18-Month Outlook

An Assessment of the Reliability and Operability of the Ontario Electricity System

FROM OCTOBER 2017 TO MARCH 2019

Connecting Today.
Powering Tomorrow.

Executive Summary

The outlook for the reliability of Ontario's electricity system remains positive for the next 18 months, with adequate domestic generation and transmission to supply Ontario's demand under normal weather conditions.

Under extreme weather conditions, the reserve levels that reflect current planned generator outages are below requirement for a combined total of 16 weeks over the period of May to September 2018. If extreme weather conditions materialize, the IESO may need to reject some generator maintenance outages to ensure that Ontario demand is met during the summer peak. Therefore, generators expecting to perform maintenance during the summer are advised to review their plans and consider rescheduling their outages.

Demand Forecast

Ontario's peak demand remains relatively flat. Conservation savings, growing embedded generation output and the Industrial Conservation Initiative (ICI) have offset the increased demand from population growth and economic expansion. This trend is expected to continue over the forecast horizon.

Energy demand has been trending down over the first part of 2017, causing demand to decrease compared to 2016. Demand is expected to show an increase in 2018 as stronger economic growth in the industrial sector will increase electricity consumption. At the same time, the growth in embedded generation capacity, a major offset to demand, will begin to plateau.

The following table summarizes the forecast seasonal peak demands over the next 18 months.

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2017-18	21,761	22,869
Summer 2018	22,278	24,656
Winter 2018-19	21,715	22,522

Supply

About 1,300 MW of new supply – 1,000 MW of gas, 275 MW of wind and 25 MW of hydroelectric – is expected to be connected to the province's transmission grid over the Outlook period. By the end of the period, the amount of grid-connected wind is expected to increase to about 4,500 MW and grid-connected solar is expected to remain at 380 MW.

By the end of the Outlook period, embedded wind capacity will exceed 600 MW and embedded solar will surpass 2,200 MW. Overall contracted embedded capacity will reach 3,300 MW over the Outlook horizon.

Transmission Adequacy

Ontario's transmission system is expected to continue to reliably serve Ontario demand while experiencing normal contingencies defined by planning criteria under both normal and extreme weather conditions forecast for this Outlook period. Several local area supply and transmission improvement projects underway will be placed in service during the timeframe of this Outlook. These projects, shown in Appendix B, will help relieve loading of existing transmission stations and provide additional capacity for future load growth. This outlook includes the following schedule changes, none of which impact reliability:

- During peak load periods, the two under-sized autotransformers at Hawthorne TS are expected to be overloaded after a contingency. As per the recommended solution in the IESO's Integrated Regional Resource Plan (IRRP) for the Ottawa area, Hydro One is proceeding with the replacement of these transformers with standard-sized units; the expected completion date for this work is now Q2 2019, previously Q2 2018.
- The new Bruce Remedial Action Scheme (RAS) is now scheduled to replace the existing Special Protection System in Q4 2018, previously Q4 2017. The new scheme will increase operational flexibility by detecting and responding to a greater number of system contingencies.
- The new Clarington 500/230 kV transformer station near the GTA is now expected to be in service by the end of Q2 2018, previously Q1 2018. The station will improve the power system reliability of central and eastern GTA, especially after the retirement of Pickering Nuclear Generating Station (NGS).

Operability

Conditions for surplus baseload generation (SBG) will continue over the Outlook period. However, the magnitude and the frequency of SBG are reduced with the nuclear refurbishment program. It is expected that SBG will continue to be managed effectively through existing market mechanisms, which include inter-tie scheduling, the dispatch of grid-connected renewable resources and nuclear manoeuvres or shutdowns.

The need for more flexible capability to respond to intra-hour differences between expected and actual variable generation and expected and actual Ontario demand continues to be a priority. The IESO has been engaging with stakeholders to explore a range of potential solutions for enhanced flexibility in the electricity system. The IESO encourages all stakeholders in Ontario's electricity sector, or their representatives, with an interest in this initiative to participate in this stakeholder engagement.

In addition, the IESO plans to expand its capability to schedule more regulation as required. The IESO issued an RFP for incremental regulation capacity on June 29 with a deadline of 3:00 p.m. on September 28, 2017. Further information regarding the Regulation RFP may be found on the IESO public website at:

http://www.ieso.ca/en/sector-participants/market-operations/markets-and-related-programs/regulation-service-rfp

The impact that embedded solar capacity can have on grid operations was demonstrated on Monday August 21, 2017 when Ontario experienced a partial solar eclipse. The eclipse over Ontario reached its peak coverage at approximately 2:30 p.m. EDT, where the total solar production was reduced by two thirds. Following the eclipse, solar production recovered to around 80% of what it was prior to the event. This celestial event was unique as it is the first solar eclipse to take place since large amounts of solar generation has been installed across North America. Leading up to August 21, the IESO planned extensively for this unique event and communicated widely with Ontario electricity sector partners, including its interconnected neighbours, as well as weather and solar forecasters to plan the day's power system operations accordingly. During the eclipse, there were no power system reliability issues in Ontario. More information can be found on the IESO public website at:

http://www.ieso.ca/en/corporate-ieso/media/also-of-interest/2017-solar-eclipse

Caution and Disclaimer

The contents of these materials are for discussion and information purposes and are provided "as is" without representation or warranty of any kind, including without limitation, accuracy, completeness or fitness for any particular purpose. The Independent Electricity System Operator (IESO) assumes no responsibility for the consequences of any errors or omissions. The IESO may revise these materials at any time in its sole discretion without notice. Although every effort will be made by the IESO to update these materials to incorporate any such revisions, it is up to you to ensure you are using the most recent version.

Table of Contents

List of Tables

List of Figures

1 Introduction

This Outlook covers the 18-month period from October 2017 to March 2019 and supersedes the last Outlook released on June 22, 2017.

The purpose of the 18-Month Outlook is:

- to advise market participants of the resource and transmission reliability of the Ontario electricity system
- to assess potentially adverse conditions that might be avoided through adjustment or coordination of maintenance plans for generation and transmission equipment
- to report on initiatives being put in place to improve reliability within the 18-month timeframe of this Outlook.

Additional supporting documents are located on the IESO website at:

http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook

This Outlook presents an assessment of resource and transmission adequacy based on the stated assumptions, using the described methodology. Readers may envision other possible scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own 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 at:

- Toll Free: 1-888-448-7777
- Tel: 905-403-6900
- Fax: 905-403-6921
- E-mail: customer.relations@ieso.ca.

- End of Section -

2 Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast is based on actual demand, weather and economic data through to the end of May 2017. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for June, July and August 2017 has been included in the tables.

2.2 Updates to Resources

The 18-Month Outlook uses planned generator outages submitted by market participants to the IESO's outage management system.

As of August 14, 2017, the following generators completed the market registration process since the last Outlook:

- Peter Sutherland Senior Generating Station – 29MW (Hydroelectric)
- Niagara Region Wind Farm (also known as West Lincoln NRWF) – 230 MW

2.3 Updates to Transmission Outlook

For this Outlook, transmission outage plans submitted to the IESO's outage management system as of July 28, 2017, were used.

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 August 14, 2017.

- End of Section -

3 Demand Forecast

The IESO forecasts electricity demand on the IESO-controlled grid. This demand forecast covers the period October 2017 to March 2019 and supersedes the previous forecast released in September 2017. Tables of supporting information are contained in the 2017 Q3 Outlook Tables spreadsheet.

Electricity demand is shaped by a several factors, which have differing 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)
- 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. The forecast of demand incorporates these impacts.

