Reliability Outlook

An adequacy assessment of Ontario's electricity system

FROM APRIL 2019 TO SEPTEMBER 2020

Connecting Today.
Powering Tomorrow.

Executive Summary

The Independent Electricity System Operator (IESO) ensures the reliability of Ontario's power system on behalf of all Ontarians. Planning for today, tomorrow, and into the future is essential to ensuring Ontario's electricity system continues to be reliable and resilient. Today, with the grid becoming less centralized, and a changing portfolio of resources, preparing for the future has never been more complex. With this in mind, and driven by the need to enhance planning transparency and help market participants make more informed decisions and investments, the IESO has renewed its approach to planning, with a particular emphasis on its commitment to regular sharing of information with stakeholders.

As a first step in delivering on this commitment, and helping generators and transmitters plan for and schedule outages, the IESO extended its traditional 18-month planning horizon twice yearly. Every summer and winter, the Reliability Outlook will complement its in-depth adequacy assessment for the upcoming 18 months with information aimed at giving critical resources insights into the longer-term issues of nuclear refurbishments and end-of-supply contracts.

To complement this process, and ensure stakeholder input is built into every program deliverable, the IESO recently launched an engagement on the development of an annual planning outlook. Designed to provide more public touchpoints, this process will provide interested parties with an opportunity to shape the development of this important planning tool and ensure it meets their needs.

Planning for a reliable electricity system

The outlook for resource availability remains positive over the next 18 months with sufficient resources to maintain the reliability of Ontario's electricity system, under normal weather conditions.

The IESO recently revised its outage approval methodology, using the extreme weather scenario with up to 2,000 megawatts of imports. This will be applied to any outages that extend past or begin after May 1, 2019. Under extreme weather conditions, the reserve is lower than the requirement without reliance on imports for a total of five weeks under the extreme weather scenario in 2020. This potential shortfall is largely attributed to planned generator outages scheduled during those weeks.

> Outage plans play a large role in assessing resource availability for short-, mid- and long-term planning. Market participants are reminded to submit their reliability assessment information by the April 1, 2019 deadline.

Transmission adequacy

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

Contents

List of Figures

List of Tables

1. Introduction

This quarterly *Reliability Outlook* (formerly known as the *18-month Outlook*) covers the 18-month period from April 2019 to September 2020 and supersedes the previous *Reliability Outlook* released in December 2018.[1]

This 18-month assessment is published in accordance with the requirements provided in the Market Rules, Chapter 5, Power System Reliability.

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 through adjustment or coordination of maintenance plans for generation and transmission equipment, and
- Report on initiatives being implemented to improve reliability within this timeframe.

The assumptions and assessment approach in this report are focused only on outage management. This report is intended to support generation and transmission owners with scheduling and approval of outages and to inform changes in resource adequacy within the 18-month timeframe that may make outage coordination and assessments more challenging in the future. Outage approval is also not guaranteed; for example, outages may be rejected due to re-preparation concerns.

Information on global adequacy needs that require investments beyond outage management are provided in the IESO's Planning Outlook.

Additional supporting documents are located on the Reliability Outlook section of the IESO website.

This Outlook presents an assessment of resource and transmission adequacy based on the stated assumptions, using the described methodology. Due to uncertainties associated with various assumptions, readers are encouraged to use their judgment in considering possible future scenarios.

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, contact us at 905-403-6900 or toll-free at 1-888-448-7777 or email customer.relations@ieso.ca.

[1] The quarterly Reliability Outlook was renamed to reflect the extended planning horizon, to be published every June and December with an additional 42 months, providing a five-year assessment of reliability every six months.

2. Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast used in this Outlook is informed by actual demand, weather and economic data through to the end of December 2018, and has been updated to reflect the most recent economic projections. Actual weather and demand data for January and February are included in the tables.

2.2 Updates to Resources

This *Reliability Outlook* considers planned generator outages submitted by market participants to the IESO's outage management system as of February 15, 2019. To enable the IESO to conduct reliability assessments, Market participants are required to submit outage information annually and provide updates when there are material changes. This information, provided to the IESO through Form 1230, was submitted by April 1, 2018.

No new resources completed market registration since the last Outlook.

2.3 Updates to Transmission Outlook

Transmission outage plans that were submitted to the IESO's outage management system by January 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 February 15, 2019.

3. Demand Forecast

Over the forecast period, peak demands will continue to face downward pressure from energy efficiency and the effects of the Industrial Conservation Initiative (ICI). Grid-supplied energy demand rebounded in 2018 compared to 2017. Looking forward, both energy and peak demand are expected to continue to decline in line with the trend experienced over the past five years.

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period April 2019 to September 2020 and supersedes the previous forecast released in December 2018. Tables of supporting information are contained in the 2019 Q1 Outlook Tables.

Electricity demand is shaped by many factors with differing and/or competing impacts: those that increase the demand for electricity (population growth, economic expansion and the increased penetration of end-uses); those that reduce the need for grid-supplied electricity (energy efficiency and embedded generation) and those that reduce peak demand (time-of-use rates and the Industrial Conservation Initiative (ICI). The extent to which each of these factors impacts electricity consumption varies by season and time of day. The demand forecast incorporates these impacts.

Grid-supplied demand has been fairly flat since the 2009 recession with small increases and decreases year over year. The exception to this trend occurred in 2017, when demand dropped significantly across all regions of the province and sectors of the economy. During 2018, demand rebounded to continue on the previously established trajectory. After weather-correcting 2018's energy values demand showed a 0.8% decrease against 2016. This is roughly a 0.4% decrease after accounting for the additional leap day in 2016. Looking to 2019, demand is expected to exhibit a 0.5% decline.

The demand forecast for the next 18 months is expected to decline compared to 2018, as increased energy-efficiency savings and structural changes to the economy outweigh growth from economic expansion and demographic growth. The announced closure of the General Motors Oshawa plant is emblematic of the long-term economic structural change, associated with the decline of manufacturing as a share of Ontario's economy. Embedded generation output also reduces the need for grid-supplied electricity but those impacts have moderated with the plateauing of capacity additions.

Peak demands are subject to the same forces as energy demand, though the impacts vary. This is true when comparing energy versus peak demand and when comparing summer and winter peaks. Summer peaks are significantly affected by the growth in embedded generation capacity and rate impacts (ICI and time-of-use rates). The majority of embedded generation is provided by solar-powered facilities that have high output levels during the summer peak period and low output during the winter peak periods. In addition to reducing summer peaks, increased embedded solar output is pushing the peak to later in the day. As such, peak demands will show a small decline over the forecast horizon. ICI puts downward pressure on both seasonal peaks.

