
Reliability Outlook

An adequacy assessment of Ontario's
electricity system

FROM JULY 2019 TO JUNE 2024

Executive Summary

The Independent Electricity System Operator (IESO) ensures the reliability of Ontario's power system on behalf of all Ontarians. Balancing electricity supply and demand depends on comprehensive short- and long-term planning that enables the IESO to continue to meet reliability requirements, while giving market participants the data and insights they need to make informed operational and investment decisions.

This summer edition provides the extended five-year outlook addressing a period of nuclear refurbishment outages, and expiring contracts. This information is intended to help market participants plan their outages, while providing additional insights into considerations affecting the reliability of Ontario's electricity system.

Ontario's electricity demand forecast

Ontario's electricity demand is shaped by many competing factors – factors that increase, reduce or shift that demand. Since 2009, grid-supplied energy demand has been fairly flat, with only small increases and decreases year to year. Over the next 18 months, a series of small demand increases is expected, as a strong U.S. economy and a low Canadian dollar continue to foster demand growth in the industrial sector.

Contributing to this demand is the Windsor-Essex region, which is home to North America's largest greenhouse vegetable production, and an expanding cannabis market, both of which require energy-intensive crop lighting to extend the growing season into winter. With demand expected to double in the region over the next five years, load is exceeding existing transmission infrastructure. To address near- and mid-term system needs, the IESO is recommending a new switching station (SS) at or near the existing Leamington Junction, which is expected to be in-service in 2022. Also recommended is a new 230 kV double circuit transmission line from the Chatham station to the Leamington Junction SS, which is expected to be in operation in the winter of 2025/26.

Ontario's transmission system is expected to reliably supply province-wide demand; however, a combination of transmission and generation outages could create operating challenges. Additional transmission considerations for the next 18 months are identified and categorized by zone in the Transmission Reliability Assessment section of this Outlook.

Ontario's short- and long-term resource adequacy

The outlook for resource availability remains positive over the next 18 months with sufficient resources to meet demand for most of the 2019 and 2020 summer periods. Potential risks during those periods are expected to be mitigated by outage rescheduling.

As indicated in the 20-year planning outlook released last fall, a capacity need will arise in 2020 and is expected to grow in 2023 as long-term contracts with generation facilities begin to expire, and with the upcoming retirement of Pickering Nuclear Generating Station and refurbishments at Darlington Nuclear Generating Station. These factors contribute to additional pressures on outage coordination longer term. At the outset of summer 2023, additional capacity may be required in addition to outage coordination to ensure sufficient generation to serve Ontario's demand needs.

In the absence of changes to existing retirement and refurbishment timelines for nuclear generating facilities, generators located east of the "Flow East Toward Toronto" interface will face additional outage scheduling challenges over the 60-month time horizon.

The IESO's outage management planning ensures the adequacy and operability of Ontario's electricity system is maintained. The ideal times to schedule outages are in the early spring, fall or winter months. At present, in the summers of 2021 and 2023 there is very little opportunity for new outages.

Looking ahead

Driven by the need to enhance planning transparency and help market participants make more informed decisions and investments, the IESO has committed to updating its long-term forecast with the release of an annual planning update in September. The report will provide a 20-year outlook and includes an updated demand forecast, resource adequacy assessment, operability and transmission needs assessment, and associated data to enable the sector to make those informed decisions. This outlook will help define the capacity need that future capacity auctions will address.

In the coming years, Ontario's capacity requirements will be addressed through resources such as demand response, capacity-backed imports, generators that are coming off long-term contracts, uprates of existing facilities and energy efficiency. Addressing these capacity needs will provide generators with greater flexibility to schedule outages in the future during off-peak periods.

Contents

Executive Summary	1
1. Introduction	6
2. Updates to This Outlook	7
2.1 Updates to Demand Forecast	7
2.2 Updates to Resources	7
2.3 Updates to Transmission Outlook	7
2.4 Updates to Operability Outlook	7
3. Demand Forecast for 18-Month Period	8
3.1 Actual Weather and Demand	9
3.2 Forecast Drivers	14
3.2.1 Economic Outlook	14
3.2.2 Weather Scenarios	14
3.2.3 Demand Measures and Load Modifiers	14
4. Resource Adequacy for 18-Month Period	15
4.1 Assessment Assumptions	16
4.1.1 Generation Resources	16
4.1.2 Generation Capability	17
4.1.3 Demand Measures	19
4.1.4 Firm Transactions	19
4.1.5 Summary of Scenario Assumptions	19
4.2 Capacity Adequacy Assessment	20
4.2.1 Firm Scenario with Normal and Extreme Weather	20
4.2.2 Planned Scenario with Normal and Extreme Weather	21
4.2.3 Comparison of the Current and Previous Weekly Adequacy Assessments for the Firm Normal Weather Scenario	22
4.2.4 Transitional Capacity Auction	23
4.2.5 Managing Northwest Ontario Reliability Need	23
4.3 Energy Adequacy Assessment	24
4.3.1 Summary of Energy Adequacy Assumptions	24
4.3.2 Results – Firm Scenario with Normal Weather	24
4.3.3 Findings and Conclusions	25
5. Transmission Reliability Assessment	27
5.1 Transmission Projects	27
5.2 Transmission Outages	27
5.3 Transmission Considerations	27
6. Operability	30

6.1 Surplus Baseload Generation	30
7. Beyond 18 Months	33
7.1 Introduction	33
7.1.1 Interpretation	33
7.2 Key Findings	34
7.3 Capacity Adequacy Assessment	34
7.3.1 Summary of Scenarios Considered	35
7.3.2 Capacity Adequacy Findings	36
7.4 Inputs and Assumptions	37
7.4.1 Demand	39
7.4.2 Changes to installed generation	41
7.4.3 Firm Transactions	42
7.5 Transmission Outlook	42
7.5.1 Transmission Outages	42
7.5.2 Transmission Projects	42
8. Resources Referenced in This Report	44
9. List of Acronyms	45

List of Figures

Figure 4-1 Monthly Wind Capacity Contribution Values	18
Figure 4-2 Monthly Solar Capacity Contribution Values	18
Figure 4-3 Comparison of Normal and Extreme Weather: Firm Scenario Reserve Above Requirement	21
Figure 4-4 Comparison of Normal and Extreme Weather: Planned Scenario Reserve Above Requirement	22
Figure 4-5 Comparison of Current and Previous Outlook: Firm Scenario Extreme Weather Reserve Above Requirement	23
Figure 4-6 Forecast Energy Production by Fuel Type	25
Figure 4-7 Forecast Monthly Energy Production by Fuel Type	26
Figure 6-1 Minimum Ontario Demand and Baseload Generation	31
Figure 6-2 Minimum Ontario Demand and Baseload Generation	31
Figure 6-3 Monthly Off-Peak Wind Capacity Contribution Values	32
Figure 7-1 Reserve Above Requirement for All Anticipated Outages and All Scheduled Outages Scenarios	37

List of Tables

Table 3-1 Historical and Forecast Energy Summary	9
Table 3-2 Forecasted Seasonal Peaks	9
Table 4-1 Existing Grid-Connected Resource Capacity	15

Table 4-2 Committed Generation Resources Status	16
Table 4-3 Monthly Historical Hydroelectric Median Values for Normal Weather Conditions	17
Table 4-4 Summary of Available Resources under Normal Weather	20
Table 4-5 Summary of Zonal Energy for Firm Scenario Normal Weather	24
Table 4-6 Ontario Energy Production by Fuel Type for the Firm Scenario Normal Weather	26
Table 7-1 Notable Issues or Findings	34
Table 7-2 Summary of Scenarios	35
Table 7-3 Summary of Available Resources (MW) at Summer Peak	36
Table 7-4 Methodological Differences from the 18-Month Horizon	38
Table 7-5 Summary of Forecasted Peaks and Energy	39
Table 7-6 Monthly Energy and Peak Demand Forecast	40
Table 7-7 Committed Generation Resources Status	41
Table 7-8 Generation Facilities with Contracts Expiring during this Outlook Period	41
Table 8-1 Additional Resources	44

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1. Introduction

This Outlook covers two distinct periods: the 18-month period from July 2019 to December 2020, which supersedes the Outlook released on March 20, 2019 and is presented in chapters 3 - 6, and the 42-month period from January 2021 to June 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 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 42-month period presented in chapter 7 is intended to support generation and transmission owners with scheduling and approval of outages and to inform changes in resource adequacy beyond 18 months that may make outage coordination and assessments more challenging in the future.

