18-Month Outlook

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

FROM APRIL 2018 TO SEPTEMBER 2019

Connecting Today.
Powering Tomorrow.

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 are below requirement, without reliance on imports, for a combined total of 24 weeks over the periods of June to September 2018 and 2019. Both generator and transmission outages may be placed at risk during this period. If extreme weather conditions occur, the IESO may, at that time, reject some generator maintenance outages to ensure that Ontario demand is met during the summer peak. Generators expecting to perform maintenance during the summer are advised to review their plans and consider rescheduling their outages.

While the Ontario transmission system is capable of serving the demand under the normal and extreme conditions forecast for the Outlook period, some outage combinations may create transmission limitations. In particular, transmission limitations were identified in the Flow East toward Toronto (FETT) interface due to concurrent planned outages submitted for generation resources located east of this interface. As a result of these transmission limitations, outages submitted for generation resources located east of the FETT interface and/or to circuits that impact the FETT interface may be at risk due to operability concerns.

Demand Forecast

Ontario's peak demand is expected to decline over the forecast horizon. Conservation savings, embedded generation output and the expanded Industrial Conservation Initiative (ICI) all work to offset any increase in demand due to population growth and economic expansion.

In 2017, energy demand experienced a significant decline. Demand is expected to show a slight increase in 2018 as stronger economic growth in the industrial and greenhouse sectors contribute to an increase in electricity consumption. At the same time, the growth in embedded generation capacity, a major offset to demand, has plateaued, but continues to be a significant driver of change in the sector.

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

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2018	22,002	24,458
Winter 2018-19	21,352	22,157
Summer 2019	21,965	24,338

Supply

About 1,340 MW of new supply – 1,000 MW of gas, 275 MW of wind, 50 MW of solar and 15 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 over 400 MW.

By the end of the Outlook period, embedded wind capacity will exceed 600 MW and embedded solar will surpass 2,300 MW. Overall contracted embedded capacity will reach over 3,400 MW by the end of Outlook horizon.

Transmission Adequacy

Ontario's transmission system is expected to continue to reliably serve Ontario's 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.

Operability

Conditions that may result in periods of surplus baseload generation are projected to continue over the Outlook period. It is expected that these conditions 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. To assist in addressing flexibility needs, the IESO is proposing to schedule additional 30-minute operating reserve to represent flexibility need in Spring 2018. 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 has procured 55 MW of regulation to expand its capability to schedule more regulation as required. Once in service, this additional regulation capacity will complement existing regulation service providers and allow the IESO to schedule 100-150MW each hour as needed 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

Outage Management

As a result of significant differences between normal and extreme weather forecasts in the summer and several enhancements to IESO's resource modelling, the IESO has greater visibility of generation availability and reserves above requirement in extreme weather conditions. Therefore, the IESO is moving towards approving outages using extreme weather instead of normal weather conditions. Participants should benefit from improved certainty in obtaining outages with this new criterion. The new outage approval criterion will allow more planned outages in the winter or shoulder months when there is more room for outages. IESO plans to begin using this criterion to assess requests to take planned outages that decrease resource availability over the period of May to September of 2019. Previously, the IESO used the normal weather forecast under the firm resource scenario plus up to 700 MW of imports to assess outages.

Over the last quarter, the IESO conducted a stakeholder engagement to obtain feedback on this change to outage approvals and plans to update the Market Manuals accordingly for the June

2018 release of changes. More information can be found on the stakeholder webpage available here:
http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/proposed-ieso-outage-approval-criteria

Changes to the 18-Month Outlook

The IESO thanks participants who provided feedback in late 2017 on the content and format of the 18 Month Outlook. This feedback will be incorporated into the 18 Month Outlook later this year. More information on this initiative including a summary of the feedback received can be found here:
http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/18-month-outlook-refresh.

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

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

Table of Contents

List of Tables

List of Figures

1 Introduction

This Outlook covers the 18-month period from April 2018 to September 2019 and supersedes the last Outlook released on December 12, 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. Due to uncertainties associated with various input assumptions, readers 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 used in this Outlook is based on actual demand, weather and economic data through to the end of December 2017. The demand forecast has been updated to reflect the most recent economic projections. Actual weather and demand data for January and February 2018 has also 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 23, 2018, the following generators completed the market registration process since the last Outlook:

- Namewaminikan Hydroelectric (10 MW)
- Belle River Wind (100 MW)

2.3 Updates to Transmission Outlook

Transmission outage plans that were submitted to the IESO's outage management system by January 26, 2018, were used for this Outlook.

2.4 Updates to Operability Outlook

The Outlook for surplus baseload generation (SBG) conditions over the next 18 months is based on generator outage plans submitted by market participants to the IESO's outage management system as of February 23, 2018.

- End of Section -

3 Demand Forecast

The IESO forecasts electricity demand on the IESO-controlled grid. This demand forecast covers the period April 2018 to September 2019 and supersedes the previous forecast released in December 2017. Tables of supporting information are contained in the 2018 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)
- 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 demand forecast found in this Outlook incorporates these impacts.

