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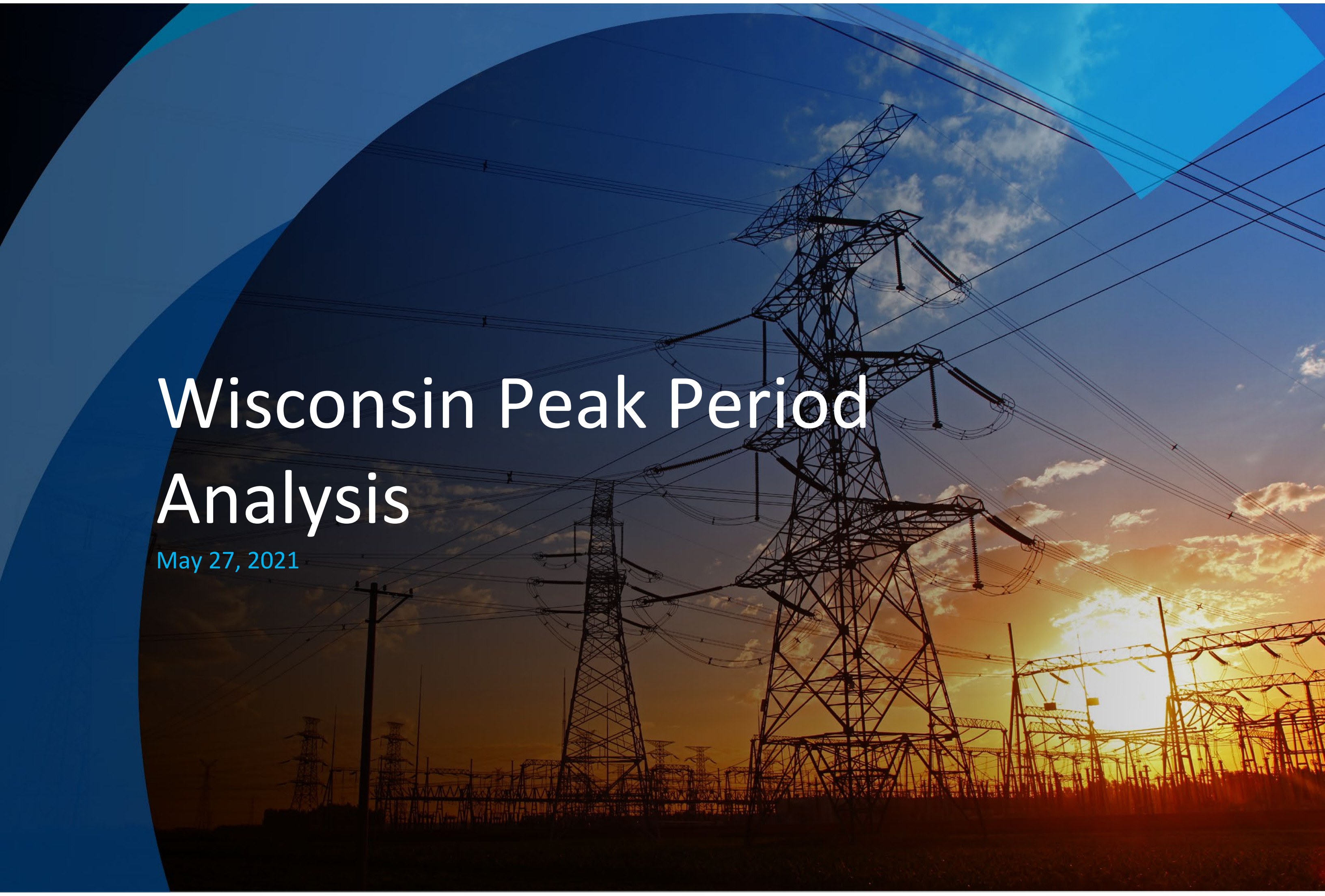

Wisconsin Peak Period Analysis

May 27, 2021

Prepared for:

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Executive Summary

Wisconsin’s current peak period definition was established approximately 20 years ago, at the inception of the state’s Focus on Energy program. Since that time, new technologies have emerged and customers’ energy consumption habits have evolved. The objective of this work is to leverage available data to determine updated peak timing periods for the state of Wisconsin.

Background

Focus on Energy has traditionally targeted direct energy savings through incentivizing energy efficiency measures (i.e., resource acquisition). As the program begins to consider alignment with the Governor's Task Force on Climate and Wisconsin Energy Distribution and Technology Initiative (WEDTI) recommendations, a deeper understanding of the state’s electric demand timing becomes more valuable.

Findings

This study uses Midcontinent Independent System Operator, Inc. (MISO) hourly system load data to identify the periods when consumer demand for electricity is at its highest. Supplementary analyses of the timing of carbon emissions and Locational Marginal Pricing (LMP) were also performed.

Data analysis identifies three Wisconsin consumption peaks. The primary demand peak occurs in the summer and two smaller peaks are observed in the winter months.

Summer Demand Peak

This analysis reveals that Wisconsin’s peak energy use has shifted later into the afternoon (2:00-6:00 p.m.) and is therefore not adequately captured by the current peak period definition (1:00-4:00 p.m.). An update to the Focus on Energy peak period definition is recommended.

Winter Demand Peaks

A substantial amount of demand is also observed during winter months, with two peaks occurring in December, January, and February. One consumption peak is evident in the morning (8:00 a.m.-noon) and one in the afternoon (5:00-9:00 p.m.) Focus on Energy has not previously adopted winter peak demand definitions, however, as winter consumption grows (e.g., due to increased use of heat pumps) adopting winter peak period definitions may become prudent. A discussion of the practical implications of winter peak adoption is provided in the body of this report.

Carbon Emissions and Energy Pricing

Analysis of the timing of carbon emissions and LMP reveals that these variables are not independent of consumption but tied to the timing of peak demand. Both emissions intensity and pricing peak slightly prior to maximum demand, suggesting that they are driven by anticipation of that demand. Therefore, a reduction in peak consumption should serve to reduce both variables.

Introduction

The Wisconsin Public Service Commission asked Cadmus to research Wisconsin's peak electricity demand period, in our role as Focus on Energy's independent evaluator. The scope of this analysis includes reviewing statewide and regional approaches for defining peak electricity consumption periods and conducting a sensitivity analysis to identify an updated peak definition for Focus on Energy. This research provides an analysis of Wisconsin's system peak demand load, including the power supply costs and emissions associated with demand, to assist in the optimization of future program planning. The scope of this analysis does not include the provision of utility-specific peak demand periods, or analysis of peak demand from the perspectives of grid transmission and distribution constraints. An investigation of these topics could provide valuable next steps in identifying Focus on Energy's priorities and determining future approaches for defining the peak demand savings from energy efficiency measures.

Background

The Public Service Commission of Wisconsin (PSC) is statutorily obligated to oversee Focus on Energy (Focus). Wisconsin Stat. § 196.374(3)(b)(1) requires the PSC to set or revise savings goals and measurable targets for Focus programs at least every four years as part of a Quadrennial Planning Process. While Commission supports the design and implementation of programs that achieve both energy and demand savings, it has historically prioritized the reduction of total energy use via resource acquisition.

As the program begins to consider alignment with the Governor's Task Force on Climate[1] and Wisconsin Energy Distribution and Technology Initiative (WEDTI)[2] recommendations, a deeper understanding of the state's electric demand timing becomes more valuable. Wisconsin's current peak period definition was established approximately 20 years ago, at the inception of the Focus on Energy program. Since that time, new technologies have emerged and customers' energy consumption habits have evolved.

The Wisconsin Focus on Energy 2020 Technical Reference Manual currently provides calculations for summer coincident peak savings under the assumption that peak electric demand in Wisconsin occurs from 1:00 to 4:00 pm on weekday afternoons in June, July, and August.[3] In researching a set of recommendations for an updated Wisconsin peak period, Cadmus identified three motivations for reducing peak demand or shifting peak demand to off-peak hours:

- **Carbon Intensity of Generation.** During peak demand hours, marginal power production is often more carbon-intensive than that produced during off-peak hours (i.e., if electricity demand is served by low-efficiency peaker plants). Likewise, changes in demand throughout the day can cause baseload plants to operate less efficiently as they scale their output up or down to follow

[1] PSC REF#: 406724

[2] PSC REF#: 406723

[3] Focus on Energy 2020 TRM

daily system load profiles. Therefore, reducing peak-coincident demand can reduce Wisconsin's overall carbon emissions, independent of reductions in overall energy consumption. However, carbon intensity of generation will also reflect the output of renewables (especially wind), which may not follow demand.

- **Costs of Meeting Demand During Peak Periods.** The megawatts (MW) that utilities purchase in real-time or day-ahead markets to meet their demand obligations during high-demand hours may have a higher cost than MWs purchased during low-demand hours. By reducing peak-coincident demand, utilities could reduce their energy supply costs, ultimately reducing the costs passed on to their customers. However, MW prices are also expected to reflect factors in addition to demand, including supply constraints and fuel mix.
- **Grid transmission and distribution constraints.** Peak demand can overload local or regional power transmission infrastructure. Reducing peak-coincident demand can reduce the need for new and costly capital investments in grid infrastructure for power transmission and distribution, from high-voltage lines down to local substations. Many of these constraints, however, are likely localized, and therefore do not affect all areas equally. A localized analysis was not part of the scope of this research, but findings from this study could be leveraged in future, more localized studies.

With these motivations in mind, Cadmus conducted a literature review and an analysis of overall demand, MW prices, and carbon intensity in the state of Wisconsin.

Literature Review

Cadmus reviewed other statewide and regional approaches for defining peak demand periods, including neighboring utilities, Regional Transmission Operators (RTO), Independent System Operators (ISO), and Technical Resource Manuals (TRM), to identify the range and breadth of peak period definitions and their justifications and uses.

To add clarity to the term "peak," Cadmus adhered to the following definitions:

- **System peak:** The maximum electricity demand (or load) for a given jurisdiction (e.g., Midcontinent Independent System Operator, Inc. or MISO) over a given period (e.g., one calendar year) and net of any behind-the-meter generation.
- **System peak hour:** The specific hour within a given year when the system peak was observed (e.g., July 18 from 2:00 p.m. to 2:59 p.m.).
- **Peak load:** Electric demand or load for a given system based on percentage of the expected maximum load (e.g., load greater than or equal to 90 percent of the expected maximum load).
- **Peak load hours:** Specific hours within a given year when peak loads were observed.
- **Peak period:** A generalized set of hours when the system peak hour and peak load hours are most likely to occur (e.g., May through September, Monday through Friday, from 4:00 p.m. to 7:00 p.m.)

To understand the range of peak periods used by other states and regions, Cadmus assembled a list of the peak periods used by other relevant jurisdictions (below). Cadmus did not find a generalized peak period (as defined above) for MISO (Wisconsin's independent system operator and regional transmission organization.)

- New England Independent System Operator (ISO NE)[4]:
  - Winter: December and January, non-holiday weekdays, 5:00 p.m. to 7:00 p.m.
  - Summer: June through August, non-holiday weekdays, 1:00 p.m. to 5:00 p.m.
- PJM[5]:
  - Winter: January and February, non-holiday weekdays, 7:00 a.m. to 9:00 a.m., 6:00 p.m. to 8:00 p.m.
  - Summer: June through August, non-holiday weekdays, 2:00 p.m. to 6:00 p.m.
- Northwest Power and Conservation Council[6] (6,7):
  - Winter: January and February, 8:00 a.m. to 9:00 a.m.
  - Summer: July and August, 4:00 p.m. to 6:00 p.m.
- Pennsylvania Public Utilities Commission (PUC) TRM[7] (10):
  - Summer: June through August, non-holiday weekdays, 2:00 p.m. to 6:00 p.m.
- California ISO[8]:
  - Summer: July and August, 12:00 p.m. to 4:00 p.m.
- IESO – Ontario[9]:
  - Summer: June through August, weekdays, 1:00 p.m. to 7:00 p.m.

Peak periods are often defined over two-seasons and are designed to include the hours that the region in question reaches a specified demand threshold. Winter peak periods typically occur between December and February and can include both a morning and evening peak. Summer peak periods are often defined as June through August, non-holiday weekdays, and frequently include hours between 2:00 p.m. and 6:00 p.m.

Though Cadmus' literature review showed a clear pattern in summer peak periods for the inclusion of non-holiday weekdays, the specific hours and months included in the definitions vary between

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[4] New England Independent System Operator. "On-Peak Hours Resource (OPHR) Program." 2015.

[5] Pennsylvania, Jersey, Maryland Power Pool. PJM Manual 18b. Page 10. December 5, 2019.

[6] Northwest Power and Conservation Council. The 2021 Northwest Power Plan, Peak Hour Determination. CRAC Webinar. March 5, 2020.

[7] Pennsylvania Public Utility Commission. Technical Reference Manual Volume 1: General Information. Page 10. August 2019.

[8] California Independent System Operator. "CA ISO time-of-use periods analysis." Page 4. January 22, 2016.

[9] Independent Electricity System Operator – Ontario. "IESO Prescriptive Measures and Assumptions List." Page 3. February 2019.

jurisdictions, and only two of the sources provided any specific rationale for the hours included in their peak periods. Notably, none of the other jurisdictions' documentation mentioned carbon or pricing motivations.

