
Reliability Outlook

An adequacy assessment of Ontario's
electricity system

FROM JANUARY 2020 TO DECEMBER 2024

Executive Summary

Ensuring Ontarians have the electricity they need, when they need it, is at the heart of the Independent Electricity System Operator's mandate. Maintaining a reliable system over the short- and long-term depends on comprehensive system planning that assesses whether the system has enough resources to reliably serve forecast demand, and evaluates the grid's ability to operate reliably over a broad range of system conditions, including extreme weather and facility or resource unavailability.

The results of our reliability assessments drive decision-making, whether short term – as in when to schedule outages – or, over the long term, which allows developers and investors to respond to the needs and price signals, and invest accordingly. The latter is addressed in the IESO's upcoming *Annual Planning Outlook* (APO), which provides a comprehensive demand forecast, capacity and energy adequacy assessment, as well as an outlook on transmission planning over a 20-year horizon.

If the APO looks at big-picture adequacy requirements for investment and asset management, the *Reliability Outlook* zeroes in on the near and mid-term – what will be needed for real and near-time operations when reliability may come into question, and when market participants will need to be prepared to adjust plans when necessary. Each issue of the quarterly *Reliability Outlook* looks at four scenarios for the upcoming 18-month period: normal weather, firm resource (only includes those currently in service); normal weather, planned resource (includes those that are scheduled to come into service during the planning period); extreme weather, firm resource; and extreme weather, planned resource.

Twice a year, in summer and winter, this report complements the 18-month outlook with an extended view that takes into account the following 42 months, providing broader (but less certain) insights over a five-year horizon.

The IESO's outage management policy is designed to ensure Ontario has enough reserve on hand to maintain reliability during extreme weather conditions and the conservative firm scenario, assuming up to 2,000 megawatts (MW) of import availability.

Scheduling outages to support reliability

In this 18-month forecast, reliability concerns could arise during the summers of 2020 and 2021. However, by proactively managing outages and with plans for new generation coming online, these concerns can be mitigated. Looking ahead over the broader five-year forecast, where greater uncertainty exists around weather and outage planning, the potential for increased reliability concerns emerges over the summers, from 2022 to 2024.

Summer continues to be the season when both the firm and planned scenarios point to potential reliability concerns in extreme weather conditions. For these reasons, the IESO recommends that, wherever possible, outages be scheduled outside the summer months.

Periods to Watch: Near term

- June 2020: four weeks
- July 2020: three weeks
- August 2020: two weeks
- September 2020: one week

Periods to Watch: Longer term

- June 2021: five weeks
- 2022: June to September
- 2023: June to September
- 2024: June to September

Overview of the 18-month forecast

Ontario's economic growth expected to increase demand

Starting in 2020, energy demand – which has remained fairly flat since the recession – is anticipated to increase gradually, owing to projected population growth and economic indicators (low Canadian dollar, strong U.S. economy) that support the province's export-oriented, energy-intensive manufacturing sector. That said, these may be counterbalanced by risks related to ongoing trade tensions, climate impacts and global economic uncertainty. If these risks do not materialize, Ontario's increasing economic output is expected to drive peak demand up slightly over the 18 months to June 2021. The downward pressure is expected to ease from energy-efficiency programs, growing contributions from DERs and the Industrial Conservation Initiative (ICI).

Reduced summer peaks expected to rise again

Combined, the effects of the ICI and the growth of solar-powered distributed energy resources have resulted in summer peaks that are lower in magnitude, and occur later in the day. As solar capacity is plateauing and energy-efficiency savings beyond 2020 are uncertain, peaks are forecast to rise again over the 18 months from January 2020 to June 2021.

The forecast sees sufficient generation supply for winter 2020, as well as winter 2020/21. While risks may arise in the heat of summer 2020 and the early part of summer 2021, they should be mitigated by outage rescheduling. Over the next 18 months, approximately 1,500 MW of new generation are planned to come into service, while only 38 MW of generation will reach the end of its contract life.

Addressing reserve requirements

When reserves fall below required levels, the IESO may be required to reject some generator maintenance outage requests if extreme weather conditions materialize.

The reserve is lower than the requirement, without reliance on imports, for a total of 16 weeks in 2020 and eight weeks in the first half of 2021, with potential shortfalls forecast for four weeks in June 2020, three weeks in July 2020, two weeks in August 2020, one week in September 2020 and five weeks in June 2021.

Tools to help meet that demand include the IESO's demand-response auction, which provides a transparent and cost-effective way to select the most competitive providers of demand response, while ensuring that all providers are held to the same performance obligations. The December 2019 demand-response auction secured capacity to help ensure the reliability of the system during the first 18 months of this Outlook, for summer 2020 (858.7 MW) and winter 2020/21 (919.3 MW).

As for energy adequacy, Ontario is expected to have sufficient supply to meet its energy forecast throughout 2020 for the firm scenario with normal weather, without needing to rely on imports. A small energy need may arise in June 2021 and require the rescheduling of some planned outages to meet capacity adequacy requirements, which should also help to ensure energy adequacy.

Careful transmission coordination

Ontario's transmission system is expected to continue to reliably supply province-wide demand, while experiencing normal contingencies defined by planning criteria for the next 18 months. However, some combinations of transmission and/or generation outages can create operating challenges.

For example, careful coordination of transmission and generation outages will be required through the second quarter of 2021, as Hydro One continues to replace aging infrastructure at the Bruce 230 kilovolt (kV) switchyard. The flow out of Bruce may be impacted from February to November 2020, and a planned two-week outage starting April 20, 2020 will reduce transfer capability into the West zone.

Significant growth in the greenhouse sector may lead to challenges in the Southwest zone, as new load connections are made and required transmission reinforcements are being implemented. The IESO is using proactive strategies to meet the anticipated need including an LED incentive for greenhouses in Windsor-Essex and Chatham-Kent, and the IESO's Grid Innovation Fund, which is providing \$2.5 million in funding to projects focused on reducing electricity demand from indoor agriculture facilities during local and bulk system peak periods.

Operational challenges due to high voltages in eastern Ontario and the Greater Toronto Area will continue to occur during low-demand periods.

Beyond 18 months: July 2021 to December 2024

Thanks, in part, to the province's diverse supply mix, Ontario is in a strong position with sufficient resources to meet its needs under most circumstances, provided the majority of existing resources remain available over the 42-month horizon.

Based on the longer-term outage plans submitted by generation and transmission owners, the five-year outlook takes into account nuclear retirements and refurbishments, and facilities reaching the end of their contract terms, considering potential delays in generation projects and the extreme weather scenario.

Uncertainties in electricity forecasting are compounded by time. For planning purposes, the scenarios modelled over the five-year horizon could vary depending on economic and demographic conditions, achievement of energy-efficiency programs, penetration of distributed energy resources, weather conditions, timing and completion of transmission and resource projects, as well as the scheduling of planned and forced outages.

Periods of increased reliability risk could emerge in the summers of 2022, 2023 and 2024, with the greatest risk in the summer of 2023, when nuclear refurbishment activity peaks and reserves fall below the adequacy threshold. Planning assessments for the months of May and June 2023 show up to seven planned nuclear outages. Market participants should attempt to avoid outages during this period and be prepared for the possibility that outages will be rejected. Going forward, capacity auctions will be an important mechanism for efficiently and competitively acquiring resources to meet Ontario's capacity needs. In June 2020, the IESO is launching its first capacity auction – an evolution of the demand-response auction that will be open to dispatchable generators coming off contract, storage and system-backed imports.

As potential negative reserves during these summers exceed the amount of potential imports that the IESO may rely upon for resource adequacy, all non-critical or short-duration outages should be rescheduled into late fall, winter or early spring. Generally, generators are advised to avoid scheduling outages in the summers throughout the Outlook period, and even beyond.

Also, the transfer capability of the Flow East Toward Toronto (FETT) interface could be reduced significantly with one or more key transmission elements out of service, particularly when Pickering or Darlington units are out of service.

Keeping ahead of emerging reliability issues

The information in this *Reliability Outlook* lend transparency to the IESO's planning process, using the latest information to paint the clearest possible picture of upcoming trends, issues and concerns that, in potentially affecting system reliability, will require ongoing monitoring and careful coordination of outages.

The IESO recognizes that continued system reliability depends on the contributions of all stakeholders. Engagement is integral to IESO planning processes, ensuring potential reliability concerns are on the radar and mitigating them long before they grow into issues.

Next year, in addition to introducing a capacity auction that will enable new resource types to compete to meet system needs, the IESO is launching a resource adequacy engagement that will explore a suite of procurement tools to ensure Ontario is well positioned to meet current – and future – capacity requirements.

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1. Introduction

This Outlook covers 60 months in two distinct periods: the 18 months from January 2020 to June 2021, which supersedes the Outlook released on September 19, 2019 and is presented in chapters 3 through 6, and the 42-month period from July 2021 to December 2024, presented in chapter 7.

The purpose of the 18-month horizon in the *Reliability Outlook* is to:

- Advise market participants of the resource and transmission reliability of the Ontario electricity system
- Assess potentially adverse conditions that might be avoided by adjusting or coordinating maintenance plans for generation and transmission equipment
- Report on initiatives being implemented to improve reliability within this time frame

The 42-month period presented in chapter 7 is intended to support generation and transmission owners with scheduling and approval of larger and more complex outages, requiring longer lead times, and to inform changes in resource adequacy beyond 18 months that may make coordinating outages and assessments more challenging in the future.

This Outlook assesses resource and transmission adequacy based on the stated assumptions, following the [Methodology to Perform the Reliability Outlook](#). Due to uncertainties associated with various assumptions, readers are encouraged to use their judgment in considering possible future scenarios.

Additional supporting documents are located on the [IESO website](#).

[Security and adequacy assessments](#) are published on the IESO website on a daily basis and progressively supersede information presented in this report.

For questions or comments on this Outlook, please contact us at 905-403-6900 (toll-free 1-888-448-7777) or customer.relations@ieso.ca.

2. Updates to this Outlook

2.1 Updates to Demand Forecast

The demand forecast is based on actual demand, weather and economic data through to the end of September 2019. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for September, October and November 2019 have been included in the [tables](#).

2.2 Updates to Resources

This *Reliability Outlook* considers planned generator outages over the 60-month period, submitted by market participants to the IESO's outage management system as of November 25, 2019. Market participants are required annually to submit information to enable the IESO to conduct reliability assessments. This information, provided to the IESO through Form 1230, was submitted by April 1, 2019.

2.3 Updates to Transmission Outlook

Transmission outage plans that were submitted to the IESO's outage management system by October 28, 2019, are considered in this Outlook.

2.4 Updates to Operability Outlook

The outlook for surplus baseload generation (SBG) conditions over the next 18 months is based on generator outage plans submitted by market participants to the IESO's outage management system as of November 25, 2019.

3. Demand Forecast for 18-Month Period

Beginning in 2020, energy demand is expected to increase due to economic expansion and population growth. Peak demand, which has been facing downward pressure from energy-efficiency programs, growing embedded generation output and the ICI, is expected to increase slightly over the forecast period.

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period January 2020 to June 2021 and supersedes the previous forecast released in September 2019. Tables of supporting information are contained in the [2019 Q4 Outlook Tables](#) spreadsheet.

Electricity demand is shaped by a number of factors that can:

- Increase the demand for electricity, e.g., population growth, economic expansion and the increased penetration of end-uses
- Reduce the need for grid-supplied electricity, e.g., conservation and embedded generation
- Shift demand, e.g., time-of-use rates and the Industrial Conservation Initiative (ICI)

How each of these factors impacts electricity consumption varies by season and time of day – and is reflected in the demand forecast.

Grid-supplied energy demand has been fairly flat since the 2009 recession with small increases and decreases year to year. The Outlook projects increasing electricity demand over the forecast horizon, thanks to the combined impact of economic expansion and demographic growth. A strong U.S. economy and a low dollar will continue to foster demand growth in the industrial sector. Embedded generation capacity has stopped growing and energy-efficiency conservation savings are forecast until the end of 2020, eliminating the downward pressure on electricity demand.

