Ontario Demand Forecast

DECEMBER 14, 2015

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Executive Summary

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid 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 2016 to June 2017 and supersedes the previous forecast released in September 2015.

Economic Outlook

The economic outlook has been fairly consistent since the end of the 2009-10 recession. Canada has strong domestic fundamentals: it is resource rich, has low interest rates and a healthy financial sector. Despite this, it is also very dependent on trade and is not immune to the state of the global economy. Debt concerns and sluggish growth amongst the developed world has meant that the economic results have also been fairly consistent since the end of the recession – growth remains weak compared to historical recovery periods.

Ontario is particularly affected by the state of the U.S. economy, which is a major consumer of its goods. With stronger U.S. growth and a lower dollar, Ontario is in a position to see improved growth. However, weaker growth in China will not impact goods producers within the province but does result in lower commodity prices, which will impact the resource sectors. The current and developing economic environment will have both positive and negative impacts depending on the sector.

Growth risks remain in geopolitics, debt issues and energy price shocks. However, Ontario is in a relatively good position for growth.

Actual Weather and Demand

Since the last Ontario Demand Forecast document was published, actual demand and weather data have been reported for the six months of June through November. Demand for the six-month period was down 0.8% over the same period a year earlier and the weather-corrected demand had a very similar but smaller 0.4% decline.

For the past six months, distributor loads have dropped by 0.4% 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. However after adjusting for weather, distributor loads were virtually flat.

Over the same period, wholesale customers' consumption has dropped, reversing a trend of year-over-year increases for 13 consecutive months. For the six months, wholesale loads have dropped by 4.4% compared to a year ago.

The 2015 summer peak demand occurred on July 28, which was part of the heat wave at the end of the month. The afternoon high was 32.5°C (Toronto) and the humidex peaked at 36°C. July and August were both fairly normal but June was very mild with significant amounts of precipitation. Both the actual (22,516 MW) and weather-corrected

(22,559 MW) peaks were higher than the previous summers', but that is more a reflection of the extremely mild summer of 2014. From a historical perspective, both 2015 summer peaks are low. However, the continued growth in embedded generation capacity, conservation savings and the impacts of the Industrial Conservation Initiative (ICI) are having a significant impact on seasonal peaks in general and the summer peak in particular. Embedded solar capacity had surpassed 1,800 MW at the time of the July 28 peak. At the time of the 2008 summer peak of 24,195 MW, there was no embedded solar generation. Conservation and energy efficiency savings continue to reduce the underlying summer peak demands. The ICI program was recently expanded to include customers whose peak was 3 MW, a reduction from the previous threshold of 5 MW. July 28 was an ICI day, leading industrial customers to alter their consumption and reducing the peak demand.

September was unusually warm at the beginning of the month. But the high temperatures (33.5 °C) didn't translate into high peaks because they landed on Labour Day and school hadn't started yet. Temperatures dropped as students returned to the classroom. The remainder of the fall has been milder than normal but there is minimal cooling load in October and November.

Demand Forecast

The 18-Month Outlook's demand forecast includes the impact of additional conservation savings and demand reductions from projected off-grid or embedded generation. In the 18-Month Outlook, the impacts of conservation, embedded generation and prices are incorporated into the demand forecast with the result of reducing demand. Conversely, demand response programs are included in our 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 decline 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, ICI impacts and growth in solar embedded generation.

Grid-supplied energy demand is expected to show a small increase in 2016. The growth rate in 2016 will be exaggerated by 0.3% due to the additional leap year day.

Table 1: Peak and Energy Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2015-16	22,360	23,261
Summer 2016	22,649	24,623
Winter 2016-17	22,378	23,355
Year	**Normal Weather Energy (TWh)**	**% Growth in Energy**
2006 Energy	152.3	-1.9%
2007 Energy	151.6	-0.5%
2008 Energy	148.9	-1.8%
2009 Energy	140.4	-5.7%
2010 Energy	142.1	1.2%
2011 Energy	141.2	-0.6%
2012 Energy	141.3	0.1%
2013 Energy	140.5	-0.6%
2014 Energy	138.9	-1.1%
2015 Energy (Forecast)	137.1	-1.3%
2016 Energy (Forecast)	138.5	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 this requirement and covers the period from January 2016 to June 2017. It supersedes the previous forecast released in September 2015 and the previous Ontario Demand Forecast document released in June 2015.

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/Documents/marketReports/Methodology_RTAA_2015dec.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 August 2015. Data for September, 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/Documents/marketReports/18MonthOutlookTables_2015dec.xls) spreadsheet posted alongside the Outlook documents. The spreadsheet's historical tables contain data right 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)
03-Jan-16	20,783	21,825	528	2,773	02-Oct-16	17,257	17,503	554	2,451
10-Jan-16	22,360	23,261	570	2,988	09-Oct-16	17,156	17,619	786	2,468
17-Jan-16	21,673	22,447	547	2,941	16-Oct-16	17,722	18,285	507	2,434
24-Jan-16	21,921	22,493	483	2,941	23-Oct-16	17,754	18,477	392	2,518
31-Jan-16	21,857	22,539	404	2,965	30-Oct-16	18,275	18,834	318	2,555
07-Feb-16	20,985	22,069	734	2,904	06-Nov-16	18,579	19,133	416	2,620
14-Feb-16	20,367	21,776	635	2,827	13-Nov-16	19,278	20,197	601	2,653
21-Feb-16	20,336	21,951	581	2,805	20-Nov-16	19,873	20,861	342	2,734
28-Feb-16	20,290	21,817	501	2,863	27-Nov-16	20,262	21,473	607	2,782
06-Mar-16	20,075	20,883	531	2,787	04-Dec-16	20,568	22,039	409	2,832
13-Mar-16	19,452	20,440	649	2,712	11-Dec-16	21,007	22,079	555	2,872
20-Mar-16	18,323	19,442	611	2,584	18-Dec-16	21,092	22,038	690	2,858
27-Mar-16	18,357	19,271	569	2,557	25-Dec-16	20,670	22,732	362	2,925
03-Apr-16	18,291	19,049	567	2,543	01-Jan-17	20,529	21,720	528	2,747
10-Apr-16	17,406	18,422	471	2,466	08-Jan-17	21,575	22,340	570	2,873
17-Apr-16	16,830	17,308	496	2,411	15-Jan-17	22,378	23,355	547	2,955
24-Apr-16	16,693	17,048	531	2,398	22-Jan-17	21,640	22,413	483	2,942
01-May-16	17,508	19,884	721	2,385	29-Jan-17	21,674	22,448	404	2,944
08-May-16	17,680	20,220	849	2,392	05-Feb-17	21,191	22,322	734	2,950
15-May-16	18,567	21,780	845	2,414	12-Feb-17	20,795	22,011	635	2,908
22-May-16	18,815	21,906	1,175	2,430	19-Feb-17	20,296	21,855	581	2,841
29-May-16	19,338	21,634	1,330	2,381	26-Feb-17	20,172	21,836	501	2,803
05-Jun-16	19,558	23,210	1,292	2,569	05-Mar-17	20,282	21,404	531	2,821
12-Jun-16	20,761	23,655	1,055	2,596	12-Mar-17	19,900	20,708	649	2,763
19-Jun-16	21,498	23,965	835	2,652	19-Mar-17	18,948	19,936	611	2,688
26-Jun-16	22,335	23,948	754	2,719	26-Mar-17	18,364	19,182	569	2,592
03-Jul-16	22,426	24,101	1,016	2,687	02-Apr-17	18,386	19,601	567	2,587
10-Jul-16	22,649	24,623	814	2,768	09-Apr-17	18,060	18,619	471	2,514
17-Jul-16	22,564	23,789	838	2,656	16-Apr-17	17,341	18,356	496	2,415
24-Jul-16	22,158	24,262	1,035	2,754	23-Apr-17	16,732	16,729	531	2,397
31-Jul-16	22,210	24,406	841	2,745	30-Apr-17	16,610	16,948	721	2,391
07-Aug-16	21,431	24,502	958	2,712	07-May-17	17,482	20,357	849	2,387
14-Aug-16	21,223	24,128	985	2,693	14-May-17	17,622	19,710	845	2,385
21-Aug-16	21,373	23,841	1,362	2,718	21-May-17	18,521	21,834	1,175	2,414
28-Aug-16	20,187	22,745	1,413	2,579	28-May-17	18,620	21,992	1,330	2,374
04-Sep-16	18,714	22,380	1,370	2,476	04-Jun-17	19,146	21,692	1,292	2,443
11-Sep-16	18,330	20,883	680	2,445	11-Jun-17	19,853	23,956	1,055	2,570
18-Sep-16	17,901	20,259	781	2,466	18-Jun-17	20,857	24,103	835	2,589
25-Sep-16	16,969	18,364	420	2,402	25-Jun-17	22,282	24,348	754	2,647
					02-Jul-17	22,186	23,899	1,016	2,640

Compared to the previous forecast, the peak and energy demand are lower throughout the first part of 2016 and higher in the latter part.

Figure 2.1: Weekly Energy Demand – History and Forecast

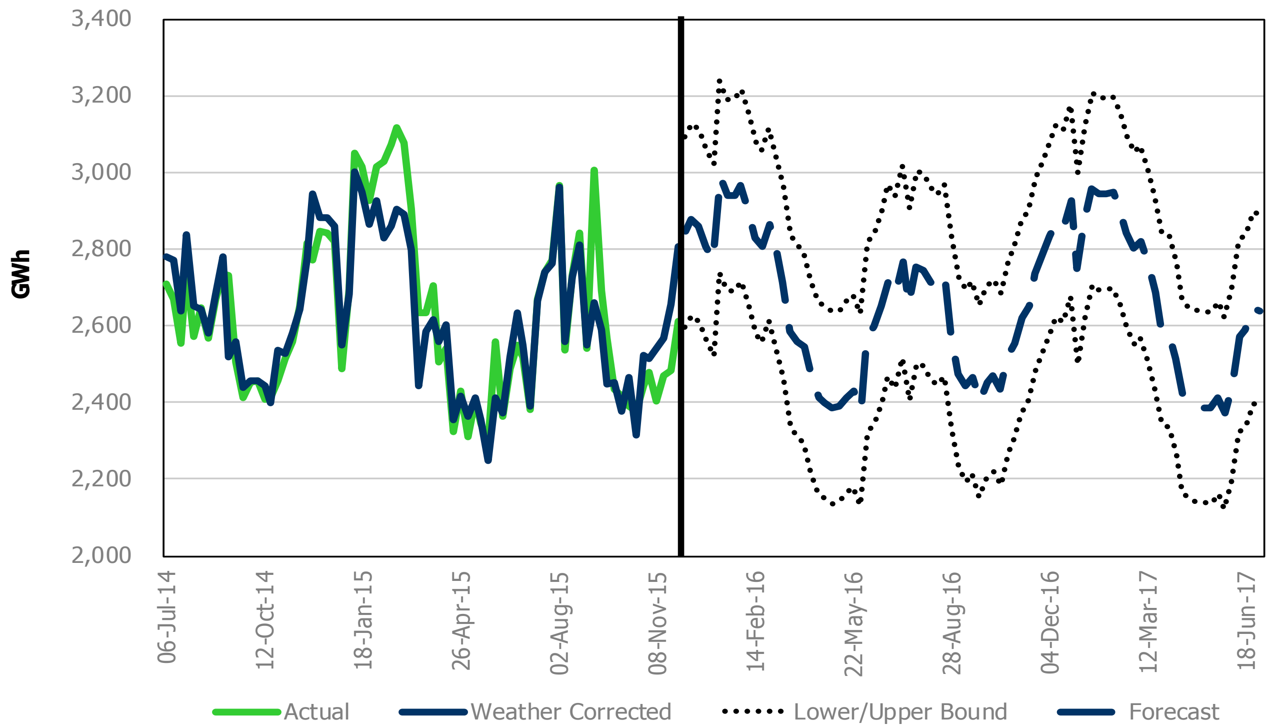
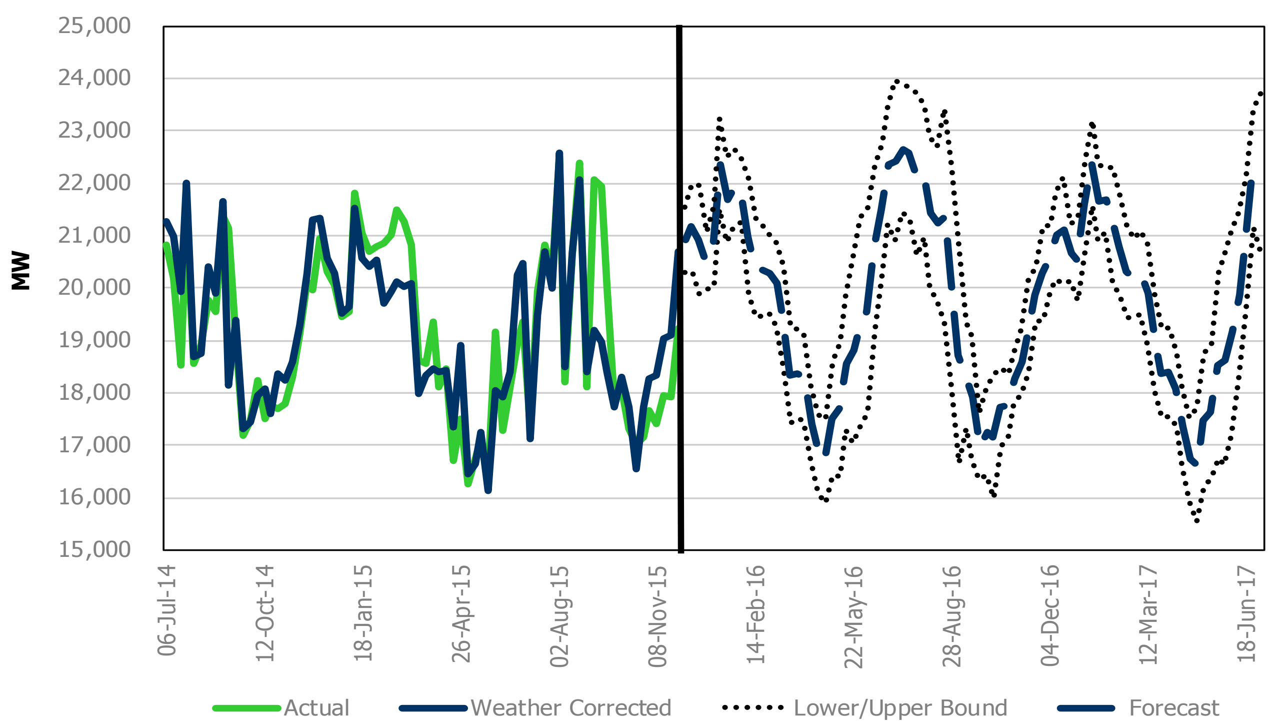