Additional supporting documents are located on 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, please contact us by:

- Telephone: 1-888-448-7777 or 905-403-6900
- E-mail: customer.relations@ieso.ca

2. Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast used in the entirety of this Outlook is informed by actual demand, weather and economic data through to the end of March 2019, and has been updated to reflect the most recent economic projections. Actual weather and demand data for April and May 2019 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 May 24, 2019 for the entirety of the 60 months. 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.

The following resources completed market registration since the last Outlook:

- Nanticoke Solar – 44 MW
- Yellow Falls – 16 MW

2.3 Updates to Transmission Outlook

Transmission outage plans that were submitted to the IESO's outage management system by April 29, 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 May 24, 2019.

3. Demand Forecast for 18-Month Period

Grid-supplied energy demand is expected to dip in 2019, as some of the weakness in the latter half of 2018 carried over into 2019. For 2020, demand is expected to see positive gains beyond the bump that comes with the additional day of a leap year. Continued economic and demographic growth will push demand higher.

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period July 2019 to December 2020 and supersedes the previous forecast released in March 2019. Tables of supporting information are contained in the [2019 Q2 Outlook Tables](#) spreadsheet.

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 (conservation and embedded generation) and those that shift demand (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 forecast is expected to see a series of small increases. A strong U.S. economy and a low Canadian dollar will continue to boost demand in the industrial sector. Combined with an expanding population, this underlying growth will lead to an overall increase in demand over the forecast period. Embedded generation capacity has stopped growing and conservation savings are forecasted 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 not only when comparing energy versus peak demand, but also in comparing summer and winter peaks. Recent history has seen summer peaks significantly impacted by the growth in embedded generation capacity and the ICI. The majority of embedded generation is provided from solar-powered facilities that have high output levels during the traditional summer peak-hour period and no output during the winter peak-hour periods. In addition to reducing summer peaks, increased embedded solar output has also pushed the peak later in the day. As before, with the amount of embedded solar capacity plateauing and no conservation savings beyond 2020, peaks will show a reversal of recent years and increase over the forecast.

The following tables show the 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	-1.9%
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	2.2%
2019 (Forecast)	134.9	-0.2%
2020 (Forecast)	136.6	1.3%

Table 3-2 | Forecasted Seasonal Peaks

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2019	22,061	24,385
Winter 2019-20	21,106	22,132
Summer 2020	22,094	24,439

3.1 Actual Weather and Demand

Since the last forecast the actual demand and weather data for March, April and May have been recorded.

March

- The weather for March was much colder than normal, with average temperatures putting it in the coldest quartile of the past 50 years. The peak temperature for the month was also in the top quartile.

- The monthly peak occurred on Tuesday, March 5, the second coldest day of the month. The afternoon high was -9°C (at Toronto), the coldest since 2015, when the March peak reached a high of 20,263 MW.
- The weather-corrected peak of 19,486 MW which is slightly higher than the past several years and the highest since March 2016.
- Energy demand for the month was 11.7 TWh (11.3 TWh weather corrected), which is slightly higher than the past several years and the highest since March 2016.
- The minimum demand for the month was 12,210 MW, which is in line with March values since the 2009 recession. The minimum occurred in the early hours of Saturday, March 30.
- Embedded generation for the month was 590 GWh, a decrease of 1.2% compared to the previous March. Solar (11.9%) and hydro (25.5%) output were up, but reductions in wind (-9.1%), bio (-8.6%) and non-contracted (-3.8%) output more than offset those increases.
- Wholesale customers' consumption dropped 2.5% year over year, representing the largest monthly decline in just under two years. Declines in chemicals (-5.3%) and steel (-9.1%) led to a broad decline across numerous industrial sectors.

April

- The weather for April was close to normal for the month.
- The peak occurred on April 1, which was the coldest day of the month and followed a cold weekend to end March. The peak day high was 2.8°C, which was slightly warmer than normal. The actual peak was 17,645 MW (18,091 MW weather corrected). The observed April peak was the second lowest since market opening, topping only the peak occurring in April 2017; the weather-corrected peak was the second lowest, topping only last year's value.
- Energy demand for the month was 10.3 TWh (10.3 TWh weather corrected). Both of these are decreases compared to April 2018.
- The minimum was 11,079 MW and occurred in the early morning hours of Saturday, April 20. This is consistent with post 2009 observations for April.
- Embedded generation for April topped 584 GWh, which represents a 0.1% decrease over the previous April. Non-contracted generation was up 37% over the previous April, while all other types declined - solar (-5.5%), wind (-3.3%), hydro (-9.3%) and bio (-0.6%) – declined.
- Wholesale customers' load fell 2.2% compared to the previous April. Though an improvement over March, April marked three consecutive months of decline. Industrial loads vary for numerous reasons and will require monitoring over the coming months should this signal a trend. While iron and steel (-9.2%) have experienced the biggest decline, that sector should see an improvement with the removal of U.S. tariffs (25%) on Canadian steel.

May

- The weather for May was cold and wet. Average temperatures for the month put it in the lowest quartile of the past 50 years.
- May had a cold weather peak for just the second time since market opening. The peak was 16,784 MW (17,354 MW weather corrected) and occurred on May 1, the coldest day of the month with a high of 8.2°C (Toronto). While the average of the last 15 May peaks was 28.7°C it never got that hot in May 2019.
- Energy demand for the month was 10.2 TWh (10.3 TWh weather corrected), which was very similar to May 2017, the low-water mark for the month. Both months had similar average temperatures (15.8°C for 2019 and 16.2°C for 2017).
- Minimum demand for the month was 10,328 MW, which is second only to 10,249 MW in May 2017. The minimum occurred in the early hours of the Victoria Day holiday Monday.
- Embedded generation for the month was 576.5 GWh, a 13.0% decrease compared to the previous May. Non-contracted generation was down significantly, leading the decline.
- Wholesale customers' consumption reversed the weakness of the last four months. Year over year consumption increased by 0.5%, led by mining, refining and automotive manufacturing.

Overall, energy demand for the three spring months from March to May was down 0.7% compared with the previous spring. After adjusting for the weather, demand for the three months showed much a small increase of 0.2%.

Embedded generation for the three months was down 1.5% over the same time a year ago. Most of the decrease came from non-contracted generation (-24%)

For the three months, wholesale customers' consumption posted a 1.4% decrease over the same months a year prior with pulp & paper and iron & steel accounting for most of the reductions.

