18-Month Outlook

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

FROM JANUARY 2018 TO JUNE 2019

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Executive Summary

Reliability Outlook

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

Under extreme weather conditions, the reserve levels that reflect current planned generator outages are below requirement for a combined total of 18 weeks over the periods of May to September 2018 and June 2019. Both generator and transmission outages may be placed at risk during this period. If extreme weather conditions materialize, the IESO may, at that time, reject some generator maintenance outages to ensure that Ontario demand is met during the summer peak. Therefore, generators expecting to perform maintenance during the summer are advised to review their plans and consider rescheduling their outages.

Demand Forecast

Ontario's peak demand is expected to remain virtually flat. Conservation savings, growing embedded generation output and the Industrial Conservation Initiative (ICI) all work to offset any increase in demand due to population growth and economic expansion.

Energy demand showed a significant decline in 2017, even after adjusting for the impact of weather and the leap year. Demand is expected to show a slight increase in 2018 as stronger economic growth in the industrial and greenhouse sectors increase electricity consumption. At the same time, the growth in embedded generation capacity, a major offset to demand, will begin to plateau.

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

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2017-18	21,619	22,785
Summer 2018	22,176	24,500
Winter 2018-19	21,523	22,339

Supply

About 1,335 MW of new supply – 1,000 MW of gas, 275 MW of wind, 50 MW of solar and 10 MW of hydroelectric – is expected to be connected to the province's transmission grid over the Outlook period. By the end of the period, the amount of grid-connected wind is expected to increase to about 4,500 MW and grid-connected solar to 434 MW.

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

Transmission Adequacy

Ontario's transmission system is expected to continue to reliably serve Ontario demand while experiencing normal contingencies defined by planning criteria under both normal and extreme weather conditions forecast for this Outlook period**.** Several local area supply and transmission improvement projects underway will be placed in service during the timeframe of this Outlook. These projects, shown in Appendix B, will help relieve loading of existing transmission stations and provide additional capacity for future load growth. Due to the negative Reserves Above Requirement (RAR) identified in one week in the firm normal weather scenario, transmission outages impacting adequacy may be at risk.

Transmission constraints may restrict resources in northwestern Ontario. The East-West Tie expansion project would primarily be required to ensure reliability of supply to the northwest while accommodating the forecast load growth for the region. The Leave to Construct applications for this project have been filed, and as requested by the Minister of Energy, on December 1st, 2017 the IESO completed and submitted an updated assessment of the need for the line, confirming the East-West Tie expansion project continues to be the least cost solution for meeting the reliability needs for the region. The IESO recommends that work continue to target an in-service date of Q4 2020.

Operability

Conditions for surplus baseload generation (SBG) will continue over the Outlook period. It is expected that SBG will continue to be managed effectively through existing market mechanisms, which include intertie scheduling, the dispatch of grid-connected renewable resources and nuclear manoeuvres or shutdowns.

The need for more flexible capability to respond to intra-hour differences between expected and actual variable generation and expected and actual Ontario demand continues to be a priority. Beginning in June of 2016, the IESO has been engaging with stakeholders to explore a range of potential solutions for enhanced flexibility in the electricity system. To address flexibility needs in the interim, the IESO is proposing to schedule additional 30-minute operating reserve to represent flexibility need. Additional details of this proposal and stakeholder engagement information are available here:
http://www.ieso.ca/en/sector-participants/market-renewal/enabling-system-flexibility

In addition, the IESO plans to expand its capability to schedule more regulation as required. Once in service, the 55 MW procured through the 2017 RFP for Incremental Regulation Capacity will complement the 100 MW of regulation service that is typically scheduled every hour to help ensure the reliable operation of the power system. Further information may be found on the 2017 Regulation RFP page here:
http://www.ieso.ca/en/sector-participants/market-operations/markets-and-related-programs/regulation-service-rfp

Changes to the 18-Month Outlook

The IESO is currently consulting with readers of this report to better understand and respond to the audience's needs. Stakeholder feedback will inform a refresh of this report in 2018. More information on this initiative can be found here:
http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/18-month-outlook-refresh.

As mentioned in the last Outlook, the IESO will also initiate a stakeholder engagement to discuss the current outage assessment methodology and to solicit feedback on utilizing extreme weather conditions instead of normal weather conditions to assess outages starting with the quarterly assessment process. More information can be found here: http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/proposed-ieso-outage-approval-criteria

Ongoing Stakeholder Engagements Relating to Reliability

- Development of IESO Implementation Plan for 2017 LTEP
- Market Renewal: System Flexibility; Capacity Exports; Single Schedule Market; Incremental Capacity Auction
- Interchange Enhancements
- Proposed IESO Outage Approval Criteria

Caution and Disclaimer

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1 Introduction

This Outlook covers the 18-month period from January 2018 to June 2019 and supersedes the last Outlook released on September 21, 2017.

The purpose of the 18-Month Outlook is:

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

Additional supporting documents are located on the IESO website at: http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook

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

Security and adequacy assessments are published on the IESO website on a daily basis and progressively supersede information presented in this report.

For questions or comments on this Outlook, please contact us at:

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

- End of Section -

2 Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast is based on actual demand, weather and economic data through to the end of August 2017. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for September, October and November 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 November 24, 2017, no new generators completed the market registration process since the last Outlook.

2.3 Updates to Transmission Outlook

For this Outlook, transmission outage plans submitted to the IESO's outage management system as of October 27, 2017, were used.

2.4 Updates to Operability Outlook

The Outlook for surplus baseload generation (SBG) conditions over the next 18 months is based on generator outage plans submitted by market participants to the IESO's outage management system as of November 24, 2017.

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3 Demand Forecast

The IESO forecasts electricity demand on the IESO-controlled grid. This demand forecast covers the period January 2018 to June 2019 and supersedes the previous forecast released in September 2017. Tables of supporting information are contained in the 2017 Q4 Outlook Tables spreadsheet.

Electricity demand is shaped by a several factors, which have differing impacts:

- those that increase the demand for electricity (population growth, economic expansion and the increased penetration of end-uses)
- those that reduce the need for grid supplied electricity (conservation and embedded generation)
- those that shift demand (time-of-use rates and the Industrial Conservation Initiative [ICI]).

How each of these factors impacts electricity consumption varies by season and time of day. The forecast of demand incorporates these impacts.

Grid-supplied energy demand has been fairly flat since the 2009 recession with small variation year to year. This year, demand will show a significant decline. For 2018, demand is expected to show a very modest rebound. The economic environment remains positive for industrial growth. As well, growth is expected in the greenhouse industry, driven by the legalization of cannabis, a very electricity-intensive crop. The province will also see continued population growth into 2018, another factor behind increasing demand.

