Ontario Demand Forecast

DECEMBER 12, 2017

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Executive Summary

The IESO is responsible for forecasting electricity demand in Ontario and for assessing whether transmission and generation facilities are adequate to meet Ontario's needs. This document presents the electricity demand forecast for the period from January 2018 to June 2019 and supersedes the previous forecast released in September 2017.

Economic Outlook

The Ontario economy has shown considerable growth and strength in 2017. However, that has not translated into increased electricity demand. Much of that is attributable to where the growth in coming from. Construction, services and technology have been strong but that doesn't lead to higher electricity demand. Job growth and increased profits are certainly positives for the economy but lower industrial export numbers has a more direct impact on energy demand.

Over the forecast horizon, the outlook for the Ontario economy remains positive. Strong economic fundamentals of low interest rates, a competitive dollar and strong U.S. growth should benefit Ontario's economy.

Many industries in the province are near full capacity, which could lead to higher investment and expansion should uncertainty around trade issues be resolved in the near future. The termination of NAFTA would have a disproportionate impact on Ontario, compared to other provinces due to our industrial make-up and deep rooted trade relationships with the U.S. Trade deals like the Trans Pacific Partnership (TPP), the Comprehensive Economic and Trade Agreement (CETA) and a potential free trade deal with China would help cushion the blow further out in the future should NAFTA negotiations prove unsuccessful.

In the near term Ontario should continue to see broad-based employment growth which helps stimulate consumer spending, the largest part of the economy. Despite a cooler housing market consumer sentiment should remain strong.

Over the forecast horizon Ontario will see increased electricity demand from the burgeoning greenhouse sector. Cannabis legalization will also lead to increased production of an electricity-intensive crop.

There remain significant risks to the near-term forecast. Debt issues and geo-political events could disrupt the trajectory of Ontario's economy. In particular, the results of the NAFTA re-negotiation could have effects over the forecast horizon.

Actual Weather and Demand

Since the last Ontario Demand Forecast document was published actual demand figures for the six months of June through November have been recorded. They show 2017 has been a very unusual year in terms of both energy and peak demand.

April 2017 was significant in that it represented all-time lows in actual monthly energy, peak and minimum demand. The months since then have continued to experience near historical lows. For the same six months energy demand was 5.0 percent lower than the same months a year previously. Some of this was attributable to the milder summer but even after correcting for weather, demand was down 3.7 percent compared to a year earlier. The reductions have been broad based across all consumer sectors.

For the past six months, distributor loads have dropped by 5.1 percent compared to the same months a year earlier. Distributor loads see the direct impact of conservation and the growth in embedded generation production, which contributes to the year-over-year drop. Once again, after adjusting for weather, the year-over-year change was a reduction of 3.5 percent.

Wholesale customers' consumption decreased by 2.6 percent. Iron and steel production showed strong growth over the six months but most other major industrial groups showed a decline.

Peak demand for the summer of 2017 was unusual in that it occurred during the fall. System demand peaked at 21,786 megawatts (MW) on September 25. At this point in time, it also represents the annual peak. In addition to being in the fall, the peak is also low by historical standards. With mild summer weather and significant output from embedded solar generation, peaks across the summer were lower than normal. After correcting for weather, the peak does move back into July but remains low at 21,905 MW. The lower peak values are also a result of expansion of the Industrial Conservation Initiative (ICI) which increased downward pressure on all peaks following the changes.

The weather over the course of the summer was milder and wetter than normal. In addition to the milder weather, there was a lack of sustained warmth. Generally, even cool summers have a heat wave and mild winters have a cold snap. But for the summer of 2017 this just didn't happen.

The fall was also milder than normal with a warm September and October. Unlike the summer weather, the September peak occurred during a sustained warm period that accounted for both the September peak and the end of the month and the October peak at the beginning of the month.

Demand Forecast

In the 18-Month Outlook, the impacts of conservation, embedded generation and prices are incorporated into the demand forecast, resulting in reduced demand. Conversely, demand response programs are included in this analysis as a resource under the category of demand measures. Load modifiers – conservation, embedded generation and prices – and demand measures are discussed in section 4.4 of this document.

Table 1 summarizes the annual peak and energy demand forecast for the period covered in this 18-month forecast. Summer peaks are expected to continue their downward trajectory over the forecast. Though winter peaks will face downward pressure from gains in lighting efficiency and embedded wind generation, summer peaks will face greater downward pressure from numerous sources – improved air conditioning efficiency, the expanded ICI impacts and growth in solar embedded generation.

Grid-supplied energy demand is expected to show a significant decrease in 2017 as actual demand and weather-corrected demand have been low through the first 11 months of the year. An improved economy, increased industrial activity and expanding electricity-intense greenhouse consumption are expected to lead to a small rebound in 2018.

Table 1: Peak and Energy Demand Forecast

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%

- End of Section

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1.0 Introduction

1.1 Outlook Documents

The Ontario Electricity Market Rules (Chapter 5 Section 7.1) require that a demand forecast for the next 18 months be produced and published on a quarterly basis. This Ontario Demand Forecast meets that requirement and covers the period from January 2018 to June 2019. It supersedes the previous forecast released in September 2017 and the previous Ontario Demand Forecast document released in June 2017.

1.2 Demand Forecast Document

This document provides an 18-month forecast of electricity demand for Ontario, based on the stated assumptions and using the methodology described in the document "Methodology to Perform Long-Term Assessments," found on the IESO website at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2017dec.pdf. Readers may envision other scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgement in considering possible future scenarios. This forecast provides a base upon which changes in assumptions can be considered.

Ontario demand is the sum of coincident loads plus the losses on the IESO-controlled grid. This demand forecast was based on actual demand, weather and economic data through the end of September 2017. Data for October and November have been incorporated into the tables and figures of this document. This document is divided into the following sections:

Section 2.0 summarizes the forecast results

Section 3.0 looks at historical demand

Section 4.0 describes the assumptions used in this forecast of electricity demand.

All the tables in this report are contained in the 18-Month Outlook Tables (http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlooktables_2017dec.xls) spreadsheet posted alongside the Outlook documents. The spreadsheet's historical tables contain data back to market opening, which would not be practical in a printed document.

Readers are invited to provide comments or suggestions regarding the content of this or future reports. To do so, please call the IESO Customer Relations at 905-403-6900 or 1-888-448-7777 or send an email to customer.relations@ieso.ca.

Electronic copies of the forecast and weather scenarios are available upon request.

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2.0 Demand Forecast

This section presents the demand forecast for the Outlook period. Additional tables are included in the [18-Month Outlook Tables]() spreadsheet.

Table 2.1 contains the forecast of system weekly peak, energy demand and the load forecast uncertainty (LFU) for the weekly peak. The LFU is a measure of variability in load due to the volatility of weather. Figures 2.1 and 2.2 show the historical weekly energy and peak demand along with the projected forecast.

Table 2.1: Weekly Peak and Energy 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

Compared to the previous forecast, the weekly peaks and energy demand are lower throughout the forecast.

Figure 2.1: Weekly Energy Demand – History and Forecast

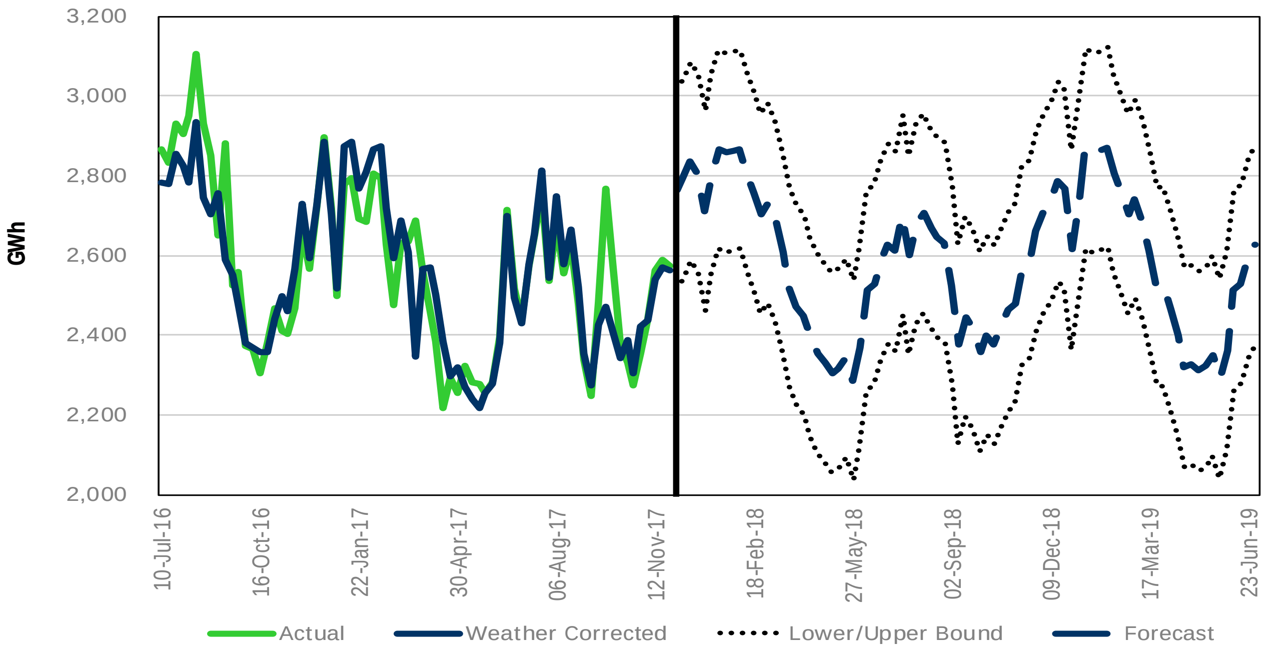
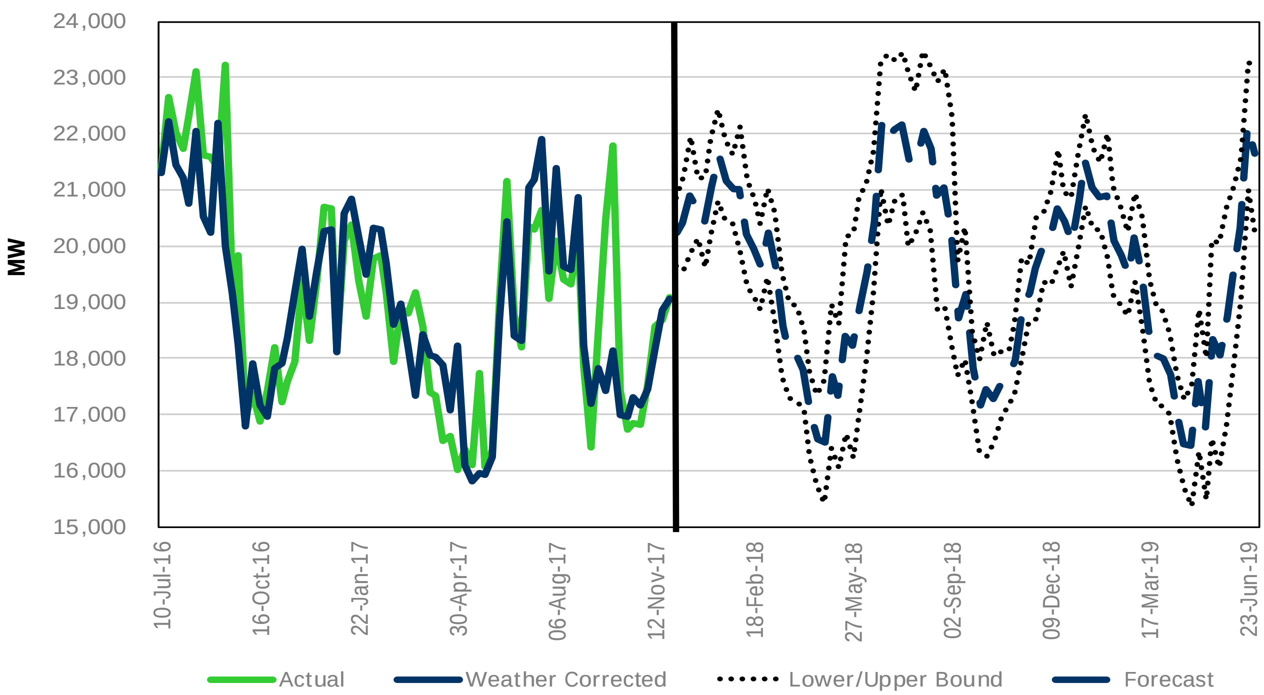


Figure 2.2: Weekly Peak Demand – History and Forecast



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3.0 Historical Review

This section discusses historical electricity demand. The weather-corrected numbers are generated based on Normal weather.

3.1 Six-Month Review – June to November

Since the last Ontario Demand Forecast document, actuals have been recorded for the period June to November. Starting in the spring of 2017, demand has seen a marked reduction compared to the previous year. This decline is broad-based and attributable to numerous factors.

The summer of 2017 was milder and wetter than normal. The fall of 2017 was milder and wetter than normal.

