this storage, for balancing any unexpected changes to operation.
- In addition to Dawn, Ontario is also supplied by the TCPL mainline. These generators make up about 40% of the Ontario’s gas-fired generation, including Napanee GS, and Lennox GS which has dual-fuel gas/oil capability.

Based on the above, the impact on resource adequacy is considered low and no further reductions in the on-peak capability of gas generation are simulated for this study to account for fuel supply and transportation risks.

3.5 Mitigation Measures for Environmental Regulations and Fuel Supply Issues

As described in Section 3.4, the reliability impacts of environmental regulations and fuel supply issues are both low. As a result, no mitigation measures were simulated for this study. To mitigate fuel supply issues, Ontario’s generation includes dual fuel capability at Lennox GS which accounts for about 20% of the gas-fired generation fleet. This generator maintains sufficient oil supply on site in winter for over a week of day-round operation.

[4] More information on the Dawn Storage Hub is available at: https://www.enbridgegas.com/storage-transportation/doing-business-with-us/our-dawn-facility

Appendix A – DESCRIPTION OF RESOURCE RELIABILITY MODEL

A.1 MARS Program

For the purposes of this study, the IESO used the Multi-Area Reliability Simulation (MARS) program. The MARS program is capable of performing the reliability assessment of a generation system composed of a number of interconnected areas and/or zones that can be grouped into pools.

A sequential Monte Carlo simulation forms the basis for MARS. In this simulation, a chronological system evolution is developed by combining randomly generated operating states for the generating units with inter-zone transfer limits and hourly chronological loads. Consequently, the system can be modelled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules that govern system operation. Various measures of reliability can be reported using MARS, including the Loss of Load Expectation for various time frames. The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for various reliability indices. These values can be calculated both with and without load forecast uncertainty. The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates LOLE values and can estimate the expected number of times various emergency operating procedures would be implemented in each zone and pool.

The first step in calculating the reliability indices is to compute the zone margins on an isolated basis for each hour, by subtracting the load for the hour from the total available capacity in the hour. If a zone is at a positive or zero margin, it has sufficient capacity to meet its load. If the zone margin is negative, the load exceeds the capacity available to serve it, and the zone is in a potential loss-of-load situation. If there are any zones that have negative margins after the isolated zone margins are adjusted for curtailable contracts, the program attempts to satisfy these deficiencies with capacity from zones that have positive margins. There are two ways for determining how the reserves from zones with excess capacity are allocated among the zones that are deficient. In the first approach, the user specifies the priority order in which deficient zones receive assistance from zones with excess resources. The second method shares the available excess resources among deficient zones in proportion to the size of their shortfalls. Priorities within pools, as well as among pools, can also be modelled. The IESO uses the first approach.

A.2 Load Model

The IESO uses a multivariate econometric model to produce the electricity demand forecast. The forecast is composed of hourly demand for Ontario and its 10 zones. The model uses three broad sets of forecast drivers: calendar variables, weather effects and economic and demographic variables. The forecast also accounts for conservation, price impacts and embedded generation.

Weather is represented by a Monthly Normal weather scenario which uses the last 31 years of historical weather data to generate typical or average monthly weather. This approach results in a monthly peak demand with a 50/50 probability of being exceeded. This methodology is in lieu of using a base year to scale the forecast demand shape. A measure of uncertainty in demand due to weather variability is used in conjunction with the Normal weather scenario to generate a distribution of possible demand outcomes. In the MARS program, demand is modelled as an hourly profile for each day of each year of the study period. An allowance for LFU is also modelled.

LFU arises due to variability in the weather conditions that drive future demand levels. LFU is modelled in MARS through the use of probability distributions. These distributions are derived from observed historical variation in weather conditions that are known to affect demand including temperature, humidity, wind speed and cloud cover. Province-wide LFU distributions are developed for every month of the year and applied to all 10 transmission zones.

The economic drivers are generated using a consensus of publicly available provincial forecasts, along with economic forecasts from service providers. Demographic projections are publicly available from the Ontario's Ministry of Finance.

