18-Month Outlook

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

FROM APRIL 2017 TO SEPTEMBER 2018

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 in all but one week during the Outlook period.

Under extreme weather conditions, the reserve levels which reflect current planned generator outages are below requirement for a combined total of 25 weeks over the summer periods in 2017 and 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 should understand that those outages are at risk and are advised to review their maintenance plans and consider rescheduling them.

Peak demand is expected to decline over the forecast period as conservation savings, increased embedded generation output and the Industrial Conservation Initiative (ICI) more than offset underlying growth. Effective January 1, 2017, ICI eligibility has been expanded to include all electricity users with a monthly average peak demand of over 1 MW. On March 2, 2017, the government announced it would further reduce the threshold to 500 kW, targeting small manufacturing and industrial consumers. Since the necessary regulatory amendments have yet to be finalized at the time of this report's publication, this impact is not included during the Outlook period.

Annual energy demand is expected to show a slight increase in 2017 as economic and demographic growth push up demand more than conservation and increased embedded generation reduce it.

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

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2017	22,614	24,902
Winter 2017-18	21,859	23,067
Summer 2018	22,550	24,731

About 1,950 megawatts (MW) of new supply – 500 MW of wind, 1,300 MW of gas, 50 MW of hydroelectric and 100 MW of solar generation – 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 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 over 600 MW by the end of the Outlook period. Meanwhile, embedded solar generation is expected to increase to over 2,200 MW.

On August 21, 2017, a solar eclipse is expected to pass over parts of the continental U.S. and Canada. Although Ontario will only see a partial eclipse, this event is expected to impact operations because a decline in embedded solar production will lead to a corresponding increase in grid demand. This temporary increase in grid demand combined with the reduction in grid-connected solar production will have to be met by other resources during the eclipse. The IESO will be working closely with market participants and interconnected Reliability Coordinators to ensure reliable operation before, during and after this meteorological event.

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. For the winter peaks, downward pressure stems from conservation whereas the summer peaks also have additional downward pressure from the ICI and increased output from embedded solar. Energy demand faces the same drivers and is expected to show only minimal growth over the forecast horizon.

Resource Adequacy

- Under the **firm scenario**, reserve requirements are expected to be met for the entire duration but for one week of this Outlook period under normal weather conditions. Under extreme weather conditions, the reserve is below the requirement for a total of 25 weeks over the summer periods; the largest shortfall is approximately 3,500 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 a total of 17 weeks over the summer periods; the largest shortfall is around 3,150 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.

- High voltages in southern Ontario continue to present operational challenges during periods when the level of transfers on the 500 kV system are reduced. This can result from combinations of medium-to-low load conditions and specific levels of transactions with neighbouring jurisdictions. The IESO and Hydro One are currently managing this situation with day-to-day operating procedures. To address this issue on a more permanent basis, the IESO requested Hydro One to install additional high voltage reactors at Lennox TS with a target in-service date of Q4 2020.

- Occasionally, imports from Hydro Quebec 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 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 remains Q2 2018.
- The new Copeland TS is planned to be in-service in downtown Toronto in Q1 2018. The new station will facilitate the refurbishment of the facilities at John TS, while also enhancing the load security in the downtown core.
- The new Manby 230/115 kV Autotransformer Overload Protection scheme, with an in-service date of Q2 2018, will protect the autotransformer that remains in-service following outages to the other two autotransformers at either the East or West yards at Manby TS.
- The new Bruce Remedial Action Scheme (RAS) will replace the existing Special Protection System (SPS) in Q4 2017. The new scheme will increase operation flexibility by detecting and responding to a greater number of system contingencies.

Operability

Conditions for surplus baseload generation (SBG) will continue over the Outlook period. However, the magnitude and the frequency of the SBG are reduced with the commencement of the nuclear refurbishment in 2016. 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 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. The IESO has initiated a stakeholder engagement to determine potential solutions that can enable and achieve flexibility to meet the evolving needs of the system, which can include getting more flexibility out of existing resources and/or enhancing our market mechanisms through the IESO's Market Renewal.

In addition, the IESO plans to expand its capability to schedule regulation by increasing the amount of regulation usually scheduled from 100 MW 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.

Caution and Disclaimer

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1 Introduction

This Outlook covers the 18-month period from April 2017 to September 2018 and supersedes the last Outlook released on December 15, 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/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:

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- Tel: 905-403-6900
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- 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 December 2016. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for January and February 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 February 10, 2017.

As of February 10, 2017, the following generators completed the market registration process since the last Outlook:

- Bow Lake Phase 1 and 2b – 60 MW (wind)

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 February 10, 2017, 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 February 10, 2017.