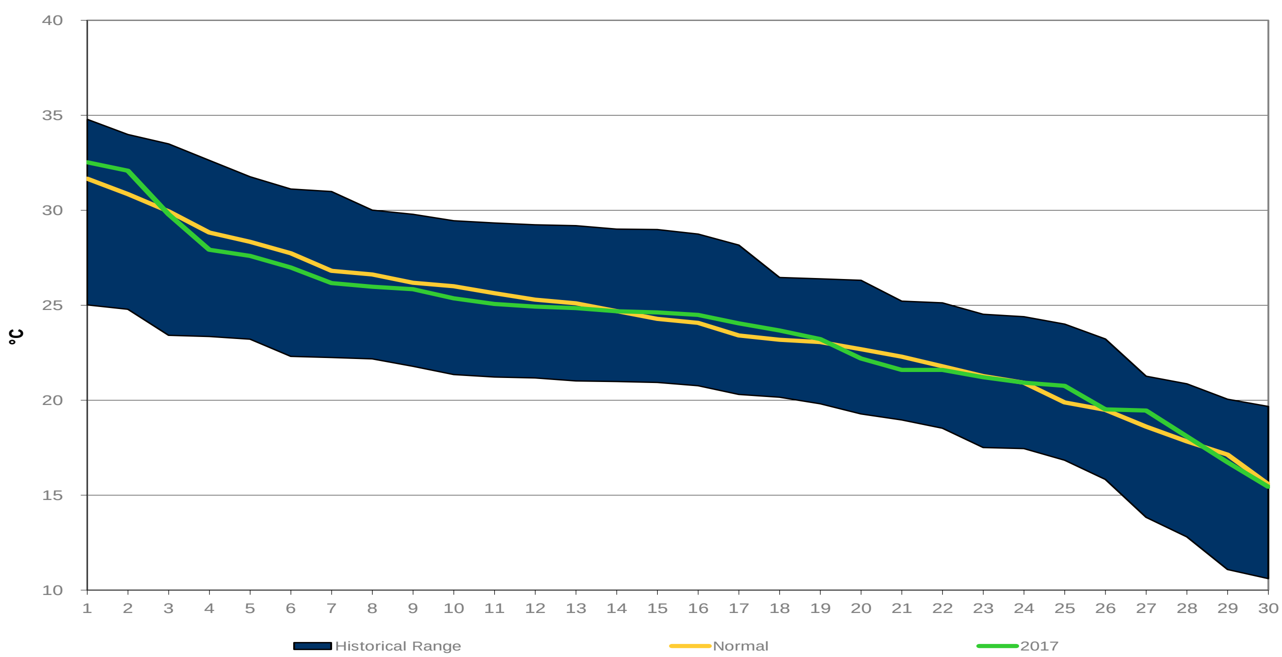
The summer peak was very unusual. The actual summer peak came from June (21,168 MW) and the weather-corrected peak (21,905 MW) occurred in July. The fall peak of 21,786 MW occurred late in September and actually represents the annual peak for 2017. After correcting for weather, the annual peak moves back into the summer.

Following is a month-by-month look at demand and weather.

June

June 2017's weather was very close to normal, both on average and peak. Figure 3.1 presents the ranked range of temperatures for the month, from warmest to coldest. The values for the month were consistently normal based on the history (1970 to present).

Figure 3.1: Daily Temperature - June



The peak demand occurred early mid-month on June 12. The peak occurred on the hottest day of the month. The peak demand was 21,168 MW (20,436 MW weather-corrected) which is low by historical standards, second lowest only to June 2014's peak.

Monthly energy demand was 10.7 terawatt-hours (TWh) and 10.6 TWh weather-corrected. Both values represent the lowest energy demand values for June since market opening.

Minimum demand for the month was 10,518 MW, another all-time low. The minimum occurred on Sunday, June 4 in the early morning hours.

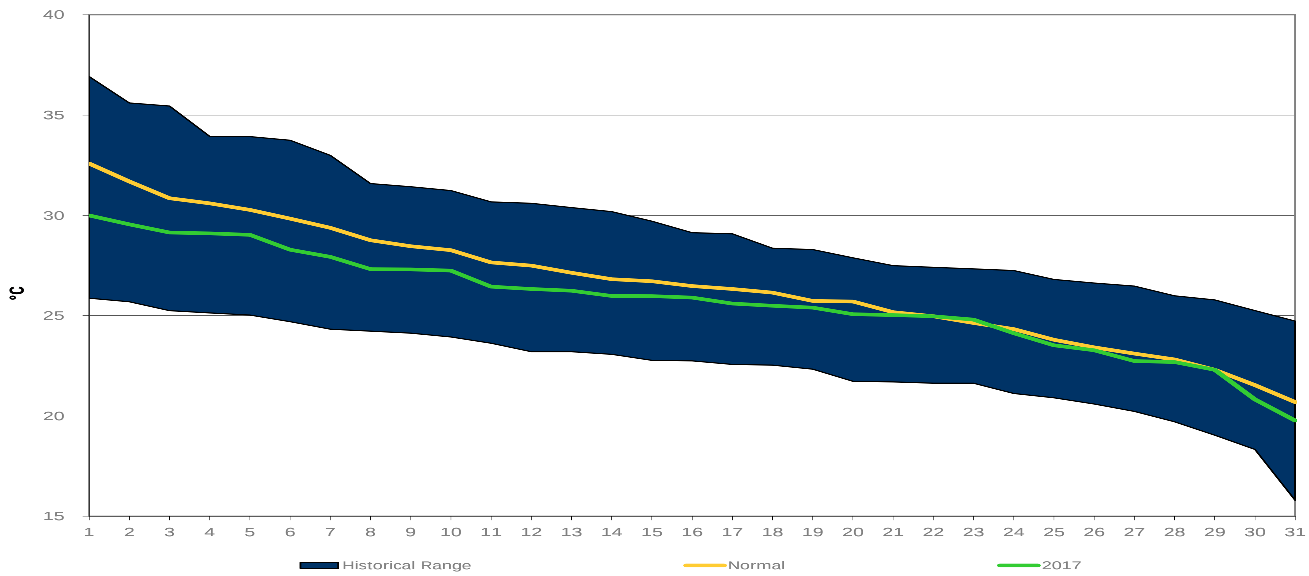
Embedded generation for the month was 577 GWh, a 5.7-percent decrease compared to the previous June. Solar output was down 17 percent compared to the previous June. This was due to a rainier than normal June in central and southern Ontario. Wind production was up 61 percent which was not enough to offset the declines in solar output.

Wholesale customers' load showed dropped 3.3 percent on a year-over-year basis. Iron and steel and motor vehicle manufacturing showed increases for the month but were overshadowed by declines in the mining sector.

July

The weather of July 2017 was cooler and wetter than normal. Figure 3.2 shows how the temperature for July 2017 stacked up against history.

Figure 3.2: Daily Temperature – July



The peak occurred on July 19, which was the hottest day of the month. However, the day wasn't part of a heat wave or any extended warm weather as the day before was the 7th hottest and the day after was the 17th hottest of the month. The peak was the second lowest July peak and the weather-corrected value of 21,905 MW was the lowest July since market opening. Despite this, the weather-corrected value represents the current annual peak for 2017 to date.

Energy demand for the month was 11.6 TWh (11.7 TWh weather-corrected). The actual is only second to the recessionary July 2009 and the weather-corrected value is the lowest July since market opening.

Minimum demand for the month was 10,806 MW, which was higher than last year. The minimum occurred at 6 a.m. on the Sunday of the Canada Day long weekend.

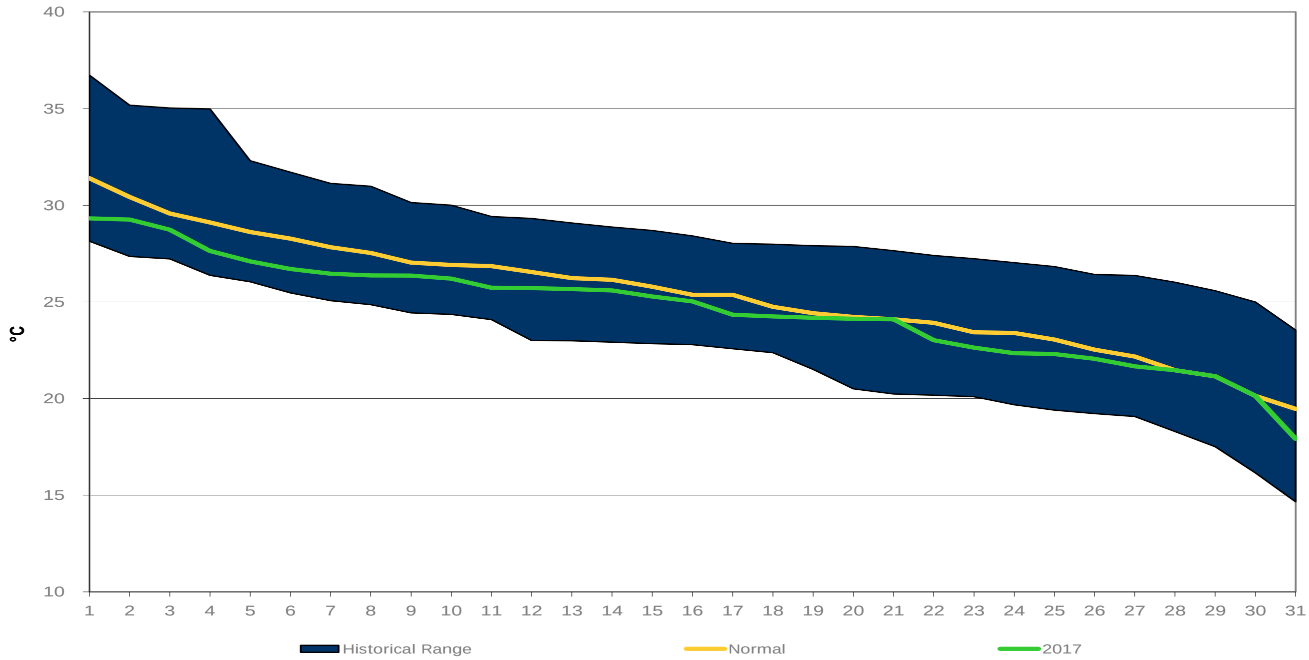
Embedded generation for the month was 581 gigawatt-hours (GWh), a 3.4-percent increase over the July 2016. Solar output fell (-11percent), while wind output was up 20percent. As happened in June, the wet weather led to lower solar production but higher wind output.

Wholesale customers' consumption showed a very modest 0.2 percent increase to July 2016, reversing the trend of the previous three months. Iron and steel once again led the growth in industrial demand.

August

August was milder than normal. Figure 3.3 shows the August 2017 temperature relative to history.

Figure 3.3: Daily Temperature - August



The month's peak occurred on the second hottest day of the month, August 21. Once again the peak was not part of a sustained heat wave but the product of a hot Monday in August. The peak was 20,158 MW and 21,041 MW weather-corrected. These are the lowest peak values for August since market opening.

Energy demand for the month was 11.4 TWh (11.5 TWh weather-corrected). This is consistent with the downward trend experienced this summer and is the lowest August values since market opening. The minimum demand was 10,829 MW for the month. Once again, this represents a new all-time low for the month. The minimum did occur on an extremely mild Sunday late in the month at 4 a.m.

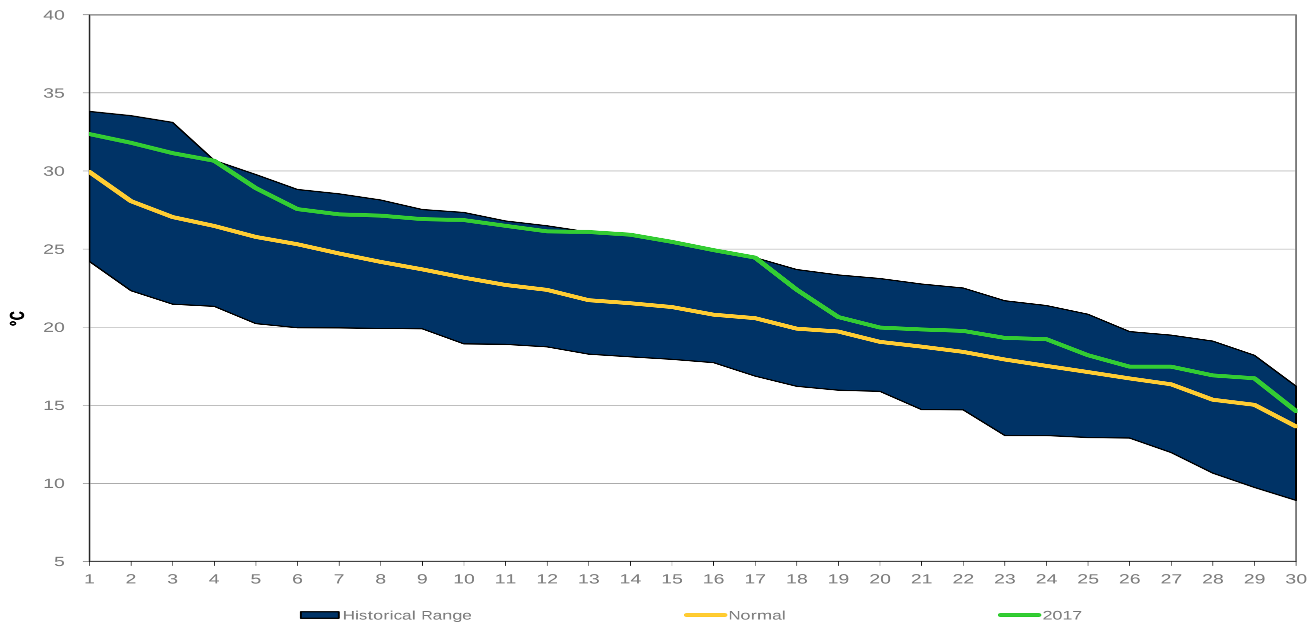
Embedded generation for the month was 449 GWh and represented a 15.6 percent decrease compared against the previous August. Both the solar (-5.6 percent) and wind (-12.6 percent) output declined compared to August 2016.