The New England Independent System Operator (ISO NE), which operates in similar climate zones to Wisconsin, defines a seasonal peak hour threshold as 90 percent of the annual maximum hourly load or system peak. The 2021 Northwest Power Plan from Northwest Power and Conservation Council also bases their peak periods on seasonal load magnitude, describing the average 24-hour load for each month during peak season as a percentage of the maximum seasonal load. This method also reduces intraday volatility by using the historical averages for each hour. Based upon these findings from the literature review, Cadmus investigated Wisconsin summer and winter peak demand periods, testing the methods employed by ISO NE and the Northwest Power and Conservation Council.

Methodology

Cadmus' analysis included three components. First, we conducted an analysis of Wisconsin's historic hourly demand over from 2015 through 2019. This analysis produced a set of possible peak period recommendations, based upon targeting hours with the highest likelihood of reaching various percentiles of total demand, but did not address outstanding research questions regarding carbon intensity or energy prices. To address these motivations, we then conducted a carbon emissions analysis and an energy pricing analysis. The following sections describe our methods and findings from each portion of the analysis.

Demand Analysis

Data Collection

Cadmus utilized hourly system load shapes, utility sales, and weather data to perform this analysis. Historical data sources included:

- Hourly system load data from the Midcontinent Independent System Operator, Inc. (MISO) for zones within WI (zones 1, 2, 7) covering the period 2015 through 2019
- System load shapes for major individual utilities contributing to WI load
- Utility specific sales data from the Annual Electric Power Industry Report (EIA form 861)
- Weather data for representative stations[10] in each state contributing to the relevant MISO zones from NOAA Integrated Surface Database (ISD)

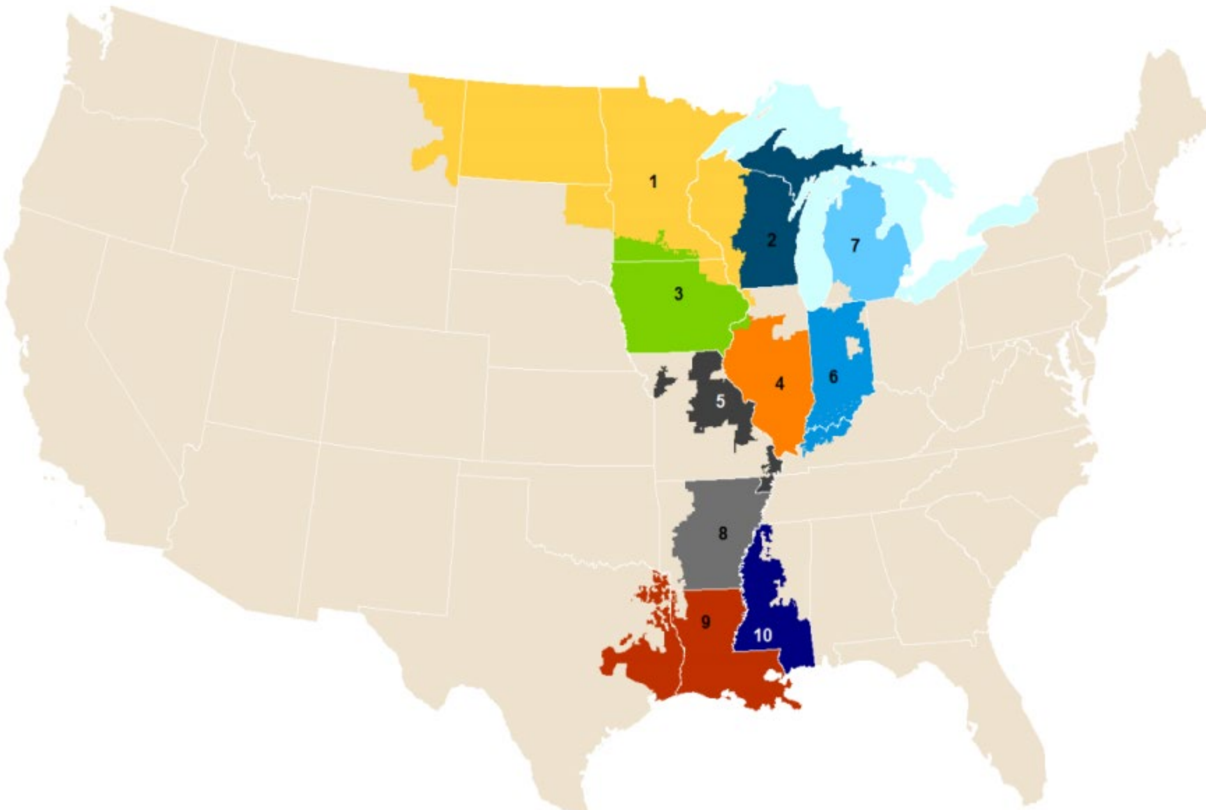
Analysis Methods

To obtain an accurate approximation of the statewide load, Cadmus used EIA electricity sales data for all Focus on Energy participating utilities to develop a weighted average of the MISO territories within

[10] MISO provides a representative weather station for each MISO zone.

Wisconsin state boundaries (MISO zones 1, 2/7[11]). Figure 1 provides a map of MISO zones[12]. Note that Wisconsin is split between MISO zones 1 and 2.

Figure 1. MISO Zone Map



Weights are based on the proportion of Focus utility sales within each MISO zone to the overall zone's load, essentially removing the demand within these MISO zones that is outside of Focus on Energy's territory. Weights were calculated for each year from 2015 to 2019 and applied to the respective MISO load shapes to create a history of single system load shapes covering the entire Focus territory. The resulting set of Focus-specific zone 1 and zone 2 load shapes, shown in Figure 2, were analyzed to determine appropriate peak period definitions for Focus. In the figure, each dot represents one of 8,760 hourly demand observations within the MISO zone in 2015-2019, and the lines represent moving averages for each year. Note that while Zone 2's moving average and maximum hourly demand always occurred in the summer, the seasonal peak of Zone 1's demand varied between years. In some years, Zone 1 sustained higher average demand in the winter than in the summer, though the maximum hourly demand always occurred in the summer.

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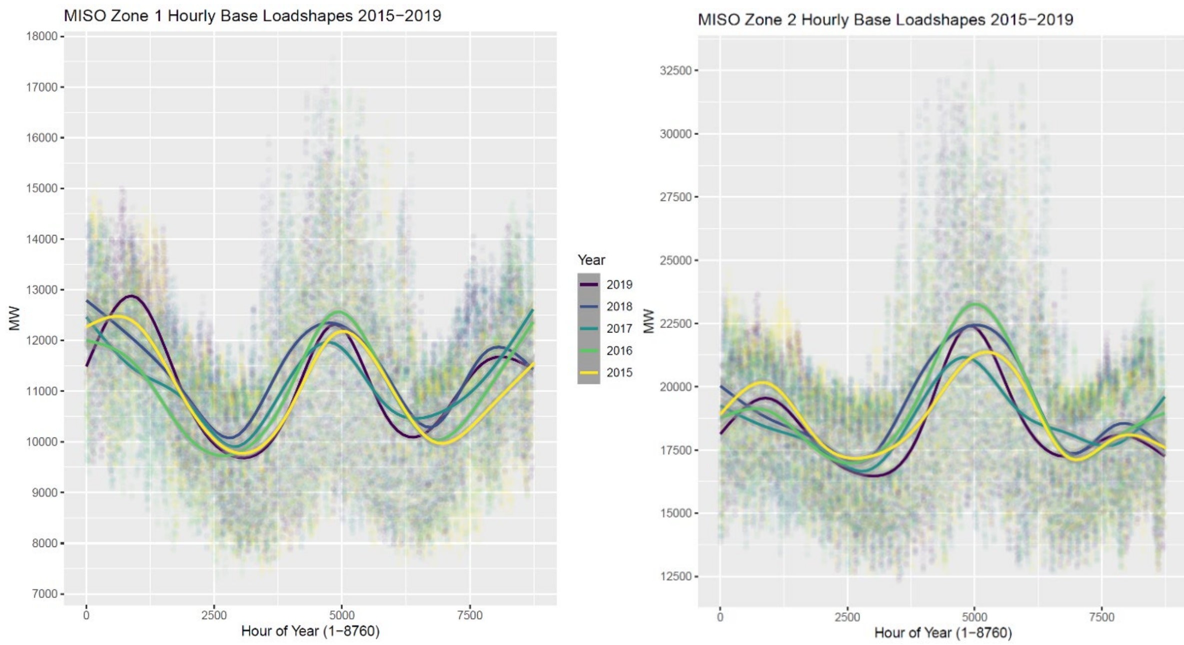
[11] MISO system load data combine the Zone 2 and Zone 7 loads into one series.

[12] Source: MISO, Available at: https://cdn.misoenergy.org/20190205%20LOLEWG%20Item%2004%202023%202024%20CILCEL%20Values315939.pdf

Figure 2. Historical Annual Load Shapes of MISO Territories in Wisconsin



Zone 1, however, accounts for a smaller share of Wisconsin load than does Zone 2, suggesting that the overall Wisconsin winter peak is not likely to be as substantial as the summer peak. The Wisconsin portion of zone 1 load ranged from 13.3% to 13.5% of total zone 1 load, and zone 2/7 weights ranged from 36.2% to 36.4% from year to year. As expected, the overall Wisconsin load-shape is summer-peaking.

Figure 3 shows the historical annual overall Wisconsin load shape, based upon the sales-weighted averages of MISO zones 1 and 2/7. In all subsequent summaries zone 1 and zone 2/7 Wisconsin-specific loads are combined into a total Wisconsin hourly load. As expected, the overall Wisconsin load-shape is summer-peaking.