Table 3-1 shows the historical and forecast annual energy demand and Table 3-2 shows forecasted seasonal peaks. Table 3-3 shows the weekly peaks and energy demand over the forecast horizon of the Outlook. The tables include both normal and extreme weather peaks. Normal peaks are based on typical weather, while extreme peaks capture the volatility of weather, when the system is most likely to be stressed. Recent IESO experience has found increasing instances of extreme conditions and challenges with managing these extreme conditions in real-time. As a result, the IESO revised some of its planning processes, such as capacity exports and outage assessments, to rely on the extreme weather forecast for approvals.

Table 3-1 | Historical and Forecast Energy Summary

Year	Normal Weather Energy (TWh)	% Growth in Energy
2006	152.3	-1.9%
2007	151.6	-0.5%
2008	148.9	-1.8%
2009	140.4	-5.7%
2010	142.1	1.2%
2011	141.2	-0.6%
2012	141.3	0.1%
2013	140.5	-0.6%
2014	138.9	-1.1%
2015	136.2	-1.9%
2016	136.2	0.0%
2017	132.3	-2.8%
2018	135.2	2.1%
2019 (Forecast)	134.5	-0.4%
2020 (Forecast)	134.3	-0.2%

Table 3-2 | Forecasted Seasonal Peaks

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2019	22,105	24,478
Winter 2019-20	21,104	22,029
Summer 2020	21,902	24,270

3.1 Actual Weather and Demand

Since the last forecast, the actual demand and weather data for December, January and February have been recorded.

December

- December's weather was much milder than normal. Usually, the month has a peak day temperature near -10.0 °C but December 2018's coldest day had an afternoon high of -5.8 °C. December can have unpredictable results depending on how the timing of the weather and the holidays interact. Overall, the weather for the month was volatile, as temperatures rose and fell without any clear sustained cold periods. Demand peaked on Tuesday, December 11, the fifth coldest day of the month with afternoon temperatures of -1.4 °C (Toronto). The demand peak (19,891 MW) was the lowest December peak over the past decade, with the exception of 2015 which had a peak day temperature of 6.8 °C.
- The weather-corrected peak[2] (20,462 MW) is consistent with December values since the recession.
- Energy demand for the month was 11.9 TWh (12.0 TWh weather-corrected). Actual energy demand was down over the previous December, but the weather-corrected value represented an increase.
- The minimum demand for the month (12,284 MW), which occurred in the early hours of Saturday, December 29, was the highest since 2015.
- Embedded generation for the month was 409 GWh, an increase of 1.2% compared to the previous December. Wholesale customers' consumption rose 2.2% over December 2017 and represented the fifth consecutive month of year over year growth thanks largely to mining, petroleum products and cement production.

January

- Although January started with temperatures above zero, it was consistently colder than normal, with temperatures progressively increasing throughout the month.

[2] Weather-correction is a method of standardizing the demand against median weather conditions. This allows comparisons of demand that exclude the impacts of weather volatility.

- The peak occurred on the fifth coldest day of the month, when daily highs reached -11.8°C (Toronto). The peak demand was 21,525 MW (21,113 MW weather-corrected) on Monday January 21. The peak value was impacted by ICI activities as Class A customers made adjustments should the peak value fall in the top five peaks (it did not).
- Energy demand for the month was 12.8 TWh (12.6 TWh weather-corrected). Both of these values are consistent with the numbers over the past five years.
- The minimum demand for the month was 12,291 MW and occurred in the early morning hours of New Year's Day. It was both a holiday and warmer than normal.
- Embedded generation for the month topped 465 GWh, which represents a 13.0 percent decrease compared to the previous January. Year-over-year increases in solar and biogas output were more than offset by declines in wind, water and non-contracted embedded generation output.
- Wholesale customers' load increased by 0.5% compared to the previous January. Mining, petroleum products and motor vehicles led the growth, while iron and steel production took a step back.

February

- Despite the weather volatility and storms, February's weather was very close to normal.
- The actual peak for the month was 20,500 MW occurring on Friday, February 1. It was the coldest day of the month with afternoon highs of -10.1°C (Toronto). The weather-corrected value was essentially the same at 20,892 MW, which is similar to the values experienced since the recession.
- Energy demand for the month was 11.3 TWh (11.2 TWh weather-corrected). Both the actual and weather-corrected values show a slight increase over the previous two Februarys.
- Minimum demand of 13,041 MW occurred Sunday, February 24 at 5 a.m. This result is not surprising as it was the second mildest day of the month and a weekend, both of which lead to lower demand.
- Embedded generation was 459 GWh for the month, which represents a decrease of 8 percent compared to the previous February. Decreases in wind (18 percent) and non-contracted generation (11 percent) outweighed the increase in solar output (15 percent).
- Wholesale customers' consumption decreased 1.5 percent compared to the previous February. While most sectors showed increases, significant decreases in pulp and paper and the iron and steel sectors overshadowed those increases.

Overall, energy demand for the three winter months from December to February was up 0.1% year over year. After adjusting for the weather, demand for the three months showed an increase of 0.3%.

The 2019 Q1 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

3.2 Forecast Drivers

3.2.1 Economic Outlook

The overall economic environment is remains fairly positive for Ontario, based on recent publicly available forecasts. Continued U.S. growth, a competitive Canadian dollar and low interest rates are conducive to growth in the province's export-oriented energy-intensive manufacturing sector. However, uncertainty persists as a result of ongoing tariffs, continued interest rate increases from the Bank of Canada, and pending ratification of the United States-Mexico-Canada Agreement (USMCA). Barring these risks, Ontario should see increasing, albeit slowing, economic output throughout 2019 and 2020. Table 3.3.4 of the 2019 Q1 Outlook Tables presents the economic assumptions for the demand forecast.

3.2.2 Weather Scenarios

To produce demand forecasts, the IESO uses weather scenarios that include normal and extreme weather, along with a measure of uncertainty in demand due to weather volatility, otherwise known as "load forecast uncertainty." Table 3.3.5 of the 2019 Q1 Outlook Tables presents the weekly weather data for the forecast period.

3.2.3 Pricing, Conservation and Embedded Generation

Both demand measures and load modifiers can affect demand, but they differ in how they are treated within the Outlook. Demand measures, such as dispatchable loads and demand response (DR) procured through an auction, are not incorporated into the demand forecast and are instead treated as resources and described in Section 4.1.3. Load modifiers are incorporated into the demand forecast.

Demand measures are dispatched like a generation resource and are included in the supply mix. Demand measures are added back into the history when forecasting demand. Therefore, demand is forecast prior to the impacts of demand measures.