Peak demands are subject to the same forces as energy demand, though the impacts vary. This is true when comparing energy demand to peak demand, and the summer to winter peaks. Recent history has seen lower summer peaks, significantly impacted by the growth in embedded-generation capacity and the ICI. The majority of embedded generation is provided by solar-powered facilities that generate high output during the traditional summer peak-hour period and limited to no output during the winter peak-hour periods. In addition to reducing summer peaks, higher embedded solar output has also pushed the peak later in the day. As before, with the amount of embedded solar capacity plateauing and no energy-efficiency savings forecast beyond 2020, peaks will show a reversal from recent years and increase over the forecast period.

The following tables show seasonal peaks and annual energy demand over the forecast horizon of the Outlook.

Table 3-1 | Historical and Forecast Energy Summary

Year	Normal Weather Energy (TWh)	% Growth in Energy
2006	152.3	-1.86%
2007	151.6	-0.49%
2008	148.9	-1.77%
2009	140.4	-5.72%
2010	142.1	1.23%
2011	141.2	-0.63%
2012	141.3	0.08%
2013	140.5	-0.63%
2014	138.9	-1.14%
2015	136.2	-1.94%
2016	136.2	0.01%
2017	132.3	-2.84%
2018	135.2	2.15%
2019 (Forecast)	134.1	-0.80%
2020 (Forecast)	136.4	1.74%

Table 3-2 | Forecasted Seasonal Peaks

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2019-20	21,185	22,353
Summer 2020	22,194	24,555
Winter 2020-21	21,239	22,533

3.1 Actual Weather and Demand

Since the last forecast, actual demand and weather data for September, October and November have been recorded.

September:

- September experienced near normal weather during both the average and peak demand temperatures.
- The monthly peak occurred on Wednesday, September 11, the second hottest day of the month. The afternoon high was 28.6 C (at Toronto), the mildest September peak since 2012. The peak was 19,717 MW (19,244 MW weather corrected). A warmer spell during the month didn't deliver a monthly peak as it took place over a weekend.
- Energy demand for the month was 10.3 TWh (10.3 TWh weather-corrected), which is the lowest September actual since market opening.
- The minimum demand for the month was 10,477 MW and occurred in the early hours of September 29. This is the lowest September minimum since market opening.
- Embedded generation production for the month was 484 GWh, virtually the same as that recorded in September 2018.
- Wholesale customers' consumption dropped 5.9% compared to September 2018, representing the largest monthly decline since September 2017. Declines in mining (-5.3%), pulp and paper (-16.3%) and petrol-chemicals (-27.3%) more than offset gains in the chemicals (14.6%) and iron and steel (5.2%) sectors.

October:

- While not warm, the weather for October was milder than typically expected.
- The peak for October occurred on the first of the month when daytime highs reached 31.2 C (Toronto). Peak demand reached 18,329 MW (18,652 MW weather-corrected), the highest for October since 2013.
- Energy demand for the month was 10.3 TWh (10.6 TWh weather-corrected), low by historical standards, due to mild weather for the month.
- Minimum demand in October was 10,739 MW, occurred during the early hours of Sunday, October 6, the second warmest day of the month. The warmer weather led to the dip in demand as October is typically a month that requires heating.
- Embedded generation production for the month was 506 GWh, a 3.8% increase over the previous year. Higher embedded hydro and wind output accounted for the growth, as solar output was down significantly (-22.0%).

- Wholesale customers' demand fell by 4.4% compared to the previous October, resulting from declines in pulp and paper, petrochemicals and iron and steel, which offset growth in mining and basic chemicals.

November

- The weather for November was colder than normal. The average temperatures for the month rank it as one of the coldest Novembers in the past 50 years.
- November's peak demand occurred on November 13, the second coldest day of the month. The peak was 19,625 MW (19,001 MW weather-corrected) and was slightly lower than last November's peak – which occurred on a significantly colder day.
- Energy demand for the month was 11.3 TWh (10.9 TWh weather-corrected) which was very similar to the month's experience since 2014.
- Minimum demand for the month was 11,711 MW, which is also consistent with the experience of recent years. The minimum occurred in the early hours of Sunday, November 3 when temperatures were mild.
- Embedded generation production for the month was 453 GWh, a 6.8% increase compared to the previous November. Wind (4.2%) and hydro (34.2%) output were up significantly, offsetting a very large decline in solar output (-37.7%).
- Wholesale customers' consumption continued the negative trend that began in July. Year-over-year consumption decreased by 4.8% with mining (-0.2%) and chemicals (3.9%) as the strongest sectors and refining showing the greatest decline (-20.3%).

Overall, energy demand for the fall months of September, October and November was down 3.9% compared with the previous fall. After adjusting for the weather, demand for the three months showed a smaller decrease of 1.3%.

Embedded generation for the three months was up 3.5% over the same time a year ago. The increase was driven by higher output by wind (24.3%) and hydro (21.5%).

For the three months, wholesale customers' consumption posted a 5.0% decrease over the same months a year prior with all major sectors showing declines, except for chemicals which posted a 10.7% increase.

The [2019 Q4 Outlook Tables](#) spreadsheet contains several tables with historical data. They are:

- Table 3.3.1 Weekly Weather and Demand History Since Market Opening
- Table 3.3.2 Monthly Weather and Demand History Since Market Opening
- Table 3.3.3 Monthly Demand Data by Market Participant Role

Table 3-3 | Weekly Energy and Peak Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
05-Jan-20	19,918	20,913	570	2,766
12-Jan-20	21,185	22,353	547	2,923
19-Jan-20	20,757	21,385	483	2,899
26-Jan-20	20,618	21,568	404	2,899
02-Feb-20	20,637	21,718	734	2,915
09-Feb-20	19,917	21,508	635	2,851
16-Feb-20	19,555	20,902	581	2,783
23-Feb-20	19,310	20,967	501	2,750
01-Mar-20	19,830	21,014	531	2,794
08-Mar-20	19,377	20,150	649	2,726
15-Mar-20	18,274	18,933	611	2,637
22-Mar-20	17,606	18,507	569	2,530
29-Mar-20	17,592	18,560	567	2,538
05-Apr-20	17,323	17,873	471	2,496
12-Apr-20	16,671	17,541	496	2,385
19-Apr-20	16,044	16,204	531	2,367
26-Apr-20	16,236	16,767	721	2,362
03-May-20	17,268	19,567	849	2,344
10-May-20	16,551	19,296	845	2,349
17-May-20	18,057	21,149	1,175	2,370
24-May-20	17,705	21,392	1,330	2,322
31-May-20	18,533	20,855	1,292	2,385
07-Jun-20	19,261	23,379	1,055	2,559
14-Jun-20	20,335	23,772	835	2,576
21-Jun-20	21,401	23,839	754	2,639
28-Jun-20	21,530	23,846	1,016	2,695
05-Jul-20	20,535	23,291	814	2,655
12-Jul-20	22,194	24,555	838	2,759
19-Jul-20	20,743	24,051	1,035	2,629
26-Jul-20	21,290	24,252	841	2,720
02-Aug-20	21,944	24,100	958	2,717
09-Aug-20	21,289	23,693	985	2,683
16-Aug-20	20,532	23,504	1,362	2,665
23-Aug-20	21,375	23,147	1,413	2,711
30-Aug-20	19,979	22,399	1,370	2,560
06-Sep-20	18,388	23,201	680	2,451
13-Sep-20	18,845	20,551	781	2,427
20-Sep-20	17,616	19,795	420	2,432

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
27-Sep-20	16,847	18,117	554	2,371
04-Oct-20	17,175	17,204	786	2,417
11-Oct-20	16,806	16,863	507	2,434
18-Oct-20	17,107	17,518	392	2,395
25-Oct-20	17,286	17,783	318	2,477
01-Nov-20	17,545	18,172	416	2,505
08-Nov-20	18,538	18,858	601	2,586
15-Nov-20	18,683	19,396	342	2,606
22-Nov-20	19,233	19,915	607	2,678
29-Nov-20	19,646	21,100	409	2,740
06-Dec-20	19,949	20,956	555	2,767
13-Dec-20	20,341	21,304	690	2,809
20-Dec-20	20,059	21,135	362	2,796
27-Dec-20	18,804	20,651	528	2,753
03-Jan-21	20,243	21,138	528	2,742
10-Jan-21	21,239	22,533	570	2,949
17-Jan-21	20,902	21,827	547	2,921
24-Jan-21	20,760	21,910	483	2,921
31-Jan-21	20,779	22,061	404	2,945
07-Feb-21	20,256	21,644	734	2,872
14-Feb-21	19,890	21,240	635	2,804
21-Feb-21	19,649	21,306	581	2,771
28-Feb-21	20,182	21,367	501	2,823
07-Mar-21	19,742	20,314	531	2,755
14-Mar-21	19,082	19,541	649	2,686
21-Mar-21	17,939	18,636	611	2,562
28-Mar-21	17,926	18,695	569	2,559
04-Apr-21	17,953	18,283	567	2,486
11-Apr-21	17,023	17,894	471	2,437
18-Apr-21	16,559	16,653	496	2,399
25-Apr-21	16,581	16,909	531	2,384
02-May-21	17,613	19,913	721	2,368
09-May-21	16,692	19,640	849	2,371
16-May-21	18,198	21,491	845	2,397
23-May-21	17,845	21,733	1,175	2,396
30-May-21	18,681	21,199	1,330	2,354
06-Jun-21	19,408	23,623	1,292	2,571
13-Jun-21	20,485	23,920	1,055	2,598
20-Jun-21	21,537	23,878	835	2,661

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
27-Jun-21	21,981	23,995	754	2,717
04-Jul-21	21,922	24,568	1,016	2,678

3.2 Forecast Drivers

3.2.1 Economic Outlook

The economic fundamentals are relatively positive for the Ontario economy. A strong U.S. economy, a low Canadian dollar and low interest rates are conducive to growth in Ontario's export-oriented, energy-intensive manufacturing sector. That said, significant downside risk to the economy remains over the forecast horizon, with trade tensions, climate impacts and global political uncertainty increasing the risk of disruption to the world economic situation. If these risks do not materialize, Ontario should see increasing economic output over the forecast.

Table 3.3.4 of the [2019 Q4 Outlook Tables](#) presents the economic assumptions for the demand forecast.

3.2.2 Weather Scenarios

The IESO uses weather scenarios to produce demand forecasts. These scenarios include normal and extreme weather, along with a measure of uncertainty in demand due to weather volatility. This measure is called Load Forecast Uncertainty.

Table 3.3.5 of the [2019 Q4 Outlook Tables](#) presents the weekly weather data for the forecast period.

3.2.3 Demand Measures and Load Modifiers

Both demand measures and load modifiers can impact demand but they differ in how they are treated within the Outlook. Demand measures are not incorporated into the demand forecast and are instead treated as resources. Load modifiers are incorporated into the demand forecast.

As demand measures are dispatched like generation resources, they are included in the supply mix, and added back into the history when forecasting demand. Therefore, the impacts of demand measures are not included in the demand forecast.

Load modifiers include conservation (energy-efficiency programs, codes and standards and fuel switching), price impacts (time-of-use rates and the ICI), and embedded generation. Each affects demand differently in terms of level and timing, but together these load modifiers have the net effect of reducing the demand for grid-supplied electricity. Conservation affects the height of peaks and the energy consumed, prices reduce demand during peak periods, and the impacts of embedded generation vary by fuel type.

4. Resource Adequacy for 18-Month Period

The IESO expects to have sufficient generation supply for winter 2020, as well as winter 2020/2021. Potential risks in summer 2020 and the early part of summer 2021 are expected to be mitigated by outage rescheduling. Over the next 18 months, 1,500 MW of new generation are planned to come into service, while approximately 38 MW of generation will reach the end of its contract life.

