Ontario Demand Forecast

JUNE 20, 2019

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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 July 2019 to December 2020 and supersedes the previous forecast released in December 2018.

Economic Outlook

The Ontario economy showed solid growth throughout 2018, although the first half of the year was stronger than the second, leading to concern about the sustainability of a 10-year economic expansion. Signs for the first half of 2019 show the Ontario economy continuing to exhibit strong growth. Employment averaged 2.8% growth from January to May, marking the strongest five months of job creation since August 2003. There are some notes of caution as full-time employment growth has not been as strong as it was in early 2018 (2.9%) and the manufacturing sector shed jobs from mid-2018 until early 2019. This performance is against an economic backdrop that is conducive to Ontario growth: low interest rates, strong U.S. growth and a competitive dollar.

Looking forward, there are two major items that could negatively impact this growth cycle: higher interest rates and potential trade disruption both from the United States and other global trading partners. Interest rates have been trending up since mid-2017, though they remain low by historical standards. Should the Bank of Canada see the need to raise rates, it would act as a brake on the economy. Canada has traditionally been a trade-based nation and relies heavily on trade with the United States. As such, the renegotiation of NAFTA and implications of having steel and aluminum tariffs on Canadian producers had a negative impact on consumer and business confidence in 2018. With the resolution of those issues, confidence rebounded. However, the on-going U.S.-China trade dispute will have negative impacts on the global economy should tensions escalate or remain unresolved.

The transition from vehicle to aftermarket parts production plant at the Oshawa General Motors (GM) location will have repercussions for the economy, with both suppliers and feeder industries facing lower demand. Although lower production levels at the facility are expected to result in economic fallout for the region, it is a positive that the plant remains operating at even a lower capacity. With the plant in production, albeit parts, there is the potential for increased activity should GM need to expand in the future.

Actual Weather and Demand

Since the last Ontario Demand Forecast document was published, actual demand figures for the six months of December - May have been recorded, and. are very similar to those documented during the same period a year earlier. Actual demand was down 0.3% compared to a year ago but was up 0.2% on a weather-corrected basis.

During the same time period, distributor loads decreased by 0.2 percent year over year – after adjusting for weather, the year-over-year change was an increase of 0.4 percent.

Wholesale customers' consumption decreased by 0.5 percent against 2017-18, as well as against the same months from 2016-17. The results varied by sector with mining (4.1%), automotive production (4.7%) and petroleum refining (8.1%) showing strength over the six months. Pulp & paper (-4.3%), chemicals (-4.3%) and iron & steel (-7.1%) were down over the six months, with the latter subject to U.S. tariffs during that time frame.

Peak demand for the winter of 2018-19 occurred in January. The peak was the highest winter peak since 2014-15 and the highest weather-corrected since 2015-16. There were some Industrial Conservation Initiative (ICI) impacts on the peak day, as Class A customers hedged against the peak falling in the top five peaks. The peak did not end up being an ICI peak day as it fell to eighth highest peak for the ICI season. The spring peak is either a cold weather peak in March or a warm weather peak in May. The spring ended up with a cold weather March peak, not because March was so cold but because May was much colder than normal. In fact, May was a cold weather peaking month for only the second time since market opening.

The weather over the course of the winter was near the 31-year Normal Weather scenario. December was warmer, January was colder and February was near normal. The spring meanwhile, was colder than normal due to a significantly colder than normal May. Overall, embedded generation for the winter and spring was 5.9 percent lower than the same period a year ago. The decline was due to lower wind (-7.4%) and non-contracted (-16.0%) output.

Demand Forecast

In the Reliability 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 and winter peaks are expected to show a slight increase over the forecast as conservation savings and increased embedded output are more than offset by the factors pushing up growth in end-uses.

Grid-supplied energy demand is expected to dip in 2019, as some of the weakness in the latter half of 2018 carried over into 2019. For 2020, demand is expected to see positive gains beyond the bump that comes with the additional day of a leap year. Continued economic and demographic growth will push demand higher.

Table 1: Peak and Energy Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2019	22,061	24,385
Winter 2019-20	21,106	22,132
Summer 2020	22,094	24,439

Year	Normal Weather Energy (TWh)	% Growth in Energy
2009	140.4	-5.7%
2010	142.1	1.2%
2011	141.2	-0.6%
2012	141.3	0.1%
2013	140.5	-0.6%
2014	138.9	-1.1%
2015	136.2	-1.9%
2016	136.2	0.0%
2017	132.3	-2.8%
2018	135.2	2.1%
2019 (Forecast)	134.9	-0.2%
2020 (Forecast)	136.6	1.3%

- End of Section –

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1. Introduction

1.1 Outlook Documents

The Market Rules for the Ontario Electricity Market (Chapter 5 Section 7.1) require the IESO to prepare and publish a demand forecast for the next 18 months on a quarterly basis. This Ontario Demand Forecast meets that requirement and covers the period from July 2019 to December 2020. It supersedes the previous forecast released in September 2018 and the previous Ontario Demand Forecast document released in December 2018.

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 "Methodology to Perform Long-Term Assessments," found on the IESO website at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookMethodology2019Jun.pdf. Readers may envision other scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgment 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 2018. 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 Reliability Outlook Tables (http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookTables_2019Jun.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 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. Demand Forecast

This section presents the demand forecast for the Outlook period. Additional tables are included in the Reliability 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)
07-Jul-19	22,061	24,385	814	2,610
14-Jul-19	21,525	22,879	838	2,687
21-Jul-19	20,920	23,050	1,035	2,567
28-Jul-19	21,172	24,030	841	2,657
04-Aug-19	21,739	24,370	958	2,678
11-Aug-19	21,200	23,788	985	2,651
18-Aug-19	20,520	23,766	1,362	2,646
25-Aug-19	20,752	22,763	1,413	2,643
01-Sep-19	20,069	22,593	1,370	2,536
08-Sep-19	19,187	23,133	680	2,464
15-Sep-19	19,470	20,843	781	2,513
22-Sep-19	18,470	19,648	420	2,502
29-Sep-19	17,584	18,152	554	2,418
06-Oct-19	17,164	17,452	786	2,381
13-Oct-19	16,983	17,007	507	2,398
20-Oct-19	17,167	17,614	392	2,351
27-Oct-19	17,324	17,889	318	2,437
03-Nov-19	17,535	18,262	416	2,453
10-Nov-19	18,560	19,171	601	2,567
17-Nov-19	18,837	19,617	342	2,584
24-Nov-19	19,504	20,044	607	2,668
01-Dec-19	19,734	20,737	409	2,703

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Table 2-1 - continued

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
08-Dec-19	19,993	21,153	555	2,746
15-Dec-19	20,437	21,340	690	2,787
22-Dec-19	20,252	21,303	362	2,786
29-Dec-19	18,970	19,637	528	2,682
05-Jan-20	19,722	20,775	570	2,822
12-Jan-20	21,106	22,132	547	2,943
19-Jan-20	20,488	21,024	483	2,919
26-Jan-20	20,292	21,414	404	2,920
02-Feb-20	20,358	21,566	734	2,940
09-Feb-20	19,697	21,253	635	2,869
16-Feb-20	19,278	20,721	581	2,805
23-Feb-20	19,158	20,877	501	2,761
01-Mar-20	19,541	20,861	531	2,800
08-Mar-20	19,137	20,042	649	2,744
15-Mar-20	17,907	18,617	611	2,642
22-Mar-20	17,522	18,247	569	2,546
29-Mar-20	17,339	18,286	567	2,533
05-Apr-20	17,088	17,769	471	2,490
12-Apr-20	16,352	17,278	496	2,367
19-Apr-20	15,788	15,952	531	2,354
26-Apr-20	15,922	16,390	721	2,340
03-May-20	16,941	19,379	849	2,318
10-May-20	16,278	19,093	845	2,334
17-May-20	17,663	20,980	1,175	2,355
24-May-20	17,370	21,189	1,330	2,291
31-May-20	18,121	20,670	1,292	2,371
07-Jun-20	18,875	23,227	1,055	2,548
14-Jun-20	20,123	23,488	835	2,561
21-Jun-20	21,006	23,598	754	2,630
28-Jun-20	21,123	23,483	1,016	2,683
05-Jul-20	20,325	23,029	814	2,650

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Table 2-1 - continued

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
12-Jul-20	22,094	24,439	838	2,755
19-Jul-20	20,654	23,683	1,035	2,611
26-Jul-20	21,104	23,710	841	2,703
02-Aug-20	21,483	23,667	958	2,693
09-Aug-20	20,951	23,287	985	2,668
16-Aug-20	20,209	23,009	1,362	2,652
23-Aug-20	21,130	22,888	1,413	2,709
30-Aug-20	19,581	22,009	1,370	2,555
06-Sep-20	17,976	23,183	680	2,460
13-Sep-20	18,545	20,439	781	2,437
20-Sep-20	17,341	19,299	420	2,447
27-Sep-20	16,518	17,750	554	2,372
04-Oct-20	16,914	16,933	786	2,416
11-Oct-20	16,499	16,609	507	2,432
18-Oct-20	16,738	17,286	392	2,390
25-Oct-20	16,895	17,572	318	2,478
01-Nov-20	17,173	18,002	416	2,507
08-Nov-20	18,475	18,832	601	2,605
15-Nov-20	18,697	19,233	342	2,625
22-Nov-20	19,179	19,692	607	2,693
29-Nov-20	19,684	21,033	409	2,764
06-Dec-20	19,918	20,826	555	2,787
13-Dec-20	20,169	21,026	690	2,833
20-Dec-20	19,919	20,933	362	2,828
27-Dec-20	19,657	20,563	528	2,805
03-Jan-21	20,404	20,957	528	2,768

Figure 2.1: Weekly Energy Demand – History and Forecast

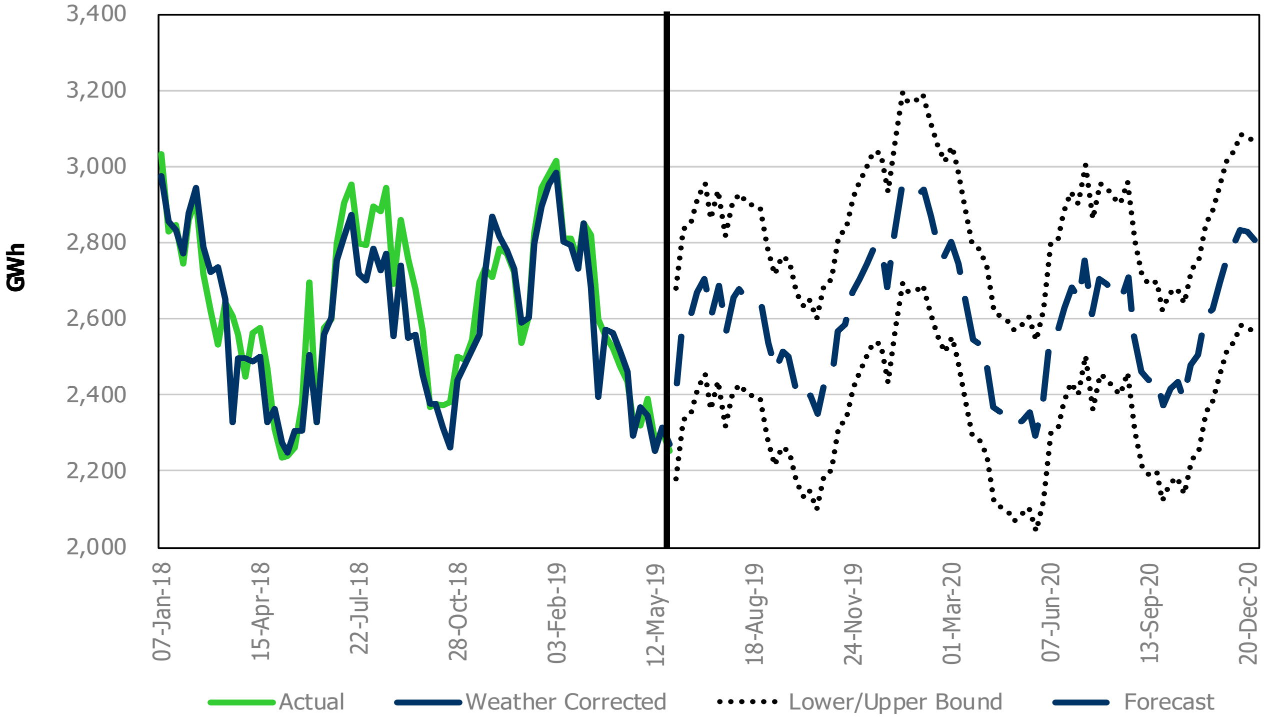
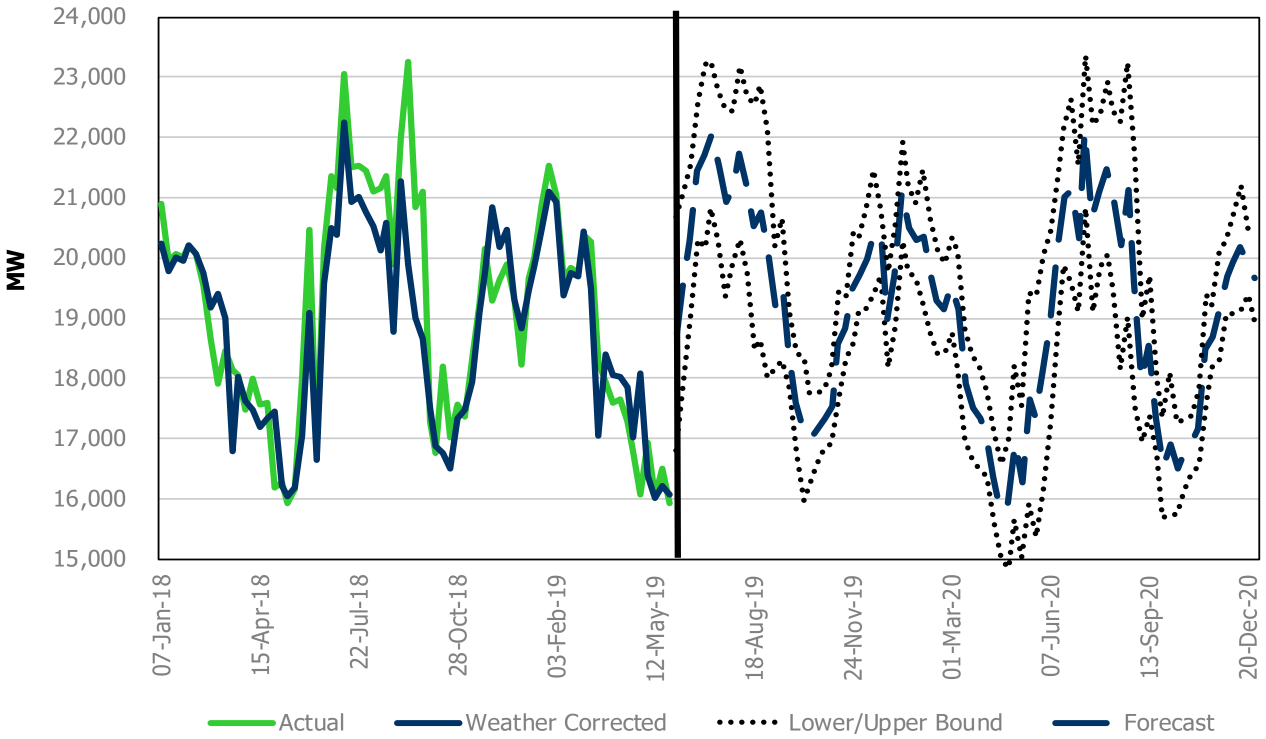