Wholesale customers' consumption declined in August by 3.3 percent compared to the previous August. Iron and steel tailed off this month and the other sectors remained in the doldrums, therefore overall consumption fell.

September

The weather for September was much warmer than normal which marks three consecutive years in a row with a significantly warmer than normal September. Figure 3.4 shows the September 2017 temperatures against the historical range.

Figure 3.4: Daily Temperature - September



The actual peak of 21,786 MW occurred on September 25, the second warmest day of the month. Unlike the peaks for the summer months, this peak occurred during a spell of consistently hot weather. Having a sustained heat wave this late in September is unusual and gives rise to the unusual circumstance of the actual annual peak occurring in the fall. Due to the unusual nature of the weather, the weather-corrected peak is significantly lower at 18,138 MW. Hot weather peaks are not unusual for September but not as late as the 25th. Previously, the latest date for the September peak had been the 15th of the month. The heat wave was unusual in that it led to a peak demand of 20,457 MW on a Sunday at the end of September. The fact that the last Sunday of September had a higher peak than any day in August, January or May is very surprising.

Energy demand for the month was 10.7 TWh and 10.3 TWh weather-corrected. As has been the experienced throughout most of 2017, this represents an all-time low for the month going back to market opening.

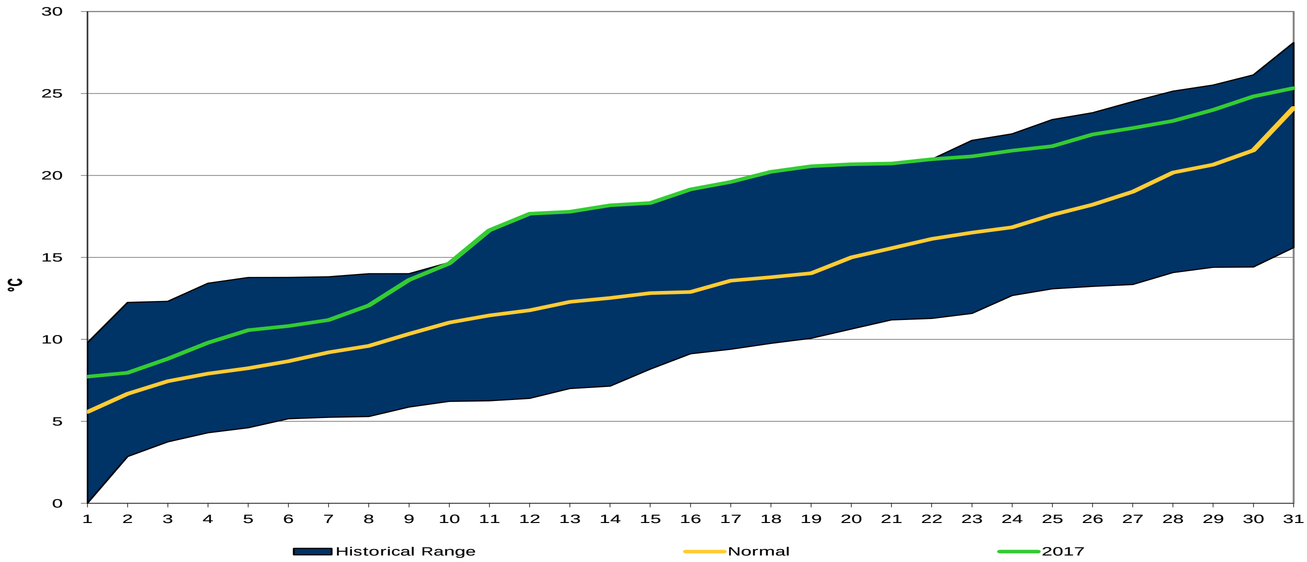
Minimum demand for the month was 10,487 MW and occurred at 4 a.m. on Labour Day. It is the lowest September minimum since market opening.

Embedded generation for the month was 483 GWh, a decrease of 7.9 percent compared to the previous September. Solar was down 1.9 percent and wind was up 22.6 percent. The biggest change came from non-contracted embedded generation which declined by 96.6 percent compared to a year ago. Wholesale customers' consumption dropped a whopping 10.6 percent against September 2017.

October

October was warmer than normal. The warm weather from the end of September carried through into October. Figure 3.5 illustrates the temperatures of October 2017 against the historical range.

Figure 3.5: Daily Temperature - 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.

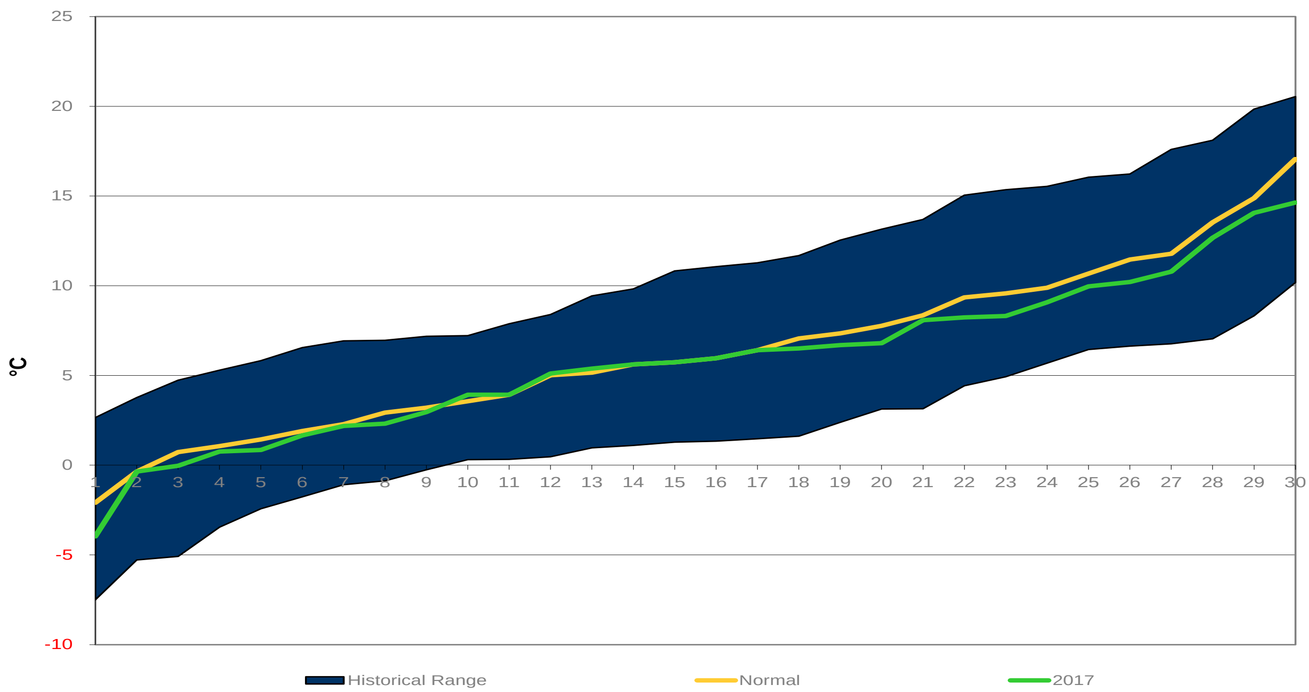
Embedded generation for the month was 533 GWh. This represents a huge 28 percent decrease over the previous October. Output from solar (4.9 percent) and water (32.5 percent) were up while wind was down (32.4 percent). Non-contracted embedded generation was 125 GWh.

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.

Figure 3.6: Daily Temperature - November



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.

Table 3.3.2 of the 18-Month Outlook Tables spreadsheet contains monthly demand information going back to market opening.

Table 3.1 contains a summary of the weather and demand for the past six months.

Table 3.1: Historical 2017 Weather and Demand Summary

Historical Analysis		June	July	August	September	October	November
Actual Weather	Average Temperature (°C)	24.0	25.9	24.6	23.7	17.8	6.8
	Minimum Temperature (°C)	16.4	16.9	18.9	14.5	7.7	-4.0
	Maximum Temperature (°C)	32.4	31.5	30.0	33.3	26.5	16.9
Normal Weather	Normal Average Temperature (°C)	23.8	26.4	24.4	20.9	12.6	6.7
	Normal Minimum Temperature (°C)	13.4	20.0	18.2	9.5	4.0	-2.0
	Normal Maximum Temperature (°C)	31.3	30.9	30.8	29.8	21.1	18.9
Actual Demand	Peak Demand (MW)	21,168	20,627	20,158	21,786	17,418	19,115
	Average Hour (MW)	14,802	15,575	15,255	14,832	13,897	15,217
	Minimum Hour (MW)	10,518	10,806	10,829	10,487	10,534	11,199
	90th Percentile (MW)	17,663	19,029	18,578	18,796	15,858	17,381
	Percent above 20,000 (MW)	1.0%	2.3%	0.7%	3.5%	0.0%	0.0%
	# of Hours Above 20,000 (MW)	7	17	5	25	0	0
	Energy Demand (GWh)	10,657	11,588	11,350	10,679	10,339	10,956
Weather Corrected Demand	Peak Demand (MW)	20,436	21,905	21,041	18,138	17,317	19,073
	Energy Demand (GWh)	10,593	11,680	11,517	10,255	10,476	10,871
Forecast Demand	Peak Demand (MW)	22,455	22,493	22,376	19,490	18,031	20,231
	Energy Demand (GWh)	11,159	11,985	12,106	10,494	10,943	11,372

Notes for Table 3.1 – Weather is for Toronto. Temperature is the daily high. Forecast is the most recent for that period.

3.2 Historical Energy Demand

The six-month period can be broken down into its two main components, summer (June, July and August) and fall (September, October and November).

The weather over the summer was milder and wetter than normal. Compared to the previous summer energy demand was down 8.5 percent. If you adjust for the weather the decline was still a rather large 5.0 percent or 1.8 TWh.

Distributors' loads have declined by 9.3 percent over the summer compared to last summer. After making the weather adjustments, the decline is still rather large at 5.3 percent. This reduction is a result of growth in embedded generation output, conservation savings and economic structural change. Over the course of the summer, embedded generation was 2.4 GWh, an increase of 0.1 percent over the previous year.

For the summer months, wholesale loads showed a decrease of 2.1 percent compared to the previous summer. Iron and steel and the petrochemical sectors showed growth over the previous summer whereas the other major sectors took a step back.

For the fall of 2017, the story is reversed. Actual energy demand was down 1.0 percent compared to the previous fall but after correcting for weather the decline is 2.2 percent. The distributor loads showed an actual decline of 0.1-percent and a 1.6-percent decline after correcting for weather.

Wholesale customers' loads decreased by 3.0 percent 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.

Figure 3.7 shows weather-corrected distributor load and embedded generation output. Though embedded generation shows seasonal volatility, the underlying upward trend is quite evident in the graph. For the year to date, embedded generation is virtually the same as last year which would be a slight increase as 2016 had an additional day as a result of a leap year. Year-to-date embedded generation output is 5.9 TWh. The growth rate has slowed in concert with the growth in capacity has slowed.

For the six months from June to November, distributors' loads declined by 5.1 percent compared to the same six-month period a year earlier. Embedded generation increased by a same 2.2 percent for the same period.