Load modifiers include energy efficiency (energy-efficiency programs, codes and standards, and fuel switching), rate structures (time-of-use and Industrial Conservation Initiative) and embedded generation. The load modifiers are incorporated into the demand forecast. Each impacts demand differently – in terms of level and timing – but all have the net effect of reducing the amount of grid-supplied electricity. Energy efficiency impacts both peaks and energy, prices reduce demand during peak periods, and embedded generation impacts vary by fuel type.

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)
07-Apr-19	17,548	18,121	471	2,479
14-Apr-19	16,833	17,782	496	2,414
21-Apr-19	16,404	16,643	531	2,335
28-Apr-19	16,407	16,551	721	2,340
05-May-19	17,432	19,872	849	2,322
12-May-19	16,643	19,460	845	2,339
19-May-19	18,225	21,543	1,175	2,365
26-May-19	17,959	21,715	1,330	2,305
02-Jun-19	18,663	21,212	1,292	2,380
09-Jun-19	19,421	23,720	1,055	2,530
16-Jun-19	20,220	23,736	835	2,542
23-Jun-19	21,391	23,959	754	2,609
30-Jun-19	21,623	23,584	1,016	2,643
07-Jul-19	22,105	24,478	814	2,626
14-Jul-19	21,579	23,269	838	2,719
21-Jul-19	21,138	23,266	1,035	2,614
28-Jul-19	21,226	23,985	841	2,691
04-Aug-19	21,885	24,368	958	2,718
11-Aug-19	21,550	24,187	985	2,688
18-Aug-19	20,726	23,823	1,362	2,664
25-Aug-19	20,776	22,834	1,413	2,646
01-Sep-19	20,056	22,559	1,370	2,513
08-Sep-19	18,559	23,494	680	2,364
15-Sep-19	18,920	21,038	781	2,425
22-Sep-19	17,643	19,586	420	2,396
29-Sep-19	16,983	18,280	554	2,334
06-Oct-19	17,240	17,345	786	2,381
13-Oct-19	17,075	17,393	507	2,415
20-Oct-19	17,241	17,739	392	2,352
27-Oct-19	17,400	18,015	318	2,442
03-Nov-19	17,621	18,399	416	2,452
10-Nov-19	18,649	19,307	601	2,565
17-Nov-19	18,917	19,749	342	2,575
24-Nov-19	19,298	20,110	607	2,641

Continued on next page

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
01-Dec-19	19,701	20,783	409	2,685
08-Dec-19	19,777	21,019	555	2,707
15-Dec-19	20,367	21,323	690	2,763
22-Dec-19	20,190	21,279	362	2,758
29-Dec-19	18,943	19,212	528	2,655
05-Jan-20	19,684	20,938	570	2,767
12-Jan-20	21,104	22,029	547	2,883
19-Jan-20	20,656	21,120	483	2,843
26-Jan-20	20,307	21,403	404	2,850
02-Feb-20	20,586	21,791	734	2,882
09-Feb-20	19,819	21,374	635	2,801
16-Feb-20	19,292	20,734	581	2,749
23-Feb-20	19,473	21,168	501	2,713
01-Mar-20	19,613	20,931	531	2,746
08-Mar-20	19,476	20,382	649	2,699
15-Mar-20	18,051	18,509	611	2,580
22-Mar-20	17,798	18,525	569	2,503
29-Mar-20	17,600	18,498	567	2,486
05-Apr-20	17,369	17,941	471	2,455
12-Apr-20	16,670	17,414	496	2,333
19-Apr-20	16,130	16,216	531	2,325
26-Apr-20	16,252	16,721	721	2,322
03-May-20	17,330	19,766	849	2,289
10-May-20	16,564	19,379	845	2,311
17-May-20	17,808	21,223	1,175	2,326
24-May-20	17,642	21,524	1,330	2,269
31-May-20	18,519	21,068	1,292	2,354
07-Jun-20	19,252	23,599	1,055	2,515
14-Jun-20	20,386	23,901	835	2,519
21-Jun-20	20,920	23,511	754	2,587
28-Jun-20	21,404	23,966	1,016	2,645
05-Jul-20	20,554	23,092	814	2,598
12-Jul-20	21,902	24,270	838	2,704

Continued on next page

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
19-Jul-20	20,421	23,749	1,035	2,578
26-Jul-20	21,041	23,899	841	2,685
02-Aug-20	21,250	23,683	958	2,660
09-Aug-20	20,751	23,539	985	2,642
16-Aug-20	20,238	23,486	1,362	2,624
23-Aug-20	21,028	23,237	1,413	2,666
30-Aug-20	19,601	22,122	1,370	2,498
06-Sep-20	17,992	23,172	680	2,408
13-Sep-20	18,773	20,793	781	2,378
20-Sep-20	17,429	19,636	420	2,409
27-Sep-20	16,517	17,863	554	2,312
04-Oct-20	17,187	17,328	786	2,392

4. Resource Adequacy

The IESO expects to have sufficient generation supply for most of summer 2019, with potential risks in early September 2019 that can be mitigated by outage rescheduling. Over the next 18 months, approximately 1,500 MW of new generation is planned to come into service, while approximately 90 MW of generation will reach its end-of-contract life. This Outlook also reflects the continued availability of DR resources.

This section provides an assessment of 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 as of February 15, 2019

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Outlook Peak (MW)	Number of Stations	Change in Installed Capacity (MW)
Nuclear	13,009	12,053	5	0
Hydroelectric	8,482	5,444	75	0
Gas/Oil	10,277	8,389	31	0
Wind	4,486	611	39	0
Biofuel	295	286	7	0
Solar	380	38	8	0
Total	**36,928**	**26,821**	**165**	**0**

4.1 Assessment Assumptions

4.1.1 Generation Resources

All generation projects that are 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 (CAA) process, 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 the best estimated date of the completion of market registration available to the IESO by February 1, 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 in the future are considered for both scenarios.

Table 4-2 | Committed Generation Resources Status

					Capacity Considered	
Project Name	**Zone**	**Fuel Type**	**Estimated Effective Date**	**Project Status**	**Firm (MW)**	**Planned (MW)**
Nanticoke Solar	Southwest	Solar	2019-Q1	Commissioning	0	44
Yellow Falls	Northeast	Hydro	2019-Q1	Commissioning	0	16
Loyalist Solar	East	Solar	2019-Q2	Under Development	0	54
Whitby Cogeneration	Toronto	Gas	2019-Q2	Expiring Contract	-56	-56
Napanee Generating Station	East	Gas	2019-Q2	Under Development	0	985
Henvey Inlet Wind Farm	Essa	Wind	2019-Q3	Under Development	0	300
Romney Wind Energy Center	West	Wind	2020-Q1	Under Development		60
Nation Rise	East	Wind	2019-Q4	Under Development	0	100
Calstock	Northeast	Biomass	2020-Q2	Expiring Contract	-38	-38
Total					**-94**	**1,465**

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 that are 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;

• Expiring Contract – generators whose contracts 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 without accounting for historical outages is also calculated (see the second row of Table 4-3). Table 4-3 uses data from May 2002 to March 2018, which are updated annually to coincide with the release of the summer 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)	6,349	6,297	6,120	6,084	6,149	5,972	5,938	5,579	5,318	5,686	5,919	6,376
Historical Hydroelectric Median Contribution without Outages (MW)	6,925	6,914	6,691	6,673	6,617	6,497	6,334	6,065	6,159	6,485	6,644	6,908

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 are used at the time of weekday peak. The specifics on wind contribution methodology can be found in the Methodology to Perform the Reliability Outlook. Figure 4-1 shows the monthly WCC values, which are updated annually to coincide with the release of the Q2 Reliability Outlook.