Grid-supplied energy demand has been fairly flat since the 2009 global economic recession with small variation year to year. In 2017, demand showed a more pronounced decline. This decline was due to the combined impacts of conservation and the continuing evolution of the Ontario economy towards less energy intensive activities. For 2018, demand growth is expected to be positive, albeit small, as the economic environment remains positive for industrial growth leading to increased demand from that sector. As well, growth is expected in the greenhouse industry, driven by the legalization of cannabis, which is an electricity-intensive agricultural commodity. The province will also see continued population growth into 2018, another which contributes to increasing demand levels.

Offsetting Ontario's growing demand are energy savings achieved through conservation efforts and contributions from distribution-connected (embedded) generators. In recent years, Ontario's economy has seen a transition from energy-intensive sectors – with the exception of mining – towards increasingly non-intensive sectors such as finance, technology and services. The longer term trends will see demand falling again in 2019. However, Bitcoin mining has the potential to increase electricity demand significantly as it is very energy-intensive, and anyone with internet access and suitable hardware can participate in mining. Bitcoin mining servers can be online very quickly and also have the ability to scale up and down just as fast. Other jurisdictions have seen the impacts of Bitcoin mining but Ontario has yet to see any measurable effects on the bulk electricity system.

Peak demands are subject to the same forces as energy demand, as described above, although 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, which are typically at night. 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, ICI impacts and prices will be the dominant factor in offsetting 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)
Summer 2018	22,002	24,458
Winter 2018-19	21,352	22,157
Summer 2019	21,965	24,338
Year	**Normal Weather Energy (TWh)**	**% Growth in Energy**
2006	152.3	-1.9%
2007	151.6	-0.5%
2008	148.9	-1.8%
2009	140.4	-5.7%
2010	142.1	1.2%
2011	141.2	-0.6%
2012	141.3	0.1%
2013	140.5	-0.6%
2014	138.9	-1.1%
2015	136.2	-1.9%
2016	136.2	0.0%
2017	132.3	-2.8%
2018 (Forecast)	133.8	1.1%
2019 (Forecast)	133.2	-0.4%

Table 3.2: Weekly Energy and Peak Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)	Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
01-Apr-18	17,998	19,103	567	2,468	06-Jan-19	20,652	21,447	570	2,721
08-Apr-18	17,670	18,246	471	2,440	13-Jan-19	21,352	22,157	547	2,844
15-Apr-18	16,908	18,016	496	2,388	20-Jan-19	20,853	21,547	483	2,833
22-Apr-18	16,478	16,798	531	2,348	27-Jan-19	20,745	21,666	404	2,840
29-Apr-18	16,461	16,849	721	2,327	03-Feb-19	20,758	21,798	734	2,847
06-May-18	17,574	20,007	849	2,298	10-Feb-19	19,952	21,274	635	2,783
13-May-18	17,205	19,484	845	2,307	17-Feb-19	19,744	21,113	581	2,735
20-May-18	18,349	21,588	1,175	2,334	24-Feb-19	19,346	21,036	501	2,684
27-May-18	18,097	21,771	1,330	2,283	03-Mar-19	20,050	21,131	531	2,722
03-Jun-18	18,817	21,308	1,292	2,359	10-Mar-19	19,421	20,202	649	2,667
10-Jun-18	19,514	23,791	1,055	2,503	17-Mar-19	18,374	19,114	611	2,590
17-Jun-18	20,342	23,770	835	2,518	24-Mar-19	17,890	18,658	569	2,503
24-Jun-18	21,874	24,129	754	2,582	31-Mar-19	17,908	18,910	567	2,511
01-Jul-18	21,726	23,668	1,016	2,615	07-Apr-19	17,583	18,086	471	2,447
08-Jul-18	21,938	24,458	814	2,595	14-Apr-19	16,855	17,865	496	2,385
15-Jul-18	22,002	23,295	838	2,683	21-Apr-19	16,423	16,642	531	2,304
22-Jul-18	21,403	23,380	1,035	2,584	28-Apr-19	16,412	16,417	721	2,314
29-Jul-18	21,364	24,186	841	2,660	05-May-19	17,516	19,851	849	2,297
05-Aug-18	21,936	24,229	958	2,693	12-May-19	16,634	19,316	845	2,304
12-Aug-18	21,650	24,384	985	2,658	19-May-19	18,298	21,436	1,175	2,333
19-Aug-18	20,832	24,167	1,362	2,635	26-May-19	17,998	21,623	1,330	2,281
26-Aug-18	20,877	22,909	1,413	2,615	02-Jun-19	18,714	21,153	1,292	2,344
02-Sep-18	20,088	22,605	1,370	2,508	09-Jun-19	19,457	23,629	1,055	2,498
09-Sep-18	18,607	21,973	680	2,359	16-Jun-19	20,232	23,563	835	2,512
16-Sep-18	19,007	20,737	781	2,425	23-Jun-19	21,855	23,961	754	2,575
23-Sep-18	17,627	19,720	420	2,392	30-Jun-19	21,544	23,436	1,016	2,607
30-Sep-18	17,001	18,291	554	2,339	07-Jul-19	21,965	24,338	814	2,584
07-Oct-18	17,285	17,474	786	2,381	14-Jul-19	21,700	23,441	838	2,670
14-Oct-18	17,125	17,434	507	2,360	21-Jul-19	21,313	23,541	1,035	2,571
21-Oct-18	17,395	17,869	392	2,404	28-Jul-19	21,335	23,931	841	2,646
28-Oct-18	17,518	18,088	318	2,446	04-Aug-19	21,867	24,054	958	2,681
04-Nov-18	17,843	18,432	416	2,460	11-Aug-19	21,568	24,201	985	2,651
11-Nov-18	18,779	19,277	601	2,557	18-Aug-19	20,767	24,004	1,362	2,630
18-Nov-18	19,025	19,822	342	2,569	25-Aug-19	20,726	22,658	1,413	2,607
25-Nov-18	19,465	20,269	607	2,644	01-Sep-19	19,979	22,392	1,370	2,503
02-Dec-18	19,797	20,887	409	2,686	08-Sep-19	18,542	21,805	680	2,352
09-Dec-18	19,949	21,148	555	2,714	15-Sep-19	18,902	20,560	781	2,420
16-Dec-18	20,491	21,387	690	2,767	22-Sep-19	17,483	19,511	420	2,386
23-Dec-18	20,263	21,359	362	2,748	29-Sep-19	16,913	18,131	554	2,336
30-Dec-18	19,872	20,736	528	2,590	06-Oct-19	17,173	17,212	786	2,377