Grid-supplied energy demand has been fairly flat since the 2009 recession with small increases and small decreases year to year. The forecast shows a continuation of that trend; a decline in 2017 followed by an increase in 2018 driven by economic activity stemming from a strong U.S. economy and a comparatively low Canadian dollar. The province will also see a continued population growth into 2018, another factor behind growing demand.

Offsetting Ontario's growing demand are greater energy savings achieved through conservation efforts and contributions from distribution-connected (embedded) generators. The increase in new embedded generation capacity that has been reported on in past Outlooks will begin to slow during this reporting period. All combined, these forces will leave demand relatively flat over the forecast period.

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 the summer and winter peak. Summer peaks are significantly impacted by the growth in embedded generation capacity and pricing impacts (ICI and time-of-use rates). The majority of embedded generation is provided from solar powered facilities that have high output levels during the summer peak period and no output during the winter peak periods. In addition to reducing summer peaks, increased embedded solar output is also pushing the peak later in the day. As such, peak demands will show a small decline over the forecast horizon.

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

Table 3.1: Forecast Summary

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2017-18	21,761	22,869
Summer 2018	22,278	24,656
Winter 2018-19	21,715	22,522
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 (Forecast)	134.7	-1.1%
2018 (Forecast)	136.1	1.1%

Table 3.2: Weekly Energy and Peak Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)	Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
01-Oct-17	17,426	18,615	554	2,410					
08-Oct-17	17,679	17,712	786	2,455	08-Jul-18	22,158	24,656	814	2,654
15-Oct-17	17,496	17,736	507	2,436	15-Jul-18	22,278	23,587	838	2,742
22-Oct-17	17,723	18,159	392	2,474	22-Jul-18	21,628	23,576	1,035	2,638
29-Oct-17	17,883	18,404	318	2,514	29-Jul-18	21,661	24,395	841	2,722
05-Nov-17	18,031	18,757	416	2,519	05-Aug-18	22,136	24,379	958	2,739
12-Nov-17	19,091	19,661	601	2,622	12-Aug-18	21,754	24,410	985	2,695
19-Nov-17	19,381	20,172	342	2,640	19-Aug-18	20,894	24,191	1,362	2,672
26-Nov-17	19,822	20,608	607	2,713	26-Aug-18	21,126	23,145	1,413	2,672
03-Dec-17	20,231	21,312	409	2,763	02-Sep-18	20,266	22,811	1,370	2,565
10-Dec-17	20,400	21,599	555	2,818	09-Sep-18	18,812	22,103	680	2,422
17-Dec-17	20,901	21,824	690	2,835	16-Sep-18	19,199	20,875	781	2,486
24-Dec-17	20,663	21,741	362	2,804	23-Sep-18	17,930	19,968	420	2,454
31-Dec-17	20,414	21,558	528	2,710	30-Sep-18	17,261	18,520	554	2,400
07-Jan-18	21,188	22,041	570	2,842	07-Oct-18	17,559	17,601	786	2,444
14-Jan-18	21,761	22,869	547	2,910	14-Oct-18	17,389	17,625	507	2,425
21-Jan-18	21,332	21,924	483	2,897	21-Oct-18	17,607	18,042	392	2,463
28-Jan-18	21,071	22,098	404	2,903	28-Oct-18	17,773	18,287	318	2,503
04-Feb-18	21,118	22,269	734	2,906	04-Nov-18	18,020	18,689	416	2,512
11-Feb-18	20,303	21,772	635	2,840	11-Nov-18	18,936	19,501	601	2,607
18-Feb-18	20,029	21,428	581	2,789	18-Nov-18	19,231	20,025	342	2,624
25-Feb-18	19,670	21,442	501	2,737	25-Nov-18	19,682	20,467	607	2,699
04-Mar-18	20,258	21,486	531	2,767	02-Dec-18	20,085	21,175	409	2,744
11-Mar-18	19,719	20,547	649	2,722	09-Dec-18	20,250	21,455	555	2,776
18-Mar-18	18,651	19,346	611	2,645	16-Dec-18	20,783	21,708	690	2,823
25-Mar-18	18,204	18,958	569	2,556	23-Dec-18	20,567	21,648	362	2,810
01-Apr-18	18,094	19,062	567	2,501	30-Dec-18	20,139	20,938	528	2,653
08-Apr-18	17,807	18,345	471	2,484	06-Jan-19	20,981	21,841	570	2,768
15-Apr-18	17,066	18,037	496	2,429	13-Jan-19	21,715	22,522	547	2,903
22-Apr-18	16,620	16,846	531	2,387	20-Jan-19	21,244	21,837	483	2,887
29-Apr-18	16,622	17,008	721	2,366	27-Jan-19	20,984	22,011	404	2,894
06-May-18	17,635	20,078	849	2,330	03-Feb-19	21,034	22,186	734	2,902
13-May-18	17,329	19,616	845	2,342	10-Feb-19	20,217	21,686	635	2,830
20-May-18	18,460	21,698	1,175	2,370	17-Feb-19	19,962	21,359	581	2,781
27-May-18	18,235	21,888	1,330	2,318	24-Feb-19	19,577	21,355	501	2,729
03-Jun-18	18,985	21,404	1,292	2,403	03-Mar-19	20,214	21,443	531	2,767
10-Jun-18	19,680	23,944	1,055	2,551	10-Mar-19	19,673	20,500	649	2,716
17-Jun-18	20,561	24,034	835	2,566	17-Mar-19	18,580	19,271	611	2,638
24-Jun-18	22,249	24,239	754	2,631	24-Mar-19	18,135	18,894	569	2,550
01-Jul-18	22,098	23,931	1,016	2,670	31-Mar-19	18,033	19,000	567	2,544

3.1 Actual Weather and Demand

Since the last forecast, the actual demand and weather data for June, July and August have been recorded.

June

- June's weather was near normal with the exception of greater than normal amounts of rain in central and southern Ontario. As well, the peak day temperature was hotter and more humid than normal.
- The June peak occurred on the hottest day of the month as temperatures topped 32°C (at Toronto). The peak was 21,168 MW which is consistent with the past several June peaks. The impact of embedded solar has not only reduced demand, it has shifted the peak

later in the day. June's peak occurred during hour ending 17 (EST) which is the later than in previous years.

- The weather corrected peak of 20,436 MW, which is consistent with the June weather-corrected peaks from 2014 and 2015.
- Energy demand for the month was 10.7 TWh (10.6 TWh weather corrected), which is also very close to the experience from 2015. Both are low by historical standards.
- The minimum demand for the month was 10,518 MW, which is in line with recent experience, but at the same time represents a new low for June since market opening. The minimum occurred in the early hours of Sunday June 4.
- Embedded generation for the month was 587 GWh, a decrease of 6.3% compared to the previous June. The rainy weather was most likely to blame as solar output declined by 18.3% compared to the previous year whereas wind output was up 61.1%.
- Wholesale customers' consumption fell for the third consecutive month, dropping by 3.2% compared to the previous June. Big declines in the mining sector (-11.7%) and pulp & paper (-7.7%) more than offset improvements in iron and steel (3.5%), chemicals (2.6%) and the automotive sector (2.0%).

July

- The weather for July was milder than normal.
- The peak occurred on July 19, which was the hottest day of the month but the weather was not sustained and temperatures quickly fell off. The actual peak was 20,627 MW (21,905 MW weather-corrected). Both values are low for July peaks.
- Energy demand for the month was 11.6 TWh (11.7 TWh weather-corrected). Once again, both represent the lowest July values since the recession year 2009.
- The minimum demand was 10,806 MW and occurred in the early morning of Sunday, July 2, the Canada Day weekend.
- Embedded generation, as reported by distributors, was 593 GWh for the month. This represents a 6.5-percent increase compared to the previous July. The increase was attributable to a higher wind output (21% increase) and water (76% increase).
- Wholesale customers' consumption was up slightly, increasing by 0.2% over the previous July.