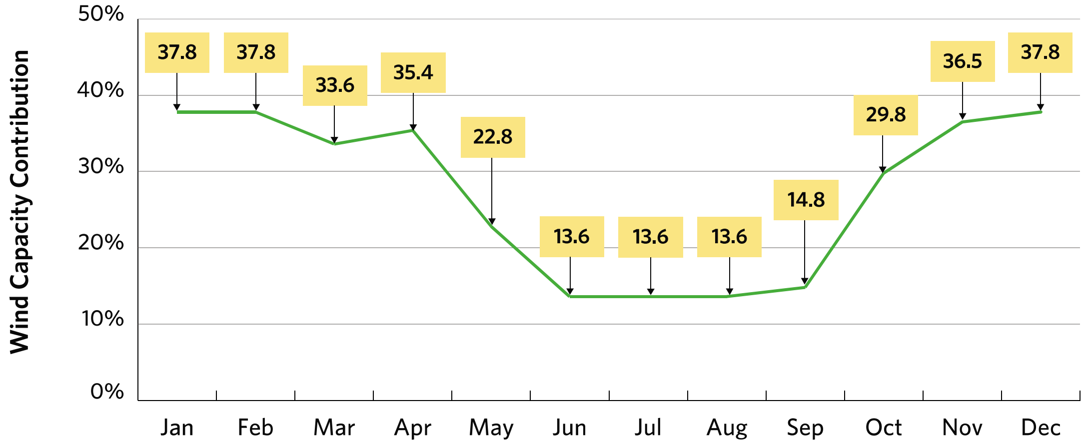

Figure 4-1 | Monthly Wind Capacity Contribution Values

Solar

For solar generation, monthly solar capacity contribution (SCC) values are used at the time of weekday peak. The specifics on solar contribution methodology can be found in the [Methodology to Perform the Reliability Outlook](). Figure 4-2 shows the monthly SCC values, which are updated annually to coincide with the release of the Q2 Reliability Outlook.

Due to the increasing penetration of embedded solar generation, the grid demand profile has been changing, with summer peaks being pushed to later in the day. As a consequence, the contribution of grid-connected solar resources at the time of peak Ontario demand has declined.

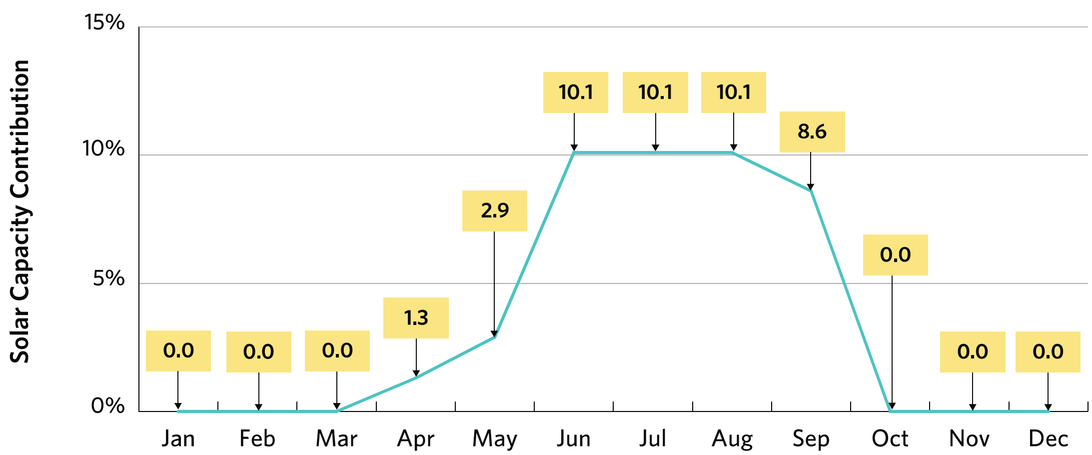

Figure 4-2 | Monthly Solar Capacity Contribution Values

4.1.3 Demand Measures

Both demand measures and load modifiers can impact demand, but they differ in how they are treated within the Outlook. Demand measures, such as dispatchable loads and demand response procured through the 2019 demand response auction (DR 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 (Pricing, Conservation and Embedded Generation). The impacts of actual activations of demand measures are added back into the demand history prior to forecasting demand for future periods.

The 2019 DR auction, conducted in early December 2018, had a target capacity of 611 MW for the summer commitment period (May 1, 2019 – October 31, 2019) and 606 MW for the winter commitment period (November 1, 2019 – April 30, 2020). The auction cleared 818 MW for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period. The results of the 2019 auction were published on December 13 (capacity acquired through the annual auction is reflected in this Outlook).

4.1.4 Firm Transactions

Capacity-Backed Export

The IESO allows Ontario resources to compete in the capacity auctions of some neighbouring jurisdictions if Ontario is adequately supplied. Capacity-backed exports of 438 MW were successful in the New York Independent System Operator (NYISO) auction for April 2019.

NYISO will be running its strip auction for the commitment period from May 1, 2019 to October 31, 2019 on March 29, 2019. The capacity that can participate is limited by NYISO to up to 128 MW, depending on the month.

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 terawatt-hours 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 Ontario's needs. This capacity was not requested for summer 2019 and is also not included in the assessments for summer 2020.

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 in the future are considered for both scenarios. Submitted generator planned outages are reflected in both scenarios. Table 4-4 shows a snapshot of the forecast available resources, 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

		Summer Peak 2019		Winter Peak 2019		Summer Peak 2020	
Notes	**Description**	**Firm Scenario**	**Planned Scenario**	**Firm Scenario**	**Planned Scenario**	**Firm Scenario**	**Planned Scenario**
1	Installed Resources (MW)	36,872	38,255	36,872	38,415	36,834	38,377
2	Total Reductions in Resources (MW)	10,329	10,750	10,774	11,167	11,903	12,450
3	Demand Measures (MW)	790	790	922	922	790	790
4	Firm Imports (+) / Exports (-) (MW)	0	0	-500	-500	0	0
5	Available Resources (MW)	27,333	28,295	26,520	27,670	25,721	26,717
6	Available Resources without Bottling (MW)	27,542	28,517	27,712	28,885	25,764	26,760

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.