Figure 3. Historical Annual Wisconsin Load Shape

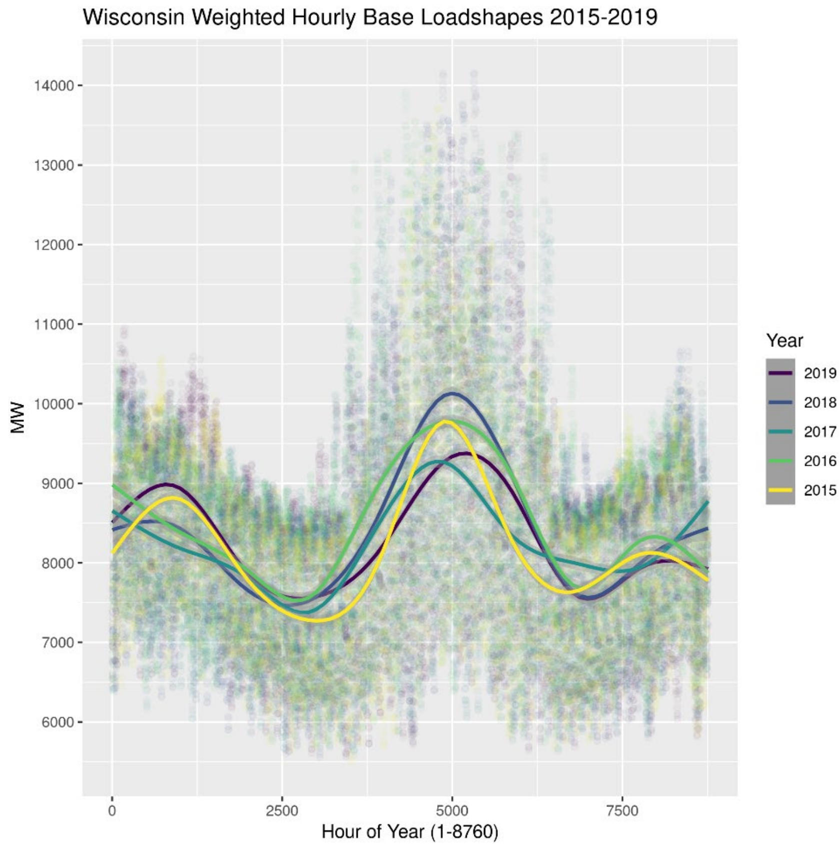


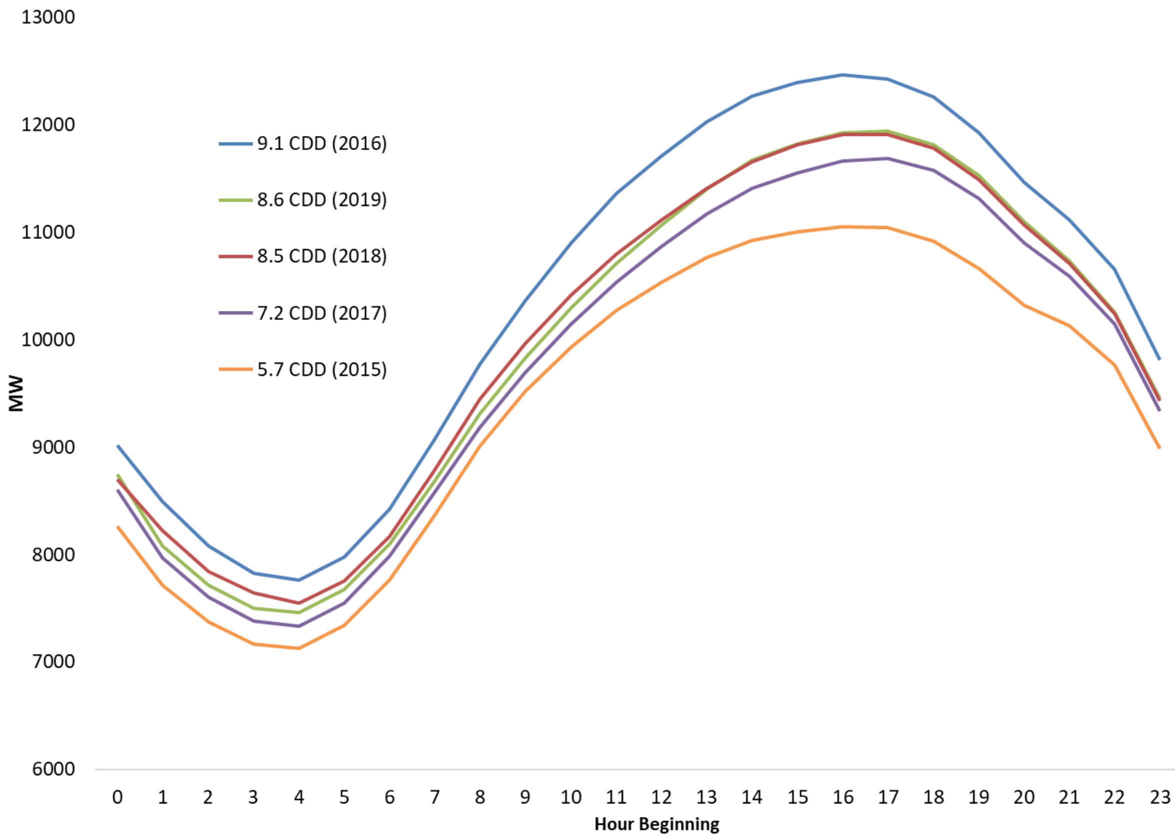
Table 1 shows the Wisconsin annual critical peak (maximum) loads and hours by year – all occurred in the summer months. Two of the annual peaks occurred in July, and one peak each in June, August, and September. The variations in maximum peak month suggest that selecting a period of June through September would be most appropriate, to capture all recent critical peak hours. Critical peak hours typically occur between 4:00 p.m. and 6:00 p.m., except in 2019 when the critical peak hour occurred from 2:00 to 3:00 pm. Note that Focus on Energy's current peak period definition (July-August non-holiday weekdays between 1:00 to 4:00 pm) excludes four out of five of the annual critical peak hours that occurred during the last five years, due to both the ranges of hours and months included. This finding supports reevaluation of the peak period definition to better align with Wisconsin's actual critical peak hours.

Table 1. Annual Critical Peak Hours

Year	Date	Hour	MW
2015	7/27/2015	5:00 to 6:00 p.m.	13,348
2016	8/10/2016	4:00 to 5:00 p.m.	14,153
2017	9/22/2017	4:00 to 5:00 p.m.	13,105
2018	6/29/2018	5:00 to 6:00 p.m.	13,912
2019	7/19/2019	2:00 to 3:00 p.m.	13,712

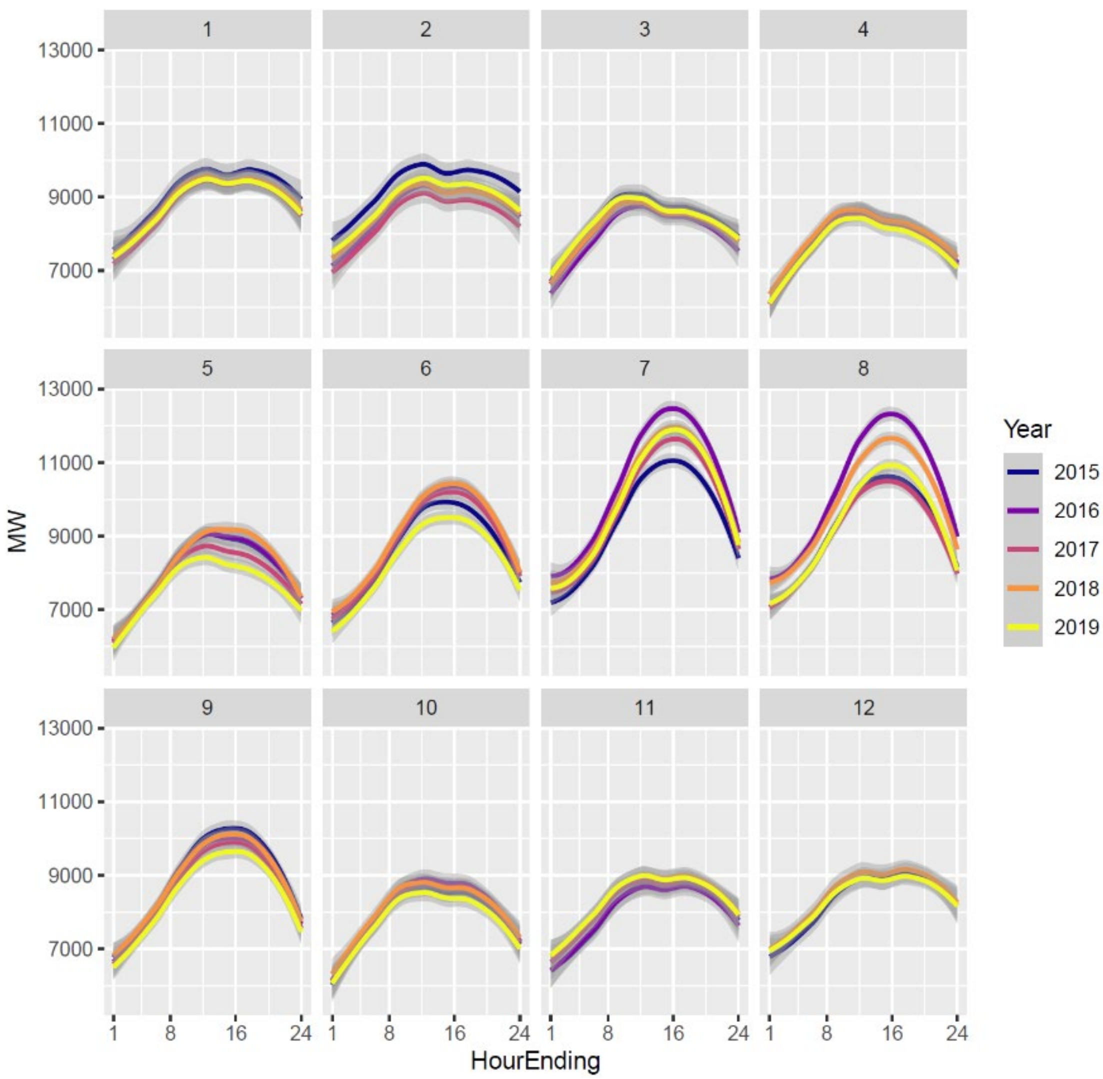
Cadmus used weather data to investigate the influence of temperature on annual load shapes. Figure 4 illustrates a correlation between the average number of Cooling Degree Days (CDD) in July with variation in weekday/business day electricity demand. Higher average CDD in July (i.e., warmer weather) leads to higher demand.

Figure 4. Wisconsin Average Hourly Loads and Cooling Degree Days for July Weekdays by Year



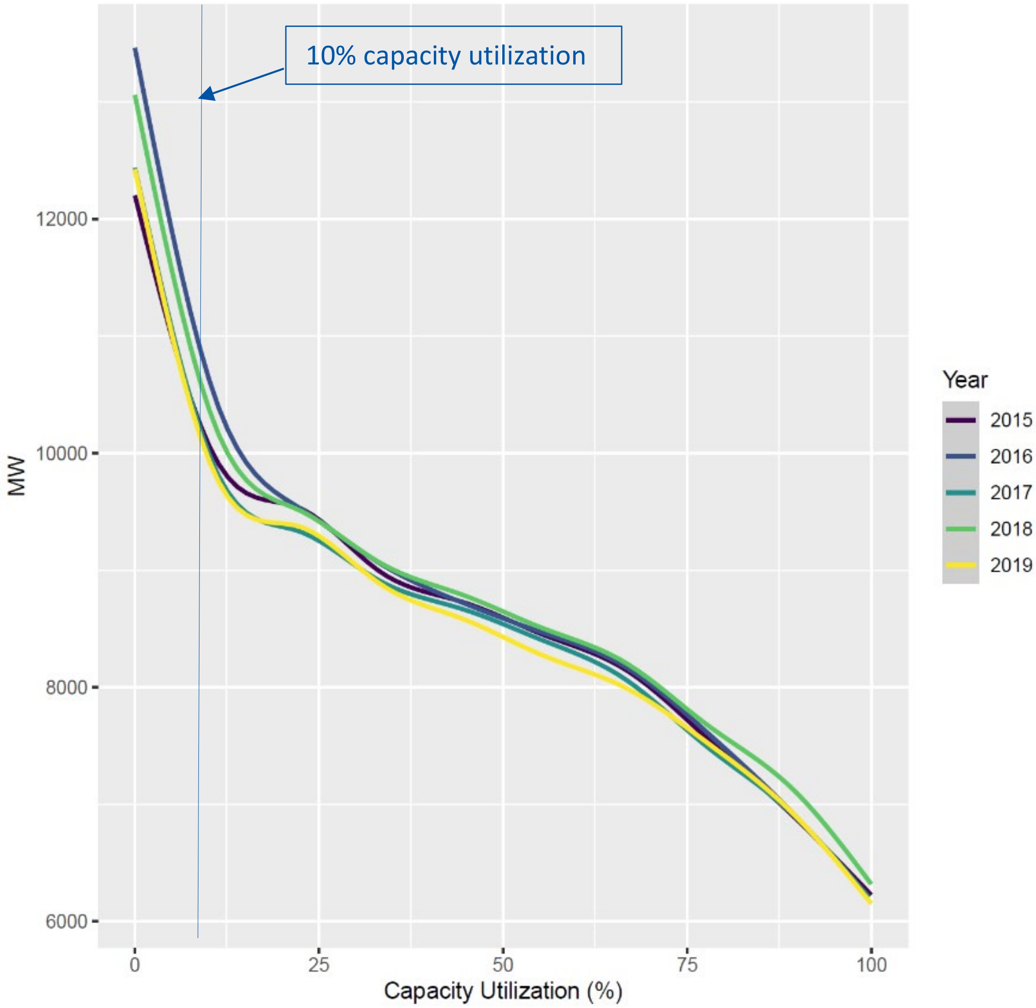
Cadmus analyzed load data using multiple peak period definitions. The literature review provided support for a two-season (winter and summer) peak period for business days (i.e., excluding weekends and federal holidays). To identify optimal peak period recommendations for Wisconsin, Cadmus first examined the average 24-hour load shape for each month and year, shown in Figure 5. These average 24-hour load shapes enable visualization of the months where average demand is highest. As shown, average demand is consistently higher in the summer months (particularly in July and August), and there is also a smaller peak in winter months (particularly in January and February).

Figure 5. Wisconsin Average 24-Hour Load Shape by Month and Year



Cadmus also examined Wisconsin load duration curves (LDCs) to identify appropriate peak definitions based on the percentage of time a given amount of load is observed. LDCs order each of 8,760 hourly demand observations within a year from the highest (the annual critical peak) on the left to the lowest on the right. Capacity utilization is thus interpreted as the inverse of a percentile ranking of hourly demands. For example, the 90th percentile of annual hourly demand corresponds with 10% capacity utilization – demand above the 90th percentile requires generation (or import) capacity that is required for less than 10% of the year. The LDCs, shown in Figure 6, illustrate that very high loads are observed for a very short amount of time (i.e., use a low percentage of capacity) and display a sharp reduction in demand at utilization below the 12.5% level (approximately 9,500-10,000 MW).

Figure 6. Wisconsin Load Duration Curves by Year (2015-2019)



Based on this finding, Cadmus chose a range of demand-percentiles to test various peak definitions (the 90th, 95th, 99th, and 99.9th percentiles of seasonal load). These percentiles describe the load attained in a given hour relative to the distribution of loads within a season, and they are used to demarcate peak period conditions. Table 2 and Table 3. present the day and hour ranges during which all peak load hours (defined by the specified demand-percentile and its corresponding capacity utilization) occurred. Holidays and weekends are excluded in both tables. These results illustrate the variability of peak periods from year to year and by peak load threshold.

The summer peak periods range from (at the lowest threshold, 10%) May 29th to September 26th, 9:00 a.m. to 11:00 p.m. and (at the highest threshold, 0.1%) June 12th to September 22nd, 2:00 to 7:00 p.m. The winter peak period ranges from December 29th to January 17th, 7:00 a.m. to 10:00 p.m. and December 19th to January 2nd, 6:00 to 8:00 p.m.