Offsetting Ontario's growing demand are energy savings achieved through conservation efforts and contributions from distribution-connected (embedded) generators. Combined, these forces will leave demand relatively flat over the forecast period.

Peak demands are subject to the same forces as energy demand, though the impacts vary. This is true not only when comparing energy versus peak demand, but also in comparing the summer and winter peaks. 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 facilities that have high output levels during the summer peak period and no output during the winter peak periods. In addition to reducing summer peaks, increased embedded solar output is also pushing the peak later in the day. Although the penetration of embedded generation has slowed, prices will be the dominant factor in moderating peak demands. Peak demands will show a small decline over the forecast horizon.

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

Table 3.1: Forecast Summary

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2017-18	21,619	22,785
Summer 2018	22,176	24,500
Winter 2018-19	21,523	22,339
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)	132.7	-2.5%
2018 (Forecast)	134.2	1.1%

Table 3.2: Weekly Energy and Peak Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)	Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
07-Jan-18	21,062	21,919	570	2,803	07-Oct-18	17,450	17,583	786	2,398
14-Jan-18	21,619	22,785	547	2,866	14-Oct-18	17,278	17,557	507	2,376
21-Jan-18	21,166	21,870	483	2,857	21-Oct-18	17,546	18,001	392	2,422
28-Jan-18	21,011	22,012	404	2,862	28-Oct-18	17,648	18,228	318	2,463
04-Feb-18	21,022	22,137	734	2,866	04-Nov-18	17,977	18,580	416	2,477
11-Feb-18	20,221	21,637	635	2,805	11-Nov-18	18,891	19,440	601	2,575
18-Feb-18	19,951	21,398	581	2,754	18-Nov-18	19,173	19,966	342	2,588
25-Feb-18	19,630	21,388	501	2,704	25-Nov-18	19,614	20,426	607	2,662
04-Mar-18	20,242	21,387	531	2,731	02-Dec-18	19,986	21,088	409	2,707
11-Mar-18	19,623	20,485	649	2,686	09-Dec-18	20,129	21,350	555	2,734
18-Mar-18	18,585	19,413	611	2,609	16-Dec-18	20,671	21,581	690	2,785
25-Mar-18	18,145	18,899	569	2,519	23-Dec-18	20,438	21,538	362	2,769
01-Apr-18	18,085	19,151	567	2,472	30-Dec-18	20,056	20,920	528	2,613
08-Apr-18	17,797	18,355	471	2,450	06-Jan-19	20,810	21,624	570	2,741
15-Apr-18	17,012	18,019	496	2,396	13-Jan-19	21,523	22,339	547	2,868
22-Apr-18	16,551	16,841	531	2,355	20-Jan-19	21,033	21,688	483	2,856
29-Apr-18	16,513	16,859	721	2,331	27-Jan-19	20,879	21,830	404	2,862
06-May-18	17,682	20,070	849	2,304	03-Feb-19	20,893	21,959	734	2,871
13-May-18	17,333	19,518	845	2,317	10-Feb-19	20,093	21,456	635	2,804
20-May-18	18,413	21,623	1,175	2,342	17-Feb-19	19,843	21,239	581	2,755
27-May-18	18,231	21,789	1,330	2,286	24-Feb-19	19,499	21,207	501	2,704
03-Jun-18	18,914	21,357	1,292	2,368	03-Mar-19	20,156	21,252	531	2,740
10-Jun-18	19,545	23,809	1,055	2,511	10-Mar-19	19,535	20,346	649	2,689
17-Jun-18	20,450	23,828	835	2,526	17-Mar-19	18,473	19,248	611	2,610
24-Jun-18	22,166	24,120	754	2,591	24-Mar-19	18,040	18,747	569	2,521
01-Jul-18	21,899	23,752	1,016	2,628	31-Mar-19	17,988	19,003	567	2,523
08-Jul-18	22,062	24,500	814	2,610	07-Apr-19	17,722	18,231	471	2,465
15-Jul-18	22,176	23,411	838	2,701	14-Apr-19	16,943	17,904	496	2,400
22-Jul-18	21,535	23,469	1,035	2,600	21-Apr-19	16,480	16,719	531	2,318
29-Jul-18	21,492	24,273	841	2,679	28-Apr-19	16,446	16,527	721	2,325
05-Aug-18	22,037	24,294	958	2,705	05-May-19	17,609	19,948	849	2,310
12-Aug-18	21,744	24,446	985	2,669	12-May-19	16,748	19,386	845	2,322
19-Aug-18	20,891	24,178	1,362	2,644	19-May-19	18,344	21,505	1,175	2,348
26-Aug-18	21,035	23,035	1,413	2,632	26-May-19	18,065	21,674	1,330	2,291
02-Sep-18	20,236	22,666	1,370	2,524	02-Jun-19	18,743	21,235	1,292	2,361
09-Sep-18	18,707	22,050	680	2,377	09-Jun-19	19,470	23,680	1,055	2,514
16-Sep-18	19,158	20,840	781	2,445	16-Jun-19	20,330	23,659	835	2,528
23-Sep-18	17,832	19,837	420	2,415	23-Jun-19	22,130	23,984	754	2,594
30-Sep-18	17,153	18,406	554	2,359	30-Jun-19	21,657	23,560	1,016	2,628

3.1 Actual Weather and Demand

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

September

- For the third year in a row, September's weather was significantly above normal. Based on average temperature, this was the third warmest September of the past fifty years. Last September was the fourth warmest and September 2015 was the second warmest.
- The September peak occurred on the second hottest day of the month as temperatures reached 32°C (in Toronto). The actual peak was 21,786 MW and occurred on Monday, September 25. This peak was lower than previous Septembers but it was also slightly cooler and much later in the month. Despite this, the September peak is currently the

annual peak. Demand response, including Peaksaver, and ICI were both active on this peak day.

- The weather-corrected peak for September was 18,138 MW, which is low by historical standards. However, it comes back into line after accounting for the demand response and the ICI impacts.
- Energy demand for the month was 10.7 TWh (10.2 TWh weather corrected), which are low by historical standards but consistent with the low demand numbers experienced in 2017.
- The minimum demand for the month was 10,487 MW, which is low by historical standards but in line with the 2017 experience. The minimum occurred in the early hours of Labour Day.
- Embedded generation for the month was 483 GWh, a decrease of 7.9% compared to the previous September. Almost all of the decline was attributable to significantly lower non-contracted generation.
- Wholesale customers' consumption fell by a considerable 10.6% compared to the previous September. All of the big six industrial segments (mining, chemicals, iron & steel, petroleum & refining, pulp & paper and motor vehicles) all showed significant year-over-year declines.