3.1 Actual Weather and Demand

Since the last forecast, the actual demand and weather data for December 2017, as well as January and February 2018 have been recorded.

December 2017

- The weather experienced throughout Ontario in December 2017 was slightly colder than normal, with several below seasonal days. Based on the monthly average temperature, it was the twenty-third coldest month of December in the past 50 years.
- The peak occurred on December 11, which was only the thirteenth coldest day of the month with temperatures reaching -4°C (in Toronto). The top six coldest days in December 2017 did not set a demand peak as they occurred over the holiday break, from

Boxing Day to New Year's Eve. On Monday, December 11, 2017 the peak demand was 20,306 MW, which is lower than previous December's. This is because the peak-day temperature was much warmer than previous December peak days.

- The weather-corrected peak for December was 21,026 MW, which is typical for a post-recession December.
- Energy demand for December 2017 was 12.3 TWh (11.9 TWh weather corrected). Both the actual and weather corrected values are comparatively low from a historical perspective which has been consistent throughout 2017.
- The minimum demand for the month was 12,093 MW, which is on the high side of historical standards. Typically minimum demand levels occur over the (statutory?) holiday period but with the very cold temperatures the minimum occurred on a much warmer Sunday earlier in the month (December 3 at 4 a.m).
- Embedded generation for the month was 404 GWh, a decrease of 8.1 percent compared to the previous December. Water and wind output was up, but offset by larger declines in solar and non-contracted generation compared to the previous year.
- Wholesale customers' consumption increased by 0.4 percent compared to the previous December. With the exception of pulp and paper, all the major sectors increased their consumption compared to the previous year.

January 2018

- January 2018 was colder than normal. The cold weather from the end of December carried into the beginning of January. Milder temperatures later in the month moderated the monthly average temperature.
- The month's peak demand occurred on Friday, January 5, which was the second coldest day of the month. The coldest day was the following day, Saturday, January 6. However, since it occurred over a weekend it was unlikely to lead to a demand peak.
- The actual peak was 20,906 MW and the weather-corrected peak was 20,229 MW. The actual peak was low by historical standards and the weather-corrected was the lowest January since the market opening in 2002. Class A customers were active on January 5 reducing their demand and, in turn, the peak demand.
- Actual energy demand for the month was 12.7 TWh and weather-corrected energy demand was 12.2 TWh. Both of these demand figures represent near all-time lows.
- The minimum demand of 12,453 MW occurred at 4 a.m. on Sunday, January 28. This was one of the warmest days of the month. The minimum was low by historical standards.
- Embedded generation for the month was 534 GWh. This represents a 14 percent increase over the previous January. Output from solar (3.7 percent) and water (26.7 percent) were up while wind was down (23.3 percent).
- Wholesale customers' consumption decreased 0.6 percent over the previous January. Iron and steel, which ended 2017 on a strong note, but slowed in January while the pulp and paper and motor vehicle manufacturing sectors were up over the previous January.

February

- Overall, February was warmer than normal. Each month has warm and cold days. For February, the cold days were near normal whereas the milder days were much warmer than normal.
- The actual peak for the month was 20,076 MW occurring on Monday, February 5. It was the second coldest day of the month. The weather-corrected value was virtually the same at 20,081 MW. Both of these values represent low values for February.
- Energy demand for the month was 11.0 TWh (11.2 TWh weather-corrected). Both are an increase over February 2017 but are low by historical standards.
- Minimum demand of 12,716 MW occurred Sunday, February 25 at 3 a.m. This was one of the warmest days of the month. Once again, it was higher than the previous February but otherwise low by historical standards.
- Embedded generation topped 497 GWh for the month, which represents an increase of 0.7 percent compared to the previous February. Increases in output from wind (45.1 percent), hydro (12.2 percent) and solar (5.5 percent) were offset by declines in the amount of non-contracted generation reported (-36.5%).
- Wholesale customers' consumption decreased 0.6 percent for the second consecutive month. Consumption was up in motor vehicle manufacturing and pulp and paper while most the other major consuming sectors were down.

