18 Month Outlook

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

FROM OCTOBER 2016 TO MARCH 2018

ieso
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 generation and transmission to supply Ontario's demand under normal weather conditions.

Under extreme weather conditions, the reserve levels are below requirement for 10 weeks over the 2017 summer period due to planned generator maintenance. 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 on their units during the summer of 2017 should understand that those outages are at risk and are advised to review their maintenance plans and reschedule them if they are critical for the continued operation of the units.

Peak demand has been facing downward pressure over the last few years as conservation savings, growing embedded generation output and the Industrial Conservation Initiative (ICI) have more than offset increased demand from population growth and economic expansion. This trend is expected to continue over the forecast horizon.

Energy demand is expected to show a slight increase in 2016 due primarily to the additional leap year day. Though Ontario's economy has picked up momentum, the growth has not been strong enough to overcome the reductions due to conservation and embedded generation output. Ontario is expected to see stronger economic growth in 2017 and 2018 due to a robust U.S. economy and a low value of Canadian dollar.

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

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2016-17	21,981	23,230
Summer 2017	22,591	24,934
Winter 2017-18	21,867	23,064

About 1,050 MW of new supply – 550 MW of wind, 300 MW of gas, 100 MW of hydroelectric and 100 MW of solar generation – is expected to be connected to the province's transmission grid over the Outlook period. Contracts for approximately 260 MW of Non-Utility Generators (NUGs) are expiring but at least 140 MW will remain in the planned scenario where forecast data has been provided beyond the contract expiration date. By the end of the period, the amount of grid-connected wind and solar generation is expected to increase to about 4,500 MW and 380 MW, respectively.

The embedded wind generation over the same period is expected to increase to about 650 MW. Meanwhile, embedded solar generation is expected to increase to over 2,100 MW.

The Ontario Planning Outlook was published on September 1, 2016. Long-term outlooks indicate that Ontario will remain adequately supplied into the foreseeable future if demand remains at or below today's level. Additional resources could be required in the mid-2020s to meet higher demand outlooks driven by increased electrification in support of climate change actions.

Conclusions & Observations

The following conclusions and observations are based on the results of this Outlook assessment.

Demand Forecast

- Ontario's grid supplied peak demand is expected to decline throughout the period of this Outlook. Growth in embedded solar and wind generation capacity and on-going conservation initiatives reduce the need for energy from the bulk power system, while also putting downward pressure on peak electricity demands. Conservation, time-of-use rates and the ICI will also put downward pressure on peak demands and summer peaks in particular. Grid supplied energy demand is expected to show small increases in 2016 and 2017 after adjusting for the leap year impacts.

Resource Adequacy

- Under the **firm scenario**, reserve requirements are expected to be met for the entire duration of this Outlook during normal weather conditions. Under extreme weather conditions, the reserve is below the requirement for 13 weeks, with the largest shortfall of around 2,650 MW. The firm scenario excludes any new generating facilities that haven't reached commercial operation. If extreme weather materializes, planned generator outages may need to be rescheduled.
- For the **planned scenario**, reserve requirements are expected to be met for the entire duration of this Outlook during normal weather. Under extreme weather conditions with planned resources, the reserve is below requirement for 10 weeks, with the largest shortfall of around 2,150 MW.

Transmission Adequacy

Ontario's transmission system is expected to be able to reliably supply 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 improvement projects are underway and will be placed in service during the timeframe of this Outlook. These projects, shown in Appendix B, will help relieve loadings of existing transmission stations and provide additional supply capacity for future load growth. Additional planning activities through the regional planning process are currently active throughout the province.
- When the level of transfers on the 500 kV system are markedly reduced as a result of medium-to-low load conditions combined with the effect of transactions through the interconnections with Ontario's neighbouring jurisdictions, periods of high voltages can occur. While the IESO and Hydro One are currently managing this situation with day-to-day operating procedures, Hydro One is planning to install additional new high voltage reactors at Lennox transformer station (TS) to address this issue. Details of this project are currently being confirmed; the expected in-service date of this project is mid-2020.
- There is an increased possibility that imports may need to be restricted in Eastern Ontario during peak load periods. Hydro One is planning to reinforce the Hawthorne-

to-Merivale circuits by upgrading their conductors to address this issue. This project is currently planned to be in-service by Q1 2020.

- During peak load periods, the two under-sized autotransformers at Hawthorne TS in Ottawa are expected to be overloaded post-contingency. Hydro One is planning to replace these transformers with standard-sized units; the work is expected to be completed in Q2 2018.
- Hydro One continues the construction on the Guelph Area Transmission Refurbishment project. This project will improve the transmission capability into the Guelph area by reinforcing the supply into Guelph-Cedar (TS). While most of the work at Cedar TS is already complete and is in operation, this project is expected to be completed in Q4 2016.
- A new transformer station, Copeland TS, is still planned to be in service in downtown Toronto in Q4 2016. The new station will facilitate the refurbishment of the facilities at John TS, while also enhancing the load security in the downtown core.

Operability

Conditions for surplus baseload generation (SBG) will continue over the Outlook period. However, 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 maneuvering or shutdown.

As part of its regular reviews, the IESO is looking carefully at some of the grid's operational needs. The results of a recent operability assessment indicated that there is a system need for enhanced flexibility to balance supply and demand, more regulation and additional grid voltage control. These findings reinforce the need for a portfolio of resources that contributes to the reliability of the grid. The IESO has recently launched a stakeholder initiative to present its findings and discuss potential solutions to address the need for enhanced flexibility in both the short- and the long-term. More information can be found on the Stakeholder Engagement webpage at http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx.

In addition, the IESO is conducting a Request for Information (RFI) for regulation services that will be open to both incumbent providers and potential new entrants into the regulation service marketplace. Responses to the RFI are due by September 30, 2016.

Caution and Disclaimer

Table of Contents

List of Tables

List of Figures

1 Introduction

This Outlook covers the 18-month period from October 2016 to March 2018 and supersedes the last Outlook released on June 21, 2016.