October

- October was warmer than normal. The warm weather from the end of September carried through into October.
- The month's peak demand occurred on October 4, which was the hottest day of the month. Generally, October is a cold weather peak month. For the 16 Octobers since market opening, only 3 have been hot weather peaking.
- The actual peak was 17,418 MW and the weather-corrected peak was 17,572 MW. Continuing the trend for 2017 both of these represent lows since market opening.
- Actual energy demand for the month was 10.4 TWh and weather-corrected energy demand was 10.5 TWh. Once again, both figures represent lows for October.
- The minimum demand of 10,534 MW occurred at 4 a.m. on Sunday October 22. This is the lowest October minimum since market opening.
- Embedded generation for the month was 533 GWh. This represents a huge 28 percent decrease over the previous October. Output from solar (4.9 percent) and water (32.5 percent) were up while wind was down (32.4 percent). Non-contracted embedded generation was 125 GWh.
- Wholesale customers' consumption increased 1.2 percent over the previous October. The iron and steel and motor vehicle manufacturing sectors were behind the increase.

November

- November was cooler than normal with an early taste of winter on Remembrance Day. Figure 3.6 shows how the temperature for November 2017 stacked up against history.

- The actual peak for the month was 19,115 MW occurring on Monday, November 27. It was the fourth coldest day of the month. The weather-corrected value was virtually the same at 19,073 MW. As was the case throughout 2017, these values represent the lowest since market opening.
- Energy demand for the month was 11.0 TWh (10.9 TWh weather-corrected). The actual is a slight increase over the past two Novembers, whereas the weather corrected value is virtually flat over the same time horizon.
- Minimum demand of 11,199 MW occurred Sunday, November 5 at 4 a.m. This was also the warmest day of the month. This value is the lowest November minimum since market opening.
- Embedded generation topped 497 GWh for the month, which represents a decrease of 17.8 percent compared to the previous November. Increases in output from wind (34.5 percent), hydro (38.2 percent) and non-contracted (60.9 percent) accounted for the jump in output.
- Wholesale customers' consumption increased 0.2 percent compared to the previous November. Motor vehicle manufacturing and iron and steel continued to account for the growth with most other major sectors had showing a decline.

2017 Fall Actuals

Overall, a warmer than normal fall led to two warm weather monthly peaks. Energy demand for the three months from September to November was down 1.0 percent compared with the same three months one year prior. After adjusting for the weather, demand for the three months showed a more significant, 2.2 percent decline.

Embedded generation for the fall was up 11 percent compared to the previous fall. Wind, hydro and non-contracted generation output were all up significantly while solar saw a small increase (1%). and hydro-electric output was up by nearly the same amount.

For the three months, wholesale customers' consumption posted a 3.0-percent decline compared to the previous fall. Consumption for the iron and steel sector showed strong growth, motor vehicle production load was flat but the remaining sectors showed declines compared to the previous fall.

Since the recession, there has been a shift towards less energy intensive industries such as construction, finance, retail and technology, resulting in an overall decrease in load consumption that is not attributed to an economic downturn.

The 2017 Q4 Outlook Tables contain several tables with historical data. They are:

- Table 3.3.1 Weekly Weather and Demand History Since Market Opening
- Table 3.3.2 Monthly Weather and Demand History Since Market Opening
- Table 3.3.3 Monthly Demand Data by Market Participant Role.

3.2 Forecast Drivers

3.2.1 Economic Outlook

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

Table 3.3.4 of the 2017 Q4 Outlook Tables presents the economic assumptions for the demand forecast.

3.2.2 Weather Scenarios

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

Table 3.3.5 of the 2017 Q4 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 changes to the ICI program this year have opened the door for participation from the commercial sector. Hospitals, office buildings, hotels, universities and other large commercial buildings with peaks greater than 1 MW can now minimize their electricity costs by shifting loads during the ICI peak day periods. The success of these changes from the perspective of the commercial sector comes back to their load flexibility and their ability to follow the system peaks. The commercial sector impacts are not visible to the IESO as all of these participants would be distributor customers. The ICI program is estimated to have reduced peak demand by about 1,300 MW in the summer of 2016 and with the changes to the program the expectation is that those savings will have increased in 2017.

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 now include Dispatchable Loads, Capacity-Based Demand Response (CBDR) and resources secured through the Demand Response (DR) auction. The PeaksaverPlus program expired at the end of September 2017. It was activated for the September peak. The expectation is that those PeaksaverPlus capacities will migrate to the Demand Response auction. Demand measures are treated as resources in the assessment and are further discussed in section 4.1.3. Demand reductions due to these programs are added back to the actual demand, and the forecast is based on demand prior to the impacts of these programs.

- End of Section -

4 Resource Adequacy Assessment

This section provides an assessment of the adequacy of resources to meet the forecast demand. When reserves are below required levels, with potentially adverse effects on the reliability of the grid, the IESO will reject outage requests based on their order of precedence. Conversely, an opportunity exists for additional outages when reserves are above required levels.

The existing installed generation capacity is summarized in Table 4.1. This includes capacity from new projects that have completed IESO's market registration process since the previous Outlook. The forecast capability at the Outlook peak is based on the firm resource scenario, which includes resources currently under commercial operation, and takes into account deratings, planned outages and allowance for capability levels below rated installed capacity.

Table 4.1: Existing Generation Capacity as of November 24, 2017

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Outlook Peak (MW)	Number of Stations	Change in Installed Capacity (MW)	Change in Stations
Nuclear	13,009	10,660	5	0	0
Hydroelectric	8,480	5,805	74	0	0
Gas/Oil	10,277	8,371	31	0	0
Wind	4,213	545	36	0	0
Biofuel	495	439	9	0	0
Solar	380	38	8	0	0
Total	**36,853**	**25,845**	**163**	**0**	**0**

4.1 Assessment Assumptions

4.1.1 Generation Resources

All generation projects that are scheduled to come into service, be upgraded or shut down within the Outlook period are summarized in Table 4.2. This includes generation projects in the IESO's Connection Assessment and Approval process (CAA), those that are under construction, as well as contracted resources. Details regarding the IESO's CAA process and the status of these projects can be found on the IESO's website below, under Application Status:

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

The estimated effective date in Table 4.2 indicates the date on which additional capacity is assumed to be available to meet Ontario demand or when existing capacity will be shut down. This information is current as of November 24, 2017. If a project is delayed, the estimated effective date will be the best estimate of the commercial operation date for the project that is available to the IESO by the cutoff date.