This section assesses the adequacy of resources to meet the forecast demand. Resource adequacy is one of the reliability considerations used for approving outages. When reserves are below required levels, with potentially adverse effects on the reliability of the grid, the IESO will reject outage requests based on their order of precedence. Conversely, when reserves are above required levels, additional outages can be contemplated, provided other factors – such as local considerations, operability or transmission security – do not pose a reliability concern. In those cases, the IESO may place an outage at risk, signaling to the facility owner to consider rescheduling the outage.

The existing installed generation capacity is summarized in Table 4-1. This includes capacity from new projects that have completed the IESO's market registration process since the previous Outlook. The forecast capability at the Outlook peak is based on the firm resource scenario, which includes resources currently under commercial operation, and takes into account deratings, planned outages and allowance for capability levels below rated installed capacity.

Table 4-1 | Existing Grid-Connected Resource Capacity

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Outlook Peak Normal Weather (MW)	Forecast Capability at Outlook Peak [Extreme] (MW)	Number of Stations	Change in Number of Stations	Change in Installed Capacity
Nuclear	13,009	11,258	11,258	5	0	0
Hydroelectric	9,065	4,828	4,212	76	0	0
Gas/Oil	10,277	8,439	8,023	31	0	0
Wind	4,486	611	611	39	0	0
Biofuel	295	254	254	7	0	0
Solar	424	58	58	9	0	0
Demand Measures	-	554	554	-	-	-
Firm Imports (+) / Exports (-) (MW)	-	0	0	-	-	-
Total	37,555	26,004	24,972	167	0	0

4.1 Assessment Assumptions

4.1.1 Generation Resources

All generation resources scheduled to come into service, or to be upgraded or shut down within the Outlook period are summarized in Table 4-2. This includes generation projects in the IESO's connection assessment and approval process (CAA), those under construction, and contracted resources. Details regarding the IESO's CAA process and the status of these projects can be found on the [Application Status](#) section of the IESO website.

The estimated effective date column in Table 4-2 indicates when the market registration process is expected to be complete for each generation resource, based on information available to the IESO as of November 25, 2019. Two scenarios are used to describe project risks:

- The **planned scenario** assumes that all resources scheduled to come into service are available over the assessment period.
- The **firm scenario** assumes resources are restricted to those that have reached commercial operation status.

Planned shutdowns or retirements of generators that have a high certainty of occurring are considered for both scenarios.

Table 4-2 | Committed Generation Resources Status

Project Name	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered	
					Firm (MW)	Planned (MW)
Loyalist Solar	East	Solar	2019-Q4	Commissioning	0	54
Henvey Inlet Wind Farm	Essa	Wind	2020-Q1	Commissioning	0	300
Napanee Generating Station	East	Gas	2020-Q1	Commissioning	0	985
Nation Rise ¹	East	Wind	2020-Q1	Under Development	0	100
Romney Wind Energy Centre	West	Wind	2020-Q1	Under Development	0	60
Calstock	Northeast	Biofuel	2020-Q2	Expiring Contract	-38	-38
Total					-38	1,461

Notes on Table 4-2:

The total may not add up due to rounding and does not include in-service facilities. Project status provides an indication of the project progress, using the following terminology:

- Under Development – projects in approvals and permitting stages (e.g., environmental assessment, municipal approvals, IESO connection assessment approvals) and projects under construction.
- Commissioning – projects undergoing commissioning tests with the IESO.
- Commercial Operation – projects that have achieved commercial operation status under the contract criteria, but have not met all of the IESO's market registration requirements.

¹ The Renewable Energy Approval (REA) for this project was recently revoked and the IESO will continue to monitor developments on the status of the project.

- Expiring Contract – contracts that will expire during the Outlook period are included in both scenarios only up to their contract expiry date. Generators (including non-utility generators) that continue to provide forecast output data are also included in the planned scenario for the rest of the 18-month period.

4.1.2 Generation Capability

Hydroelectric

A monthly forecast of hydroelectric generation output is calculated based on median historical values of hydroelectric production and contribution to operating reserve during weekday peak demand hours. Through this method, routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data (see the first row in Table 4-3). To reflect the impact of hydroelectric outages on the reserve above requirement (RAR) and allow the assessment of hydroelectric outages as per the outage approval criteria, the hydroelectric capability is also calculated, without accounting for historical outages (see the second row of Table 4-3). Table 4-3 uses data from May 2002 to March 2019, which are updated annually to coincide with the release of the Q2 Outlook.

Table 4-3 | Monthly Historical Hydroelectric Median Values for Normal Weather Conditions

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical Hydroelectric Median Contribution (MW)	6,338	6,276	6,102	6,035	6,139	5,958	5,876	5,522	5,273	5,643	5,882	6,336
Historical Hydroelectric Median Contribution without Outages (MW)	6,851	6,846	6,609	6,555	6,594	6,465	6,270	6,047	6,104	6,449	6,616	6,846

Thermal Generators

Thermal generators' capacity, planned outages and deratings are based on market participant submissions. Forced outage rates on demand are calculated by the IESO based on actual operations data. The IESO will continue to rely on market participant-submitted forced outage rates for comparison purposes.

Wind

For wind generation, monthly wind capacity contribution (WCC) values from the weekday peak time are used. The process for determining wind contribution can be found in the [Methodology to Perform the Reliability Outlook](#). Figure 4-1 shows the monthly WCC values, which are updated annually with the release of the Q2 Outlook.

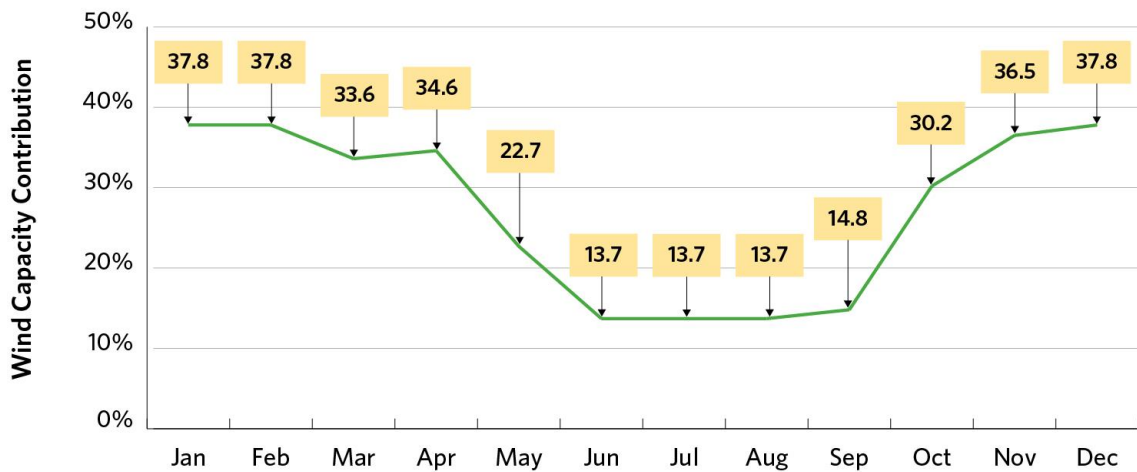


Figure 4-1 | Monthly Wind Capacity Contribution Values

Solar

For solar generation, monthly solar capacity contribution (SCC) values are used from the weekday peak time. Information on how the solar contribution is calculated can be found in the [Methodology to Perform the Reliability Outlook](#). Figure 4-2 shows the monthly SCC values, which are updated annually for the release of the Q2 Outlook.

The grid demand profile has been changing, due to the increasing penetration of embedded solar generation, which is pushing summer peaks to later in the day. As a result, the contribution from grid-connected solar resources has declined at the time of peak Ontario demand.

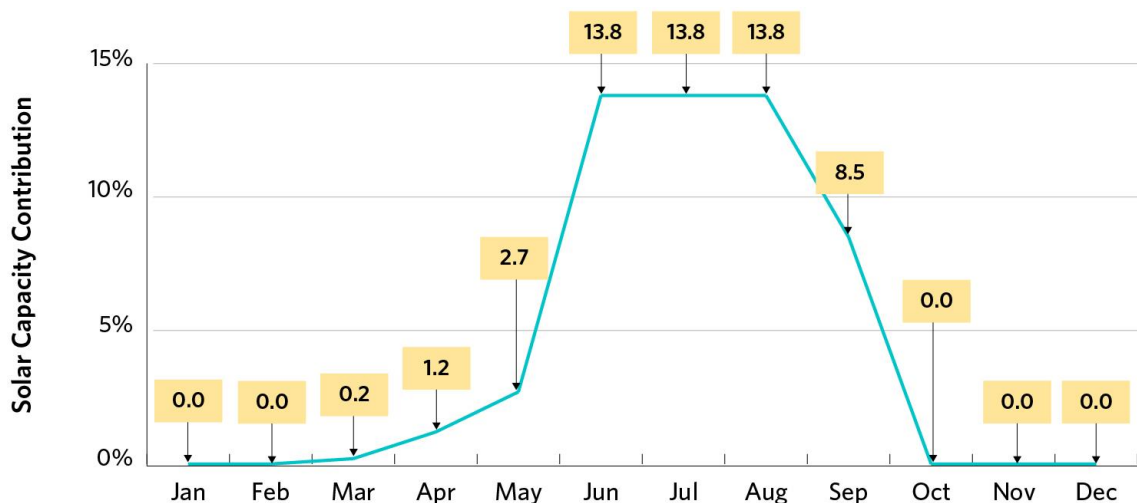


Figure 4-2 | Monthly Solar Capacity Contribution Values

4.1.3 Demand Measures

Both demand measures and load modifiers can impact demand, but differ in how they are treated within the Outlook. Demand measures, such as dispatchable loads and demand response procured through an annual demand-response [auction](#), are not incorporated into the demand forecast and are instead treated as resources. Load modifiers are incorporated into the demand forecast, as explained in [3.2.3](#) (Demand Measures and Load Modifiers). The impacts of activated demand measures are added back into the demand history prior to forecasting demand for future periods.

4.1.4 Firm Transactions

Capacity-Backed Export

The IESO allows Ontario resources to compete in the capacity auctions held by certain neighbouring jurisdictions, only if Ontario is adequately supplied. Capacity-backed exports of up to 128 MW installed capacity were successful in the New York Independent System Operator (NYISO) auctions for delivery between November 2019 and April 2020.

System-Backed Export

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. In addition, Ontario will receive up to 2.3 TWh of clean energy annually scheduled economically via Ontario's real-time markets. The imported energy will target peak hours to help reduce greenhouse gas emissions in Ontario. The agreement includes the opportunity to cycle energy.

As part of this capacity exchange agreement, Ontario can call on 500 MW of capacity during summer before September 2030, based on the province's needs.

4.1.5 Summary of Scenario Assumptions

To assess future resource adequacy, the IESO must make assumptions about the amount of available resources. The Outlook considers two scenarios: a firm scenario and a planned scenario.

The starting point for both scenarios is the existing installed resources shown in Table 4-1. The planned scenario assumes that all resources scheduled to come into service are available over the assessment period. The firm scenario assumes resources are restricted to those that have reached commercial operation status. Generator-planned shutdowns or retirements that have a high certainty of occurring are considered for both scenarios. They also both reflect planned outages submitted by generators. Table 4-4 shows the available resources that are forecast for the 18 months, under the two scenarios in normal weather conditions, at the time of the summer and winter peak demands during the Outlook.