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/Pages/Participate/Reliability-Requirements/Forecasts-&-18-Month-Outlooks.aspx.

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 June 2016. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for July and August 2016 has been included in the tables.

2.2 Updates to Resources

The 18-month assessment uses planned generator outages submitted by market participants to the IESO's outage management system as of August 12, 2016.

This report period incorporates a number of outages, as identified in Table A8 of the [2016 Q3 Outlook Tables], including the commencement of the nuclear refurbishment program.

As of August 12, 2016, the following generator completed the market registration process since the last Outlook:

- Grand Bend Wind Farm (also known as Zurich) – 99.3 MW

2.3 Updates to Transmission Outlook

The list of transmission projects, planned transmission outages and actual experience with forced transmission outages have been updated from the previous 18-Month Outlook. For this Outlook, transmission outage plans submitted to the IESO's outage management system as of July 8, 2016, were used.

2.4 Updates to Operability Outlook

The Outlook for 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 12, 2016.

- End of Section -

3 Demand Forecast

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period October 2016 to March 2018 and supersedes the previous forecast released in June 2016. Tables of supporting information are contained in the 2016 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), 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. The forecast of demand incorporates these impacts.

Grid-supplied energy demand is forecasted to show a slight increase over the forecast horizon. For 2016, demand is projected to show a small increase (0.5%) due primarily to the additional leap day and remain flat in 2017. Strong U.S. growth and a low dollar, additional demand from increased economic activity, combined with population growth, will offset the reductions stemming from increased embedded generation output and conservation savings leaving demand relatively flat over the forecast.

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 to 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 2016-17	21,981	23,230
Summer 2017	22,591	24,934
Winter 2017-18	21,867	23,064
Year	**Normal Weather Energy (TWh)**	**% Growth in Energy**
2006 Energy	152.3	-1.9%
2007 Energy	151.6	-0.5%
2008 Energy	148.9	-1.8%
2009 Energy	140.4	-5.7%
2010 Energy	142.1	1.2%
2011 Energy	141.2	-0.6%
2012 Energy	141.3	0.1%
2013 Energy	140.5	-0.6%
2014 Energy	138.9	-1.1%
2015 Energy	136.5	-1.7%
2016 Energy (Forecast)	137.3	0.5%
2017 Energy (Forecast)	137.3	0.0%

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)
02-Oct-16	17,244	17,388	554	2,441					
09-Oct-16	17,204	17,593	786	2,470	09-Jul-17	22,591	24,934	814	2,740
16-Oct-16	17,620	18,243	507	2,416	16-Jul-17	22,304	24,018	838	2,772
23-Oct-16	17,778	18,522	392	2,500	23-Jul-17	22,037	23,987	1,035	2,668
30-Oct-16	18,079	18,950	318	2,527	30-Jul-17	22,091	24,765	841	2,755
06-Nov-16	18,544	19,312	416	2,604	06-Aug-17	22,358	24,544	958	2,772
13-Nov-16	19,204	20,184	601	2,627	13-Aug-17	21,947	24,650	985	2,726
20-Nov-16	19,726	20,695	342	2,697	20-Aug-17	21,368	24,513	1,362	2,701
27-Nov-16	20,210	21,443	607	2,749	27-Aug-17	21,370	23,545	1,413	2,705
04-Dec-16	20,296	21,873	409	2,782	03-Sep-17	20,594	23,184	1,370	2,587
11-Dec-16	20,837	21,954	555	2,825	10-Sep-17	18,899	22,333	680	2,434
18-Dec-16	20,888	21,951	690	2,827	17-Sep-17	19,354	21,119	781	2,497
25-Dec-16	20,478	22,504	362	2,891	24-Sep-17	18,076	20,223	420	2,465
01-Jan-17	20,400	21,463	528	2,703	01-Oct-17	17,355	18,760	554	2,408
08-Jan-17	21,436	22,347	570	2,847	08-Oct-17	17,553	17,722	786	2,457
15-Jan-17	21,981	23,230	547	2,926	15-Oct-17	17,522	17,654	507	2,439
22-Jan-17	21,658	22,219	483	2,916	22-Oct-17	17,831	18,321	392	2,475
29-Jan-17	21,466	22,404	404	2,921	29-Oct-17	17,973	18,571	318	2,516
05-Feb-17	21,141	22,352	734	2,926	05-Nov-17	18,184	18,927	416	2,525
12-Feb-17	20,531	22,162	635	2,868	12-Nov-17	19,302	19,886	601	2,632
19-Feb-17	20,231	21,782	581	2,817	19-Nov-17	19,596	20,387	342	2,651
26-Feb-17	19,909	21,821	501	2,764	26-Nov-17	20,033	20,814	607	2,723
05-Mar-17	20,179	21,572	531	2,785	03-Dec-17	20,451	21,526	409	2,772
12-Mar-17	19,902	20,886	649	2,748	10-Dec-17	20,593	21,793	555	2,797
19-Mar-17	18,847	19,684	611	2,672	17-Dec-17	20,950	22,028	690	2,841
26-Mar-17	18,420	19,299	569	2,582	24-Dec-17	20,790	21,937	362	2,811
02-Apr-17	18,282	19,386	567	2,557	31-Dec-17	20,533	21,738	528	2,717
09-Apr-17	17,905	18,593	471	2,505	07-Jan-18	21,290	22,041	570	2,842
16-Apr-17	17,158	18,253	496	2,398	14-Jan-18	21,867	23,064	547	2,910
23-Apr-17	16,653	16,738	531	2,387	21-Jan-18	21,450	21,911	483	2,898
30-Apr-17	16,698	17,251	721	2,377	28-Jan-18	21,256	22,096	404	2,903
07-May-17	17,435	20,381	849	2,348	04-Feb-18	21,112	22,270	734	2,913
14-May-17	17,599	19,932	845	2,362	11-Feb-18	20,373	21,855	635	2,850
21-May-17	18,600	22,009	1,175	2,390	18-Feb-18	20,092	21,491	581	2,800
28-May-17	18,530	22,190	1,330	2,338	25-Feb-18	19,846	21,515	501	2,747
04-Jun-17	19,128	21,712	1,292	2,433	04-Mar-18	20,214	21,557	531	2,777
11-Jun-17	19,787	24,227	1,055	2,569	11-Mar-18	19,788	20,621	649	2,733
18-Jun-17	20,818	24,349	835	2,585	18-Mar-18	18,706	19,390	611	2,656
25-Jun-17	22,300	24,508	754	2,651	25-Mar-18	18,282	19,016	569	2,568
02-Jul-17	22,136	24,021	1,016	2,638	01-Apr-18	18,155	19,108	567	2,509