Table 4.2: Committed Generation Resources Status

Project Name	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered Firm (MW)	Capacity Considered Planned (MW)
Namewaminikan Hydro	Northwest	Water		Commercial Operation	10	10
Belle River Wind	West	Wind		Commercial Operation	100	100
Kapuskasing Generating Station	Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
North Bay Generating Station	Northeast	Gas	2017-Q4	Expiring Contract	-60	-60
Napanee Generating Station	East	Gas	2018-Q2	Under Development	0	985
North Kent Wind 1	West	Wind	2018-Q2	Under Development	0	100
Amherst Island Wind	East	Wind	2018-Q2	Under Development	0	75
Loyalist Solar Project	East	Solar	2018-Q3	Under Development	0	54
Douglas Generating Station	Toronto	Gas	2018-Q4	Expiring Contract	-122	-122
Whitby Cogeneration	Toronto	Gas	2019-Q2	Expiring Contract	-56	-56
Total					**-188**	**1,026**

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.

4.1.2 Generation Capability

Hydroelectric

A monthly forecast of hydroelectric generation output forecast is calculated based on median historical values of hydroelectric production and contribution to operating reserve during weekday peak demand hours. Through this method, routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data. Table 4.3 shows the historical hydroelectric median values calculated with data from May 2002 to March 2017. These values are updated annually to coincide with the release of the summer 18-Month Outlook.

Table 4.3: Monthly Historical Hydroelectric Median Values for Normal Weather Conditions

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical Hydroelectric Median Values (MW)	6,069	6,008	5,864	5,795	5,843	5,653	5,633	5,319	5,068	5,383	5,699	6,099

Thermal Generators

Thermal generators' capacity, planned outages and deratings are based on market participant submissions. Forced outage rates on demand are calculated by the IESO based on actual operations data. The IESO will continue to rely on market participant-submitted forced outage rates for comparison purposes.

Wind

For wind generation, the monthly Wind Capacity Contribution (WCC) values are used at the time of weekday peak. The specifics on wind contribution methodology can be found in the Methodology to Perform Long-Term Assessments. Table 4.4 shows the monthly WCC values. These values are updated annually to coincide with the release of the summer Outlook.

Table 4.4: Monthly Wind Capacity Contribution Values

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

Solar

For solar generation, the monthly Solar Capacity Contribution (SCC) values are used at the time of weekday peak. The specifics on solar contribution methodology can be found in the Methodology to Perform Long-Term Assessments. Table 4.5 shows the monthly SCC values that are updated annually to coincide with the release of the summer Outlook.

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

Table 4.5: Monthly Solar Capacity Contribution Values

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

4.1.3 Demand Measures

Both demand measures and load modifiers can impact demand but they differ in how they are treated within the Outlook. Demand measures, i.e., Dispatchable Loads, DR procured through an annual Demand Response Auction 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. The impacts of actual activations of demand measure are added back into the demand history prior to forecasting demand for future periods.

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

4.1.4 Firm Transactions

Capacity Backed Export

In November 2017, Quebec released an RFP for 200 MW with a commitment period of January and February, 2018. 125 MW of capacity is committed to Quebec during this period and is reflected in the outlook.

The New York Independent System Operator (NYISO) winter 2017/2018 capacity auction, held in September 2017, cleared 127 MW of Ontario capacity for the six-month commitment period from November 2017 to April 2018. The capacities cleared in the NYISO capacity auctions by Ontario generators are posted on the NYISO website. The cleared amount is reflected in the Outlook.

System Backed Export

As part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. In addition, Ontario will receive up to 2.3 terawatt-hours of clean energy annually. The imported energy will be targeting peak hours to help reduce greenhouse gas emissions in Ontario. The agreement includes the opportunity to cycle energy.

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

4.1.5 Summary of Scenario Assumptions

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

Table 4.6: Summary of Scenario Assumptions for Resources

	Planned Scenario	Firm Scenario
Total Existing Installed Resource Capacity (MW)	36,853	
New Generation and Capacity Changes (MW)	1,026	-188

The starting point of both scenarios is the existing installed resources shown in Table 4.1. The **planned scenario** assumes that all resources scheduled to come into service are available over the assessment period. The **firm scenario** only assumes resources that have reached commercial operation. The generator planned shutdowns or retirements that have high certainty of occurring in the future are also considered for both scenarios. The **firm** and **planned** scenarios also differ in their assumptions regarding the amount of demand measures. The **firm scenario** considers DR programs from existing participants only, while the **planned scenario** considers DR programs from future participants too. Submitted generator planned outages are reflected in both scenarios. Table 4.7 shows a snapshot of the forecast available resources, under the two scenarios, at the time of the summer and winter peak demands during the Outlook.

Table 4.7: Summary of Available Resources

Notes	Description	Winter Peak 2018 Firm Scenario	Winter Peak 2018 Planned Scenario	Summer Peak 2018 Firm Scenario	Summer Peak 2018 Planned Scenario	Winter Peak 2019 Firm Scenario	Winter Peak 2019 Planned Scenario
1	Installed Resources (MW)	36,843	36,853	36,843	36,853	36,721	36,853
2	Total Reductions in Resources (MW)	9,754	9,645	11,291	10,230	9,255	8,177
3	Demand Measures (MW)	621	621	690	764	582	754
4	Firm Imports (+) / Exports (-) (MW)	-752	-752	0	0	-500	-500
5	Available Resources (MW)	26,958	27,077	26,242	27,387	27,548	28,930

Notes on Table 4.7:

1. Installed Resources: the total generation capacity assumed to be installed at the time of the summer and winter peaks.
2. Total Reductions in Resources: the sum of deratings, planned outages, limitations due to transmission constraints and allowance for capability levels below rated installed capacity.
3. Demand Measures: the amount of demand expected to be available for reduction at the time of peak.
4. Firm Imports / Exports: the amount of expected firm imports and exports at the time of summer and winter peaks.
5. Available Resources: Installed Resources (line 1) minus Total Reductions in Resources (line 2) plus Demand Measures (line 3) and Firm Imports / Exports (line 4).