The [2019 Q2 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)
07-Jul-19	22,061	24,385	814	2,610
14-Jul-19	21,525	22,879	838	2,687
21-Jul-19	20,920	23,050	1,035	2,567
28-Jul-19	21,172	24,030	841	2,657
04-Aug-19	21,739	24,370	958	2,678
11-Aug-19	21,200	23,788	985	2,651
18-Aug-19	20,520	23,766	1,362	2,646
25-Aug-19	20,752	22,763	1,413	2,643
01-Sep-19	20,069	22,593	1,370	2,524
08-Sep-19	18,449	23,133	680	2,369
15-Sep-19	18,721	20,843	781	2,416
22-Sep-19	17,760	19,648	420	2,406
29-Sep-19	16,908	18,152	554	2,325
06-Oct-19	17,164	17,452	786	2,367
13-Oct-19	16,983	17,007	507	2,398
20-Oct-19	17,167	17,614	392	2,351
27-Oct-19	17,324	17,889	318	2,437
03-Nov-19	17,535	18,262	416	2,453
10-Nov-19	18,560	19,171	601	2,567
17-Nov-19	18,837	19,617	342	2,584
24-Nov-19	19,504	20,044	607	2,668
01-Dec-19	19,734	20,737	409	2,703
08-Dec-19	19,993	21,153	555	2,746
15-Dec-19	20,437	21,340	690	2,787
22-Dec-19	20,252	21,303	362	2,786
29-Dec-19	18,970	19,637	528	2,682
05-Jan-20	19,722	20,775	570	2,822
12-Jan-20	21,106	22,132	547	2,943
19-Jan-20	20,488	21,024	483	2,919
26-Jan-20	20,292	21,414	404	2,920
02-Feb-20	20,358	21,566	734	2,940
09-Feb-20	19,697	21,253	635	2,869
16-Feb-20	19,278	20,721	581	2,805
23-Feb-20	19,158	20,877	501	2,761
01-Mar-20	19,541	20,861	531	2,800
08-Mar-20	19,137	20,042	649	2,744
15-Mar-20	17,907	18,617	611	2,642
22-Mar-20	17,522	18,247	569	2,546
29-Mar-20	17,339	18,286	567	2,533

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
05-Apr-20	17,088	17,769	471	2,490
12-Apr-20	16,352	17,278	496	2,367
19-Apr-20	15,788	15,952	531	2,354
26-Apr-20	15,922	16,390	721	2,340
03-May-20	16,941	19,379	849	2,318
10-May-20	16,278	19,093	845	2,334
17-May-20	17,663	20,980	1,175	2,355
24-May-20	17,370	21,189	1,330	2,291
31-May-20	18,121	20,670	1,292	2,371
07-Jun-20	18,875	23,227	1,055	2,548
14-Jun-20	20,123	23,488	835	2,561
21-Jun-20	21,006	23,598	754	2,630
28-Jun-20	21,123	23,483	1,016	2,683
05-Jul-20	20,325	23,029	814	2,650
12-Jul-20	22,094	24,439	838	2,755
19-Jul-20	20,654	23,683	1,035	2,611
26-Jul-20	21,104	23,710	841	2,703
02-Aug-20	21,483	23,667	958	2,693
09-Aug-20	20,951	23,287	985	2,668
16-Aug-20	20,209	23,009	1,362	2,652
23-Aug-20	21,130	22,888	1,413	2,709
30-Aug-20	19,581	22,009	1,370	2,555
06-Sep-20	17,851	23,183	680	2,446
13-Sep-20	18,416	20,439	781	2,420
20-Sep-20	17,220	19,299	420	2,430
27-Sep-20	16,403	17,750	554	2,356
04-Oct-20	16,796	16,933	786	2,409
11-Oct-20	16,499	16,609	507	2,432
18-Oct-20	16,738	17,286	392	2,390
25-Oct-20	16,895	17,572	318	2,478
01-Nov-20	17,173	18,002	416	2,507
08-Nov-20	18,475	18,832	601	2,605
15-Nov-20	18,697	19,233	342	2,625
22-Nov-20	19,179	19,692	607	2,693
29-Nov-20	19,684	21,033	409	2,764
06-Dec-20	19,918	20,826	555	2,787
13-Dec-20	20,169	21,026	690	2,833
20-Dec-20	19,919	20,933	362	2,828
27-Dec-20	19,657	20,563	528	2,805
03-Jan-21	20,404	20,957	528	2,768

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. Over the forecast horizon, there remains significant downside risk to the economy. Trade tensions, climate impacts and global political uncertainty increase 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 Q2 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 load forecast uncertainty, which is a measure of uncertainty in demand due to weather volatility. Table 3.3.5 of the [2019 Q2 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 a generation resource, they are included in the supply mix, and added back into the history when forecasting demand. Therefore, the demand forecast is prior to the impacts of demand measures.

Load modifiers include conservation (energy-efficiency programs, codes and standards and fuel switching) price impacts (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 together have the net effect of reducing the amount of grid-supplied electricity. Conservation impacts both peaks and energy, prices reduce demand during peak periods and embedded generation impacts vary by fuel type.

4. Resource Adequacy for 18-Month Period

The IESO expects to have sufficient generation supply for summer 2019. Potential risks in summer 2020 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 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

Fuel Type	Total Installed Capacity (MW)	Capability at Outlook Peak (MW)	Number of Stations	Change in Number of Stations	Change in Installed Capacity
Nuclear	13,009	11,973	5	0	0
Hydroelectric	8,499	5,069	76	1	16
Gas/Oil	10,277	8,437	31	0	0
Wind	4,486	611	39	0	0
Biofuel	295	81	7	0	0
Solar	424	58	9	1	44
Demand Measures	-	794	-	-	-
Firm Imports (+) / Exports (-) (MW)	-	-116	-	-	-
Total	36,989	26,907	167	2	60

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 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 best estimated date of the completion of market registration available to the IESO by May 24, 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

Project Name	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered	
					Firm (MW)	Planned (MW)
Loyalist Solar	East	Solar	2019-Q2	Commissioning	0	54
Henvey Inlet Wind Farm	Essa	Wind	2019-Q3	Commissioning	0	300
Napanee Generating Station	East	Gas	2019-Q4	Commissioning	0	985
Nation Rise	East	Wind	2020-Q1	Under Development	0	100
Romney Wind Energy Centre	West	Wind	2020-Q1	Under Development	0	60
Calstock	Northeast	Biofuel	2020-Q3	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.
- 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 2019, 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)	6,338	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 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 Outlook.

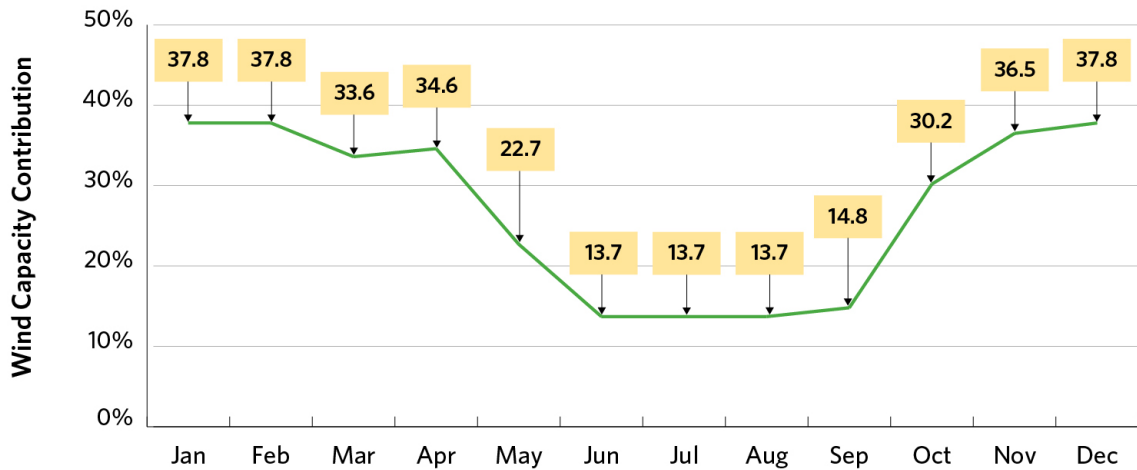


Figure 4-1 | Monthly Wind Capacity Contribution Values

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 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.