The demand forecast accounts for the impacts of embedded generation. Capacity projections based on projected generation are combined with historical production functions to generate estimated hourly output. This information is then applied to the demand forecast to determine the need for grid-supplied electricity.[5]

A.3 Demand Side Resources

There are two main demand management mechanism at the IESO that are modelled as resources: Demand Response (DR) and Dispatchable Loads. Resources with capacity obligation are required to be available for curtailment during times of system need. Dispatchable Loads are loads that bid into the market and are dispatched economically like other resources without participating in the Demand Response Auction.

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[5] More details on load modelling are described in the IESO document titled "Demand Forecast Methodology" (https://ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/APO-Demand-Forecast-Methodology.ashx).

Table A-1 | Demand-Side Management Assumptions

Year	Gross Demand Management (MW)	Effective Demand Management (MW)
2022	1,429	621
2023	1,422	511
2024	1,422	511
2025	1,422	511
2026	1,422	511

The IESO treats DR as a resource. As such, to maintain consistency, the impacts of DR programs are added back to the historical data when forecasting demand. Effective values of DR programs are used in MARS to reflect dependable capacity.
Effective capacity available from Dispatchable Loads is determined based on historical capacity offered, using five-year history, by the participants during peak demand hours. In MARS, Dispatchable Loads are modelled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone.
Effective capacity for DR is determined based on historical performance of the participants of individual programs. In MARS, DR is modelled as EOPs that are available at all times and are represented as monthly values aggregated for each transmission zone.
Price impacts from time-of-use rates and critical peak pricing programs are treated as load modifiers and decremented from the forecast. In Ontario, some participants of demand measure programs also participate in a critical peak pricing program. Therefore, at the time of the annual peak, the demand forecast is reduced for the peak pricing impacts but, concurrently, the total available demand response capacity is decremented to ensure that the contribution of these resources is not counted twice.

A.4 Supply-Side Resource Representation

The aggregated installed capacity values as of September 2021 for all generating units expected to be participating in the IESO markets during the assessment period are shown in Table A-2. These values do not include generators that operate within local distribution service areas, except for those that participate in the IESO-administered market.

Table A-2 | Existing Installed Generation Capacity, as of September 2021

Fuel Type	Total Installed Capacity (MW)	Number of Stations
Nuclear	13,089	5
Gas/Oil	10,515	33
Hydroelectric	8,918	76
Wind	4,783	40
Solar	478	10
Biofuel	296	7
Total	**38,079**	**171**

Table A-3 | Planned Generation Resources expected in 2021

Project Name	Fuel Type	Capacity
Romney Wind Energy Centre	Wind	60
Nation Rise	Wind	100

A.4.1 Resource Ratings

Definitions

The ratings of resources were based the ratings methodologies specified in the *IESO* Resource Adequacy and Energy Assessment Methodology. Summaries of the methodology for each resource type are provided below.

Thermal Resources

Four resource types are modelled as thermal resources: nuclear, gas, oil and biofuel. The capacity values for each unit are modelled on a monthly granularity, to capture external factors such as ambient temperature and humidity or cooling water temperature. For nuclear generators and the like whose MCR is not ambient temperature sensitive, the IESO models the genator's expected monthly gross MCR and their station service load (as submitted annually by the generator). Fossil- or biofuel-fired generators whose MCR is sensitive to ambient temperature provide gross MCR at five different temperatures specified by the IESO which are used to construct a temperature derating curve. For each such generator, monthly gross MCR values calculated at normal monthly temperatures using the derating curve.

Hydroelectric, Wind and Solar Resources

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are determined on an aggregated basis for each transmission zone. Maximum capacity values are based on historical median monthly production and contribution to operating reserve at the time of system weekday peaks. Minimum capacity values are based on the bottom 25th percentile of historical production during hours ending one through five for each month. Monthly energy values are based on historical monthly median energy production since market opening.

For new hydroelectric projects, the maximum capacity value, the minimum capacity value and the monthly energy value are calculated using the methodology described above based on the historical production data of other generators in the zone where the new project is located.

Criteria for Verifying Ratings

The Ontario Market Rules (*Market Rules Chapter 4, Section 5)* require that all generators connected to the IESO-controlled grid test their equipment to ensure compliance with all applicable reliability standards, including NPCC Directory #9 "Verification of Generator Gross and Net Real Power Capability" and Directory #10 "Verification of Generator Gross and Net Reactive Power Capability."