Figure 2.2: Weekly Peak Demand – History and Forecast



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3. Historical Review

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

3.1 Six-Month Review – December to May

Since the last Ontario Demand Forecast document, actuals have been recorded for the period December to May 2019. The winter of 2018-19 was near normal and the spring of 2019 was colder than normal. After May was warmer than-normal for three consecutive years, temperatures in May 2019 were colder than normal.

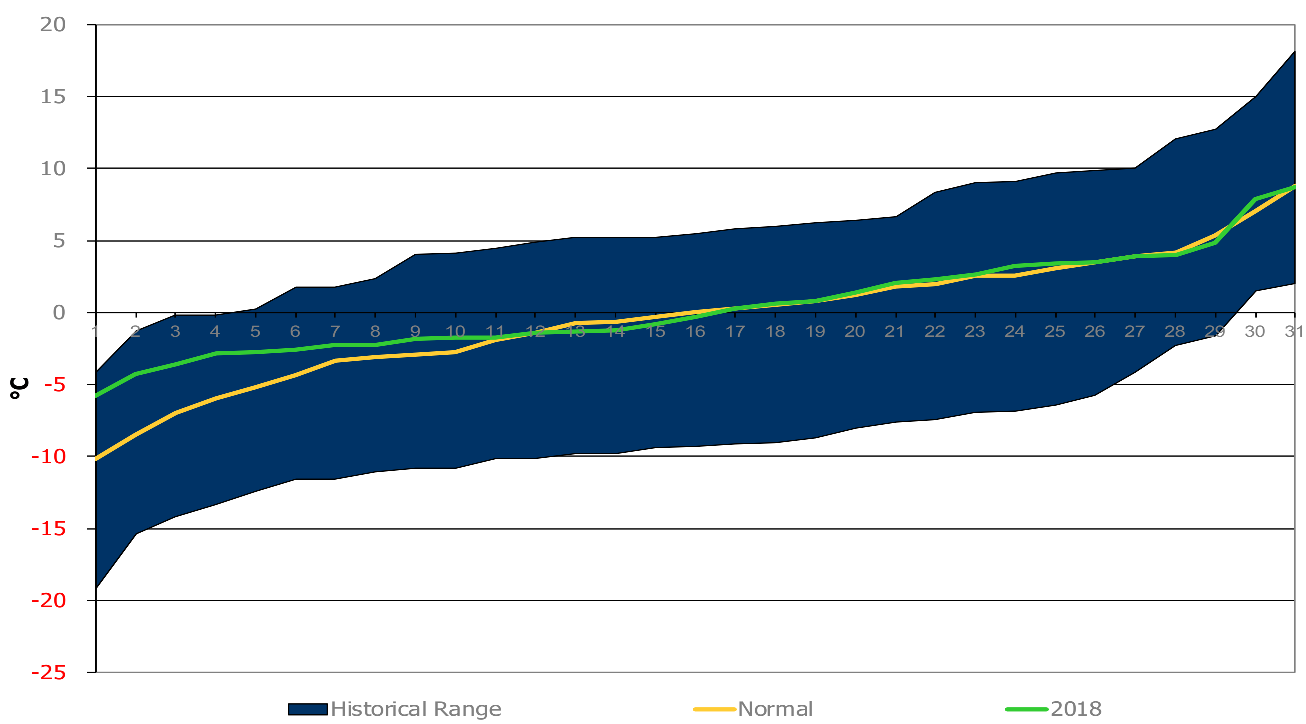
The actual and weather-corrected winter peak occurred in January (21,525 MW and 21,113 MW weather-corrected). The spring peak occurred in March (20,263 MW and 19,486 MW weather-corrected). The spring peak is either driven by cold temperatures in March or warm temperatures in May as the spring is a transition season.

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

December

December's weather was much milder than normal. Figure 3.1 shows the 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 - December



Usually, the month has a peak day temperature near -10.0 °C, but the coldest day in December 2018 coldest day had an afternoon high of -5.8 °C. December can have unpredictable results depending on how the timing of the weather and the holidays interact. Overall, the weather for the month was volatile, as temperatures rose and fell without any clear sustained cold periods. Demand peaked on Tuesday, December 11, the fifth coldest day of the month with afternoon temperatures of -1.4 °C (Toronto). The demand peak (19,891 MW) was the lowest December peak over the past decade, with the exception of 2015 which had a peak day temperature of 6.8 °C. The weather-corrected peak (20,462 MW) is consistent with December values since the recession.

Energy demand for the month was 11.9 TWh (12.0 TWh weather-corrected). Actual energy demand was down over the previous December, but the weather-corrected value represented an increase.

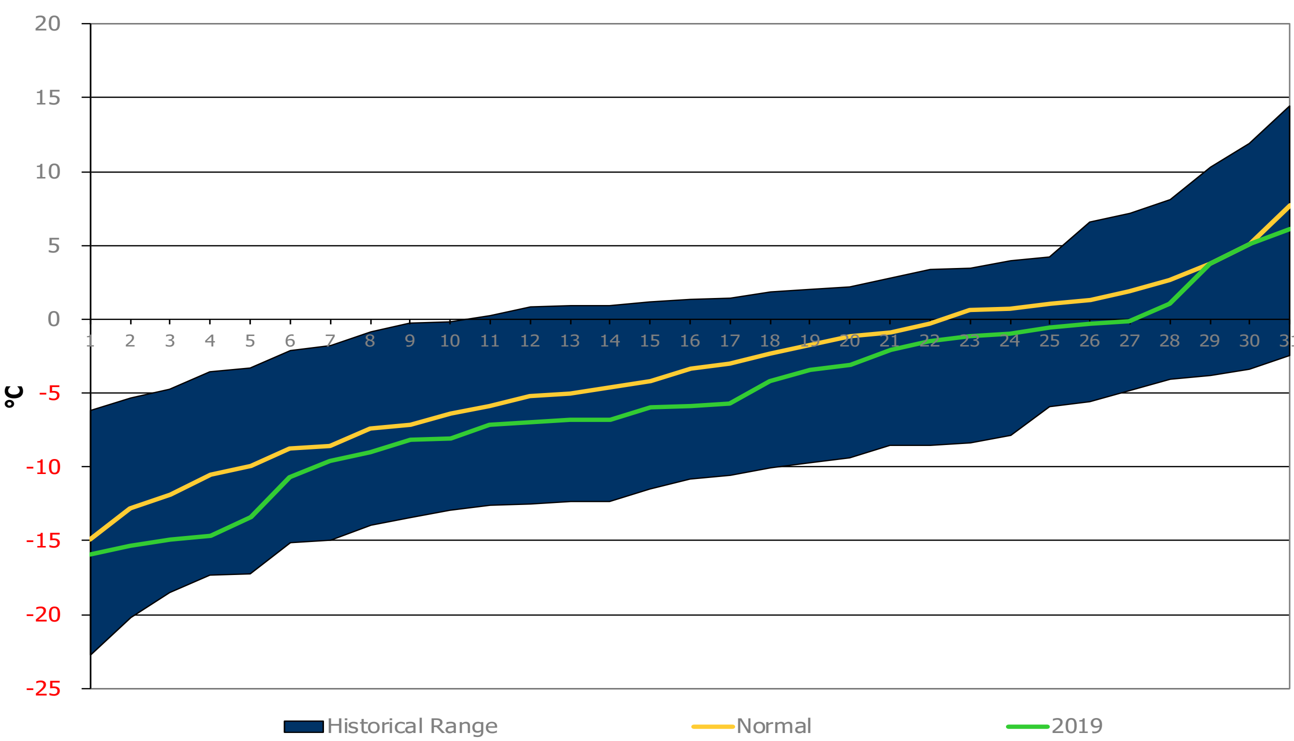
The minimum demand for the month (12,284 MW), which occurred in the early hours of Saturday, December 29, was the highest since 2015.

Embedded generation for the month was 409 GWh, an increase of 1.2% compared to the previous December. Wholesale customers' consumption rose 2.2% over December 2017, resulting in the fifth consecutive month of year-over-year growth, thanks largely to mining, petroleum products and cement production.

January

While the weather for January started off above normal, the month ended up being colder than normal. Figure 3.2 shows how the temperature for January 2019 stacked up against history.

Figure 3.2: Daily Temperature – January



Although January started with temperatures above zero, it was consistently colder than normal, with temperatures progressively increasing throughout the month.

The peak occurred on the fifth coldest day of the month, when daily highs reached -11.8 °C (Toronto). The peak demand was 21,525 MW (21,113 MW weather-corrected) on Monday January 21. The peak value was impacted by ICI activities as Class A customers made adjustments should the peak value fall in the top five peaks (it did not).

Energy demand for the month was 12.8 TWh (12.6 TWh weather-corrected). Both of these values are consistent with the numbers over the past five years.

The minimum demand for the month was 12,291 MW and occurred in the early morning hours of New Year's Day. It was both a holiday and warmer than normal.

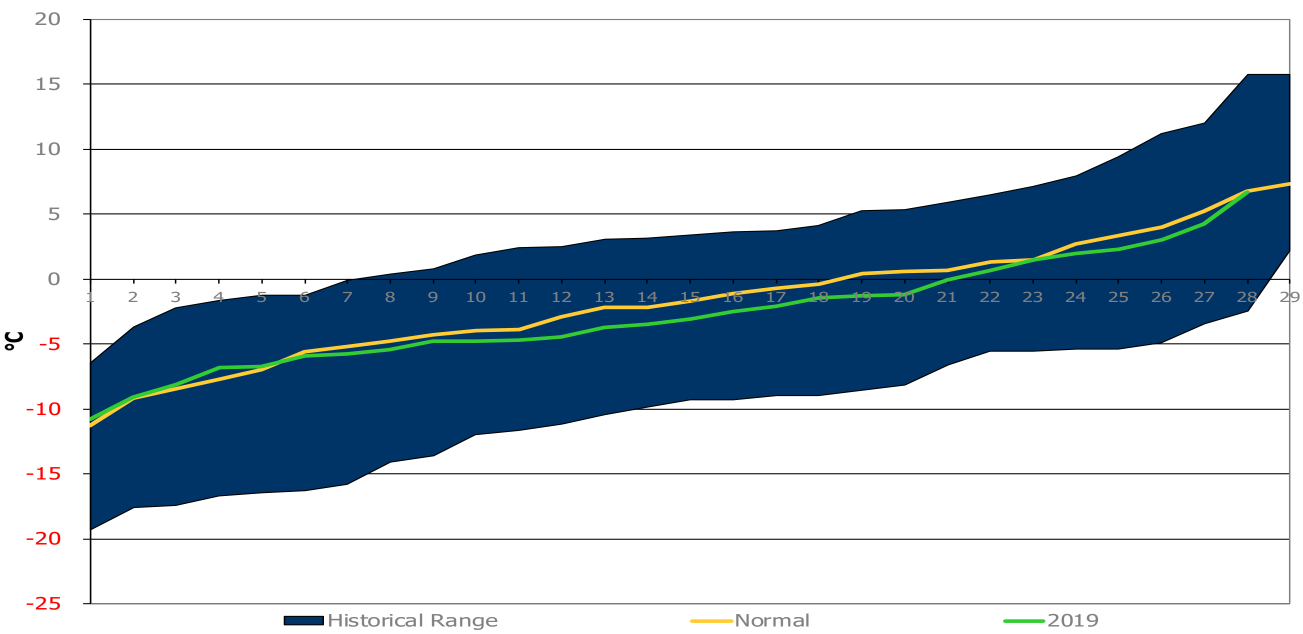
Embedded generation for the month topped 465 GWh, which represents a 13.0 percent decrease compared to the previous January. Year-over-year increases in solar and biogas output were more than offset by declines in wind, water and non-contracted embedded generation output.