Figure 2.2: Weekly Peak Demand – History and Forecast



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3.0 Historical Review

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

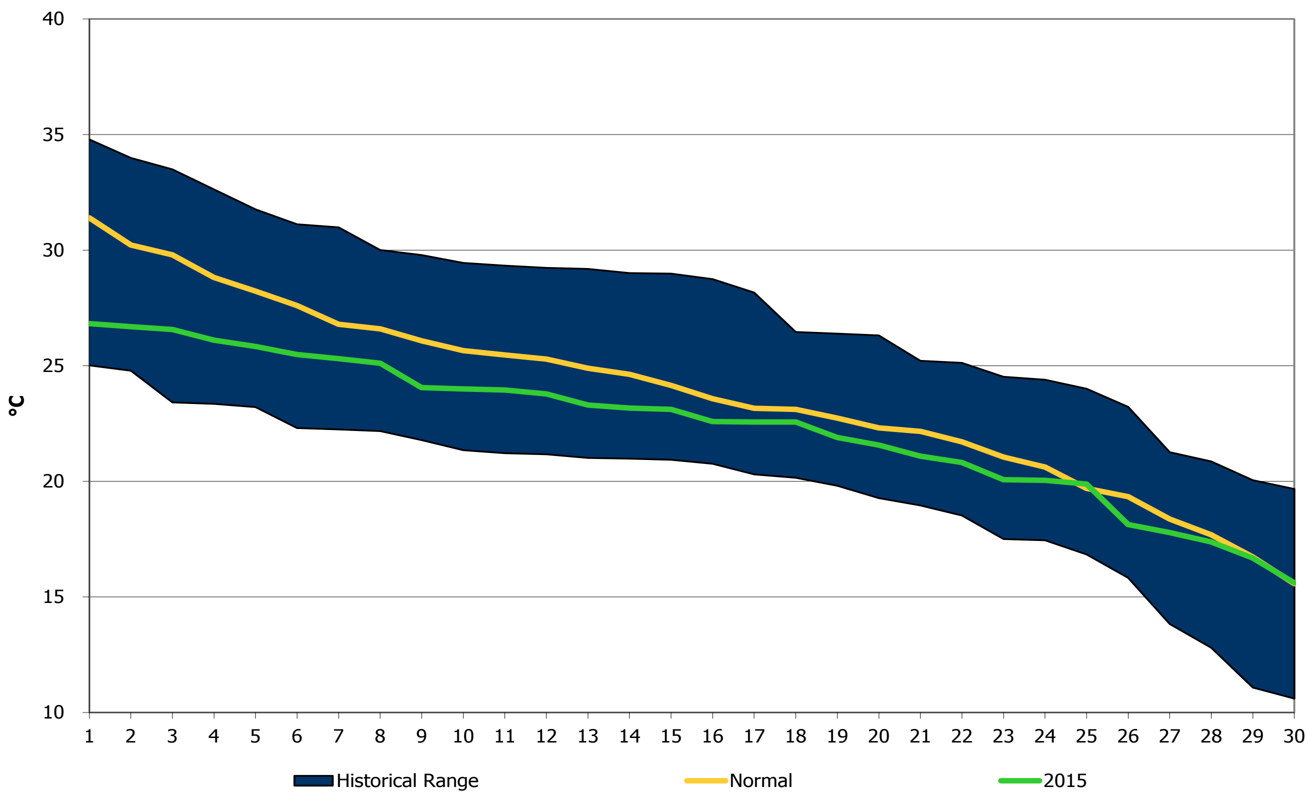
3.1 Six-Month Review – June to November

Since the last Ontario Demand document, actuals have been recorded for the period June to November. The summer of 2015 was composed of an extremely mild and wet June followed by a normal July and August. The fall has been warmer than normal. For each month there are notes regarding the weather, actual and weather-corrected energy and peak demands as well as wholesale customers' consumption. The information is presented to provide insight into the historical data. At times, the weather and weather-corrected values may seem inconsistent. This is due to the fact that the weather-correction process includes the impact of temperature, humidity, cloud cover and wind speed across six weather stations. As well, when the peak-eliciting weather (hottest day) occurs on a weekend or holiday, it can further impact the weather-correction process.

June

- June's weather was milder and wetter than normal. Precipitation is not a factor in our weather analysis but extreme amounts do have a dampening effect on demand. The peak temperatures were the second lowest June values since 1970. The average temperature was also low by historical measures.

Figure 3.1: Daily Temperature - June



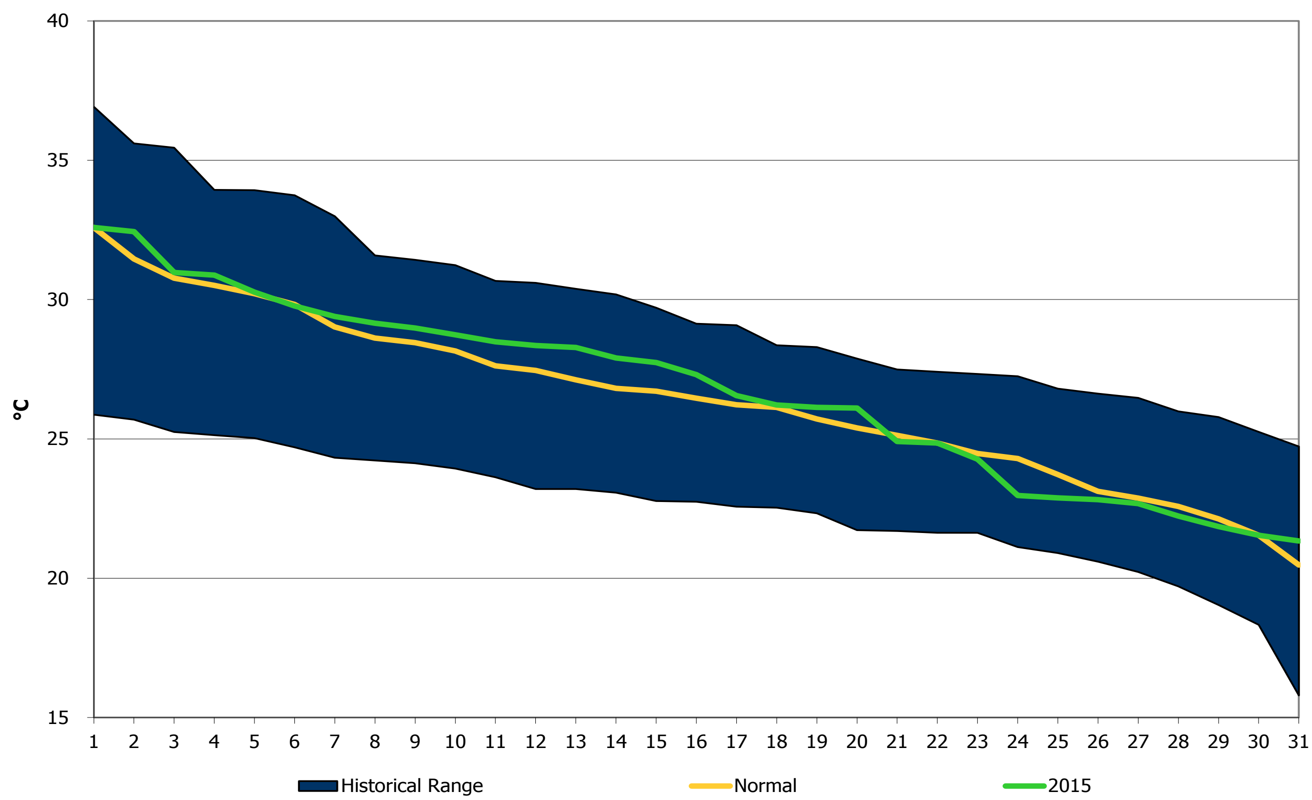
- The month's peak demand occurred on June 22, which was the third hottest day of the month. Given that the peak temperatures were cool, and that the peak didn't even occur on the hottest day of the month, it is not surprising the actual peak (19,339 MW) was the lowest since June 1996. The weather-corrected peak was 20,472 MW, which is still low by historical standards but higher than June 2014.

- With the milder weather, monthly energy demand was 10.6 TWh (10.8 TWh weather corrected). The actual is once again the lowest since 1996 and the weather-corrected the lowest since the 2009 recession.
- Minimum demand for the month was 10,804 MW occurring on a mild Sunday at 4 a.m. The value is typical of June minimums since the recession.
- Embedded generation for the month was 596 GWh, a 25% increase over the previous June with almost all the increase coming from solar generation.
- Wholesale customers' load continued to decline, dropping by 7.1% compared to the previous June. The reduction was across all industries.

July

- July's weather was normal as Figure 3.2 shows.

Figure 3.2: Daily Temperature - July



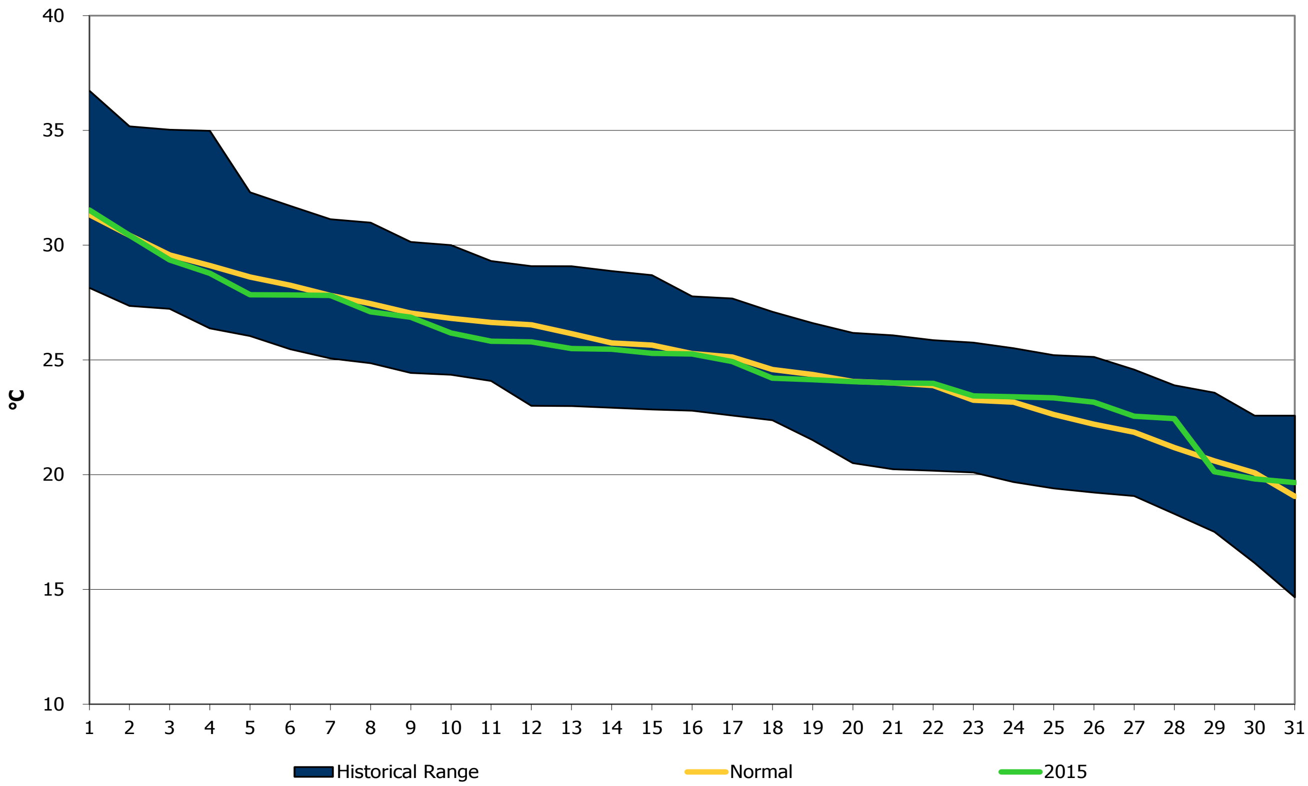
- The peak occurred on July 28, which was the hottest day of the month. The actual peak was 22,516 MW and the weather-corrected peak was an almost identical 22,559 MW. This value is low by historical standards, but it was an ICI day and, combined with increasing embedded generation capacity, these elements are having a downward impact on peak demands.
- Energy demand for the month was 12.1 TWh – both actual and weather-corrected. This is low compared to history but roughly equal to the previous July.
- Minimum demand for the month was 11,010 MW which was slightly lower than last year. The minimum occurred at 6 a.m. on a Sunday morning.
- Embedded generation for the month was 539 GWh TWh, a 17% increase over the previous July. Once again embedded solar accounted for almost all of the increase.