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 unusual; the temperature was higher than normal but the month was less humid than normal. Overall, this made the month near normal. Though it doesn't factor into demand, the month was very dry.
- The June peak occurred on the hottest day of the month as temperatures topped 34°C (at Toronto) and the humidex exceeded 40°C. The peak of 21,692 MW, which is low by historical standards, occurred on June 20. The continued impacts of conservation,

embedded generation output and ICI, acts to reduce the peak demand. The impact of embedded solar has not only reduced demand, it has shifted the peak later in the day as well. June's peak occurred during hour ending 18 (EST) which is the latest time for a June peak.

- The weather corrected peak of 21,183 MW is an increase over the previous two weather-corrected June peaks.
- Energy demand for the month was 11.1 TWh (11.0 TWh weather corrected), which also is an increase over the previous June. Both are still low by historical standards.
- The minimum demand for the month was 10,596 MW, which is the lowest value for the month since market opening. The minimum occurred early Sunday June 12.
- Embedded generation for the month was 626 GWh, an increase of 5.0% over the previous June and driven by increased solar output.
- Wholesale customers' consumption for the month increased by 2.6% compared to the previous June. The increase was driven by mining and the chemicals sector.

July

- The weather for July was consistently warmer than normal across the month.
- The peak occurred on July 13, which was the second hottest day of the month with the humidex topping 40°C. As such, the actual peak was a 22,659 MW (22,214 MW weather corrected). The July peak occurred during hour ending 18 (EST) which makes it the first time the July peak has occurred that late in the day. This is attributable to the impact of embedded solar generation on the demand profile. In addition to the solar impacts, the ICI also reduced demand for electricity on July 13.
- Energy demand for the month was 12.5 TWh (12.2 TWh weather corrected). Both of these are increases over the past two Julys.
- The minimum was 10,985 MW and occurred in the early morning hours following the Canada Day holiday.
- Embedded generation for the month topped 574 GWh, which represents a 6.4% increase over the previous July due to increased solar and wind output.
- After six fairly robust months, the wholesale customer load had a reversal in July dropping by 1.3% compared to the previous July.

August

- The weather for August was much hotter than normal. The average temperatures for the month made it the hottest August in the past forty years. While above normal, the peak temperatures were not record highs. The peak of 23,100 MW occurred on the hottest day of the month which was August 10.
- Energy demand for the month was 13.1 TWh (12.3 TWh weather corrected) which was driven by the warm temperatures. The actual demand was the highest August since the recession.

- Minimum demand for the month was 12,287 MW, which is the highest minimum for the month since 2005. This is attributable to the hot weather throughout the month. The minimum was unusual in that it did not occur on a weekend or holiday.
- Embedded generation for the month was 548 GWh, a 9.5% increase over the previous August.
- Wholesale customer consumption declined by 0.7% compared to the previous August.

2016 Summer Actuals

Overall, energy demand for the three months from June to August was up 6.3% compared with the same three months one year prior. After adjusting for the weather, demand for the three months showed much smaller increase of 2.6%.

Embedded generation for the summer months was up 6.8% over the previous summer. Increased embedded solar output accounted for roughly two thirds of the increase and increased embedded wind the remainder.

For the three months, wholesale customers' consumption posted a 0.2% increase over the previous summer. Consumption by the mining sector was up but was offset by declines in iron and steel as well as the automotive sectors.

The 2016 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

Despite a great deal of global instability, the overall economic environment has, and will continue to be beneficial for Ontario's growth prospects. 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 picked up over the last six months as both full-time and manufacturing employment have increased. Wholesale loads over the same timeframe have also increased, reversing a trend that had been in place since the fall of 2014. Barring any further shocks to the global economy, Ontario should see increasing economic output throughout the forecast.

Table 3.3.4 of the 2016 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 (LFU).

Table 3.3.5 of the 2016 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 can factor into all weekdays throughout the year, and the size of the impact will be determined by the pricing structure. The ICI impacts the five to 10 highest peak days of the program year. Prior to 2014, the impact of ICI was just under 900 MW on the five highest peaks. In 2014, the program was expanded to include loads with a peak demand of 3 - 5 MW. This has led to an increase in the ICI impacts for the period May 2015 to April 2016. Estimates indicate that ICI impacts over the five highest peaks increased up to 1,075 MW, up almost 100 MW from the previous year. Part of the increase might have come from the fact that most of the peaks were grouped and therefore easier to anticipate.

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.

The demand measures, which are 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. In terms of the demand forecast, the actual impacts of these programs are added back to the demand and the forecast is based on demand prior to the effects 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 commissioning and 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 Generation Capacity as of August 12, 2016

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Outlook Peak (MW)	Number of Stations	Change in Installed Capacity (MW)	Change in Stations
Nuclear	12,978	10,153	5	0	0
Hydroelectric	8,432	5,843	71	0	0
Gas/Oil	9,942	8,643	30	0	0
Wind	3,923	479	34	99	1
Biofuel	495	459	9	0	0
Solar	280	28	6	0	0
Total	**36,050**	**25,605**	**155**	**99**	**1**

4.1 Assessment Assumptions

4.1.1 Committed and Contracted 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 committed generation projects in the IESO's Connection Assessment and Approval process (CAA), those that are under construction, as well as projects contracted by the IESO. Details regarding the IESO's CAA process and the status of these projects can be found on the IESO's website at http://www.ieso.ca/Pages/Participate/Connection-Assessments/default.aspx under Application Status.