Table 2. Summer Peak Periods

Summer Peak					
Year	Earliest Date	Latest Date	Earliest Hour	Latest Hour	Capacity Utilization
2015	6/10/2015	9/8/2015	10	23	10%
2016	6/20/2016	9/7/2016	10	23	10%
2017	6/12/2017	9/26/2017	10	23	10%
2018	5/29/2018	9/17/2018	10	23	10%
2019	6/26/2019	9/11/2019	9	23	10%
2015	7/13/2015	9/8/2015	11	22	5%
2016	6/20/2016	9/6/2016	11	22	5%
2017	6/12/2017	9/26/2017	12	22	5%
2018	5/29/2018	9/17/2018	11	22	5%
2019	6/27/2019	8/21/2019	10	22	5%
2015	7/27/2015	9/2/2015	13	20	1%
2016	7/22/2016	8/11/2016	14	20	1%
2017	6/12/2017	9/22/2017	14	20	1%
2018	6/29/2018	9/4/2018	14	20	1%
2019	7/2/2019	8/5/2019	12	20	1%
2015	7/27/2015	7/28/2015	15	18	0.10%
2016	7/22/2016	8/10/2016	16	18	0.10%
2017	6/12/2017	9/22/2017	16	18	0.10%
2018	6/29/2018	6/29/2018	16	19	0.10%
2019	7/19/2019	7/19/2019	14	17	0.10%

Table 3. Winter Peak Periods

Winter Peak					
Season	Begin Date	End Date	Earliest Hour	Latest Hour	Capacity Utilization
2015-2016	12/3/2015	2/17/2016	8	22	10%
2016-2017	12/6/2016	2/9/2017	8	22	10%
2017-2018	12/5/2017	2/12/2018	8	22	10%
2018-2019	12/3/2018	2/27/2019	8	22	10%
2015-2016	12/17/2015	2/12/2016	8	22	5%
2016-2017	12/7/2016	1/12/2017	8	22	5%
2017-2018	12/6/2017	2/8/2018	9	22	5%
2018-2019	12/6/2018	2/26/2019	8	22	5%
2015-2016	1/11/2016	1/20/2016	9	21	1%
2016-2017	12/13/2016	1/5/2017	18	21	1%
2017-2018	12/12/2017	1/5/2018	10	21	1%
2018-2019	1/29/2019	1/31/2019	10	21	1%
2015-2016	1/11/2016	1/12/2016	19	19	0.1%
2016-2017	12/15/2016	12/19/2016	19	19	0.1%
2017-2018	1/2/2018	1/4/2018	19	19	0.1%
2018-2019	1/31/2019	1/31/2019	19	20	0.1%

Cadmus also analyzed combined load shapes for each month, averaged over the five years in the study (Table 4.) The purpose of this analysis was to show the hours and months that have the highest average loads. To calculate the percentages shown in the table, Cadmus first calculated the average demand for each hour, month, and year combination, and then divided these by the maximum of these averages within the season and year. Cadmus then averaged across years to determine hours and months that peak load is likely to occur. For example, a value of 95% reflects that the average demand during that month and hour reached 95% of the seasonal maximum of average hourly loads. This is a similar approach to that used by the Northwest Power and Conservation Council for determining peak load. The summer and winter weighted average columns shows the average across June through September hours[13] for summer and December through February hours for winter, weighted by the percent of hours in each month that were in the top 10% of loads.

[13] May is excluded from this column because May average loads were never greater than 75% of the summer season maximum as described below, and as shown previously critical peak hours never occurred in May.

Table 4. Average Summer and Winter Demand Utilization over 2015-2019 by Hour of Day

Summer Season					Summer Weighted Average	Hour of Day	Winter Season			Winter Weighted Average
May	June	July	Aug	Sept	June-Sept		Dec	Jan	Feb	Dec-Feb
60%	65%	73%	70%	64%	71%	0	76%	80%	79%	79%
57%	61%	69%	67%	61%	67%	1	74%	78%	77%	77%
55%	59%	65%	64%	59%	64%	2	72%	76%	76%	75%
54%	58%	64%	62%	58%	62%	3	72%	76%	75%	75%
55%	58%	63%	62%	58%	62%	4	72%	77%	76%	76%
57%	60%	65%	64%	60%	64%	5	75%	80%	79%	79%
62%	64%	68%	69%	66%	68%	6	82%	86%	86%	85%
67%	69%	74%	73%	72%	73%	7	89%	94%	93%	93%
71%	74%	79%	78%	75%	78%	8	91%	96%	95%	95%
73%	77%	84%	81%	77%	82%	9	92%	97%	95%	96%
74%	79%	88%	85%	79%	85%	10	92%	97%	95%	96%
75%	81%	91%	88%	81%	88%	11	92%	96%	95%	95%
75%	83%	94%	90%	82%	91%	12	92%	96%	94%	95%
75%	84%	96%	92%	84%	93%	13	91%	95%	93%	94%
75%	85%	98%	94%	85%	94%	14	91%	95%	93%	94%
75%	86%	99%	95%	85%	95%	15	90%	94%	92%	93%
74%	86%	100%	95%	85%	95%	16	91%	94%	91%	93%
74%	85%	100%	94%	84%	95%	17	95%	96%	92%	95%
73%	84%	99%	93%	83%	94%	18	97%	100%	95%	98%
72%	83%	96%	90%	82%	92%	19	96%	99%	97%	98%
72%	80%	93%	88%	82%	89%	20	94%	97%	95%	96%
72%	79%	90%	87%	79%	87%	21	91%	94%	92%	93%
69%	76%	86%	82%	74%	83%	22	87%	89%	88%	88%
64%	71%	80%	76%	68%	76%	23	81%	84%	83%	83%

The results of the above analyses informed the identification of possible summer and winter peak period definitions. In Summer, no hours in May ever reached more than 75% of the summer demand peak, suggesting that hours in May should not be included in any definitions. June and September were similar, achieving up to 85-86% of the seasonal peak on average. Excluding May, Summer average demand peaked broadly between 12:00 p.m. and 9:00 p.m. In Winter, there appeared to be a morning peak broadly between 8:00 a.m. and 12:00 p.m. and an evening peak broadly between 5:00 p.m. and 9:00 p.m. These broadly defined peak periods serve as the basis for our widest possible peak definition, with more narrow possibilities defined by a higher percent utilization.

Figure 5 shows the average weekday load shapes for the summer (June-September) period months. The widest peak period we are investigating is also highlighted in blue (i.e., noon to 9:00 p.m.).

Figure 5. Average Summer Weekday Load Shape

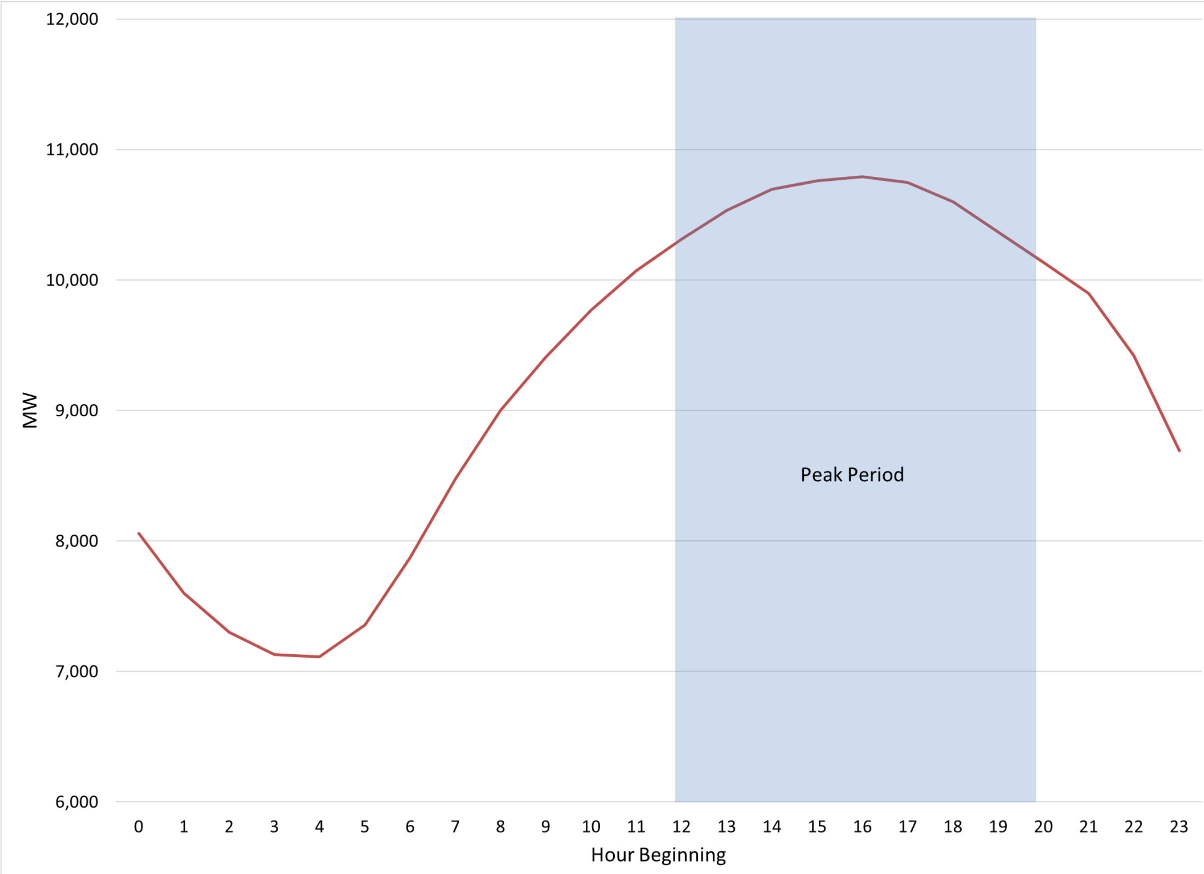
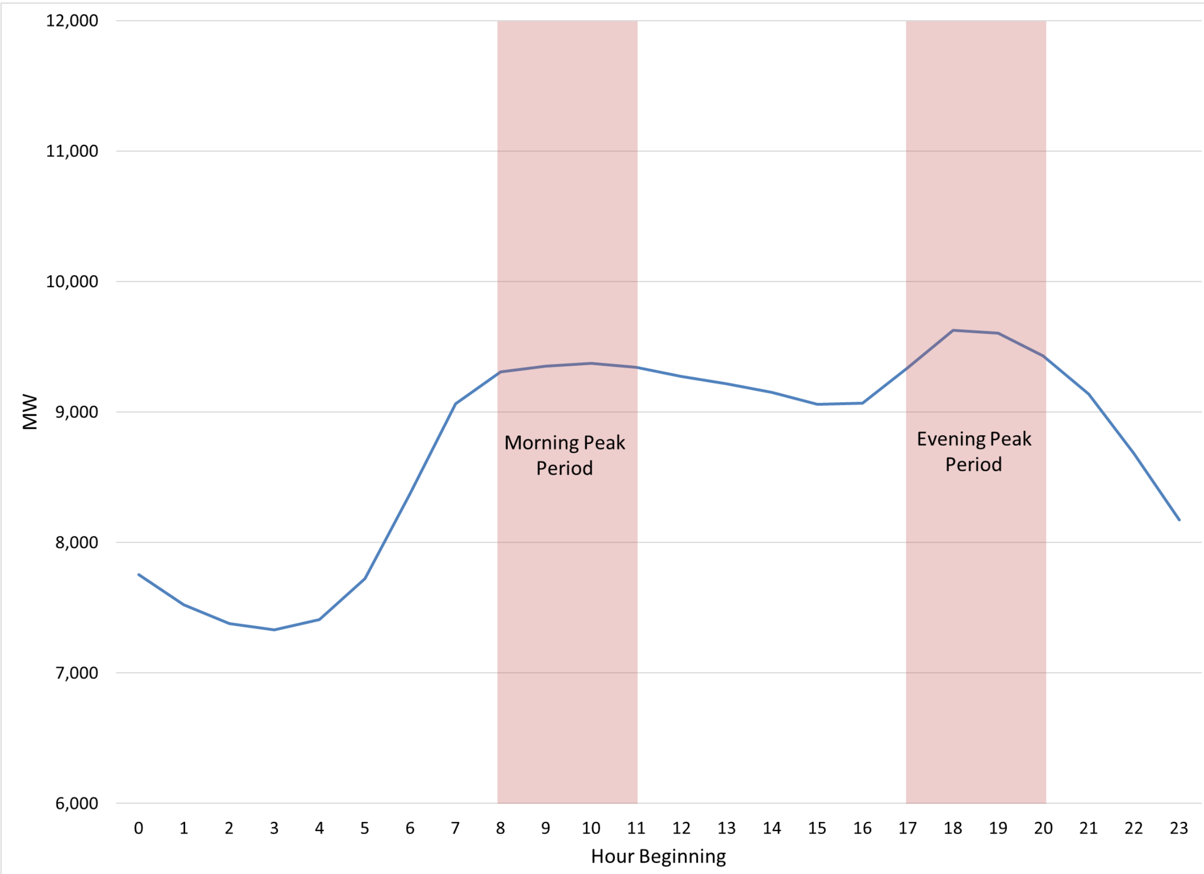


Figure 6 shows the average weekday load shapes for the winter (December-February) period months. The widest morning peak period (8:00 a.m. – 12:00 p.m.) and evening peak period (5:00 – 9:00 p.m.) we are investigating is highlighted in pink.

Figure 6. Average Winter Weekday Load Shape



Peak Period Capture Rates

Cadmus identified a set of possible summer and winter peak period combinations and analyzed their performance according to their ability to capture demand within various thresholds above the 90th peak demand percentile for each season. These performance metrics are referred to as peak capture rates. The potential peak period month/hour business day only combinations Cadmus examined are:

- Winter:
  - Month definition
    - December, January, February
  - Evening definition
    - a: 6:00 to 8:00 p.m.
    - b: 5:00 to 9:00 p.m.
  - Morning definition
    - a: 9:00 to 11:00 a.m.
    - b: 8:00 a.m. to noon

- Summer:
  - Focus on Energy's current Summer peak definition
    - 1:00 to 4:00 p.m., June, July, August
  - Month definition
    - 1: July, August
    - 2: June, July, August
    - 3: July, August, September
    - 4: June, July, August, September
  - Hour definition
    - a: 4:00 to 6:00 p.m.
    - b: 3:00 to 7:00 p.m.
    - c: 2:00 to 8:00 p.m.
    - d: 12:00 to 9:00 p.m.
    - e: 2:00 to 6:00 p.m.
    - f: noon to 8:00 p.m.
    - g: 1:00 to 7:00 p.m.
    - h: 1:00 to 8:00 p.m.