Figure 3.7: Monthly Weather-Corrected Distributor Load and Embedded Generation Output

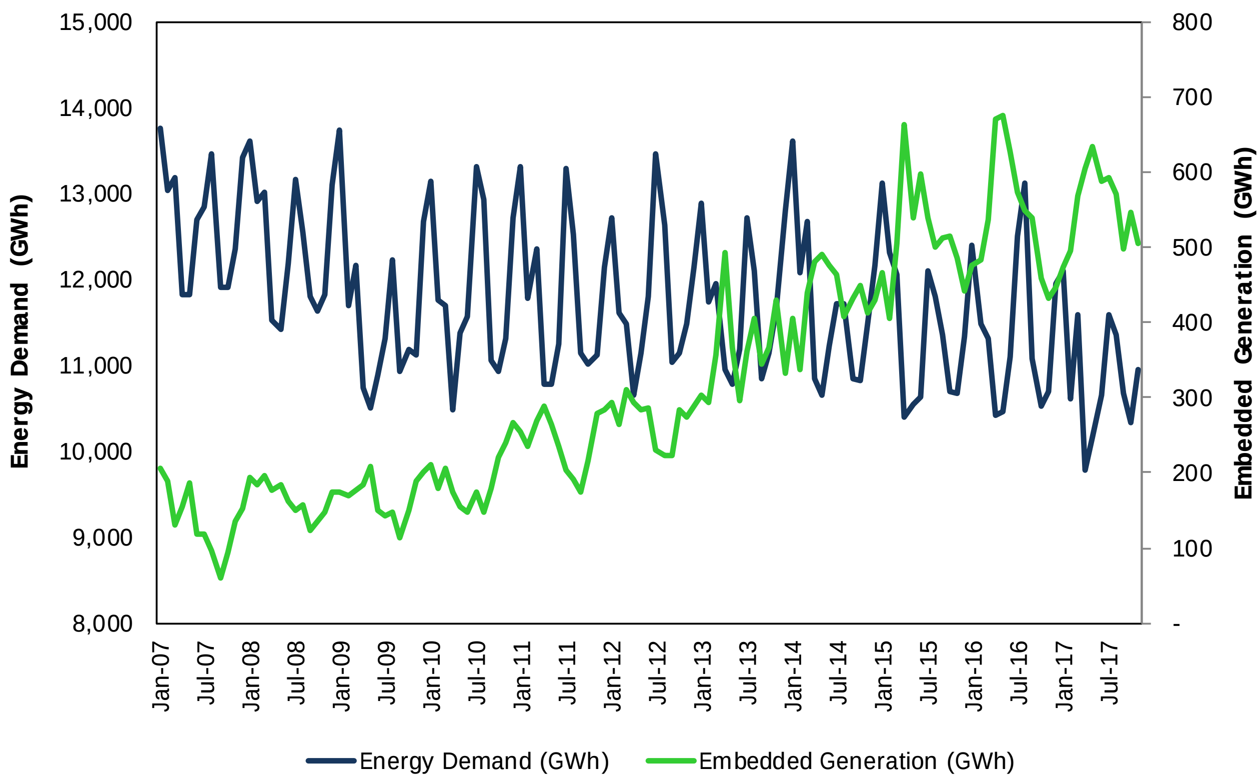


Figure 3.8 shows the year-over-year change in wholesale customers' average hourly consumption. The graph traces the impact of the recession, the short and modest recovery in 2010 and the relatively flat demand since that time.

Figure 3.9 shows the wholesale customers' highest monthly average hourly load by industry segment for each of 2008, 2015, 2016 and 2017 year to date.

Mining is the only sector that is higher than its pre-recession value. Pulp and paper, by contrast, has shown the greatest decline. The other sectors show a similar pattern of having fallen from the pre-recession values and appear to have found a new equilibrium that has been more or less stable over the past four years. Mining and iron and steel are up over last year.

The changing industrial structure is due to a variety of causes. Some changes are sector specific – the impact of the decline in demand for newsprints on pulp and paper – while other changes are broad-based. Wholesale loads declined by 24 percent in 2009. Since 2010 loads have shown a 4.4percent increase.

Figure 3.8: Wholesale Customers' Year-over-Year Change in Consumption

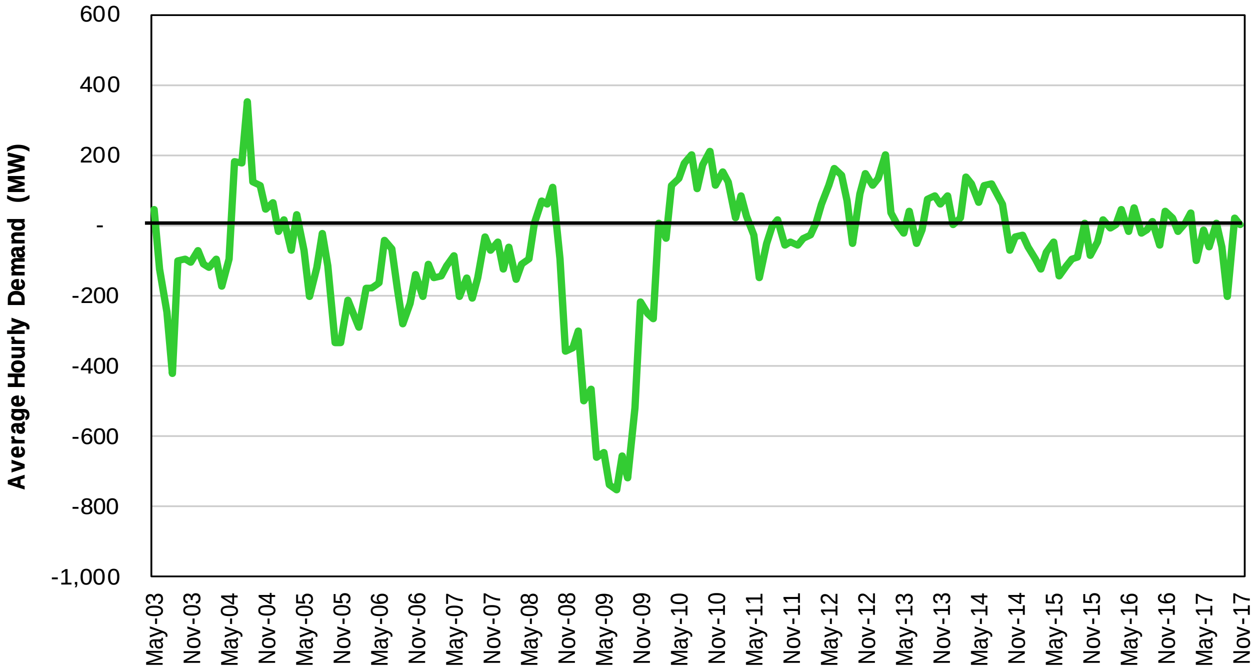


Figure 3.9: Wholesale Customers' Average Hourly Consumption by Industry Segment

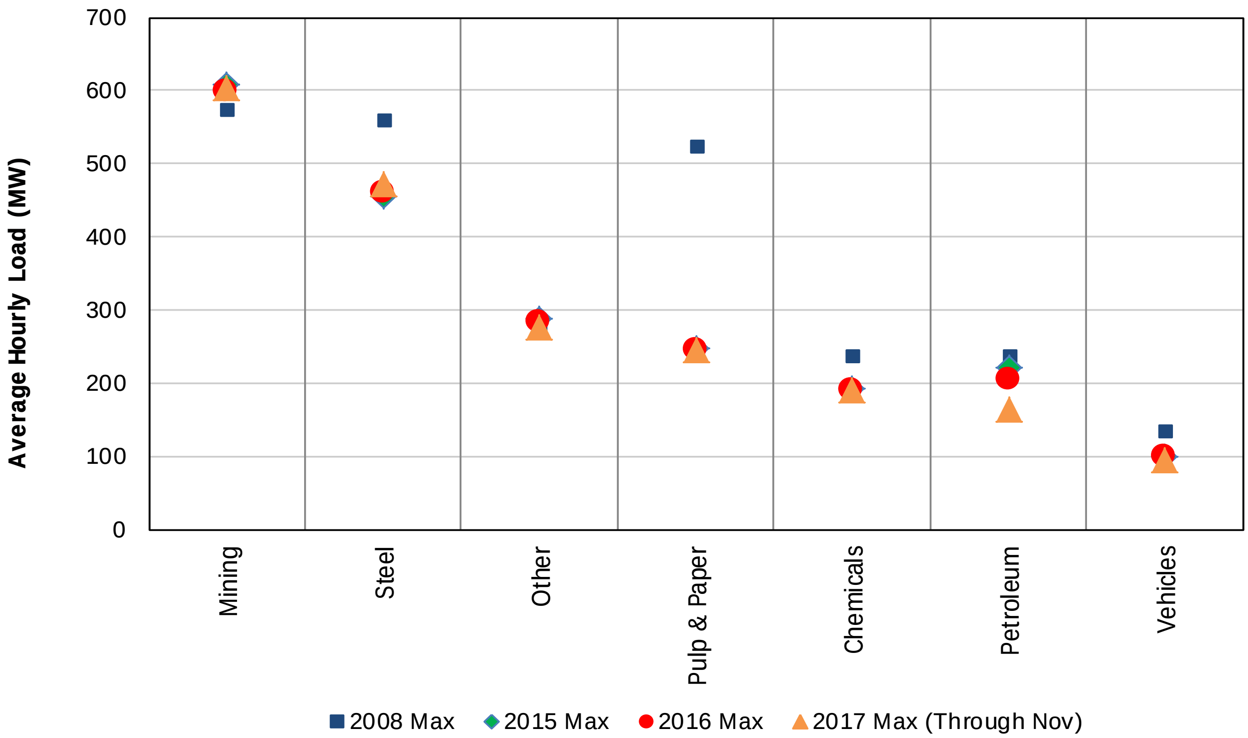


Table 3.2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week and notes any item of significance for the week. If the weather-corrected demand is greater than the actual demand, it means that the actual weather was milder than normal. Additional history is available in the 18-Month Outlook Tables spreadsheet in Table 3.3.1.

Table 3.2: Historical Weekly Energy Demand

Week Number	Week Ending	Peak Day	Actual Energy (GWh)	Corrected Energy (GWh)	Notes
22	04-Jun-17	29-May-17	2,279	2,276	
23	11-Jun-17	11-Jun-17	2,396	2,379	
24	18-Jun-17	12-Jun-17	2,712	2,698	
25	25-Jun-17	19-Jun-17	2,515	2,492	
26	02-Jul-17	30-Jun-17	2,436	2,429	Canada Day
27	09-Jul-17	06-Jul-17	2,572	2,576	
28	16-Jul-17	11-Jul-17	2,649	2,655	
29	23-Jul-17	19-Jul-17	2,756	2,814	
30	30-Jul-17	27-Jul-17	2,536	2,543	
31	06-Aug-17	31-Jul-17	2,679	2,749	
32	13-Aug-17	10-Aug-17	2,553	2,576	Civic Holiday
33	20-Aug-17	14-Aug-17	2,628	2,664	
34	27-Aug-17	21-Aug-17	2,480	2,521	
35	03-Sep-17	30-Aug-17	2,337	2,353	
36	10-Sep-17	05-Sep-17	2,247	2,273	Labour Day
37	17-Sep-17	14-Sep-17	2,483	2,426	
38	24-Sep-17	24-Sep-17	2,768	2,472	
39	01-Oct-17	25-Sep-17	2,569	2,405	
40	08-Oct-17	04-Oct-17	2,376	2,340	
41	15-Oct-17	10-Oct-17	2,330	2,387	
42	22-Oct-17	16-Oct-17	2,274	2,305	
43	29-Oct-17	26-Oct-17	2,354	2,421	
44	05-Nov-17	01-Nov-17	2,441	2,436	
45	12-Nov-17	10-Nov-17	2,560	2,539	Remembrance Day
46	19-Nov-17	13-Nov-17	2,588	2,568	
47	26-Nov-17	22-Nov-17	2,575	2,561	

3.3 Historical Peak Demand

Peak demands are weather-driven and generally occur on weekdays. Peak demands have been facing downward pressure due to a number of factors. Conservation, time-of-use rates, embedded generation, demand response, the Industrial Conservation Initiative (ICI) and economic restructuring have all contributed to lower peak demands.

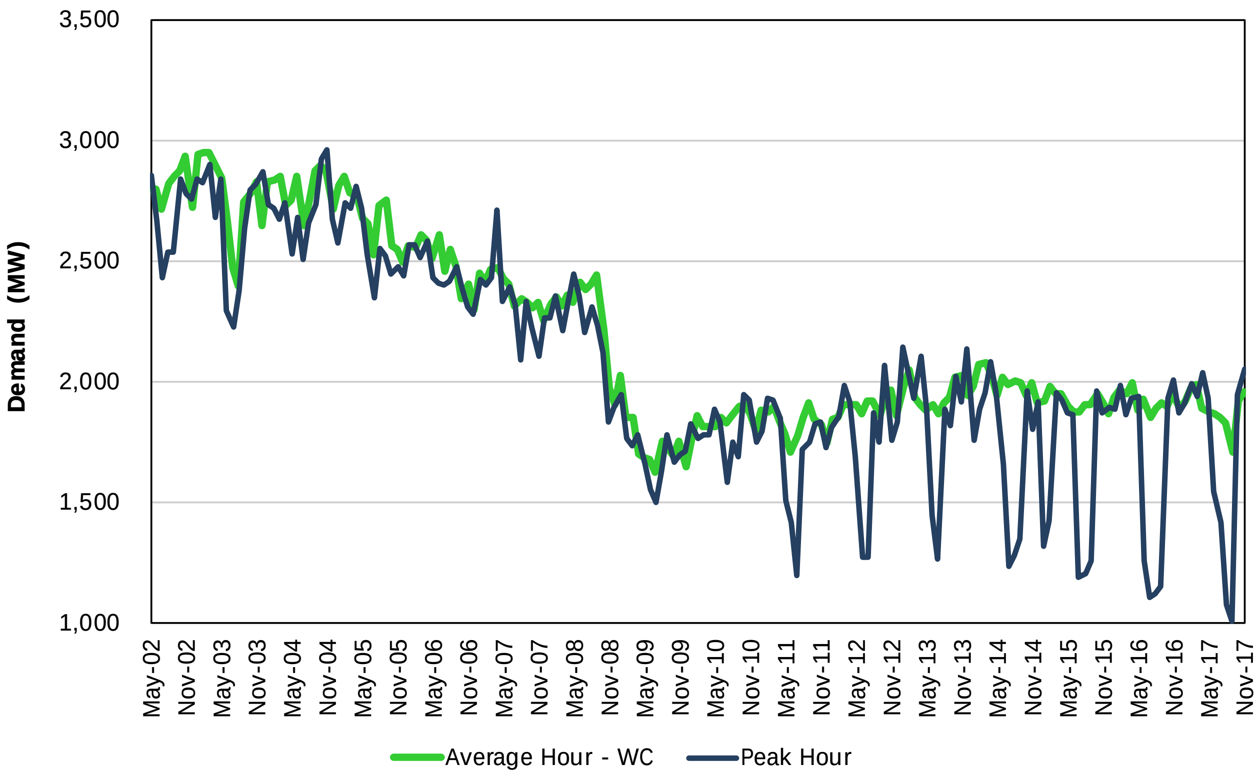
The summer peak was 21,168 MW, which is lower than last summer's peak (23,100 MW). The peak weather was cooler than the previous summer. As well, the actual summer peak occurred quite early in the summer on June 12. The weather-corrected summer peak was lower than the previous one but most of that reduction can be attributed to increased ICI impacts.