2017-18 Winter Actuals

Overall, the winter weather was colder than normal due to a colder than normal January. Energy demand for the three months from December to February was up 3.6 percent compared with the same three months one year prior. After adjusting for the weather, demand for the three months showed a more modest, 1.0 percent increase.

Embedded generation for the fall was up 2.4 percent compared to the previous winter. Increases in hydro output (up 27.9%) and wind (8.1) offset reductions in solar, biomass and non-contracted generation.

For the three months, wholesale customers' consumption posted a decline of 0.3 percent compared to the previous winter. Mining was the only sector of the big six (Mining, Pulp and Paper, Chemicals, Refining, Iron and Steel and Motor Vehicle Manufacturing) that showed a year over year decline. However, since it is the largest sector the declines in mining outweighed the growth in the remaining five.

Since the recession, there has been a shift in the economy towards less energy intensive industries such as construction, finance, retail and technology. The large energy consuming sectors remain relatively flat.

The 2018 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

The economic environment remains positive for the Ontario economy. A strong U.S. economy, a low Canadian dollar and, low interest rates are all favourable to Ontario's export-oriented industrial sector. Strong growth in the greenhouse industry as the result of the legalization of cannabis will lead to an increase in electricity demand. Ontario has 48 of the 89 licensed production facilities. Since the United States is the largest consumer of Ontario exports, there is a downside economic risk with the potential disruption of NAFTA and/or trade disputes.

Table 3.3.4 of the [2018 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.

Table 3.3.5 of the [2018 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 Industrial Conservation Initiative (ICI). TOU rates incent consumers to reduce loads during peak demand periods by either shifting to off-peak periods or reducing overall consumption. 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 in 2017 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 reduce their electricity costs by shifting loads during the ICI peak day periods. These changes enable the commercial sector to have greater load flexibility and the ability to follow the system peaks. The commercial sector impacts are not visible to the IESO as these participants, based on size, would be distribution-level customers. The ICI year runs from May to the following April and as such reporting for the May 2017 to April 2018 timeframe had not concluded when this report was created. Based on preliminary data, the initial estimate of the ICI impact for a peak day is a demand reduction of 1,400 MW.

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. Demand measures are treated as peak 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. Resource adequacy is one of the reliability considerations used for approving outages. When reserves are below required levels, with potentially adverse effects on the reliability of the grid, the IESO will reject outage requests based on their order of precedence. Conversely, an opportunity can exist for additional outages when reserves are above required levels, provided other factors such as local considerations, operability or transmission security do not pose a reliability concern. In those cases, the IESO may place an outage at risk signaling to the facility owner to consider rescheduling the outage.

The existing installed generation capacity is summarized in Table 4.1. This includes capacity from new projects that have completed 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 23, 2018

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	8,472	5,793	74	-8	0
Gas/Oil	10,277	8,337	31	0	0
Wind	4,313	545	37	100	1
Biofuel	495	439	9	0	0
Solar	380	38	8	0	0
Total	**36,945**	**25,812**	**164**	**92**	**1**

4.1 Assessment Assumptions

4.1.1 Generation Resources

All generation projects that are scheduled to come into service, or those scheduled to be upgraded or shut down within the Outlook period are summarized in Table 4.2. This includes generation projects in the IESO's Connection Assessment and Approval process (CAA), those 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 February 23, 2018. 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)	Planned (MW)
North Kent Wind 1	West	Wind	2018-Q2	Under Development	0	100
Yellow Falls	Northeast	Hydro	2018-Q2	Under Development	0	16
Amherst Island Wind	East	Wind	2018-Q3	Under Development	0	75
Napanee Generating Station	East	Gas	2018-Q3	Under Development	0	985
Douglas Generating Station	Toronto	Gas	2018-Q4	Expiring Contract	-122	-122
Loyalist Solar Project	East	Solar	2018-Q3	Under Development	0	54
Whitby Cogeneration	Toronto	Gas	2019-Q2	Expiring Contract	-56	-56
Total					**-178**	**1,052**

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, demand response 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 measures are added back into the demand history prior to forecasting demand for future periods.

The December 2017 DR auction procured 570.7 MW for the summer six-month commitment period beginning on May 1, 2018, and 712.4 MW for the winter six-month commitment period beginning on November 1, 2018. The DR capacity acquired through the DR auction is reflected in the Outlook.

4.1.4 Firm Transactions

Capacity Backed Export

The New York Independent System Operator (NYISO) summer 2018 capacity auction will be held at the end of March 2018. Up to 453 MW may be allowed by NYISO from Ontario for this period. The IESO assesses the capacity export requests from participants and determines how much will be approved to participate in NYISO's auction based on the resource adequacy assessment under firm resource, extreme weather scenario. The capacities cleared in the NYISO capacity auctions by Ontario generators are posted on the NYISO website. The 18 Month Outlook reflects the cleared amounts upon completion of the auction.

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.