Wholesale customers' load increased by 0.5% compared to the previous January. Mining, petroleum products and motor vehicles led the growth, while iron and steel production took a step back.

February

Despite the weather volatility and storms, February's weather was very close to normal. Figure 3.3 shows the February 2019 temperature relative to history.

Figure 3.3: Daily Temperature - February



The actual peak for the month was 20,500 MW occurring on Friday, February 1. It was the coldest day of the month with afternoon highs of -10.1 °C (Toronto). The weather-corrected value was essentially the same at 20,892 MW, which is similar to the values experienced since the 2009 recession.

Energy demand for the month was 11.3 TWh (11.2 TWh weather-corrected). Both the actual and weather-corrected values show a slight increase over the previous two Februarys.

Minimum demand of 13,041 MW occurred Sunday, February 24 at 5 a.m. This result is not surprising as it was the second mildest day of the month and a weekend, both of which lead to lower demand.

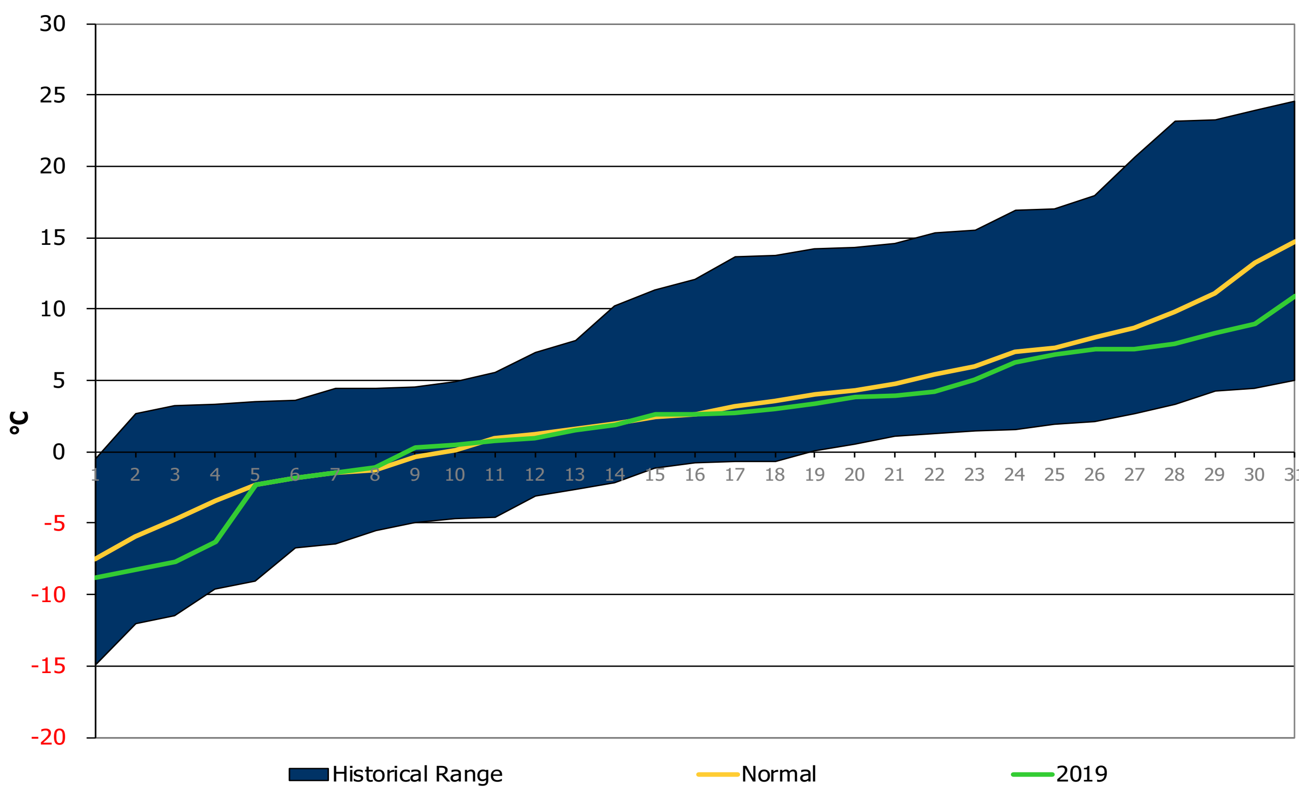
Embedded generation was 459 GWh for the month, which represents a decrease of 8 percent compared to the previous February. Decreases in wind (18 percent) and non-contracted generation (11 percent) outweighed the increase in solar output (15 percent).

Wholesale customers' consumption decreased 1.5 percent compared to the previous February. While most sectors showed increases, significant decreases in pulp and paper and the iron and steel sectors overshadowed them.

March

The weather for March was much colder than normal. The average temperatures for the month put it in the coldest quartile of the past 50 years. The peak temperature for the month was also in the top quartile. Figure 3.4 shows the March 2019 temperatures against the historical range.

Figure 3.4: Daily Temperature - March



The monthly peak occurred on Tuesday March 5, which was the second coldest day of the month and in the midst of a cold snap. The afternoon high was -9 °C (at Toronto), which is the coldest March peak since 2015. The peak was 20,263 MW, which is the highest since March 2015.

The weather-corrected peak of 19,486 MWs slightly higher than the past several years and the highest since March 2016.

Energy demand for the month was 11.7 TWh (11.3 TWh weather-corrected), which is slightly higher than the past several years and the highest since March 2016.

The minimum demand for the month was 12,210 MW which is in line with March values since the 2009 recession. The minimum occurred in the early hours of Saturday, March 30.

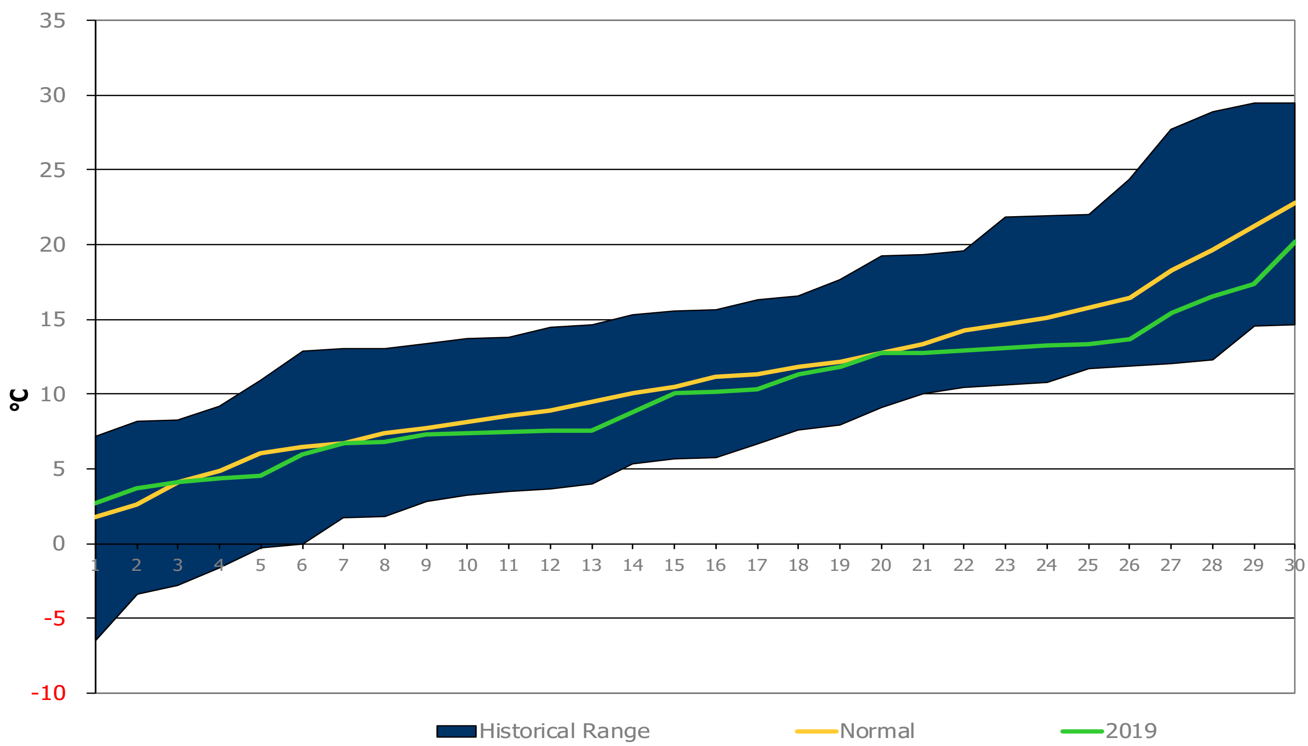
Embedded generation for the month was 590 GWh, a decrease of 1.2% compared to the previous March. Solar (11.9%) and hydro (25.5%) output were up, but reductions in wind (-9.1%), bio (-8.6%) and non-contracted (-3.8%) output more than offset those increases.

Wholesale customers' consumption dropped 2.5% compared to March 2018 and represented the largest monthly decline in just under two years. Declines in chemicals (-5.3%) and steel (-9.1%) led a broad decline across numerous industrial sectors.

April

The weather for April was fairly close to normal. Figure 3.5 illustrates the temperatures of April 2019 against the historical range.

Figure 3.5: Daily Temperature - April



The peak occurred on April 1, which was the coldest day of the month and followed a cold weekend. The peak day high was 2.8 °C, which was slightly warmer than normal. The actual peak was 17,645 MW (18,091 MW weather-corrected). The observed April peak was the second-lowest since market opening, topping only the peak occurring in April 2017 and the weather-corrected was the secondlowest, surpassing only last year's value.

Energy demand for the month was 10.3 TWh (10.3 TWh weather-corrected). Both of these are decreases compared to April 2018.

The minimum was 11,079 MW and occurred in the early morning hours of Saturday, April 20. This is consistent with the post-recession observations for April.

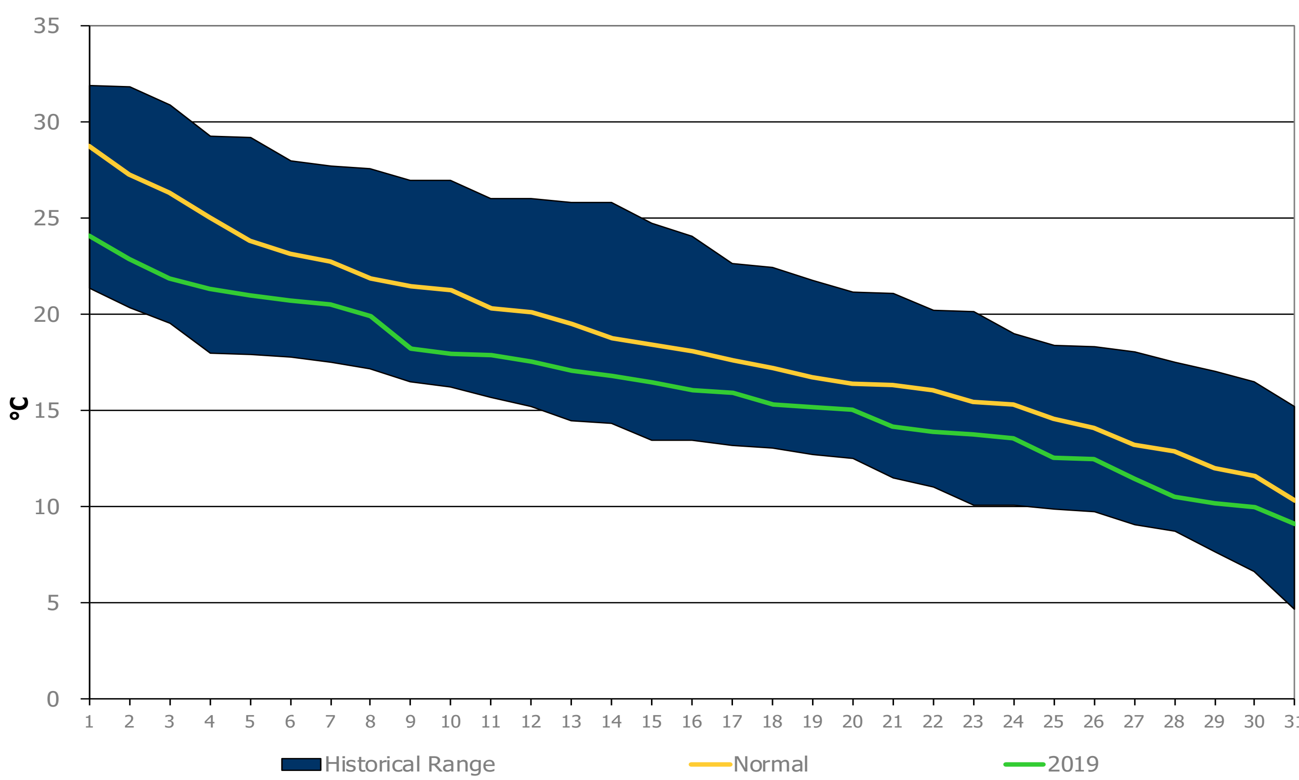
Embedded generation for April topped 584 GWh, which represents a 0.1% decrease over the previous April. Non-contracted was up 37% over the previous April, while all other types declined: solar (-5.5%), wind (-3.3%), hydro (-9.3%) and bio (-0.6%).