6. Available Resources without Bottling: Available resources after they are reduced due to transmission limitations ("bottling").

4.2 Capacity Adequacy Assessment

The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages that have been assessed as of January 28, 2019. The generation planned outages occurring during this Outlook period have been assessed as of February 15, 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 February 1, 2019.

Figure 4-3 shows reserve above requirement (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) will be applied for any outages that extend past or begin after May 1, 2019. During these conditions, the reserve is lower than the requirement without reliance on imports for a total of five weeks under the extreme weather scenario in 2020. This potential shortfall is largely attributed to planned generator outages scheduled during those weeks. To mitigate the risk of extreme conditions, the IESO may reject some generator maintenance outage requests to ensure that Ontario demand is met during the summer peak periods.

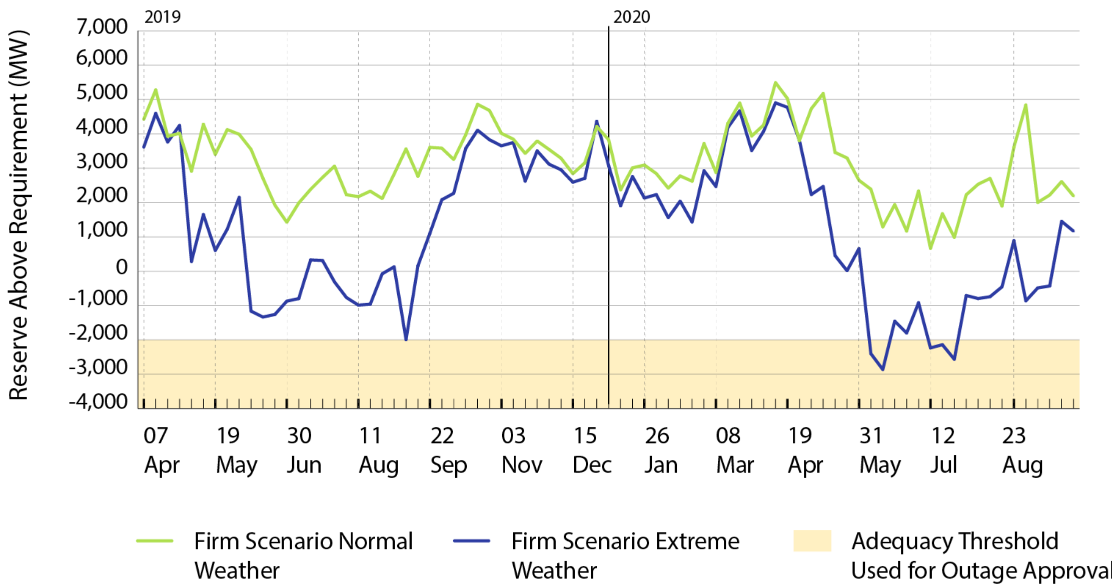

Figure 4-3 | Comparison of Normal and Extreme Weather: Firm Scenario Reserve Above Requirement

4.2.2 Planned Scenario with Normal and Extreme Weather

The planned scenario incorporates all existing capacity plus all capacity coming into service, as per Table 4-2.

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

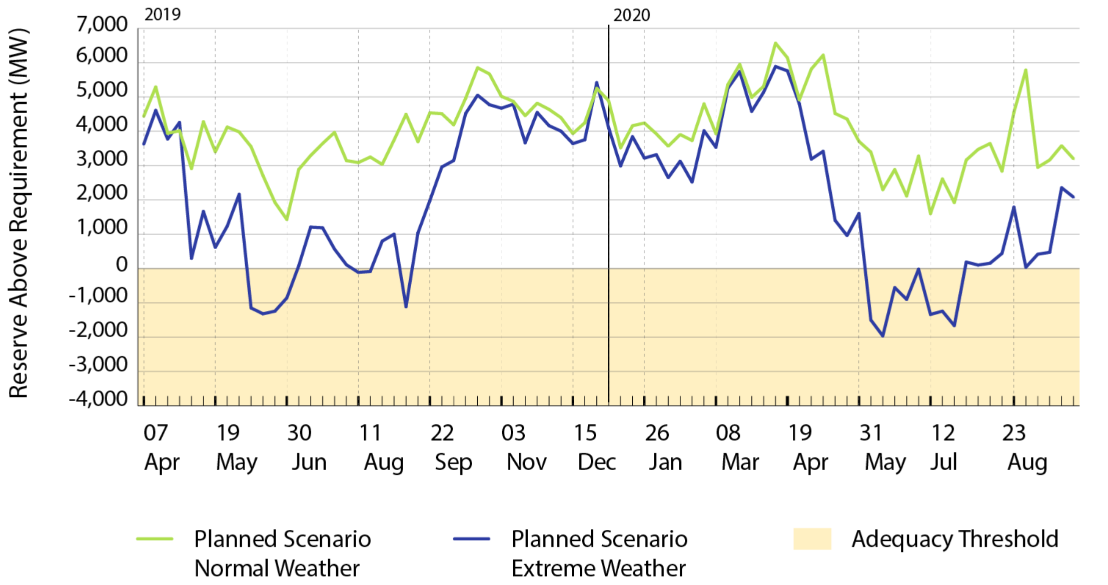

Figure 4-4 | Comparison of Normal and Extreme Weather: Planned Scenario Reserve Above Requirement

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

Figure 4-5 compares the forecast RAR values in the current Outlook with those in the previous Outlook published in December 2018. The difference is primarily the result of changes in planned outages and the expected in-service dates of new resources. Resource adequacy assumptions and risks are discussed in detail in the Methodology to Perform the Reliability Outlook.