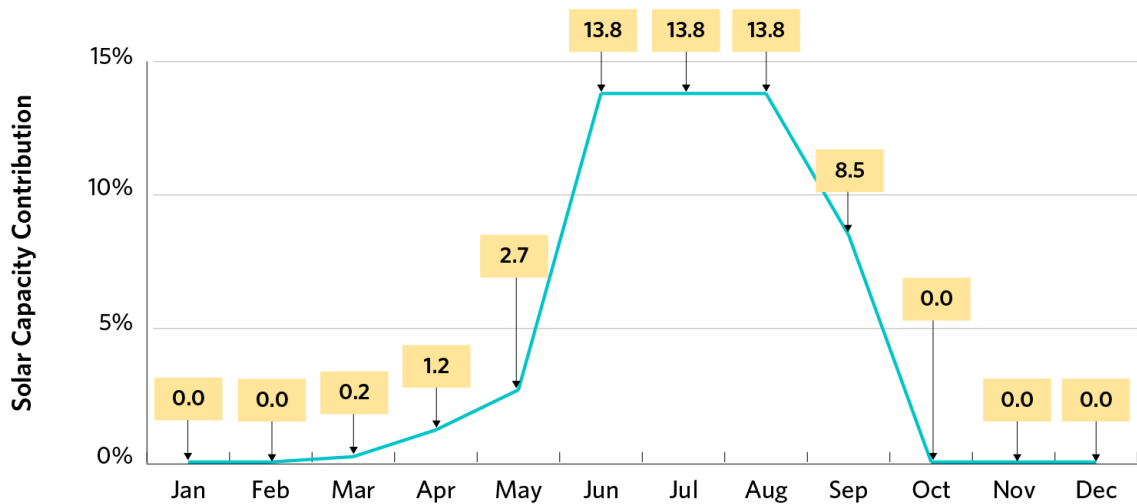


Figure 4-2 | Monthly Solar Capacity Contribution Values

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 an annual demand-response [\(DR\) 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](#) (Demand Measures and Load Modifiers). The impacts of actual activations of 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 of some neighbouring jurisdictions 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) strip auction for delivery between May and October 2019.

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 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 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

Notes	Description	Summer Peak 2019		Winter Peak 2020		Summer Peak 2020	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,989	37,343	36,989	38,328	36,989	38,488
2	Total Reductions in Resources (MW)	10,760	11,065	10,747	11,200	12,434	13,161
3	Demand Measures (MW)	794	794	924	924	794	794
4	Firm Imports (+) / Exports (-) (MW)	-116	-116	-500	-500	0	0
5	Available Resources (MW)	26,907	26,956	26,666	27,552	25,349	26,121
6	Bottling (MW)	0	0	1,910	1,910	36	36
7	Available Resources without Bottling (MW)	26,907	26,956	28,576	29,462	25,385	26,157

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 April 29, 2019. The generation planned outages occurring during this Outlook period have been assessed as of May 24, 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 May 24, 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. During these conditions, the reserve is lower than the requirement without reliance on imports for a total of eight weeks under the extreme weather scenario in

2019 and 13 weeks in 2020. Under the current outage schedule, the RAR is below the -2,000 MW threshold for one week in June 2020, three weeks in July 2020 and one week in September 2020. 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.

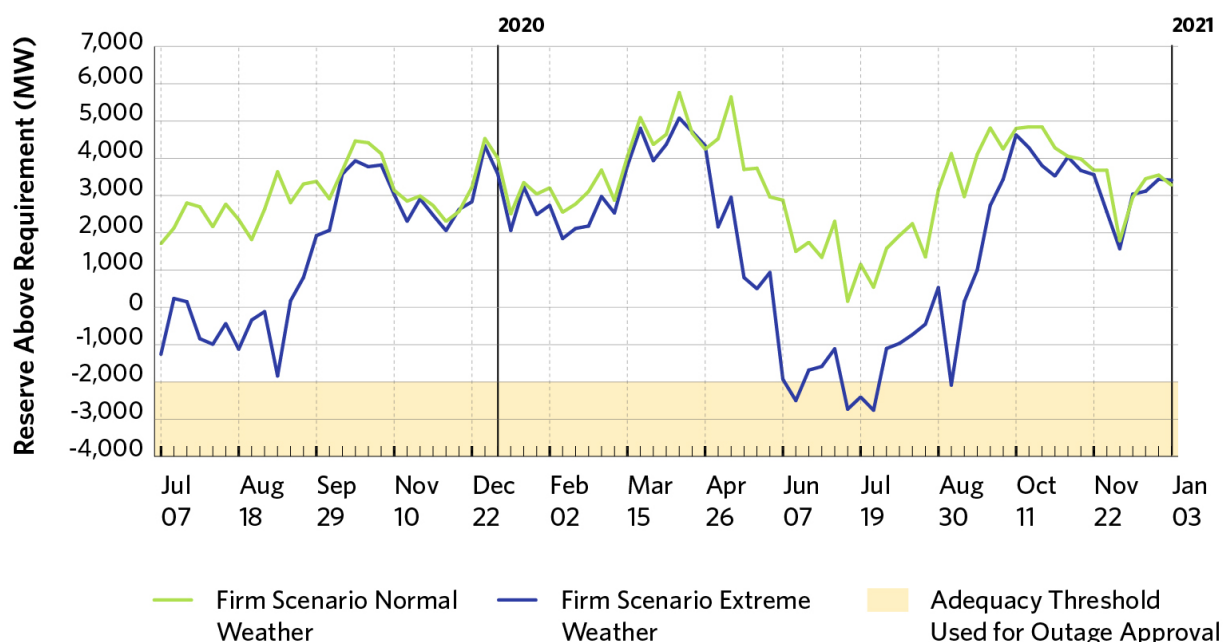


Figure 4-3 | Comparison of Normal and Extreme Weather: Firm Scenario Reserve Above Requirement

4.2.2 Planned Scenario with Normal and Extreme Weather

The planned scenario incorporates all existing capacity plus 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 approximately 38 MW of generation capacity will reach contract expiry.

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.

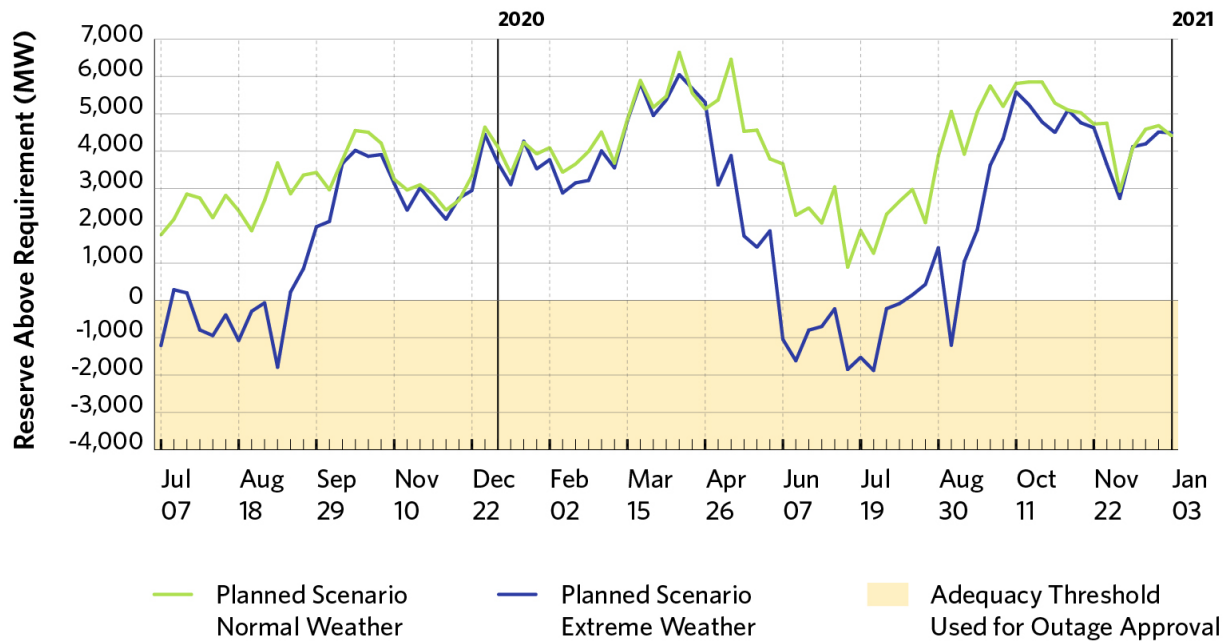


Figure 4-4 | Comparison of Normal and Extreme Weather: Planned Scenario Reserve Above Requirement

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 published on March 20, 2019. The difference is primarily the result of changes in planned outages and the expected in-service dates of new resources.