The fall peak was 21,786 MW, which was also significantly lower than the previous fall peak (23,213 MW). The difference in the two peaks was that last year the peak occurred at the beginning of September whereas this year it came at the end. It was also hotter during last year's peak.

Figure 3.10 shows the wholesale customers' average hourly monthly demand and their consumption at the time coincident with the system peak. It is evident that prior to the ICI program, the average and coincident peak tracked quite closely as many sectors operated 24/7. With the introduction of the program in 2010, wholesale customers have responded by reducing their load during the five peak days. The graph shows a portion of the response as the program applies to Class A customers -- that includes wholesale customers and a number of customers served by distributors.

In 2017, the program was expanded to include customers with a peak load of 0.5 MW or higher. Additionally, for those with an average peak load in excess of 1 MW, the North American Industrial Classification (NAIC) code restrictions were lifted. Previously, participants were restricted to manufacturing sectors. This change will enable large commercial facilities to access the program. Those between 0.5 MW and 1 MW are still restricted to specific sectors: manufacturing, greenhouses and floriculture.

Figure 3.10: Wholesale Customers' Coincident Peak and Average Hourly Consumption



For most years, the province has been summer peaking, but the summer peaks face more downward pressure compared to the winter peaks. In particular, conservation and embedded solar generation do not impact the seasonal peaks to the same degree. The summer peak is primarily driven by air conditioning load, whereas the winter peak is a result of a mix of end uses. As such, conservation programs that increase air conditioner efficiency and improve the building envelope will have a direct impact on summer peak. The winter peak is mostly impacted through conservation initiatives that improve lighting efficiency, and the resulting impact on the winter peak is smaller. The second factor is embedded solar generation. Since the winter peak occurs after sunset, the output of embedded solar will be zero and have no impact on the winter peak. The summer peak occurs during daylight hours when embedded solar output is significant. This is reducing the summer peaks but is also having an impact of pushing the summer peaks later in the day.

Traditionally, the summer peak occurred in the late afternoon as air conditioners worked to dissipate the accumulated heat. Now embedded solar is effectively "carving out" demand in the middle of the day and having the effect of pushing the peak later in the day when solar output is declining more rapidly than demand.

Figure 3.11 shows the winter weekday peaks levels in MW and the hour in which they occurred for the winter of 2005, 2016 and the winter of 2017. The graph clearly shows how peaks are lower today – a result of conservation and lower industrial load – but that the peaks occur in the same timeframe from hours 18-20. Figure 3.12 shows the weekday peaks in MW and the hour in which they occurred for the summer of 2005, 2016 and 2017. Here the peaks are once again lower but in the case of the summer, the hours at which those peaks are occurring have changed. Generally, the peaks have shifted to later in the day. Even comparing last summer to this past one, there were five weekday peaks in the summer of 2016 that occurred in hour ending 20 (8 p.m.) or later. In 2017 that quadrupled to 20 weekday peaks. The contrast between the summer and winter distribution of peak hours shows the impact that embedded solar in having on the summer peaks. Embedded solar is making the summer peaks lower and later in the day.

Figure 3.11: Seasonal Weekday Peak Hour Distribution - Winter

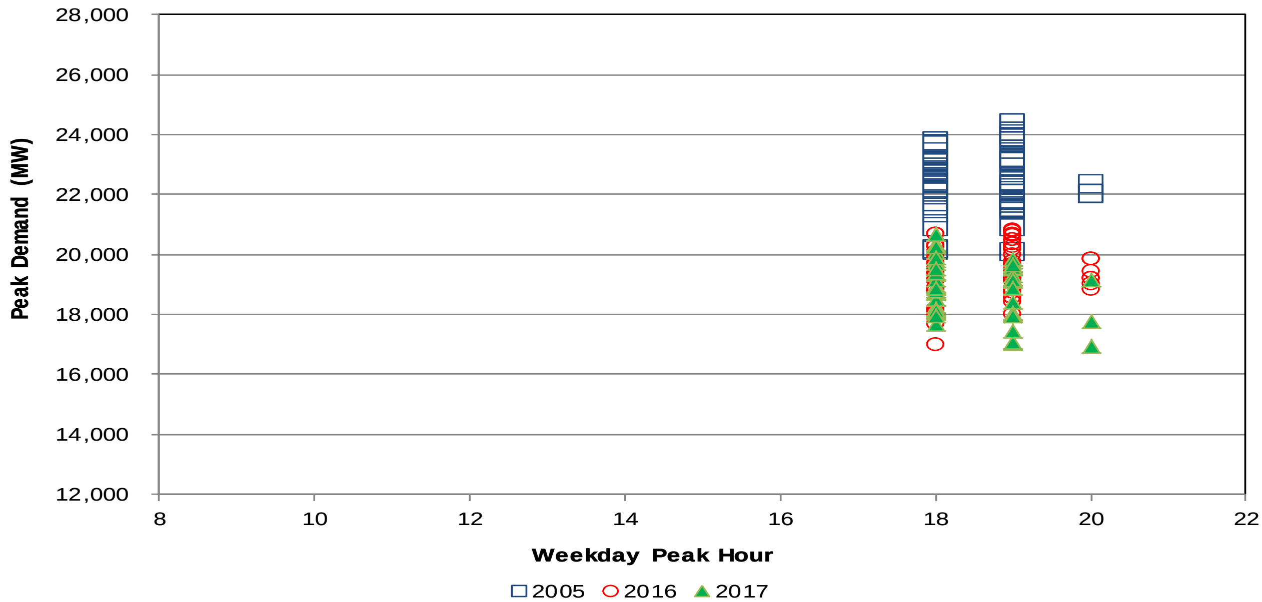
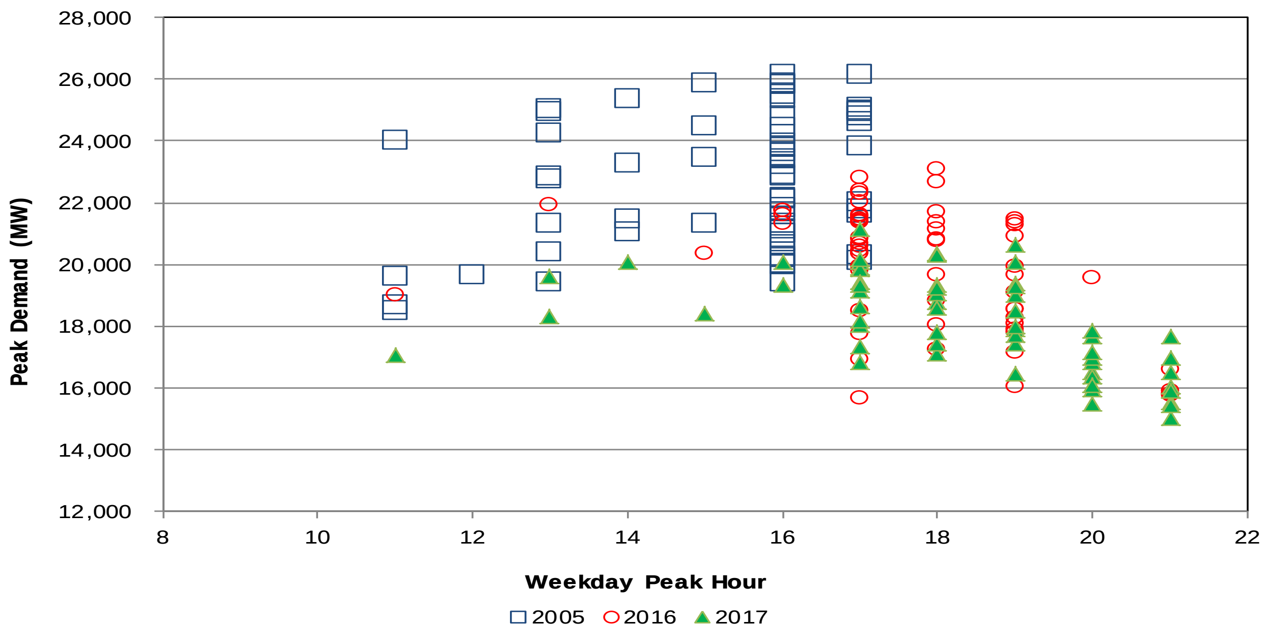


Figure 3.12: Seasonal Weekday Peak Hour Distribution – Summer



The interesting aspect of the seasonal peaks is that the winter peak has less underlying growth, but fewer factors are acting to mitigate that growth, while the summer peak has greater underlying growth but more factors working to reduce them.

Figure 3.13 shows the break-down for the past two summer and winter peaks. For the past two winters ICI has not been a factor. As well, for all of the seasonal peaks depicted it was only during the summer peaks where demand response was activated. Generally, the embedded generation is higher during the summer peak as the significantly larger solar capacity doesn't impact the winter peak which occurs after dark. However, the 2017 summer peak had a very low level of embedded generation output as it peak occurred late in the day, late in September.