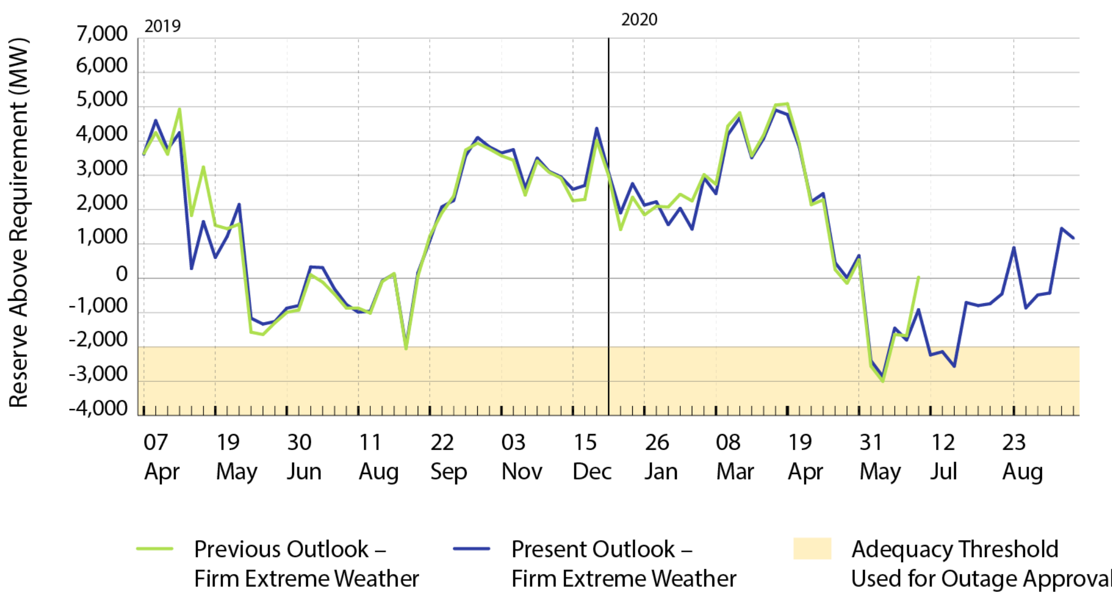

Figure 4-5 | Comparison of Current and Previous Outlook: Firm Scenario Extreme Weather Reserve Above Requirement

4.3 Energy Adequacy Assessment

This section provides an assessment of energy adequacy to determine whether Ontario has sufficient supply to meet its forecast energy demands and to highlight potential adequacy concerns during the Outlook timeframe. 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, in Table 4-1 and Table 4-2, pertaining to resources expected to be available over the next 18 months as the capacity assessment. The monthly forecast of energy production capability, based on the energy modelling results, is included in the 2019 Q1 Outlook Tables.

For the EAA, only the firm scenario in Table 4-5 with normal weather demand is considered. 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

	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
Zone	**TWh**	**Average MW**	**TWh**	**Average MW**	**TWh**	**GWh**	**GWh**
Bruce	0.8	58.0	56.5	4,302.0	55.7	1.2	145.5
East	10.8	825.0	14.2	1,080.0	3.4	28.1	79.1
Essa	9.5	721.0	0.0	3.0	-9.5	24.8	9.0
Niagara	4.8	368.0	16.4	1,247.0	11.6	13.3	45.3
Northeast	13.0	992.0	12.5	954.0	-0.5	26.5	36.1
Northwest	4.8	368.0	5.6	429.0	0.8	9.8	21.3
Ottawa	11.2	851.0	0.0	3.0	-11.2	23.7	1.4
Southwest	34.7	2,640.0	4.5	341.0	-30.2	92.9	23.8
Toronto	61.1	4,657.0	50.9	3,874.0	-10.2	174.8	164.8
West	17.0	1,294.0	7.1	541.0	-9.9	48.4	63.3
Ontario	**167.7**	**12,774.0**	**167.7**	**12,774.0**	**0.0**	**443.5**	**589.5**

4.3.3 Findings and Conclusions

The EAA results indicate that Ontario is expected to have sufficient supply to meet its energy forecast during the next 18 months for the firm scenario with normal weather demand, with no anticipated reliance on support from external jurisdictions. The figures and tables in this section are based on simulation of the Ontario power system using the assumptions presented within the Outlook to confirm that Ontario will be energy adequate.

Figure 4-6 shows the percentage production by fuel type to supply Ontario energy demand 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.

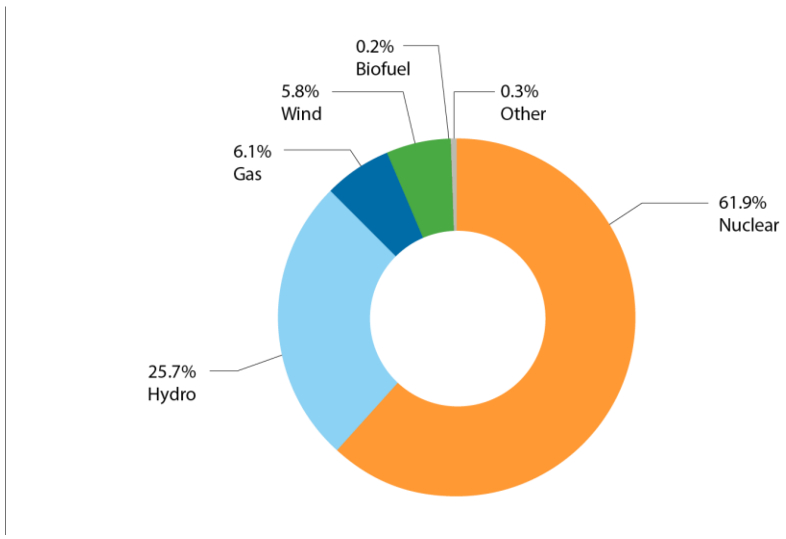

Figure 4-6 | Energy Production by Fuel Type: April 1, 2019 to September 30, 2020

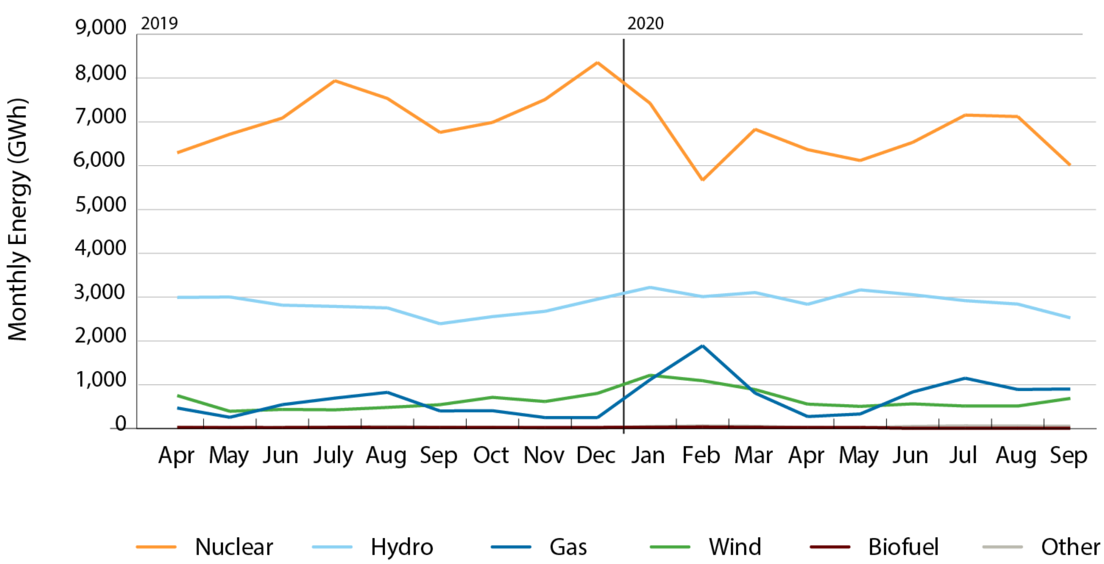

Figure 4-7 | Monthly Energy Production by Fuel Type: April 1, 2019 to September 30, 2020