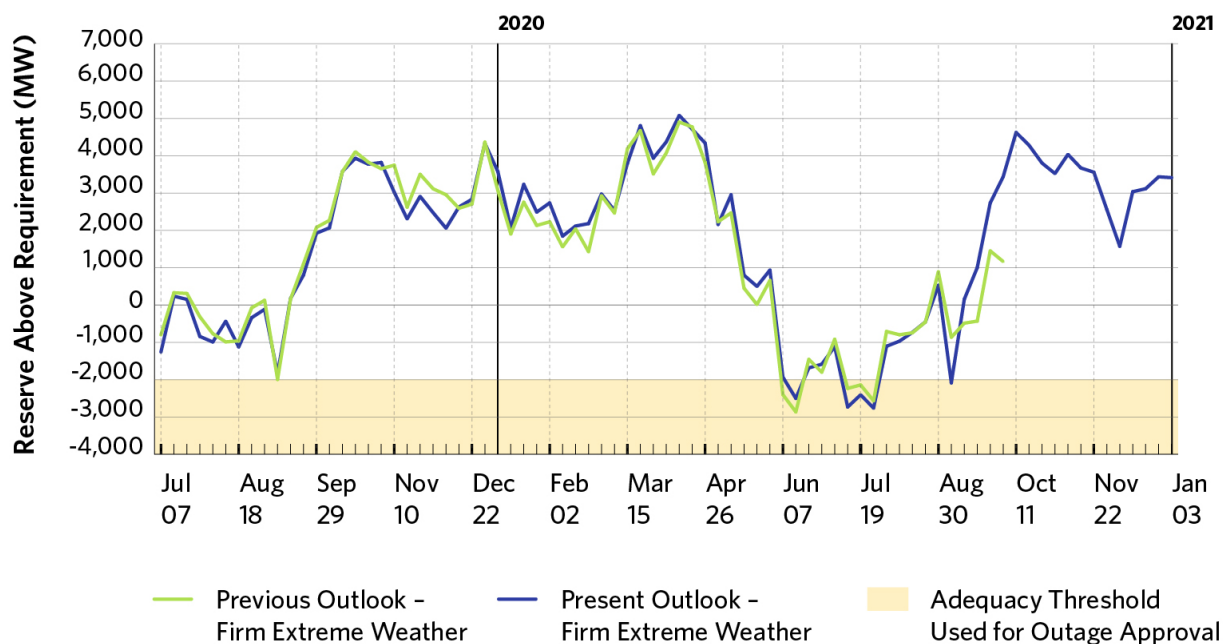


Figure 4-5 | Comparison of Current and Previous Outlook: Firm Scenario Extreme Weather Reserve Above Requirement

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

4.2.4 Transitional Capacity Auction

For this report, the Capacity Adequacy Assessment assumes the continued availability of off contract existing resources. Beginning in 2019, the IESO will introduce a Transitional Capacity Auction as a mechanism that will enable these resources to provide capacity through a competitive auction process. Given that the TCA will eventually acquire future capacity beyond the timeframe of the 18 month assessment, this capacity will be reflected in future reported RAR values.

4.2.5 Managing Northwest Ontario Reliability Need

In February 2019, the Ontario Energy Board granted NextBridge Infrastructure leave to construct the transmission reinforcements to the East-West Tie (EWT). The EWT expansion is the long-term solution to meet the capacity need in the Northwest. Additional capacity is needed in the Northwest due to expiry of generator contracts, load growth, and the risk of transmission outages.

The planned in-service date is the end of 2021, which is later than the IESO's recommended in service date of 2020. The IESO is determining what actions are required to mitigate any reliability risks of the Northwest that may be caused by the delay.

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 as the capacity assessment, as outlined in Table 4-1 and Table 4-2, pertaining to resources expected to be available over the next 18 months. The monthly forecast of energy production capability, based on the 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 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

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		GWh	GWh
Ontario	206.2	9,389	206.2	9,389	0.0	445.7	577.7
Bruce	0.9	41	65.7	2,993	64.8	1.0	154.7
East	11.6	526	12.9	586	1.3	24.5	70.2
Essa	11.4	520	2.9	132	-8.5	24.4	13.6
Niagara	5.4	247	19.9	904	14.5	15.4	46.2
Northeast	15.8	721	15.1	687	-0.7	26.0	37.8
Northwest	6.1	279	6.8	311	0.7	9.9	16.9
Ottawa	14.1	641	0.2	10	-13.9	24.4	1.4
Southwest	43.8	1,994	6.2	281	-37.6	94.5	25.1
Toronto	75.3	3,430	62.4	2,841	-12.9	175.8	141.3
West	21.7	990	14.2	645	-7.5	49.8	70.5
Ontario	206.2	9,389	206.2	9,389	0.0	445.7	577.7

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 province's 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.