August

- The weather for August was milder than normal.
- The actual peak for the month was 20,158 MW, occurring on Monday August 21, which was the second warmest day of the month. However, the weather was not sustained and the month never really experienced a heat wave. The weather-corrected value was nearly 1,000 MW higher at 21,041 MW. Both these observations are the lowest August values since market opening.

- The mild weather led actual demand to 11.4 TWh, which is the lowest August since market opening. Weather-corrected demand was a similar 11.5 TWh and represents an all-time low for the month.
- Minimum demand of 10,829 MW occurred Sunday, August 27 at 4 a.m. This was low by historical standards.
- Embedded generation reported by distributors was 553 GWh for the month, an increase of 1 percent over the previous August. Solar (-6%) and wind output (-13%) both declined. Increased embedded hydro-electric output (129%) offset the declines in solar and wind.

  Wholesale customers' consumption fell by 3.3% compared to the previous August. Declines were across all the major industrial sectors.

2017 Summer Actuals

Overall, a generally wet and cool summer led to lower demand across the months. Energy demand for the three months from June to August was down 8.5 percent compared with the same three months one year prior. After adjusting for the weather, demand for the three months showed a significant, but smaller, 5.0 percent decline.

Embedded generation for the summer was down 1 percent compared to the previous summer. Solar and non-contracted generation output were both down while wind and hydro-electric output was up by nearly the same amount.

For the three months, wholesale customers' consumption posted a 2.1-percent decline compared to the previous summer. Mining and pulp & paper were responsible for the vast majority of the decline in hourly consumption, despite a strong increase in summer demand from the iron & steel and petroleum refining sectors.

The 2017 Q3 Outlook Tables contain 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 remains quite positive for the Ontario economy. Strong U.S. growth, a lower Canadian dollar, low interest rates and lower oil prices are all favourable to Ontario's export-oriented energy-intensive manufacturing sector. Ontario's economy has been strong compared to the rest of Canada. The manufacturing sector has seen considerable strength over the course of 2017 despite reduced electricity consumption. That apparent contradiction is due to reduction in certain energy intensive sectors and not a reflection of the broader economy.

Table 3.3.4 of the 2017 Q3 Outlook Tables presents the economic assumptions for the demand forecast.

3.2.2 Weather Scenarios

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

Table 3.3.5 of the 2017 Q3 Outlook Tables presents the weekly weather data for the forecast period.

3.2.3 Pricing, Conservation and Embedded Generation

The demand forecast accounts for pricing, conservation and embedded generation impacts. These impacts are grouped together and assessed as load modifiers as they act to reduce the grid-supplied demand.

Pricing incentives cause both the reduction in demand and the shifting of demand away from peak periods. Pricing includes time-of-use (TOU) rates and the ICI. TOU rates incent consumers to reduce loads during peak demand periods by either shifting to off-peak periods or reducing consumption altogether. TOU rates can factor into all weekdays throughout the year, and the size of the impact will be determined by the pricing structure. The ICI impacts demand beyond the five peak days as participants adjust their consumption based on projected values that are weather dependent. In 2017 two changes were made to the program that will increase the number of participants. First, the restrictions on loads greater than 1 MW were removed, allowing businesses from the commercial sector (hospitals, universities, hotels etc.) to participate. Secondly, the program was expanded to market participants in the manufacturing and greenhouse sector with an average peak load greater than 500 kW. The ICI program is estimated to have reduced peak demand by about 1,300 MW in the summer of 2016.

Output from embedded generators directly offsets the need for the same quantity of grid-supplied electricity. Embedded generation capacity is expected to grow over the forecast horizon, and the impact of increased embedded output is factored into the demand forecast.

Conservation also reduces the need for grid-supplied electricity by reducing end-use consumption. Conservation will continue to grow throughout the forecast period, and the demand forecast is decremented for those impacts.

Demand measures – dispatchable loads, Peaksaver Plus, Capacity-Based Demand Response (CBDR) and resources secured through the Demand Response (DR) auction are treated as resources in the assessment and are further discussed in section 4.1.3. Demand reductions due to these programs are added back to the actual demand, and the forecast is based on demand prior to the impacts of these programs.

- End of Section -

4 Resource 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 exists for additional outages when reserves are above required levels.

The existing installed generation capacity is summarized in Table 4.1. This includes capacity from new projects that have completed 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 Generation Capacity as of August 14, 2017

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Outlook Peak (MW)	Number of Stations	Change in Installed Capacity (MW)	Change in Stations
Nuclear	13,009	11,537	5	31	0
Hydroelectric	8,480	5,786	74	29	1
Gas/Oil	10,277	8,371	31	0	0
Wind	4,213	533	36	230	1
Biofuel	495	439	9	0	0
Solar	380	38	8	0	0
Total	**36,853**	**26,704**	**163**	**290**	**2**

4.1 Assessment Assumptions

4.1.1 Generation Resources

All generation projects that are scheduled to come into service, 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 that are under construction, as well as contracted resources. Details regarding the IESO's CAA process and the status of these projects can be found on the IESO's website below, under Application Status:

http://www.ieso.ca/Pages/Participate/Connection-Assessments/default.aspx

The estimated effective date in Table 4.2 indicates the date on which additional capacity is assumed to be available to meet Ontario demand or when existing capacity will be shut down. This information is current as of August 14, 2017. If a project is delayed, the estimated effective date will be the best estimate of the commercial operation date for the project that is available to the IESO by the cutoff date.

Table 4.2: Committed Generation Resources Status

Project Name	Also Known As	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered	
						Firm (MW)	Planned (MW)
Namewaminikan Hydro		Northwest	Water	2017-Q4	Commissioning	0	10
Harmon Unit 2 Runner Upgrade		Northeast	Water	2017-Q4	Commissioning	0	10
Harmon Unit 1 Runner Upgrade		Northeast	Water	2017-Q4	Commissioning	0	10
Kapuskasing Generating Station		Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
North Bay Generating Station		Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
Belle River Wind		West	Wind	2018-Q1	Commissioning	0	100
Napanee Generating Station		East	Gas	2018-Q2	Under Development	0	985
North Kent Wind 1		West	Wind	2018-Q2	Under Development	0	100
Amherst Island Wind		East	Wind	2018-Q2	Under Development	0	75
Douglas Generating Station		Toronto	Gas	2018-Q4	Expiring Contract	-122	-122
Total						**-242**	**1,049**

Notes on Table 4.2:

1. The total may not add up due to rounding and does not include in-service facilities.
2. Project status provides an indication of the project progress. The milestones used are:
    a. Under Development – includes projects in approvals and permitting stages (e.g., environmental assessment, municipal approvals, IESO connection assessment approvals, etc.) and projects under construction.
    b. Commissioning – the project is undergoing commissioning tests with the IESO.
    c. Commercial Operation – the project has achieved commercial operation under the contract criteria but has not met all the market registration requirements of the IESO.
    d. Expiring Contract – Non-Utility Generators (NUGs) whose contracts expire during the Outlook period are included in both scenarios only up to their contract expiry date. If the NUGs continue to provide forecast output data, they are also included in the planned scenario for the rest of the Outlook period, too.