Wholesale customers' load fell 2.2% compared to the previous April. Though an improvement over March, April marked three consecutive months of decline. Industrial loads vary for numerous reasons and will require monitoring over the coming months should this decline signal a trend. While iron and steel (-9.2%) has experienced the biggest decline, that sector should see an improvement with the removal of the U.S. tariffs (25%) on Canadian steel.

May

The weather for May was cold and wet. The average temperatures for the month put it in the lowest quartile of the past 50 years. Figure 3.6 shows how the temperature for May 2019 stacked up against history.

Figure 3.6: Daily Temperature - May



May had a cold-weather peak for just the second time since market opening. The peak was 16,784 MW (17,354 MW weather-corrected) and occurred on May 1, the coldest day of the month. The peak day high was 8.2 °C (Toronto), the average of the last 15 May peaks was 28.7 °C. It never got that hot in May 2019.

Energy demand for the month was 10.2 TWh (10.3 TWh weather-corrected) which was very similar to May 2017, the low-water mark for the month. Both months had similar average temperatures (15.8 °C for 2019 and 16.2 °C for 2017).

Minimum demand for the month was 10,328 MW, which is second only to the low of 10,249 MW in May 2017. The minimum occurred in the early hours of the Victoria Day holiday Monday.

Embedded generation for the month was 577 TWh, a 13.0% decrease compared to the previous May. Both hydro (17.0%) and wind (30.4%) were up significantly, but were more than offset by the reduction in non-contracted embedded generation output.

Wholesale customers' consumption reversed course from the negative numbers registered over the past four months. Year-over-year consumption increased by 0.5% and the sectoral breakdown is a continuation of the trend of the past few months. Once again, mining (7.1%), refining (39.0%) and automotive manufacturing (4.9%) led the growth, while pulp & paper (4.6) and iron & steel (-12.1%) showed year-over-year decreases.

Table 3-3.2 of the Reliability 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 2018-19 Weather and Demand Summary

Historical Analysis		December	January	February	March	April	May
Actual Weather	Average Temperature (°C)	2.1	-4.4	-1.6	2.5	9.9	15.8
	Minimum Temperature (°C)	-4.0	-16.9	-10.1	-9.0	1.3	7.2
	Maximum Temperature (°C)	12.4	7.7	12.2	11.3	21.7	26.1
Normal Weather	Normal Average Temperature (°C)	0.2	-3.3	-1.5	3.6	10.7	17.1
	Normal Minimum Temperature (°C)	-8.4	-13.5	-13.5	-5.5	2.8	8.7
	Normal Maximum Temperature (°C)	10.0	6.7	8.2	16.7	25.0	27.2
Actual Demand	Peak Demand (MW)	19,891	21,525	20,500	20,263	17,645	16,784
	Average Hour (MW)	15,981	17,174	16,803	15,670	14,256	13,736

	Minimum Hour (MW)	12,284	12,291	13,041	12,210	11,079	10,328
	90th Percentile (MW)	18,215	19,588	19,051	17,519	16,134	15,587
	Percent above 20,000 (MW)	0.0%	5.6%	1.3%	0.3%	0.0%	0.0%
	# of Hours Above 20,000 (MW)	-	42	9	2	-	-
	Energy Demand (GWh)	11,890	12,777	11,292	11,659	10,265	10,220
Weather-Corrected Demand	Peak Demand (MW)	20,462	22,113	20,892	19,486	18,091	17,354
	Energy Demand (GWh)	12,020	12,646	11,239	11,327	10,314	10,250
Forecast Demand	Peak Demand (MW)	20,503	21,506	20,008	19,457	17,548	18,663
	Energy Demand (GWh)	12,007	12,973	11,162	11,522	10,253	10,412

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 into its two main components – winter (December, January and February) and spring (March, April and May).

The weather over the winter was near normal with December being warmer, January colder and February normal. Compared to the previous winter, energy demand was up 0.1 percent; after adjusting for the weather, the increase was 0.3 percent.

Not surprisingly, distributors' loads followed a similar pattern. For the winter of 2018-19, they were up 0.4 percent over the previous winter and 0.6 percent after making weather adjustments. The output of embedded generation (1.33 TWh) was lower than the previous winter (1.44 GWh). Solar output was up 4.0%, while all other fuel types declined with wind showing the biggest decrease (-16.8%).

For the winter months, wholesale loads showed an increase of 0.4 percent compared to the previous winter. However, the growth profile raised concerns as month-over-month changes went from 2.2% in December to 0.5% in January and -1.5% in February. Mining, refining and auto manufacturing were the sources of growth, while pulp & paper and iron & steel showed declines.

For the spring, weather was colder than normal. March and April were slightly cooler than normal, leading to higher demand. However, May was significantly colder than normal, which reduced demand in the month as it is generally a cooling load month. Overall, demand for the spring was 0.7% lower than the previous spring. After adjusting for weather, spring demand was up by 0.2% over the spring of 2018. Distributor loads showed a decrease of 0.9% and a 0.1% increase after correcting for weather.

Wholesale customers' loads decreased by 1.4 percent compared to the previous spring, carrying the declines from February into March and April. Four consecutive months of declines started raising caution flags, but May showed a return to positive growth. Once again, the sectors of growth and decline were generally the same with mining, refining and auto manufacturing showing growth and pulp & paper and iron & steel showing declines. The chemicals sector tipped the overall pattern to decline, dropping by 7.0% compared to the previous spring. With the elimination of the U.S. tariffs on Canadian steel and aluminum, we should see a change in that sector.

Figure 3.7 shows weather-corrected distributor load and embedded generation output. Though embedded generation shows seasonal volatility, the underlying upward trend is evident until 2016, when the output appears to level off. For the year to date, embedded generation is down 6.9 percent compared to last year. Year-to-date embedded generation output is 2.7 TWh.

For the six months from December to May, distributors' loads decrease by 0.2 percent compared to the same six-month period in 2017-18. Weather-corrected values were up 0.4 percent over 2017-18. Embedded generation decreased by 5.9 percent over the same period a year ago.

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

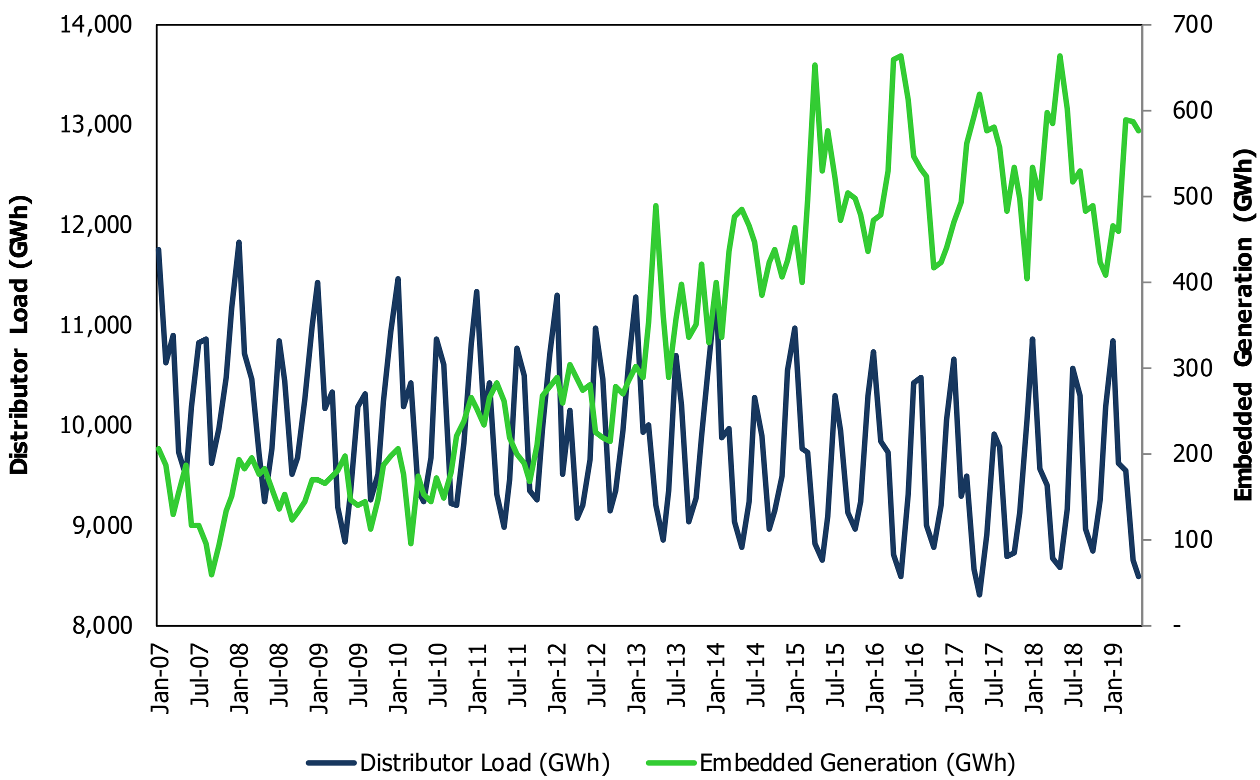


Figure 3.8 shows the year-over-year change in wholesale customers' average hourly consumption. The graph traces the impact of the recession and the relatively flat demand since that time. Economic restructuring after the

2009 recession has been common among many western economies and are not unique to Ontario. The combination of technology, a shift to service sector industries and the rise of manufacturing in developing countries has led to flat or declining manufacturing in advanced economies.

Figure 3.9 shows the wholesale customers' highest monthly average hourly load by industry segment for each of 2008 and 2019 year to date. The purpose of this graph is to illustrate how demand has changed across various electricity-intense sectors of the economy. Only the mining sector and refining are above their pre-recession levels. All the other major sectors saw a significant decline in 2009 and relative stability since. Some of the change is due to the economic cycle, while others are sector specific. The decline in demand for newsprint explains the decline in the pulp and paper sector.