As part of the capacity exchange agreement, 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)	36,945	
New Generation and Capacity Changes (MW)	1,052	-178

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	Summer Peak 2018		Winter Peak 2019		Summer Peak 2019	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	36,945	37,061	36,823	37,999	36,767	37,997
2	Total Reductions in Resources (MW)	11,375	10,876	10,509	10,514	10,382	10,530
3	Demand Measures (MW)	630	630	793	793	533	533
4	Firm Imports (+) / Exports (-) (MW)	0	0	-500	-500	0	0
5	Available Resources (MW)	26,200	26,815	26,607	27,778	26,917	27,999

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

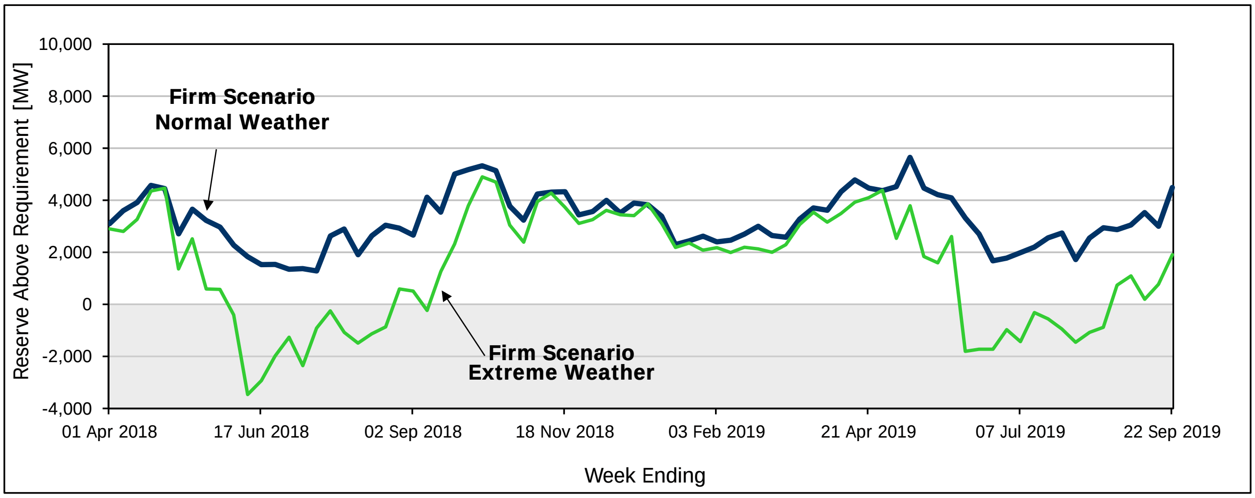
The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages and have been assessed as of January 16, 2018. The generation planned outages occurring during this Outlook period have been assessed as of February 23, 2018.

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 February 23, 2018.

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 24 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

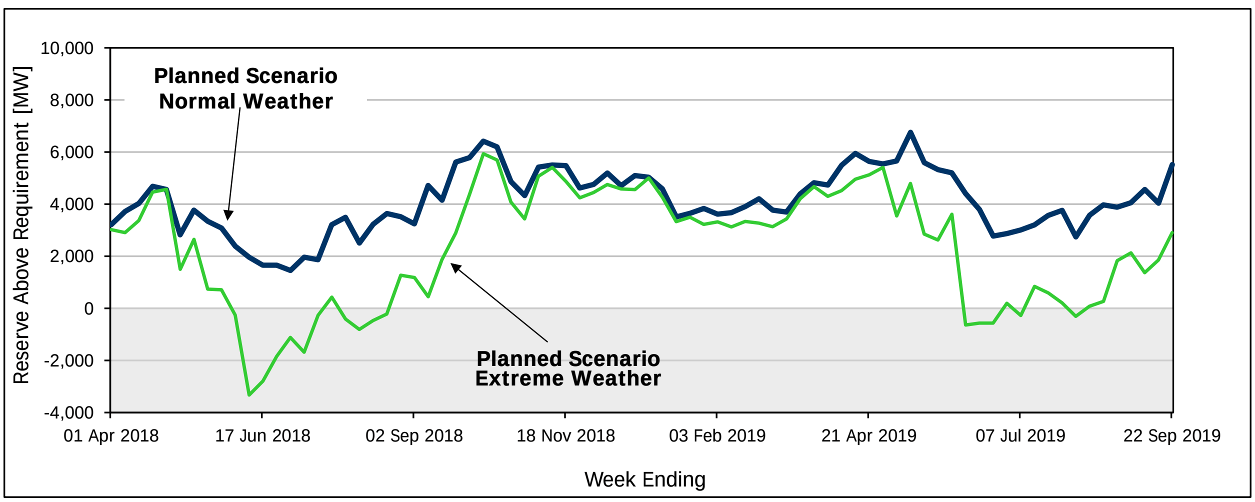


4.2.2 Planned Scenario with Normal and Extreme Weather

The **planned scenario** incorporates all existing capacity plus all capacity coming in service. Approximately 1,100 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.