- Wholesale customers' consumption continued to decline, dropping by 5.7% compared to July 2014. Once again the weakness was spread across all the major electricity consuming sectors.

August

- August, like July, experienced near normal weather. This is clearly illustrated in Figure 3.3.

Figure 3.3: Daily Temperature - August

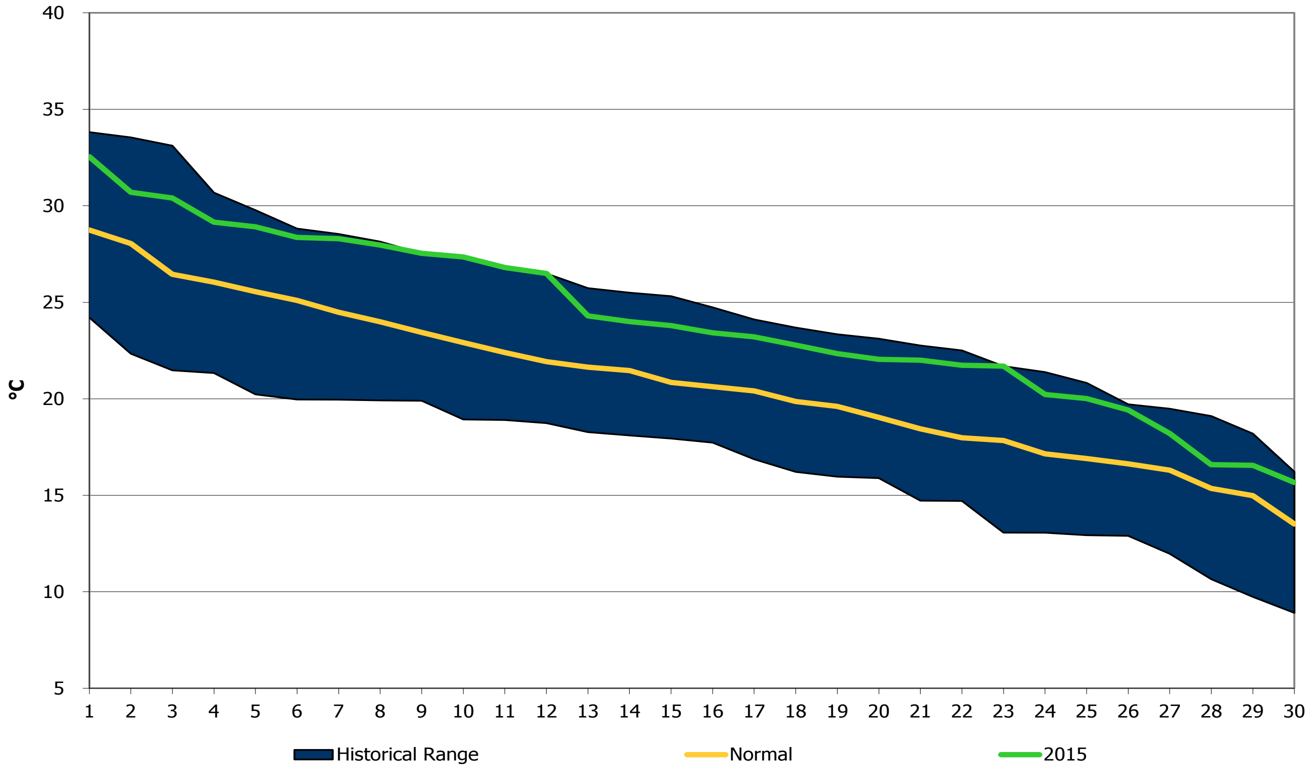


- Like July, the peak occurred on the hottest day of the month, August 17. The peak was 22,383 MW and 22,055 MW weather-corrected. These numbers are consistent with the observations for August since the recession. The day currently ranks as the third highest ICI peak for the 2015-16 program year.
- Energy demand for the month was 11.8 TWh (both actual and weather-corrected). This is consistent with the downward trend since the recession and a reflection of the increased embedded generation – particularly solar – reducing the need for grid demand.
- The minimum demand was 11,414 MW for the month. This occurred at 4 a.m. on a Sunday and is consistent with the August minimums since 2008.
- Embedded generation for the month was 501 GWh and represents a 23% increase over the previous August. Solar output was the cause of the increase.
- Wholesale customers' consumption continued to decline, falling 4.9% compared to the previous August. Mining saw a significant decline in consumption, but consumption by the motor vehicle manufacturing segments was up.

September

- The weather for September was – in this analyst's opinion – beautiful. As Figure 3.4 shows, the weather was above normal the duration of the month. September had more days above 30°C (3) than either June (0) or August (2).

Figure 3.4: Daily Temperature - September

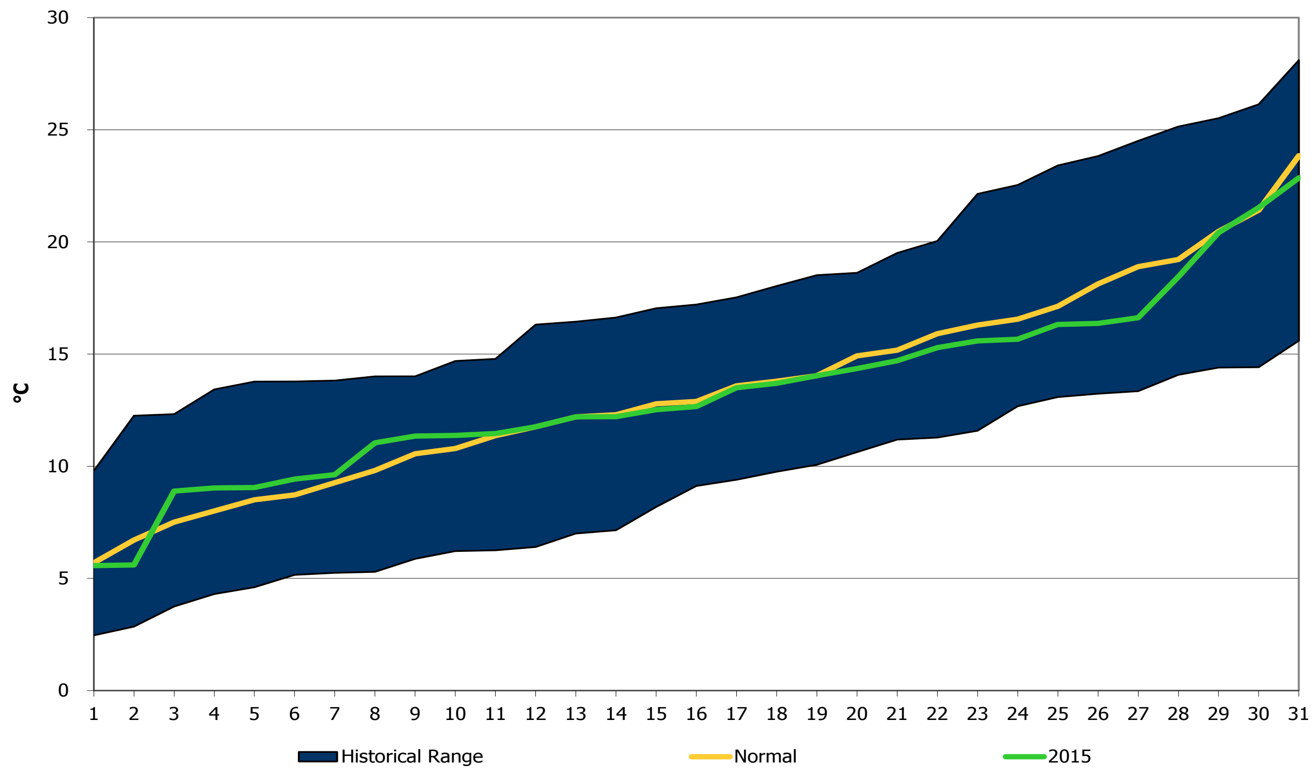


- The actual peak of 22,063 MW occurred on September 2. This was not the hottest day of the month but the third hottest. The two hottest days fell on the Labour Day weekend. The weather-corrected peak was a much lower 19,206 MW. Though the weather was warm, the actual peak was not particularly high by historical standards, which was most likely due to the fact that it was an ICI day.
- Energy demand for the month was 11.4 TWh and 10.9 TWh weather-corrected. The actual was the highest post-recession September but after weather–correcting, it is typical of the post-recession values.
- Minimum demand for the month was 10,927 MW, which is marginally lower than recent experience and most likely a product of the weather. The minimum occurred at 4 a.m. on a Sunday morning.
- Embedded generation for the month was 513 GWh an increase of 19% over the previous September, due mostly to increased solar generation.
- Wholesale customers' consumption decreased by 4.6% compared to the previous September. This marks six consecutive months of decline and the largest percent decline during that period. Once again the reductions were spread across most sectors. This marks 12 consecutive months of declines in wholesale customers' consumption.

<u>October</u>

- The weather for October was near normal. October is cold weather peaking roughly two-thirds of the time. The peak is generally a warm weather peak at the beginning of the month or a cold weather peak at the end of the month. As such, the highs and lows could both be important. For October 2015, both the highs and low temperatures were near normal. Figure 3.5 shows the ranked temperatures for the month versus the historical range.