Cadmus reviewed all of these combinations and their capture rates over various peak load percentile definitions to determine the most appropriate month/hour peak period definitions for each season.

Table 5 summarizes the capture rates for non-holiday weekdays across all the hour combinations above for the three summer periods. The higher the capture rate, the better the peak definition captures the hours above a given percentile. The June to September (4) period captures 73% of the summer load hours above the 90th percentile – and shows a considerable improvement over the July to September (3) period that only captures 60% of the summer load hours above the 90th percentile.

The 10% off peak rate measures the percentage of hours captured in each summer month period that were actually off-peak hours (below the 90th percentile), not peak hours. This column represents the error rate associated with each definition. The lower the 10% off peak rate, the fewer non-peak hours are captured by a given peak definition. The 65% off peak rate for the June - September combination is comparable with the July – September period at 60%. The gain in the capture rate for these months (+13%) is higher than the gain in off peak hours included (+5%.)

Table 5. Summer Month Definition Capture Rates

Month Definition	Capture Rate 10%	Capture Rate 5%	Capture Rate 1%	Capture Rate 0.1%	10% Off Peak Rate
1: July – August	37%	44%	57%	74%	52%
2: June – August	51%	59%	75%	98%	59%
3: July – September	60%	70%	87%	92%	60%
4: June – September	**73%**	**82%**	**92%**	**100%**	**65%**

Table 6 shows the summer capture rates for all the month (1-4) and hour (a-h) period combinations for the top 10%, 5%, 1%, and 0.1% of hours. There are only two combinations that always included the top 0.1% of the hours - June-August (2) and June-September (4). The combinations that are highlighted in gray were excluded because they did not capture all the 0.1% hours.

Based on Table 5, and the previous findings of the demand analysis, Cadmus selected the June – September period (4). Within this month definition, Cadmus identified the June-September (4) 2:00 to 6:00 p.m. (e) period (highlighted in green) because it captures 78% of the top 1% of the hours and 100% of the top 0.1% of the hours. The selected period also corresponds to the hours where the average June through September load is above 90% of the maximum peaks (Table 4) and would have included all of the annual critical peak periods (Table 1) over the last 5 years. Despite similarities in percentage of captured peak, period (e) was selected over period (b) as selection (b) would have missed the 2019 critical peak which occurred at 2:00 p.m. The wider noon to 8:00 p.m. (f) and noon to 9:00 p.m. (h) periods capture a higher percentage of the top 10% of the hours, however, they also include more off-peak hours and are broader than the peak definitions of other jurisdictions reviewed in this study.

Table 6. Demand Analysis Summer Peak Capture Rates

Month Definition	Hour Definition	Capture Rate 10%	Capture Rate 5%	Capture Rate 1%	Capture Rate 0.1%	10% Off Peak Rate
1: July - August	a: 4:00 - 6:00 p.m.	19%	23%	36%	55%	44%
1: July - August	b: 3:00 - 7:00 p.m.	37%	44%	61%	70%	46%
1: July - August	c: 2:00 - 8:00 p.m.	52%	62%	78%	78%	48%
1: July - August	d: noon - 9:00 p.m.	69%	76%	79%	78%	54%
1: July - August	e: 2:00 - 6:00 p.m.	37%	44%	61%	78%	46%
1: July - August	f: noon - 8:00 p.m.	64%	72%	79%	78%	52%
1: July - August	g: 1:00 - 7:00 p.m.	52%	62%	74%	78%	49%
1: July - August	h: 1:00 - 8:00 p.m.	59%	69%	79%	78%	50%
2: June - August	a: 4:00 - 6:00 p.m.	22%	26%	39%	78%	57%
2: June - August	b: 3:00 - 7:00 p.m.	42%	49%	67%	100%	59%
2: June - August	c: 2:00 - 8:00 p.m.	60%	68%	86%	100%	61%
2: June - August	d: noon - 9:00 p.m.	78%	84%	88%	100%	65%
2: June - August	e: 2:00 - 6:00 p.m.	42%	49%	67%	100%	59%
2: June - August	f: noon - 8:00 p.m.	73%	80%	88%	100%	64%
2: June - August	g: 1:00 - 7:00 p.m.	59%	68%	82%	100%	61%
2: June - August	h: 1:00 - 8:00 p.m.	67%	76%	87%	100%	62%
3: July - September	a: 4:00 - 6:00 p.m.	21%	27%	42%	62%	57%
3: July - September	b: 3:00 - 7:00 p.m.	41%	51%	72%	78%	59%
3: July - September	c: 2:00 - 8:00 p.m.	59%	71%	90%	86%	60%
3: July - September	d: noon - 9:00 p.m.	79%	87%	93%	86%	65%
3: July - September	e: 2:00 - 6:00 p.m.	41%	52%	72%	86%	58%
3: July - September	f: noon - 8:00 p.m.	73%	83%	93%	86%	63%
3: July - September	g: 1:00 - 7:00 p.m.	59%	71%	87%	86%	60%
3: July - September	h: 1:00 - 8:00 p.m.	67%	79%	92%	86%	61%
4: June - September	a: 4:00 - 6:00 p.m.	24%	29%	45%	86%	64%
4: June - September	b: 3:00 - 7:00 p.m.	46%	56%	78%	100%	65%
4: June - September	c: 2:00 - 8:00 p.m.	66%	77%	99%	100%	67%
4: June - September	d: noon - 9:00 p.m.	88%	95%	100%	100%	70%
4: June - September	**e: 2:00 - 6:00 p.m.**	**46%**	**56%**	**78%**	**100%**	**65%**
4: June - September	f: noon - 8:00 p.m.	82%	91%	100%	100%	69%
4: June - September	g: 1:00 - 7:00 p.m.	66%	78%	95%	100%	67%
4: June - September	h: 1:00 - 8:00 p.m.	75%	86%	100%	100%	68%

Table 7 shows the winter peak capture rates for the evening hours and (secondary) morning hours. Peak demand in the winter occurs predominantly in the evening, as is evident in Table 4. This is also why the morning hour 0.1% capture rates register as 0% (i.e., all winter 0.1% peak hours occur in the evening).

Table 7. Demand Analysis Winter Peak Capture Rates

Month Definition	Evening Hour Definition	Capture Rate 10%	Capture Rate 5%	Capture Rate 1%	Capture Rate 0.1%	10% Off Peak Rate
December - February	a: 6:00 - 8:00 p.m.	31%	41%	70%	100%	62%
December - February	b: 5:00 - 9:00 p.m.	48%	60%	90%	100%	70%
Month Definition	**Morning Hour Definition**	**Capture Rate 10%**	**Capture Rate 5%**	**Capture Rate 1%**	**Capture Rate 0.1%**	**10% Off Peak Rate**
December - February	a: 9:00 - 11:00 a.m.	17%	14%	5%	0%	80%
December - February	b: 8:00 a.m. - noon	31%	27%	10%	0%	81%

As shown previously, Wisconsin's average winter demand is substantially lower than the average demand in summer, and system critical peak hours never occurred in winter. The investigation of winter peak periods was conducted primarily as an informative exercise, to aid carbon mitigation efforts and strategic electrification conversations as they arise, rather than to address winter demand itself. In the next two sections, we broaden our analysis to include considerations of the carbon intensity of power generation and the variability of wholesale energy prices, which may deliver more support for a winter peak demand period.

Carbon Analysis

In this section, we discuss the data collection, analysis methods, and findings from our analysis of Wisconsin's average hourly carbon emissions from power generation. These findings inform our recommendations for summer and winter peak periods.

Data Collection & Analysis Methods

Cadmus collected hourly carbon emissions data, covering 2015-2019, from the EPA's Clean Air Markets Division (CAMD) Air Markets Program Data FTP site. These data included hourly carbon dioxide emissions from all Wisconsin generating stations affected by the EPA's trading programs. In Wisconsin, these include the Acid Rain Program (which requires SO2 and NOx reductions) and the Cross-State Air Pollution Rule (CSAPR). In general, these values are derived from fossil fuel-fired power plants over 25 MW nameplate capacity.

To calculate total emissions from power generation in Wisconsin, Cadmus summed the reported emissions from all facilities by hour, resulting in five years of 8,760 observations of total hourly carbon emissions. This approach has a number of caveats:

- **It does not account for power imports.** Wisconsin's grid is connected with neighboring states through MISO. However, any carbon emissions associated with power produced outside of Wisconsin, including fossil fuel-fired generation, is excluded from this analysis due to the limitations of the CAMD data.

- **Missing data are treated as zeroes.** The CAMD data does not specify when observations for individual plants are missing. Therefore, when we sum to the state level, any missing observations of true non-zero emissions values are effectively treated as zeroes.
- **Wind, solar, hydroelectric, nuclear, and any generation under 25 MW is assumed to be carbon-free, and lifecycle carbon emissions are excluded.** CAMD data only include combustion emissions, excluding any other carbon emissions (including the emissions associated with operating or maintaining power generation, manufacturing generation equipment, etc.) Therefore, renewable and nuclear generation is implicitly assumed to be carbon-free.

An analysis addressing these shortcomings would require a significantly more complex research project that includes emissions factors for all generation sources and accounts for the carbon intensity of within-MISO energy flows. Despite these shortcomings, the following carbon analysis is a major first step in assessing the time-variant carbon intensity of Wisconsin's grid and the benefits of reducing peak demand toward achieving climate goals in Wisconsin.

Findings

Figure 7 compares Wisconsin's average hourly demand (on the right axis, shown in green) with average hourly carbon intensity of generation by month (on the left axis, shown in blue). Y-axis values are independent of one another; the two ranges were chosen to adequately visualize all data across both variables and should not be interpreted as representing a direct relationship between carbon intensity and electric demand.

In general, carbon intensity is highest in summer months (July, August, and September), which corresponds with high overall demand in these months. Carbon intensity is lower in spring and fall months, corresponding with lower overall demand in those months. However, note that carbon intensity during some morning and evening hours in January meets or exceeds the carbon intensity observed during summer months. Based on these findings, we conclude that the months previously identified for peak period season definitions in the demand analysis (December, January, and February in winter; June, July, August, and September in summer) also include the months with highest carbon intensity of generation, and that the month ranges selected previously do not require adjustment as a result of findings from the carbon intensity analysis.

Figure 7. Average Wisconsin Hourly Demand and Carbon Intensity of Generation by Month

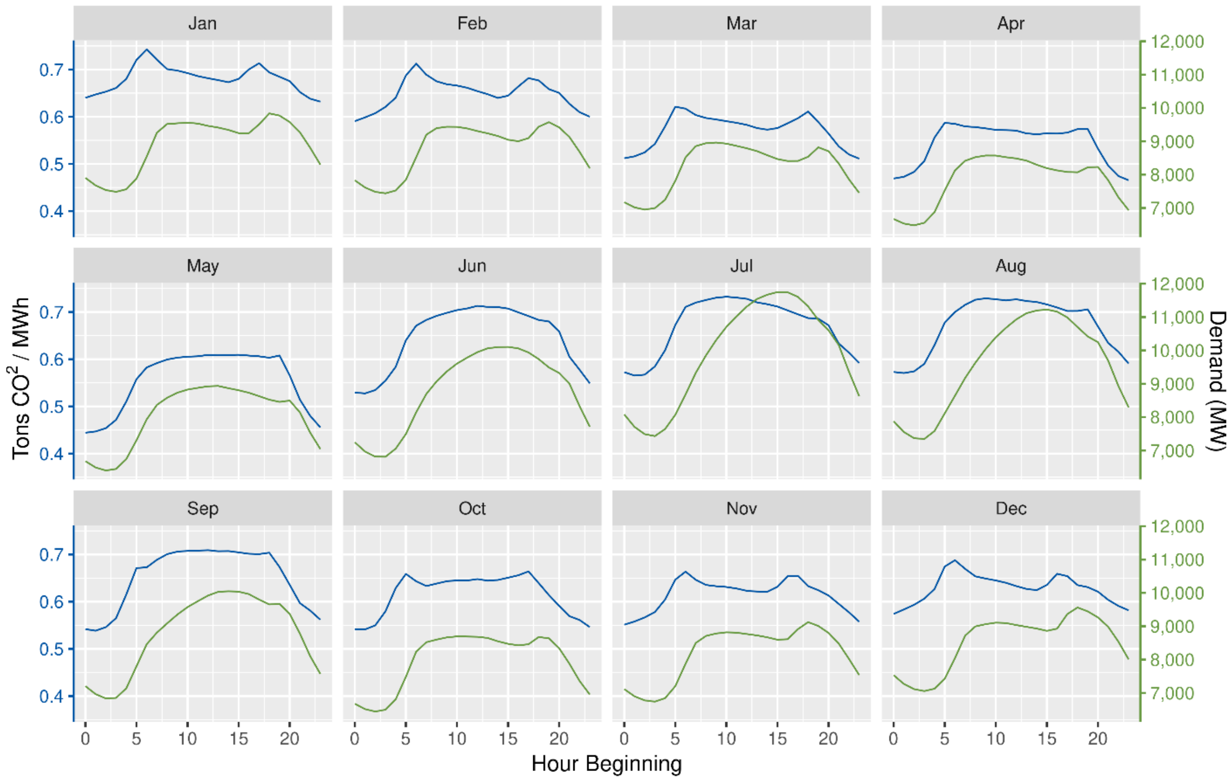
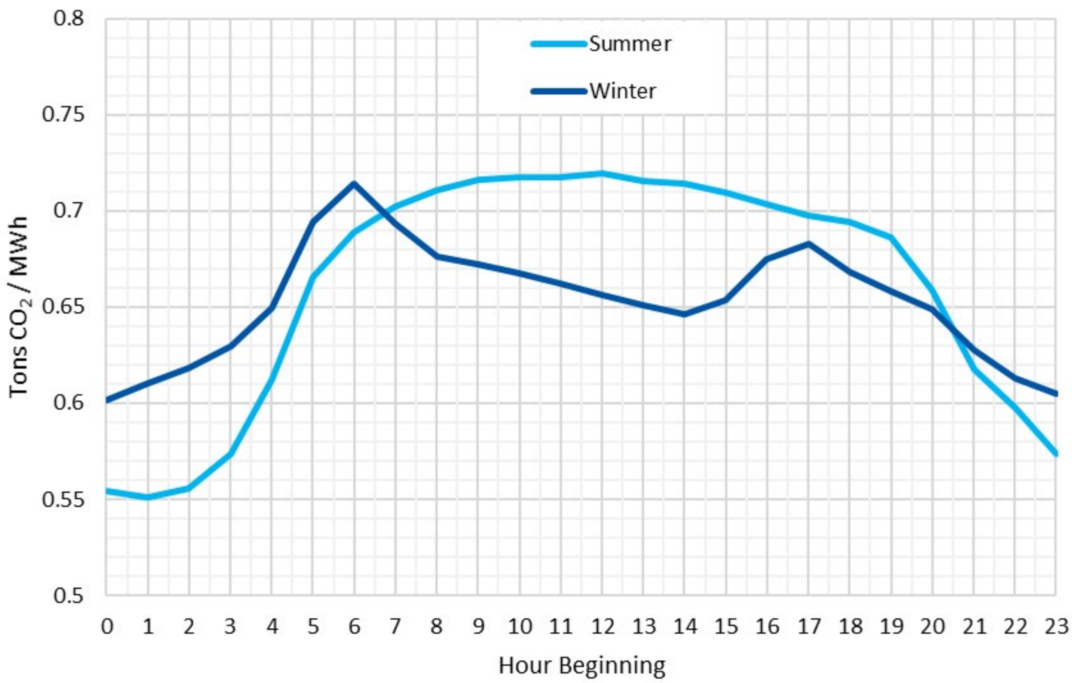