4.2 Capacity Adequacy Assessment

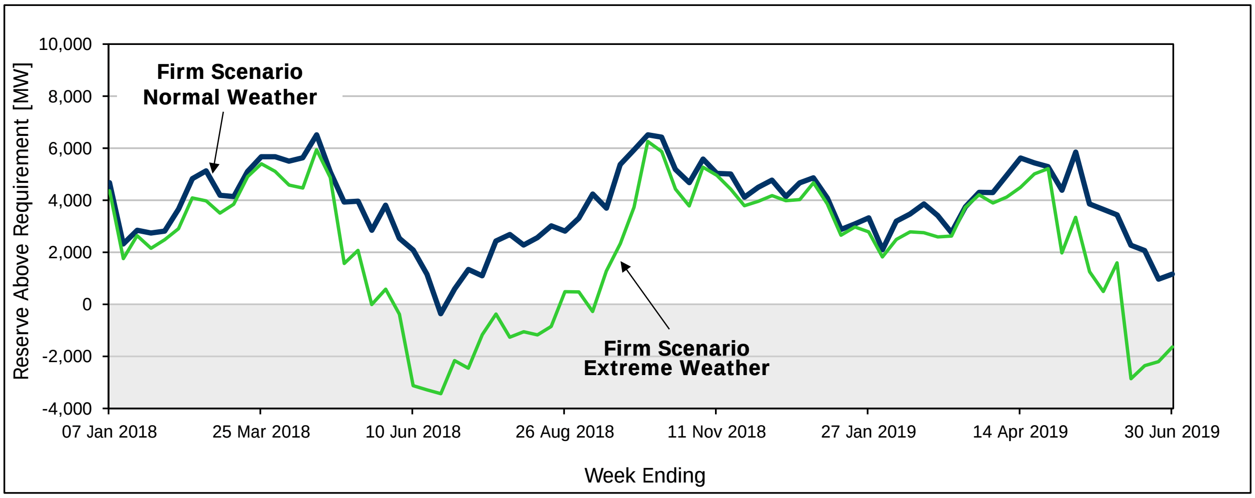
The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages and have been assessed as of October 27, 2017. The generation planned outages occurring during this Outlook period have been assessed as of November 24, 2017.

4.2.1 Firm Scenario with Normal and Extreme Weather

The **firm scenario** incorporates all existing capacity that had achieved commercial operation status as of November 24, 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 met throughout the entire Outlook period, save for one week. During extreme weather conditions, the reserve is lower than the requirement for a total of 18 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 reject some generator maintenance outage requests to ensure that Ontario demand is met during the summer peak periods. Therefore, generators expected to perform maintenance on their units during the summer should understand that those outages are at risk and are advised to review their planned maintenance plans and consider rescheduling them if they are critical for the continued operation of the units.

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

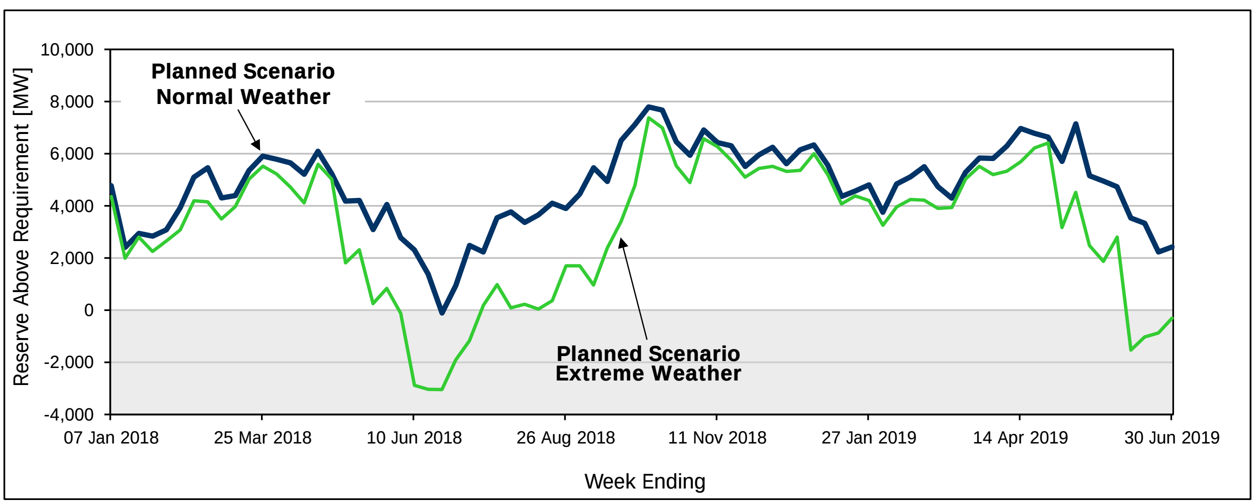


4.2.2 Planned Scenario with Normal and Extreme Weather

The **planned scenario** incorporates all existing capacity plus all capacity coming in service. Approximately 1,000 MW of net generation capacity is expected to connect to Ontario's grid over this Outlook period.

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

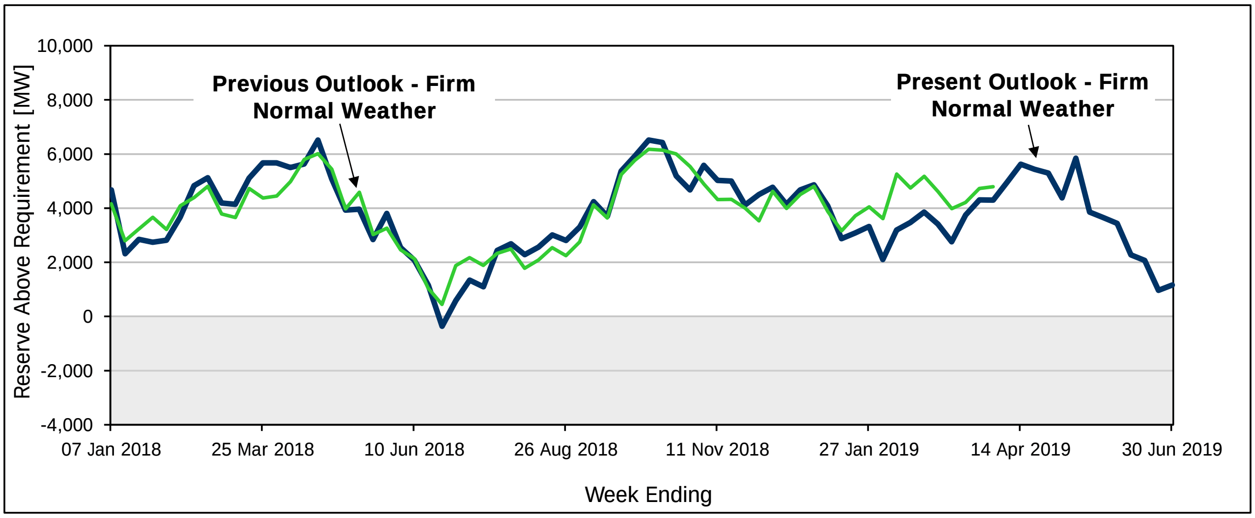
Figure 4.2: Normal vs. Extreme Weather: Planned Scenario RAR



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

Figure 4.3 provides a comparison between the forecast RAR values in the present Outlook and the forecast RAR values in the previous Outlook published on September 21, 2017. The difference is mainly due to changes in planned outages.