Figure 3.5: Daily Temperature - October

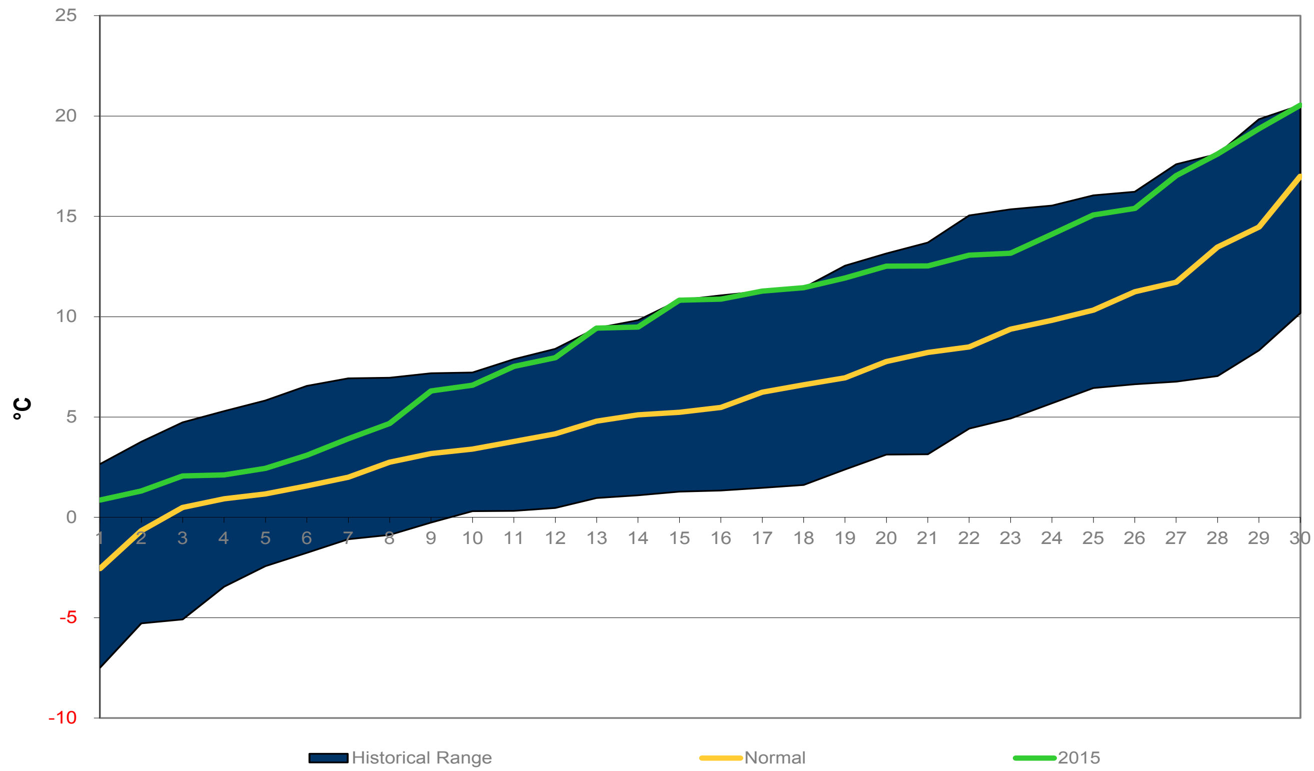


- The month's peak demand occurred on October 28, which would indicate it was a cold weather peak. The month ended with fairly mild temperatures, so the peak was a rather low 17,667 MW. The weather corrected peak was 18,256 MW. Both peaks are on the low side of October peaks since the recession.
- Energy demand for the month was 10.7 TWh (10.8 TWh weather corrected). This is on the low side of the October values posted since the recession.
- The minimum demand of 10,539 MW occurred at 4 a.m. on Thanksgiving Day. This value is low but is the result of it being a holiday and the warmest day of the month.
- Embedded generation for the month was 516 GWh. This represents a 15% increase over the previous October. As with the previous months, the main reason for the increase was solar output. The reason the increase wasn't as great as the previous numbers is due to the declining hours of daylight.
- Wholesale customers' consumption increased for the first time in a year, albeit by a small amount, 0.4%. Petroleum and chemicals were the cause behind the increase.

<u>November</u>

- Like September, November was milder than normal. There wasn't a daily high below zero for the month. This is evident in Figure 3.6 where, other than the 10 coldest days, the weather was near all-time highs.

Figure 3.6: Daily Temperature - November



- The actual peak for November was 19,239 MW occurring on Monday November 23, which was the second coldest day of the month. The weather-corrected value was a much higher 20,688 MW. Both values are low by historical standards and continue the slow decline since the recession.
- With the impacts of conservation and embedded generation, combined with mild weather, led actual demand to the lowest November (10.7 TWh) since market opening. A significant part of that is due to the weather and after weather-correcting the energy (11.3 TWh) is slightly higher than last November.
- Minimum demand of 11,338 MW occurred Sunday, November 1 at 4 a.m. As the temperature drops the minimums tend to increase as heating load runs overnight. This number is only slightly higher than the November value during the recession.
- Embedded generation topped 485 GWh for the month. An increase of 18% over the previous November. Of the increase, two thirds was attributable to solar power and a third to wind power.
- The wholesale customers' consumption fell 4.2% compared to the previous November. The reductions were fairly widespread across all the sectors.

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 2015 Weather and Demand Summary

Historical Analysis		June	July	August	September	October	November
Actual Weather	Average Temperature (°C)	21.7	26.6	25.0	24.0	13.4	10.4
	Minimum Temperature (°C)	15.7	19.9	18.9	14.4	4.9	1.8
	Maximum Temperature (°C)	27.6	32.5	32.1	33.5	22.9	20.6
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)	19,339	22,516	22,383	22,063	17,667	19,239
	Average Hour (MW)	14,756	16,270	15,856	15,780	14,365	14,836
	Minimum Hour (MW)	10,804	11,010	11,414	10,927	10,539	11,338
	90th Percentile (MW)	17,221	19,757	19,007	19,813	16,384	17,157
	Percent above 20,000 (MW)	0.0%	8.3%	6.3%	8.6%	0.0%	0.0%
	# of Hours Above 20,000 (MW)	0	62	47	62	0	0
	Energy Demand (GWh)	10,624	12,105	11,797	11,362	10,687	10,682
Weather Corrected Demand	Peak Demand (MW)	19,781	22,559	22,055	19,206	18,256	20,688
	Energy Demand (GWh)	10,742	12,083	11,788	10,866	10,779	11,334
Forecast Demand	Peak Demand (MW)	22,277	22,888	21,464	18,485	18,339	20,306
	Energy Demand (GWh)	11,410	12,174	11,821	10,513	11,150	11,595

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

Demand for the six-month period of June to November was down 0.8% over the same period a year earlier. After correcting for weather variation, the decline was a more modest 0.4%. The decline can be attributed to increased conservation savings, growth in embedded generation output and lower wholesale customer consumption.

Distributors' loads have declined by 0.4% over the past six months. After correcting for weather, the load increased by 0.1% compared to the previous year. The distributor load levels would be impacted by all of conservation, embedded generation and the level of economic activity. For the past six months, the output by embedded generators grew by 19% or 500 GWh.

The past six months have seen a change in the underlying load at the consumer level. Previously, distributors' loads have declined while wholesale customers have been showing year-over-year increases. However, since the last quarter of 2014, wholesale loads have also been declining. For the past six months, distributor loads have dropped by 0.4% compared to the same months a year earlier. Wholesale loads have dropped by 4.4% over the same periods.

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. Annual embedded generation topped 5.2 TWh in 2014, up from 2.0 TWh in 2009. Moving forward, the embedded generation component will continue to grow as more renewable energy comes into commercial operation. After correcting for weather and adding back the impact of embedded generation, distributor loads would have increased 1.0% for the period June to November over the same period a year earlier.

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

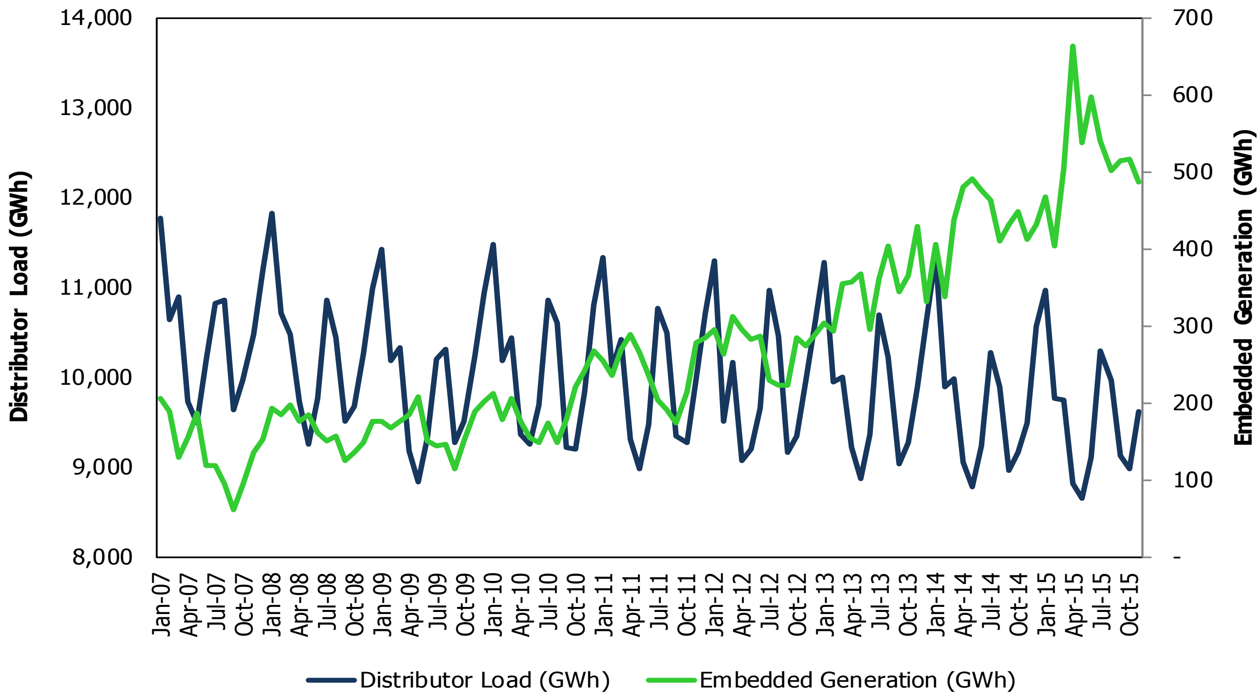


Figure 3.8 shows the year-over-year change in wholesale customers' average hourly consumption. The graph illustrates the impact of the recession, modest recovery and erosion of the past year.

Figure 3.9 shows the wholesale customers' average hourly load by industry segment for the past six months (June to November) compared to the same six months prior to the recession (June 2008 to November 2008) and a year ago. Mining and Other were the only sectors that had seen increases from the pre-recessionary period to last year. Both those sectors fell back slightly this year. For the remaining sectors, most have been at or near the levels they were last year.

Using the same six month period – June to November – the size and share of the wholesale loads have changed since market opening in 2002. At market opening, Pulp & Paper was the largest industrial segment with average hourly load of 787 MW. Now that segment ranks fourth. Mining is now the largest industrial segment with an average hourly load of 540 MW up from 514 MW at market opening. The changing industrial structure is due to a variety of causes. Some changes are sector specific –- the decline in demand for newsprints' impact on Pulp & Paper – while other changes are broad based – such as the appreciation of the Canadian dollar from 2004 through to 2014. Generally, loads were declining over the 2004-2008 timeframe as the Canadian dollar appreciated. In 2009, the financial crisis and ensuing recession led to a sharp decline in wholesale load as industry re-structured and scaled back production. Wholesale loads declined by 24% in 2009. Loads rebounded in 2010 and have averaged annual growth of 2.7% since the recession. However, the recovery has been slow and wholesale loads remain below the pre-recessionary levels of 2008 by 13%.