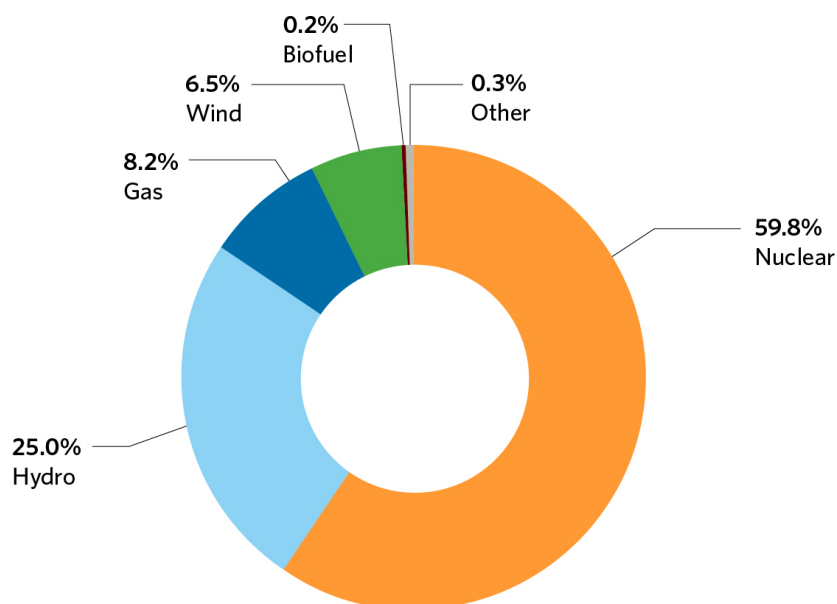


Figure 4-6 | Forecast Energy Production by Fuel Type

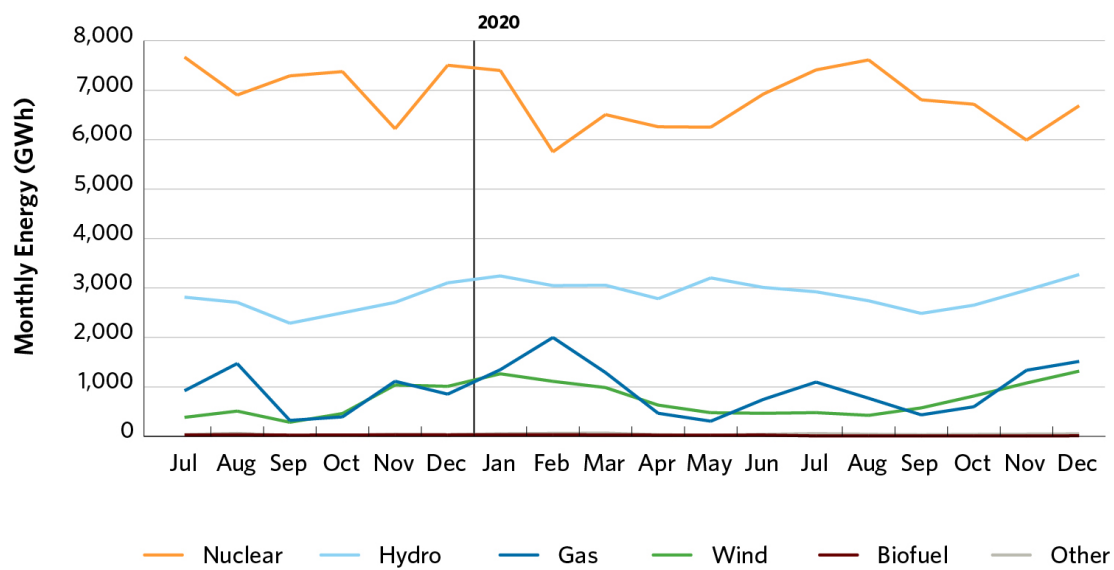


Figure 4-7 | Forecast Monthly Energy Production by Fuel Type

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

Fuel Type (Grid Connected)	2019 (Jan 1 - Dec 31) (GWh)	2020 (Jan 1 - June 30) (GWh)	Total (GWh)
Nuclear	42,966	80,321	123,287
Hydro	16,123	35,377	51,501
Gas & Oil	5,077	11,902	16,979
Wind	3,687	9,626	13,313
Bio Fuel	169	217	386
Other (Solar & DR)	189	526	715
Total	68,212	137,969	206,181

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 section, the information that transmitters provide, with respect to transmission projects that are planned for completion within the next 18 months, is considered. Transmission projects that are planned for completion beyond the next 18 months 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 April 29, 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 reliability. These considerations are categorized by zone.

Bruce and Southwest Zones

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 August 19, 2019 will impact B561M, significantly reducing the transfer capability out of the Bruce area. In addition, a planned three-week outage starting November 2019 will impact circuit B560V, significantly reducing the transfer capability out of the Bruce area.

Niagara Zone

A number of non-contiguous planned outages from May 5, 2019 until October 25, 2019 will impact circuits out of Beck #2 TS, significantly reducing the transfer capability out of the Niagara area.

West Zone

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 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 Q4 2020.

A planned outage at St. Lawrence TS from June 11, 2019 to July 4, 2019, a planned outage at Lennox TS from July 8, 2019 to September 5, 2019, and a planned outage impacting circuit L24A from September 3, 2019 to September 27, 2019 will reduce the transfer capability into the Ottawa area during those periods.

Northwest and Northeast Zones

Reinforcements to the system in the Kapuskasing area, consisting of upgrades to circuit H9K and reactive compensation, are planned to be installed with in-service dates of Q1 2020 and Q1 2021, respectively. During the construction of these reinforcements, certain outages may be restricted.

Planned outages, including a six-week-plus outage starting July 2019 and a one-month outage starting September 2019, will reduce transfer capability on the North-South Tie. The latter outage, in particular, will substantially reduce transfer capability on the North-South Tie.

A planned two-week outage starting November 30, 2019 impacting M31L will significantly reduce transfer capability across the East-West Tie.

Interconnections

The failure of the phase angle regulator (PAR) connected to Ontario-New York 230 kV interconnection circuit L33P in early 2018 continues to impact 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 St. Lawrence area resources in real-time. Additionally, careful coordination of transmission and generation outages will be required in the area. 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.

Intermittent planned outages will impact interconnection circuit PA302 from June 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, and in summer 2020.

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 during which curtailment of nuclear generation may be expected.

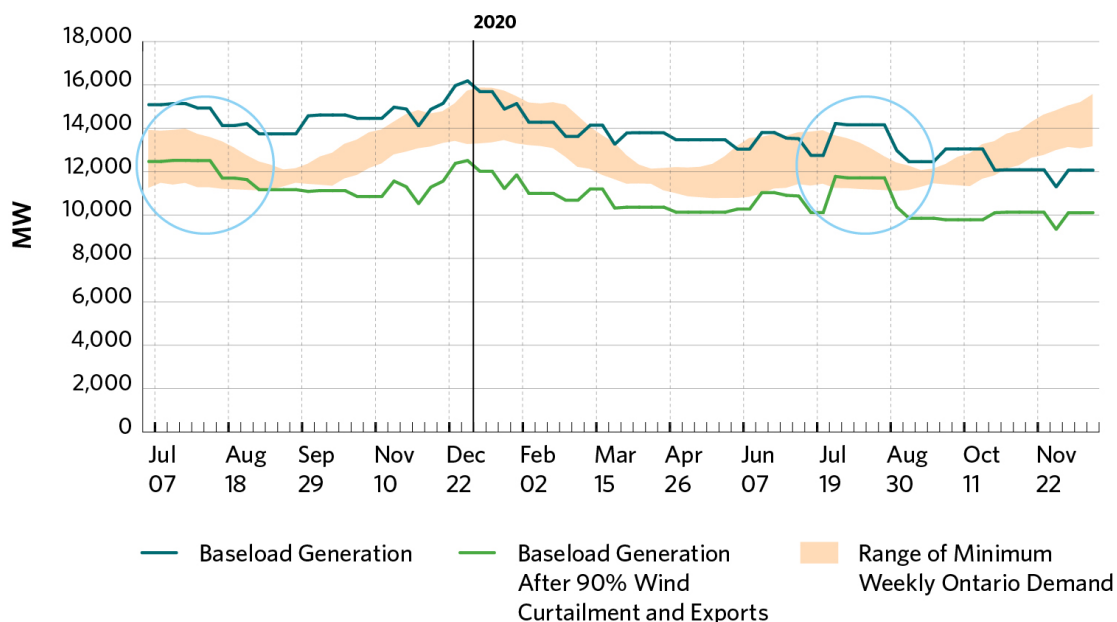


Figure 6-1 | Minimum Ontario Demand and Baseload Generation

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.