Generators communicate to the IESO any changes to their units' verified gross and net MW capabilities as part of the Outage Management Process and the Facility Registration, Maintenance and De-registration Process, as described in *Market Manual 7.3 "Outage Management"* and *Market Manual 1.2 "Facility Registration, Maintenance and De-registration."*

Permanent changes to equipment that affect the MW output capabilities of generating units are communicated and assessed through the Connection Assessments process described in *Market Manual 2.10 "Connection Assessment and Approval Procedure."*

Generators provide to the IESO at least annually, the declared Maximum Continuous Rating at five temperature points for resources sensitive to ambient temperatures, as described in *Market Manual 2.8 "Reliability Assessments Information Requirements."* The IESO then determines the seasonal net MW values for these units consistent with the ambient temperatures assumed for each month's normal weather demand forecast. For generators that are not sensitive to ambient temperatures, generators provide their monthly Maximum Continous Rating, reflective of expected deratings due to external factors such as cooling water temperature.

The Market Rules (*Market Rules Chapter 4, Section 5.2)* also authorise the IESO to test any generation facility connected to the IESO-controlled grid to determine whether such facility complies with the applicable reliability standards.

A.4.2 Unavailability Factors

Hydroelectric, Wind and Solar Profiles

Hydroelectric, wind, and solar resource performance is captured through measures other than ICAP ratings. To inform the modelling of hydroelectric, wind, and solar resources, historical and simulated hourly profiles are used for each generator.

Hourly historical hydroelectric data is plant-specific and includes historical production, scheduled operating reserve and market offer data. Hourly simulated production data is specific to a certain site; resources are mapped to the closest appropriate simulated site, depending on technology type.

Wind generation currently uses 28 years of simulated hourly profiles. Wind generators are matched to the closest simulated site, and then output is scaled relative to installed capacity.

Solar generation currently uses the median production year from 10 years of simulated hourly profiles. Solar generators are matched to the closest simulated site and technology type (groundmount or rooftop), and then output is scaled relative to installed capacity.

Forced Outage Rates

For thermal resources, performance is measured with Equivalent Forced Outage Rate on Demand ($EFOR_d$). An industry metric defined by the IEEE[6], EFORd is the probability that a generating unit will not be available (completely or in part) during hours the unit is called upon to generate (i.e., during on-demand hours) due to forced outages and forced de-ratings. $EFOR_d$ is calculated using the following formula, where FOH_d is Forced Outage Hours on Demand, $EFDH_d$ is Equivalent Forced DeRated Outage Hours on Demand, and SH is Service Hours:

[6] For more information, refer to the IEEE Std 762-2006: IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity.

$$EFOR_d = \frac{FOH_d + EFDH_d}{SH + FOH_d} \times 100$$

$EFOR_d$ is calculated for each thermal generator on a rolling five-year basis using a combination of data submitted by market participants, data collected using IESO's outage management system, and historical production data.

For non-thermal generators, forced outages are embedded within the historical and/or simulated production profiles described previously.

Tabulation of Typical Unavailability Factors

The projected $EFOR_d$ values in the form of weighted average and range by fuel type are provided in Table A-4.

Table A-4 | Ontario Projected Equivalent Demand Forced Outage Rates

Fuel Type	Weighted Average EFORd	Range of EFORd
Nuclear	5.1%	2.4 – 6.4 %
Gas/Oil	10.7%	1.0 – 33.0%
Biomass	5.9%	2.9 - 6.9%

Maturity Considerations

Immature units are assigned an $EFOR_d$ based on the youngest facility with the same technology type and size.

Planned Outages

Planned outage information is received from market participants, and used to develop planned outage schedules for each generator over the planning horizon. Data from the outage management system takes precedence, followed by data submitted through Form 1230s or submitted directly by market participants. For years and/or generators for which no planned outage information has been submitted, the IESO uses a combination of available submitted information and historical planned outage rates to make assumptions about future planned outages.

Some resource types require resource-specific inputs for planned outages:

- Hydroelectric planned outages are generally not modelled explicitly, as outages are embedded within the historical profiles. When significant outages of sufficient duration are planned, these outages are modelled.
- Wind and solar planned outages are not modelled explicitly as they are embedded within the simulated profiles.
- Demand response is assumed to have no planned outages.