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

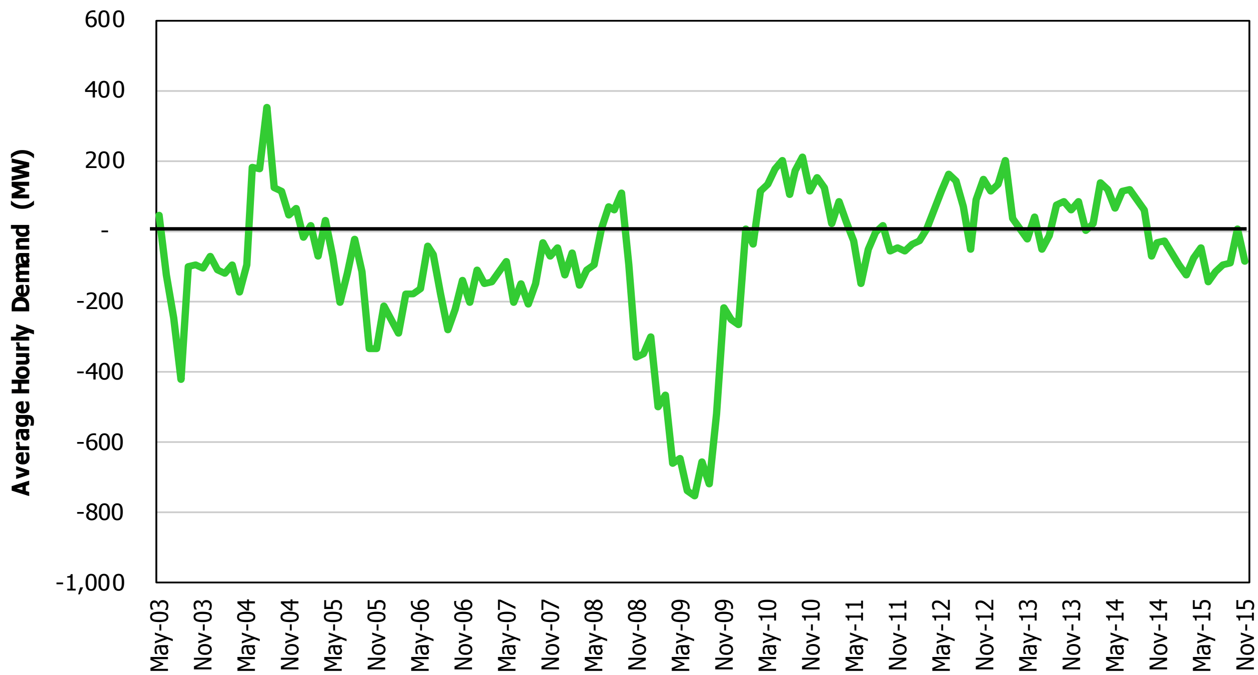


Figure 3.9: Wholesale Customers' Average Hourly Consumption by Industry Segment

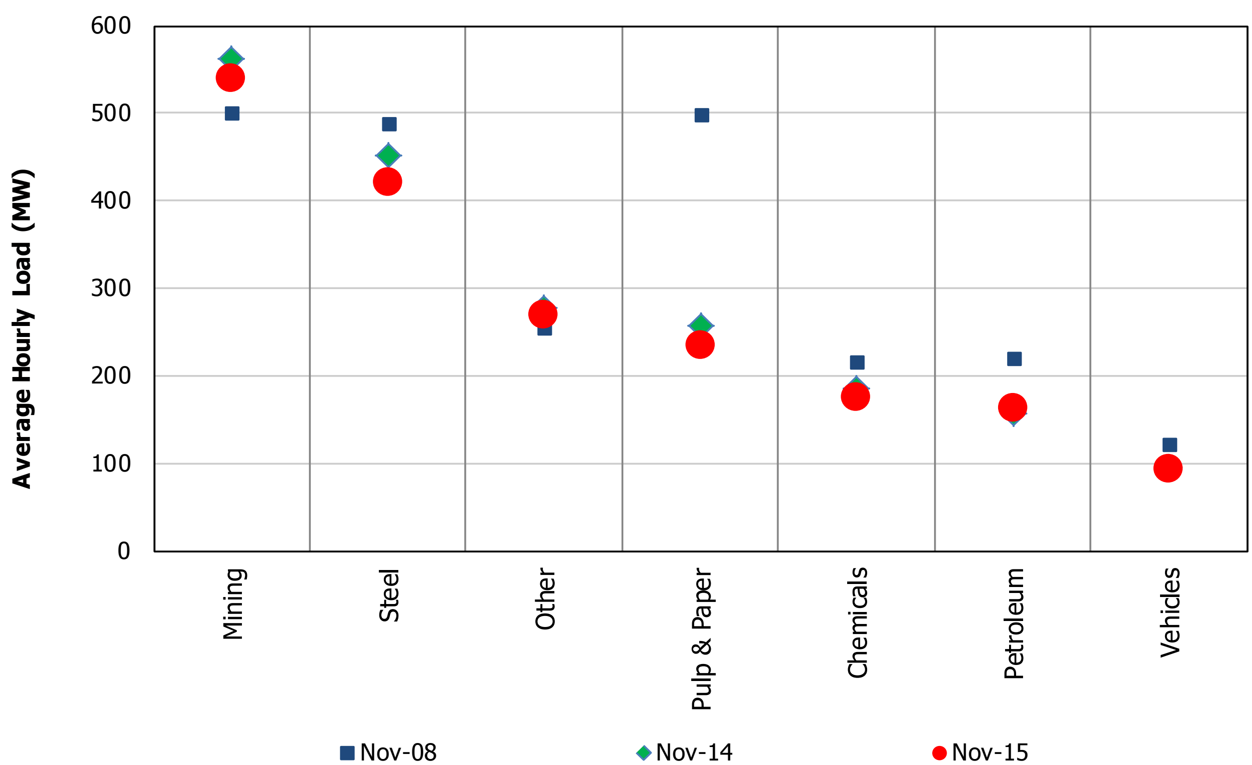


Table 3.2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week and notes any item of significance for the week. If the weather-corrected demand is greater than the actual demand, it means that the actual weather was milder than 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
23	07-Jun-15	05-Jun-15	2,363	2,370	
24	14-Jun-15	10-Jun-15	2,488	2,520	
25	21-Jun-15	15-Jun-15	2,548	2,634	
26	28-Jun-15	22-Jun-15	2,520	2,549	
27	05-Jul-15	05-Jul-15	2,382	2,390	Canada Day
28	12-Jul-15	06-Jul-15	2,667	2,665	
29	19-Jul-15	13-Jul-15	2,741	2,738	
30	26-Jul-15	20-Jul-15	2,772	2,762	
31	02-Aug-15	28-Jul-15	2,965	2,961	
32	09-Aug-15	04-Aug-15	2,537	2,557	Civic Holiday
33	16-Aug-15	16-Aug-15	2,732	2,725	
34	23-Aug-15	17-Aug-15	2,842	2,810	
35	30-Aug-15	30-Aug-15	2,541	2,548	
36	06-Sep-15	02-Sep-15	3,004	2,658	
37	13-Sep-15	08-Sep-15	2,692	2,589	Labour Day
38	20-Sep-15	17-Sep-15	2,566	2,448	
39	27-Sep-15	23-Sep-15	2,436	2,451	
40	04-Oct-15	28-Sep-15	2,415	2,376	
41	11-Oct-15	05-Oct-15	2,389	2,463	
42	18-Oct-15	15-Oct-15	2,374	2,315	Thanksgiving Day
43	25-Oct-15	22-Oct-15	2,444	2,523	
44	01-Nov-15	28-Oct-15	2,478	2,514	
45	08-Nov-15	03-Nov-15	2,402	2,542	
46	15-Nov-15	10-Nov-15	2,471	2,567	Remembrance Day
47	22-Nov-15	17-Nov-15	2,481	2,657	
48	29-Nov-15	23-Nov-15	2,613	2,808	

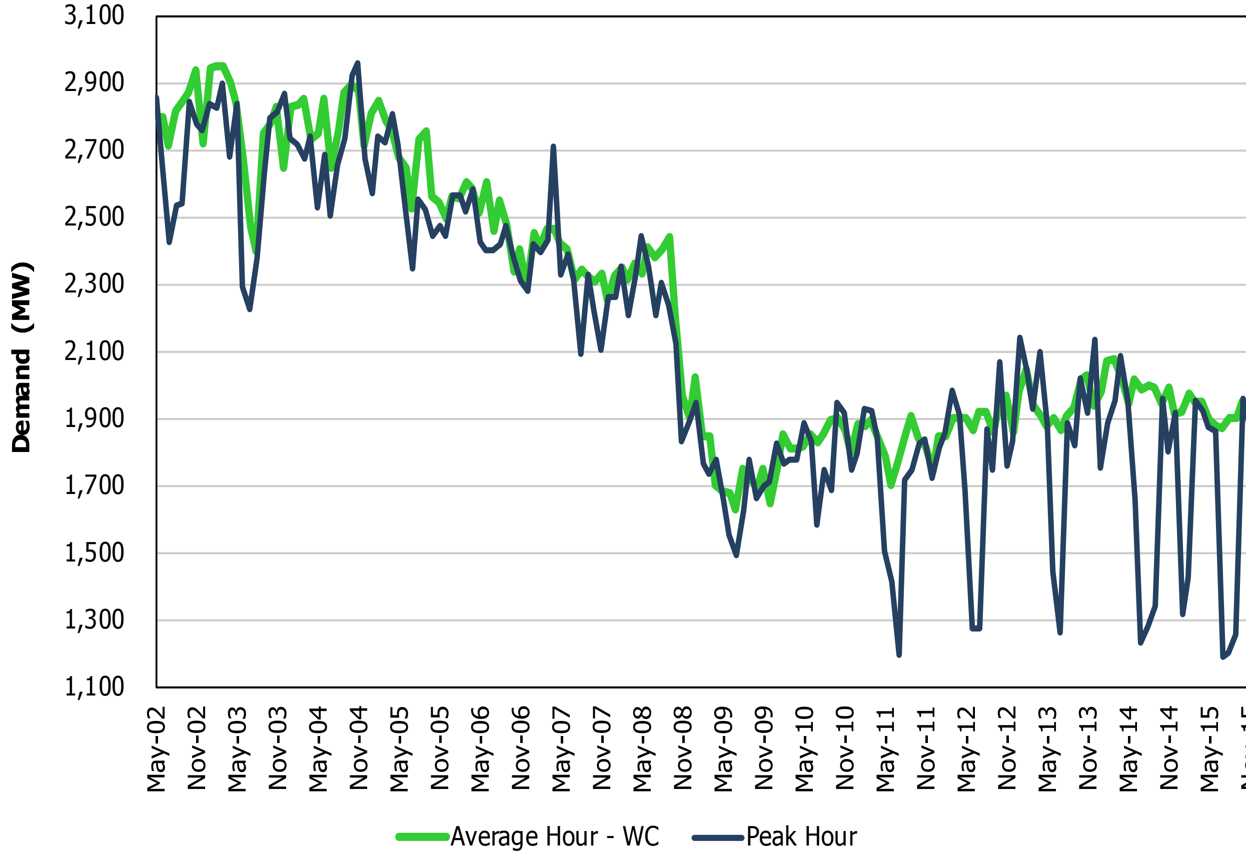
3.3 Historical Peak Demand

Peak demands are weather-driven, weekday events. 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 22,516 MW, which was higher than last summer's peak (21,363 MW). The summer of 2014 was quite mild but even after adjusting for weather, the summer peak was higher than the previous summer. Both peak days were subject to the impact of ICI reductions.

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. 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 2014, the program was expanded to include customers with a peak load of 3 MW or higher. Previously, the program had a threshold of 5 MW or higher.

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

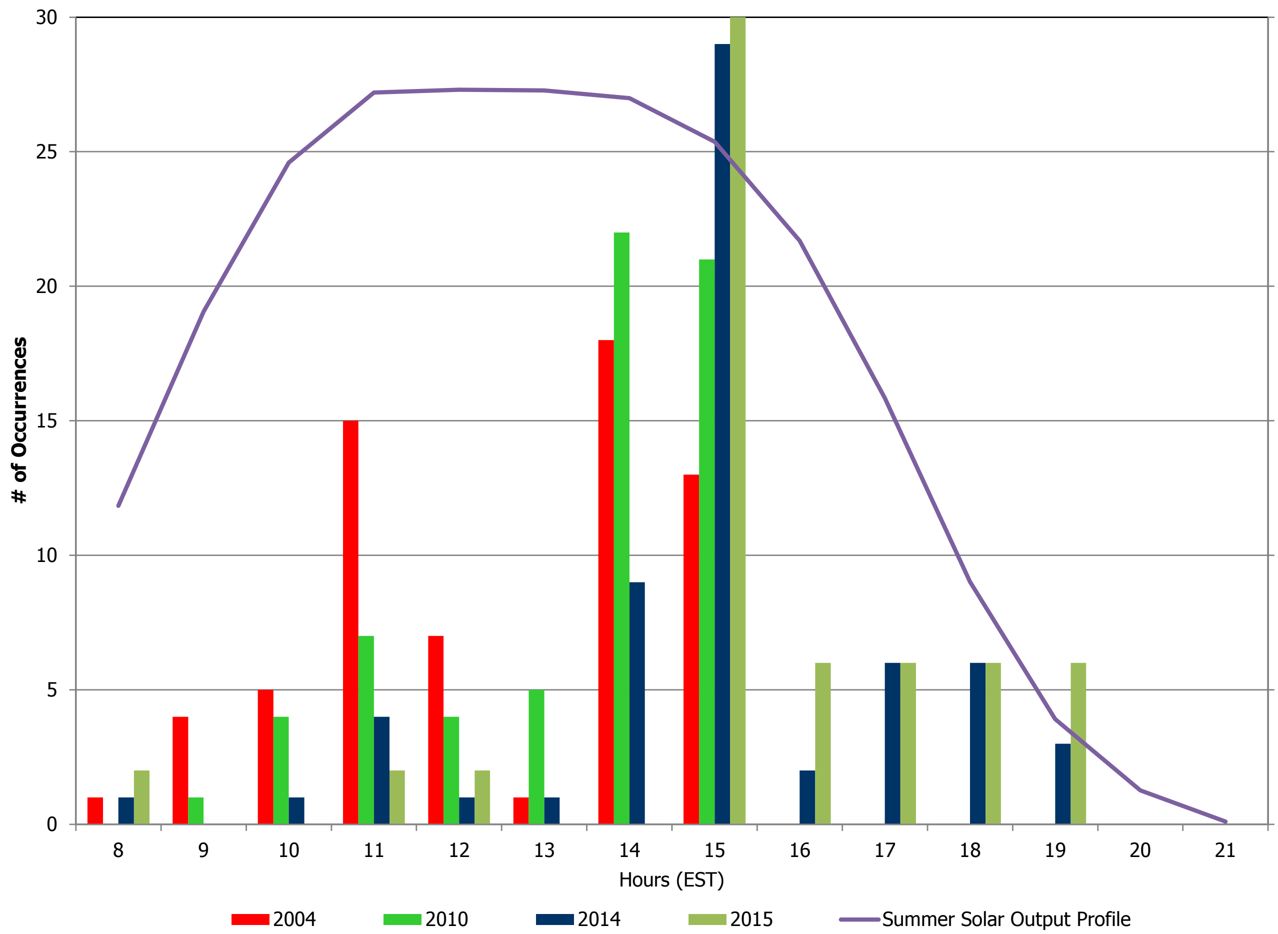


For most years, the province has been summer peaking, but the summer peaks face more downward pressure than the winter peaks. In particular, conservation and embedded solar generation do not impact the seasonal peaks to the same degree. The summer peak is primarily driven by air conditioning load, whereas 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 late afternoon as air conditioners worked to dispel the accumulated heat. Now the embedded solar is "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 that the summer weekday peaks are slowly shifting to later in the day. This graph was introduced after the 2014 summer and has been updated for 2015. It is interesting to note that most peaks still occur in hour 15. Previously, hour 14 was usually the second most common peaking hour but, in 2015, none of the weekday peaks occurred in that hour. Bear in mind that the graph shows hours in Eastern Standard Time – during the summer Daylight Savings Time would mean that the peaks are occurring an hour later. Therefore, in 2015, six of the weekday peaks occurred in the hour ending at 8 pm.