Figure 8 shows Wisconsin's average hourly CO_2 emissions per MWh by season (winter and summer, based on the months previously defined.) The two seasons show distinctly different curves. Winter carbon intensity is characterized by two daily peaks, first in the morning between 6:00 and 7:00 a.m. and then again in the evening from 5:00 to 6:00 p.m. Summer carbon intensity is much flatter throughout the day, peaking from noon to 1:00 p.m. and then slowly decreasing until 7:00 p.m., when it rapidly decreases. In both seasons, carbon intensity grows rapidly in the early morning (from 3:00 to 5:00 a.m. in the summer and from 4:00 to 5:00 a.m. in the winter.) Maximum daily carbon intensity is higher in summer than in winter, but summer nights have lower carbon intensity than winter nights. Overall, carbon intensity during the day is substantially higher in summer than in winter.

Figure 8. Wisconsin Average Hourly CO_2 Emissions per MWh by Season



When considering the implications of average hourly carbon emissions in determining new peak demand periods for Wisconsin, we note that we expect carbon intensity to be largely determined by demand, as fossil-fueled generators ramp throughout the day in anticipation of demand later in the day.

Figure 9 and Figure 10 examine this relationship for summer and winter periods. In each figure, the y-axis shows values that are normalized to the maximum of the seasonal average. A normalized value of '1' represents the seasonal maximum of either load or carbon intensity. In summer, carbon emissions begin rising about an hour before demand begins to rise, and then begin to fall slowly at 1:00 p.m., while demand continues to rise. The sharp drop in carbon emissions at 7:00 p.m. also precedes the corresponding drop in demand at 8:00 p.m. by one hour. Likewise, in winter carbon emissions peak between 6:00 and 7:00 a.m., which precedes the demand peak at 10:00 a.m.

These findings suggest that carbon intensity increases in anticipation of increases in demand, as well as overall demand. These findings support both flattening the demand curve (i.e., transferring demand to off-peak hours) and reducing overall demand in any hour (energy efficiency.) They also illustrate that Focus' new peak period definition need not target hours with high carbon intensity. Instead, Focus' peak period selection will reduce carbon emissions by targeting the hours with the highest demand, which will improve carbon emissions overall and their intensity in the hours preceding the peak period.

Figure 9. Summer Normalized Average Load & Carbon Emissions per MWh

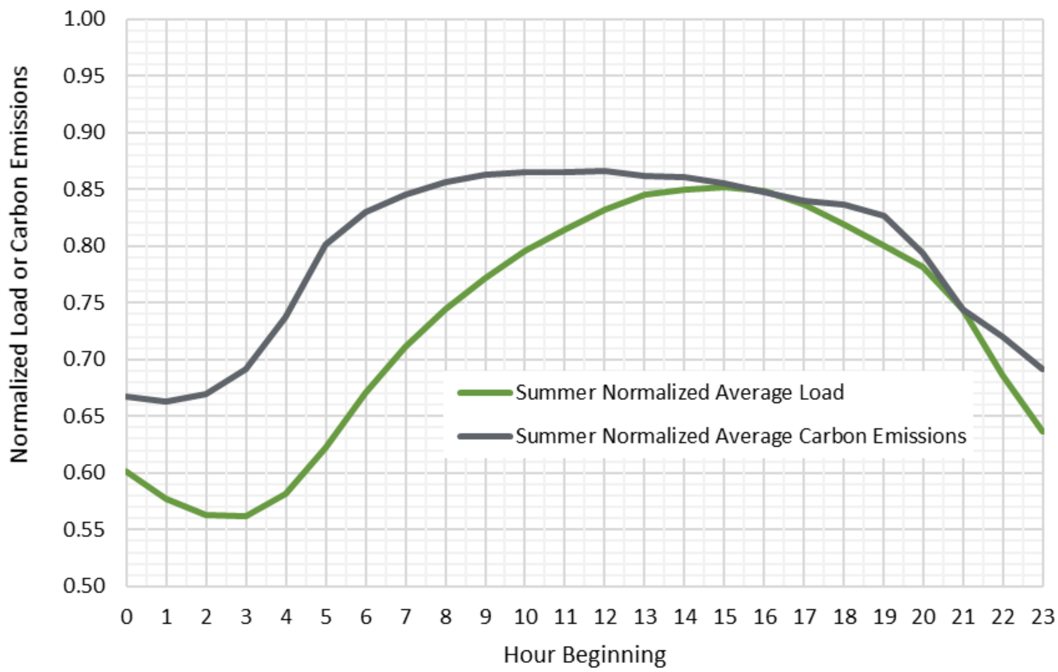
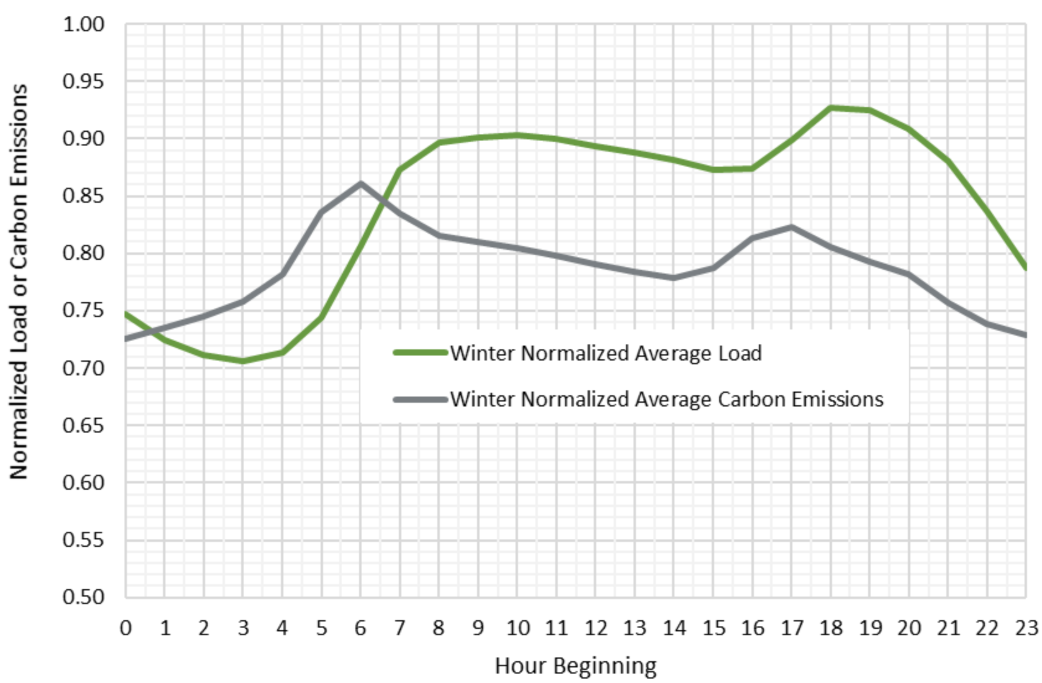


Figure 10. Winter Normalized Average Load & Carbon Emissions per MWh



Cost Analysis

The final component of Cadmus' peak period analysis addresses one of the primary motivations for reducing peak demand: cost savings to utilities and their customers through reduced exposure to high Locational Marginal Pricing (LMP). For this analysis, we collected hourly day-ahead LMP data from 2015 through 2019, and used these data to identify the months and hours with the highest average energy prices to assist in informing peak period recommendations.

Data Collection

Cadmus obtained hourly LMP data from MISO covering 2015 through 2019. These data were available separately for each MISO node, and for both day-ahead and real-time prices. We opted to use the day-ahead prices, instead of the real-time prices, for two reasons. First, the real-time prices display much more volatility, which could bias the results towards specific weather or grid stability events that occurred during the five-year period under analysis. Second, the goal of our analysis is to provide recommendations for seasonal peak periods which could be used in future Wisconsin TRMs to aid in planning and quantifying demand reductions associated with energy efficiency measures; these demand savings would result in reductions in the amount of day-ahead energy purchases that utilities plan for.

There are 510 nodes in the entire MISO system with hourly LMP data available. Cadmus filtered the raw data down to seven Wisconsin nodes covering nearly all the load in the state. See below for the list of chosen nodes and their associated utilities:

Node	Utility
ALTE.ALTE	Alliant (Wisconsin Power & Light)
DPC.DPC	Dairyland Power (18 member coops/municipal utilities)
MGE.MGE	Madison Gas and Electric
UPPC.INTEGRATD	Upper Penninsula Power Company
WEC.S	Wisconsin Electric Company
WEC.WPPI	WPPI Energy (51 member coops/municipal utilities)
WPS.WPSM	Wisconsin Public Service

Cadmus calculated final hourly LMP prices as averages across these seven nodes.

Findings

Figure 11 shows the average hourly day-ahead LMPs (2015-2019) by month. The results are similar to those previously shown in the carbon analysis, in that the summer months of July, August, and September, and January in the winter, have the highest price peaks (exceeding $40/MW on average in many hours of the day.) These figures also confirm that the months we selected for inclusion in our peak periods based upon average demand also correspond with the months that have the highest average prices.