4.1.2 Generation Capability

Hydroelectric

A monthly forecast of hydroelectric generation output forecast 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. Table 4.3 shows the historical hydroelectric median values calculated with data from May 2002 to March 2017. These values are updated annually to coincide with the release of the summer 18-Month 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 Values (MW)	6,069	6,008	5,864	5,795	5,843	5,653	5,633	5,319	5,068	5,383	5,699	6,099

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, the 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 Long-Term Assessments. Table 4.4 shows the monthly WCC values. These values are updated annually to coincide with the release of the summer Outlook.

Table 4.4: Monthly Wind Capacity Contribution Values

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
WCC (% of Installed Capacity)	37.8%	37.8%	33.7%	33.2%	22.0%	12.6%	12.6%	12.6%	16.2%	30.8%	35.8%	37.8%

Solar

For solar generation, the 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 Long-Term Assessments. Table 4.5 shows the monthly SCC values that are updated annually to coincide with the release of the summer Outlook.

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

Table 4.5: Monthly Solar Capacity Contribution Values

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCC (% of Installed Capacity)	0.0%	0.0%	0.0%	1.3%	2.9%	10.1%	10.1%	10.1%	8.6%	0.0%	0.0%	0.0%

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, i.e., dispatchable loads, Peaksaver Plus, DR procured through an annual Demand Response Auction held in December 2017 and CBDR, are not incorporated into the demand forecast and are instead treated as resources. Load modifiers are incorporated into the demand forecast, as explained in section 3.2.3.

Demand measures are treated as supply resources and are therefore included in the supply mix. The impacts of actual activations of demand measure are added back into the demand history prior to forecasting demand for future periods.

The second annual DR auction held in December 2016 procured 455.2 MW for the summer six-month commitment period ending on October 31, 2017, and 477.5 MW for the winter six-month commitment period beginning on November 1, 2017. The DR capacity acquired through the DR auction is reflected in the Outlook. The next annual DR auction will be held in December 2017.

4.1.4 Firm Transactions

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 two terawatt-hours of clean energy annually. The imported energy will be targeting peak hours to help reduce greenhouse gas emissions in Ontario. The agreement includes the opportunity to cycle energy.

The 500 MW capacity delivered to Quebec in 2015/2016 winter will have to be returned to Ontario during summer before September 2030, based on Ontario's needs.

The capacities cleared in the New York Independent System Operator (NYISO) capacity auctions by Ontario generators are posted on the NYISO website. NYISO will receive 127 MW for October 2017, which is reflected in the Outlook. The NYISO's next auction to procure up to 128 MW capacity for 2017/2018 six-month winter period will be held in the last week of September.

4.1.5 Summary of Scenario Assumptions

To assess future resource adequacy, the IESO must make assumptions on the amount of available resources. The Outlook considers two scenarios: a **firm scenario** and a **planned scenario** as compared in Table 4.6.

Table 4.6: Summary of Scenario Assumptions for Resources

	Planned Scenario	Firm Scenario
Total Existing Installed Resource Capacity (MW)	36,853	
New Generation and Capacity Changes (MW)	1,049	-242

The starting point of 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** only assumes resources that have reached commercial operation. The generator planned shutdowns or retirements that have high certainty of occurring in the future are also considered for both scenarios. The **firm** and **planned** scenarios also differ in their assumptions regarding the amount of demand measures. The **firm scenario** considers DR programs from existing participants only, while the **planned scenario** considers DR programs from future participants too. Submitted generator planned outages are reflected in both scenarios. Table 4.7 shows a snapshot of the forecast available resources, under the two scenarios, at the time of the summer and winter peak demands during the Outlook.

Table 4.7: Summary of Available Resources

Notes	Description	Winter Peak 2018		Summer Peak 2018		Winter Peak 2019	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,702	36,733	36,702	37,993	36,580	37,871
2	Total Reductions in Resources (MW)	9,247	9,143	10,284	10,477	8,631	8,659
3	Demand Measures (MW)	752	752	732	806	581	752
4	Firm Imports (+) / Exports (-) (MW)	-500	-500	0	0	-500	-500
5	Available Resources (MW)	27,707	27,842	27,150	28,322	28,030	29,464

Notes on Table 4.7:

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).

4.2 Capacity Adequacy Assessment

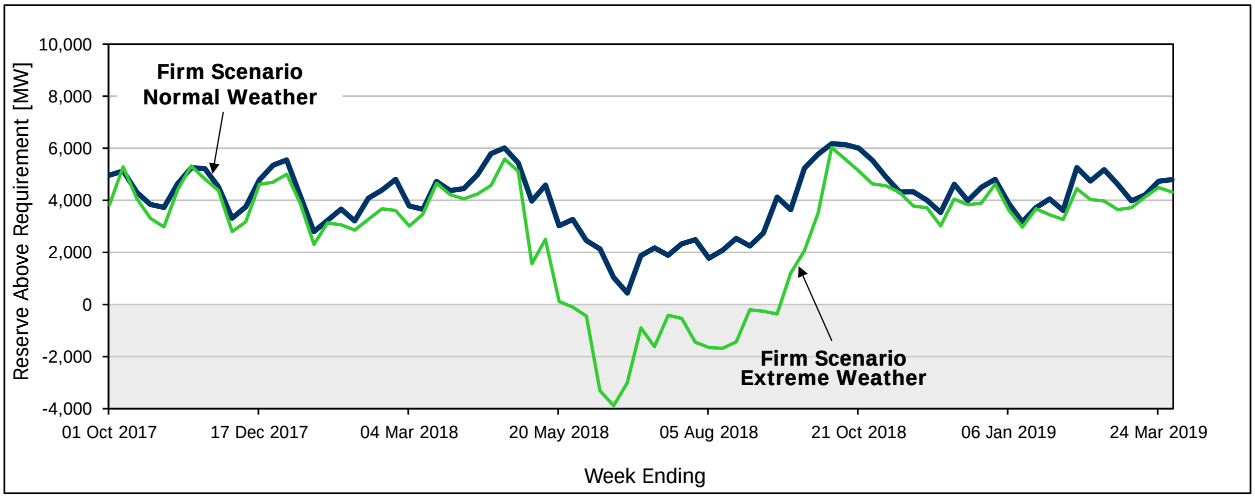
The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages and have been assessed as of July 28, 2017. The generation planned outages occurring during this Outlook period have been assessed as of August 14, 2017.

4.2.1 Firm Scenario with Normal and Extreme Weather

The **firm scenario** incorporates all existing capacity that had achieved commercial operation status as of August 14, 2017.

Figure 4.1 shows the Reserve Above Requirement (RAR) levels, which represent the difference between Available Resources and Required Resources. The Required Resources equals the Demand plus Required Reserve. As can be seen, the reserve requirement in the **firm scenario** under normal weather conditions is being met throughout the entire Outlook period. During extreme weather conditions, the reserve is lower than the requirement for a total of 16 weeks during the 18-Month Outlook timeframe. This shortfall is largely attributed to the planned generator outages scheduled during those weeks. If extreme weather conditions do materialize, the IESO may need to reject some generator maintenance outage requests to ensure that Ontario demand is met during the summer peak periods. Therefore, generators expected to perform maintenance on their units during the summer should understand that those outages are at risk and are advised to review their planned maintenance plans and consider rescheduling them if they are critical for the continued operation of the units.