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

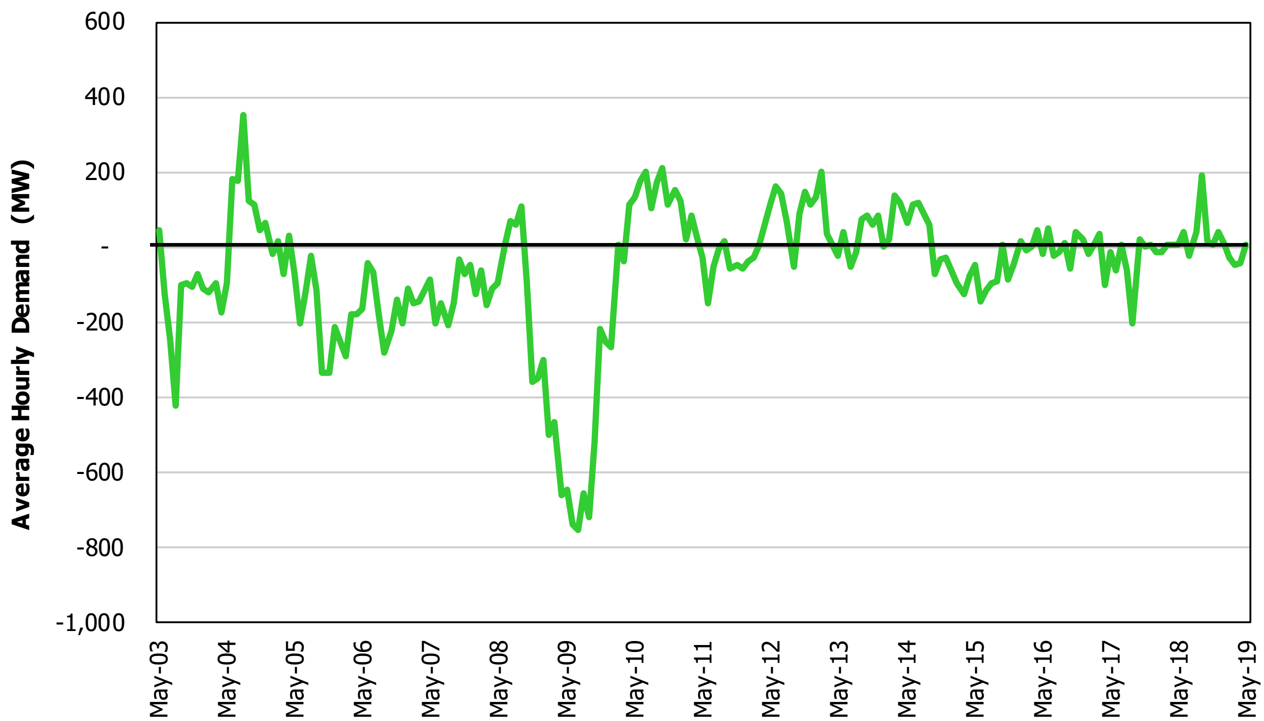


Figure 3.9: Wholesale Customers' Average Hourly Consumption by Industry Segment

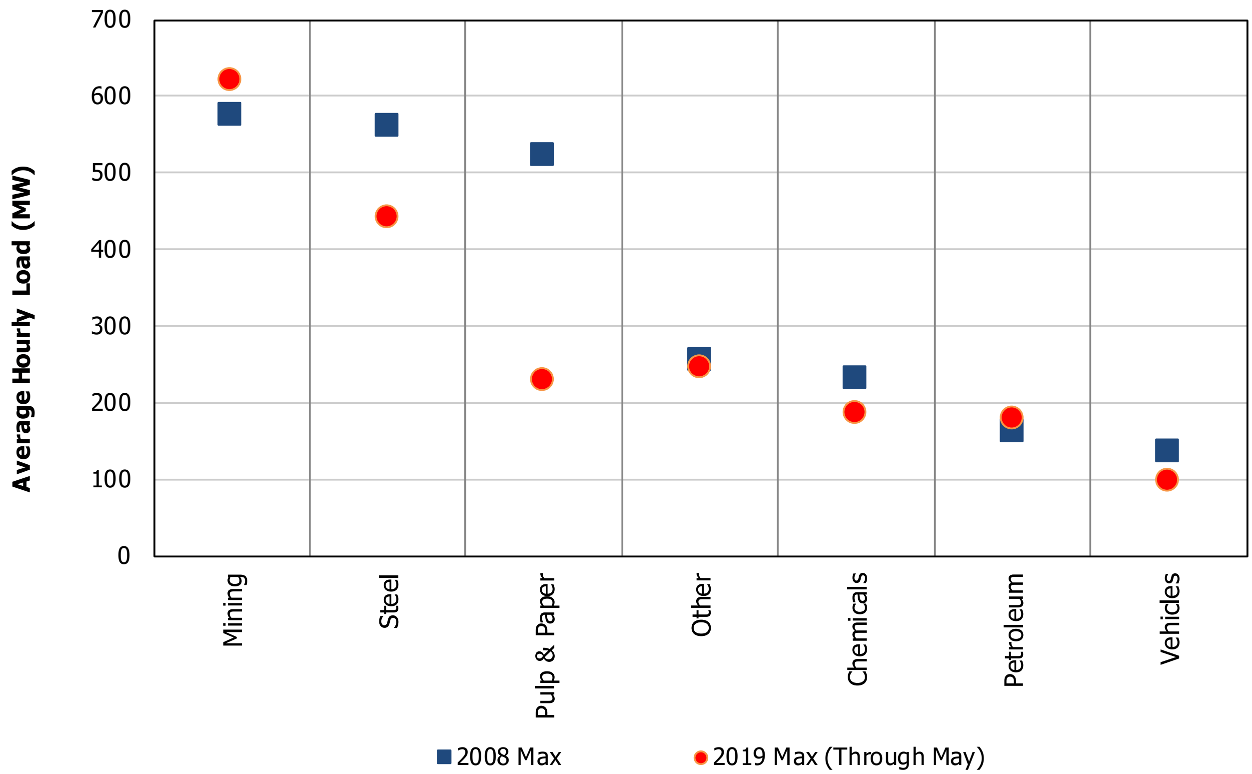


Table 3-2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week and notes any item of significance for the week. If the weather-corrected demand is greater than the actual demand, actual weather was milder than normal. Additional history is available in the Reliability 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
49	09-Dec-18	07-Dec-18	2,782	2,814	
50	16-Dec-18	11-Dec-18	2,770	2,781	
51	23-Dec-18	17-Dec-18	2,722	2,733	
52	30-Dec-18	27-Dec-18	2,534	2,591	Christmas & Boxing Day
1	06-Jan-19	02-Jan-19	2,609	2,601	New Year's Day
2	13-Jan-19	10-Jan-19	2,822	2,799	
3	20-Jan-19	20-Jan-19	2,943	2,894	
4	27-Jan-19	21-Jan-19	2,978	2,952	
5	03-Feb-19	28-Jan-19	3,016	2,984	
6	10-Feb-19	06-Feb-19	2,809	2,801	

7	17-Feb-19	12-Feb-19	2,812	2,791	
8	24-Feb-19	19-Feb-19	2,753	2,731	Family Day
9	03-Mar-19	27-Feb-19	2,852	2,853	
10	10-Mar-19	05-Mar-19	2,820	2,683	
11	17-Mar-19	11-Mar-19	2,598	2,394	
12	24-Mar-19	18-Mar-19	2,553	2,570	
13	31-Mar-19	26-Mar-19	2,522	2,564	
14	07-Apr-19	01-Apr-19	2,473	2,513	
15	14-Apr-19	11-Apr-19	2,432	2,462	
16	21-Apr-19	16-Apr-19	2,332	2,293	Good Friday
17	28-Apr-19	24-Apr-19	2,320	2,366	Easter Monday
18	05-May-19	29-Apr-19	2,391	2,345	
19	12-May-19	09-May-19	2,280	2,254	
20	19-May-19	13-May-19	2,307	2,314	
21	26-May-19	22-May-19	2,251	2,270	Victoria Day

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.

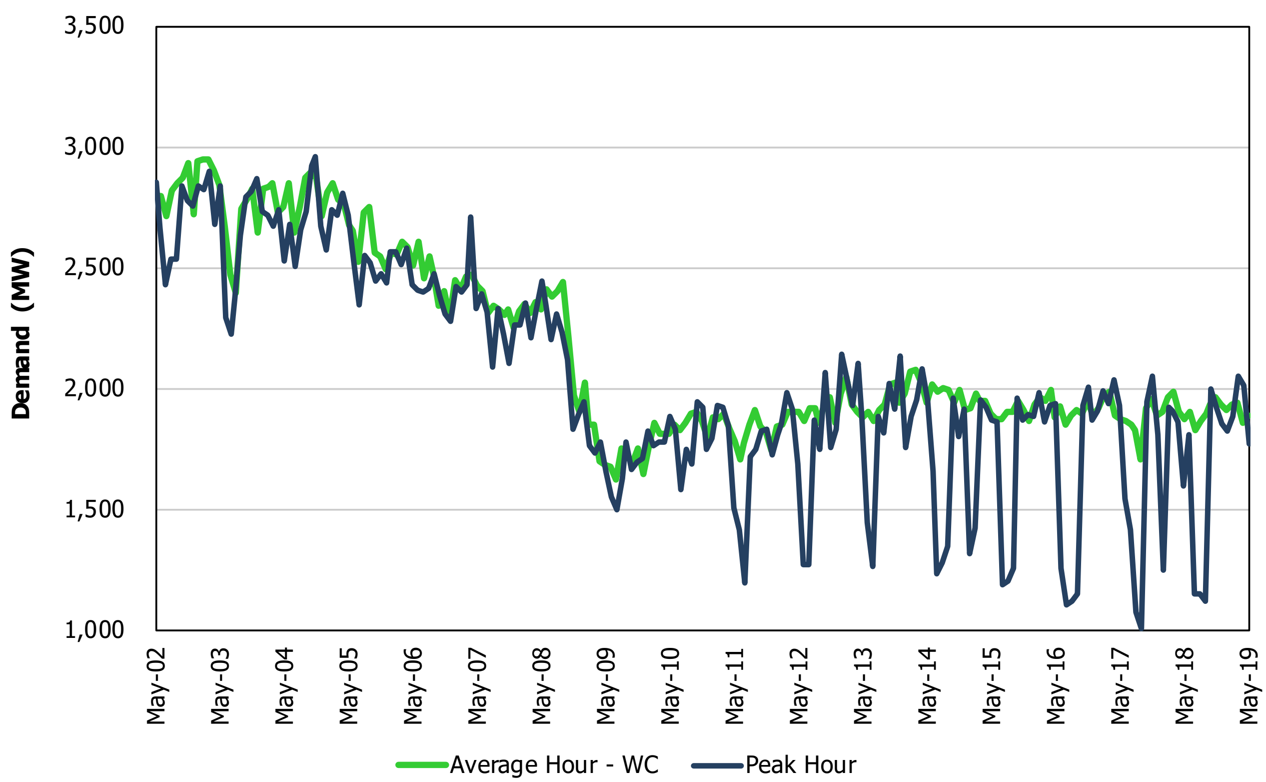
The winter peak was 21,525 MW, which was the highest peak since the winter of 2014-15. Peak weather was warmer than the previous winter peak. However, the previous winter's peak was subject to ICI activity as it was one of the five peak days of the ICI calendar. This winter's peak had some ICI activity as Class A customers hedged their bets, but the day did not end up being one of the top five peaks. The difference in ICI activity suppressed the previous winter's peak by roughly 1,000 MW, explaining the difference between the two winter peaks. The weather-corrected winter peak was the highest since 2015-16. Once again, the ICI impacts account for the difference between this winter's and the previous winter's weather-corrected peak demand.

The spring peak was 20,263 MW, which was slightly lower than the previous spring peak (20,473 MW). This spring's peak occurred during March (-9.0 °C) early in March whereas the spring of 2018 had a warm weather peak in May (30.7 °C) at the end of the month. The timing will influence the peak, as fewer people will be running their air conditioning on September 25 than September 5.

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 now face more downward pressure than the winter peaks. In particular, conservation and embedded solar generation do not impact seasonal peaks to the same degree. The summer peak is primarily driven by air conditioning load, whereas the winter peak results from 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 both reduces the summer peaks and pushes them to 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 pushing the peak to 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 2019. The graph clearly shows that peaks are lower today – a result of conservation and lower industrial load – but occur in the same time frame from hours 18-20.

The previous Ontario Demand Forecast highlighted the changes to the summer peak, so this document Figure 3.12 shows the weekday peaks in MW and the hour in which they occurred for the spring of 2005, 2016 and 2019. The spring peaks are mixed, being driven by both heating load in March and April and cooling load in May. The heating load peaks occur later in the day and those have been pushed later in the day and lower. The cooling load peaks occur in the middle of the day and those have been reduced and pushed outside of the solar output time frame.