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

Fuel Type (Grid Connected)	2019 (Apr 1 - Dec 31) (GWh)	2020 (Jan 1 - Sep 30) (GWh)	Total (GWh)
Nuclear	65,188	59,228	124,415
Hydro	24,934	26,686	51,620
Gas & Oil	4,108	8,205	12,313
Wind	5,177	6,545	11,722
Bio Fuel	232	175	407
Other (Solar & DR)	238	426	664
Total	**99,877**	**101,264**	**201,142**

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 / 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

For the purpose of this report, transmitters provide information on the transmission projects that are planned for completion within the next 18 months. A list of such projects is provided in Appendix B1. Only transmission and load-serving projects that are either major modifications or significantly improve reliability are included.

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 January 28, 2019.

5.3 Transmission Considerations

The purpose of this section of the report is to highlight both projects and outages that may affect the scheduling of other outages and/or may affect operations. These considerations are categorized by zone below.

Bruce and Southwest

Hydro One's replacement of aging infrastructure at the Bruce 230 kV switchyard is underway and requires careful coordination of transmission and generation outages. This project is scheduled to be completed by Q4 2020.

A planned three-week outage starting November 2019 will impact circuit B560V, significantly reducing the power transfer capacity out of the Bruce area.

Niagara

Completion of the transmission reinforcements from the Niagara area into the Hamilton-Burlington area is underway with an expected in-service date of Q2 2019. Once complete, this project will increase the summertime transfer capability from the Niagara region to the rest of Ontario by approximately 800 MW and improve the ability to take transmission outages on the impacted 230 kV system.

West

Significant growth in the greenhouse sector has led to a number of 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 currently proceeding towards a Q4 2022 in-service date. Outages may be more challenging to facilitate in the area starting in late 2019, when new load connections are made and required transmission reinforcements are being implemented.

East and Greater Toronto Area

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 Q4 2020.

A planned outage impacting circuit X523A in the East area will last about five weeks, starting March 2019. This outage will reduce the capability to transfer power into the Ottawa area.

Northeast

Reinforcements to the system in the Kapuskasing area, consisting of upgrades to circuit H9K and reactive compensation, are being installed with planned in-service dates of Q4 2019 and Q2 2020, respectively. During the construction of these reinforcements, the ability to take certain outages may be more restrictive in the area.

Planned outages throughout 2019 will impact X503E and X504E. This includes a three-month outage starting January 2019, a one-month outage starting May 2019 and a one-month outage starting September 2019. These outages will reduce the transfer capacity on the North-South Tie.

Interconnections

The failure of the phase angle regulator (PAR) connected to Ontario-New York 230 kV interconnection circuit L33P that occurred in early 2018 has impacted the province’s ability to import 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 on the St. Lawrence area resources in real-time. PARs are unique pieces of equipment and replacements are not readily available. Replacement options for the unit are currently being investigated jointly with the IESO, Hydro One, NYISO and the New York Power Authority.

Planned outages will impact interconnection circuits L4D and L51D in April and May 2019. L4D will be out of service for about four weeks starting April 2019 and L51D will be out of service for about three weeks starting May 2019. These outages will reduce the import and export transfer capacity between Ontario and Michigan and increase the difficulty of controlling unscheduled flow on the interface.

Three planned outages will impact interconnection circuit PA302. These outages will occur consecutively starting July to November 2019 and will reduce the import and export transfer capacity between Ontario and New York at Niagara ties.

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. Nuclear curtailments may be required in summer through to early fall 2019.

The IESO's 2016 Operability Assessment determined the need for an additional 50 MW of regulation service. As a result, the 2017 RFP for Incremental Regulation Capacity was aimed at obtaining incremental regulation capacity from all manner of technologies, including those that are existing and currently registered in the IESO-administered markets and those that have the ability to register in the IESO-administered markets at a later date. The IESO is now revisiting this regulation needs assessment for 2020 onward.

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

6.1 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. Resources and activity at the interties respond accordingly to the prices. The resulting outcomes from the market include higher export schedules, dispatching down of hydroelectric generation and grid-connected renewable resources, and nuclear maneuvering or shutdown. For severe surplus conditions, which may affect reliability of the system, the IESO may take out-of-market actions, such as manual curtailments of resources and/or imports.

Ontario will continue to experience potential surplus baseload conditions during the Outlook period. Figure 6-1 highlights the periods where curtailment of nuclear generation may be expected.