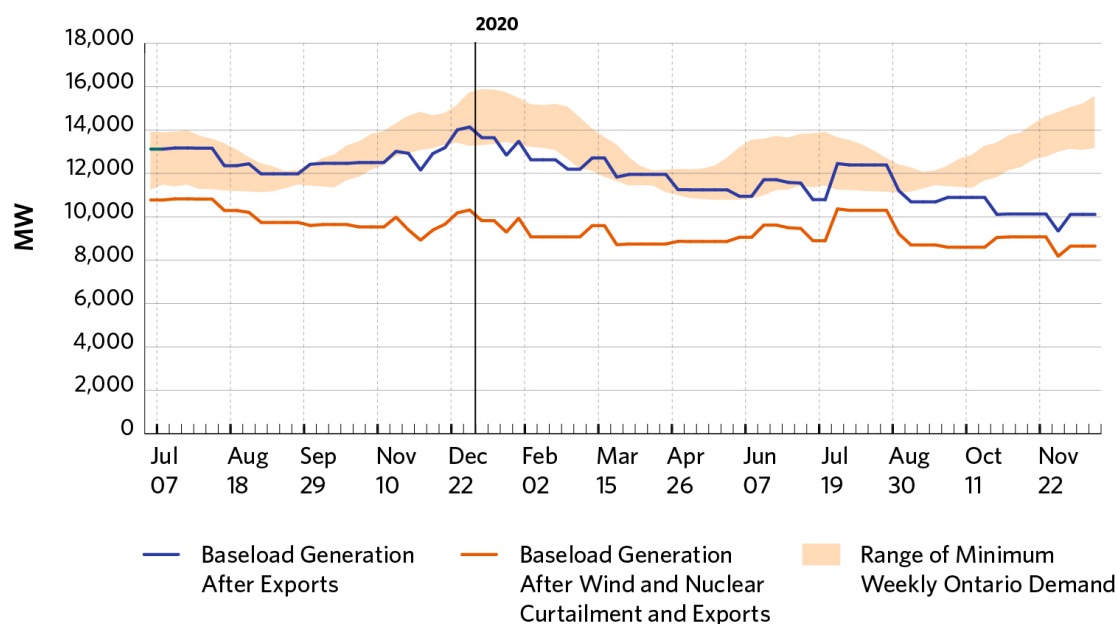


Figure 6-2 | Minimum Ontario Demand and Baseload Generation

The baseload generation assumptions include 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 summer Outlook.

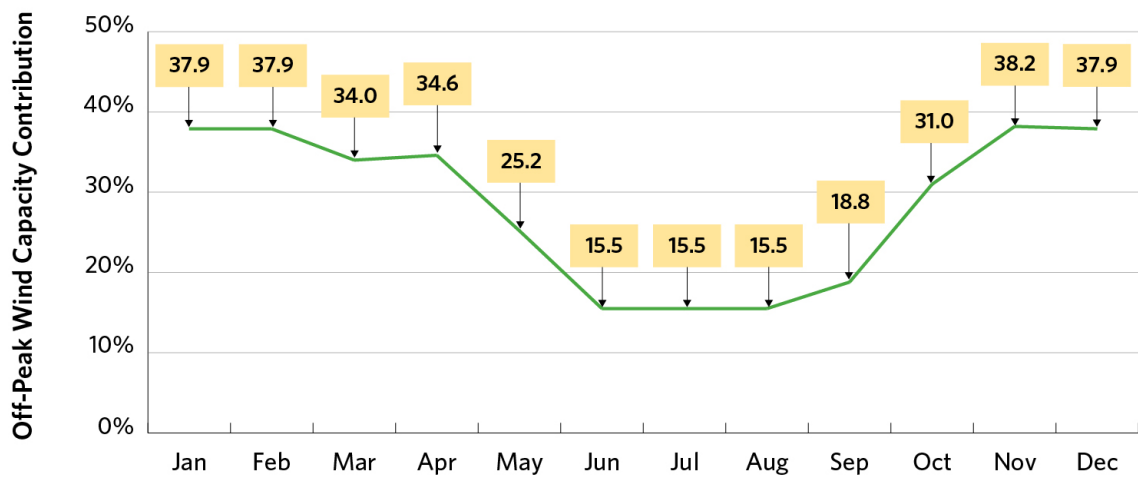


Figure 6-3 | Monthly Off-Peak Wind Capacity Contribution Values

7. Beyond 18 Months

The ideal times to schedule additional outages are in early spring, late fall or winter months. In summer 2021 and summer 2023, there is very little opportunity for new outages. In summer 2023, additional capacity may be required in addition to outage coordination to ensure we have sufficient generation to serve Ontario's demand.

The refurbishment of Darlington units and the retirement of Pickering Nuclear Generating Station will create additional outage scheduling challenges for generators located east of the "Flow East Toward Toronto" interface and transmission elements affecting that interface.

7.1 Introduction

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

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 timeframe 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. The IESO is developing the transitional capacity auction (TCA) to address this requirement.

Information on global adequacy needs that require investments beyond outage management are 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 has been engaging with stakeholders to inform development of an updated Planning Outlook, scheduled for release in September. 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 January 2021 and June 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: - July 2021 - 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: - May and July 2021 - June to September 2023 - May 2024	Section 7.3
Periods where outage management alone cannot resolve capacity adequacy needs	Capacity Adequacy Assessment	Additional capacity likely required in addition to outage rescheduling 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 Towards Toronto interface	Recent observations of system conditions	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	Section 7.5

7.3 Capacity Adequacy Assessment

This section provides an assessment of the adequacy of resources to meet the 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, an opportunity can exist for additional outages when reserves are above required levels, 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 is provided in the Planning Outlook, delivered at the [2018 Technical Planning Conference](#).

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, as well as 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 outages submitted to IESO's 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 timeframe, 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 IESO's outage management system. Because of this uncertainty, outages are treated as an additional sensitivity in this longer-term view; in the 18-month timeframe, only project risks and weather are incorporated as sensitivities.

This Outlook for January 2021 to June 2024 presents the results of combining the above sensitivities into three scenarios. Results from these scenarios are shown in the [2019 Q2 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 forecast available resources, 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	25,219	24,649	25,219
2022	24,606	25,780	24,606
2023	23,996	24,088	23,118
2024	Summer Peak of 2024 not in assessment timeframe		

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 is the incremental outages that were submitted to the IESO in the 2019 Form 1230s.

All Anticipated Outages Scenario

The “All Anticipated Outages” scenario factors all outages submitted to CROW (outage management system) 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 shows significant periods of risk. As seen below, this fulsome outage plan is close to the threshold for resource adequacy in July 2020. Generators that have outages scheduled in July 2021 and from June to September 2023 should consider rescheduling outside 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 in July 2021 and from June to September 2023 should continue to monitor future Outlooks for information on the impacts of these outage plans.

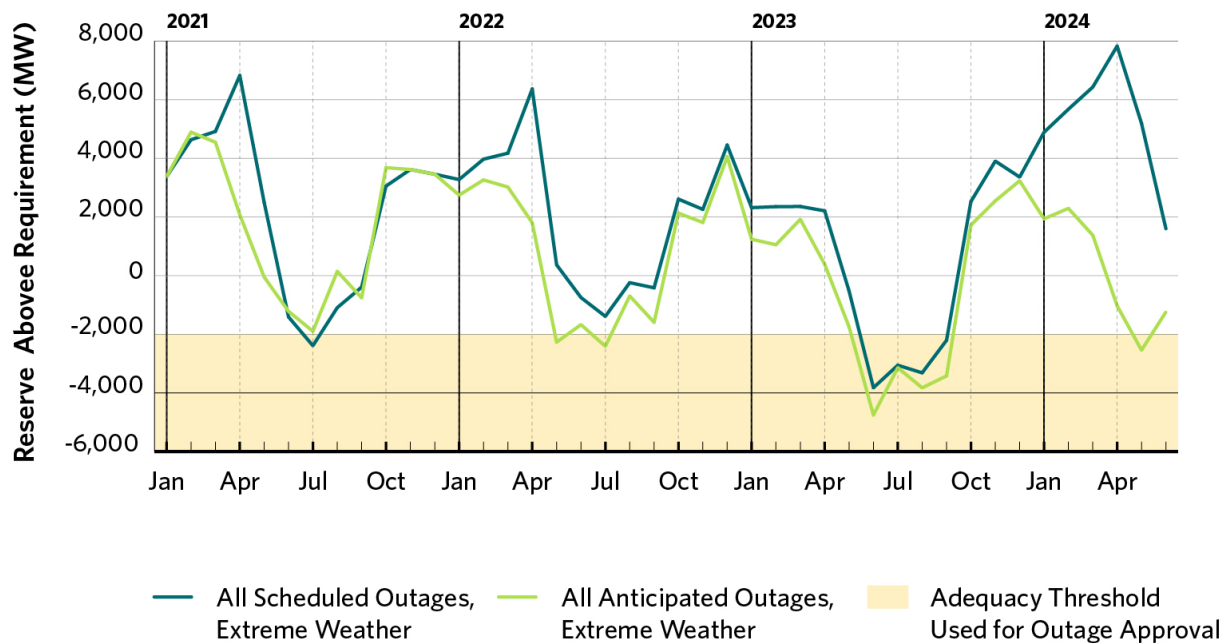


Figure 7-1 | Reserve Above Requirement for All Anticipated Outages and All Scheduled Outages Scenarios