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3 Demand Forecast

The IESO forecasts electricity demand on the IESO-controlled grid. This demand forecast covers the period April 2017 to September 2018 and supersedes the previous forecast released in December 2016. Tables of supporting information are contained in the [2017 Q1 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.

Overall, grid-supplied energy demand is forecast to remain fairly flat over the forecast horizon. For 2016, actual demand showed a very small decline (0.02%) whereas weather-corrected demand showed a very small increase (0.05%) over 2015. However, the year had an additional day due to the leap year, so adjusting for the additional day would mean that demand declined in 2016. For 2017, the expectation is that energy demand will increase slightly as economic and demographic growth outstrip increased conservation savings and increased embedded generation output. The growth is small, so variations in any of the components could easily lead to a reduction in 2017 energy demand. The economy still enjoys excellent fundamentals: a low dollar, strong U.S. growth, low interest rates and low inflation. However, the amount of uncertainty has grown extensively over the past six months due to geopolitical events and the potential for trade disruptions.

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 solar generation capacity and pricing impacts (ICI and time-of-use rates). In addition to reducing summer peaks, increased embedded solar output is also pushing the peak to later in the day. Winter peaks face more downward pressure from conservation than they do from embedded generation. Since the winter peaks occur after sundown, improvement to lighting efficiency impact winter peaks.

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)
Summer 2017	22,614	24,902
Winter 2017-18	21,859	23,067
Summer 2018	22,550	24,731
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)	136.6	0.3%
2018 (Forecast)	136.5	-0.1%

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)
02-Apr-17	18,231	19,359	567	2,555					
09-Apr-17	17,970	18,659	471	2,516	07-Jan-18	21,287	22,038	570	2,843
16-Apr-17	17,211	18,338	496	2,409	14-Jan-18	21,859	23,067	547	2,910
23-Apr-17	16,716	16,808	531	2,398	21-Jan-18	21,424	21,927	483	2,898
30-Apr-17	16,759	17,302	721	2,387	28-Jan-18	21,275	22,095	404	2,904
07-May-17	17,501	20,441	849	2,359	04-Feb-18	21,119	22,267	734	2,912
14-May-17	17,654	19,978	845	2,372	11-Feb-18	20,370	21,835	635	2,851
21-May-17	18,669	22,054	1,175	2,400	18-Feb-18	20,097	21,496	581	2,800
28-May-17	18,594	22,241	1,330	2,349	25-Feb-18	19,834	21,507	501	2,748
04-Jun-17	19,193	21,770	1,292	2,443	04-Mar-18	20,229	21,551	531	2,778
11-Jun-17	19,849	24,272	1,055	2,579	11-Mar-18	19,788	20,613	649	2,733
18-Jun-17	20,880	24,393	835	2,595	18-Mar-18	18,723	19,424	611	2,656
25-Jun-17	22,374	24,573	754	2,660	25-Mar-18	18,267	19,029	569	2,567
02-Jul-17	22,187	24,072	1,016	2,645	01-Apr-18	18,163	19,138	567	2,513
09-Jul-17	22,614	24,902	814	2,743	08-Apr-18	17,877	18,415	471	2,495
16-Jul-17	22,317	24,021	838	2,775	15-Apr-18	17,133	18,114	496	2,439
23-Jul-17	22,063	24,009	1,035	2,671	22-Apr-18	16,687	16,916	531	2,398
30-Jul-17	22,098	24,788	841	2,757	29-Apr-18	16,689	17,074	721	2,376
06-Aug-17	22,378	24,571	958	2,775	06-May-18	17,414	20,209	849	2,349
13-Aug-17	21,966	24,679	985	2,729	13-May-18	17,555	19,744	845	2,362
20-Aug-17	21,393	24,536	1,362	2,704	20-May-18	18,392	21,827	1,175	2,390
27-Aug-17	21,393	23,559	1,413	2,707	27-May-18	18,465	22,019	1,330	2,338
03-Sep-17	20,608	23,193	1,370	2,590	03-Jun-18	19,116	21,685	1,292	2,421
10-Sep-17	18,920	22,369	680	2,437	10-Jun-18	19,773	24,188	1,055	2,565
17-Sep-17	19,375	21,149	781	2,501	17-Jun-18	20,756	24,278	835	2,581
24-Sep-17	18,083	20,255	420	2,469	24-Jun-18	22,283	24,488	754	2,645
01-Oct-17	17,370	18,777	554	2,411	01-Jul-18	22,293	24,178	1,016	2,685
08-Oct-17	17,504	17,693	786	2,451	08-Jul-18	22,233	24,731	814	2,665
15-Oct-17	17,471	17,613	507	2,432	15-Jul-18	22,550	23,857	838	2,753
22-Oct-17	17,804	18,290	392	2,470	22-Jul-18	21,903	23,851	1,035	2,650
29-Oct-17	17,937	18,532	318	2,511	29-Jul-18	21,932	24,622	841	2,733
05-Nov-17	18,163	18,883	416	2,521	05-Aug-18	22,227	24,421	958	2,753
12-Nov-17	19,263	19,827	601	2,625	12-Aug-18	21,844	24,552	985	2,710
19-Nov-17	19,549	20,343	342	2,644	19-Aug-18	21,285	24,432	1,362	2,687
26-Nov-17	19,993	20,781	607	2,717	26-Aug-18	21,219	23,385	1,413	2,687
03-Dec-17	20,398	21,482	409	2,765	02-Sep-18	20,456	23,050	1,370	2,575
10-Dec-17	20,557	21,755	555	2,792	09-Sep-18	18,805	22,097	680	2,421
17-Dec-17	20,904	21,974	690	2,836	16-Sep-18	19,240	20,868	781	2,485
24-Dec-17	20,739	21,895	362	2,805	23-Sep-18	17,920	19,963	420	2,454
31-Dec-17	20,493	21,717	528	2,711	30-Sep-18	17,252	18,511	554	2,399