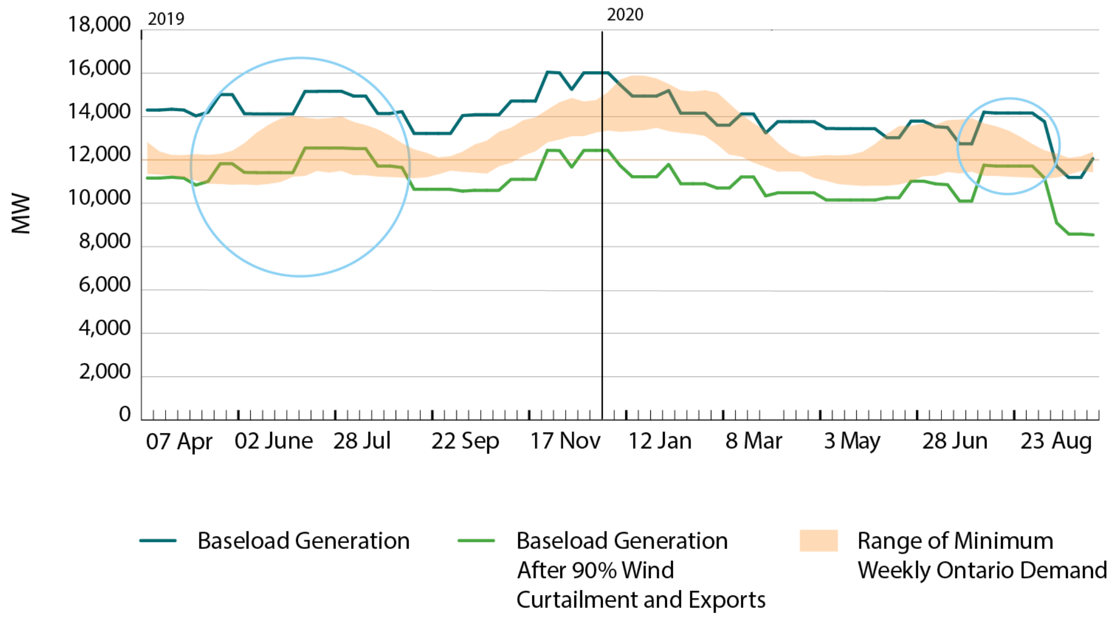

Figure 6-1 | Minimum Ontario Demand and Baseload Generation

Much of the surplus baseload conditions can be managed with existing market mechanisms signaling for exports, and curtailment of variable and nuclear generation. Going forward, as shown in Figure 6-2, existing mechanisms will be sufficient for managing SBG.

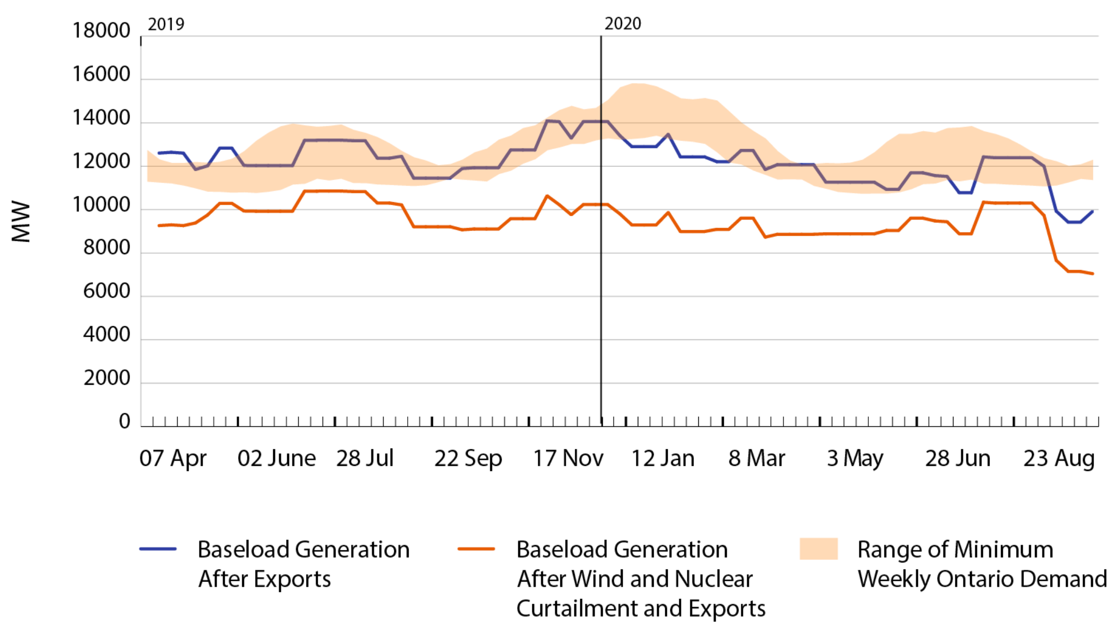

Figure 6-2 | Minimum Ontario Demand and Baseload Generation

The baseload generation assumptions include the 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 6-3 shows the monthly off-peak wind capacity contribution values calculated from actual wind output up to March 31, 2018. These values are updated annually to coincide with the release of the summer Outlook.

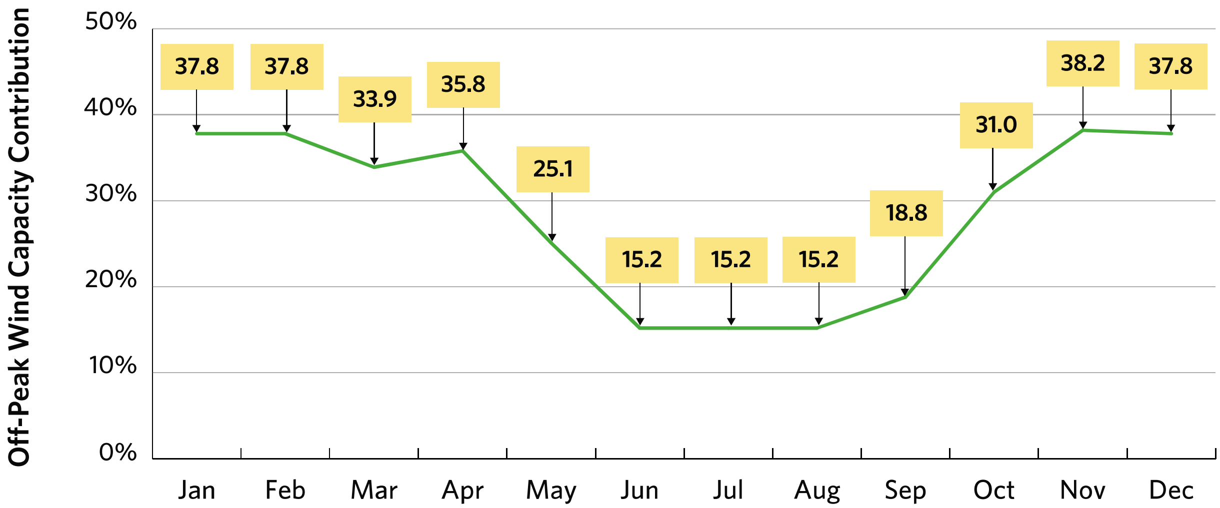

Figure 6-3 | Monthly Off-Peak Wind Capacity Contribution Values

7. Resources Referenced in This Report

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

Table 7-1 | 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 Q1 Outlook Tables	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookTables_2019mar.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/ReliabilityOutlookMethodology2019mar.pdf	Throughout
DR Auction	http://www.ieso.ca/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Demand-Response-Auction	Demand Measures
2019 DR Auction Post Auction Summary	http://reports.ieso.ca/public/DR-PostAuctionSummary/PUB_DR-PostAuctionSummary.xml	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

8. List of Acronyms

CAA	Connection Assessment and Approval
DR	Demand Response
EAA	Energy Adequacy Assessment
GWh	Gigawatt-hours
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
MW	Megawatts
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
SBG	Surplus Baseload Generation
SCC	Solar Capacity Contribution
TS	Transmission Station
TWh	Terawatt-hours
WCC	Wind Capacity Contribution

Independent Electricity System Operator

1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca
@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/ieso

Connecting Today.
Powering Tomorrow.