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



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

4.3 Energy Adequacy Assessment

This section provides an assessment of energy adequacy, the purpose of which is to determine whether Ontario has sufficient supply to meet its forecast energy demands and to highlight any potential concerns associated with energy adequacy within the period covered under this 18-Month Outlook. At the same time, the assessment estimates the aggregate production by each resource category to meet the projected demand based on assumed resource availability.

4.3.1 Summary of Energy Adequacy Assumptions

The Energy Adequacy Assessment (EAA) is performed using the same set of assumptions pertaining to resources expected to be available over the next 18 months as in the capacity assessment. Refer to Table 4.1 for the summary of Existing Generation Capacity and Table 4.2 for the list of Generation Resources Status for this information. The monthly forecast of energy production capability, based on the energy modelling results, is included in Table A7 of the 2017 Q4 Outlook Tables.

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

4.3.2 Results – Firm Scenario with Normal Weather

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

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

Zone	18-Month Energy Demand		18-Month Energy Production		Net Inter-Zonal Energy Transfer	Zonal Energy Demand on Peak Day of 18-Month Period	Available Energy on Peak Day of 18-Month Period
	TWh	Average MW	TWh	Average MW	TWh	GWh	GWh
Ontario	**203.6**	**15,538**	**203.6**	**15,538**	**0.0**	**445.0**	**564.9**
Bruce	1.0	78	70.0	5,340	69.0	1.3	135.5
East	12.7	973	15.4	1,176	2.7	26.8	66.8
Essa	11.7	892	3.5	264	-8.2	24.3	12.7
Niagara	5.8	440	19.6	1,493	13.8	13.3	41.7
Northeast	13.9	1,057	15.2	1,163	1.3	22.6	36.6
Northwest	5.3	406	5.1	389	-0.2	8.9	19.0
Ottawa	14.5	1,109	0.0	2	-14.5	25.4	2.3
Southwest	42.1	3,216	6.4	488	-35.7	92.2	25.9
Toronto	76.7	5,857	57.8	4,407	-18.9	183.1	159.7
West	19.8	1,510	10.7	815	-9.1	47.1	64.5

4.3.3 Findings and Conclusions

The EAA results indicate that Ontario is expected to have sufficient supply to meet its energy forecast during the 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 – Jan. 1, 2018, to Jun. 30, 2019

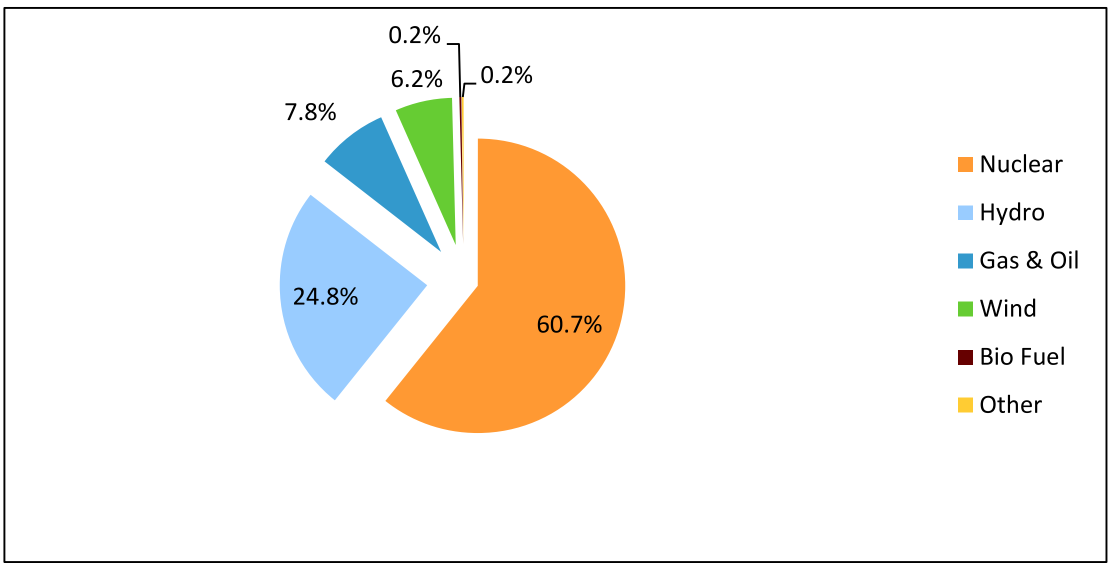


Figure 4.5: Monthly Production by Fuel Type – Jan. 1, 2017, to Jun. 30, 2019

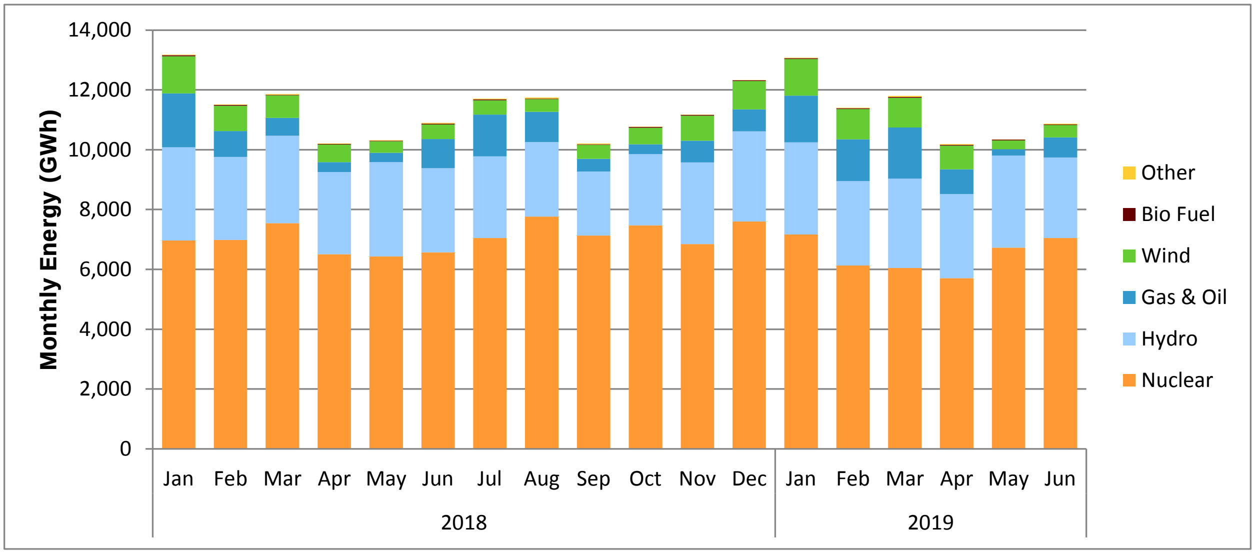


Table 4.9: Firm Scenario - Normal Weather: Ontario Energy Production by Fuel Type