Figure 3.13: Anatomy of Seasonal Peaks

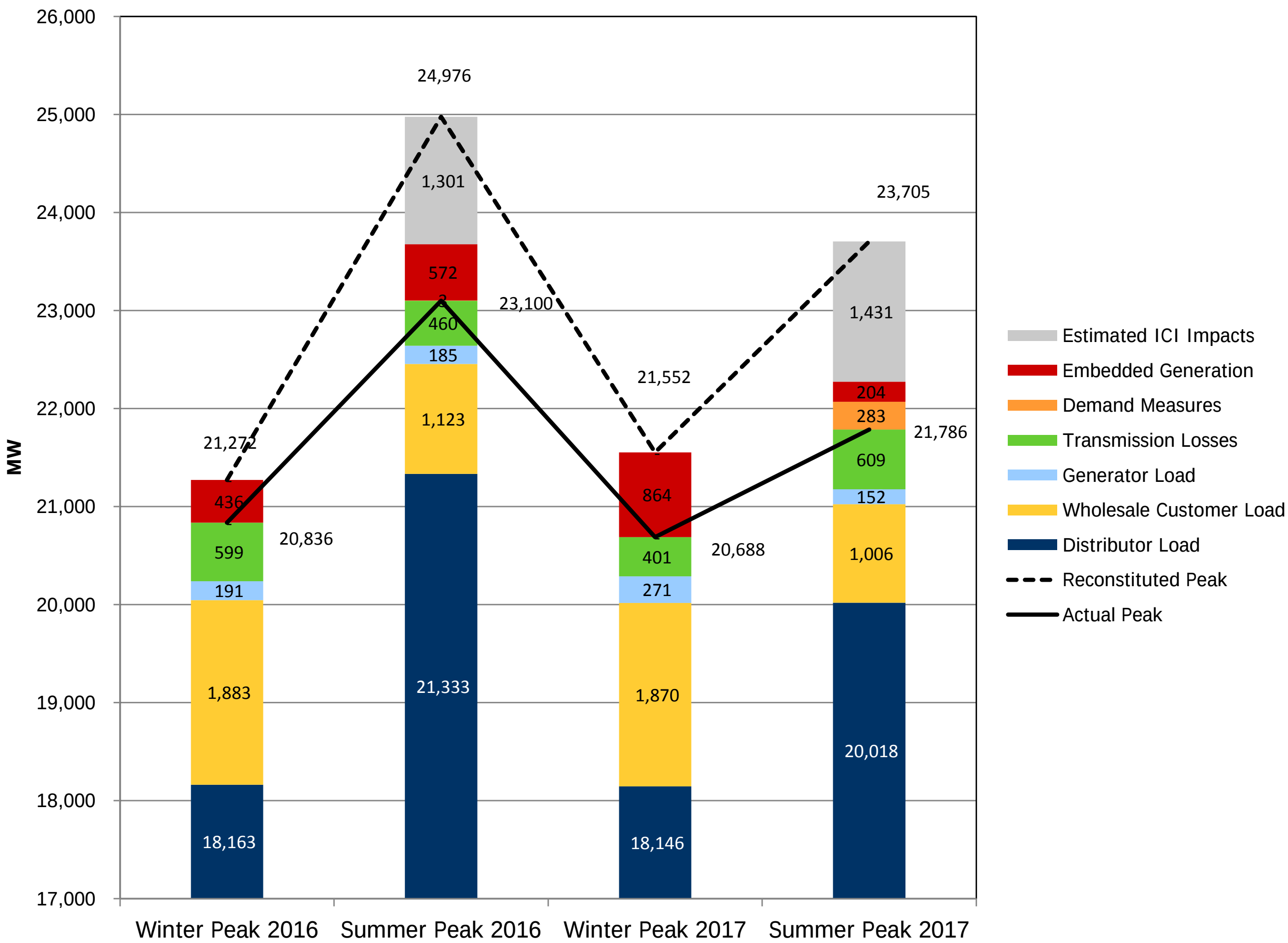


Table 3.3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3.3: Historic Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
22	04-Jun-17	29-May-17	16,357	16,251	25.1
23	11-Jun-17	11-Jun-17	19,062	18,717	31.6
24	18-Jun-17	12-Jun-17	21,168	20,436	32.4
25	25-Jun-17	19-Jun-17	18,770	18,405	25.8
26	02-Jul-17	30-Jun-17	18,201	18,325	27.9
27	09-Jul-17	06-Jul-17	20,366	21,029	29.6
28	16-Jul-17	11-Jul-17	20,302	21,181	28.9
29	23-Jul-17	19-Jul-17	20,627	21,905	31.5
30	30-Jul-17	27-Jul-17	19,070	19,553	25.8
31	06-Aug-17	31-Jul-17	20,096	21,391	30.8
32	13-Aug-17	10-Aug-17	19,409	19,626	26.7
33	20-Aug-17	14-Aug-17	19,317	19,574	25.7
34	27-Aug-17	21-Aug-17	20,158	20,871	30.0
35	03-Sep-17	30-Aug-17	17,858	18,226	23.9
36	10-Sep-17	05-Sep-17	16,406	17,181	21.0
37	17-Sep-17	14-Sep-17	18,473	17,829	27.0
38	24-Sep-17	24-Sep-17	20,457	17,428	33.3
39	01-Oct-17	25-Sep-17	21,786	18,138	31.3
40	08-Oct-17	04-Oct-17	17,418	17,006	26.5
41	15-Oct-17	10-Oct-17	16,746	16,969	22.9
42	22-Oct-17	16-Oct-17	16,838	17,317	10.1
43	29-Oct-17	26-Oct-17	16,821	17,166	10.6
44	05-Nov-17	01-Nov-17	17,545	17,448	6.7
45	12-Nov-17	10-Nov-17	18,565	18,180	-4.0
46	19-Nov-17	13-Nov-17	18,696	18,871	5.3
47	26-Nov-17	22-Nov-17	19,092	19,073	0.1

3.4 Load Duration Curves

The following load duration curves display load for the four seasons. The seasons are defined as: fall (September, October and November), summer (June, July and August), spring (March, April and May) and winter (December, January and February).

The figures are not weather-corrected so the weather will influence the shape of each of the graphs. The spring and fall load duration curves are more heavily influenced by the level of economic activity than by the weather. Those load duration curves show that demand for 2017 was low by historical standards.

Figure 3.14: Fall Load Duration Curve

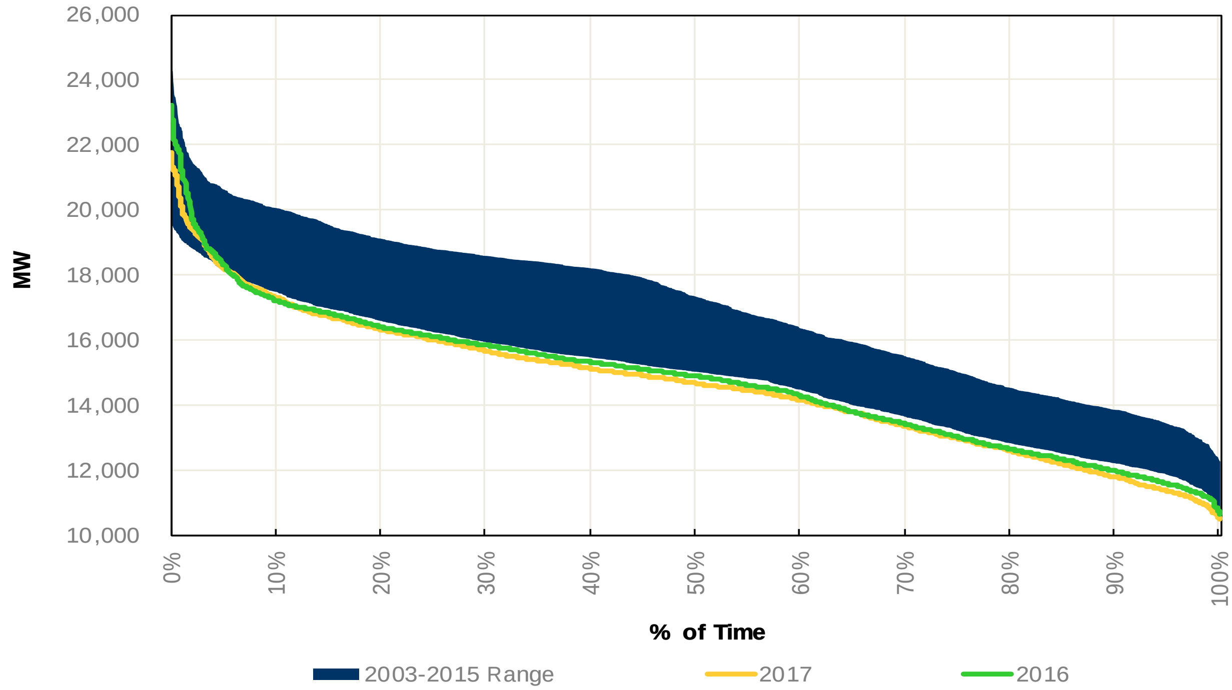


Figure 3.15: Summer Load Duration Curve

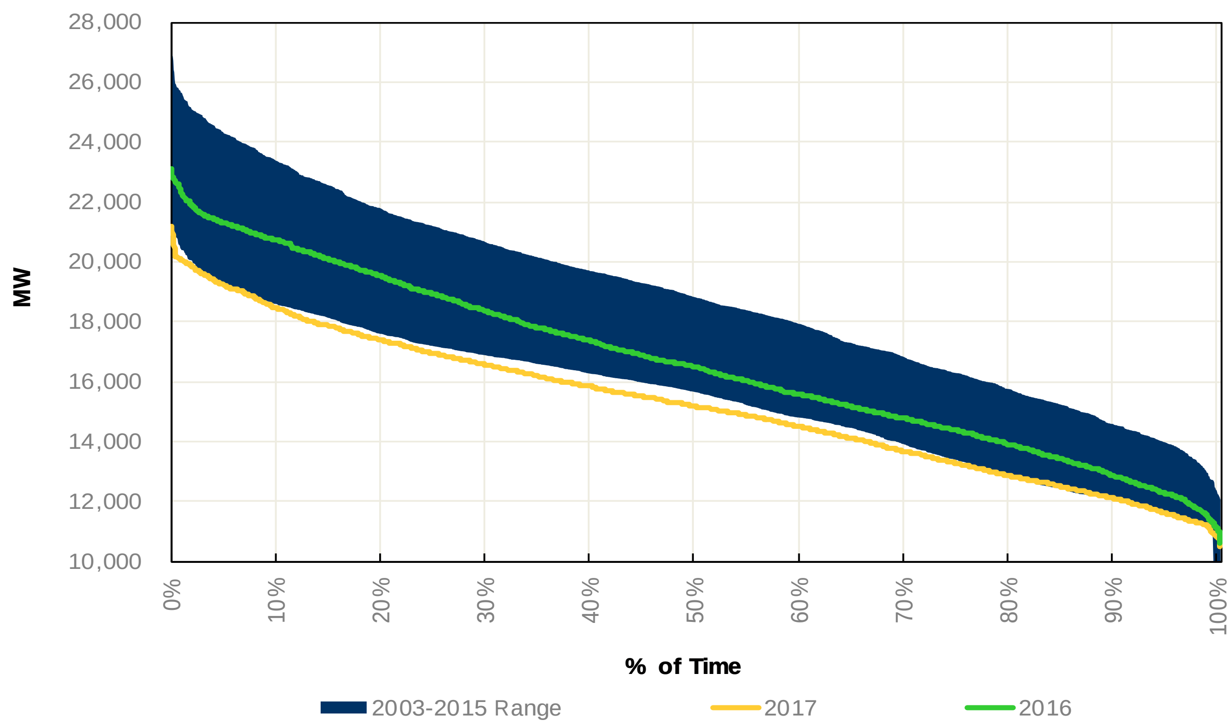


Figure 3.16: Spring Load Duration Curve

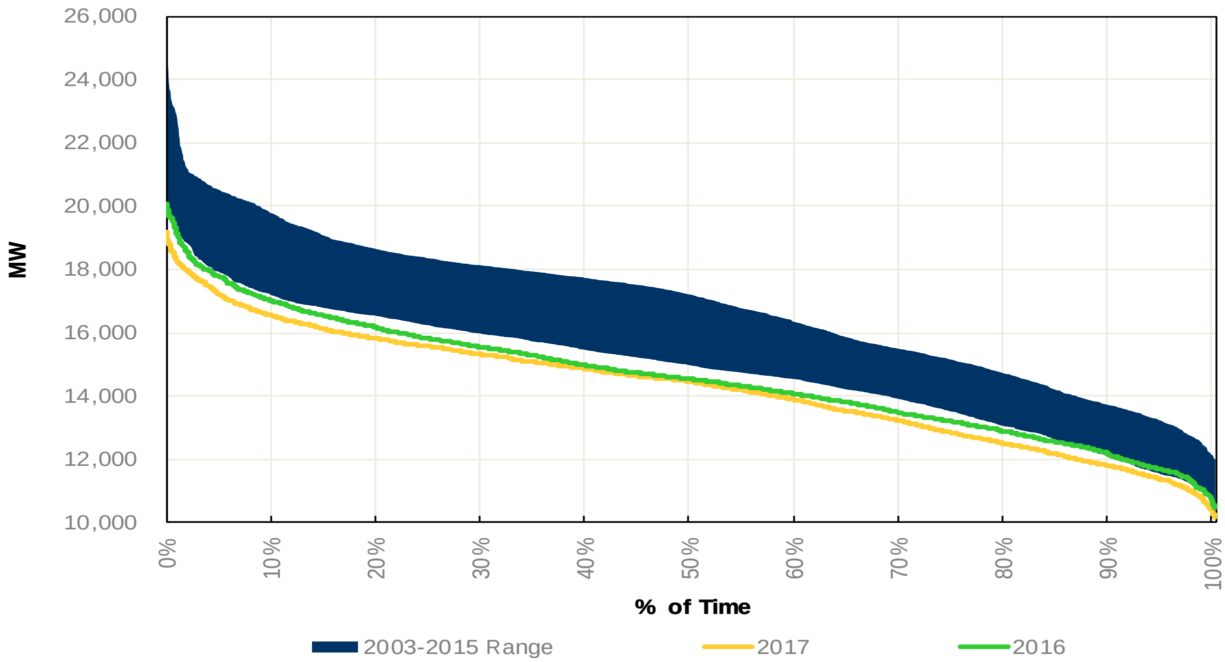
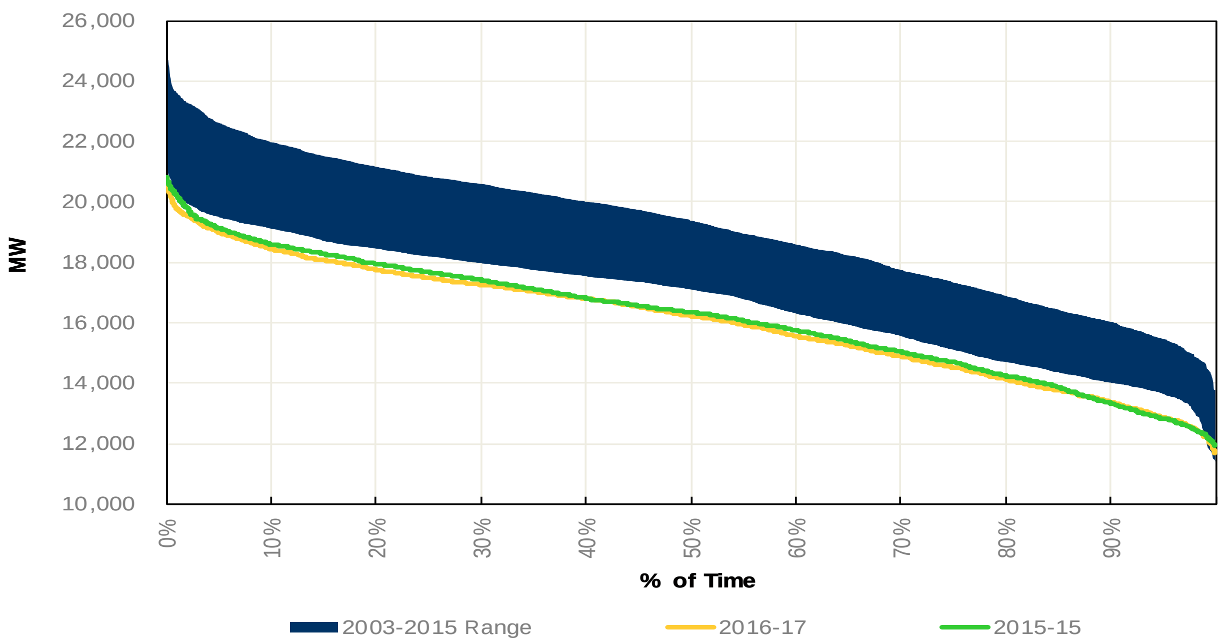