Figure 4.1: Normal vs. Extreme Weather: Firm Scenario RAR

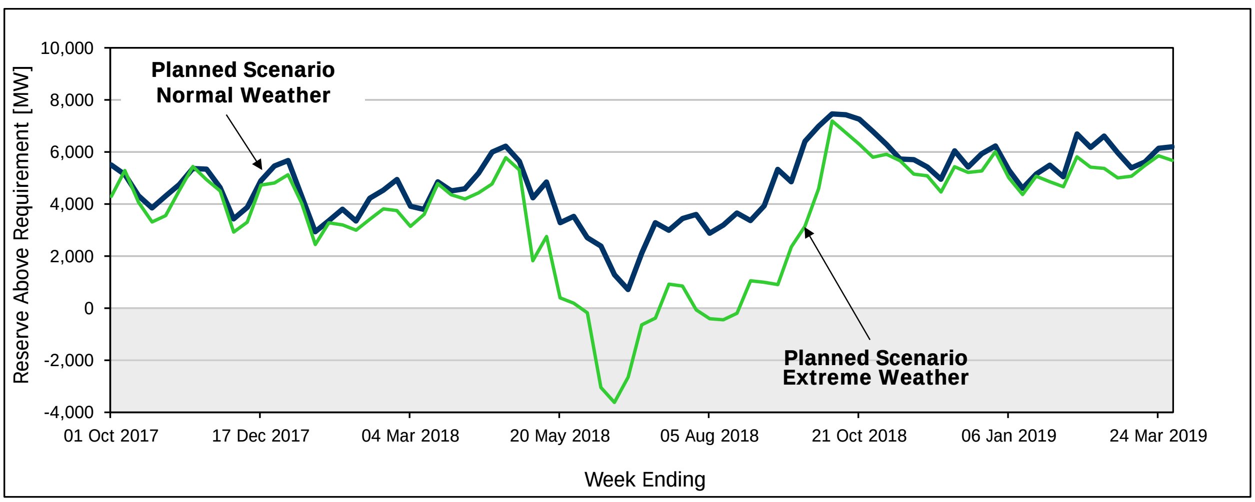


4.2.2 Planned Scenario with Normal and Extreme Weather

The **planned scenario** incorporates all existing capacity plus all capacity coming in service. Approximately 1,300 MW of net generation capacity is expected to connect to Ontario's grid over this Outlook period.

Figure 4.2 shows the RAR levels under the **planned scenario**. As observed, the reserve requirement is being met throughout the Outlook period under normal weather conditions. The reserve is lower than the requirement for a total of 10 weeks during the 18-Month Outlook timeframe under extreme weather conditions. This shortfall is largely attributed to the planned outages scheduled for those weeks.

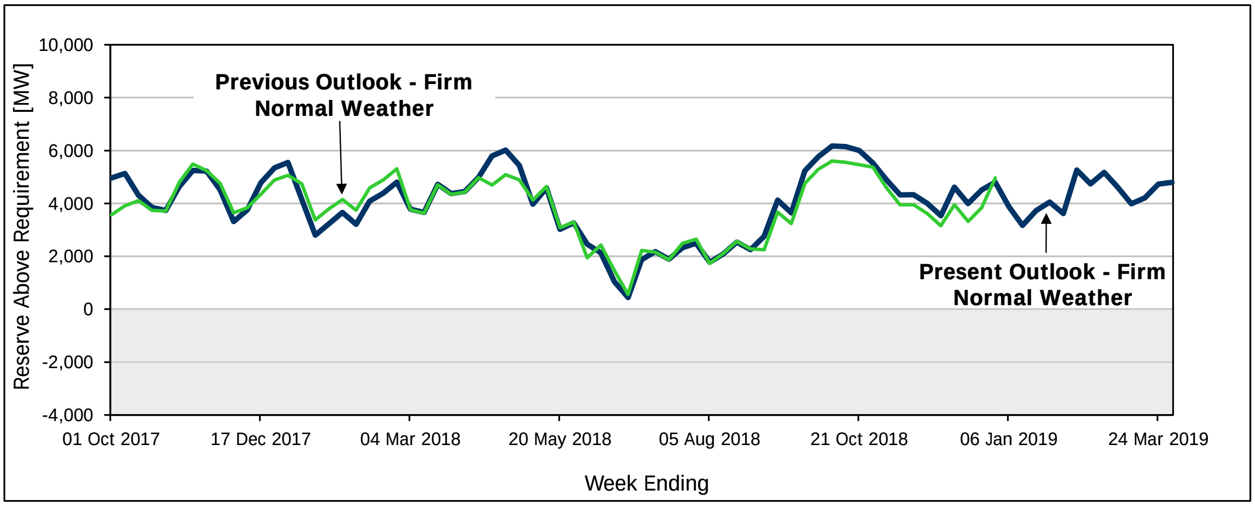
Figure 4.2: Normal vs. Extreme Weather: Planned Scenario RAR



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

Figure 4.3 provides a comparison between the forecast RAR values in the present Outlook and the forecast RAR values in the previous Outlook published on June 22, 2017. The difference is mainly due to changes in planned outages.

Figure 4.3: Present Outlook vs. Previous Outlook: Firm Scenario - Normal Weather RAR



Resource adequacy assumptions and risks are discussed in detail in the Methodology to Perform Long-Term Assessments.

4.3 Energy Adequacy Assessment

This section provides an assessment of energy adequacy, the purpose of which is to determine whether Ontario has sufficient supply to meet its forecast energy demands and to highlight any potential concerns associated with energy adequacy within the period covered under this 18-Month Outlook. At the same time, the assessment estimates the aggregate production by each 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) is performed using the same set of assumptions pertaining to resources expected to be available over the next 18 months as in the capacity assessment. Refer to Table 4.1 for the summary of Existing Generation Capacity and Table 4.2 for the list of Generation Resources Status for this information. The monthly forecast of energy production capability, based on the energy modelling results, is included in Table A7 of the 2017 Q3 Outlook Tables.

For the EAA, only the **firm scenario** as per Table 4.6 with normal weather demand is considered. The key assumptions specific to this assessment are described in the IESO document titled Methodology to Perform Long-Term Assessments.

4.3.2 Results – Firm Scenario with Normal Weather

Table 4.8 summarizes the energy simulation results over the 18-month Outlook period for the firm scenario with normal weather demand for Ontario as a whole and provides a breakdown by each transmission zone.

Table 4.8: Firm Scenario - Normal Weather: Summary of Zonal Energy

Zone	18-Month Energy Demand		18-Month Energy Production		Net Inter-Zonal Energy Transfer	Zonal Energy Demand on Peak Day of 18-Month Period	Available Energy on Peak Day of 18-Month Period
	TWh	Average MW	TWh	Average MW	TWh	GWh	GWh
Ontario	**209.3**	**15,940**	**209.3**	**15,940**	**0.0**	**449.4**	**584.3**
Bruce	1.1	81	72.6	5,531	71.5	1.3	135.5
East	13.3	1,010	15.1	1,149	1.8	27.1	73.2
Essa	12.2	929	3.9	297	-8.3	24.5	13.4
Niagara	5.9	449	19.6	1,494	13.7	13.5	42.2
Northeast	14.5	1,107	15.0	1,144	0.5	22.9	33.2
Northwest	5.7	432	5.2	393	-0.5	8.9	21.2
Ottawa	15.3	1,163	0.0	2	-15.3	25.6	2.3
Southwest	43.0	3,274	7.1	539	-35.9	93.1	23.2
Toronto	78.2	5,958	60.9	4,636	-17.3	184.9	161.8
West	20.2	1,539	9.9	754	-10.3	47.6	78.3

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 18-month Outlook period for the firm scenario with normal weather demand, with no anticipated reliance on support from external jurisdictions.

Figure 4.4 shows the percentage production by fuel type to supply Ontario energy demand for the entire duration of the Outlook, while Figure 4.5 shows the production by fuel type for each month of the 18-month period. Exports out of Ontario and imports into Ontario are not considered in this assessment. Table 4.9 summarizes these simulated production results by fuel type, for each year.