Figure 3.11: Summer Weekday Peak Hour Distribution



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 3.12 shows the break-down for the summer 2014 and winter 2014-15 peaks. Complete data for the summer 2015 has not been submitted so was not included in the graph. The illustration shows that there are a number of factors working to reduce the seasonal grid peaks. The figure shows a reconstituted peak demand, the peak demand that would have been had it not been for a variety of load modifiers. The interesting aspect is that the winter peak of 2014-15 was the first winter peak to be impacted by ICI.

Figure 3.12: Anatomy of Seasonal Peaks

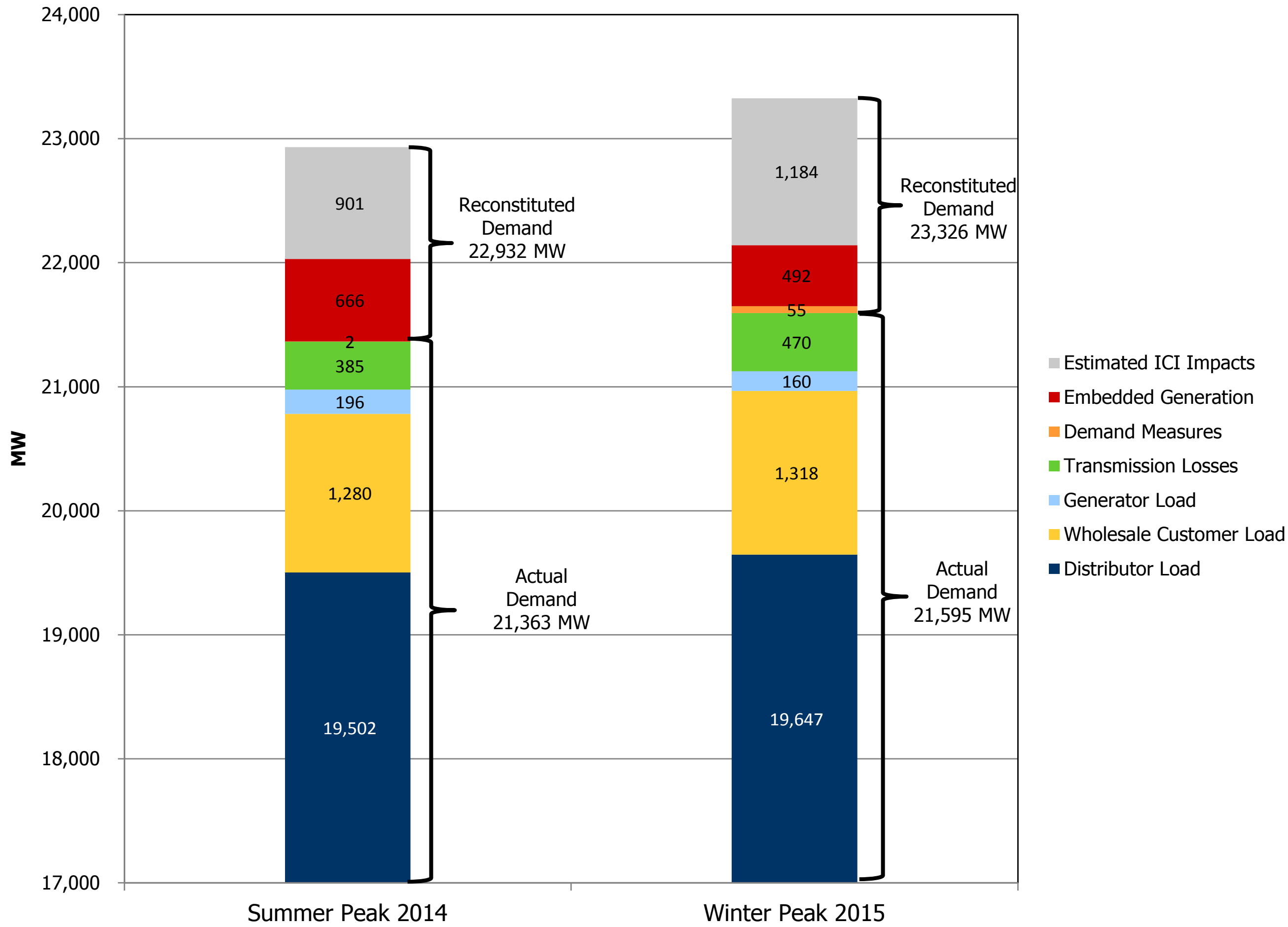


Table 3.3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3.3: Historic Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
23	07-Jun-15	05-Jun-15	17,285	17,914	28.8
24	14-Jun-15	10-Jun-15	18,099	18,387	24.3
25	21-Jun-15	15-Jun-15	18,951	20,249	27.6
26	28-Jun-15	22-Jun-15	19,339	20,472	24.1
27	05-Jul-15	05-Jul-15	17,329	17,103	25.5
28	12-Jul-15	06-Jul-15	19,929	19,493	25.6
29	19-Jul-15	13-Jul-15	20,811	20,707	26.6
30	26-Jul-15	20-Jul-15	20,259	19,996	28.1
31	02-Aug-15	28-Jul-15	22,516	22,559	28.0
32	09-Aug-15	04-Aug-15	18,189	18,474	32.5
33	16-Aug-15	16-Aug-15	20,639	20,663	25.8
34	23-Aug-15	17-Aug-15	22,383	22,055	30.4
35	30-Aug-15	30-Aug-15	18,105	18,397	32.1
36	06-Sep-15	02-Sep-15	22,063	19,206	25.4
37	13-Sep-15	08-Sep-15	21,923	18,984	32.6
38	20-Sep-15	17-Sep-15	20,010	18,400	28.7
39	27-Sep-15	23-Sep-15	17,809	17,728	27.2
40	04-Oct-15	28-Sep-15	18,073	18,302	24.2
41	11-Oct-15	05-Oct-15	17,301	17,725	21.7
42	18-Oct-15	15-Oct-15	17,022	16,543	14.2
43	25-Oct-15	22-Oct-15	17,164	17,715	17.6
44	01-Nov-15	28-Oct-15	17,667	18,256	15.9
45	08-Nov-15	03-Nov-15	17,401	18,340	13.1
46	15-Nov-15	10-Nov-15	17,956	19,047	20.6
47	22-Nov-15	17-Nov-15	17,919	19,087	9.2
48	29-Nov-15	23-Nov-15	19,239	20,688	7.6

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 remains low by historical standards. The winter curve illustrates the cold winters over the past two years and the summer curve shows a more typical summer compared to 2014. However, the impact of conservation and embedded solar has significantly shifted load compared to history.