Figure 3.17: Winter Load Duration Curve



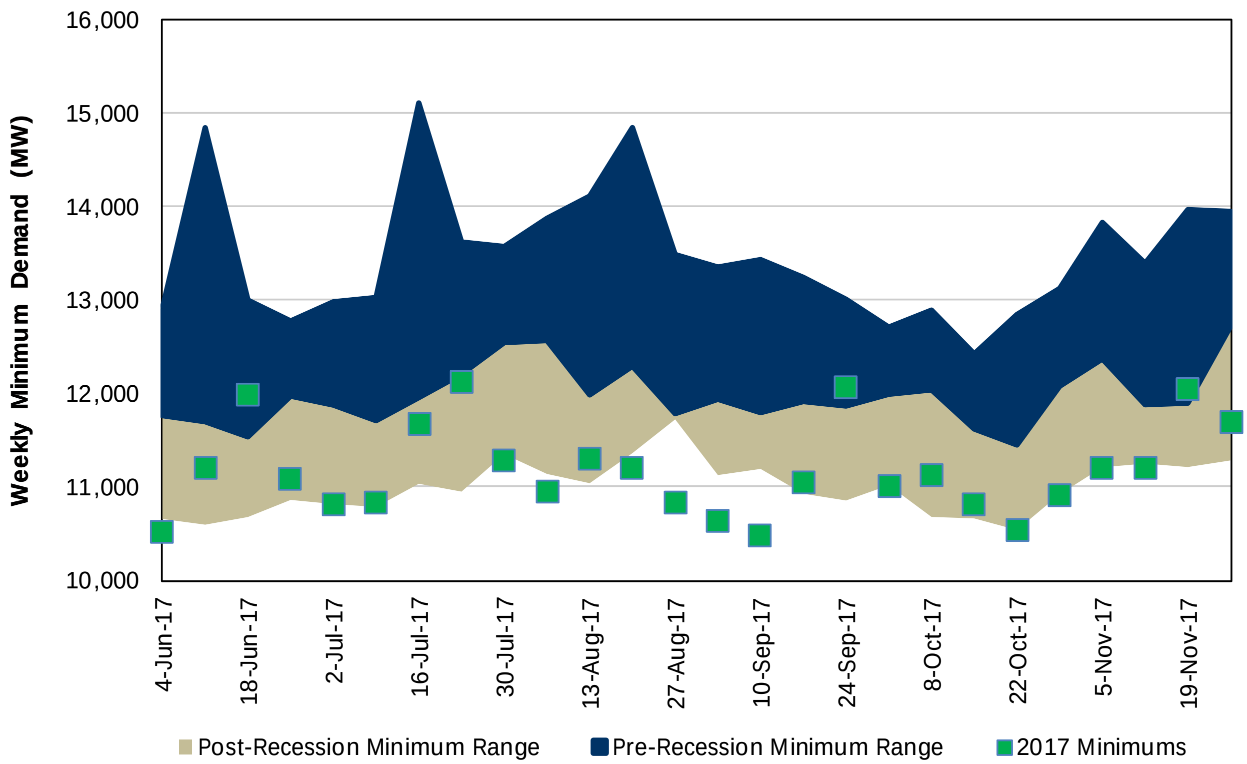
3.5 Historical Minimum Demand

Like peak demands, minimum demands are driven by weather, calendar and economic effects. The importance of the drivers varies by season. The winter, spring and fall have the potential for heating load, whereas the summer period has the potential for cooling loads. Minimums continue to establish new lows in the post-recession era due to lower industrial loads, conservation and increased embedded generation. In the case of minimums that occur during the predawn hours, it is embedded wind that is further reducing the need for grid-supplied electricity. In fact, some load points with high quantities of embedded wind actually push power back onto the grid overnight when embedded wind output is high.

Figure 3.18 shows the minimum weekly demands for the period June to November since market opening. The dark band represents the range of values for the years 2002 – 2008 while the lighter band shows the post-recession minimums for the 2009 to 2016 time frame. The squares represent the weekly minimums for the past six months.

The minimums of the past six months reflect the generally mild weather and low levels of demand throughout 2017. Numerous times in 2017 the weekly minimums were reaching new lows. This is due to the aforementioned combination of impacts – embedded generation, conservation, mild weather and the level of overnight economic activity. The weekly minimums occur during the early morning hours of the weekend, when the level of economic activity is lowest.

Figure 3.18: Weekly Minimum Demands



- End of Section -

4.0 Forecasting Process and Assumptions

A detailed description of the forecasting methodology can be found in the document entitled "Methodology to Perform Long-Term Assessments" found on the IESO web site at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2017dec.pdf.

The form and structure of the model have been modified to enhance and strengthen the explanatory powers of the economic drivers, conservation and embedded generation. The most recent demand, weather and economic data were incorporated into the model, which was re-estimated based on this information.

The forecast of demand requires inputs, and this section covers each class of drivers.

4.1 Calendar Drivers for Forecast

Calendar variables are addressed in the Methodology document. Essentially, forecasting demand for electricity according to the calendar – days of the week, holidays, sunrises and sunsets – is pretty straightforward.

4.2 Economic Drivers for Forecast

To produce an energy and peak demand forecast, an economic forecast of various drivers is required. The IESO uses both a consensus of publicly available provincial forecasts and purchases forecasts of economic data in order to generate economic drivers for the demand forecast and to provide additional insight and analysis.

Canada continues to benefit from strong economic fundamentals - low interest rates, a low exchange rate and good corporate profits. This should benefit both Canada and Ontario over the forecast horizon.

Ontario's economy has seen strong growth throughout 2017. Many of the sectors that have driven growth this year have not been electricity-intense sectors. Construction, retail, financial services and the technology sector have helped propel Ontario's economic growth but do not translate into increased electricity demand.

The energy-intense manufacturing sectors of Ontario's economy tend to be export-oriented and exports are down on a year–to-date basis. Though certain sectors were up – metals and iron and steel, others have tailed off – consumer goods and motor vehicles.

Ontario generated 124,000 jobs in 2017, an increase of 1.8 percent over 2016. That growth was broad based – full time employment is up 1.8 percent and part time is up 1.7 percent. Manufacturing is up 2.0 percent and service sector employment is up 2.1 percent. The resource sector was the one sector that saw a slight decline. These are encouraging numbers as they indicate sustained economic growth.

Looking forward over the forecast horizon the stable economic environment is expected continue with increased opportunity for export-oriented businesses and continued strong U.S. growth. Electricity demand is also expected to be buoyed by increased demand from the greenhouse sector in 2018-19.

There are a significant number of downside risks to the Ontario economic outlook. In particular, Ontario would be disproportionately impacted, more so than any province, should NAFTA be terminated. Although CETA and the TPP would present additional export opportunities, they would take time to grow. Those expanded markets will not shield the Ontario economy from any US/Canada trade issues in the near term.

Table 4.1 summarizes the key economic drivers for the demand forecast. The Ontario growth index is a weighting of the economic drivers as they relate to demand.

Table 4.1: Forecast of Ontario Economic Drivers

Year	Ontario Employment		Ontario Housing Starts		Ontario Growth Index	
	Thousands	Annual Growth (%)	Thousands	Annual Growth (%)	Index	Annual Growth (%)
2001	5,921	2.1	70.3	4.2	1.150	1.88
2002	6,034	1.5	79.6	13.3	1.169	1.65
2003	6,213	3.1	80.9	1.7	1.198	2.49
2004	6,314	1.7	79.9	-1.3	1.219	1.81
2005	6,381	1.3	73.2	-8.4	1.236	1.39
2006	6,452	1.5	67.8	-7.4	1.253	1.35
2007	6,545	1.6	62.8	-7.4	1.271	1.41
2008	6,610	1.5	71.9	14.6	1.287	1.23
2009	6,433	-2.7	47.9	-33.3	1.276	-0.85
2010	6,538	1.6	57.1	19.1	1.294	1.41
2011	6,658	1.8	65.2	14.3	1.314	1.60
2012	6,703	0.7	74.4	14.1	1.329	1.09
2013	6,823	1.8	58.6	-21.2	1.348	1.49
2014	6,878	0.8	56.2	-4.2	1.361	0.96
2015	6,923	0.7	68.3	21.6	1.375	1.00
2016	6,999	1.1	73.6	7.8	1.392	1.26
2017 (f)	7,107	1.5	78.4	6.5	1.413	1.52
2018 (f)	7,189	1.2	70.8	-9.7	1.431	1.24
2019 (f)	7,253	0.9	68.7	-3.0	1.446	1.08

The IESO has highlighted the shifting patterns in Ontario's employment as a measuring stick for sustained growth. Since the recession, growth has been sector- or region-specific and not broad-based. To generalize, much of the growth was centered in the service sector and in the GTA. However, 2017 showed a marked departure in the labour markets as the following graphs show.

Figure 4.1 shows the year-over-year change in employment for Ontario, the Toronto zone and all other zones combined. Broad-based growth would mean that both Toronto and the other zones would be enjoying similar job creation. For the period following the recession, Ontario's economy experienced fairly broad-based growth over the 2010-2011 timeframe. Over the 2012-2016 time frame growth has been an "either/or" experience with either the GTA or the rest of the province dominating. This year job growth has been more balanced between the two sub-provincial areas.

Figure 4.2 shows the year-over-year changes in employment broken down into services, manufacturing and other goods (mining, construction, agriculture, forestry, etc.). As with the zonal growth, a more broad-based and sustainable growth pattern would have growth across all of the sub-sectors. Throughout 2017 employment growth is showing signs of being across all sectors.

These graphs point to a more broad-based employment pattern, across regions and sectors. This is indicative of a more sustained economic expansion. Together with strong underlying economic fundamentals of low inflation, low interest rates and a competitive dollar, this will help the Ontario economy grow over the forecast horizon.

Figure 4.1: Zonal Employment Growth

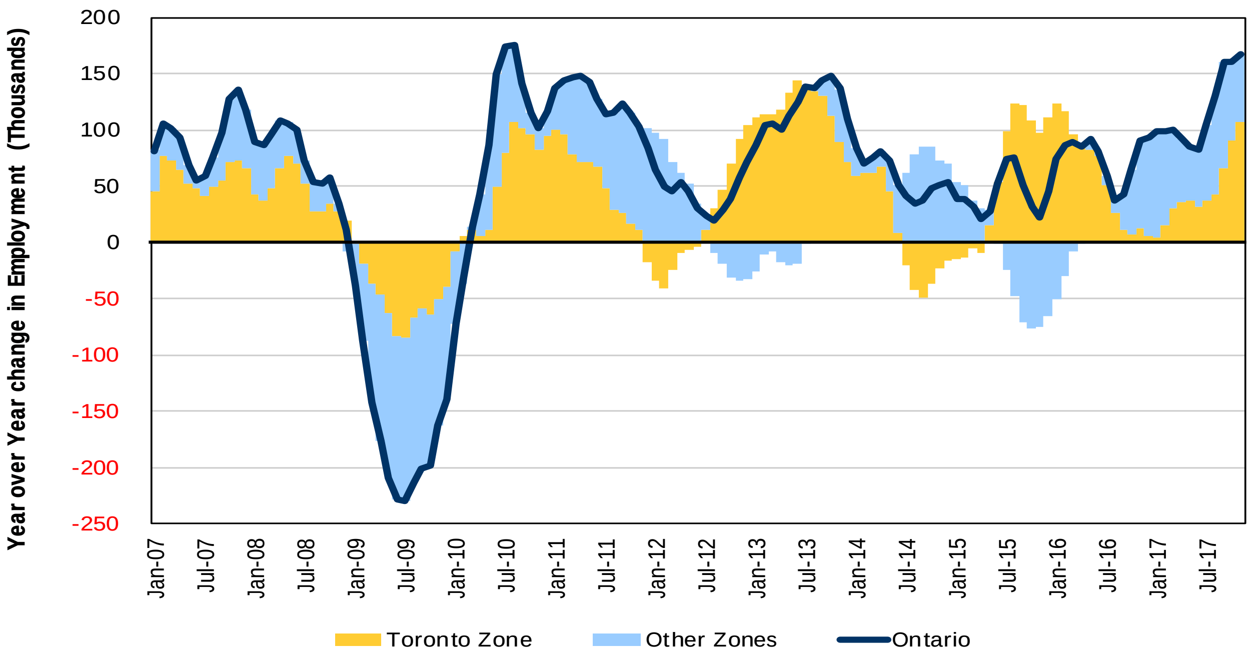
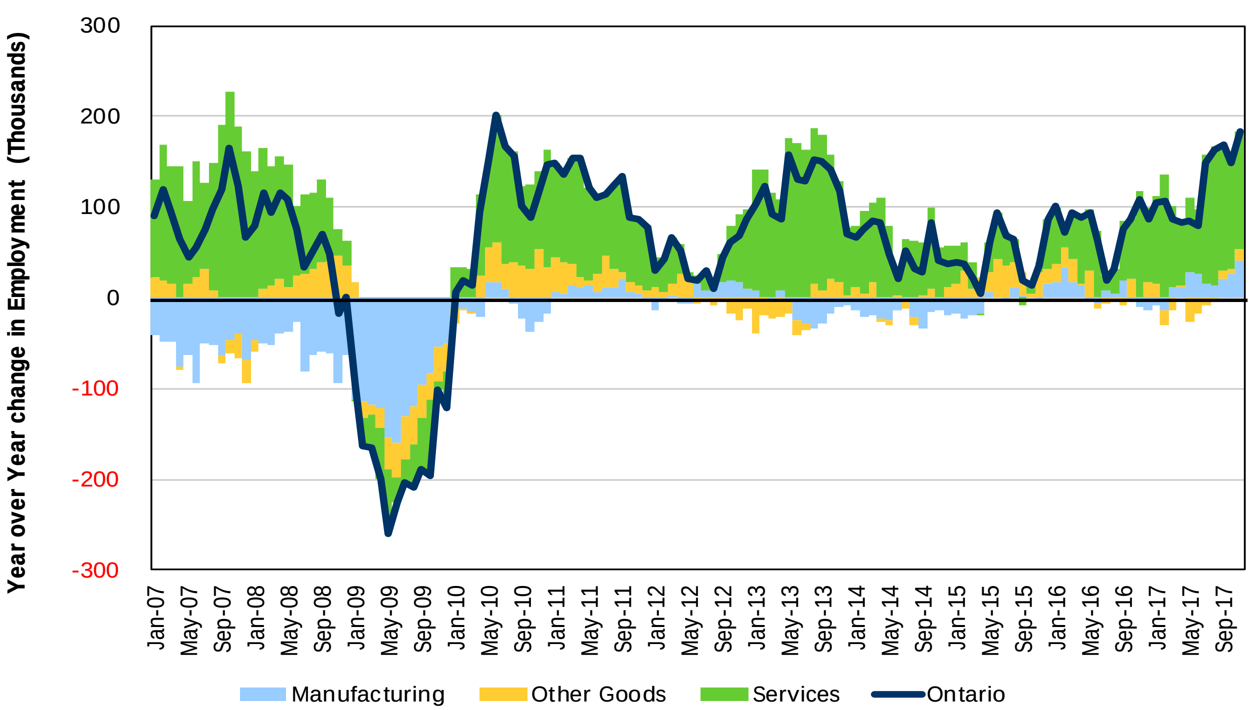