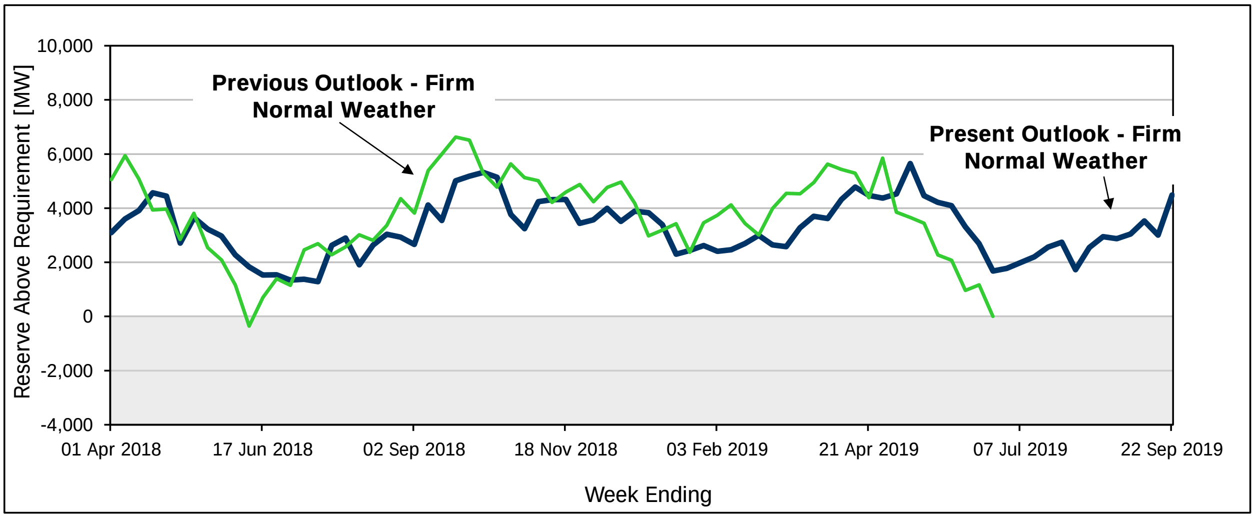
Figure 4.2: Normal vs. Extreme Weather: Planned Scenario RAR



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 12, 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	**197.9**	**15,051**	**197.9**	**15,051**	**0.0**	**441.5**	**564.9**
Bruce	1.0	75	68.3	5,194	67.3	1.4	135.5
East	12.4	940	14.7	1,115	2.3	26.9	66.8
Essa	11.2	850	3.0	226	-8.2	24.2	12.6
Niagara	5.6	427	19.1	1,451	13.5	13.4	41.3
Northeast	14.4	1,095	14.5	1,100	0.1	24.7	37.3
Northwest	5.5	415	4.6	347	-0.9	9.4	18.9
Ottawa	11.5	875	0.0	2	-11.5	25.1	2.3
Southwest	41.2	3,136	5.5	417	-35.7	90.0	25.9
Toronto	75.4	5,732	59.9	4,552	-15.5	179.9	159.7
West	19.8	1,505	8.5	648	-11.3	46.5	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 – Apr. 1, 2018, to Sep. 30, 2019