Figure 4.4: Production by Fuel Type – Oct. 1, 2017, to Mar. 31, 2019

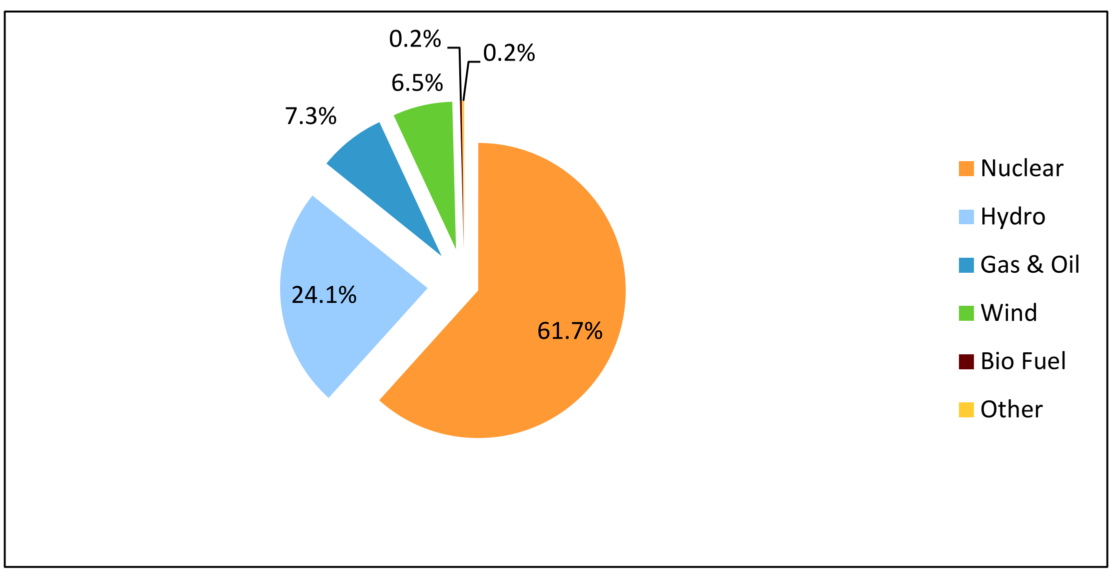


Figure 4.5: Monthly Production by Fuel Type – Oct. 1, 2017, to Mar. 31, 2019

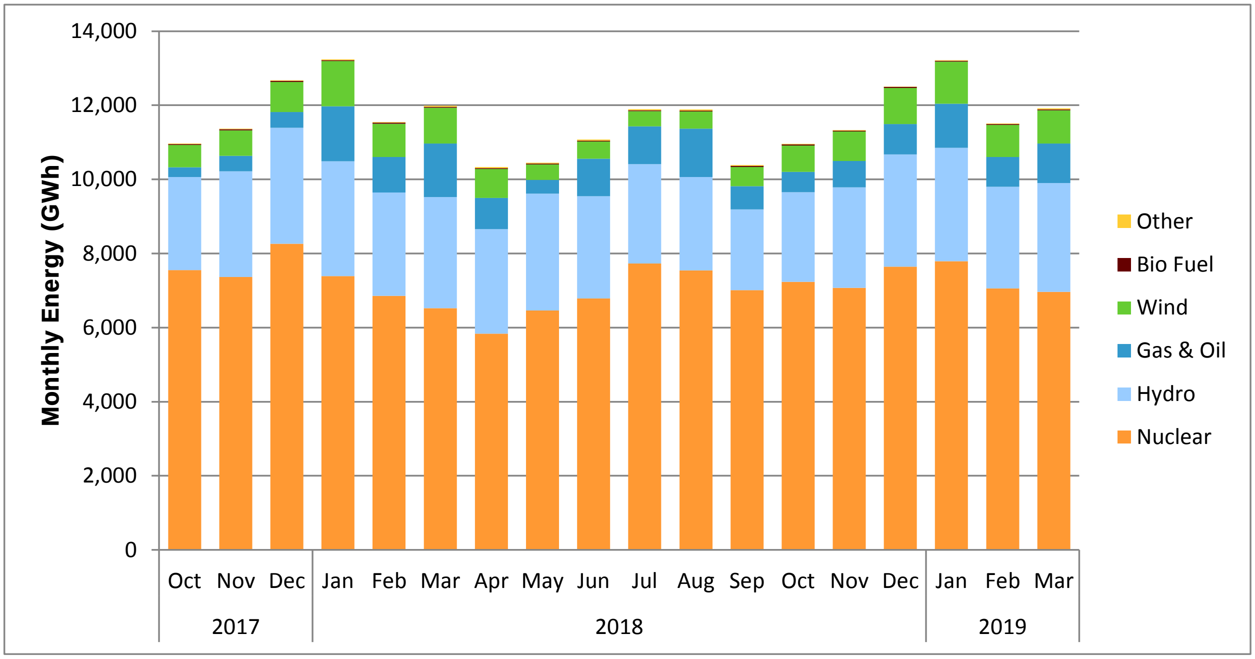


Table 4.9: Firm Scenario - Normal Weather: Ontario Energy Production by Fuel Type

Fuel Type (Grid Connected)	2017 (Oct 1 - Dec 31) (GWh)	2018 (Jan 1 - Dec 31) (GWh)	2019 (Jan 1 - Mar 31) (GWh)	Total (GWh)
Nuclear	23,178	84,081	21,809	129,069
Hydro	8,493	33,174	8,743	50,409
Gas & Oil	1,113	11,129	3,056	15,297
Wind	2,097	8,633	2,898	13,628
Bio Fuel	80	293	74	447
Other (Solar & DR)	57	291	64	413
Total	**35,018**	**137,602**	**36,644**	**209,264**

4.4 Outage Assessment Methodology

As mentioned in the last Outlook, the IESO will initiate a stakeholder engagement later this year to discuss the current outage assessment methodology and to solicit feedback on utilizing extreme weather conditions instead of normal weather conditions to assess outages starting with the quarterly assessment process.

- End of Section -

5 Transmission Reliability Assessment

For the purpose of this report, transmitters provide information on the transmission projects that are planned for completion within the 18-month Outlook period. A list of such projects is provided in Appendix B. Only transmission and load-serving projects that are either major modifications or significantly improve reliability are included. Projects that are already in service or whose completion is planned beyond the period of this Outlook, or that are minor transmission equipment replacements or refurbishments, are not shown.

Some areas have experienced load growth to warrant additional investments in new load-serving stations and reinforcements of local area transmission. Several local area transmission improvement projects are underway and will be placed in service during the timeframe of this Outlook. These projects help relieve loadings on existing transmission infrastructure and provide additional capacity to serve future load growth.

5.1 Transmission Outages

The IESO's assessment of the 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 IESO document titled Methodology to Perform Long-Term Assessments. This Outlook contains transmission outage plans submitted to the IESO as of July 28, 2017.

5.2 Transmission System Adequacy

The IESO assesses transmission adequacy using the methodology based on conformance to established criteria including the Ontario Resource and Transmission Assessment Criteria (ORTAC), NERC transmission planning standard TPL 001-4 and NPCC Directory #1 as applicable. Planned system enhancements and known transmission outages are also considered for the studies. Zonal assessments are presented in the following sections. Overall, the Ontario transmission system is capable of serving the demand under the normal and extreme conditions forecast for the Outlook period.