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 May 24, 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 in July 2021 and June through September 2023. Many anticipated outages beyond 2021 are not yet submitted to CROW, making summers 2022 and 2023 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 this assessment from January 2021 to June 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, it is prudent to adapt some assumptions or methods 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 April 29, 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 April 29, 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 considers all new resources; however, they are delayed by six months from their scheduled start date. 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	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 remain fairly flat with an annual growth rate of 0.2%. Much of the growth in Ontario's economy is occurring outside of the province's electrically intense industrial sectors. Though those more energy-intensive sectors are stable, energy efficiency gains means that increased activity is not translating into significant demand growth, except in regions, such as Windsor-Essex, which will continue to experience unprecedented expansion in greenhouse production over the forecast horizon. A strong U.S. economy, low Canadian dollar and low interest rates all help Ontario's export-oriented economy. However, trade disruptions, higher interest rates and increasing prices put current economic expansion at risk.

Both the summer and winter peaks are expected to remain virtually flat over the forecast horizon. This is due to strong downward pressure from peak pricing incentives and increased energy-efficiency savings. With the expansion of embedded capacity plateauing, this downward impact has lessened going forward.

An estimate of an additional 1,400 MW of price-responsive demand is incorporated in the demand forecast. This is a result of price-responsive loads reducing on their own under the ICI. Other demand measures (dispatchable loads and resources secured through the DR auction) estimates are forecast based on past performance of these programs, using the same values as in the 18-month horizon.

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	22,113	21,262	137	24,509	22,440
2022	22,176	21,347	137	24,568	22,622
2023	22,256	21,402	137	24,684	22,858
2024	22,367	21,489	138	24,921	22,892

Table 7-6 | Monthly Energy and Peak Demand Forecast

Week Ending	Normal Peak (MW)	Load Forecast Uncertainty (MW)	Extreme Peak (MW)	Normal Energy Demand (GWh)
Jan-21	21,262	570	22,440	12,917
Feb-21	20,216	734	21,520	11,279
Mar-21	19,478	531	20,335	11,676
Apr-21	17,319	721	19,655	10,190
May-21	18,243	1,330	21,457	10,369
Jun-21	21,876	1,016	23,874	11,333
Jul-21	22,113	814	24,509	11,912
Aug-21	21,242	1,362	23,410	11,669
Sep-21	18,523	680	23,286	10,392
Oct-21	17,276	318	18,104	10,844
Nov-21	19,585	607	21,128	11,498
Dec-21	20,432	528	21,150	12,560
Jan-22	21,347	570	22,622	12,899
Feb-22	19,897	501	21,544	11,296
Mar-22	19,576	531	20,379	11,685
Apr-22	17,400	721	19,736	10,100
May-22	18,315	1,330	23,573	10,479
Jun-22	21,327	754	23,991	11,373
Jul-22	22,176	814	24,568	11,855
Aug-22	20,904	1,362	23,472	11,752
Sep-22	18,583	680	22,854	10,389
Oct-22	17,210	318	18,470	10,900
Nov-22	19,335	607	20,925	11,558
Dec-22	20,469	528	21,123	12,553
Jan-23	21,402	570	22,858	12,979
Feb-23	20,119	734	21,800	11,410
Mar-23	19,205	531	21,024	11,853
Apr-23	17,206	471	19,717	10,298
May-23	18,287	1,292	21,559	10,456
Jun-23	21,095	754	23,559	11,110
Jul-23	22,256	814	24,684	11,909
Aug-23	21,326	958	24,666	12,067
Sep-23	18,604	781	23,150	10,461
Oct-23	17,038	318	18,457	10,873

Week Ending	Normal Peak (MW)	Load Forecast Uncertainty (MW)	Extreme Peak (MW)	Normal Energy Demand (GWh)
Nov-23	19,251	409	20,699	11,430
Dec-23	20,057	528	21,359	12,413
Jan-24	21,489	570	22,892	13,080
Feb-24	19,829	635	21,784	11,839
Mar-24	19,132	649	21,072	11,684
Apr-24	17,352	471	19,587	10,393
May-24	18,424	1,292	21,346	10,505
Jun-24	21,254	1,016	23,620	11,141

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
Total						-1,030

Table 7-8 is provided for information only and lists generation facilities with contracts expiring prior to June 2024. These facilities are assumed to continue operation following their contract expiry in all scenarios of this Outlook.

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-Q4	-131
Lennox Generating Station	East	Natural Gas/ Oil	2022-Q3	-2,100
Thunder Bay Condensing Turbine Project	Northwest	Biomass	2023-Q1	-50
Nipigon Generating Station	Northwest	Natural Gas	2022-Q4	-43
Total				-2281

7.4.3 Firm Transactions

For this outlook, only committed transactions – those where an agreement between two jurisdictions for a set amount of capacity for a period exists – 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 delivered to Quebec in 2015/2016 winter will be returned to Ontario during summer before September 2030, based on Ontario's needs. Because the period for this transaction has not yet been confirmed, this capacity was not included in any scenario.

7.5 Transmission Outlook

7.5.1 Transmission Outages

No outages have been submitted beyond the 18-month horizon that materially impact system reliability, with the exception of the continued outage of the PAR connected to Ontario-New York 230 kV interconnection circuit L33P (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 both Pickering and Darlington Nuclear Generation Stations – retiring and undergoing refurbishment respectively - are located east of the interface. To help mitigate potential future constraints on the FETT interface, the IESO has requested Hydro One study various upgrade options for the Richview x Trafalgar 230 kV transmission lines (R14/R17T and R19/21TH) to increase the transfer capability of the FETT interface..

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

In January 2019, the IESO requested that Hydro One proceed with development of a new switching station at Leamington Junction to sectionalize and switch the four existing 230 kV circuits from Chatham to the Windsor Area (C21J/C22J/C23Z/C24Z). The expected in-service date is Q4 2022. This project will improve load meeting capability in the local area and form a basis for future bulk system improvements to reinforce the transmission path west from Chatham SS. Outages may be restricted in the area while work is being conducted to incorporate the project. More information regarding the load growth in the Leamington area is provided in section [5.3](#). Additional reinforcements are being initiated but currently fall outside the 18-month time frame.

In February 2019, the IESO requested that Hydro One proceed with upgrading circuits M30A and M31A, between Merivale TS and Hawthorne TS. Hydro One has indicated that a target in-service date of December 2022 is feasible. This project will address supply capacity constraints to west Ottawa. Additionally, this project is expected to enhance the ability for capacity imports from Quebec. Outages may be restricted in the area while work is being conducted to incorporate the project.

In February 2019, the Ontario Energy Board granted NextBridge Infrastructure leave to construct the transmission reinforcements to the East-West Tie. The planned in-service date is the end of 2021. Following completion of the project, the transfer capability of the East-West Transfer East and West interfaces will increase. Outages may be restricted in the area while work is being conducted to incorporate the project.

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 Q2 Outlook Tables	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookTables_2018dec.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/ReliabilityOutlookMethodology2018dec.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/TTCMethodology2018dec.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	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
RAS	Remedial Action Scheme
SBG	Surplus Baseload Generation
SCC	Solar Capacity Contribution
TS	Transmission Station
TWh	Terawatt-hours
WCC	Wind Capacity Contribution



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