Fuel Type (Grid Connected)	2018 (Jan 1 - Dec 31)	2019 (Jan 1 - Jun 30)	Total
	(GWh)	(GWh)	(GWh)
Nuclear	84,860	38,819	123,679
Hydro	32,994	17,469	50,463
Gas & Oil	9,525	6,388	15,913
Wind	7,997	4,728	12,725
Bio Fuel	291	145	436
Other (Solar & DR)	260	138	398
Total	**135,928**	**67,687**	**203,615**

4.4 Outage Assessment Methodology

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

- End of Section -

5 Transmission Reliability Assessment

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

Some areas have experienced load growth to warrant additional investments in new load-serving stations and reinforcements of local area transmission. Several local area transmission improvement projects are underway and will be placed in service during the timeframe of this Outlook. Many of these projects are a direct result of the IESO's regional planning process. As part of the Long Term Energy Plan implementation, the IESO will review and report on the regional planning process, taking into account lessons learned, and provide options and recommendations. Engagement on the IESO's Implementation Plan for the 2017 LTEP is underway and will continue during the Outlook period. These projects help relieve loadings on existing transmission infrastructure and provide additional capacity to serve future load growth.

5.1 Transmission Outages

The IESO's assessment of the transmission outage plans is shown in Appendix C, Tables C1 to C11. The methodology used to assess the transmission outage plans is described in the IESO document titled Methodology to Perform Long-Term Assessments. This Outlook contains transmission outage plans submitted to the IESO as of October 27, 2017.

5.2 Transmission System Adequacy

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

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

5.2.1 Toronto and Surrounding Area

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

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

In central Toronto, the expected completion date for Copeland TS is now Q2 2018, previously Q1 2018. The new station will allow some load to be transferred from John TS. This will help meet the short- and mid-term need for additional load-serving capacity in the area and will also enable the refurbishment of the facilities at John TS.

Since the last Outlook, Hydro One completed installation of two 230 kV in-line breakers at Holland TS. This will increase the load-meeting capability of the 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.

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

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

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

5.2.2 Bruce and Southwest Zones

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

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

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

5.2.3 Niagara Zone

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

5.2.4 East Zone and Ottawa Zone

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

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

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

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

5.2.5 West Zone

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

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

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

5.2.6 Northeast and Northwest Zones

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

Following the expansion of the Mattagami River plants, increased transfers are being experienced from the 230 kV system to the 115 kV system at Kapuskasing TS. These higher transfers, combined with the output from the 30 MW of new hydroelectric and solar projects in the Kapuskasing area, are expected to cause the thermal capability of the 115 kV transmission facility between Hunta and Kapuskasing to be exceeded. To ensure that the existing level of service reliability is maintained, it is expected that the output of the generating facilities in the Kapuskasing area will need to be limited whenever these high transfers occur. As recommended by the IESO, Hydro One is finalizing plans to reinforce the system in the Kapuskasing area in order to maintain supply reliability to local customers in the future. These plans are also expected to help accommodate higher transfers.

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

Transmission constraints may restrict resources in northwestern Ontario. This is evident in the constrained generation amounts shown for the Northwest zone in Tables A3 and A6. As a result, additional generation connection is restricted in this area. The upcoming East-West Tie expansion project may help address part of these constraints, but generation in Northwestern Ontario will continue to be limited by the remaining constraints in the Sault Ste. Marie and Sudbury areas. The East-West Tie expansion project is primarily required to ensure reliability of supply to the northwest while accommodating the forecast load growth for the region. The Leave to Construct applications for this project have been filed, and as requested by the Minister of Energy, on December 1st, 2017 the IESO completed and submitted an updated assessment of the need for the line, confirming the East-West Tie expansion project continues to be the least cost solution for meeting the reliability needs for the region. The IESO recommends that work continue to target an in-service date of Q4 2020.

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

- End of Section -

6 Operability

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

6.1 Storage

At the end of 2015, nine energy storage projects totaling 16.75 MW were offered 10-year contracts for capacity services as part of the Phase II energy storage competitive procurement process. Suppliers with Phase II Energy Storage Facility Agreements are developing their Projects and the IESO anticipates these facilities to be in Commercial Operation before December 2019.

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 Phase I projects are expected to become operational in the latter part of 2017 with the balance of projects entering operations during the first half of 2018.

6.2 Surplus Baseload Generation

Baseload generation is made up of nuclear, run-of-the-river hydroelectric and variable generation such as wind and solar. When the baseload supply is expected to exceed Ontario demand, the system is balanced using market mechanisms that include intertie 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 MWh Curtailments versus Ontario Demand shows the nuclear, wind and import curtailments from October 2016 to the end of September 2017. The lower demand, high nuclear availability and the increasing amount of wind and solar generation in the system resulted in a high volume of curtailment starting in the fall of 2016.