3.1 Actual Weather and Demand

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

December

- December's weather was normal, with the peak weather a little colder than normal and the average temperature for the month a little warmer than normal.
- The month's peak occurred on the third coldest day of the month as daytime highs reached -10.1°C (at Toronto) under gusty wind conditions.

- The actual peak was 20,688 MW, with the weather-corrected value of 20,299 MW. These values are low by historical standards but represent a slight increase over December 2015.
- Energy demand for the month was 11.9 TWh and 11.9 TWh weather-corrected. It is the first time that December weather-corrected demand has dropped below 12.0 TWh since market opening.
- The minimum demand for the month was 11,684 MW, which occurred in the early hours of December 27.
- Embedded generation for the month was 446 GWh, an increase of 0.8 percent over the previous December and was driven by gains in solar production. Declines in other embedded generation led to the small growth rate. Wholesale customers' consumption for the month increased by 1.0 percent compared to the previous December.

January

- The weather for January was milder than normal.
- The peak occurred on January 9, which was the eighth coldest day of the month. The actual peak was 20,372 MW (20,830 MW weather-corrected). Both values are the lowest since market opening.
- Energy demand for the month was 12.1 TWh (12.5 TWh weather-corrected). Once again, both represent the lowest January values since market opening.
- The minimum was 12,246 MW and occurred in the early morning of Sunday, January 22, which was a warm weekend. The minimum was an increase over the previous January.
- Embedded generation, as reported by distributors, was 472 GWh for the month. This represents a 0.8% decrease over the previous January. The decline was attributable to a drastic reduction in solar production (-13.8%) as the month was very overcast. Wind production was up significantly (46%).

February

- February was the second warmest of the past fifty years.
- The actual peak for February was 19,838 MW, occurring on Tuesday February 7, which was the seventh coldest day of the month. The weather-corrected value was higher (20,306 MW). It was the lowest actual February peak since market opening due to the weather. The weather corrected value was consistent with February post-recession peaks.
- The mild weather pushed actual demand to 10.6 TWh, which is the lowest February since market opening. Weather-corrected demand was higher at 11.0 TWh, but still represents an all-time low for the month.
- Minimum demand of 11,867 MW occurred Sunday, February 19 at 4 a.m. This was the Family Day long weekend. Once again this is the lowest February value since market opening.

- Embedded generation reported by distributors was 493 GWh for the month, an increase of 2% over the previous February. Both wind and solar output were down from a year earlier; increased output from other energy sources drove the year-over-year increases.
- Wholesale customer consumption decreased by 3.0 percent compared to the previous February. However, after adjusting for the different number of days due to the leap year, consumption would show a 0.4% increase.

2016-17 Winter Actuals

Overall, energy demand for the three months from December to February was down 1.5 percent compared with the same three months one year prior. After adjusting for the weather, demand for the three months showed a greater decline of 2.4 percent. After adjusting for the extra leap year day, weather-corrected demand declined by 1.3% for the winter.

Embedded generation for the winter months was up 1 percent over the previous winter. Embedded solar output increased by 13% and embedded wind output showed a 1 percent decline.

For the three months, wholesale customers' consumption posted a 1.0 percent decline compared to the previous winter. Once again, adjusting for the leap year day, consumption would have increased 0.1%.