Figure 4.2: Composition of Ontario's Employment Growth



4.3 Weather Drivers for Forecast

Since forecasting long-term weather is not possible, weather scenarios are generated using historical data. The analytical studies that the IESO produces serve a variety of purposes and needs. As such, a variety of inputs are required. Therefore, the IESO produces demand forecasts based on a number of different weather scenarios. The most commonly utilized scenarios are Normal and Extreme.

The weather scenarios are generated using the following steps:

For each day over the past 31 years, a "weather factor" is calculated based on the weather conditions of that day (temperature, wind speed, cloud cover and humidity). This weather factor represents the MW impact on demand if those weather conditions were observed in the forecast horizon.

The daily weather factors are sorted from highest to lowest for each month.

Normal weather is based on the median value of the sorted weather factors across the 31 years of history. For example, the median value of the maximum weather factor from each January from 1980 to 2010 would be the first value for the normal January. The median value of the second highest weather factor from each January from 1980 to 2010 would be the second day in the normal January. This is repeated until all days in the month are generated. Once the normal months are created, they are mapped to the calendar based on the weekly average distribution of weather. The weekly peak-eliciting weather is always mapped to Wednesday to ensure that peaks do not occur on weekends or holidays.

Extreme weather is generated in a similar manner except that the maximum, rather than the median, value from the sorted 31-year history is used.

Load forecast uncertainty (LFU) -- a measure of demand fluctuations due to weather variability -- is a critical part of the analysis. In conjunction with the normal weather forecast, LFU is valuable in determining a distribution of potential outcomes under various weather conditions. The resource adequacy assessments use the Normal weather forecast in combination with LFU to consider a full range of peak demands that can occur under various weather conditions with varying probability of occurrence.

The Extreme weather scenario is valuable for studying situations where the system is under duress. Although the Extreme weather scenario is useful when examining peak conditions, it is unrealistic from an energy demand standpoint, as severe weather conditions do not persist over a long time period.

The 18-Month Outlook Tables spreadsheet includes Table 3.3.5, which has the Normal and Extreme weather scenarios. For each week, the table shows the historical weather used for the peak day of that week. The table shows the daily high (temperature) and wind speed. Not shown but used in forecasting demand are humidity and cloud cover. The IESO uses six weather stations in the demand models – the data in the table is for Toronto. The weather scenarios were updated for data through the end of December 2012.

4.4 Demand Measures and Load Modifiers

There are a number of initiatives and policies that have an impact on electricity demand. They can be grouped into two categories: demand measures and load modifiers. The rationale for the two categories is how they are treated with respect to the demand forecast. Demand measures are not incorporated into the demand forecast whereas the load modifiers are. In essence, demand measures are controllable while load modifiers are not. Demand measures include dispatchable loads, demand response programs and the peaksaver PLUS program. Load modifiers include conservation, prices and embedded generation.

Demand Measures

Demand measures are dispatched like a generation resource. Whether you dispatch a gas plant to meet a level of demand or dispatch a load off to reduce that level of demand, the system is indifferent as supply effectively equals demand. For the correct accounting of demand measures, they must be treated equitably on both sides of the ledger. Therefore, since demand measures are included in the supply mix to be dispatched off, demand must be forecasted at the higher level prior to demand measures. The historical demand is reconstituted to include load that was shed through the various demand response programs. Demand measures have no impact on the demand forecast.

As of the end of September 2017 the peaksaver PLUS program has been terminated. Those who previously participated in the program are eligible to participate in the Demand Response Auction.

Load Modifiers -- Conservation

Conservation includes energy-efficiency programs, codes and standards and fuel switching. Projected conservation numbers are based on existing and future programs.

The impacts of conservation vary according to the program mix. For example, programs that promote increasing the efficiency of air conditioners will reduce the demand for electricity in summer but have no impact in the winter. Programs aimed at improving the insulation of building envelopes will impact electricity consumption year round.

Projected conservation impacts are incorporated into the demand forecast with the result of reducing forecasted demand.

Load Modifiers -- Prices

Prices include the impact of time-of-use (TOU) rates and the Industrial Conservation Initiative (ICI). Both are factored into the demand forecast. As both are relatively new, information continues to be gathered and analyzed. The impact of these programs continues to evolve as market participants and consumers gain more experience and adjust their consumption.

TOU impacts will vary as rates are set. The overall impact will be to shift load within the day or week. Overall, peaks will be impacted more than energy in the short term. However, an increased awareness of electricity pricing will lead consumers to make equipment and usage decisions that can impact total electricity consumption in the future.

The ICI offers a financial incentive to participants who reduce their consumption at the time of the peak for the five highest peak days. The program runs from May to April. The ICI was expanded this year to allow customers with an average monthly peak demand greater than 500 kW and less than 1 MW who are in the manufacturing and greenhouse sectors. As well, those sector restrictions were lifted for customers with a peak greater than 1 MW. This will allow large commercial customers such as hospitals, universities and hotels to participate. Peak reductions have grown as both the number of participants have increased and the participants have improved their ability to identify and react to the peaks. First-year (2010) reductions were estimated at 200 MW, growing to an estimated 1,300 MW for the five peak days in 2016. The preliminary estimate for the ICI impact on the 2017 peak is 1,425 MW. That estimate will be finalized at the end of the ICI year.

Both TOU and ICI impacts are incorporated into the demand forecast.

Load Modifiers -- Embedded Generation

Embedded generation refers to load-displacing generation that is located on the market participants' side of the meter. This would include all generation under the Renewable Energy Standard Offer Program (RESOP), all generation under the microFIT program and some generation under the Green Energy Act's Feed-in Tariff (FIT program). It also includes distribution-connected generators that are not contracted through the above programs. All output provided by embedded generation is an offset to grid-supplied electricity. Therefore, the impact of embedded generation is factored into the 18-month demand forecast as a reduction to demand.

For the forecast, embedded generation is split into groups according to fuel type: solar, wind, biomass, hydro and gas-fired generation. Figure 4.3 shows the installed and projected capacity of embedded generation by fuel type. As the graph shows, the vast majority of the embedded generation is solar. Due to its large share, solar output is treated differently than the other fuel types. The impact of solar generation is generated by using engineering models that use location, cloud cover and temperature to estimate solar production. The remaining embedded generation fuel types' output is produced using average production profiles based on history. The total embedded generation output is then incorporated into the demand forecast. Table 4.2 has a summary of the estimated embedded capacity by fuel type as of June for the history and the forecast period. A more detailed table is included in the 18-Month Outlook Tables.

Figure 4.3: Projected Embedded Generation Capacity

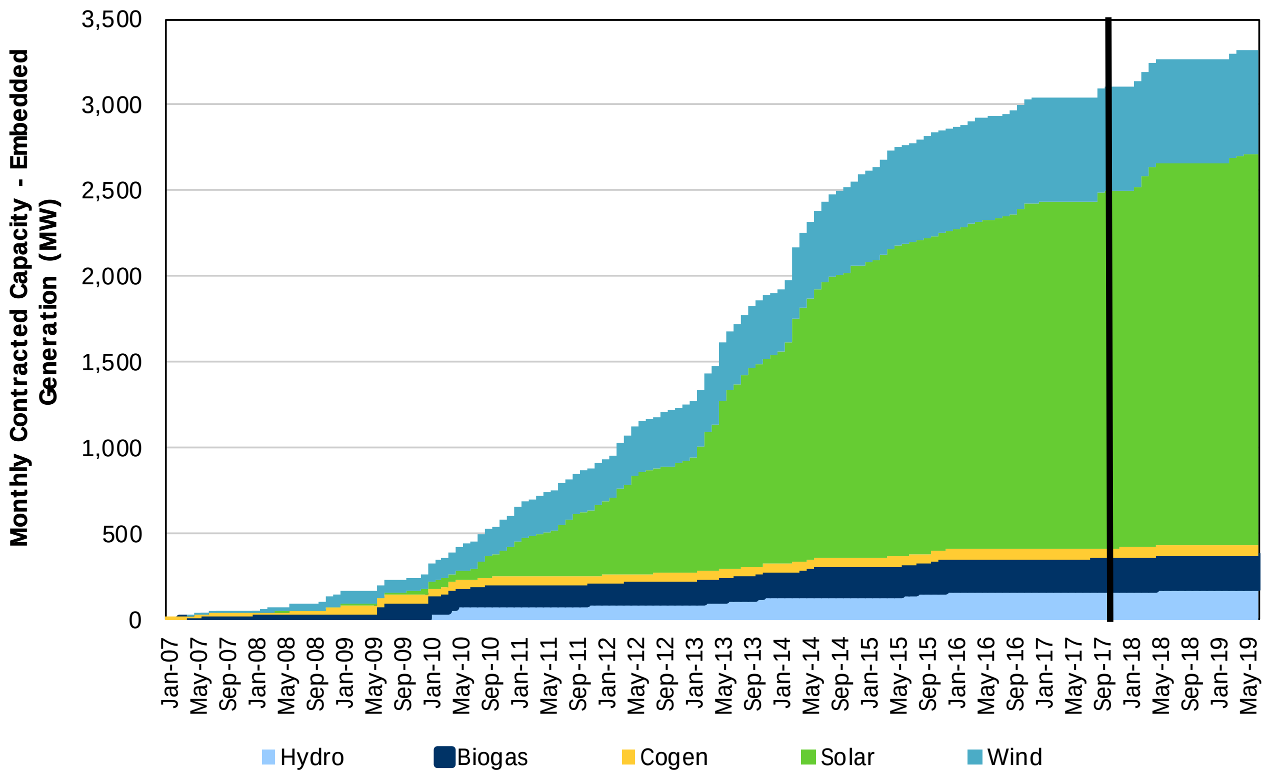


Table 4.2: Embedded Capacity

Month	Estimate of Contracted Embedded Generation Capacity (MW)					
	Biogas	Cogeneration	Solar	Hydro	Wind	Total
Jun-07	14	18	0	5	7	43
Jun-08	20	25	0	7	38	91
Jun-09	61	49	10	12	74	207
Jun-10	94	49	53	92	160	448
Jun-11	108	49	262	99	241	759
Jun-12	114	49	595	106	298	1,162
Jun-13	125	49	1,042	123	345	1,684
Jun-14	156	55	1,567	148	461	2,386
Jun-15	161	55	1,816	158	575	2,765
Jun-16	176	60	1,921	176	598	2,931
Jun-17	179	60	2,017	177	608	3,041
Jun-18	182	63	2,228	187	608	3,269
Jun-19	182	63	2,272	194	608	3,319

Over the course of the 18-month forecast, the amount of embedded solar installed capacity will range from over 2,000 MW to just over 2,200 MW. The impact of embedded solar on demand will vary over the course of the year and the time of day, due to the amount of sunlight available. Note that, as discussed in section 3.3, embedded solar is having the impact of pushing summer peaks later in the day. As peaks move later in the day, the result is a reduction in the solar capacity contribution. Therefore solar capacity contribution during peak demand has decreased and will continue to decline.

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