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 data is current as of August 12, 2016. For projects that are under contract, the estimated effective date is based on the best information available to the IESO. If a project is delayed, the estimated effective date will be the best estimate of the commercial operation date for the project.

Table 4.2: Committed and Contracted Generation Resources

Project Name	Also Known As	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered Firm (MW)	Capacity Considered Planned (MW)
Bow Lake Phase 1		Northeast	Wind		Commercial Operation	20	20
Bow Lake Phase 2b		Northeast	Wind		Commercial Operation	40	40
Upper White River Generating Station		Northwest	Water		Commercial Operation	9	9
Lower White River Generating Station		Northwest	Water		Commercial Operation	10	10
Harmon Unit 2 Runner Upgrade		Northeast	Water	2016-Q4	Commissioning		10
Beck 1 Unit Overhaul		Niagara	Water	2016-Q4	Under Development		12
Greenfield South Power Corporation	Green Electron Power	West	Gas	2016-Q4	Commissioning		298
Niagara Region Wind Farm		Southwest	Wind	2016-Q4	Under Development		230
South Gate Solar		Southwest	Solar	2016-Q4	Under Development		50
Windsor Solar		West	Solar	2016-Q4	Under Development		50
Namewaminikan Hydro		Northwest	Water	2016-Q4	Under Development		10
Kingston Cogen		East	Gas	2017-Q1	Expiring Contract	-140	
Amherst Island Wind		East	Wind	2017-Q1	Under Development		75
Harmon Unit 1 Runner Upgrade		Northeast	Water	2017-Q3	Under Development		10
Peter Sutherland Senior Generating Station		Northeast	Water	2017-Q3	Under Development		28
Belle River Wind		West	Wind	2017-Q3	Under Development		100
North Kent Wind 1		West	Wind	2017-Q4	Under Development		100
Kapuskasing Generating Station		Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
North Bay Generating Station		Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
Total						**-182**	**932**

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 data, they are included in the planned scenario for the rest of the Outlook period, too.

4.1.2 Generation Capability Assumptions

Hydroelectric

Monthly 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. These values are updated annually to coincide with the release of the summer 18-Month Outlook.

Table 4.3: Monthly Historical Hydroelectric Median Values

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical Hydroelectric Median Values (MW)	6,069	6,003	5,869	5,792	5,818	5,658	5,671	5,382	5,086	5,416	5,728	6,122

Thermal Generators

Thermal generators' capacity and energy contributions, planned outages, expected forced outage rates and seasonal deratings are based on market participant submissions or calculated by the IESO based on actual experience.

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%	33.3%	33.2%	21.2%	12.2%	12.2%	12.2%	16.2%	31.2%	34.2%	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.

The grid demand profile has been changing, with summer peaks being pushed later in the day.

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 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. Demand measures that have been executed are added back into the history before we forecast demand for future periods.

The first DR auction, held in December 2015, procured 391.5 MW of DR capacity for the 2016 summer beginning May 1, 2016, period and 403.7 MW for the 2016-17 winter period beginning November 1, 2016. The DR capacity acquired through the DR auction is reflected in the Outlook. The next DR auction will be held in December 2016, with a target capacity of 393 MW, and the first commitment period beginning May 1, 2017.

In addition, approximately 70 MW of demand is participating in the DR Pilot Program since May 2016 for a two-year term. These pilot projects will be used to help identify opportunities to enhance participation of DR in meeting Ontario's existing system needs, assess their ability to follow changes in electricity consumption and help balance supply and demand.

The IESO will be initiating a pilot program to test the capability of DR to assist in meeting localized needs which have been identified in the regional planning process. This program will look to secure approximately 15 MW of DR capacity in the Brant Area in advance of the installation of additional transmission upgrades in 2019. A procurement process to acquire this DR capacity will be launched in Q4 2016 with capacity expected to be available for the summer periods of 2017 and 2018.

4.1.4 Firm Transactions

As part of the seasonal firm capacity sharing agreement between Ontario and Quebec, Ontario will make available 500 MW of capacity to Quebec for the winter of 2016-17, similar with the last winter. This commitment has been reflected in the adequacy assessments for the period covered under this Outlook. This Outlook period also includes the 2017-18 winter, and although the 500 MW of exports has yet to be confirmed, it is included in our assessment.

The IESO has the option to call on up to 500 MW of capacity from Quebec for summer seasons, at least one year in advance of the delivery period. No request was made for summer 2017.

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)	36,050	
New Generation and Capacity Changes (MW)	932	-182

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. 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 data, they are included in the planned scenario for the rest of the outlook period, too. 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. Both scenarios recognize that resources are not available during times for which the generator has submitted planned outages.

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 2017		Summer Peak 2017		Winter Peak 2018	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,030	36,690	35,890	36,765	35,769	36,883
2	Total Reductions in Resources (MW)	7,902	8,098	10,856	11,374	7,781	8,298
3	Demand Measures (MW)	692	692	694	694	662	662
4	Firm Imports (+) / Exports (-) (MW)	-500	-500	0	0	-500	-500
5	Available Resources (MW)	28,320	28,784	25,816	26,173	28,150	28,747