A.4.3 Purchase and Sale of Capacity

As part of the Amended and Restated Capacity Sharing Agreement between Ontario and Quebec, signed in November 2016, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. As a result of the previous agreement, Quebec will provide Ontario a total of 500 MW of capacity in the summer months (June to September) to be exercised, when needed, any time before September 30, 2030. This summer capacity was not relied upon in this Comprehensive Review.

A.4.4 Retirements

The IESO estimate of future retirements is based on information provided annually by Market Participants to the IESO. Pickering Nuclear Generating Station retirement has been delayed. Two units with a capacity of 1,030 MW have received regulatory approval to delay retirement by two years and retire in the fall of 2024. The remaining four units, with a capacity of 2,064 MW, have approval for operation until the end of 2025, delaying retirement by one year.

A.5 Transmission System

A.5.1 Representation of Interconnected Systems

There are five systems with which the Ontario system is interconnected: Manitoba, Minnesota, Michigan, New York and Quebec. To model import assistance, an EOP is triggered in each Ontario zone that has an interconnection. The amount of EOP in each of the zones is based on the transfer capabilities of the interconnection.

To model the firm contract of 500 MW with Quebec, Quebec is created in MARS with a transmission line interface to Ottawa. This transmission line interface is limited to a maximum transfer capability of 500 MW. To model conservatively, over the winter months (December to March) a 500 MW load in Quebec is used to represent Ontario's firm capacity export contract.

The NPCC CP-8 study entitled "Review of Interconnection Assistance Reliability Benefits," published in December 2019 indicates a range of estimated tie benefit potential of 3,663 MW to 3,789 MW for 2024. The expected capacity values used in this study vary, depending on Ontario needs, but are always subject to the limitations of the transmission interconnections outlined in Table A-4. Limits apply year-round except where seasonal ratings are indicated.

Table A- 5 | Ontario Interconnection Limits

Interconnection	Limit - Flows Out of Ontario (MW)	Limit - Flows Into Ontario (MW)
Manitoba – Summer*	210	210 [3,6]
Manitoba – Winter*	300 [3]	300 [3,6]
Minnesota	150	100 [3]
Quebec North (Northeast) – Summer*	105	65
D4Z	0 [5]	65
H4Z	105 [5]	0
Quebec North (Northeast)– Winter*	105	85
D4Z	0	85
H4Z	105	0
Quebec South (Ottawa) – Summer*	1570	1865
X2Y	0	65
Q4C	120	not of concern
P33C	0 [6]	300
D5A	200	250
H9A	0	0
HVDC	1250	1250
Quebec South (Ottawa) – Winter*	1590	1865
X2Y	0	65
Q4C	140	not of concern
P33C	0	300
D5A	200	250
H9A	0	0
HVDC	1250	1250
Quebec South (East) – Summer*	470	400
B31L + B5D	470	400
Quebec South (East) – Winter*	470	400