Figure 3.13: Fall Load Duration Curve

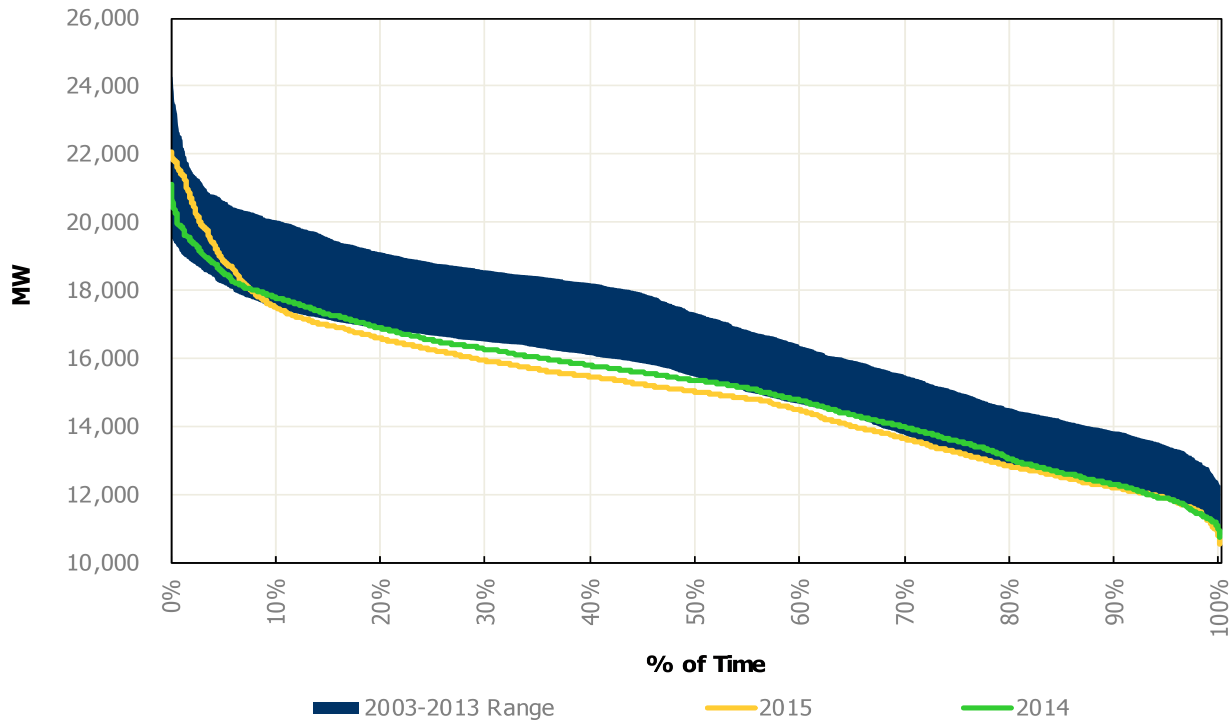


Figure 3.14: Summer Load Duration Curve

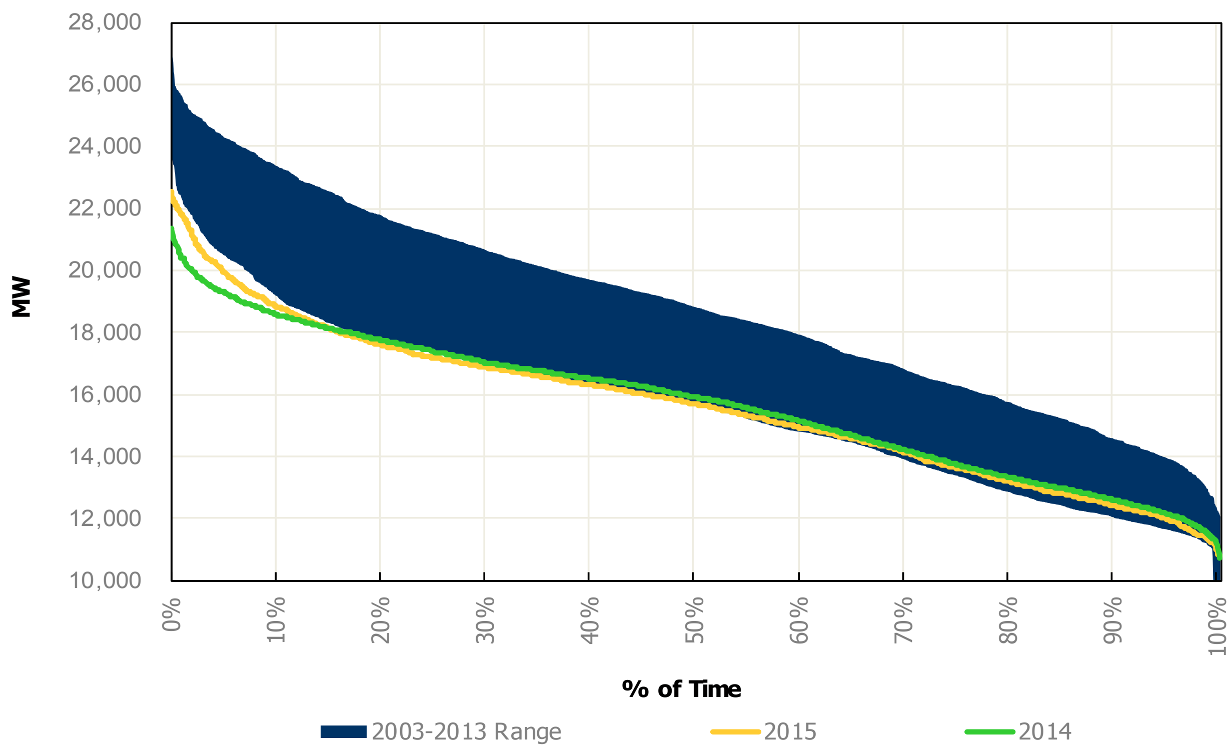


Figure 3.15: Spring Load Duration Curve

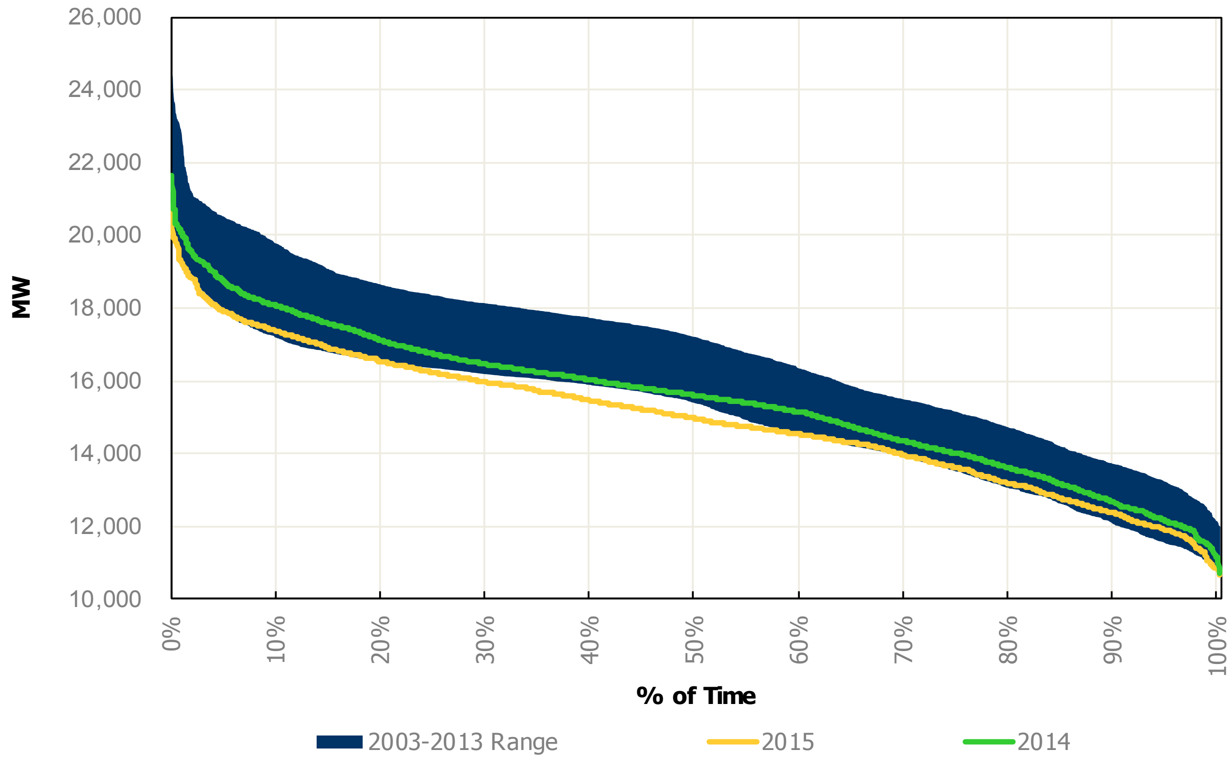
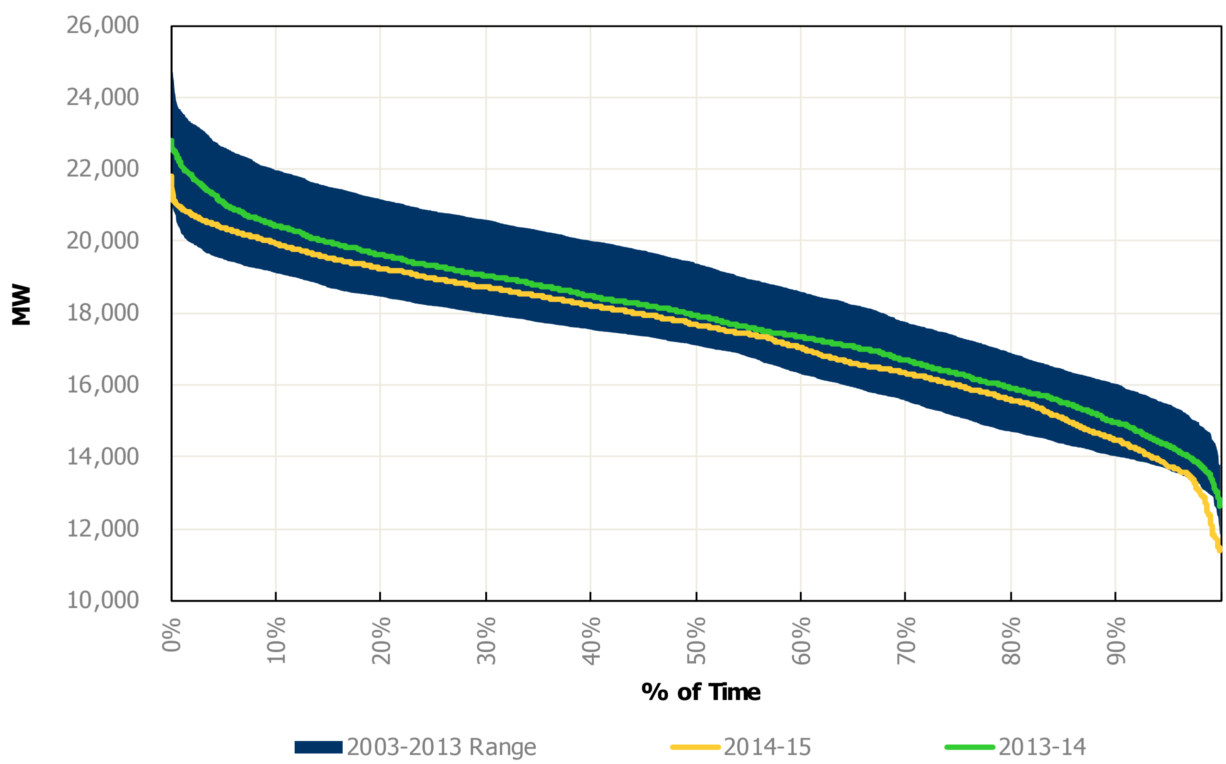


Figure 3.16: Winter Load Duration Curve



3.5 Historical Minimum Demand

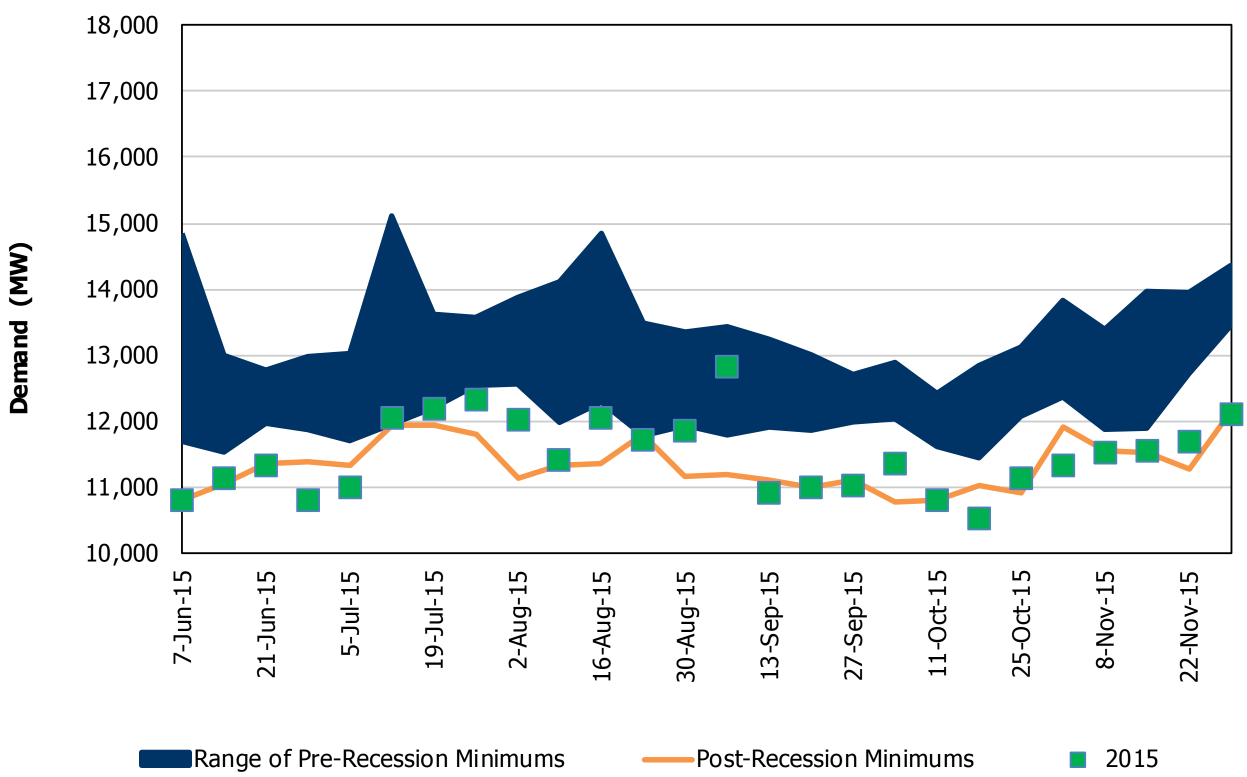
Like peak demands, the minimums are driven by weather, calendar and economic effects. Which of the drivers is most important varies throughout the seasons. The winter, spring and fall have the potential for heating load, whereas the summer period has the potential for cooling loads. Minimums continue 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 early predawn hours, it is embedded wind that is further reducing the need for grid-supplied electricity.

During the recession, load was not affected proportionally. Overnight loads bore a higher proportion of load loss as industries cut overnight and weekend shifts first. As well, overnight loads are the least weather sensitive, so that the economic reductions would have a more profound impact on minimums than on overall energy demand.

Figure 3.17 shows the minimum weekly demands for the period June to November since market opening. The band represents the range of values for the years 2002 - 2008. The line shows the lowest weekly minimums post-recession, and the squares represent the weekly minimums for the past six months.

The minimums of the past six months reflect the weather. The mild June weather reduced the need for cooling load and minimums dropped accordingly. More typical weather in July and August pushed the minimums back up as cooling load increased. The warm fall weather mitigated the need for overnight heating and minimums dropped down. Most of the weekly minimums come on the weekend or holidays when the level of economic activity is lower.

Figure 3.17: 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/Documents/marketReports/Methodology_RTAA_2015dec.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, sunrise and sunset – 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.

Despite strong economic fundamentals – low interest rates, a strong financial sector and a rich resource base -- Canada has not experienced strong growth in the post-recession recovery period. Much of that can be explained by the overall global situation. Since Canada is trade dependent, sluggish growth throughout the industrialized countries was felt here in Canada. The developing nations -- China in particular -- were experiencing strong growth but are generally not markets for our finished goods. They are consumers of commodities and their strong performance had a positive impact on the resource sector.

The recent decline in oil prices has had two significant impacts for Canada. First has been the direct impact on the oil producing regions of Canada, where jobs have been lost and investment significantly scaled back. The second impact has been a weakening of the Canadian dollar. The oil price collapse and stronger U.S. growth has led to a significant change in the exchange rate with our major trading partner. The dollar is the lowest it has been in well over 10 years.

This economic climate bodes well for central Canada's export-oriented manufacturing sector. Strong U.S. growth means there is a market for our goods. Lower commodity prices means the cost of inputs has declined. Finally, a lower dollar means our exports will be more competitively priced. All this lays the ground work for improved economic activity in Ontario. However, that stronger growth has yet to become reality.

Lower commodity prices have had a negative impact on the resource sector. Despite this, Ontario's resource sector employment hasn't seen a decline. Conversely, manufacturing has improved only because the sector has stopped shedding jobs. The conditions for improved growth are there but whether the economy shows significant improvement will be seen over the coming months. As long as the conditions hold, barring an economic or geopolitical shock, the greater are the chances for increased economic activity.

There are a number of downside risks to the economic outlook including geopolitical, the impacts of the Trans-Pacific Partnership and forthcoming environmental initiatives. The impacts of the latter two will be seen as more details are provided.