Table 4-4 | Summary of Available Resources under Normal Weather

Notes	Description	Winter Peak 2020		Summer Peak 2020		Winter Peak 2021	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	37,555	37,609	37,555	39,054	37,555	39,054
2	Total Reductions in Resources (MW)	12,678	12,732	12,142	12,652	10,380	10,737
3	Demand Measures (MW)	770	770	554	554	770	770
4	Firm Imports (+) / Exports (-) (MW)	-629	-629	0	0	-500	-500
5	Available Resources (MW)	25,018	25,018	25,967	26,956	27,445	28,587
6	Bottling (MW)	2,032	2,032	37	37	420	420
7	Available Resources without Bottling (MW)	27,050	27,050	26,004	26,993	27,865	29,007

Notes on Table 4-4:

1. Installed Resources: The total generation capacity assumed to be installed at the time of the summer and winter peaks.
2. Total Reductions in Resources: The sum of deratings, planned outages, limitations due to transmission constraints and allowance for capability levels below rated installed capacity.
3. Demand Measures: The amount of demand expected to be available for reduction at the time of peak.
4. Firm Imports/Exports: The amount of expected firm imports and exports at the time of summer and winter peaks.
5. Available Resources: Installed Resources (line 1) minus Total Reductions in Resources (line 2) plus Demand Measures (line 3) and Firm Imports/Exports (line 4). This differs from the Forecast Capability at System Peak shown in Table 4-1 due to the impacts of generation bottling (transmission limitations).
6. Available Resources without Bottling: Available resources after they are reduced due to bottling.

4.2 Capacity Adequacy Assessment

The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages assessed as of October 28, 2019. The generation planned outages occurring during this Outlook period have been assessed as of November 25, 2019.

4.2.1 Firm Scenario with Normal and Extreme Weather

The firm scenario incorporates all capacity that had achieved commercial operation status as of November 25, 2019.

Figure 4-3 shows RAR levels, which represent the difference between available resources and required resources. The latter equals the demand plus required reserve. The reserve requirement in the firm scenario under normal weather conditions is met throughout the entire Outlook period.

The IESO's revised outage approval methodology (using the extreme weather scenario with up to 2,000 MW of imports) has been in effect since May 1, 2019. Under extreme weather conditions, the reserve is lower than the requirement, without reliance on imports for a total of 16 weeks in 2020 and eight weeks in the first half of 2021. Under the current outage schedule, the RAR falls below the -2,000 MW threshold for four weeks

in June 2020, three weeks in July 2020, two weeks in August 2020, and one week in September 2020, as well as five weeks in June 2021. This potential shortfall is largely attributed to planned generator outages scheduled during those weeks. If extreme weather conditions materialize, the IESO may reject some generator maintenance outage requests to ensure that Ontario demand is met during the summer peak periods.

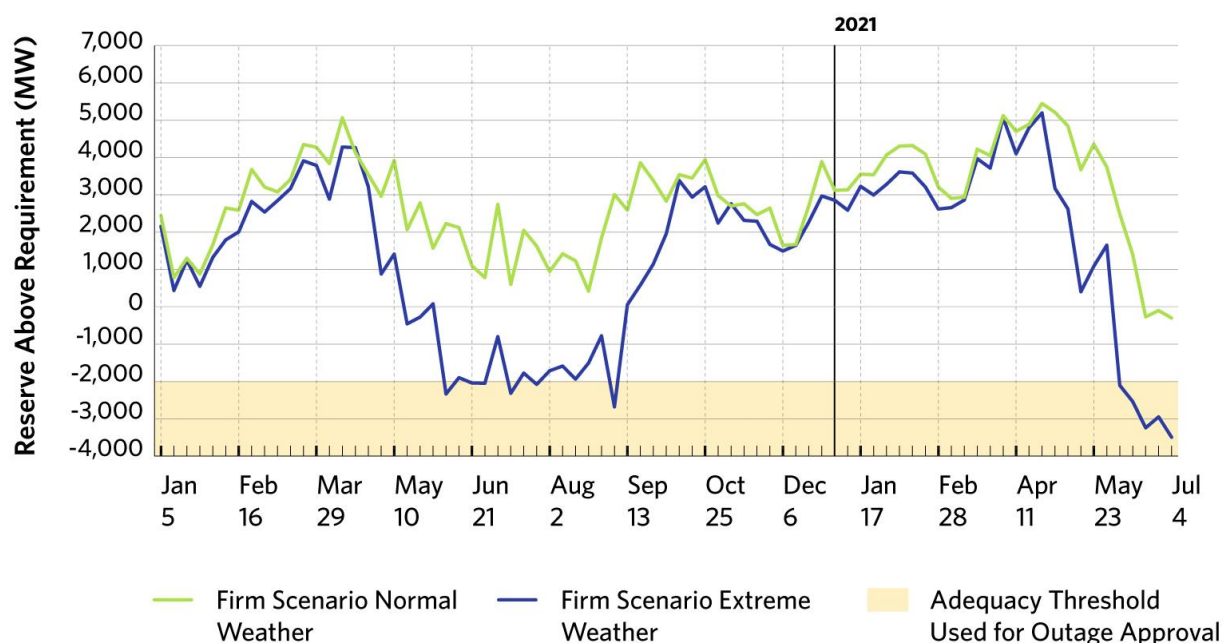


Figure 4-3 | Comparison of Normal and Extreme Weather: Firm Scenario Reserve Above Requirement

4.2.2 Planned Scenario with Normal and Extreme Weather

The planned scenario incorporates all existing capacity, as well as all capacity coming into service. Approximately 1,500 MW of generation capacity is expected to connect to Ontario's grid over this Outlook period, while 38 MW of generation capacity contracts will expire.

Figure 4-4 shows RAR levels under the planned scenario. As observed, the reserve requirement is being met throughout the Outlook period under normal weather conditions.

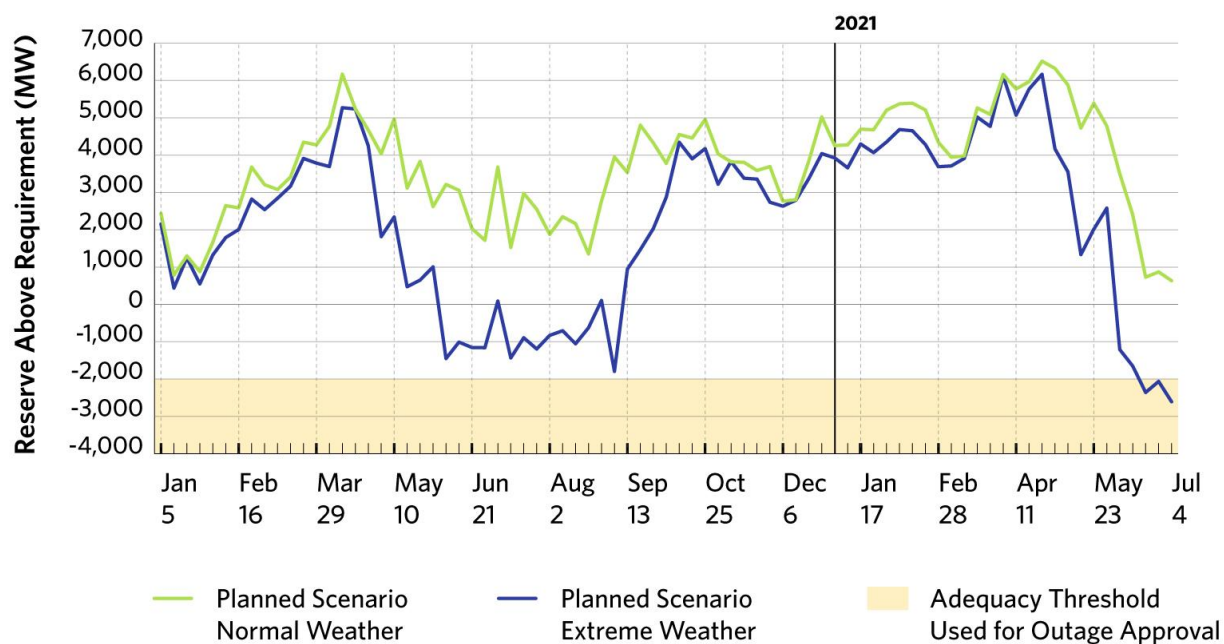


Figure 4-4 | Comparison of Normal and Extreme Weather: Planned Scenario Reserve Above Requirement

4.2.3 Comparison of the Current and Previous Weekly Adequacy Assessments for the Firm Normal Weather Scenario

Figure 4-5 compares forecast RAR values in the current Outlook with those in the previous Outlook, which was published on September 19, 2019. The difference is primarily the result of changes in planned outages and the expected in-service dates of new resources.

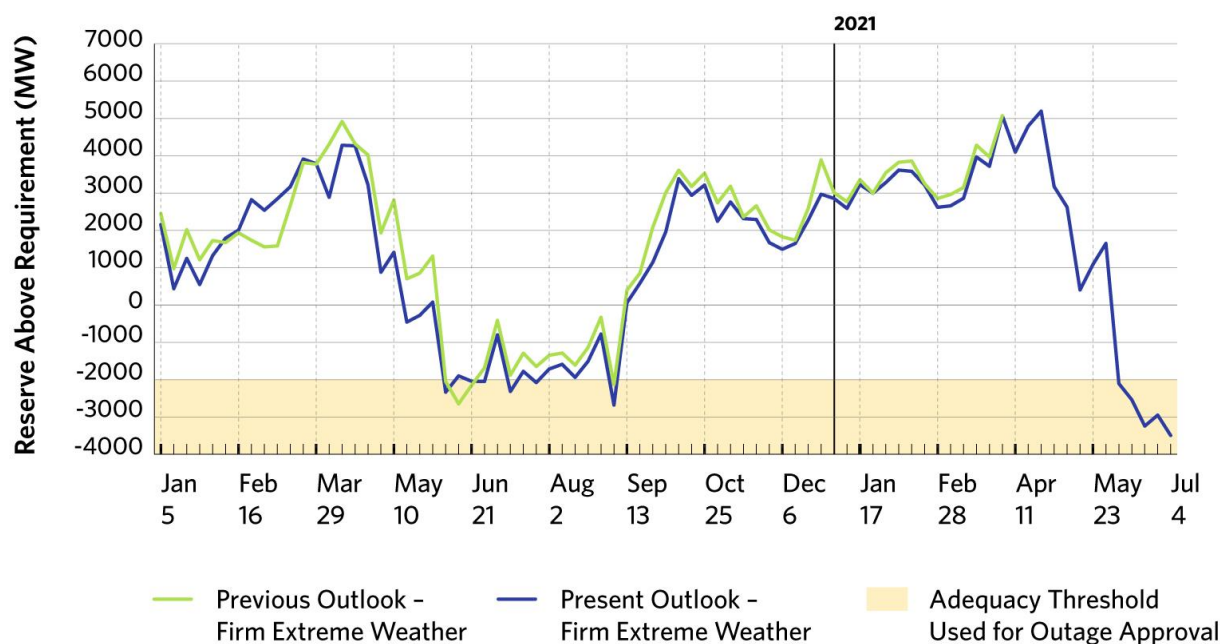


Figure 4-5 | Comparison of Current and Previous Outlook: Firm Scenario Extreme Weather Reserve Above Requirement

Resource adequacy assumptions and risks are discussed in detail in the [Methodology to Perform the Reliability Outlook](#).

4.3 Energy Adequacy Assessment

This section assesses energy adequacy to determine whether Ontario has sufficient supply to meet its forecast energy demands, while highlighting potential adequacy concerns during the Outlook time frame. At the same time, the assessment estimates the aggregate production by resource category to meet the projected demand based on assumed resource availability.

4.3.1 Summary of Energy Adequacy Assumptions

The energy adequacy assessment (EAA) uses the same set of assumptions as the capacity assessment, as outlined in Table 4-1 and Table 4-2, which indicate the total capacity of committed resources and when they are expected to be available over the next 18 months. The monthly forecast of energy production capability, based on energy modelling results, is included in the [2019 Q2 Outlook Tables](#).

For the EAA, only the firm scenario in Table 4-5 with normal weather demand is assessed. The key assumptions specific to this assessment are described in the [Methodology to Perform the Reliability Outlook](#).

4.3.2 Results – Firm Scenario with Normal Weather

Table 4-5 summarizes the energy simulation results over the next 18 months for the firm scenario with normal weather demand both for Ontario and for each transmission zone.