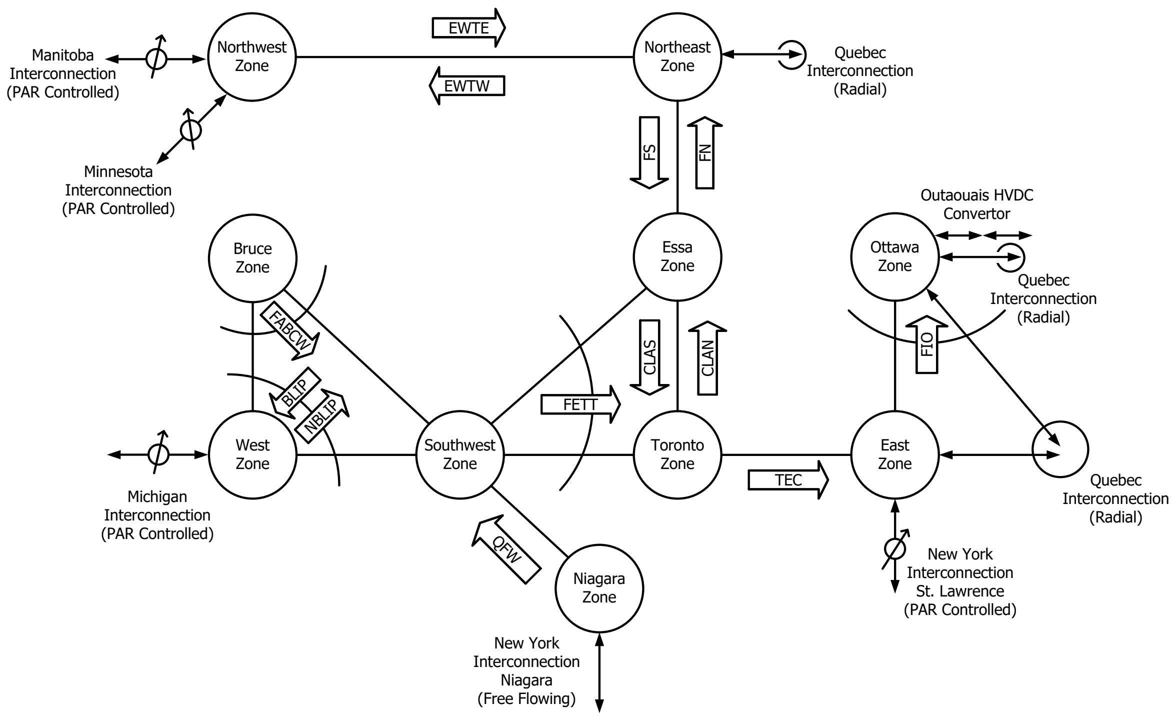
B31L + B5D	470		400	
New York St. Lawrence – Summer*	300		300	
New York St. Lawrence – Winter*	300		300	
New York Niagara – Summer*	1650	1	1500	1,7
Emergency Transfer Limit - Summer*	2160	1	1860	1,7
New York Niagara – Winter*	1800	1	1650	1,7
Emergency Transfer Limit - Winter*	2200	1	2200	1,7
Michigan – Summer*	1650	2,3	1550	2,3
Emergency Transfer Limit - Summer*	N/A	2,3	N/A	2,3
Michigan – Winter*	1650	2,3	1700	2,3
Emergency Transfer Limit - Winter*	N/A	2,3	N/A	2,3

* Summer Limits apply from May 1 to October 31. Winter Limits apply from November 1 to April 30.
(1) Flow limits depend on generation dispatch outside Ontario.
(2) Normal limits are based on LT ratings and Emergency limits are based on STE ratings.
(3) For real time operation of the interconnection, limits are based on ambient conditions.
(4) Limit based on 0 to 4 km/h wind speed and 30˚C ambient temperature.
(5) Flows into Ontario include flows on circuit SK1.
(6) Flow limits into Ontario are shown without considering QFW transmission constraints within Ontario.

A.5.2 Internal Transmission Limitations

The Ontario transmission system is represented by 10 interconnected zones with transmission limits between the zones explicitly modelled. Figure A-1 provides a pictorial representation of Ontario's 10 zones. The limits modelled are the operating security limits (OSL) specified for each interface and any projected limit increase due to future transmission system enhancements is appropriately represented.

Figure A-1 | Ontario's Zones, Interfaces, and Interconnections



The East-West Tie Expansion project consists of a new 230 kV transmission line roughly paralleling the existing East-West Tie Line between Wawa and Thunder Bay. The new line will increase the electricity transfer capability into Northwest Ontario and will improve the flexibility and efficiency of the Northwest electricity system. As part of this project, upgrades are being planned for the Lakehead, Marathon and Wawa transformer stations to accommodate the new line. The planned in-service date of the project is Q1 2022.

A.6 Modelling of Variable and Limited Energy Sources

Modelling of Variable Energy Sources were described in Section A.4. Hydroelectric resources are treated as limited energy sources. Ontario also has a biomass facility whose contract specifies its annual fuel requirement. It is treated as a limited energy source in MARS, with an annual limit of 140 GWh.

A.7 Modelling of Demand Side Resource and Demand Response Programs

Treatment of Demand Side Resources and Demand Response are described in Section A.3.

A.8 Modelling of All Resources

Treatment of in-service date uncertainty, capacity value and availability and were described Section A.4. Emergency assistance is described in Section 2.1. Scheduling and deliverability limitations of individual resources are considered as part of determining the monthly available capacity of the resource, where applicable. For example, by using coincident hydro production, deliverability to the grid is implicitly accounted for.

A.9 Reliability Impacts of Market Rules

No reliability impacts due to market rules are anticipated in this review. The IESO publishes expected changes to its Market Rules on an ongoing basis at http://www.ieso.ca/Sector-Participants/Change-Management/Pending-Changes-Documents.

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