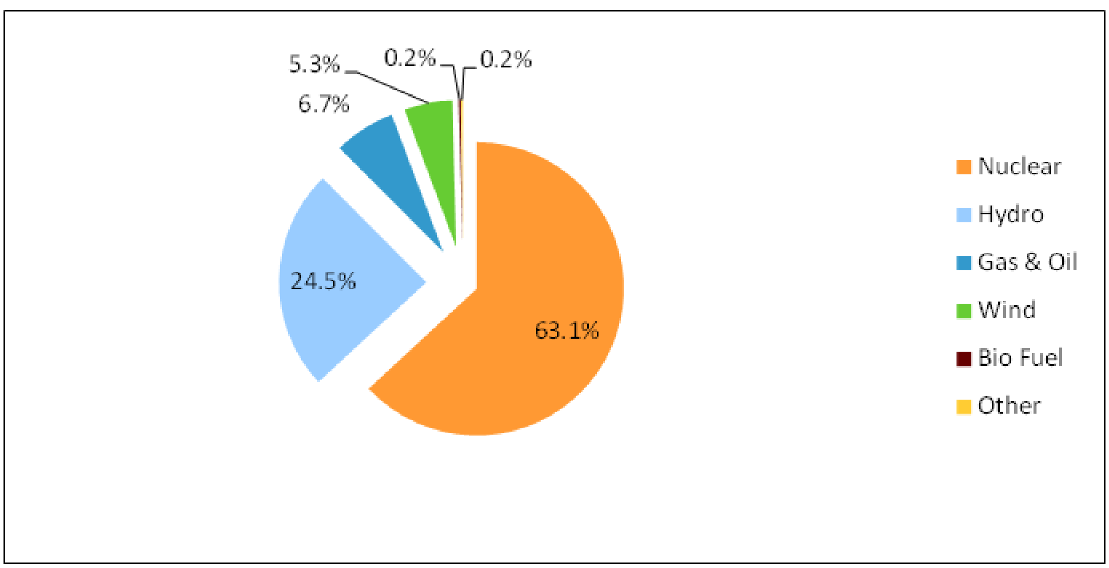


Figure 4.5: Monthly Production by Fuel Type – Apr. 1, 2018, to Sep. 30, 2019

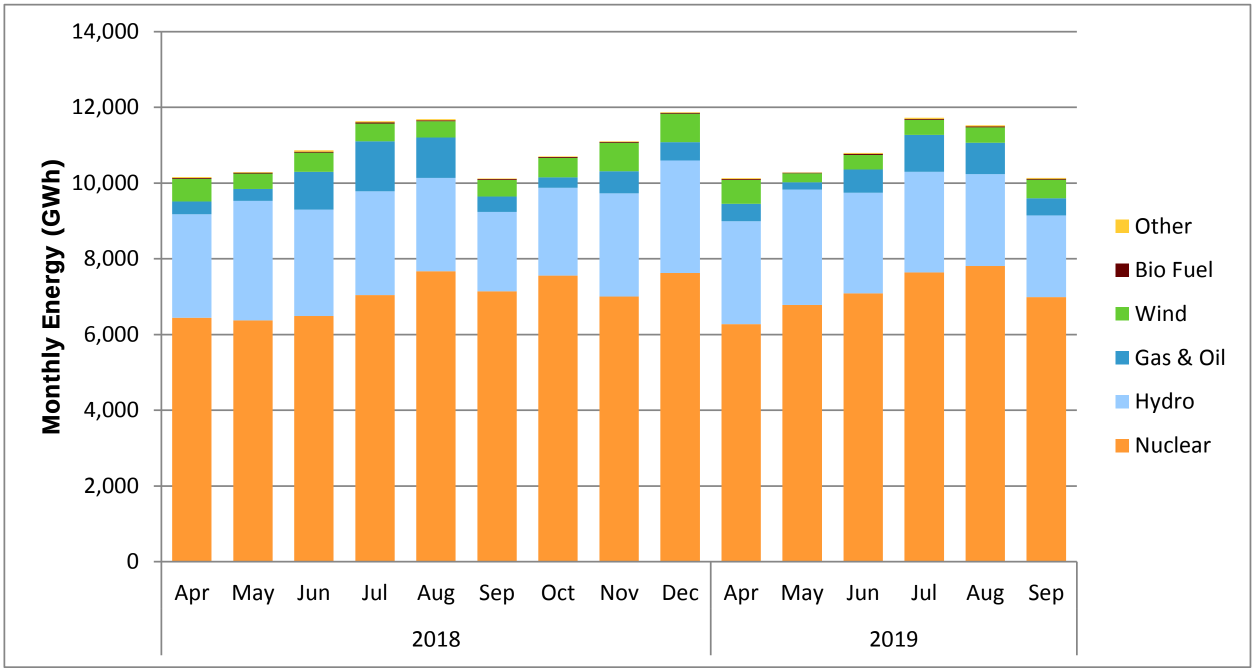


Table 4.9: Firm Scenario - Normal Weather: Ontario Energy Production by Fuel Type

Fuel Type (Grid Connected)	2018 (Apr 1 - Dec 31) (GWh)	2019 (Jan 1 - Sep 30) (GWh)	Total (GWh)
Nuclear	63,660	61,210	124,870
Hydro	23,997	24,456	48,453
Gas & Oil	5,548	7,812	13,360
Wind	4,809	5,630	10,438
Bio Fuel	217	212	429
Other (Solar & DR)	195	201	396
Total	**98,426**	**99,520**	**197,946**

4.4 Outage Assessment Methodology

Over the past couple of years, the IESO enhanced the generation availability forecast of hydroelectric and thermal generators in the extreme weather scenario. The performance of thermal generators was adjusted to account for differences in ambient temperature between normal and extreme weather conditions. The performance of hydroelectric generators was also adjusted to account for seasonal low water conditions. Additionally, the spread between normal and extreme weather forecasts is very pronounced during the May to September timeframe. The resource modelling enhancements allowed us to have greater visibility of generation availability, and as a result, the IESO has proposed improvements to the outage approval process through using extreme weather instead of normal weather conditions. This outage approval criterion will increase resource availability during May to September, where resource deficits have been identified in extreme weather conditions in the 18-Month Outlook. The new criterion will further encourage outages to be scheduled when there are sufficient resources forecast to be available using the firm resource scenario plus up to 2,000 MW of imports under the extreme weather forecast. Participants should benefit from improved certainty in obtaining outages with this new criterion and allow more planned outages in the winter or shoulder months when there is more room for outages.

The IESO plans to begin using this criterion to assess requests to take planned outages that decrease resource availability over the period of May to September of 2019. Previously, the IESO used the normal weather forecast under the firm resource scenario plus up to 700 MW of imports to assess outages.

Over the last quarter, the IESO conducted a stakeholder engagement to obtain feedback on this change to outage approvals and plans to update the Market Manuals accordingly for the June 2018 release of changes. More information can be found on the stakeholder webpage available here:
http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/proposed-ieso-outage-approval-criteria

- End of Section -

5 Transmission Reliability Assessment

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

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

5.1 Transmission Outages

The IESO's assessment of the transmission outage plans is shown in Appendix C, Tables C1 to C11. The methodology used to assess the transmission outage plans is described in the IESO document titled Methodology to Perform Long-Term Assessments. This Outlook contains transmission outage plans submitted to the IESO as of January 26, 2018.