Table 4-5 | Summary of Zonal Energy for Firm Scenario Normal Weather

Zone	18-Month Energy Demand		18-Month Energy Production		Net Inter-Zonal Energy Transfer	Zonal Energy Demand on Peak Day of 18-Month Period	Available Energy on Peak Day of 18-Month Period
	TWh	Average MW	TWh	Average MW	TWh	GWh	GWh
Bruce	1.0	79.0	63.2	4,811.0	62.2	1.5	133.3
East	13.7	1,047.0	16.8	1,281.0	3.1	29.4	73.9
Essa	12.4	946.0	4.7	356.0	-7.7	26.0	15.6
Niagara	6.1	466.0	20.8	1,584.0	14.7	14.0	52.1
Northeast	16.0	1,217.0	15.3	1,162.0	-0.7	26.3	33.1
Northwest	6.0	457.0	6.9	524.0	0.9	9.6	16.5
Ottawa	18.6	1,417.0	0.3	24.0	-18.3	37.4	1.4
Southwest	41.6	3,172.0	8.9	682.0	-32.7	90.9	25.2
Toronto	75.1	5,722.0	59.3	4,516.0	-15.8	179.8	152.4
West	20.8	1,585.0	15.3	1,168.0	-5.5	48.5	76.0
Ontario	211.5	16,107.0	211.5	16,107.0	0.0	463.4	579.5

4.3.3 Findings and Conclusions

The EAA results indicate that Ontario is expected to have sufficient supply to meet its energy forecast throughout 2020 for the firm scenario with normal weather demand, without being expected to rely on support from external jurisdictions. However, they also indicate the potential for unserved energy in June 2021. Note that the EAA does not consider either new generation resources that are anticipated to be in service before this time, or the possibility of energy imports. As highlighted in section 4.2, some planned outages are likely to be shifted during this period to meet capacity adequacy requirements, which should also help to ensure energy adequacy.

Figure 4-6 forecasts the percentage of Ontario's energy demand expected to be supplied by each fuel type for the next 18 months, while Figure 4-7 shows the production by fuel type for each month. Exports out of Ontario and imports into Ontario are not considered in this assessment. Table 4-6 summarizes these simulated production results by fuel type, for each year.

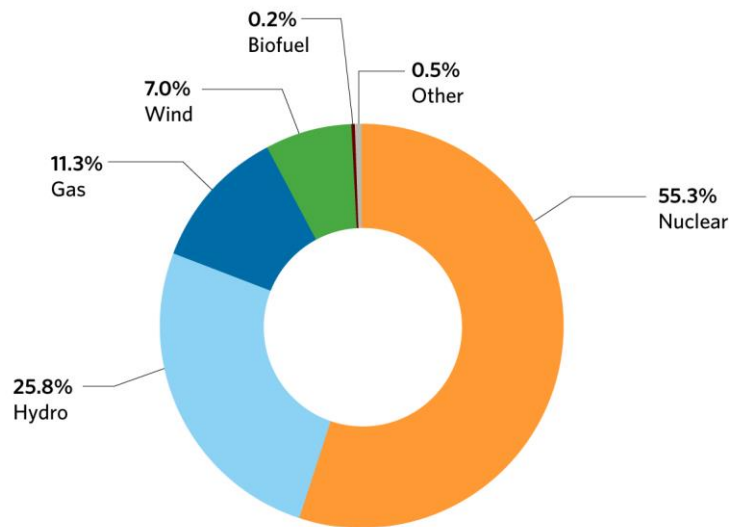


Figure 4-6 | Forecast Energy Production by Fuel Type

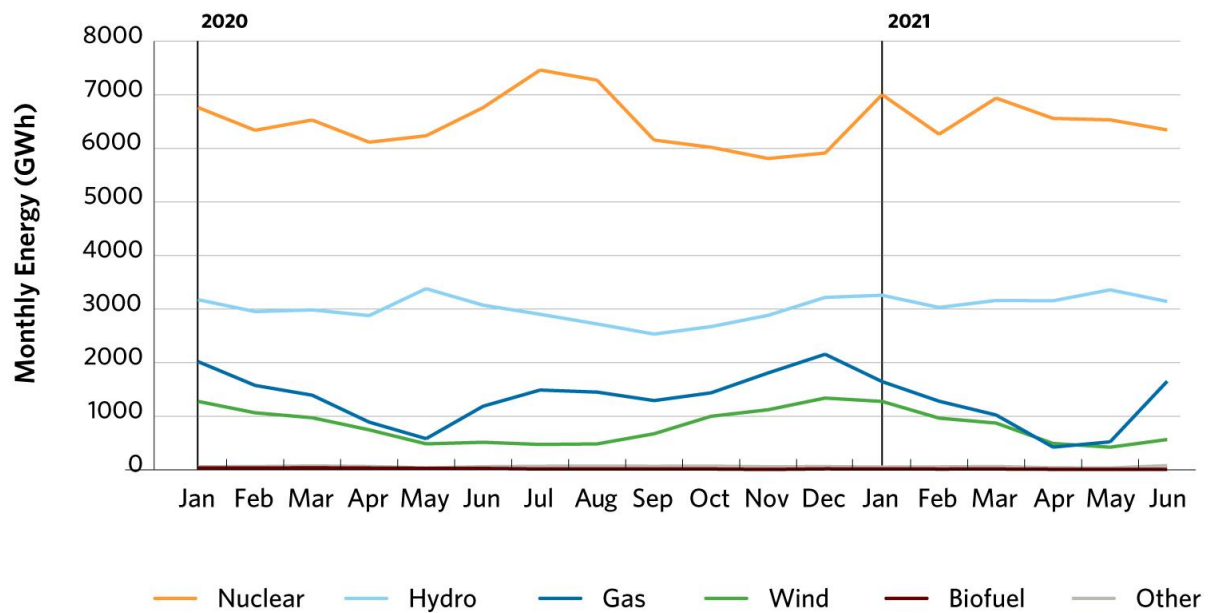


Figure 4-7 | Forecast Monthly Energy Production by Fuel Type

Table 4-6 | Ontario Energy Production by Fuel Type for the Firm Scenario Normal Weather

Fuel Type (Grid Connected)	2020 (Jan 1 - Dec 31) (GWh)	2021 (Jan 1 - June 30) (GWh)	Total (GWh)
Nuclear	77,368	39,639	117,007
Hydro	35,378	19,105	54,482
Gas & Oil	17,279	6,545	23,824
Wind	10,145	4,590	14,735
Bio Fuel	284	70	354
Other (Solar & DR)	734	319	1,052
Total	141,188	70,268	211,455

5. Transmission Reliability Assessment

Ontario's transmission system is expected to continue to reliably supply province-wide demand, while experiencing normal contingencies defined by planning criteria for the next 18 months. However, some combinations of transmission and/or generation outages can create operating challenges.

The IESO assesses transmission adequacy using a methodology based on conformance to established criteria, including the [Ontario Resource and Transmission Assessment Criteria](#) (ORTAC), [NERC transmission planning standard TPL 001-4](#) and [NPCC Directory #1](#) as applicable. Planned system enhancements and projects, and known transmission outages are also considered in the studies.

Ontario's transmission system is expected to continue to reliably supply province-wide demand while experiencing normal contingencies defined by planning criteria for the next 18 months.

5.1 Transmission Projects

This section considers the information transmitters provide with respect to transmission projects that are planned for completion within the next 18 months. Transmission projects planned for completion beyond this time frame are considered in section [7.5](#). The list of transmission projects is provided in [Appendix B1](#).

5.2 Transmission Outages

The IESO's assessment of transmission outage plans is shown in [Appendix C, Tables C1 to C11](#). The methodology used to assess the transmission outage plans is described in the [Methodology to Perform the Reliability Outlook](#). This Outlook contains transmission outage plans submitted to the IESO as of October 28, 2019.

5.3 Transmission Considerations

The purpose of this section of the report is to highlight projects and outages that may affect the scheduling of other outages and/or may affect reliability, and categorize these considerations by zone.

Bruce, Southwest and West Zones

Hydro One has begun replacing the aging infrastructure at the Bruce 230 kV switchyard, which requires careful coordination of transmission and generation outages. This project is scheduled to be completed by 2021-Q2.

Aging circuit breakers in the Richview 230 kV switchyard are to be replaced in 2020. Hydro One and the IESO will coordinate the outages required to reduce the impact on the FETT transfer capabilities.

A series of non-contiguous planned outages will impact the flow out of Bruce from February to November 2020. Planned outages include the following circuits: B601M, B502M, B560V, B561M, N582L, M585M and V586M. A planned two-week outage starting April 20, 2020 will impact circuit B569B, reducing transfer capability into the West zone.

Significant growth in the greenhouse sector has led to a number of customer connection requests in the Windsor-Essex region that are expected to exceed the capacity of the existing transmission system in the area. A new switching station at the Leamington Junction is proceeding toward a 2022-Q3 in-service date. Outages may be more challenging to facilitate starting in late 2019, when new load connections are made and required transmission reinforcements are being implemented.

Toronto, East and Ottawa Zones

Operational challenges due to high voltages in eastern Ontario and the Greater Toronto Area continue to occur during low demand periods. The IESO and Hydro One are currently managing this situation by removing one of the 500 kV circuits in eastern Ontario during those periods. To address this issue on a longer-term basis, two 500 kV line-connected shunt reactors will be installed at Lennox TS with a target in-service date of 2020-Q4 for the first reactor and 2021-Q4 for the second reactor.

Northwest, Northeast and Essa Zones

In the Kapuskasing area, system reinforcements, including upgrades to circuit H9K and the installation of reactive compensation, are planned for 2020-Q1 and 2021-Q2, respectively. During the construction of these reinforcements, certain outages may be restricted.

A number of non-contiguous planned outages, from February 2020 to November 2020, will reduce transfer capability on the North-South Tie. Planned outages include circuits X503E, X504E, and D5H and breakers at Hanmer TS.

A two-week outage in September 2020 and a four-week outage in November 2020 will impact transfer capacities between the Essa and Toronto zones.

Outages in February and March 2020 will reduce transfer capability into the Northwest zone across the East-West Tie. Significant construction activities for the East West Tie reinforcement project will also occur over the Outlook period, requiring outages to existing transmission facilities in the northwest. Additional information regarding the impacts of this project will be provided in the 2020-Q1 *Reliability Outlook*.

Interconnections

The early 2018 failure of the phase angle regulator (PAR) connected to the Ontario-New York 230 kV interconnection circuit L33P continues to hinder the province's ability to import electricity from New York through the New York-St. Lawrence interconnection and from Quebec through the Beauharnois interconnection. This has required enhanced coordination with affected parties and more focused management of St. Lawrence area resources in real-time. Careful coordination of transmission and generation outages will continue to be required in the area. PARs are unique pieces of equipment and replacements are not readily available. Replacement options for the unit are being investigated jointly with the IESO, Hydro One, NYISO and the New York Power Authority. The preferred replacement option is a new PAR with a +/- 50-degree angle range, based on the recommendation by the joint New York/Ontario team to Hydro One for tendering. The return to service date for the L33P PAR is not expected to be earlier than 2021-Q4.

A planned two-and-a-half-week outage starting March 16, 2020 will impact interconnection circuit L51D, reducing import and export transfer capability between Ontario and Michigan.

6. Operability

During the Outlook period, Ontario will continue to experience potential surplus baseload conditions, much of which can be managed with existing market mechanisms, such as exports and curtailment of variable generation.

This section highlights existing or emerging operability issues that could impact the reliability of Ontario's power system.

6.1 Regulation Needs

The IESO recently completed a regulation study to assess Ontario's short-term regulation needs. The IESO's study identified the need for an additional +/-15 MW of regulation service (currently the IESO schedules at least +/- 100 MW). This results in a regulation capacity need of 35 MW. The IESO will be conducting a competitive RFP in 2020 to acquire this additional service.

6.2 Seasonal Readiness

The IESO continues to use its existing programs such as unit readiness to test readiness of the generation fleet for the upcoming winter season. The IESO is also tracking industry developments, utility best practices and programs implemented by other jurisdictions for winter readiness and, where appropriate, will share the relevant information with market participants to facilitate development and enhancement of their winter readiness programs.