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

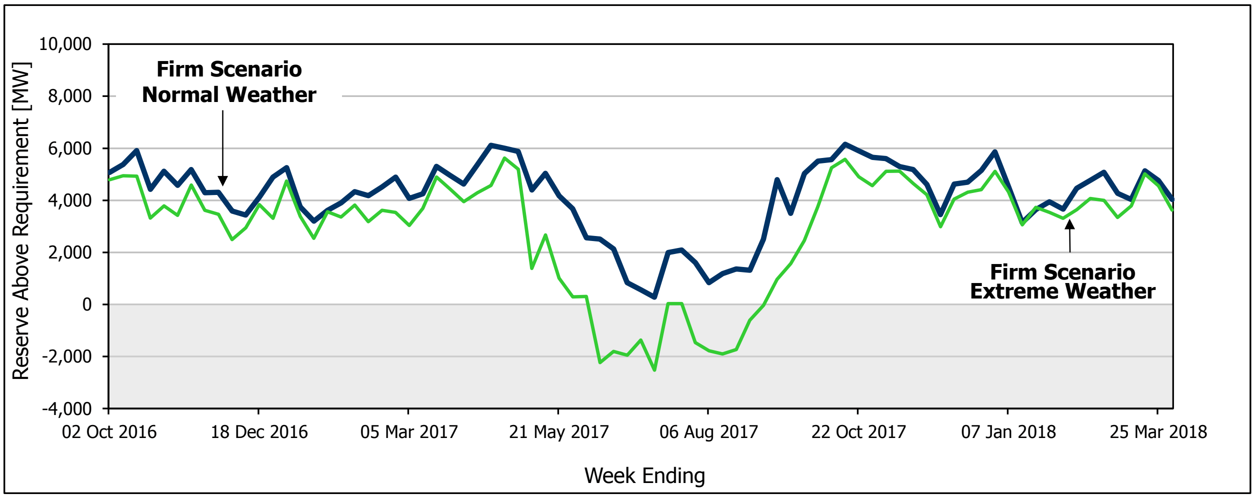
The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages. The planned outages occurring during this Outlook period have been assessed as of August 12, 2016.

4.2.1 Firm Scenario with Normal and Extreme Weather

The **firm scenario** incorporates all existing capacity plus capacity that reached commercial operation as on August 12, 2016. Roughly 60 MW of wind and 19 MW of hydroelectric capacity have achieved commercial operation status.

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 13 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. Therefore, generators expected to perform maintenance on their units during the summer of 2017 should understand that those outages are at risk and are advised to review their planned maintenance plans and reschedule them if they are critical for the continued operation of the units.

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

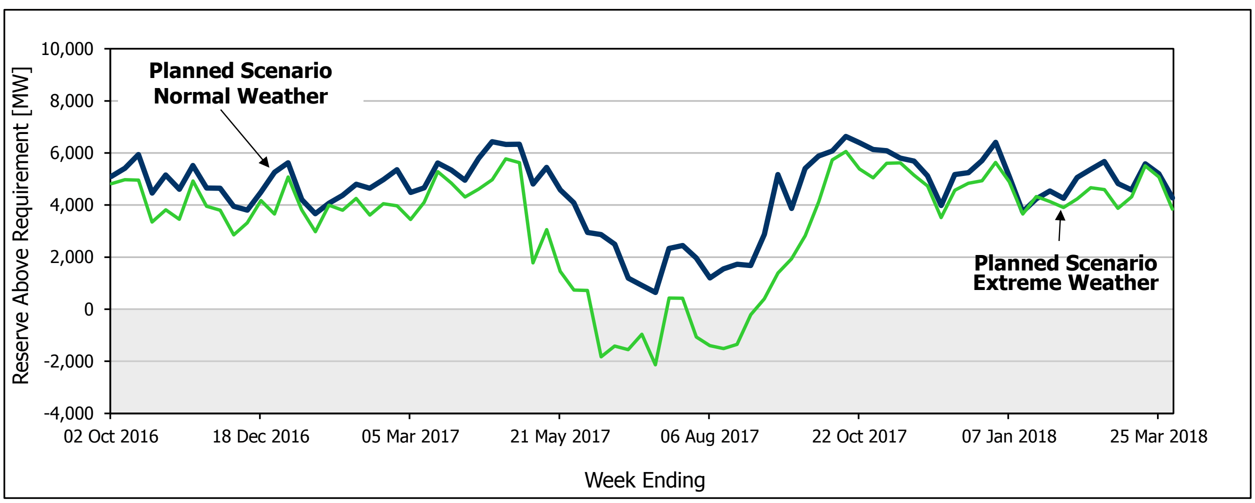


4.2.2 Planned Scenario with Normal and Extreme Weather

The **planned scenario** incorporates all existing capacity plus all capacity coming in service. Approximately 950 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 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.

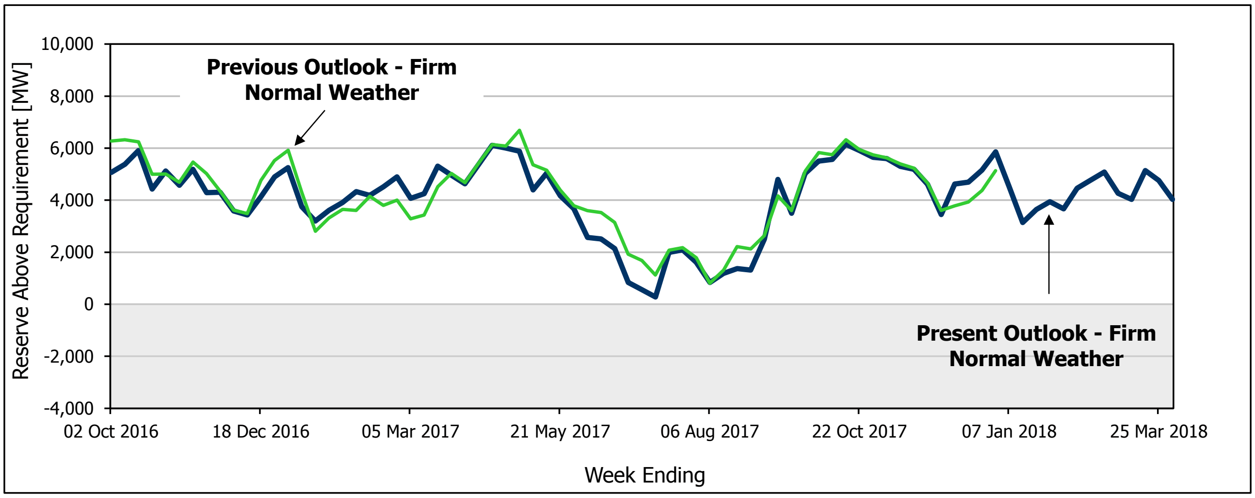
Figure 4.2: Normal vs. Extreme Weather: Planned Scenario RAR



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 21, 2016. The difference is mainly due to the changes to outages and changes in the demand forecast.