Figure 6.1 MWh Curtailments versus Ontario Demand

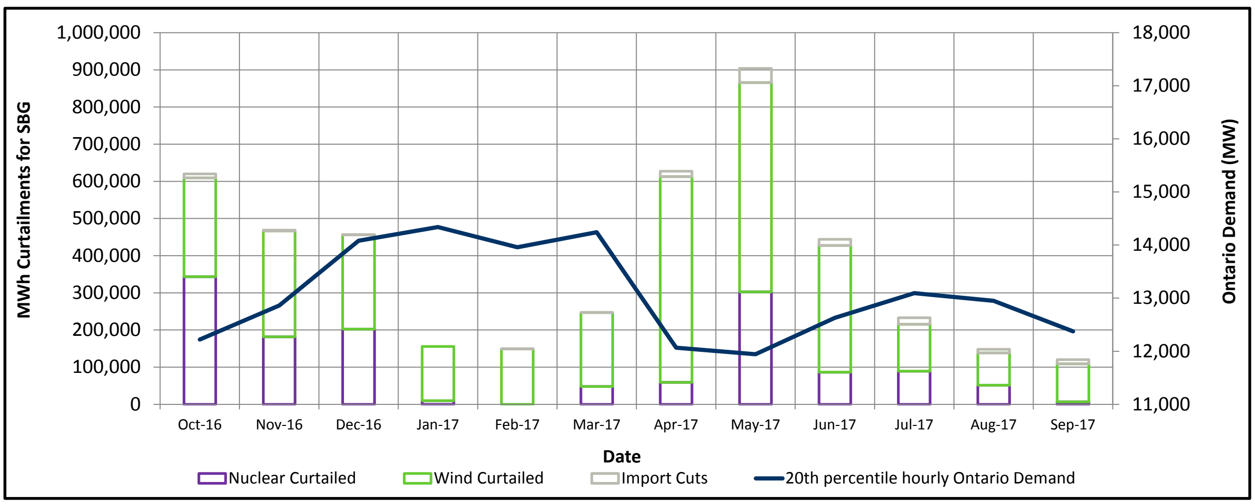
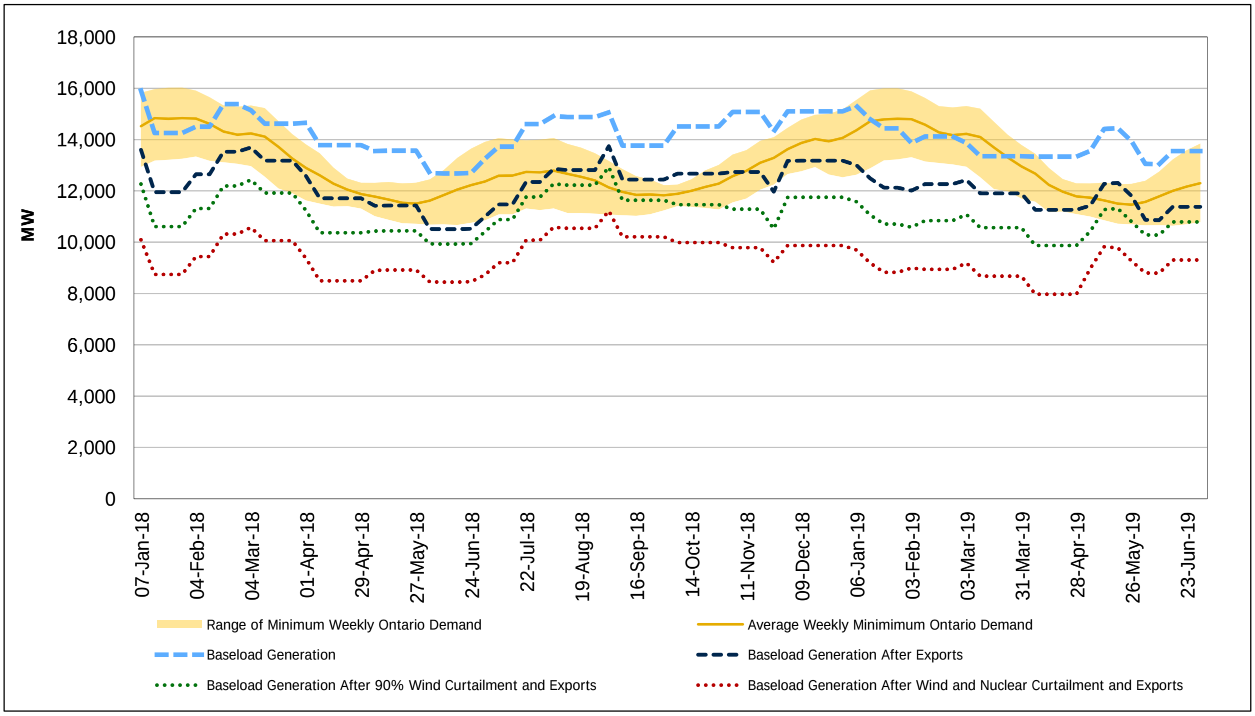


Figure 6.2 shows the forecast SBG for the next 18 months and the flexibility from nuclear, wind and solar generation and exports.

Figure 6.2 Minimum Ontario Demand and Baseload Generation



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

The baseload generation assumptions include the expected exports and run-of-river hydroelectric production, the latest planned outage information and in-service dates for new or refurbished generation. The expected contribution from self-scheduling and intermittent generation has also been updated to reflect the latest data. The information on the dispatch order of wind, solar and flexible nuclear resources can be found in Market Manual 4 Part 4.2. Output from commissioning units is explicitly excluded from this analysis due to uncertainty and the highly variable nature of commissioning schedules. Table 6.1 shows the monthly off-peak wind capacity contribution values calculated from actual wind output up to March 31, 2017. These values are updated annually to coincide with the release of the summer 18-Month Outlook.

Table 6.1: Monthly Off-Peak Wind Capacity Contribution Values

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

6.3 Operability Assessment

- The need for more flexible capability to respond to intra-hour differences between expected and actual variable generation production and expected and actual Ontario

demand continues to be a priority. As the output from the variable generation fleet continues to rise, the need for flexible resources capable of responding to IESO dispatch signals and increasing their output within 30 minutes continues to increase. At times, to maintain reliability, the IESO may take control actions such as, but not limited to, committing/constraining on dispatchable resources or manually adjusting the variable generation forecast. The need for more flexible capability to respond to intra-hour differences between expected and actual variable generation and expected and actual Ontario demand continues to be a priority. Beginning in June of 2016, the IESO has been engaging with stakeholders to explore a range of potential solutions for enhanced flexibility in the electricity system. To address flexibility needs in the interim, the IESO is proposing to schedule additional 30-minute operating reserve to represent flexibility need. Additional details of this proposal and stakeholder engagement information are available here:
http://www.ieso.ca/en/sector-participants/market-renewal/enabling-system-flexibility

- Energy price spikes have been observed in the last few shoulder seasons, but especially this spring, reflecting the need for and value of flexibility through an ability to respond to short-term supply-demand imbalances.

Regulation service acts to match total system generation to total system demand on a second-to-second basis and helps correct variations in power system frequency. The IESO plans to expand its capability to schedule more regulation as required. On June 29, 2017 IESO issued an RFP for incremental regulation capacity and on November 28, two contracts were offered representing ±55 MW of regulation capacity across two new energy storage facilities in Ontario. Under the 2017 regulation request for proposals (RFP), the IESO received 42 submissions representing approximately 350 MW of regulation capacity from a variety of existing and new build facilities, including energy storage and waterpower facilities. Once in service, the 55 MW procured through this process will complement the 100 MW of regulation service that is typically scheduled every hour to help ensure the reliable operation of the power system. Further information may be found on the 2017 Regulation RFP page here:

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

- End of Document -

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