6.3 Outage Management Concerns

Market participants are reminded that outage coordination is becoming more challenging given that significant capital upgrades, such as refurbishment outages and station rebuilds, will occur at the same time as ongoing routine maintenance. The *Reliability Outlook* informs market participants about critical periods, giving them the opportunity to reschedule outages and minimize the risk of outages being revoked by the IESO in the operating time frame.

6.4 Grid Voltage Control

During low demand periods, including overnight, maintaining system voltages within the prescribed limits in certain parts of the system can be challenging. Increased supply from distribution-connected resources results in the displacement of centralized generation facilities, leading to reduced transfers across the transmission system. Lightly loaded lines are a source of reactive power and result in high system voltages. The IESO and

Hydro One are currently managing this situation with day-to-day operating procedures and plan to address this issue on a longer-term basis (refer to section [5.3](#) – Toronto, East and Ottawa Zones).

6.5 Surplus Baseload Generation

Baseload generation is made up of nuclear, run-of-the-river hydroelectric and variable generation, such as wind and solar. When the baseload supply is expected to exceed Ontario demand, market signals reflect such conditions through lower prices, and resources and activity at the interties respond accordingly. The resulting market outcomes include higher export schedules, dispatching down of hydroelectric generation and grid-connected renewable resources, and nuclear maneuvering or shutdown. For severe surplus conditions that could affect reliability of the system, the IESO may take out-of-market actions, such as manually curtailing resources and/or imports.

Figure 6-1 shows the nuclear, wind and import curtailments from October 2018 to the end of September 2019.

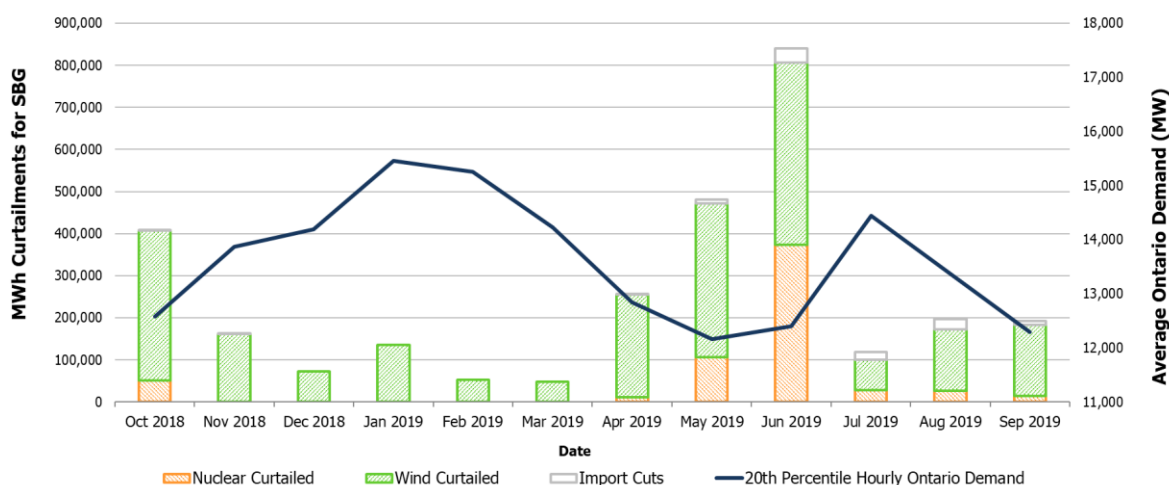


Figure 6-1 | MWh Curtailments versus Ontario Demand

Ontario will continue to experience potential surplus baseload conditions during the Outlook period. Figure 6-2 highlights the periods during which expected baseload generation may exceed forecast demand.

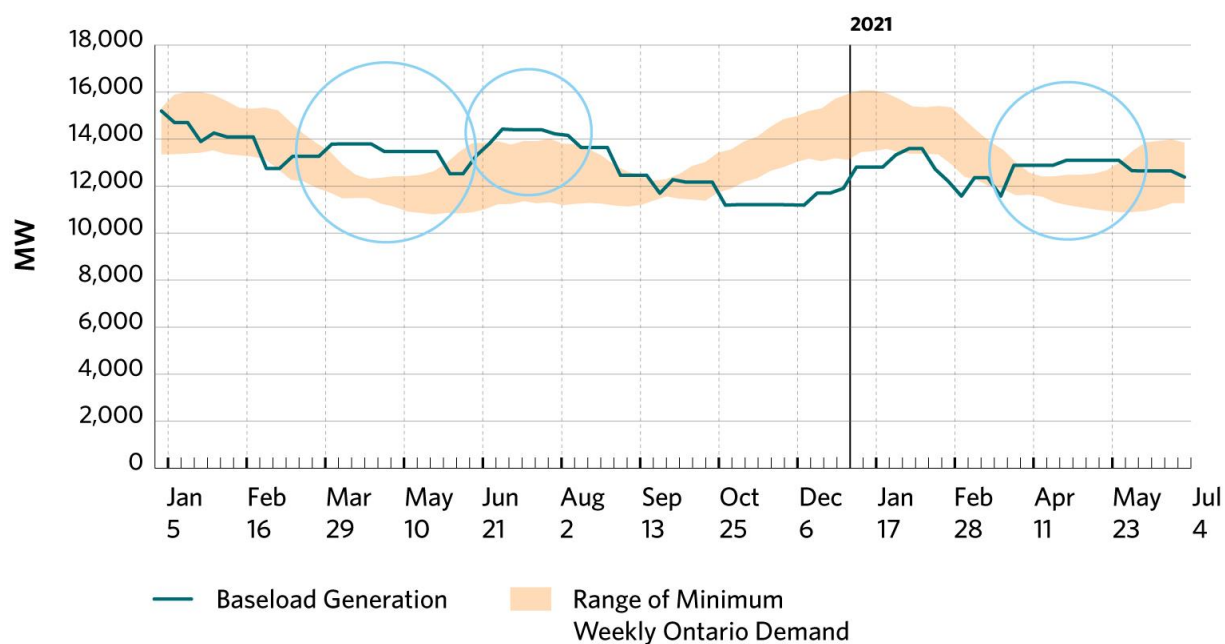


Figure 6-2 | Minimum Ontario Demand and Baseload Generation

Much of the surplus baseload conditions can be managed with existing market mechanisms signaling for exports, and by curtailing variable and nuclear generation. Going forward, as shown in Figure 6-3, existing mechanisms will be sufficient for managing SBG.

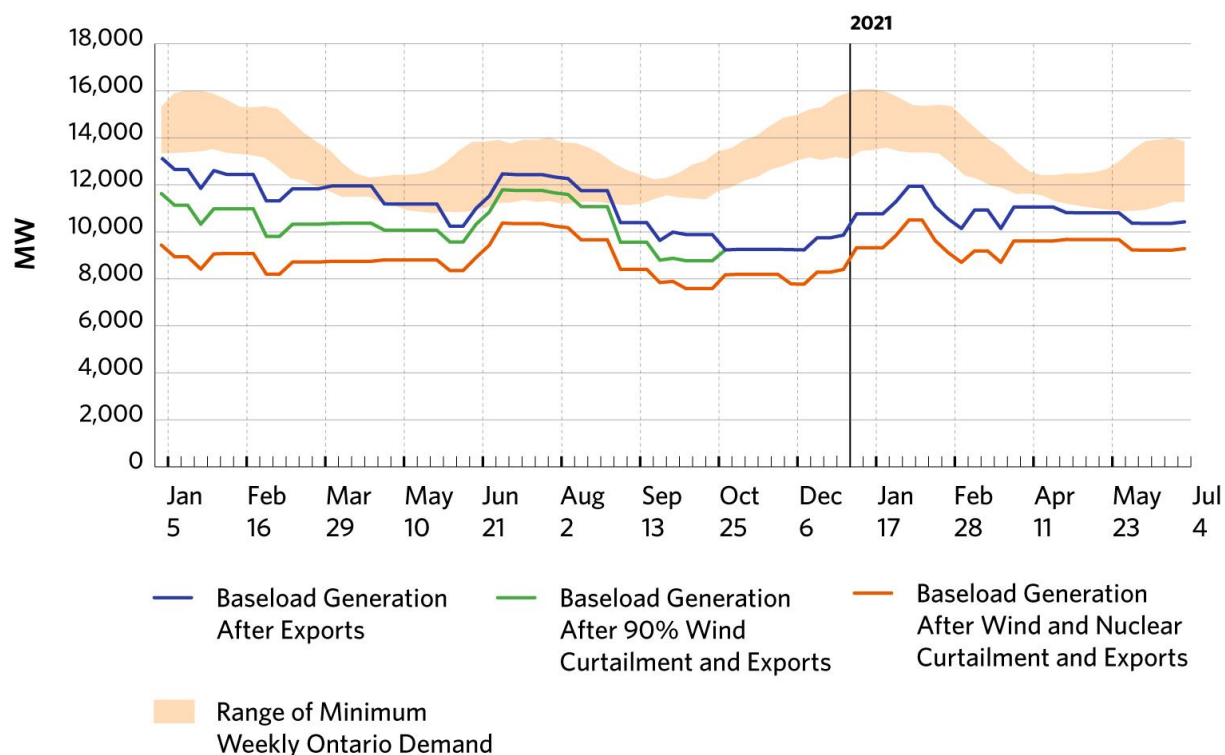


Figure 6-3 | Minimum Ontario Demand and Baseload Generation

The baseload generation assumptions include expected exports and run-of-river hydroelectric production, the latest planned outage information and in-service dates for new or refurbished generation. The expected contribution from self-scheduling and intermittent generation has been updated to reflect the latest data. Information on the dispatch order of wind, solar and flexible nuclear resources can be found in [Market Manual 4 Part 4.2](#). Output from commissioning units is explicitly excluded from this analysis due to uncertainty and the highly variable nature of commissioning schedules. Figure 6-4 shows the monthly off-peak wind capacity contribution values calculated from actual wind output up to March 31, 2019. These values are updated annually to coincide with the release of the Q2 Outlook.

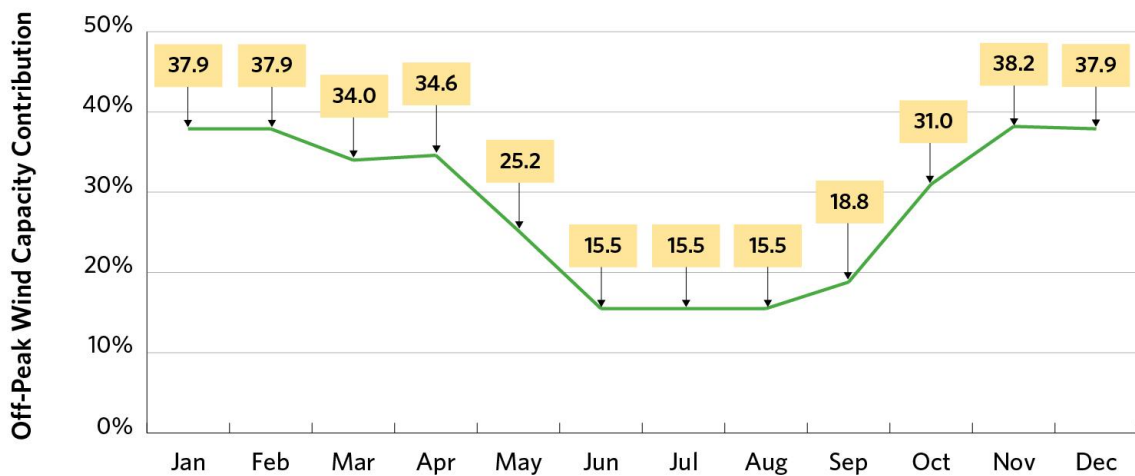


Figure 6-4 | Monthly Off-Peak Wind Capacity Contribution Values

7. Beyond 18 Months

The months from June to September of 2023 continue to be the most significant period of system need in the forecast horizon, with reserves falling below the adequacy threshold for a significant fraction of that period.