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. While the Ontario transmission system is capable of serving the demand under the normal and extreme conditions forecast for the Outlook period, some outage combinations can create transmission limitations. In particular, transmission limitations have been identified in the Flow East toward Toronto (FETT) interface during the 18-month Outlook period due to concurrent planned outages submitted for generation resources located east of this interface. These transmission limitations may cause bottling of generation resources West of FETT, thus reducing the operating reserve available to restore the reliability of the power system following contingencies in this interface. As a result of these transmission limitations, outages submitted for generation resources located East of FETT may be at risk due to operability concerns.

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 across 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 has changed from Q2 to Q3 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.

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 has changed from Q2 2019 to Q2 2021. 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 completed in 2020 Q2, previously 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

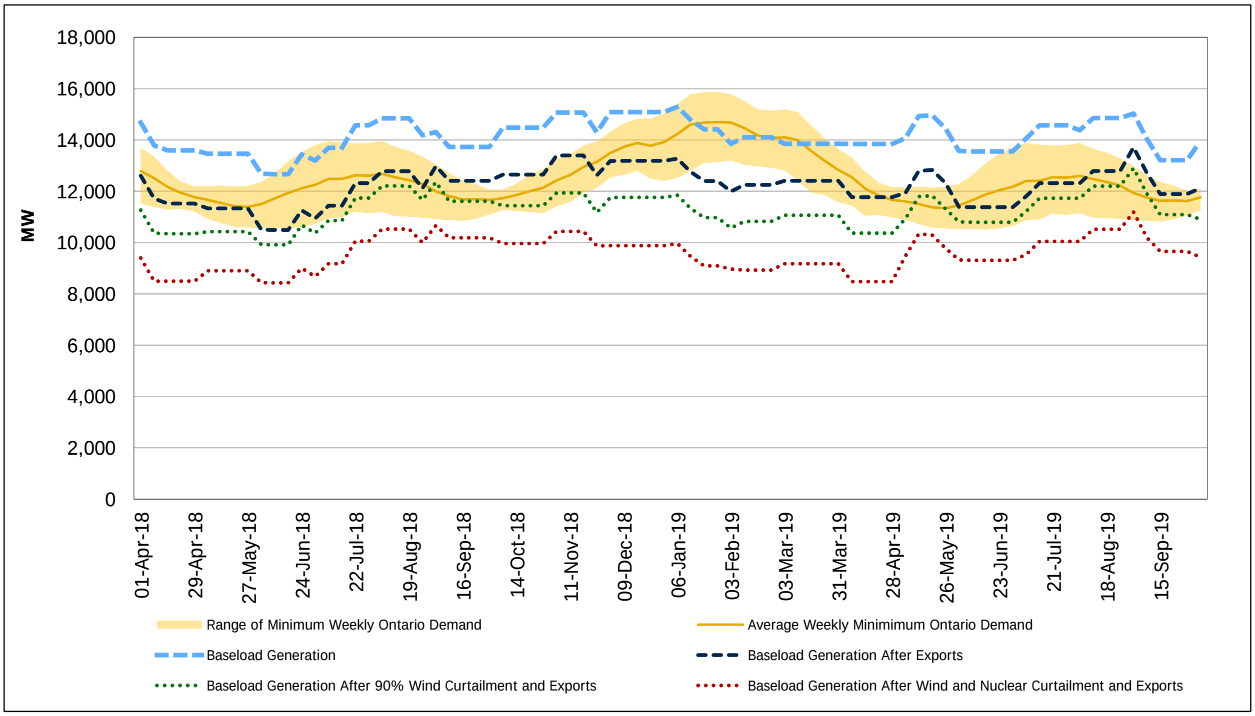
At the end of 2015, nine energy storage projects totaling 16.75 MW were offered 10-year contracts for capacity services as part of the Phase II energy storage competitive procurement process. Suppliers with Phase II Energy Storage Facility Agreements are developing their Projects and the IESO anticipates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

This complements the approximately 34 MW of grid energy storage procured in the earlier in Phase I energy storage program by the IESO to offer ancillary services to support grid reliability. Once these 11 facilities become operational, they 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 while providing ancillary services. The first Phase I projects are now commissioning their facilities and are expected to start entering service beginning in 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 potential surplus conditions. These actions usually, but not always, occur when Ontario demand is at its lowest.

Figure 6.1 Minimum Ontario Demand and Baseload Generation



Ontario will continue to experience potential surplus baseload conditions during the Outlook period, which 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. The IESO continues to make progress on increasing the 30-minute operating reserve requirement to address flexibility needs by implementing changes to the IESO Market Rules and Market Manuals. The IESO expects to make use of the increased 30-minute operating reserve in spring 2018. Additional details of this proposal and stakeholder engagement information are available here:
http://www.ieso.ca/en/sector-participants/market-renewal/enabling-system-flexibility

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. To address needs for additional regulation, the IESO completed an RFP for incremental regulation capacity in late 2017. Once in service, this additional regulation capacity will complement existing regulation service providers and allow the IESO to schedule 100-150MW each hour as needed 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 -

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca
@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/ieso

Connecting Today.
Powering Tomorrow.