The 2017 Q1 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

Though the economic fundamentals remain very favourable for Ontario, a great deal of uncertainty exists with respect to the province's major trade partner. Since the U.S. is the largest export market for Ontario goods, any changes to the North American Free Trade Agreement or the Canada-US Free Trade deals could have significant impacts later in the forecast period. Having signed the Comprehensive Economic and Trade Agreement with the European Union, Canada has obtained access to another large market. Finally, despite the U.S. withdrawal from the Trans Pacific Partnership, Canada will continue to pursue a trade deal with the Pacific Rim countries. These initiatives allow Canada to diversify its export markets.

Table 3.3.4 of the 2017 Q1 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 2017 Q1 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 the five to 10 highest peak days of the program year. The program was expanded starting January 1, 2017 to market participants with an average peak load greater than 1 MW. The ICI program is estimated to have reduced peak demand by more than 1,200 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 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 February 10, 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	12,978	10,667	5	0	0
Hydroelectric	8,451	5,845	73	0	0
Gas/Oil	9,943	8,170	30	0	0
Wind	3,983	479	35	60	1
Biofuel	495	459	9	0	0
Solar	280	28	6	0	0
Total	**36,130**	**25,648**	**158**	**60**	**1**

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 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 information is current as of February 10, 2017. 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 Generation Resources Status

Project Name	Also Known As	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered	
						Firm (MW)	Planned (MW)
Niagara Region Wind Farm	West Lincoln NRWF	Southwest	Wind		Commercial Operation	230	230
Greenfield South	Green Electron Power	West	Gas	2017-Q1	Commissioning		298
South Gate Solar		Southwest	Solar	2017-Q1	Commissioning		50
Windsor Solar		West	Solar	2017-Q1	Commissioning		50
Namewaminikan Hydro		Northwest	Water	2017-Q2	Commissioning		10
Peter Sutherland Senior Generating Station		Northeast	Water	2017-Q2	Under Development		28
Harmon Unit 2 Runner Upgrade		Northeast	Water	2017-Q2	Commissioning		10
Harmon Unit 1 Runner Upgrade		Northeast	Water	2017-Q3	Under Development		10
Belle River Wind		West	Wind	2017-Q3	Under Development		100
Napanee Generating Station		East	Gas	2017-Q4	Under Development		985
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
Amherst Island Wind		East	Wind	2018-Q2	Under Development		75
Total						**109**	**1,826**

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 2016. 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	6,003	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, 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%	33.3%	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.

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 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 beginning on May 1, 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.

4.1.4 Firm Transactions

As part of the electricity trade agreement between Ontario and Quebec announced in October 2016, 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 (GHG) emissions in Ontario. The agreement includes the opportunity to cycle energy.

The New York Independent System Operator (NYISO) winter 2016/2017 capacity auction, held in September 2016, cleared 88 MW of Ontario generation for the six-month commitment period from November 2016 to April 2017. For the summer commitment period from May to October 2017, NYISO will accept up to a maximum of 128 MW from Ontario. This Outlook does not reflect the results of that auction since it will be held at the end of March 2017. Only the amounts that cleared the winter 2016/2017 auction are reflected in the Outlook.

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)	36,130	
New Generation and Capacity Changes (MW)	1,826	109

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. Non-utility generators (NUG) whose contracts expire during the Outlook period are included in both scenarios only up to their contract expiry date. Those NUGs that continue to provide forecast data after contract expiry are also included in the planned scenario for the rest of the Outlook period. 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	Summer Peak 2017		Winter Peak 2018		Summer Peak 2018	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,360	36,806	36,360	38,002	36,360	38,077
2	Total Reductions in Resources (MW)	11,633	11,761	8,685	8,811	10,221	10,650
3	Demand Measures (MW)	737	737	729	729	771	771
4	Firm Imports (+) / Exports (-) (MW)	0	0	-500	-500	0	0
5	Available Resources (MW)	25,464	25,783	27,904	29,420	26,910	28,198