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 assessments. Refer to Table 4.1 for the summary of 'Existing Generation Capacity' and Table 4.2 for the list of 'Committed and Contracted Generation Resources' for this information. The monthly forecast of energy production capability, based on the energy modelling results, is included in the Table A7 of the 2016 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 period for the firm scenario with normal weather demand for Ontario as a whole, and provides a breakdown by each transmission zone.

The results indicate that supply is expected to be adequate over the 18-month timeframe of this Outlook, with no anticipated reliance on support from external jurisdictions.

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	**207.9**	**15,836**	**207.9**	**15,836**	**0.0**	**451.8**	**572.5**
Bruce	1.0	77	69.7	5,307	68.7	1.7	145.3
East	13.0	991	15.7	1,198	2.7	24.9	72.1
Essa	12.3	939	3.3	252	-9.0	24.8	13.6
Niagara	6.1	464	19.9	1,514	13.8	13.6	43.4
Northeast	15.4	1,171	15.9	1,212	0.5	25.3	33.3
Northwest	6.2	469	6.3	476	0.1	11.1	21.4
Ottawa	12.9	980	0.4	34	-12.5	27.5	2.1
Southwest	42.9	3,267	5.4	409	-37.5	94.9	21.2
Toronto	77.9	5,932	62.4	4,752	-15.5	180.7	149.0
West	20.3	1,546	8.9	681	-11.4	47.3	71.1

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.

Figure 4.4 shows the percentage production to supply Ontario energy demand by fuel type 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, 2016, to Mar. 31, 2018

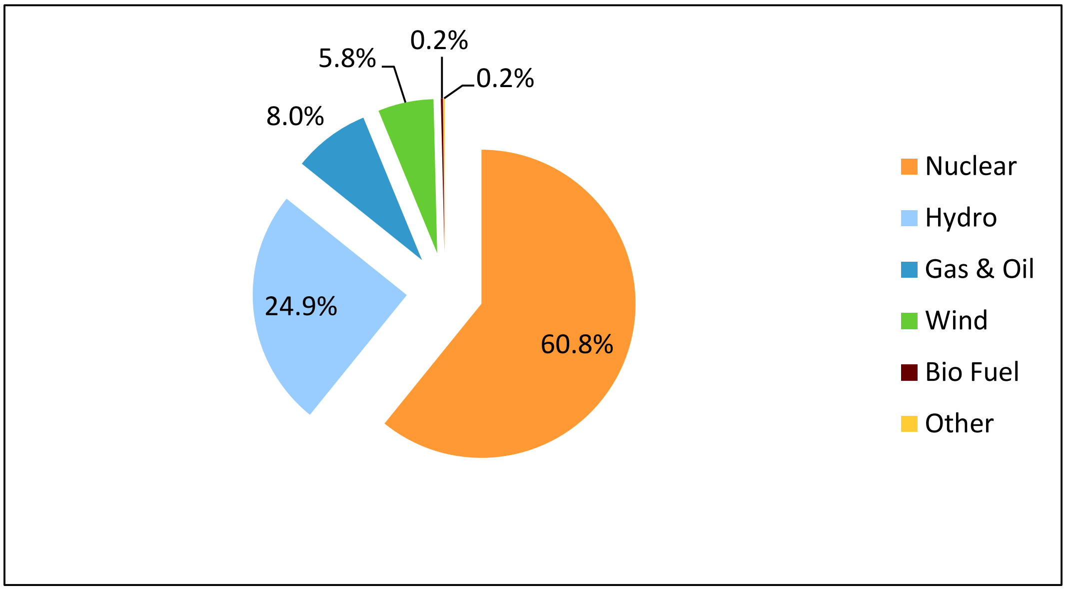


Figure 4.5 Monthly Production by Fuel Type – Oct. 1, 2016, to Mar. 31, 2018

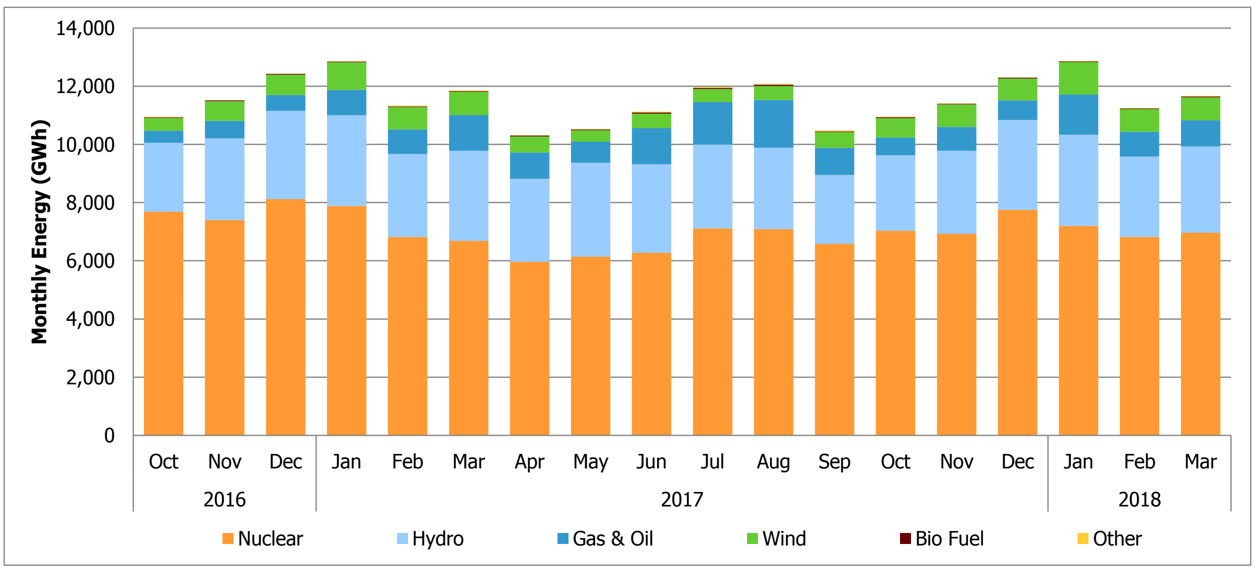


Table 4.9: Firm Scenario - Normal Weather: Ontario Energy Production by Fuel Type