Figure 11. Average Wisconsin Hourly Day-Ahead LMPs by Month

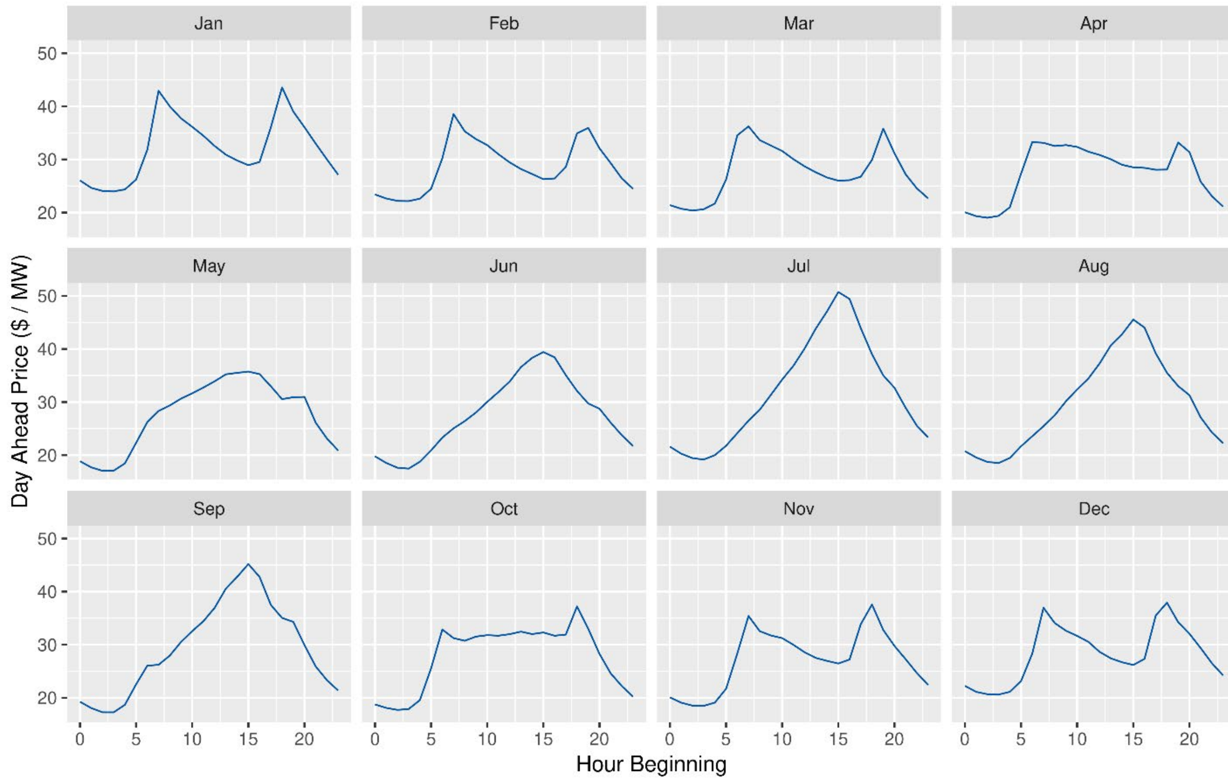


Figure 12 and Figure 13 compare normalized average hourly loads with normalized average day-ahead LMP prices. The normalization process is the same as previously described in the carbon analysis. In each figure, the y-axis shows values that are normalized to the maximum of the seasonal average. A normalized value of '1' represents the seasonal maximum of either load or LMP. Note in the figures that the normalized LMPs vary much more hour-by-hour than demand, which leads to spikier curves for LMP, in contrast to the smooth demand curves. Note also that the normalized average LMP prices only reach around 50% of the annual maximum on any given day, whereas normalized demand reaches over 80% of its seasonal average maximum. This reflects the greater relative variability of energy prices in comparison to demand.

In Summer, the average daily LMP peak is coincident with the average demand peak at 4:00 p.m. This is also true of the winter evening demand and LMP peaks at 6:00 p.m. On winter mornings, however, LMP peaks at 7:00 a.m. and then starts to fall, while demand continues to rise (plateauing on a peak between 8:00 a.m. and noon.) This finding suggests that a winter morning peak period based only on targeting demand may not reduce energy costs as much as a longer winter morning peak that includes the 7:00 a.m. hour.

Figure 12. Summer Normalized Average Load & LMPs

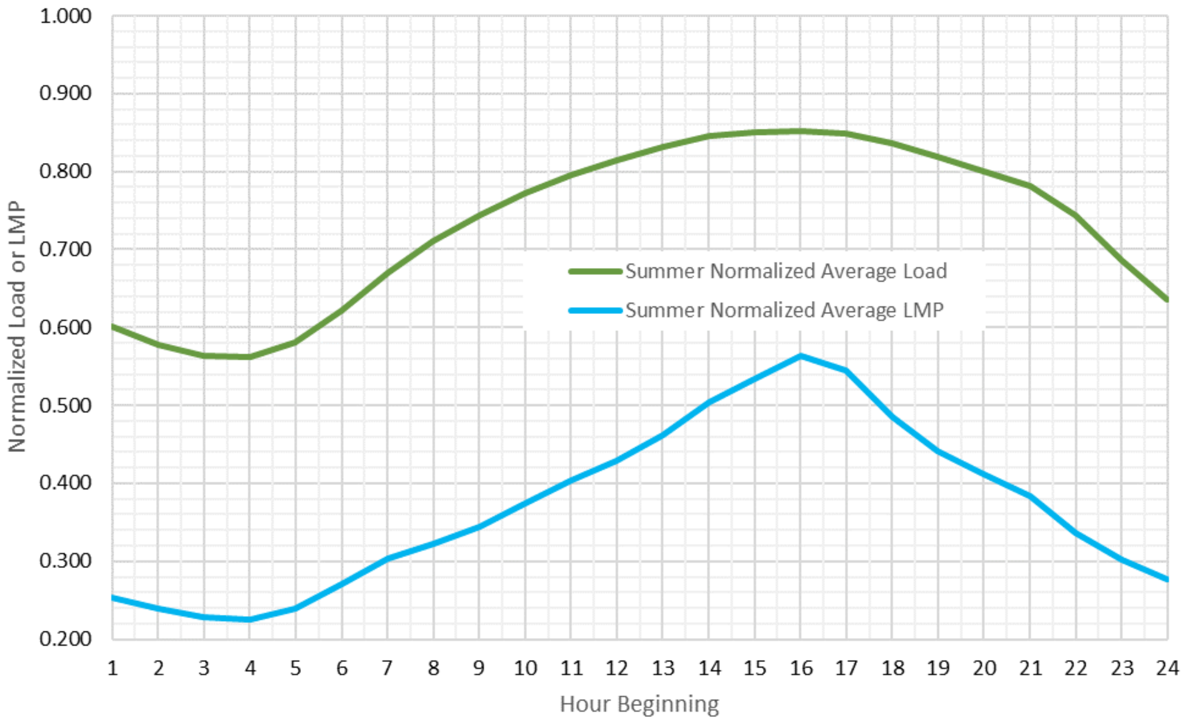
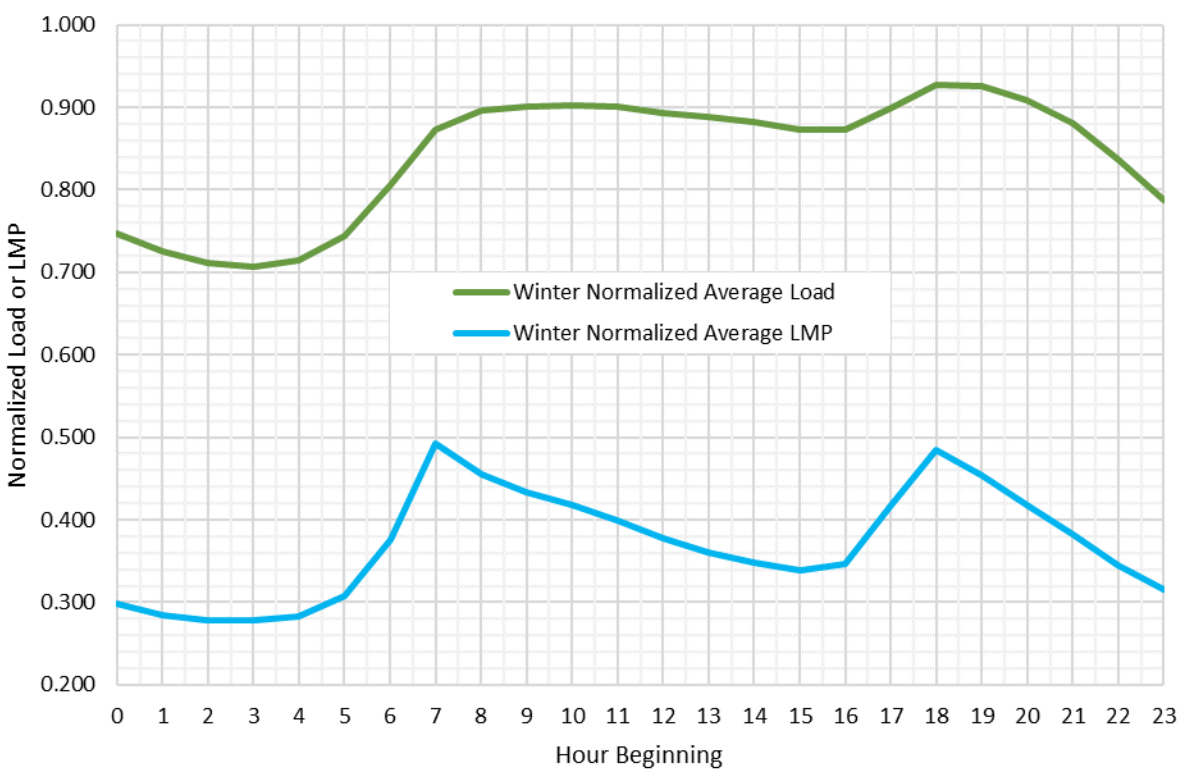
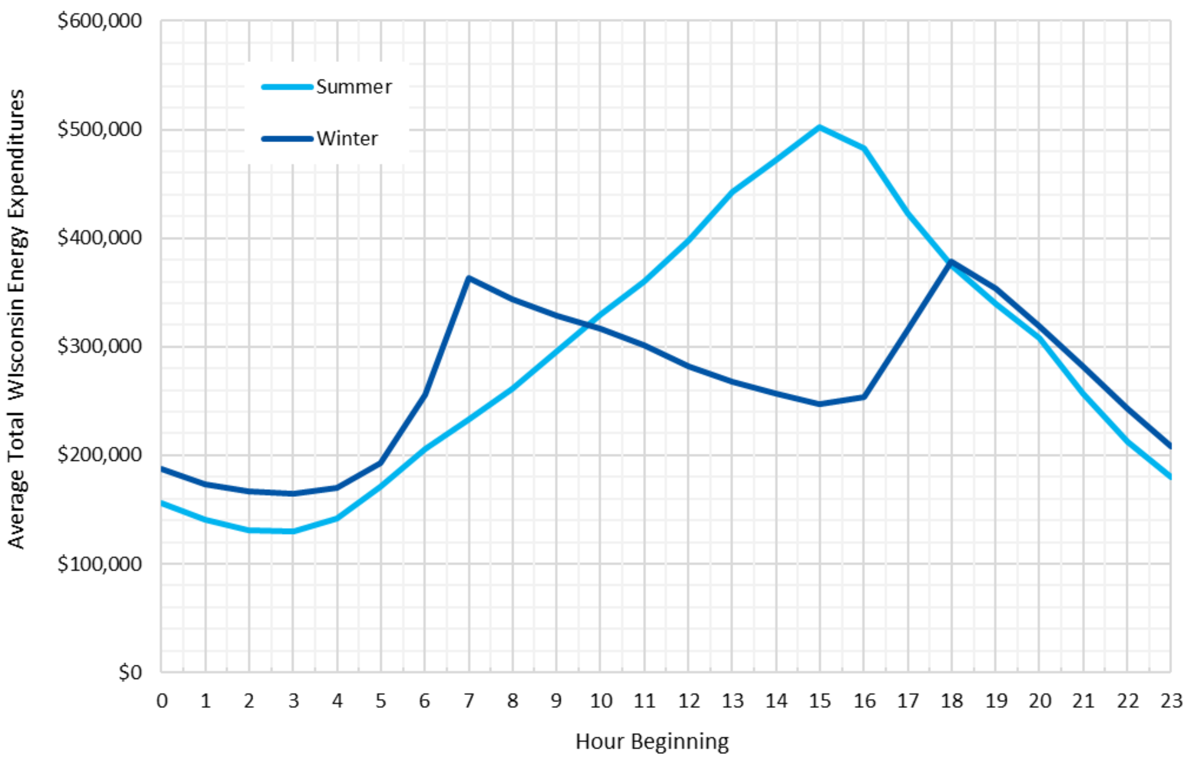


Figure 13. Winter Normalized Average Load & LMPs



In considering energy prices, we note that the analysis of day-ahead LMP may not tell the whole story: high energy prices in low-demand hours could be less costly overall to utilities than high-demand hours that coincide with lower LMPs. To investigate this possibility, we calculated total Wisconsin hourly electricity costs. Figure 14 shows the average total statewide hourly electricity costs by season. These costs are the product of the hourly total demand we identified previously and hourly day-ahead LMP prices. Overall average costs are higher in summer reflecting both higher demand in summer and higher average LMP prices. Though total costs are higher in summer due to midday demand for air conditioning, note that winter nights and mornings are associated with higher costs than those same hours in summer. This unexpected finding supports the development of winter morning and evening peak periods in Wisconsin.

Figure 14. Average Total Wisconsin Hourly Energy Costs by Season



Peak Period Capture Rates

Based upon findings from the price analysis, we revisited the peak period scenarios and capture rates previously investigated in our demand analysis, choosing a new, additional set of peak periods informed by total cost peaks as well as demand. We also revisited the demand analysis to identify additional scenarios (based upon demand) that we had omitted previously: 1:00 to 6:00 p.m. in Summer and 7:00 a.m. to noon on Winter mornings.

Figure 15 shows the average total statewide hourly electricity costs by season with highlighted areas showing the high-cost hours we targeted in identifying additional peak period scenarios. In Summer, we added new scenarios for 3:00 to 5:00 p.m., 2:00 to 5:00 p.m., and 1:00 to 5:00 p.m. For Winter mornings we added 7:00 to 8:00 a.m., 7:00 to 10:00 a.m., and 7:00 to 11:00 a.m. scenarios. We did not add any new Winter evening scenarios, as the previously-selected scenarios (6:00 to 8:00 p.m. and 5:00 to 9:00 p.m.) already aligned with the winter evening cost peak.