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

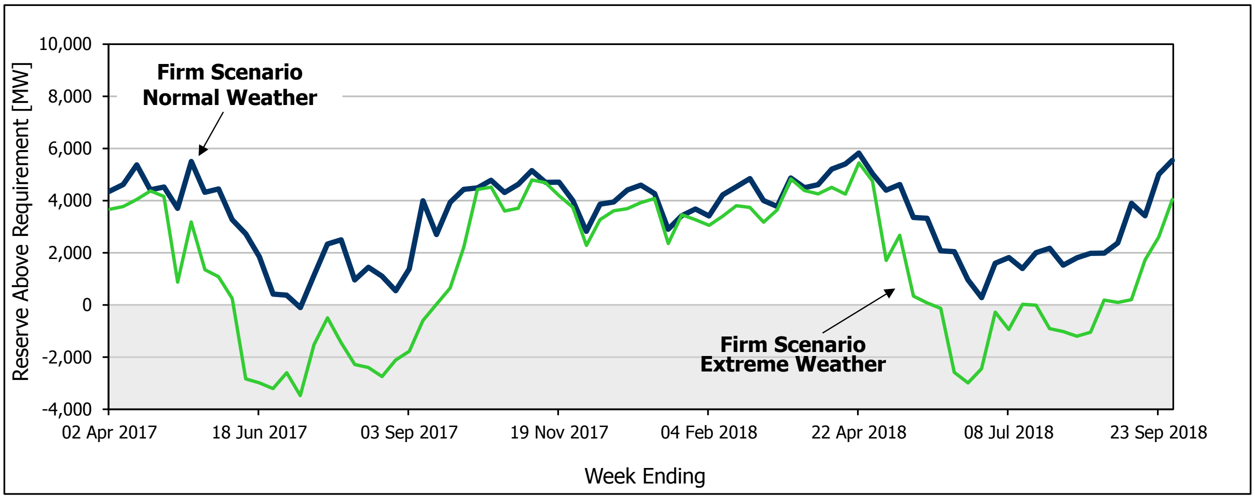
The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages. The planned outages occurring during this Outlook period have been assessed as of February 10, 2017.

4.2.1 Firm Scenario with Normal and Extreme Weather

The **firm scenario** incorporates all existing capacity plus approximately 230 MW of wind capacity that had achieved commercial operation status as of February 10, 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, except for one week. During extreme weather conditions, the reserve is lower than the requirement for a total of 25 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 consider rescheduling them if they are critical for the continued operation of the units.

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

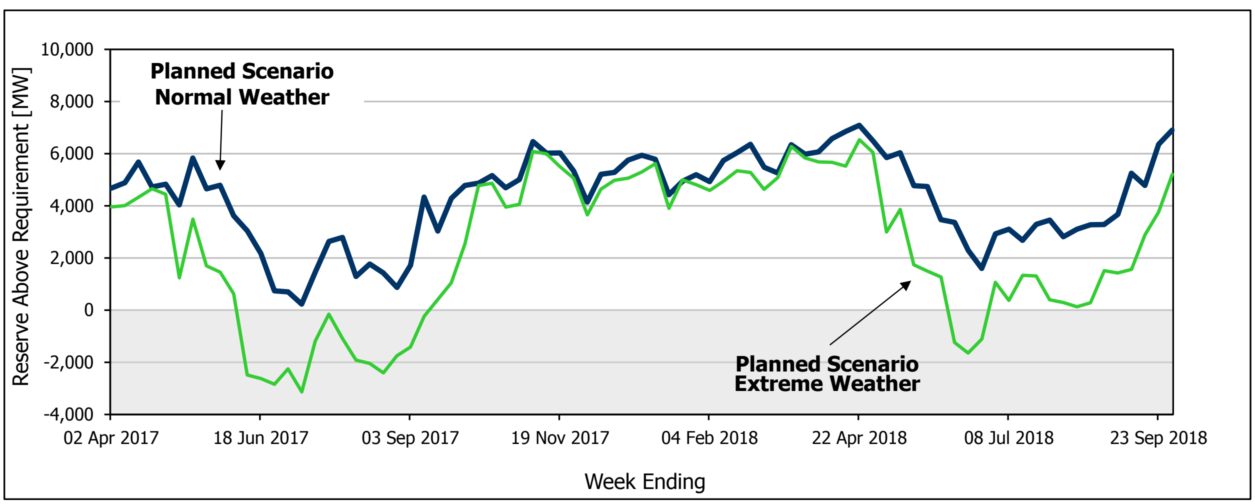


4.2.2 Planned Scenario with Normal and Extreme Weather

The **planned scenario** incorporates all existing capacity plus all capacity coming in service. Approximately 1,950 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 a total of 17 weeks during the 18-Month Outlook timeframe under extreme weather conditions. This shortfall is largely attributed to the planned outages scheduled for those weeks.