Figure 3.11: Seasonal Weekday Peak Hour Distribution - Winter

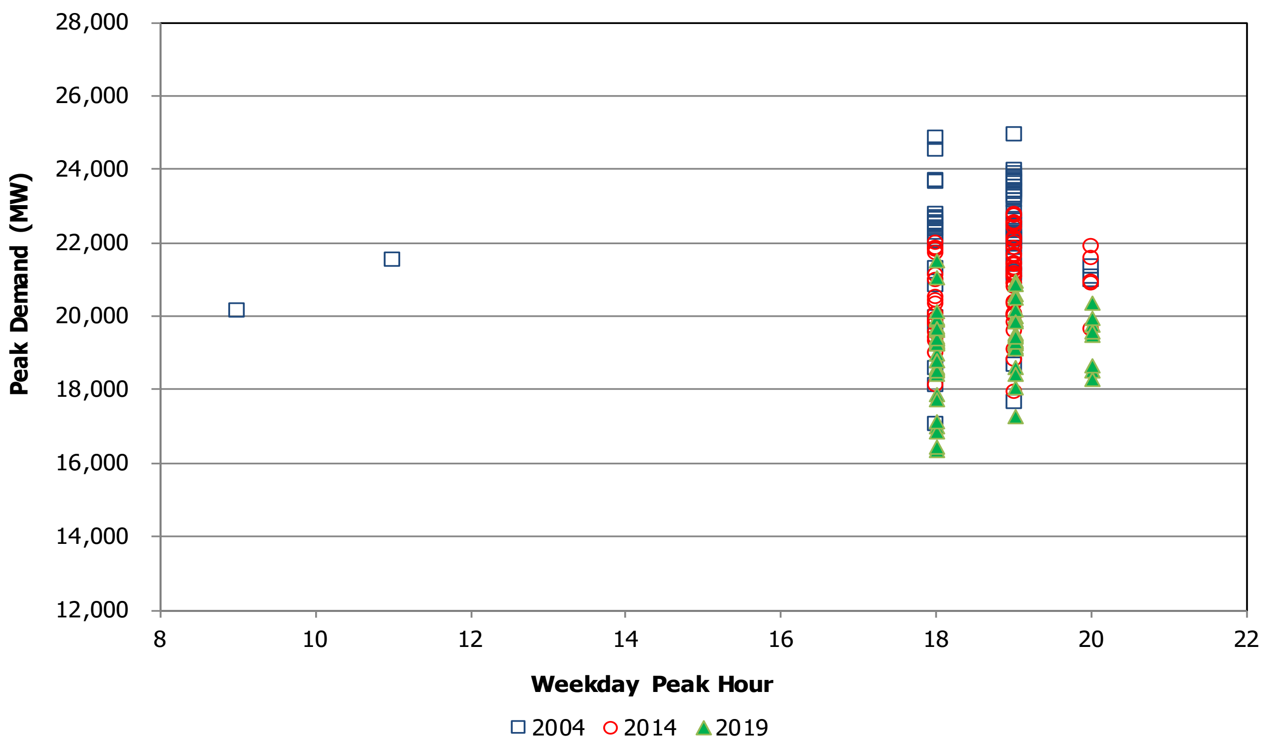


Figure 3.12: Seasonal Weekday Peak Hour Distribution – Spring

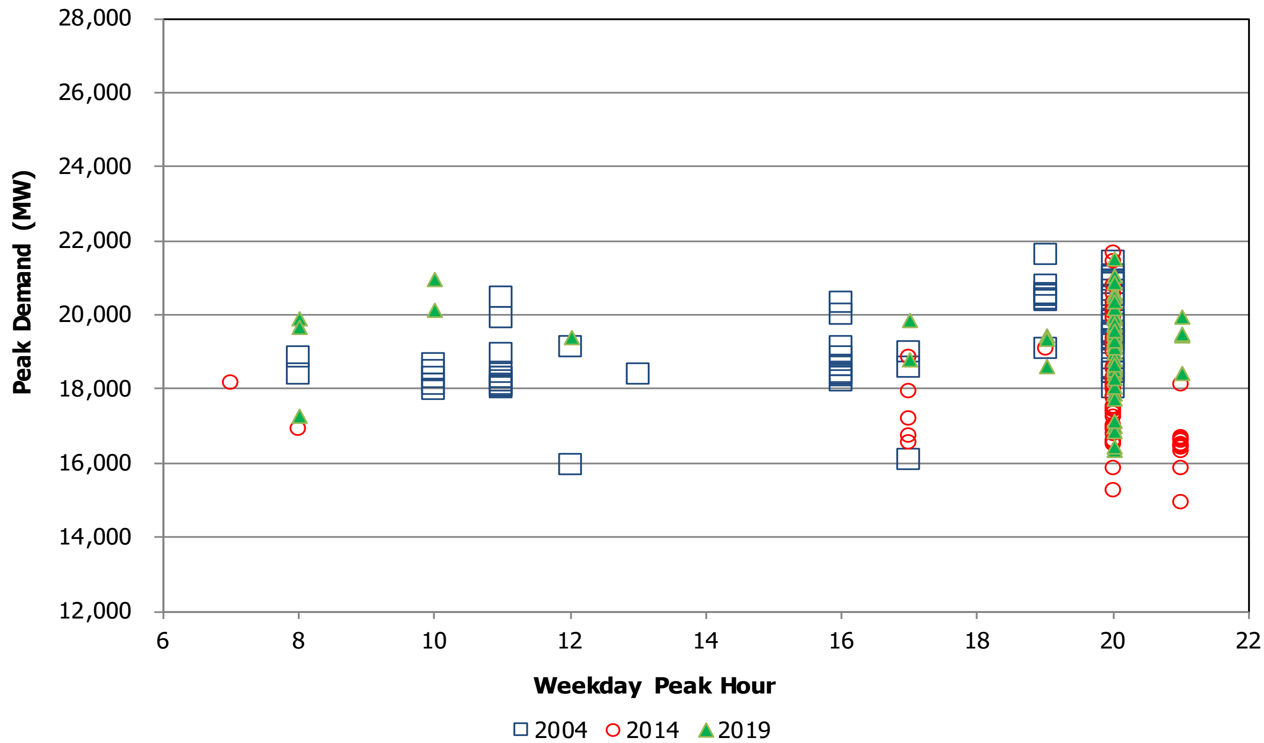


Figure 3.13 shows the break down for the past four seasonal peaks. The graph illustrates the factors that impact the peak; embedded generation and ICI had a very significant influence on the largest peaks.

Figure 3.13: Anatomy of Seasonal Peaks

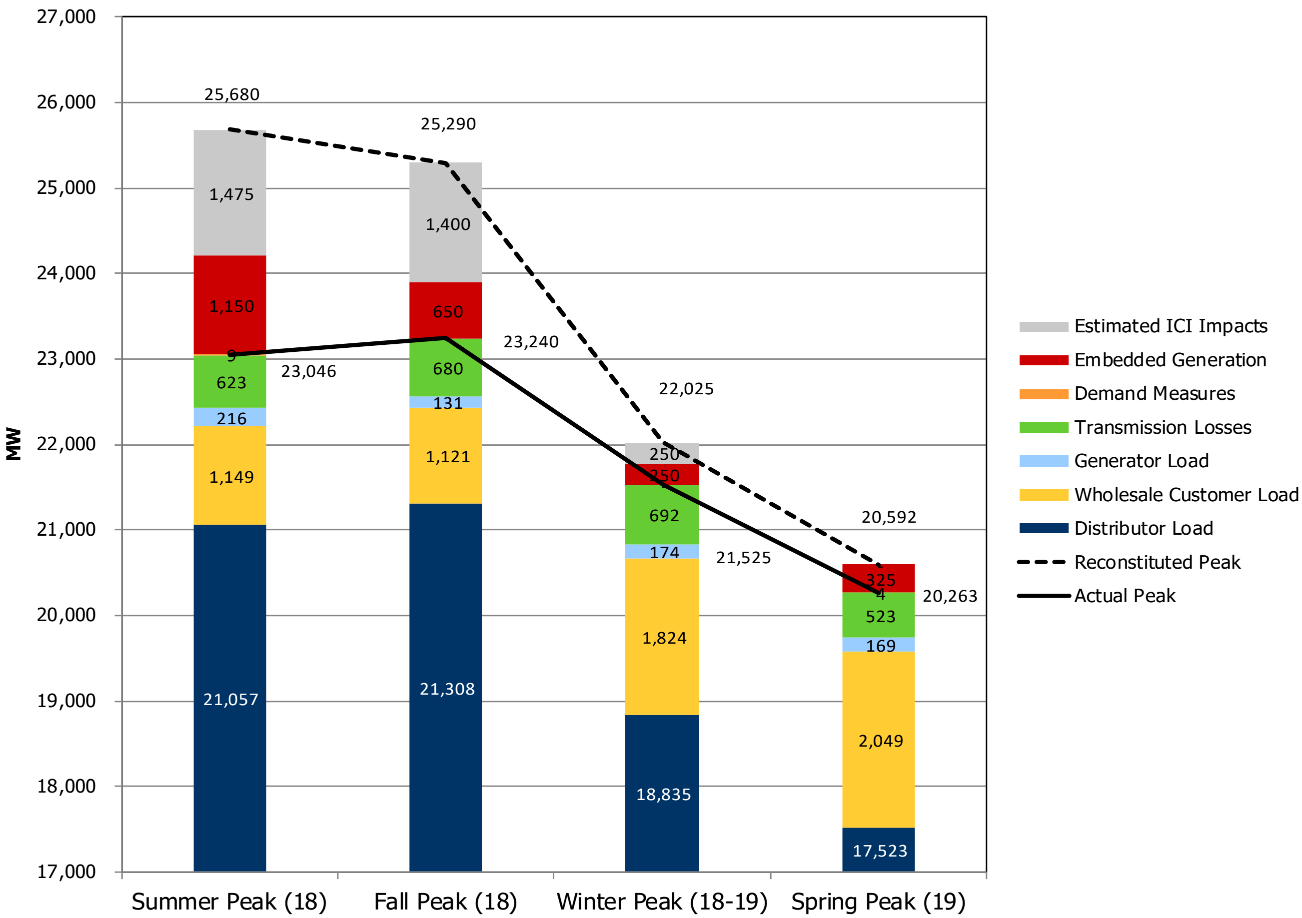


Table 3-3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3-3: Historic Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
49	09-Dec-18	07-Dec-18	19,648	20,188	-4.0
50	16-Dec-18	11-Dec-18	19,891	20,462	-1.4
51	23-Dec-18	17-Dec-18	19,337	19,330	2.6
52	30-Dec-18	27-Dec-18	18,238	18,842	-0.2
1	06-Jan-19	02-Jan-19	19,666	19,456	-3.9
2	13-Jan-19	10-Jan-19	20,012	19,867	-5.1
3	20-Jan-19	20-Jan-19	20,879	20,460	-14.5
4	27-Jan-19	21-Jan-19	21,525	21,113	-11.8
5	03-Feb-19	28-Jan-19	21,049	20,918	-8.3
6	10-Feb-19	06-Feb-19	19,661	19,370	-1.1
7	17-Feb-19	12-Feb-19	19,849	19,746	-1.2
8	24-Feb-19	19-Feb-19	19,758	19,690	-4.4
9	03-Mar-19	27-Feb-19	20,378	20,431	-7.7
10	10-Mar-19	05-Mar-19	20,263	19,486	-9.0
11	17-Mar-19	11-Mar-19	18,295	17,061	2.0
12	24-May-19	18-Mar-19	17,951	18,403	2.6
13	31-May-19	26-Mar-19	17,592	18,051	3.6
14	07-Apr-19	01-Apr-19	17,645	18,034	2.8
15	14-Apr-19	11-Apr-19	17,285	17,863	1.3
16	21-Apr-19	16-Apr-19	16,782	17,026	8.6
17	28-Apr-19	24-Apr-19	16,074	18,091	12.8
18	05-May-19	29-Apr-19	16,936	16,381	6.9
19	12-May-19	09-May-19	16,033	16,022	14.4
20	19-May-19	13-May-19	16,510	16,204	7.2
21	26-May-19	22-May-19	15,933	16,069	15.1

3.4 Load Duration Curves

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

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 2018 was low by historical standards.

For the summer curve, the graph also includes the load duration curve for 2016. This highlights the similarity between the summers of 2016 and 2018.