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 (%)
2000	5,801	3.2	67.4	7.1	1.128	2.39
2001	5,924	2.1	70.3	4.2	1.150	1.88
2002	6,014	1.5	79.6	13.3	1.169	1.65
2003	6,203	3.1	80.9	1.7	1.198	2.49
2004	6,310	1.7	79.9	-1.3	1.219	1.78
2005	6,390	1.3	73.2	-8.4	1.237	1.49
2006	6,485	1.5	67.8	-7.4	1.256	1.53
2007	6,585	1.6	62.8	-7.4	1.275	1.47
2008	6,664	1.5	71.9	14.6	1.292	1.34
2009	6,511	-2.3	47.9	-33.3	1.283	-0.66
2010	6,599	1.4	57.1	19.1	1.300	1.28
2011	6,724	1.9	65.2	14.3	1.321	1.62
2012	6,776	0.8	74.4	14.1	1.336	1.14
2013	6,876	1.5	58.6	-21.2	1.354	1.33
2014	6,927	0.7	56.2	-4.2	1.366	0.93
2015 (e)	6,985	0.8	60.8	8.3	1.380	1.01
2016 (f)	7,065	1.2	60.7	-0.3	1.396	1.17
2017 (f)	7,144	1.1	59.1	-2.6	1.412	1.12

In the previous reports, we highlighted the shifting patterns in Ontario's employment as a measuring stick for sustained growth. Since the recession, it had been the case that growth was sector- or region-specific and not broad-based. To generalize, much of the growth was centered in the service sector and in the GTA.

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. However, the graph would indicate otherwise. Right out of the recession, most of the jobs were being generated in the GTA. Then 2014 saw a reversal of that trend with all the job growth outside the GTA. In 2015, this once again swung around so that now all the growth is concentrated once again in the GTA. This cyclical back and forth does not represent broad-based growth.

Figure 4.2 shows the year-over-year changes in employment broken down into services, manufacturing and other goods (mining, construction, agriculture, forestry, etc.). The positive in this graph is the fact that manufacturing has stopped shedding jobs. After two years of consecutive year-over-year manufacturing job reductions, for the past 7 months employment has stabilized in the sector. Though industrial loads have continued to fall, perhaps the stable employment figures can be seen as a leading indicator for improvement.

Figure 4.1: Zonal Employment Growth

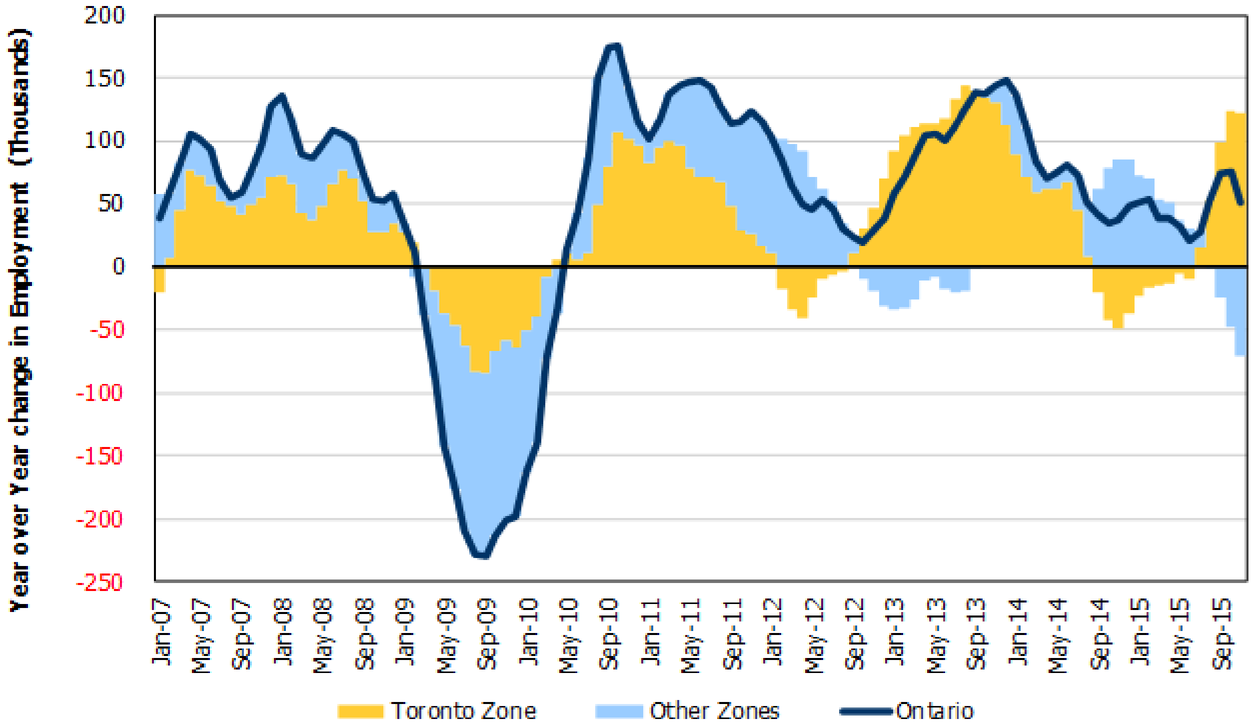
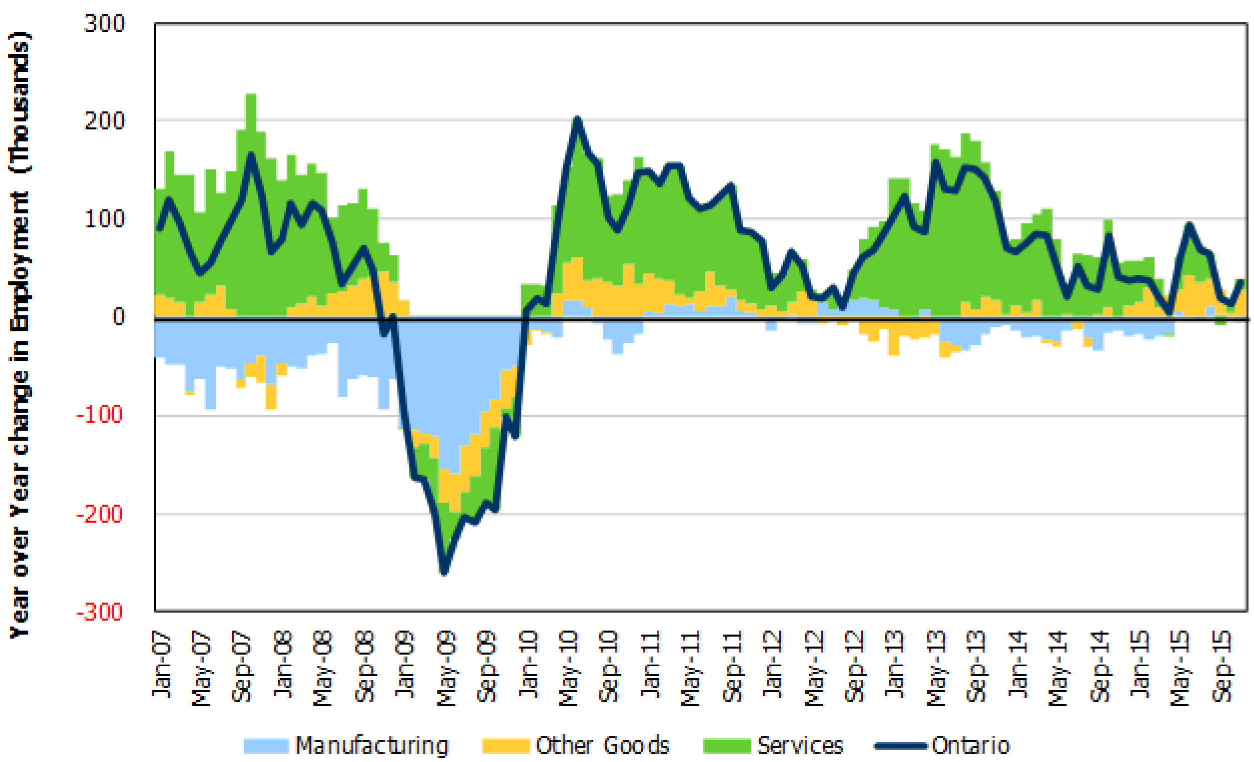


Figure 4.2: Composition of Ontario's Employment Growth



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 we use the maximum, rather than the median, value from the sorted 31-year history.

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 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.

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 in 2014 to include customers who have a peak demand of greater than 3 MW. 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 975 MW for the five peak days in 2013-14.

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 micro-FIT program and some generation under the Green Energy Act's Feed-in Tariff (FIT). It also includes 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

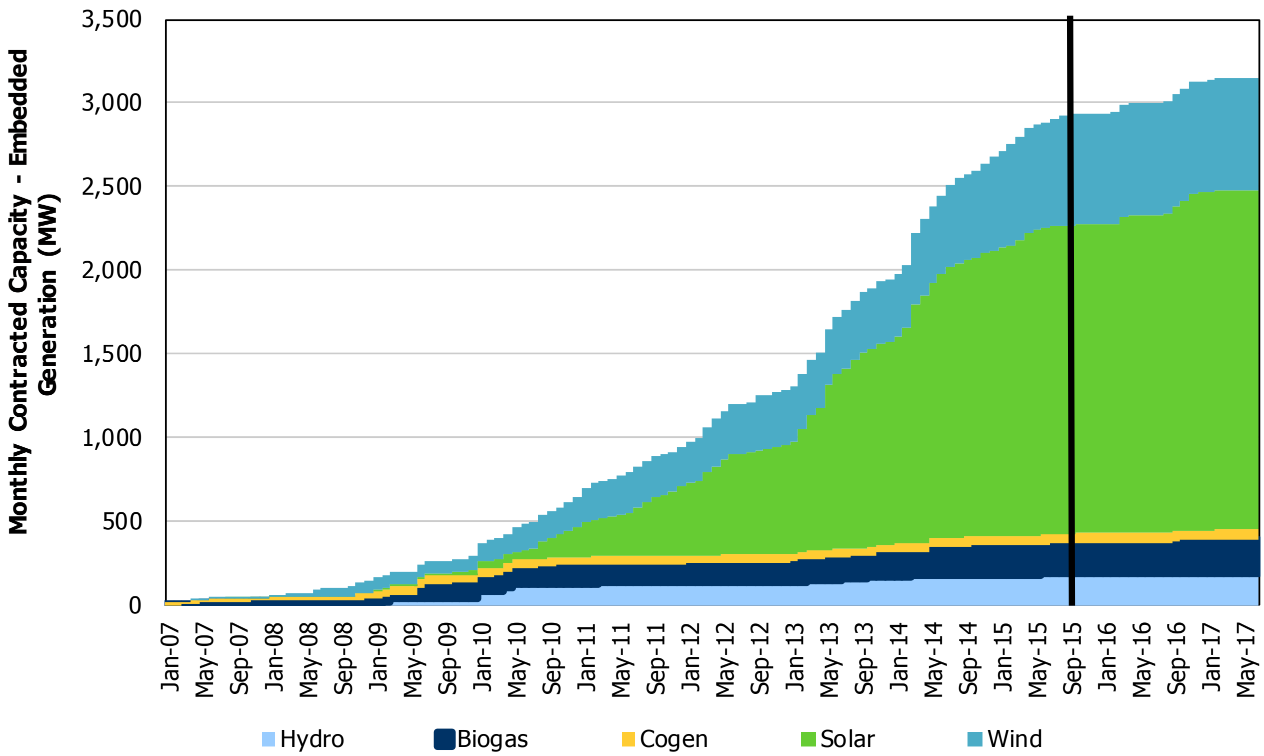


Table 4.2: Embedded Capacity

Month	Estimate of Contracted Embedded Generation Capacity (MW)					
	Biogas	Cogeneration	Hydro	Solar	Wind	Total
Jun-07	17	18	5	0	7	47
Jun-08	23	25	7	0	38	94
Jun-09	65	49	41	10	74	239
Jun-10	97	49	127	53	160	487
Jun-11	111	49	134	262	241	798
Jun-12	118	49	138	595	298	1,197
Jun-13	133	49	154	1,043	345	1,724
Jul-13	134	49	157	1,076	345	1,761
Jun-14	174	55	176	1,568	473	2,447
Jun-15	180	59	187	1,828	635	2,888
Jun-16	180	60	193	1,895	669	2,998
Jun-17	198	60	195	2,025	669	3,146

Over the course of the 18-month forecast, the amount of embedded solar installed capacity will range from 1,800 MW to 1,925 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. Table 4.3 shows the monthly average forecasted capacity factor (%) of embedded solar at the time of the weekday peak hour. Since winter peaks occur after sunset, the average contribution is zero for the winter months. 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.

Table 4.3: Forecasted Embedded Solar Capacity for the Weekday Peak Hour

Monthly Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Forecasted Embedded Solar Capacity Factor (%) at Weekday Peak Hour	0.0%	0.0%	0.0%	0.4%	12.4%	14.2%	20.2%	23.4%	3.2%	0.0%	0.0%	0.0%

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