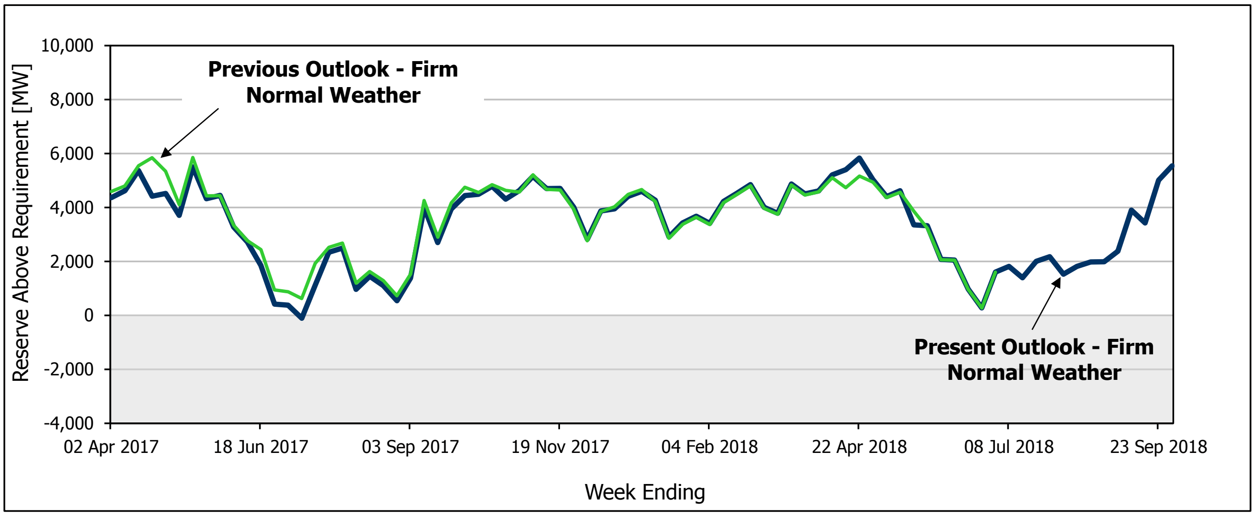
Figure 4.2: Normal vs. Extreme Weather: Planned Scenario RAR



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 December 15, 2016. The difference is mainly due to changes in planned outages and a slight increase 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 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 Q1 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.

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	**203.1**	**15,445**	**203.1**	**15,445**	**0.0**	**453.2**	**567.5**
Bruce	0.9	71	70.2	5,340	69.3	1.2	165.8
East	12.0	916	15.6	1,189	3.6	25.4	65.2
Essa	11.5	875	3.4	262	-8.1	24.9	14.0
Niagara	6.1	462	19.6	1,494	13.5	14.6	41.3
Northeast	14.3	1,089	14.8	1,127	0.5	24.4	31.7
Northwest	5.7	432	6.0	453	0.3	10.0	20.6
Ottawa	12.4	945	0.0	3	-12.4	26.2	2.2
Southwest	42.4	3,222	5.7	436	-36.7	94.6	26.3
Toronto	77.5	5,896	59.1	4,490	-18.4	183.8	134.3
West	20.2	1,539	8.6	651	-11.6	48.1	66.1

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, 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 – Apr. 1, 2017, to Sep. 30, 2018