Figure 3.14: Spring Load Duration Curve

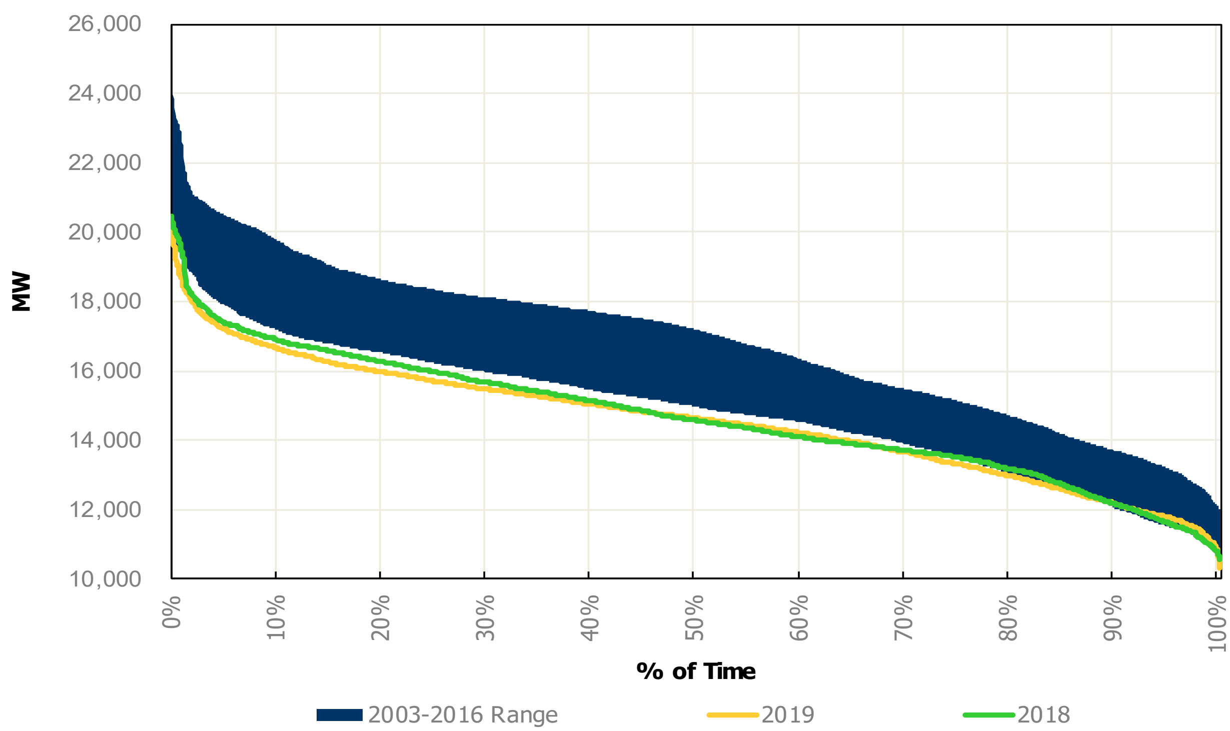


Figure 3.15: Winter Load Duration Curve

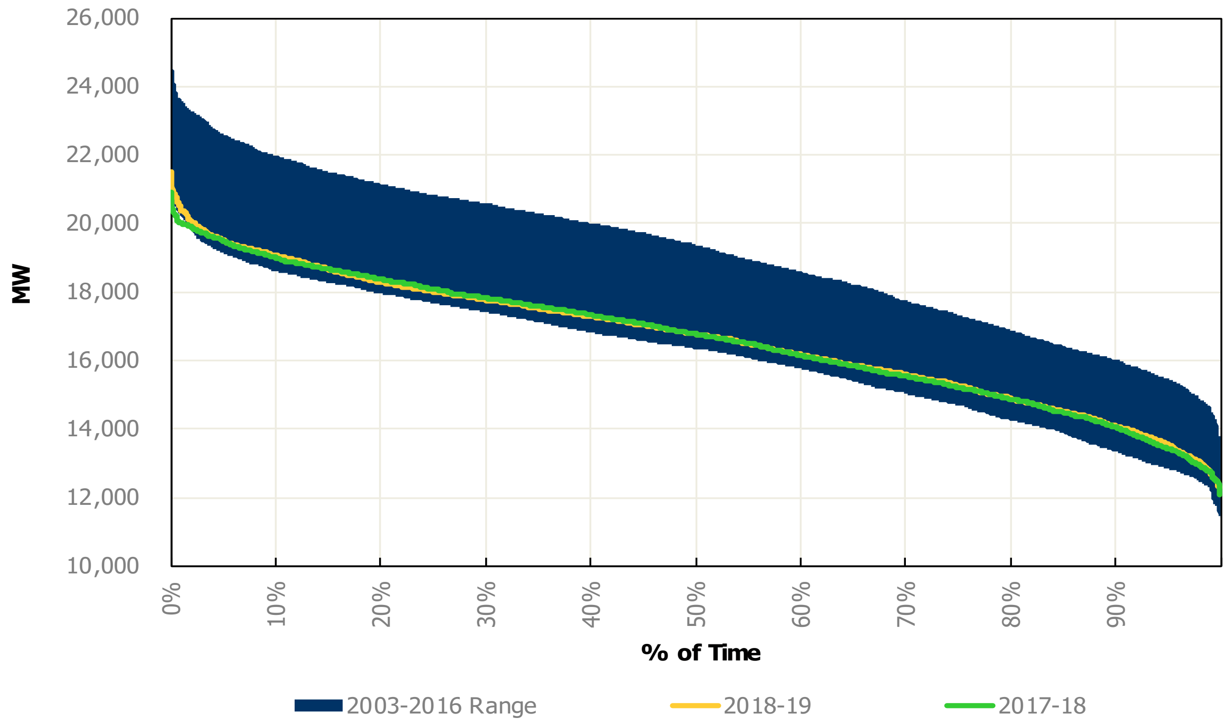


Figure 3.16: Fall Load Duration Curve

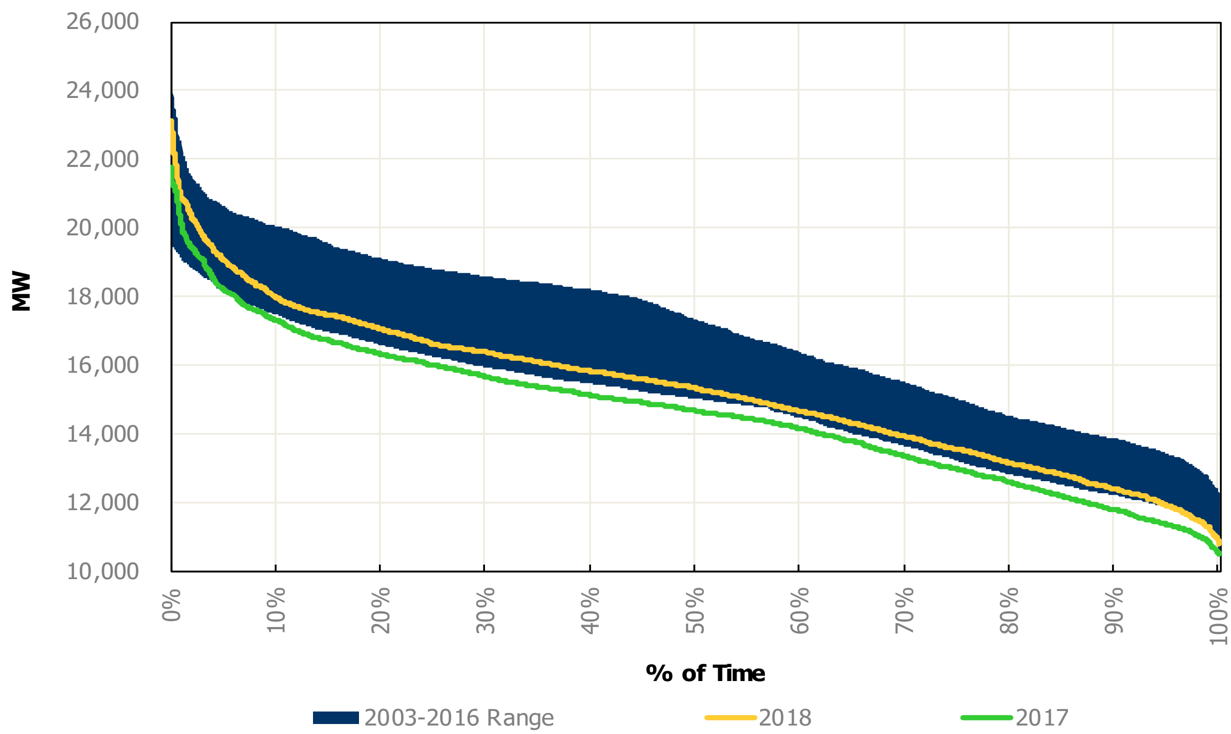
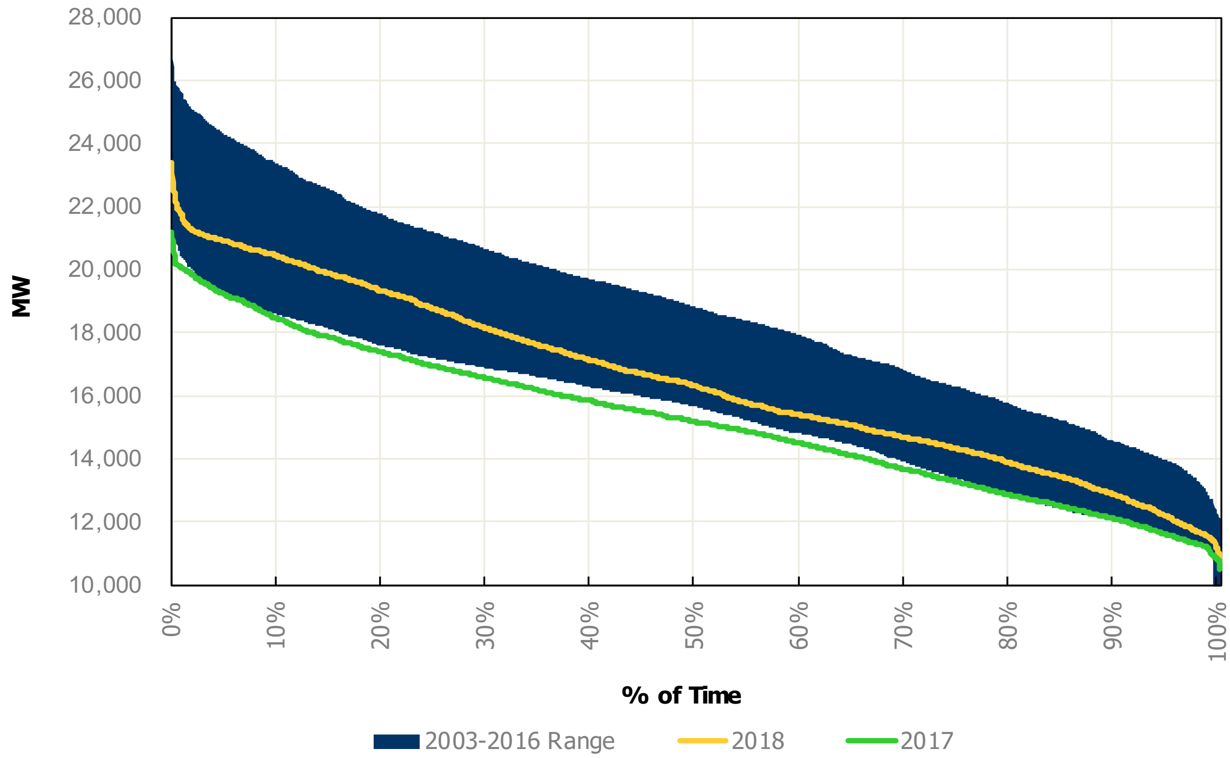


Figure 3.17: Summer Load Duration Curve



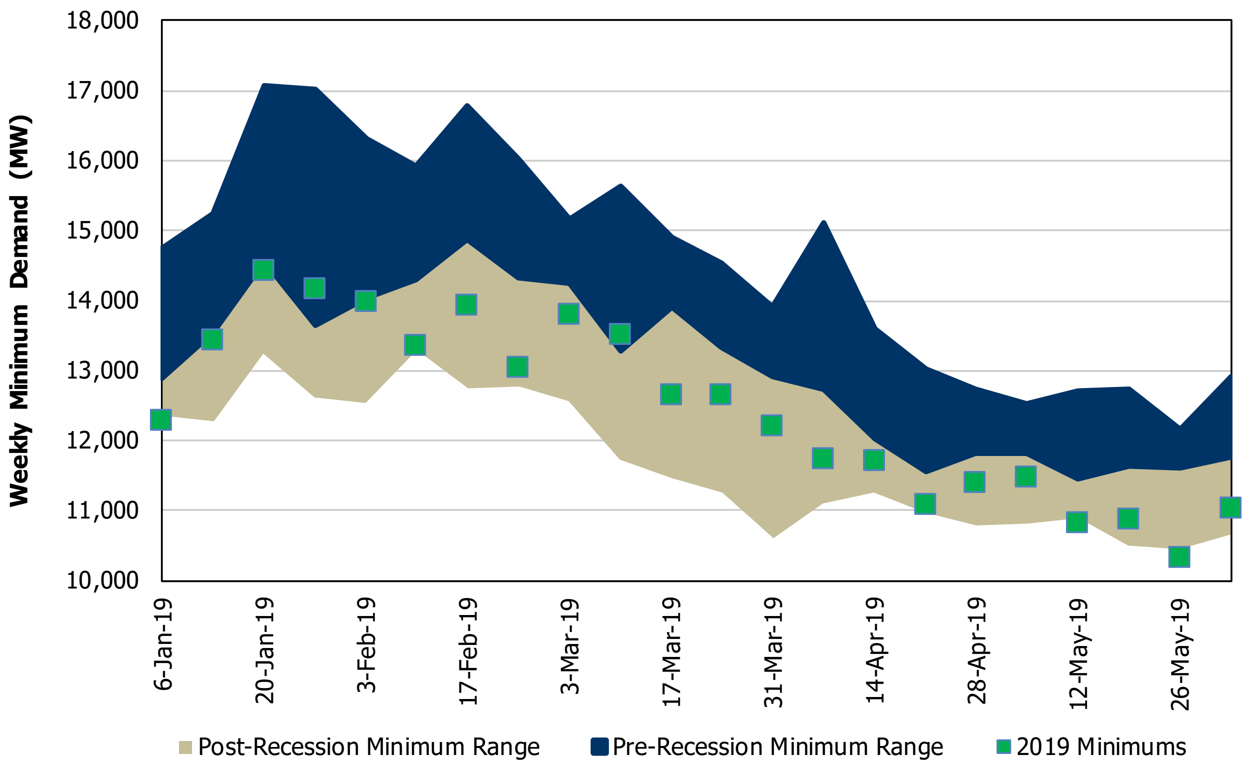
3.5 Historical Minimum Demand

Similar to 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, embedded wind 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 January to May 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 - 2018 time frame. The squares represent the weekly minimums for the past six months.

The minimums of the past six months reflect the generally colder weather and higher levels of demand throughout 2019. 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. 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 website at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookMethodology2019Jun.pdf.

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 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.

The economic fundamentals – low interest rates, a lower dollar, high consumer confidence and strong U.S. growth all create an environment that benefits both Canada and Ontario over the forecast horizon. Despite this, there are substantial risks to economic growth. Consumer confidence had been negatively impacted by the uncertainty surrounding the NAFTA negotiations, and while it was buoyed with the conclusion of the trade agreement, the escalating U.S.-China trade war could reverse this optimism. In addition to these global events, increasing U.S. deficits will put upward pressure on interest rates, which, in turn, would act as a brake on the economy.