In some areas in the province, existing transmission infrastructure as described below, have been identified as either currently having or anticipated to have some limitations to serve the local needs. Additional planning activities are currently active throughout the province through regional planning with projects being initiated to address local area needs. For additional information on IESO's regional planning activities, please visit the IESO regional planning webpage: http://www.ieso.ca/get-involved/regional-planning.

5.2.1 Toronto and Surrounding Area

The load-serving capability to the GTA is expected to be adequate to meet the forecast demand through to the end of this 18-month Outlook period.

Due to the existing switching arrangement at both Manby East and Manby West TS, the failure of a single breaker to operate as intended can result in two autotransformers being removed from service simultaneously. During peak load periods, this could potentially overload the remaining autotransformer. A load rejection scheme, which will help minimize customer service interruptions while alleviating these overloads, is expected to be in service by Q2 2018. This scheme will also address the possible overloading that could occur should one of the three autotransformers be forced out of service while another is already out-of-service.

In central Toronto, the expected completion date for Copeland TS is now Q1 2018. The new station will allow some load to be transferred from John TS. This will help meet the short- and mid-term need for additional load-serving capacity in the area and will also enable the refurbishment of the facilities at John TS.

To increase the load-meeting capability of the two 230 kV circuits between Claireville TS and Minden TS and enable the proposed Vaughan TS No. 4 to be connected, as recommended in the York Region IRRP, Hydro One is planning to install two 230 kV in-line breakers at Holland TS, together with a load rejection scheme. These facilities are still expected to come in service by Q4 2017. Until these facilities become available, operational measures may be required. Once completed, the project will relieve possible overloading of these 230 kV circuits during peak load periods.

In the eastern portion of the GTA, a new 500/230 kV transformer station named Clarington TS is expected to be in service by the end of Q2 2018. Clarington TS provides a new 230 kV serving point and improves the customers' service reliability for Pickering, Ajax, Whitby, Oshawa and Clarington areas. Also, Clarington TS is critical in maintaining the service reliability of central and eastern GTA, by relieving the 500/230 kV transformers at Cherrywood TS, which could be overloaded when Pickering NGS retires.

As was recommended in the Central Toronto IRRP, Hydro One is proceeding with construction of a new transformer station at Runnymede TS and upgrading the 115 kV circuits that serve Runnymede TS from Manby TS. This project, planned to be in service by Q4 2018, will provide relief for the existing Runnymede TS and nearby Fairbank TS, which are at capacity to serve the peak demand in the area. In addition, it will serve the new Eglinton Light Rail Transit project that is currently under construction.

Transmission transfer capability in Toronto and surrounding area is expected to be sufficient for the purpose of serving load, with sufficient margin to allow for planned outages.

5.2.2 Bruce and Southwest Zones

Hydro One is continuing work to replace the aging infrastructure at the Bruce 230 kV switchyard, which is scheduled to be completed by Q2 2019. While this work is being implemented, careful coordination of transmission and generation outages will be needed.

Hydro One is also continuing work on a new Bruce Remedial Action Scheme (RAS), which is now scheduled for completion by December 2018. This new RAS will replace the existing Special Protection System while having increased functionality to detect and operate for a greater number of system contingencies.

The transmission transfer capability in the Southwest zone and its vicinity is expected to be sufficient to serve the load in this area with enough margin to allow for planned outages.

5.2.3 Niagara Zone

Completion of the transmission reinforcements from the Niagara region into the Hamilton-Burlington area continues to be delayed, and the transmission congestion continues to restrict the connection of new generation. This project, if completed, would increase the transfer capability from the Niagara region to the rest of the Ontario system by approximately 700 MW.

5.2.4 East Zone and Ottawa Zone

Occasionally, imports may be reduced in Eastern Ontario, typically for brief periods during the summer, due to the thermal limitations of the 230 kV Hawthorne-to-Merivale circuits, which are part of the transmission network path between Eastern Ontario and the major load centers near the GTA area. Reinforcement on the Hawthorne-to-Merivale path is being considered.

During peak load periods, the two under-sized autotransformers at Hawthorne TS are expected to be overloaded post-contingency. As recommended in the IRRP for Ottawa, Hydro One is proceeding with the replacement of these transformers with standard-sized units, and the expected completion date for this work is now Q2 2019. Once completed, this project will increase the step-down capability at Hawthorne TS to support the load in its 115 kV system.

High voltages in Eastern Ontario and the GTA continue to present operational challenges. This can result from low transfer levels across the 500 kV transmission system from Bowmanville SS to Hawthorne TS. Temporary removal from service of at least one of the 500 kV circuits in Eastern Ontario continues to be required during those periods. The IESO and Hydro One are currently managing this situation with day-to-day operating procedures. To address this issue on a longer-term basis, the IESO requested Hydro One to install two 500 kV line-connected shunt reactors at Lennox TS with a target in-service date of Q4 2020.

Overall transmission transfer capability in the East and Ottawa zones is expected to be sufficient for the purpose of serving load in these areas with sufficient margin to allow for planned outages.

5.2.5 West Zone

Transmission constraints in this zone may restrict resources in southwestern Ontario. This is evident in the constrained generation amounts shown for the Bruce and West zones in Tables A3 and A6. Additional generation connection is restricted in some parts of this area.

As per the near-term plan in the Windsor-Essex Region IRRP, Hydro One continues to proceed with the Supply to Essex County Transmission Reinforcement (SECTR) project, which consists of the new 230 kV Leamington TS along with a new double-circuit connection line. This project, when completed in Q4 2018, will address the region's service capacity and restoration needs, while leveraging the refurbishment of the end-of-life assets at the nearby Kingsville TS.

Transmission transfer capability into the West zone is expected to be sufficient to serve load in this area with enough margin to allow for planned outages.

5.2.6 Northeast and Northwest Zones

Work to modify the existing line-connected reactors at Hanmer TS continues. This modification will allow for post-contingency switching of these reactors, thereby increasing the transfer capability of the Flow South Interface. This project is now expected to be complete in Q3 2019.

Following the expansion of the Mattagami River plants, increased transfers are being experienced from the 230 kV system to the 115 kV system at Kapuskasing TS. These higher transfers, combined with the output from the 30 MW of new hydroelectric and solar projects in the Kapuskasing area, are expected to cause the thermal capability of the 115 kV transmission facility between Hunta and Kapuskasing to be exceeded. To ensure that the existing level of service reliability is maintained, it is expected that some of the generating facilities in the

Kapuskasing area will need to be constrained-off whenever these high transfers occur. As recommended by the IESO, Hydro One is finalizing plans to reinforce the system in the Kapuskasing area in order to maintain supply reliability to local customers in the future. These plans are also expected to help accommodate higher transfers.

The limited reactive absorption facilities that are available in the Timmins area are proving to be an obstacle to the restoration of the system in the northeast following an outage involving either of the 500 kV circuits. Maintaining voltages below the specified maximum of 550 kV during the restoration process before the system can be loaded has been challenging, particularly with the demand reduction that has occurred in the Timmins area.

Transmission constraints may restrict resources in northwestern Ontario. This is evident in the constrained generation amounts shown for the Northwest zone in Tables A3 and A6. As a result, additional generation connection is restricted in this area. The upcoming East-West Tie expansion project may help address part of these constraints, but generation in Northwestern Ontario will continue to be limited by the remaining constraints in the Sault Ste. Marie and Sudbury areas. The East-West Tie expansion project is primarily required to ensure reliability of supply to the northwest while accommodating the forecast load growth for the region. The Leave to Construct applications for this project have been filed, and the IESO is currently working on providing an update on the need for this project, including whether or not the East-West Tie project continues to be the least cost solution for meeting the reliability needs in the region.