Fuel Type (Grid Connected)	2016 (Oct 1 – Dec 31)	2017 (Jan 1 – Dec 31)	2018 (Jan 1 – Mar 31)	Total
	(GWh)	(GWh)	(GWh)	(GWh)
Nuclear	23,203	82,275	20,983	126,461
Hydro	8,212	34,750	8,862	51,824
Gas & Oil	1,570	11,979	3,139	16,688
Wind	1,815	7,631	2,683	12,129
Biofuel	76	329	69	474
Other (Solar & DR)	25	245	50	320
Total	**34,901**	**137,209**	**35,786**	**207,896**

- 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 period. Construction of several transmission reinforcements is expected to be completed during this Outlook period. Major transmission and load supply projects planned to be in service are shown in Appendix B. Projects that are already in service or whose completion is planned beyond the period of this Outlook are not shown. The list includes only transmission projects that are considered major modifications or significant improvements to system reliability. Minor transmission equipment replacements or refurbishments are not shown.

Some areas have experienced load growth to warrant additional investments in new load supply stations and reinforcements of local area transmission. Several local area supply 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 supply capacity for 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 8, 2016.

5.2 Transmission System Adequacy

The IESO assesses transmission adequacy using the methodology on the basis of conformance to established criteria, planned system enhancements and known transmission outages. Zonal assessments are presented in the following sections. Overall, the Ontario transmission system is expected to supply the demand under the normal and extreme weather conditions forecast for the Outlook period.

The existing transmission infrastructure in some areas in the province, as described below, have been identified as currently having or anticipated to have some limitations to supply 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/Pages/Participate/Regional-Planning/.

5.2.1 Toronto and Surrounding Area

The load supply capability to the GTA is expected to be adequate to meet the forecast demand through to the end of this 18-month 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. With the expected increase in load resulting from the proposed electrification of the GO Train System, the remaining autotransformer could potentially be overloaded during peak load periods. 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 either of the remaining autotransformers fail while one autotransformer is already out-of-service.

In central Toronto, the expected completion date for Copeland TS remains Q4 2016. 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 supply capacity in the area and will also enable the refurbishment of the facilities at John TS.

High voltages in southern Ontario continue to present operational challenges during periods when the level of transfers on the 500 kV system are markedly reduced as a result of medium-to-low load conditions, combined with the effect of transactions via the interconnections with our neighbouring utilities. Temporary removal from service of at least one of the 500 kV circuits between Lennox TS and Bowmanville Switching Station (SS) continues to be required during those periods. The situation has become especially acute during those periods when the shunt reactors at Lennox TS have been unavailable. While the IESO and Hydro One are currently managing this situation with day-to-day operating procedures, Hydro One is planning to install additional high voltage reactors at Lennox TS to address this issue. Details of this project are being confirmed and the expected in service date of this project is mid-2020.

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, Hydro One is planning to install two 230 kV in-line breakers at Holland TS, together with a load rejection scheme. These facilities are expected to be in service by Q4 2017. Until these facilities become available, operational measures will be required. Once completed, the project will relieve possible overloading of these 230 kV circuits during peak load periods.

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

5.2.2 Bruce and Southwest Zones

In the Guelph area, Hydro One continues construction on the Guelph Area Transmission Refurbishment project to improve the transmission capability into the Guelph area by reinforcing the supply into Guelph-Cedar TS. The expected completion date remains at Q3 2016. As part of this project, circuit switchers are to be installed at Guelph North Junction that will enable the 230 kV system between Detweiler TS and Orangeville TS to be sectionalized. These devices will reduce the restoration times for the loads in the Waterloo, Guelph and Fergus areas following a supply interruption. At the time of this report, the majority of the work at Cedar TS has been completed and the station is now in operation.

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 continues to be scheduled for completion by December 2016. 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 supply 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

There is an increased possibility that imports may need to be restricted during peak load periods due to the thermal limitation on the 230 kV Hawthorne-to-Merivale circuits. The situation may be especially challenging during periods of low hydroelectric output from the plants on the Ottawa and Madawaska Rivers, which is not uncommon during summer peak periods. Further increases in the amount of load supplied from the 230 kV system in the Merivale area will also worsen the situation. Hydro One is planning to reinforce the Hawthorne to Merivale circuits by upgrading their conductors to address this issue. This project is currently planned to be in-service by Q1 2020.

During peak load periods, the two under-sized autotransformers at Hawthorne TS in Ottawa are expected to be overloaded post-contingency. Hydro One is planning to replace these transformers with standard-sized units and the work is expected to be completed in Q2 2018. Once completed, this project will increase the step-down capability at Hawthorne TS to support the load on its 115 kV system.

Overall transmission transfer capability in the East and Ottawa zones is expected to be sufficient for the purpose of supplying 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.

Transmission transfer capability into the West zone is expected to be sufficient to supply 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 to occur, thereby increasing the transfer capability of the Flow South Interface. This is expected to be complete by the end of 2017.