Additionally, transmission assessments for May and June 2023 indicate that up to seven coincident nuclear outages will present a material reliability risk. Under this condition, there would be inadequate dependable resources east of the FETT interface.

Market participants should avoid outages during spring and summer of 2023 and be prepared for the possibility that outages may be rejected.

7.1 Introduction

This chapter is intended to inform stakeholders about changes in resource adequacy during the 42-month period from July 2021 to December 2024 that will make outage coordination and assessments more complex.

Published twice a year in the June and December Outlooks, this section provides a longer-term view of the landscape, with the understanding that the extended time frame means the values provided are necessarily less precise than those for shorter-term outlooks. To improve the precision of this report, generation and transmission owners should submit their longer-term outage plans to the IESO's outage management system at the earliest opportunity.

7.1.1 Interpretation

The assumptions and assessment approach in this report are focused only on outage management. At the [2018 Technical Planning Conference](#), the IESO identified a need for additional capacity in 2023, increasing through 2025. Preliminary results from the 2019 *Annual Planning Outlook* (APO), which have been presented at forums such as the [Stakeholder Advisory Committee](#), have confirmed this need. The IESO is developing a capacity auction, as well as launching a resource adequacy engagement to explore alternative or complementary approaches to address this requirement.

Information on global adequacy needs that require investments beyond outage management were provided in the IESO's Planning Outlook, delivered at the Conference. This Outlook included nuclear retirements and refurbishments, and facilities reaching end-of-contract terms. As a transparent, forward-looking planning process is core to addressing emerging developments, in 2019 the IESO engaged with stakeholders to inform development of the 2019 *Annual Planning Outlook*. Access to this information will enable market participants to work collaboratively with the IESO to coordinate planned maintenance outages and help ensure Ontarians continue to have the energy they need to power their homes and businesses.

7.2 Key Findings

Table 7-1 describes key reliability issues expected between July 2021 and December 2024 that may affect outage scheduling or be mitigated by outage rescheduling.

Table 7-1 | Notable Issues or Findings

Issue or Finding	How Issue was Identified	Impact to Outage Management	Additional Information
Periods where the IESO should reconsider scheduling of outages in its outage management system	Capacity Adequacy Assessment (All Scheduled Outages Scenario)	Generators are advised to consider rescheduling outages to avoid: • June to September 2023	Section 7.3
Periods where the IESO should consider scheduling of outages not yet in its outage management system	Capacity Adequacy Assessment (All Anticipated Outages Scenario)	Generators are advised to consider scheduling outages to avoid: • June to September 2023 • May and July to September 2024	Section 7.3
Periods where outage management alone cannot resolve capacity adequacy needs	Capacity Adequacy Assessment	Beyond outage rescheduling, additional capacity likely required from June to September 2023	Section 7.3 and 2018 Technical Planning Conference Presentation
Periods where there are opportunities for outages to take place	Capacity Adequacy Assessment	Under all scenarios, there are opportunities for outages to take place from November to April each year	Section 7.3
Flow East Toward Toronto (FETT) interface	Recent observations of system conditions	Transfer capability of the FETT interface could be reduced significantly with one or more key transmission elements out of service, particularly when Pickering or Darlington units are out of service	Section 7.5

7.3 Capacity Adequacy Assessment

This section assesses the adequacy of resources to meet forecast demand. When reserves are below required levels, with potentially adverse effects on the reliability of the grid, the IESO will reject outage requests based on their order of precedence. Conversely, when reserves are above required levels, additional outages may be approved, provided other factors – such as local considerations, operability, or transmission security – do not pose a reliability concern. This assessment is focused solely on outage management. Longer-term information regarding electricity resource needs will be provided in the 2019 *Annual Planning Outlook*.

Uncertainties in the five-year horizon include economic and demographic conditions, achievement of energy-efficiency targets, penetration of embedded generation, weather conditions, timing and completion of transmission and resource projects, and the scheduling of planned and forced outages. In all cases, these uncertainties increase over time. Load forecast uncertainty and forced outages were considered probabilistically in these assessments, while other uncertainties were evaluated using a scenario-based assessment of capacity adequacy. These scenarios are described in Section 7.3.1 and the details of those results are available in [Appendix A.11-A.13](#). Further information on the assumptions and inputs are provided in Section 7.4.

7.3.1 Summary of Scenarios Considered

To assess future capacity adequacy, the IESO used a scenario-based approach to compare various risks. The three sensitivities considered are:

- **Outages:** Outages were divided into scenarios based on how the IESO received the schedule, recognizing that submissions to the IESO outage management system may have less flexibility to be rescheduled than those submitted annually through the [Generator Information Submittal Form for Reliability Assessments](#) (Form 1230).
- **Project risks:** The planned scenario shows all projects coming into service on time. The delay scenario groups several project risks together by delaying new generation schedules by six months, the completion date of nuclear refurbishment outages by one year, and the in-service date of new transmission equipment by one year.
- **Weather:** The extreme weather scenario combines extreme temperature impacts on demand, along with generator ratings at the extreme temperatures.

In this time frame, because outage schedules are less certain, not all are submitted to the IESO's outage management system. As scheduling certainty increases, generator owners will be expected to provide that information in the IESO's outage management system. Because of this uncertainty, outages are treated as an additional sensitivity in this longer-term view; while in the 18-month time frame, only project risks and weather are incorporated as sensitivities.

This Outlook for July 2021 to December 2024 presents the results of three scenarios combining the above sensitivities. Results from these scenarios are shown in the [2019 Q4 Outlook Tables](#) on a monthly basis and discussed in Section 7.3.2.

Table 7-2 | Summary of Scenarios

	Outages	Project Risk	Weather
All Anticipated Outages	All outages submitted in the IESO's outage management system and Form 1230s	Planned	Extreme
All Scheduled Outages	All outages submitted in the IESO's outage management system	Planned	Extreme
Delayed	All outages submitted in the IESO's outage management system and Form 1230s	Delay	Extreme

Table 7-3 shows a snapshot of the available resources that are forecast, under all scenarios, at the time of the annual peaks during the Outlook.

Table 7-3 | Summary of Available Resources (MW) at Summer Peak

Year	All Scheduled Outages	All Anticipated Outages	Delayed
2021	24,306	25,278	25,278
2022	25,484	24,221	24,221
2023	23,940	22,372	22,372
2024	24,551	24,443	24,443

7.3.2 Capacity Adequacy Findings

The three scenarios previously described show a range of possible outcomes. The all anticipated outages scenario represents the reference case for the findings, while the other two scenarios bookend what may occur. Figure 7-1 compares the RAR for the all anticipated outages scenario and for the all scheduled outages” scenario – the difference between the two scenarios represents the incremental outages submitted to the IESO in the 2019 Form 1230s.

All Anticipated Outages Scenario

The all anticipated outages scenario factors all outages submitted to the outage management system (CROW), and all anticipated outages received in the 2019 annual submission of Form 1230s. This scenario assumes all new generation and transmission comes into service as scheduled.

Under extreme weather, the existing outage plan show a significant period of risk in the summer of 2023. The summers of 2022 and 2024 are also periods of reliability concern, although to a lesser degree. Generators that have outages scheduled from June to September 2023 should consider rescheduling them outside of the summer months, as these are unlikely to be approved. As potential negative reserves during these summers exceed the amount of potential imports that the IESO may rely upon for resource adequacy, all non-critical or short-duration outages should be rescheduled into late fall, winter or early spring.

Generator owners with short-duration outages from June to September 2023 should continue to monitor future Outlooks for information on the impacts of these outage plans.

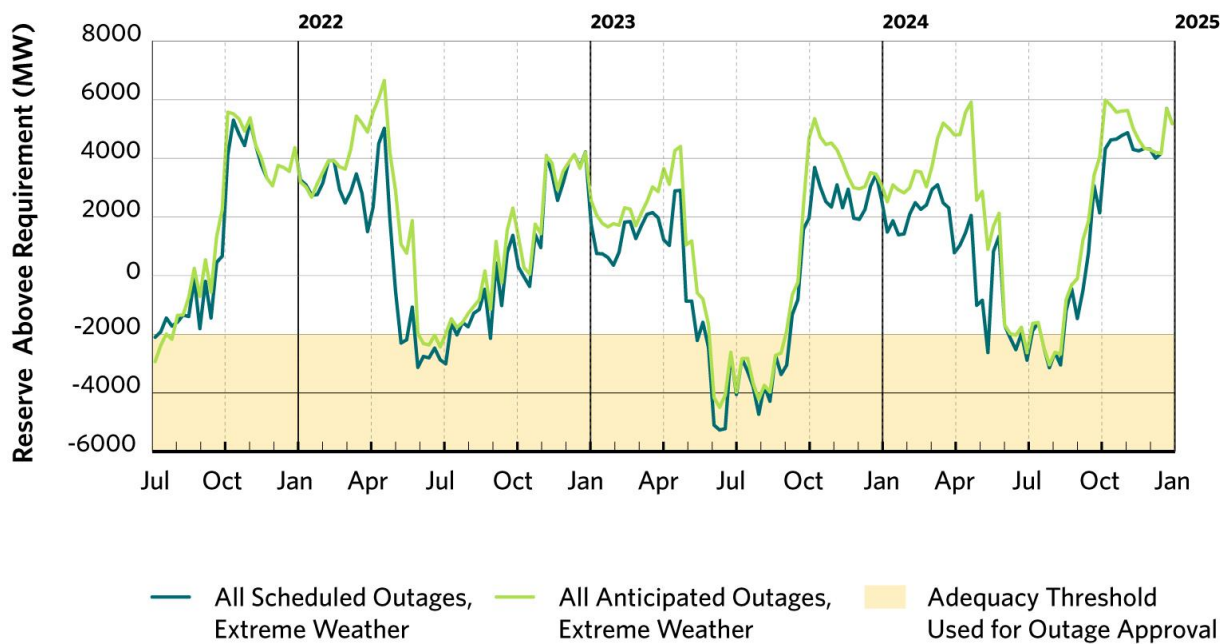


Figure 7-1 | Reserve Above Requirement for All Anticipated Outages and All Scheduled Outages Scenarios

Additional Scenarios

The all scheduled outages scenario, provided in [Appendix A.12](#) and shown in Figure 7-1, factors all outages submitted to CROW, as of November 25, 2019. This scenario assumes all new generation and transmission comes into service as scheduled. Under extreme weather, existing outages in CROW will drive the RAR lower than 2,000 MW below the requirement from June to September 2023, as well as significant parts of the June to September period in 2022 and 2024. Many anticipated outages beyond 2021 are not yet submitted to CROW, making summers 2022 to 2024 optimistic views in this scenario.

The delayed scenario shows a simulation where refurbishment outages and new generation projects are delayed by six months and new transmission lines are delayed by one year. Under normal weather, these additional risks can significantly change the view of capacity adequacy. As a result, the IESO will provide bi-annual updates to the RAR assessment so that market participants can monitor and update their outage plans, should delays occur.

7.4 Inputs and Assumptions

The inputs used for the assessment from July 2021 to December 2024 described in this section are:

- Demand
- Expected installed generation
- Transactions

Further details on the inputs, assumptions and methodology are available in the [Methodology to Perform the IESO Reliability Outlook](#). To reflect the uncertainty in outage schedules, weather, and in-service dates of new resources, several scenarios are employed. These were described in Section 7.3.1.

For resource adequacy assessments that consider periods beyond seasonal planning, some assumptions or methods should be adapted to reflect additional drivers or uncertainties that are better reflected in long-term adequacy assessments. The differences between the 18-month horizon and the longer-term view are described in Table 7-4. IESO assessments may adopt different methodologies or reflect newer/older data, depending on the requirements of each assessment.