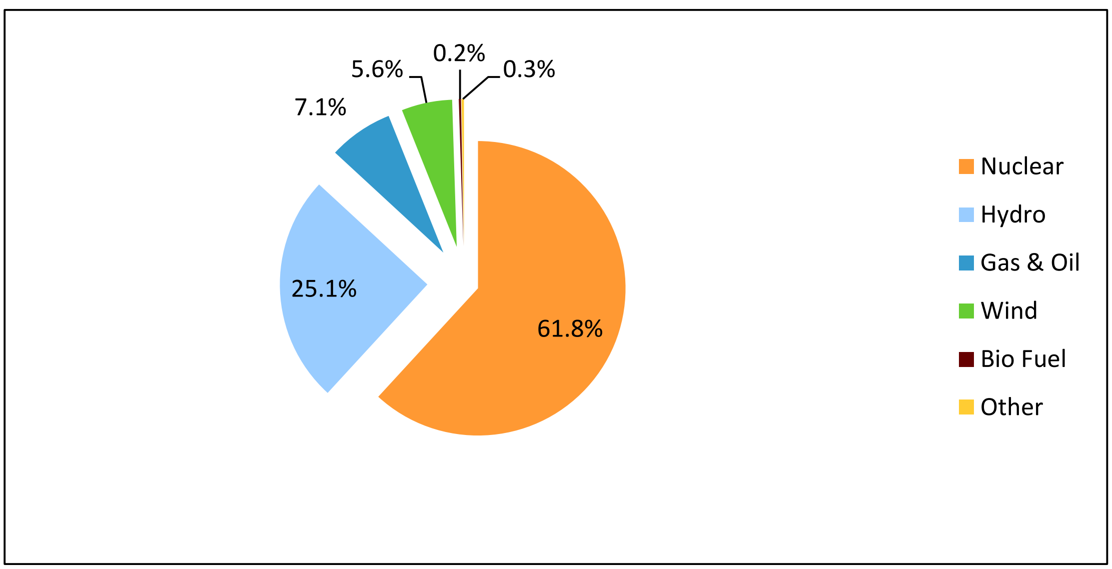


Figure 4.5: Monthly Production by Fuel Type – Apr. 1, 2017, to Sep. 30, 2018

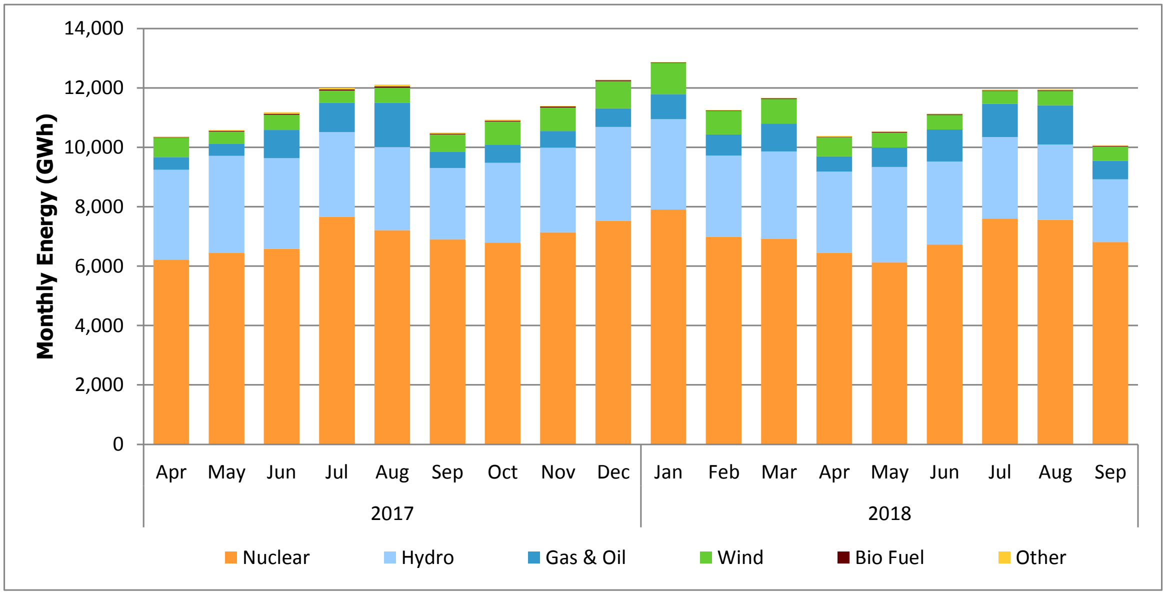


Table 4.9: Firm Scenario - Normal Weather: Ontario Energy Production by Fuel Type

Fuel Type (Grid Connected)	2017 (Apr 1 – Dec 31) (GWh)	2018 (Jan 1 – Sep 30) (GWh)	Total (GWh)
Nuclear	62,493	63,080	125,572
Hydro	26,069	24,843	50,912
Gas & Oil	6,558	7,802	14,361
Wind	5,601	5,677	11,279
Bio Fuel	281	208	489
Other (Solar & DR)	317	204	521
Total	**101,319**	**101,815**	**203,134**

- 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. A list of such projects is provided in Appendix B. Only transmission and load supply projects that either are 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 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 February 10, 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 supplying 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 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/get-involved/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 one of the three autotransformers fail 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 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 low. This can result from combinations of medium-to-low load conditions and specific levels of transactions with neighbouring jurisdictions. Temporary removal from service of at least one of the 500 kV circuits in Eastern Ontario 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. The IESO and Hydro One are currently managing this situation with day-to-day operating procedures. To address this issue on a more permanent basis, the IESO requested Hydro One to install additional high voltage reactors at Lennox TS with a target in-service date of Q4 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, 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.

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 2017. 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 from Hydro Quebec 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 remains to be Q2 2018. Once completed, this project will increase the step-down capability at Hawthorne TS to support the load in its 115 kV system.

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 Q2 2018, will address the region's supply 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 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. As recommended by the IESO, 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 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 one of these constraints. This project is currently scheduled to be in-service by 2020. However, additional constraints in the Sault Ste. Marie and Sudbury areas will continue to limit generation in Northwestern Ontario.