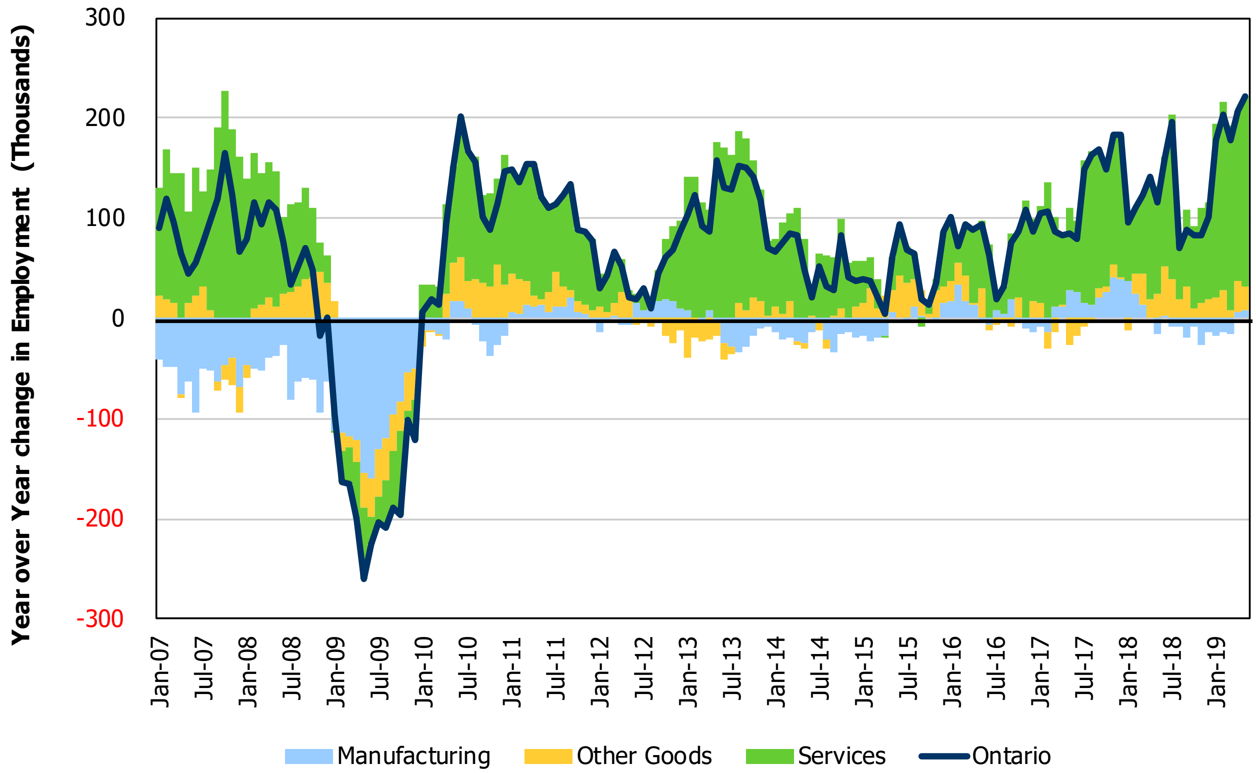
Ontario economic growth was strong throughout the first half of 2018 but slowed in the second half. The start of 2019 would provide insight into whether the latter half was a trend or a blip.

In the first five months of 2019, Ontario's employment grew by 2.8 percent overall, higher than any five-month period since August 2003. That would indicate that the economy has not slowed. As for manufacturing, the average for the five months was -0.8%, an improvement over the second half of 2018. Manufacturing growth was strong to start 2018 and then sputtered in the second half of the year, when it fell by 1.8%. Recent data has shown a swing to the positive with year-over-year manufacturing employment growing by 0.9% in April and 1.0% in May. The elimination of the U.S. steel and aluminum tariffs should provide a boost to Ontario's economy.

Figure 4.1 shows the year-over-year changes in employment broken down into services, manufacturing and other goods (e.g., mining, construction, agriculture, forestry). A broad-based and sustainable growth pattern would have growth across all of the sub-sectors. The graph clearly depicts the deceleration in the latter part of 2018, when employment growth slowed and manufacturing started shedding jobs. The graph also illustrates the strong rebound in total employment and the positive growth in manufacturing employment in the first part of 2019. The

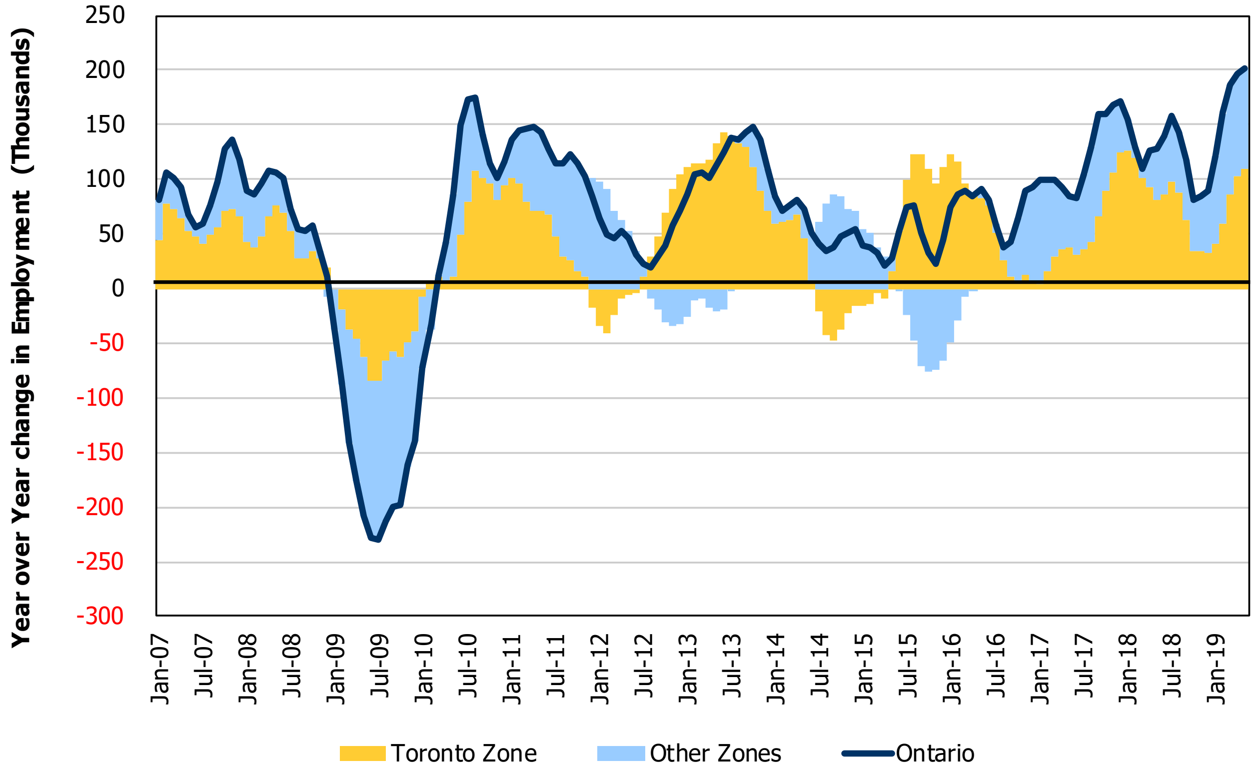
Oshawa GM plant is going to see a drastic decrease in output as it shifts from vehicle to parts production and this will have cascading impacts across the economy – due to the integrated nature of the supply chain. Some of the negative impacts were mitigated by keeping the facility in production

Figure 4.1: Composition of Ontario's Employment Growth



Where employment growth is occurring is also indicative of the health of the economy. Once again, geographically broad-based growth is desirable for a robust economy. At times, employment growth or job losses have been concentrated within the GTA or in another region in the province. Throughout 2018 and into 2019, job growth has been fairly balanced across the province. Figure 4.2 shows the year-over-year employment change for Toronto and the rest of the province.

Figure 4.2: Zonal Employment Growth



Combined the actual job growth for the latter half of 2018 and the start of 2019 was a very positive sign for the economy. The job growth is balanced geographically and across all sectors.

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	1.6
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	7,000	1.1	71.9	5.2	1.392	1.25
2017	7,128	1.8	75.2	4.7	1.415	1.64
2018	7,242	1.6	76.0	1.0	1.436	1.52
2019 (f)	7,377	1.9	69.5	-8.6	1.459	1.57
2020 (f)	7,450	1.0	66.8	-3.8	1.475	1.11

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, the IESO produces demand forecasts based on a number of different weather scenarios, the most common being "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

The extreme weather scenario is valuable for studying situations where the system is under duress. Although it 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 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.

4.4 Demand Measures and Load Modifiers

A number of initiatives and policies have an impact on electricity demand. These can be grouped into two categories: demand measures, which are not incorporated into the demand forecast and load modifiers, which are included. In essence, demand measures are controllable while load modifiers are not. Demand measures include dispatchable loads and the capacity from the demand-response auction. 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.

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 provincial energy-efficiency programs, codes and standards and fuel switching. Projected conservation numbers are based on committed provincial 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 and the impacts are assessed as 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 greater the price ratio between off and peak prices the greater the likelihood that consumers will react to prices. The overall impact will be to shift load within the day or week to off-peak hours and/or the weekend. 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 in the manufacturing and greenhouse sectors with an average monthly peak demand greater than 500 kW and less than 1 MW to participate. As well, 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 both as the number of participants has increased and as participants have improved their ability to identify and react to peaks. First-year (2010) reductions were estimated at 200 MW, growing to an estimated ICI impact on the 2018 peak of 1,300 MW.

Both TOU and ICI impacts are incorporated into the demand forecast. Load-displacing generation, as opposed to distribution-connected generation (embedded) would also factor into the demand forecast as a load modifier.

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. Since all output provided by embedded generation is an offset to grid-supplied electricity, 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 estimated using engineering models that use location, cloud cover and temperature to estimate solar production. The output of remaining embedded generation fuel types is produced using average production profiles based on history. The total embedded generation output is then incorporated into the demand forecast. Table 4-2 summarizes 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 Reliability Outlook Tables.

Figure 4.3: Projected Embedded Generation Capacity

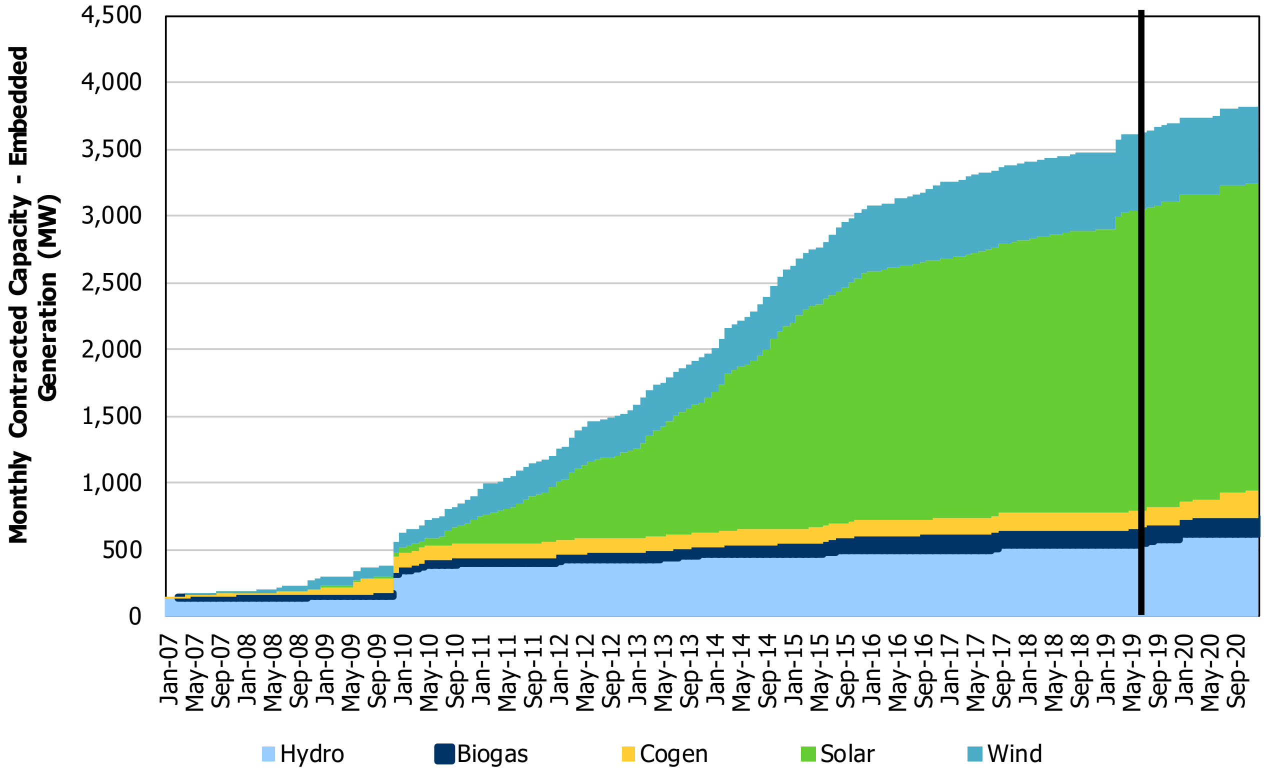


Table 4-2: Embedded Capacity

Month	Estimate of Contracted Embedded Generation Capacity (MW)					
	Biogas	**Cogen**	**Hydro**	**Solar**	**Wind**	**Total**
Jun-07	14	18	137	0	7	176
Jun-08	20	25	142	0	35	222
Jun-09	24	87	147	10	74	341
Jun-10	31	112	388	53	160	744
Jun-11	45	112	395	262	241	1,055
Jun-12	51	112	421	579	298	1,461
Jun-13	62	112	437	847	335	1,793
Jun-14	74	118	458	1,239	347	2,237
Jun-15	90	118	477	1,694	430	2,809
Jun-16	113	123	490	1,897	515	3,137
Jun-17	113	130	497	1,999	580	3,320
Jun-18	114	136	530	2,082	580	3,442

Jun-19	115	136	539	2,246	580	3,615
Jun-20	116	141	618	2,287	580	3,741

Over the course of the 18-month forecast, the amount of embedded installed capacity will increase by 125 MW raising the total to 3,741 MW. The amount of embedded generation capacity added over the forecast will be small compared to what the system has added the last several years.

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