Table 7-4 | Methodological Differences from the 18-Month Horizon

Consideration	18 Months	Next 42 Months
Transmission Outages	Considered transmission outage plans that were submitted to the IESO's outage management system by October 28, 2019. Reductions in transmission capacity due to an outage condition are expressed as a change in the base flow/operational limit associated with the interface or interconnection.	Considered transmission outage plans that were submitted to the IESO's outage management system by October 28, 2019. Impacts of outages assessed according to the Transfer Capability Assessment Methodology.
Treatment of New Transmission Equipment	The Planned Scenario assumes that all new transmission equipment is in-service as scheduled. The Firm Scenario considers the transmission system as at the beginning of the Outlook for the duration of the Outlook.	The Planned Scenario assumes that all new transmission equipment is in-service as scheduled. The Delay Scenario considers the new transmission equipment in-service date is delayed by one year.
Treatment of New Generator Resources	The Planned Scenario assumes that all new resources are available as scheduled. The Firm Scenario considers only new resources that have reached commercial operation. The capacity of new generation is the higher of the contracted capacity or the maximum generator capability submitted as part of the market registration process.	The Planned Scenario assumes that all new resources are available as scheduled. The Delay Scenario assumes that the scheduled start date of all new resources is delayed by six months. The capacity of new generation is assumed to be equal to its contracted capacity.
Generator Outages	Only outages submitted in IESO's outage management system are considered.	Outages submitted in the IESO's outage management system and the Form 1230s are considered (see Table 7-2).
Treatment of Resources at End of Contract Term	All resources are removed from the Firm Scenario at the end-of-contract term. Resources that forecast continued operation may be included in the Planned Scenario.	Only resources with publicly confirmed retirement dates are removed from the assessment.

7.4.1 Demand

Over the forecast period, Ontario energy demand is expected to show modest increases with an annual growth rate of 0.8%. Much of the growth in Ontario's economy is occurring outside of the province's electrically intense industrial sectors. Overall, consumption from the traditional energy-intensive sectors is stable with some growth in certain sectors (most notably mining) and declines in others (pulp and paper). Similar to how growth varies across economic segments, growth is different from region to region, with strong growth forecast for the Windsor-Essex area and continuing declines in the Northwest. Strong economic fundamentals in the form of a robust U.S. economy, low Canadian dollar and low interest rates underpin this demand growth profile. There is significant downside risk to the forecast due to the potential for continued trade disruptions, higher debt loads and their exposure to rising interest rates, and climate-related impacts. Both the summer and winter peaks are expected to grow over the forecast horizon. Population growth and economic expansion will help push the seasonal peaks higher over this period. Downward pressure still exists in the form of the ICI and the growing potential for peak modifying technology as a means to reduce consumers' peak consumption. This will act as a drag on seasonal peak demand growth.

Table 7-5 | Summary of Forecasted Peaks and Energy

Year	Normal Weather			Extreme Weather	
	Summer (MW)	Winter (MW)	Energy (TWh)	Summer (MW)	Winter (MW)
2021	22,285	21,239	137	24,697	22,533
2022	22,368	21,303	138	24,781	22,208
2023	22,715	21,423	138	24,920	22,566
2024	22,935	21,626	140	25,105	22,794

Table 7-6 | Monthly Energy and Peak Demand Forecast

Month	Normal Peak (MW)	Load Forecast Uncertainty (MW)	Extreme Peak (MW)	Normal Energy Demand (GWh)
Jul-21	22,285	814	24,697	12,030
Aug-21	21,519	1,362	24,045	11,766
Sep-21	18,977	680	23,328	10,472
Oct-21	17,673	318	18,403	10,900
Nov-21	19,763	607	21,317	11,474
Dec-21	20,772	362	21,917	12,477
Jan-22	21,303	547	22,208	12,824
Feb-22	20,350	734	21,740	11,267
Mar-22	19,860	531	20,636	11,699
Apr-22	17,716	721	20,112	10,216
May-22	20,899	1,330	22,310	10,914
Jun-22	22,091	1,016	24,738	11,473
Jul-22	22,368	814	24,781	11,947
Aug-22	21,618	1,362	24,141	11,840
Sep-22	19,061	680	21,397	10,452
Oct-22	17,760	318	18,489	10,938
Nov-22	20,002	409	21,393	11,523
Dec-22	20,890	362	22,037	12,455
Jan-23	21,423	547	22,566	12,923
Feb-23	20,966	734	22,025	11,390
Mar-23	20,095	531	21,279	11,879
Apr-23	17,811	471	18,343	10,403
May-23	18,879	1,292	21,991	10,603
Jun-23	22,170	754	24,311	11,222
Jul-23	22,715	814	24,865	12,012
Aug-23	22,462	958	24,920	12,151
Sep-23	19,122	781	22,134	10,525
Oct-23	17,824	416	18,474	10,939
Nov-23	19,990	409	20,999	11,420
Dec-23	20,658	690	21,522	12,330
Jan-24	21,626	547	22,794	13,131
Feb-24	20,633	635	22,025	11,915
Mar-24	20,060	649	20,827	11,786
Apr-24	18,011	471	18,648	10,592

Month	Normal Peak (MW)	Load Forecast Uncertainty (MW)	Extreme Peak (MW)	Normal Energy Demand (GWh)
May-24	19,070	1,292	22,180	10,737
Jun-24	22,361	754	24,501	11,332
Jul-24	22,935	814	25,105	12,307
Aug-24	22,032	985	24,634	12,096
Sep-24	19,306	781	22,310	10,627
Oct-24	18,131	416	18,758	11,144
Nov-24	20,164	409	21,175	11,540
Dec-24	20,853	690	21,715	12,427

7.4.2 Changes to installed generation

Table 7-7 describes changes to installed generation as a result of:

- Contracted facilities anticipated to enter the IESO-administered markets, listed as under development. Their capacity is their contracted capacity.
- Modifications to existing facilities, listed as “Under Development.”
- Confirmed retirement of existing facilities.

All resource changes described in Table 4-2 are also included in this assessment.

Table 7-7 | Committed Generation Resources Status

Project Name	Zone	Fuel Type	Planned Date	Delayed Date	Project Status	Capacity (MW)
Pickering A Nuclear Generating Station	Toronto	Nuclear	2022-Q4	2022-Q4	Confirmed Retirement	-1,030
Pickering B Nuclear Generating Station	Toronto	Nuclear	2024-Q4	2024-Q4	Confirmed Retirement	-2,072
Total						-3,102

Table 7-8 is provided for information only and lists generation facilities with contracts expiring prior to December 2024. All scenarios assume these facilities continue operation after their contract expires.

Table 7-8 | Generation Facilities with Contracts Expiring during this Outlook Period

Project Name	Zone	Fuel Type	Contract Expiry Date	Capacity (MW)
Iroquois Falls	Northeast	Natural Gas	2021-Q3	-130
Nipigon GS	Northwest	Natural Gas	2021-Q4	-40
Lennox Generating Station	East	Natural Gas/Oil	2022-Q1	-2,100
Thunder Bay Condensing Turbine	Northwest	Biomass	2023-Q2	-44
Brighton Beach Power Station	West	Natural Gas	2024-Q1	-583
Atikokan GS	Northwest	Biomass	2024-Q3	-205
Total				-3,102

7.4.3 Firm Transactions

For this outlook, only committed transactions – those with an agreement between two jurisdictions for a set amount of capacity for a period – were assumed. The only agreement for this time period is the Ontario-Quebec electricity trade agreement, whereby Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. As part of this capacity exchange agreement, the 500 MW capacity that was delivered to Quebec in the winter of 2015/2016 will be returned to Ontario during the summer, based on needs, before September 2030. Because the period for this transaction has not yet been confirmed, this capacity has not been included in any scenario.

7.5 Transmission Outlook

7.5.1 Outage Impacts

The continued outage of the PAR connected to Ontario-New York 230 kV interconnection circuit L33P will continue to impact interconnection transfer capabilities (discussed in greater detail in section 5.3).

The Flow East Toward Toronto (FETT) transmission interface transfers power from generation in the Bruce, Niagara, Southwest and West zones to the province's other six electricity zones (Toronto, East, Ottawa, Essa, Northwest and Northeast). Transfer capability of the FETT interface could be reduced significantly with one or more key transmission elements out of service. This situation is expected to be more critical as resources located east of the interface, namely Pickering and Darlington Nuclear Generation Stations, are retiring or undergoing refurbishment. Transmission assessments for the months of May and June 2023 indicate that up to seven coincident nuclear outages will present a material reliability risk. Under this condition, there would be inadequate dependable resources east of the FETT interface, and with two Bruce units out of service, FETT would be penalized to approximately 4,700 MW prior to any transmission outages. To help mitigate potential future constraints on the FETT interface, the IESO has requested [that](#) Hydro One study various upgrade options to increase the transfer capability.

Outage requests for generation resources located east of the FETT interface or transmission elements that impact the transfer capability of the FETT interface could be denied. Market participants are encouraged to carefully schedule outages for generation resources located east of FETT and transmission elements that

impact FETT transfer capability, outside of peak demand periods. Submitting outage slips through the IESO's outage management system early is also advised.

7.5.2 Transmission Projects

Hydro One is proceeding with reinforcement of the 230 kV Richview-Manby transmission corridor, which was recommended in the [IRRP for the Toronto region](#) to accommodate demand growth. The reinforcement is expected to be in-service by 2024-Q2.

In the next five years, Hydro One will replace aging infrastructure at a number of the province's switchyards, including the Bruce B and Nanticoke 500 kV and Beck 2, Cherrywood, Nanticoke and Middleport 230 kV switchyards. Carefully coordinated outage plans between Hydro One and IESO are required for these projects in order to mitigate their impact on reliability.

Additional projects within the five-year time frame are included in Table B1.

8. Resources Referenced in This Report

The table below lists additional resources in the order they appear in the report.

Table 8-1 | Additional Resources

Resource	URL	Location in This Report
Reliability Outlook Webpage	http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook	Introduction
Security and Adequacy Assessments	http://www.ieso.ca/power-data/data-directory	Introduction
2019 Q4 Outlook Tables	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookTables_2019Dec.xls	Throughout
Connection Assessments and Approval Process	http://www.ieso.ca/en/sector-participants/connection-assessments/application-status	Assessment Assumptions
Methodology to Perform the Reliability Outlook	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookMethodology2019Dec.pdf	Throughout
DR Auction	http://www.ieso.ca/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Demand-Response-Auction	Demand Measures
Enabling Capacity Exports	http://www.ieso.ca/en/Sector-Participants/Market-Renewal/Capacity-Exports	Firm Transactions
Ontario Resource and Transmission Assessment Criteria	http://www.ieso.ca/-/media/files/ieso/Document%20Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf	Transmission Considerations
NERC Transmission Planning Standard TPL-001-4	http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf	Transmission Considerations
NPCC Directory #1	https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf	Transmission Considerations
Market Manual 4 Part 4.2	http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-operations/mo-dispatchdatartm.pdf?la=en	Surplus Baseload Generation
Grid-LDC Interoperability Standing Committee	http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Standing-Committees/Grid-LDC-Interoperability-Standing-Committee	Distributed Energy Resources
2018 Technical Planning Conference and Planning Outlook	http://www.ieso.ca/en/sector-participants/planning-and-forecasting/technical-planning-conference	Beyond 18 Months: Introduction
Generator Information Submittal Form for Reliability Assessments	http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/ma-f1230-GenInfo-ReliabilityAssessments.xlsx?la=en	Beyond 18 Months: Capacity Adequacy Assessment
Transfer Capability Assessment Methodology	http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/TTCMethodology2019Dec.pdf	Beyond 18 Months: Inputs and Assumptions

9. List of Acronyms

CAA	Connection Assessment and Approval
CROW	Control Room Operations Window
DER	Distributed Energy Resource
DR	Demand Response
EAA	Energy Adequacy Assessment
ESAG	Energy Storage Advisory Group
FETT	Flow East Toward Toronto
GS	Generating Station
GTA	Greater Toronto Area
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt(s)
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
ORTAC	Ontario Resource and Transmission Criteria
PAR	Phase Angle Regulator
RAR	Reserve Above Requirement
RAS	Remedial Action Scheme
SBG	Surplus Baseload Generation
SCC	Solar Capacity Contribution
TS	Transmission Station
TWh	Terawatt-hour(s)
WCC	Wind Capacity Contribution



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