Some additional transmission constraints restricting the connection of additional load in northwestern Ontario will be addressed by the proposed 230 kV single-circuit line to Pickle Lake, which is currently scheduled to be in service in early 2020. The IESO has completed IRRPs for Northwest Ontario, which identify plans to address other load connection constraints. Transmission transfer capability in the Northeast and Northwest zones is expected to be sufficient to serve the existing load in this area with enough margin to allow for planned outages.

- End of Section -

6 Operability

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

6.1 Storage

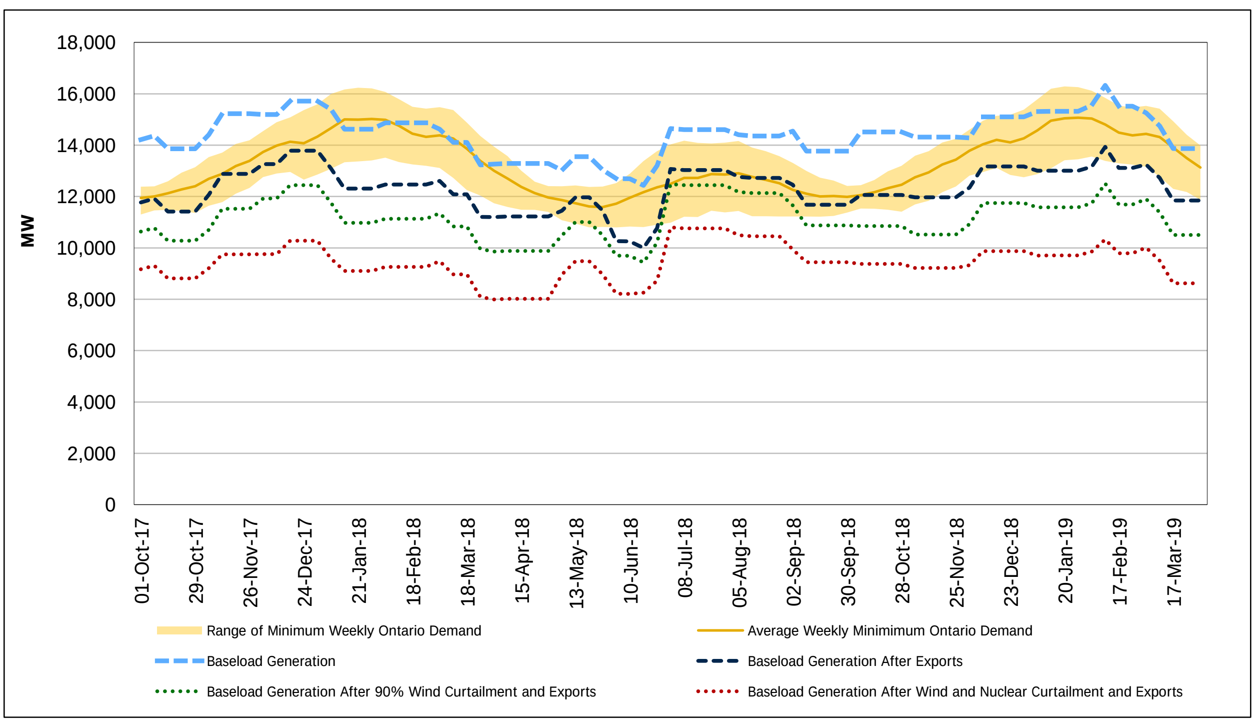
At the end of 2015, nine energy storage projects totaling 16.75 MW were offered 10-year contracts for capacity services as part of the Phase II energy storage competitive procurement process. This complements the approximately 34 MW of grid energy storage procured in Phase I by the IESO to offer ancillary services to support grid reliability. Once they become operational, these procurements are intended to support the province's efforts to better understand the integration and operation of energy storage in Ontario's electricity system and markets. Phase I projects are expected to become operational in the latter part of 2017.

6.2 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, the system is balanced using market mechanisms that include inter-tie scheduling, the dispatch of hydroelectric generation and grid-connected renewable resources, and nuclear manoeuvering or shutdown. In addition, out-of-market mechanisms such as import cuts and curtailment of linked wheels could also be utilized to alleviate SBG conditions. These actions usually, but not always, occur when Ontario demand is at its lowest.

Figure 6.1 shows the forecast SBG for the next 18 months and the flexibility from nuclear, wind and solar generation and exports.

Figure 6.1 Minimum Ontario Demand and Baseload Generation



Ontario will continue to experience SBG conditions during the Outlook period, and SBG can be managed through existing market mechanisms.

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 also been updated to reflect the latest data. The 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. Table 6.1 shows the monthly off-peak wind capacity contribution values calculated from actual wind output up to March 31, 2017. These values are updated annually to coincide with the release of the summer 18-Month Outlook.

Table 6.1: Monthly Off-Peak Wind Capacity Contribution Values

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Off-Peak WCC (% of Installed Capacity)	35.3%	35.3%	33.2%	34.6%	24.8%	14.5%	14.5%	14.5%	20.0%	30.0%	36.0%	35.3%

6.3 Operability Assessment

- The need for more flexible capability to respond to intra-hour differences between expected and actual variable generation production and expected and actual Ontario demand continues to be a priority. As the output from the variable generation fleet continues to rise, the need for flexible resources capable of responding to IESO dispatch signals and increasing their output within 30 minutes continues to increase. At times, to maintain reliability, the IESO may take control actions such as, but not limited to, committing/constraining on dispatchable resources or manually adjusting the variable generation forecast. The IESO has been engaging with stakeholders to explore a range of potential solutions for enhanced flexibility in the electricity system. The IESO encourages all stakeholders in Ontario's electricity sector, or their representatives, with an interest in this initiative to participate in this stakeholder engagement.
- Energy price spikes have been observed in the last few shoulder seasons, but especially this spring, reflecting the need for and value of flexibility through an ability to respond to short-term supply-demand imbalances.
- Regulation service acts to match total system generation to total system demand on a second-to-second basis and helps correct variations in power system frequency. The IESO is seeking to expand the depth of the regulation service market in Ontario.

  The IESO plans to expand its capability to schedule regulation by increasing the amount of regulation usually scheduled from 100 MW to up to 150-200 MW as needed between 2017 and 2019, and have sufficient market depth to schedule up to 250-300 MW of regulation capacity on an as-needed basis by the year 2020. The IESO issued a draft RFP for incremental regulation capacity for public comment on June 1, 2017, and a final version of the RFP on June 29 with a proposal submission deadline of 3:00 p.m. on September 28 2017. Further information regarding the Regulation RFP may be found on the IESO public website at:

http://www.ieso.ca/en/sector-participants/market-operations/markets-and-related-programs/regulation-service-rfp

- Ontario experienced a partial solar eclipse on Monday August 21, 2017, between 1:10 p.m. EDT and 3:50 p.m. EDT. The eclipse over Ontario reached its peak coverage at approximately 2:30 p.m. EDT, where the total solar production was reduced by two thirds. Following the eclipse, solar production recovered to around 80% of what it was prior to the event. This celestial event was unique as it is the first solar eclipse to take place since large amounts of solar generation has been installed across North America. Leading up to August, 21, the IESO planned extensively for this unique event and communicated widely with Ontario electricity sector partners, including its interconnected neighbours, as well as weather and solar forecasters to plan the day's power system operations accordingly. More information can be found on the IESO public website at:

  http://www.ieso.ca/en/corporate-ieso/media/also-of-interest/2017-solar-eclipse

- End of Document -

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

ieso
Connecting Today.
Powering Tomorrow.