Figure 15. Identification of New Peak Period Scenarios, Based Upon Total Costs

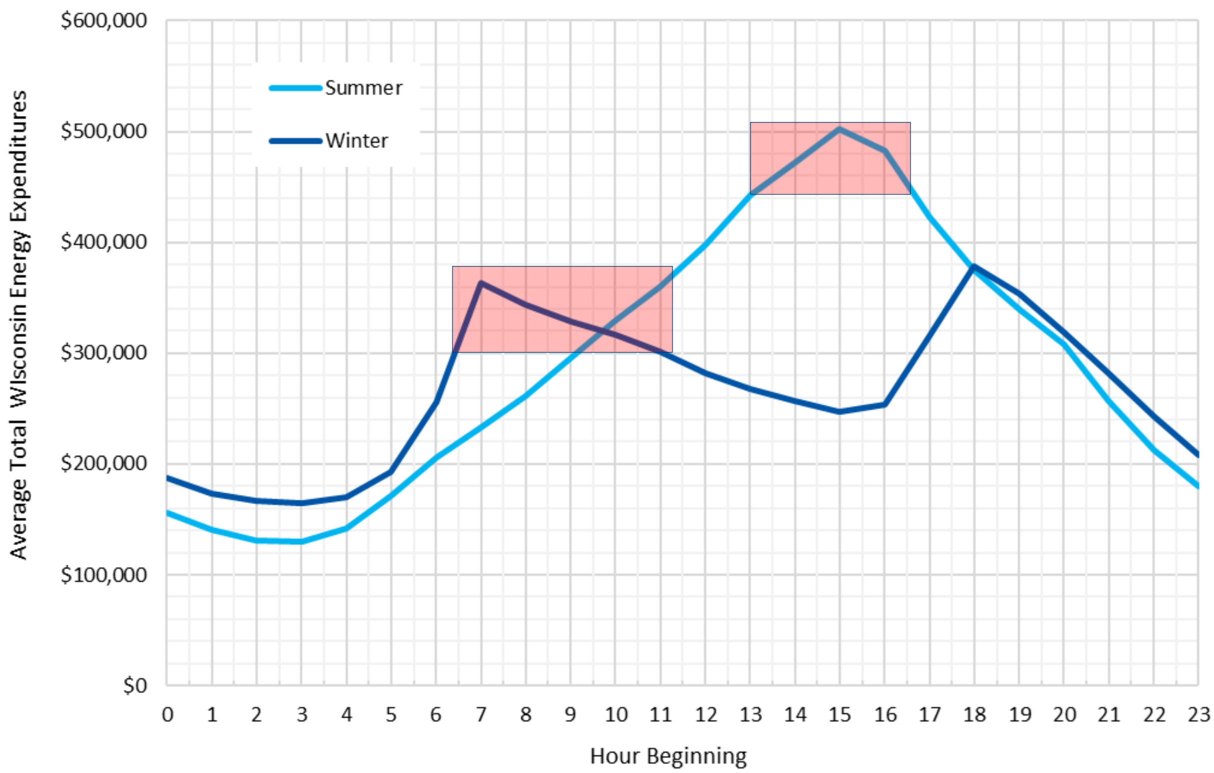


Table 8 shows the capture and off-peak rates associated with the new Summer scenarios (hour definitions i through m) alongside the previous scenarios (a through h) and the Wisconsin TRM's current definition (June through August, 1:00 to 4:00 p.m.)

Table 8. Demand and Price Analysis Summer Peak Capture Rates

Month Definition	Hour Definition	Capture Rate 10%	Capture Rate 5%	Capture Rate 1%	Capture Rate 0.1%	10% Off Peak Rate
Current WI TRM definition: June – August, 1:00 – 4:00 p.m.		28%	31%	29%	23%	63%
4: June - September	a: 4:00 - 6:00 p.m.	24%	29%	45%	86%	64%
	b: 3:00 - 7:00 p.m.	46%	56%	78%	100%	65%
	c: 2:00 - 8:00 p.m.	66%	77%	99%	100%	67%
	d: noon - 9:00 p.m.	88%	95%	100%	100%	70%
	e: 2:00 - 6:00 p.m.	**46%**	**56%**	**78%**	**100%**	**65%**
	f: noon - 8:00 p.m.	82%	91%	100%	100%	69%
	g: 1:00 - 7:00 p.m.	66%	78%	95%	100%	67%
	h: 1:00 - 8:00 p.m.	75%	86%	100%	100%	68%
	i: 2:00 to 5:00 p.m.	34%	42%	56%	78%	65%
	j: 3:00 to 5:00 p.m.	23%	29%	40%	70%	65%
	k: 1:00 to 5:00 p.m.	43%	51%	58%	78%	67%
	l: 1:00 to 6:00 p.m.	55%	65%	79%	100%	67%
	m: 1:00 to 4:00 p.m.	31%	36%	34%	23%	68%

First, we note that Wisconsin's current TRM peak period definition underperforms compared to almost all of the peak periods investigated, especially with regard to capturing the highest demand hours. This result is expected, as the current definition included only one of the annual critical peak hours in 2015-2019 (Table 1).

Using the demand analysis we recommended the June to September 2:00 to 6:00 p.m. (4e) peak period definition (highlighted in green) because it provides a good balance between the inclusion of hours above the 99^{th} percentile of summer demand, exclusion of hours with average demand less than 90% of the seasonal maximum average. Among the new Summer scenarios (hour definitions i through m) identified in the price analysis, the 1:00 to 6:00 p.m. (4l) peak period definition outperforms the others in capturing high demand hours. This definition adds one hour to the 2:00 to 6:00 p.m. window previously identified, and subsequently corresponds to a slightly higher error rate (67%) as it captures more hours that are not above the 90^{th} percentile of demand. Based on these findings, we continue to recommend adopting the 2:00 to 6:00 p.m. period, particularly if targeting demand is the main priority.

Table 9 shows the capture and off-peak rates associated with the new Winter Morning scenarios (hour definitions c through f) alongside the previous scenarios (a and b). As previously discussed, the two winter evening scenarios previously identified in the demand analysis also covered the winter evening cost peak (6:00 to 8:00 p.m.), so we did not add any new evening peaks. Our recommended peak period for winter evenings – 5:00 to 9:00 p.m. – is highlighted in green.

Table 9. Demand and Price Analysis Winter Peak Capture Rates

Period	Month Definition	Hour Definition	Capture Rate 10%	Capture Rate 5%	Capture Rate 1%	Capture Rate 0.1%	10% Off Peak Rate
Winter Evening	December - February	a: 6:00 - 8:00 p.m.	31%	41%	70%	100%	62%
		b: 5:00 - 9:00 p.m.	**48%**	**60%**	**90%**	**100%**	**70%**
Winter Morning	December - February	a: 9:00 - 11:00 a.m.	17%	14%	5%	0%	80%
		b: 8:00 a.m. - noon	**31%**	**27%**	**10%**	**0%**	**81%**
		c: 7:00 - 8:00 a.m.	2%	1%	0%	0%	94.3%
		d: 7:00 - 10:00 a.m.	19%	14%	4%	0%	84.7%
		e: 7:00 - 11:00 a.m.	26%	20%	9%	0%	84.3%
		f: 7:00 a.m. - noon	34%	27%	10%	0%	83.6%

As discussed previously, the winter morning energy price peak occurs at least an hour before the demand peak. For this reason, most of the new morning scenarios we tested (based upon targeting the morning price peak) perform more poorly in capturing high demand hours, which typically occur later in the morning. However, the 7:00 a.m. to noon period (f), which adds an hour to capture the price peak occurring between 7:00 and 8:00 a.m., captures slightly more 10% capture rate demand hours than the 8:00 a.m. to noon period (b) – albeit with a correspondingly higher error rate in capturing off-peak hours.

In recommending a winter morning peak period, prioritizing demand or energy prices lead to slightly different outcomes. Considering only a peak period that targets demand, the 8:00 a.m. to noon period (b) performs best.

Discussion

This study reveals that Wisconsin exhibits two peak demand periods during winter months which approach the magnitude of the summer peak period. As heat pump adoption grows in the state these winter peaks are more likely to grow than diminish. In particular, when coupled with pricing data, the cost of energy during winter demand peaks is nearly equivalent to the cost of energy during the summer peak. These findings suggest that Focus on Energy should consider adopting winter peak periods.

To prepare for the eventual inclusion of winter peaks, Cadmus recommends a stepwise adoption that would lay the groundwork for this transition with a modest amount of resource investment. This section describes some of the steps that might be taken to support this process.

Framework

To begin assessing winter peak savings, some initial logistics would have to be addressed within Focus on Energy's measure documentation, project tracking database, and evaluation process.

Technical Reference Manual

Wisconsin's Technical Reference Manual (TRM) document acts as a comprehensive resource for describing the energy and demand savings associated with each incentivized efficiency measure. To begin tracking winter peak demand savings, the TRM would have to be updated to include measure-specific coincidence factors for each peak period. This could be undertaken in small increments, beginning with a handful of measures that currently represent the majority of demand savings in the Focus on Energy portfolio. Some jurisdictions already have established winter peaks (e.g., Maryland) and coincidence factors listed in their TRMs could be adopted as a coarse first approximation.

More accurate summer and winter peak savings could be determined through the development of Wisconsin-specific end use load profiles. Constructing a database of hourly load profiles requires a significantly larger effort but also comes with added benefits. Identifying the timing of energy savings delivers a more accurate accounting of avoided emissions benefits (particularly when coupled with a changing generation mix) and is a necessary precursor to successful planning and evaluation of programs that are designed to save both energy and demand.

Tracking Database

The database used to track Focus program participation and project details (SPECTRUM) currently contains a single variable dedicated to demand savings. If Wisconsin adopts two winter peaks, SPECTRUM should be updated to enable tracking of three demand savings variables for each measure within the database.

Evaluation Processes

As a first step in Focus’ winter peak adoption, the evaluation team should add winter peak savings tracking to impact workbook calculations, reports, and the data dashboard. Later steps might involve reviewing/revising avoided emissions calculations and addressing multiple peak periods in future potential studies.

Cost Effectiveness Calculations

The avoided costs of energy saved during winter peak periods contribute to the overall benefits of the Focus on Energy program. If Wisconsin adopts winter peak periods, winter-specific avoided costs would have to be calculated to enable tracking of those benefits. These would be fairly straightforward to establish during annual avoided cost updates.

Planning

In addition to addressing tracking and evaluation logistics, adoption of a winter peak period may ultimately affect Focus on Energy program planning and goals, as the PSC may consider establishing different kW savings goals in different seasons. Winter peak period adoption might also warrant a review of current methods of estimating future program potential.

Conclusions and Recommendations

This section provides a summary of our recommendations and further considerations in selecting new peak periods for inclusion in future Wisconsin TRMs.

Summer Peak Period

The current Wisconsin TRM summer peak period is not well aligned with typical summer peak demand, and excludes four of the summer critical peak hours that occurred in the last five years. Our demand and price analyses tested thirteen alternate peak period definitions.

To best capture peak demand, we recommend a 2:00 to 6:00 p.m. period including June, July, August, and September weekdays. This peak period definition provides a good balance between the inclusion of hours above the 99th percentile of summer demand, and exclusion of hours with average demand less than 90% of the seasonal maximum average. The June to September months include most of the peak hours above the 90th percentile. Within these months, the 2:00-= to 6:00 p.m. peak period definition captures all of the of the peak hours above the 99.9th percentile.

Winter Peak Period

Currently, Wisconsin's average summer demand is substantially larger than its winter demand. However, if Wisconsin makes substantial progress towards heating electrification, we expect that its winter morning and evening peak demands will grow. Our analysis of day-ahead LMP prices also showed that average energy prices in January exceed $40/MW during the morning and evening, surpassing the average peak prices in June. The total costs of electricity purchased to meet demand in winter evenings and mornings exceeds average summer costs, demonstrating the value of reducing winter peak demand. Additionally, the winter storm that led to the 2021 Texas power crisis, which prompted large blackouts across Texas and periodic controlled power outages in MISO's South Region[14], show the need for demand reduction as a tool for grid stability and resiliency in future extreme weather events, or during winter periods when generators go offline for planned maintenance. For these reasons, we recommend that Focus on Energy include winter peak periods in the next quadrennium.

We recommend adoption of a 5:00 to 9:00 p.m. winter evening peak period covering December, January, and February weekdays. This period captures the winter evening demand and price peaks, which are coincident. To capture peak demand during winter mornings, we recommend an 8:00 a.m. to noon morning peak period during December, January, and February weekdays.

Carbon Emissions

In addition to analyzing historical demand and electricity prices, we also investigated hourly carbon intensity to determine how peak demand savings from energy efficiency measures can help Wisconsin reduce emissions associated with inefficient fossil fuel peaker plants. In general, Wisconsin's carbon intensity of electricity generation is highest in summer months (July, August, and September), which corresponds with high overall demand in these months. However, we also found that carbon intensity during some morning and evening hours in January meets or exceeds the carbon intensity observed during summer months, supporting the inclusion of a winter peak period in future quadrenniums.

[14] MISO Implemented Most Severe Steps in its Emergency Actions to Protect Grid Reliability

By comparing hourly average carbon intensity with demand, we found that carbon intensity increases in the hours preceding a demand peak, in anticipation of demand ramping later in the day. Overall carbon intensity also increases with the overall magnitude of demand. These findings support both flattening the demand curve (transferring end-use demand to off-peak hours) and reducing overall demand in any hour (energy efficiency.) They also show an important conclusion in selecting new peak periods, which is that Focus' new peak period need not specifically target hours with high carbon intensity. Instead, Focus' peak period can reduce carbon emissions by targeting the hours with the highest demand. This strategy will reduce carbon intensity in the hours preceding the peak period, because lower (and smoother) demand requires less rapid changes in power generation output.