Transmission constraints are also restricting the connection of additional load in some areas in northwestern Ontario. Some of these restrictions 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

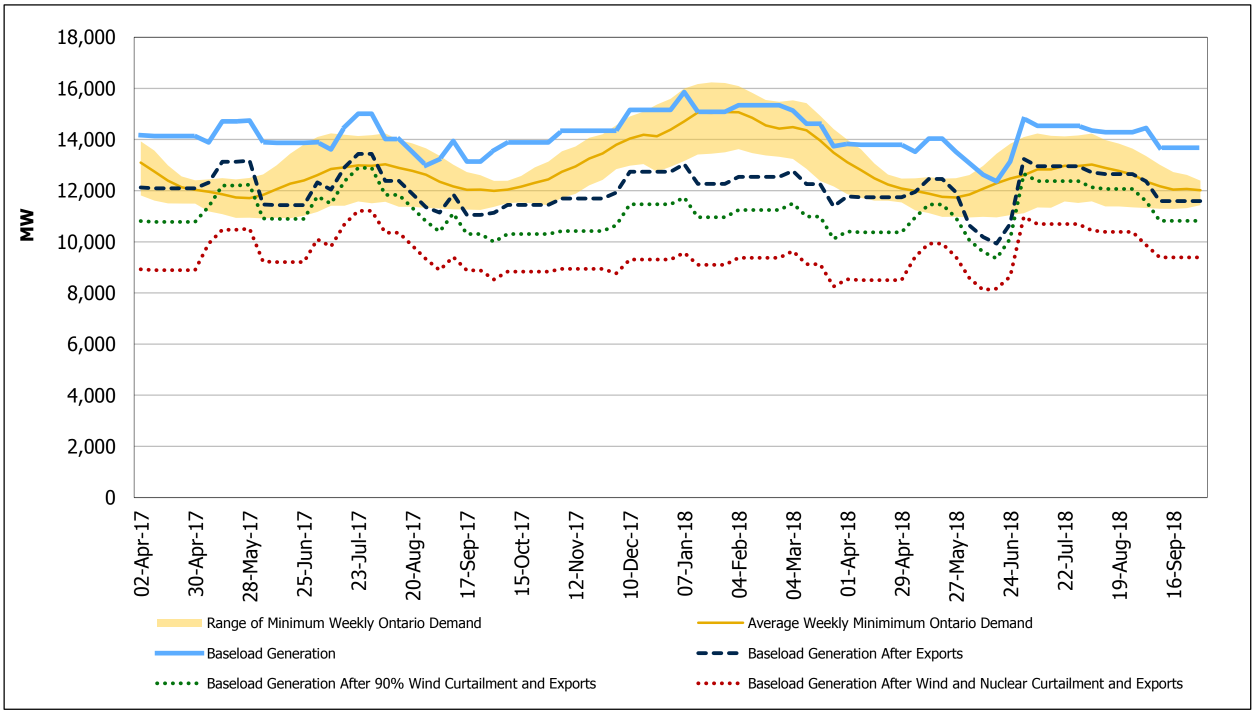
At the end of 2015, nine energy storage projects totaling 16.75 MW were offered 10-year contracts for capacity services as part of the Phase II energy storage competitive procurement process. This complements the approximately 34 MW of grid energy storage procured in Phase I by the IESO to offer ancillary 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 originally anticipated to become operational in the latter part of 2016 have revised their implementation schedules while navigating a number of unanticipated project development issues. Revised completion dates now extend into the latter part of 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 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. 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 2016 IESO Operability Assessment, the impact of uncertainty in the timeframes in which the IESO typically commits or dispatches resources to balance supply and demand was examined. This review confirmed recent trends observed in real-time operations:

- Flexibility from Ontario resources to respond to the short-term differences between expected and actual variable generation production becomes increasingly important as variable generation forms a larger proportion of the supply mix.
  As the output from our variable generation fleet continues to rise, so does the need for flexible generation online to manage forecast variability. As such, we are increasingly initiating control actions such as, but not limited to, manually adjusting the variable generation forecast, committing/constraining on dispatchable resources, and curtailing export transactions mid-hour.
  The IESO has initiated a stakeholder engagement to determine potential solutions that can enable and achieve flexibility to meet the evolving needs of the system, which can include getting more flexibility out of existing resources and/or enhancing our market mechanisms through the IESO's Market Renewal Program. More information can be found on the Stakeholder Engagement webpage at http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx.
- 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 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 has received comments on the draft RFP that was posted on December 16, 2016. The IESO is evaluating these comments and their applicability to the formal RFP which is likely to be released in Q2 2017.

On August 21, 2017, a solar eclipse is expected to pass over parts of the continental US and Canada. Although Ontario will only see a partial eclipse, this event is expected to impact operations because a decline in embedded solar production will lead to a corresponding increase in grid demand. This temporary increase in grid-demand combined with the reduction in grid-connected solar production will have to be met by other resources during the eclipse. The IESO will be working closely with market participants and interconnected Reliability Coordinators to ensure reliable operation before, during and after this meteorological event.

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