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 supply 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. Hydro One is finalizing plans to reinforce the system in the Kapuskasing Area. 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 reduction that has occurred to the loads 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 one of these constraints, however additional constraints in the Sault Ste. Marie and Sudbury areas will continue to limit generation in Northwestern Ontario. This project is currently scheduled to be in-service by 2020.

Transmission constraints are also restricting the connection of additional load in some areas in northwestern Ontario. These restrictions should be addressed by the proposed 230 kV single-circuit line to Pickle Lake which is currently scheduled to be in-service in early 2020. Transmission transfer capability in the Northeast and Northwest zones is expected to be sufficient to supply 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 system reliability of Ontario's power system.

6.1 Storage

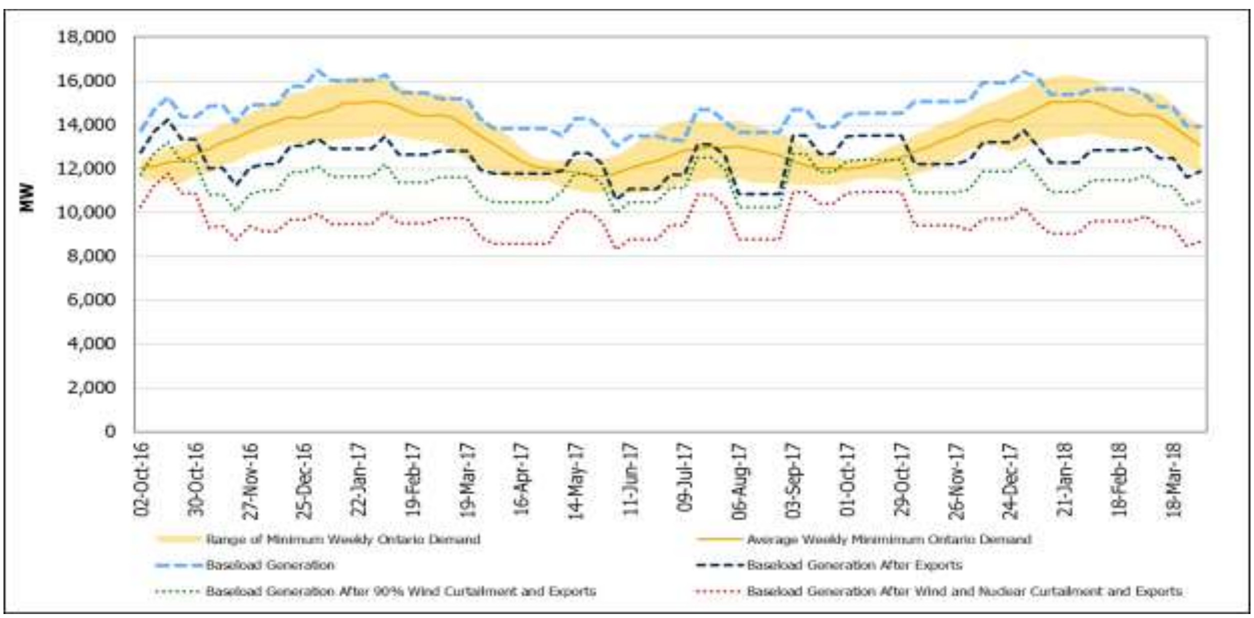
At the end of 2015, nine energy storage projects totaling 16.75 MW were offered 10-year contracts for capacity services as part of the Phase II energy storage competitive procurement process. This complements the approximately 34 MW of grid energy storage procured in Phase I by the IESO to offer ancillary 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. The first of the Phase I projects are expected to become operational in the latter part of 2016, and the balance of projects in 2017.

6.2 Surplus Baseload Generation (SBG)

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, which include export 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 run-of-river hydroelectric production, the latest planned outage information, in-service dates for new or refurbished generation, and reliable export capability. The expected contribution from self-scheduling and intermittent generation has also been updated to reflect the latest data. 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, 2016. 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)	32.8%	32.8%	32.0%	34.5%	24.7%	14.4%	14.4%	14.4%	19.3%	29.4%	32.9%	32.8%

6.3 Operability Assessment

As part of its regular review of system operability, the IESO conducts assessments to identify areas of potential operability concerns. In the most recent operability assessments, the IESO examined the impact of uncertainty in the timeframes in which the IESO typically commits or dispatches resources to balance supply and demand. This review confirmed recent trends observed in real-time operations:

- Over-forecasting of wind and solar generation output day-ahead, approximately 5 hours ahead and 1 hour ahead of real-time can lead to under-commitment of Ontario generators and under-scheduling of imports. Enhanced flexibility from Ontario resources to respond to these short-term differences between expected and actual production becomes increasingly important as the variable generation forms a larger proportion of the supply mix. It is anticipated that an additional 300 MW of flexible resource capability is needed on the system by the end of 2017. By the end of 2018, a further 700 MW of flexible resource capability is required. The need for flexibility has been experienced in other jurisdictions where a variety of solutions have been employed. The IESO has recently launched a stakeholder initiative to present its findings and discuss potential solutions to address this need in both the short- and long-term solutions. More information can be found on the Stakeholder Engagement webpage at http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx.
- Differences between actual and expected results in real-time can come from a variety of sources, including inaccuracies in the forecast of demand, inaccuracies in the forecast of wind and solar generation output, resources that ramp faster/slower than expected and resources that don't meet dispatch targets. These differences are addressed by regulation service. The IESO's assessment of operability found that regulation resources are frequently pinned at their high or low limits. As a result, the IESO is seeking to expand the depth of the regulation service market in Ontario. More information can be found at the Ancillary Services Market webpage at www.ieso.ca/ancillary-services.

- The assessment of operability also found that reduction of the load on the grid and change in patterns of demand creates high voltages at times that require special control actions to be managed. This drives a need for enhanced mechanisms to manage system voltage, both during steady-state operation and after a contingency. While the IESO and Hydro One are currently managing this situation with day-to-day operating procedures, work to identify long-term solutions continues.

- 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

Connecting Today.
Powering Tomorrow.